Attachment 1.1 Non-Technical Summary

2022/2023

Integrated Resource Plan

CenterPoint Energy

Executive Summary (Non-Technical Summary)

I. Introduction

Southern Indiana Gas and Electric Company d/b/a CEI South a CenterPoint Energy Company's ("CEI South") 2022/2023 Integrated Resource Plan is the culmination of an extensive analysis of CEI South's optimal resources for ensuring the availability of electricity to its retail electric customers over a 20-year period at a low cost with consideration for future cost risks. CEI South has adhered to the requirements of the Indiana Utility Regulatory Commission ("IURC" or "Commission") and the guidance provided in the Commission's recent orders related to the preferred portfolio described in CEI South's previous 2019/2020 Integrated Resource Plan ("IRP") both in the preparation of this IRP and the planning process that necessarily preceded the report. The analysis and its conclusions explained in this IRP demonstrate that CEI South can most cost-effectively meet the electric demands of its retail customers by continuing to transition its generation fleet from primarily coal-based generation to a generation mix that is much more diverse. The analysis demonstrates that customers receive a better balance of affordability and reliability by investing in new generation resources and transitioning existing resources to new fuel sources compared to the on-going necessary investment and future cost risk of continuing to run its existing coal-fired generation facilities.

CEI South conducts the IRP process every three years and each IRP, necessarily, builds on the IRP and the generation resource investments that have come before. The preferred portfolio in CEI South's previous 2019/2020 IRP concluded a generation transition was needed, calling for replacement of the majority of CEI South's coal fleet by the end of 2023 with 700-1,000 MWs of solar, 300 MWs of wind, energy efficiency and two gas combustion turbines while retaining FB Culley 3 coal resource. CEI South has begun implementing this 2019/2020 IRP by filing several cases seeking approval to (1) purchase a BTA to own and operate a 191 MW solar project located on its system (the "Posey County Solar Project"), (2) purchase a BTA to own and operate a 130 MW solar project located in Pike County (the "Crosstrack Solar Project"), (3) purchase a BTA to own and operate a 200 MW wind project located in MISO ("Midcontinent Independent System Operator") zone 4 (the "Wind Project"), (4) signed purchase power agreements ("PPA") for 3 solar facilities totaling 430 MWs for the Warrick County Solar Project, the Knox County Solar Project, and the Vermillion County Solar project. (5) CEI South sought and received approval for two combustion gas turbines at A.B. Brown power plant, totaling 460 MWs. Each of these projects were consistent with the 2019/2020 IRP and, as noted below, this IRP affirms the direction taken by CEI South.

The Commission approved issuance of certificates of public convenience and necessity ("CPCNs") authorizing the construction of the Posey Solar Project and Cross Track Solar Projects and approved the solar PPAs. Government action and market forces have necessitated renegotiation of several of the renewable projects and delayed their in-service dates. CEI South has worked with the project developers to obtain revised pricing and in-service dates and has sought IURC approval of the changes for the Posey County, the Knox County, the Vermillion County, and the Warrick County Solar Projects. CEI South could have refused to work with the developers of these projects, but the poor economics would have resulted in the developers terminating their relationship with CEI South. Responses to CEI South's recent request for proposal demonstrated replacement projects would have been higher cost and brought later in-service dates. This is a significant concern for CEI South and its customers due to looming compliance deadlines for its existing generation resources. As of the date of this IRP, the IURC approved increased cost for the Knox County Solar Project, and the OUCC did not oppose the cost increases for the Warrick County Solar Project or the Vermillion County Solar Project. The Posey Solar Project and the Wind Project are awaiting approval by the IURC.

CEI South began its 2022/2023 IRP process in early 2022 to explore new and existing supply-side and demand side resource options to reliably serve CEI South customers over the next 20 years. The Company's exploration included significant input and dialogue with stakeholders. While starting with 2019/2020 IRP framework as a basis for the 2022/2023 analysis, CEI South has enhanced its process and analysis in several ways. These enhancements include, but are not limited to the following:

- increased stakeholder engagement in the issuance of an All-Source RFP to provide current market project pricing to be utilized in IRP modeling and potential projects to pursue, particularly for renewable resources such as wind, solar, and battery storage;
- increased participation and collaboration from stakeholders using tech-to-tech calls and associated file sharing throughout the process for timely feedback on inputs and resource evaluation criteria;
- an encompassing analysis of wholesale market dynamics that accounts for MISO developments and market trends, including MISO's new seasonal construct, which includes four seasons;
- at stakeholder request, CEI South engaged 1898 & Co. to utilize a new sophisticated IRP modeling tool, Encompass, which provided several benefits (increased transparency for stakeholders, more efficient modeling runs and maintaining the ability to produce probabilistic modeling); and
- a robust risk analysis, which encompasses a broad consideration of risks and an exploration of resource performance over a wide range of potential futures with additional sensitivity analyses.

Based on this planning process and detailed analysis, CEI South has selected a preferred portfolio plan that continues to diversify the resource mix for its generation portfolio. This portfolio includes the addition of significant solar and wind energy resources in the near to midterm, the conversion of FB Culley 3 from coal to natural gas by 2027, and continued investment in energy efficiency and demand response resources. The conversion of Culley Unit 3 allows CEI South to maintain this critical capacity resource, protecting customers from a volatile MISO capacity market and considerably lowering CO_2 emissions. FB Culley 3 will be available for peak periods, enabling CEI South to maintain constant electric supply during potentially extended periods of low output from renewable energy sources. The converted unit will include firm gas supply and allow CEI South to continue to utilize existing equipment and interconnection to the MISO system. Additionally, CEI South has placed an emphasis on exploring demand response options to provide a cost effective capacity resource for our customers. The company is in discussions with a demand response ("DR") aggregator for commercial and industrial DR and plans to request a pilot in its upcoming rate case to explore time based rates. Indicative DR amounts were included for IRP planning purposes. CEI South's preferred portfolio is projected to save customers nearly $80 million over the next 20 years compared to continuing with this last existing coal unit operated by CEI South. This builds on savings identified in the last IRP. Additionally, the preferred portfolio reduces carbon dioxide stack emissions by approximately 88% by 2030 and 95% by 2035 when compared to projected 2023 levels. This fosters environmental stewardship and sustainability, while meeting customer expectations for clean energy that is reliable and affordable.

CEI South's preferred resource plan reduces risk through continued diversification, the cost to serve load over the next 20 years and provides flexibility to evaluate and respond to future needs through subsequent IRPs. The preferred portfolio has several advantages, including: 1) Converts CEI South's last remaining coal unit that it operates to natural gas by 2027. This saves customers money and dramatically lowers CO_2 output in the near term. FB Culley 3 can also provide resilient, dispatchable power to CEI South's system during long-duration weather events. Reliable, dispatchable power is very important as coal plants that have provided capacity in the past continue to retire in MISO Zone 6. 2) Energy supplied by this portfolio is generated primarily through renewable solar and wind projects by 2030, which can take advantage of Investment Tax Credits ("ITC") and the Production Tax Credits ("PTC"). ITCs and PTCs reduce portfolio costs and leverage current tax-advantaged assets. 3) The portfolio provides flexibility under a wide range of potential future legislative, regulatory, and market conditions. The preferred portfolio also performed well under CO_2, methane constraints, and other related regulations. Like the CTs identified in the 2019/2020 IRP, the preferred portfolio is financially supported by a converted coal unit that will predominantly run during peak load conditions. This benefit provides a financial hedge against periodic instances of high market energy and MISO's volatile capacity market, while also providing reactive reserves and system reliability in times of extended renewable generation droughts, i.e., cloud cover and low wind. 4) It reasonably balances energy sales and purchases, ready to adapt to market shifts. 5) It includes new wind, solar, and demand response capacity when it is economic to the portfolio. 6) Finally, it is timely. The conversion of F.B. Culley 3 is projected to take no more than 6 months and can be completed by 2027.

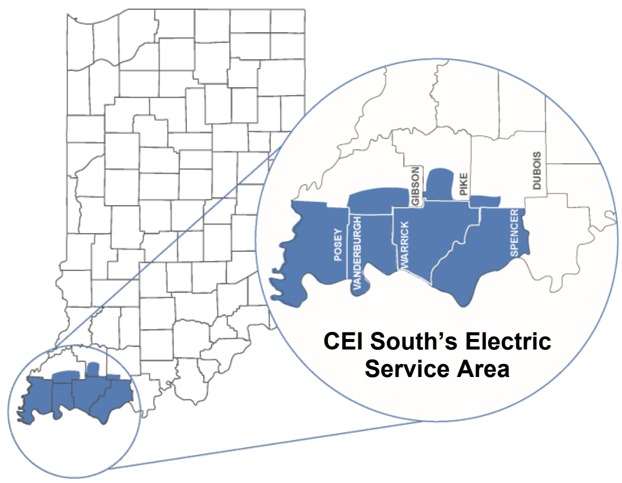
The resource options selected in this plan provide a bridge to the future. For example, the gas conversion allows battery storage technology to become more competitive in price and develop longer duration storage capabilities. Further, should there be a need for new baseload generation to accommodate a large load addition, one or both of the new CTs could be converted to a combined cycle gas turbine, a highly efficient energy resource.

The preferred portfolio also provides several off-ramps (future transitional inflection points) should they be needed. 1) CEI South plans to discontinue joint operations of Warrick 4 (“W4”) at the end of 2023 but continues to speak with Alcoa about a possible extension into 2025. This option could shield CEI South customers from costly purchases in a tight capacity market. As CEI South has worked through the generation transition plan, solar project Commercial Operation Dates (“COD”) have shifted, and there is still a need for capacity to complete phase one of the transition. Additionally, beyond delayed solar projects, time may still be needed for permitting contingency and construction of new combustion turbines, currently expected to be in service in MISO’s 2025/2026 planning period. 2) While Culley 3 is not scheduled to be retired within the timeframe of this analysis, including thermal dispatchable generation in this portfolio provides CEI South flexibility to evaluate this option in future IRPs. 3) CEI South will work to secure attractive renewable projects from the recent All-Source RFP and will likely require future RFPs to secure 200 MWs of additional wind and 200 MWs of additional solar resources by 2030. Issuing a future RFP provides two main benefits. It will provide the most up-to-date pricing for these renewables projects and attract more renewable options to select from, as some offered proposals are no longer available. Second, it provides CEI South additional time to better understand how the Inflation Reduction Act (“IRA”) effects the renewables markets, potentially unlocking more projects. Demand for wind and solar projects in Indiana is particularly high, which could lead to scarcity of projects if more potential developments do not enter the MISO queue.

The following preferred portfolio summary includes the process to identify the portfolio as well as an explanation of the planning process, all while focusing on CEI South's operations.

II. CenterPoint Energy Overview

CEI South provides energy delivery services to more than 150,000 electric customers located near Evansville in Southwestern Indiana. In 2022, approximately 43% of electric sales were made to large (primarily industrial) customers, 31% were made to residential customers and 26% were made to small commercial customers.



The table below shows CEI South generating units. Note that CEI South also offers customers energy efficiency programs to help lower customer energy usage and bills.

Unit	Installed Capacity ICAP (MW)	Primary Fuel	Unit in Service	Unit Retirement Date	Unit Age	Coal Unit Environmental Controls[1]
A.B. Brown 1	245	Coal	1979	2023	44	Yes
A.B. Brown 2	240	Coal	1986	2023	37	Yes
F.B. Culley 2	90	Coal	1966	2025	57	Yes
F.B. Culley 3	270	Coal	1973	N/A	50	Yes
Warrick 4	150	Coal	1970	2023[2]	53	Yes
A.B. Brown 3	80	Gas	1991	N/A	31	

[1] All coal units are controlled for Sulfur Dioxide ("SO_2"), Nitrogen Oxide ("NO_X"), Particulate Matter (dust), and Mercury. All coal units are controlled for Sulfur Trioxide ("SO_3") and Sulfuric Acid ("$H2S0_4$") except F.B. Culley 2.

[2] Joint operations agreement expires 12/31/23

Unit	Installed Capacity ICAP (MW)	Primary Fuel	Unit in Service	Unit Retirement Date	Unit Age	Coal Unit Environmental Controls[1]
A.B. Brown 4	80	Gas	2002	N/A	21	
A.B. Brown 5	245	Gas	2025	N/A	N/A	
A.B. Brown 6	245	Gas	2025	N/A	N/A	
Blackfoot[3]	3	Landfill Gas	2009	N/A	14	
Fowler Ridge	50	Wind PPA	2010	N/A	13	
Benton County	30	Wind PPA	2007	N/A	16	
Oak Hill[4]	2	Solar	2018	N/A	5	
Volkman Rd[5]	2	Solar	2018	N/A	5	
Troy	50	Solar	2021	N/A	2	
Rustic Hills II Solar[6]	100	Solar	2025	N/A	N/A	
Posey Solar	191	Solar	2025	N/A	N/A	
Wheatland Solar[7]	150	Solar	2024	N/A	N/A	
Vermillion Rise Solar[8]	185	Solar	2025	N/A	N/A	
Crosstrack Solar	130	Solar	2025	N/A	N/A	
Future Wind	200	Wind	2025	N/A	N/A	

III. Integrated Resource Plan

Every three years CEI South submits an IRP to the IURC as required by IURC rules. The IRP describes the analysis process used to evaluate the best mix of generation and energy efficiency resources (resource portfolio) to meet customers' needs for reliable, affordable, environmentally sustainable power over the next 20 years. The IRP can be thought of as a compass setting the direction for future generation and energy efficiency options. Future analysis, filings and subsequent approvals from the IURC are needed to implement selection of new resources.

CEI South utilized direct feedback on analysis methodology, analysis inputs, and evaluation criteria from stakeholders, including but not limited to CEI South residential, commercial and industrial customers, regulators, elected officials, customer advocacy groups and environmental advocacy groups. CEI South continues to place an emphasis

[3] The Blackfoot landfill gas generators are connected at the distribution level.
[4] Oak Hill Solar is connected at the distribution level.
[5] Volkman Rd. Solar is connected at the distribution level.
[6] Warrick County Solar Project
[7] Knox County Solar Project
[8] Vermillion County Solar Project

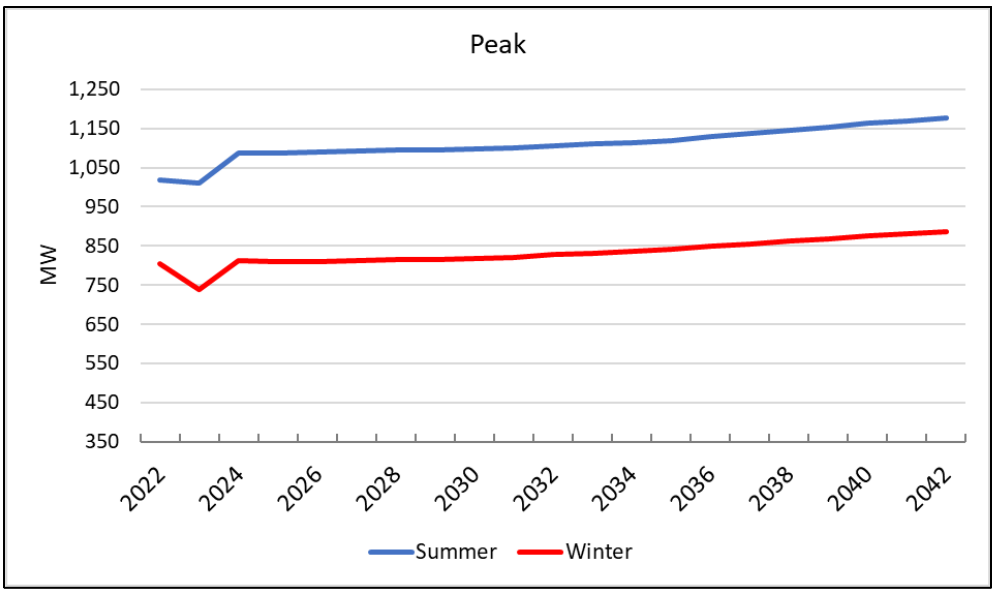
on reliability, affordability, resiliency, stability, risk, resource diversity, and environmental sustainability. The IRP process has become increasingly complex in nature as MISO implements updated resource accreditation methodologies to maintain reliability of the system that includes increased levels of renewable resources, battery energy storage, and natural gas resources to replace existing coal resources.

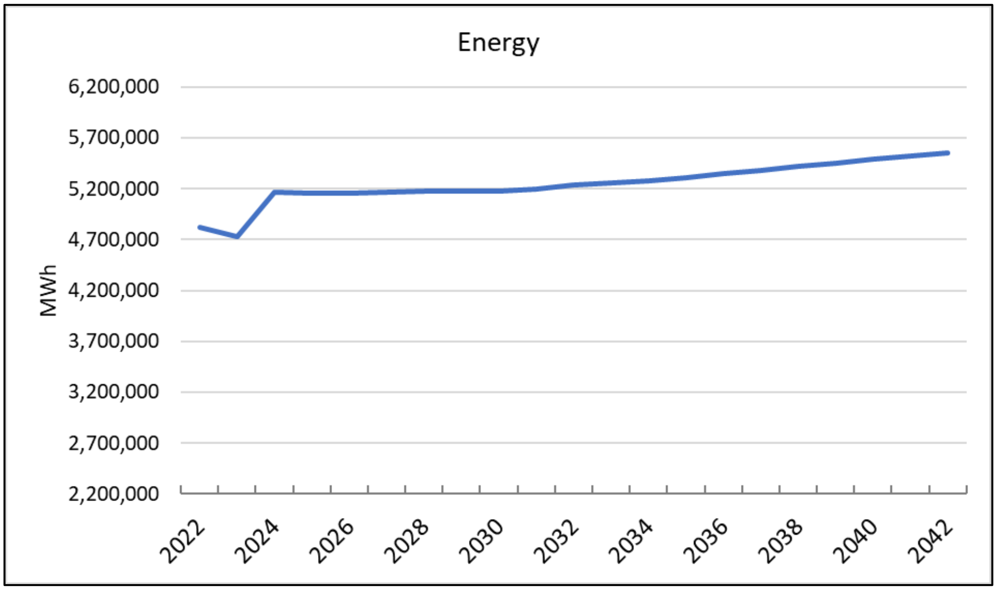
A. Customer Energy Needs

The IRP begins by evaluating customers' need for electricity over the 20-year planning horizon. CEI South worked with Itron, Inc., a leader in the energy forecasting industry, to develop a forecast of customer energy and demand requirements. Demand is the amount of power being consumed by customers at a given point in time, while energy is the amount of power being consumed over time. Energy is typically measured in Megawatt hours ("MWh") and demand is typically measured in Megawatts ("MW"). Both are important considerations in the IRP. While CEI South purchases some power from the market, CEI South is required to have enough generation and energy efficiency resources available to meet expected customers' seasonal peak demand plus additional reserve resources to meet MISO's Planning Reserve Margin Requirement ("PRMR") for reliability. Reserve resources are necessary to minimize the chance of rolling black outs; moreover, as a MISO member, CEI South must comply with MISO's evolving rules to maintain reliability.

Historically, IRPs have focused on meeting customer demand in the summer, which is typically when reserve margins are at a minimum. As the regional resource mix changes towards intermittent (variable) renewable generation, it is important to ensure resources are available to meet this demand seasonally in all hours of the year, particularly in the times of greatest need (summer and winter). MISO functions as the regional transmission operator for 15 Midwestern and Southern states, including Indiana (also parts of Canada). In recognition of MISO's ongoing evaluation of how changes in the future resource mix impact seasonal reliability, CEI South ensured its preferred portfolio would have adequate reserve margins for meeting demand in all four seasons, consistent with MISO's recently approved seasonal construct beginning in the 2023/2024 planning year on June 1, 2023. Later in this document it is further explained how MISO continues evaluating measures to help ensure year-round reliability, beyond the seasonal construct.

CEI South utilizes sophisticated models to help determine energy needs for residential, commercial and large customers. These models include projections for the major drivers of energy consumption, including but not limited to, the economy, appliance efficiency trends, population growth, price of electricity, weather, specific changes in existing large customer demand and customer adoption of solar and electric vehicles. Overall, customer energy and summer peak demand, excluding energy efficiency, are expected to grow by 0.7% per year. Winter peak demand grows at a slightly slower pace of 0.5%.





B. Resource Options

The next step in an IRP is identifying resource options to satisfy customers' anticipated need. Many resources were evaluated to meet customer energy needs over the next 20 years. CEI South considered both new and existing resource options. 1898 & Co., a well-respected engineering firm, conducted an All-Source RFP which generated 142 unique proposals to provide energy and capacity from a wide range of technologies, including: solar, solar + short duration battery storage, standalone short duration battery storage, demand response, wind, gas, nuclear, and coal. These project bids provided up-to-date, market-based information to inform the analysis and provide actionable projects to pursue to meet customer needs in the near to midterm. Additionally, CEI South utilized other information sources for long term costs and operating characteristics for these resources and others over the entire

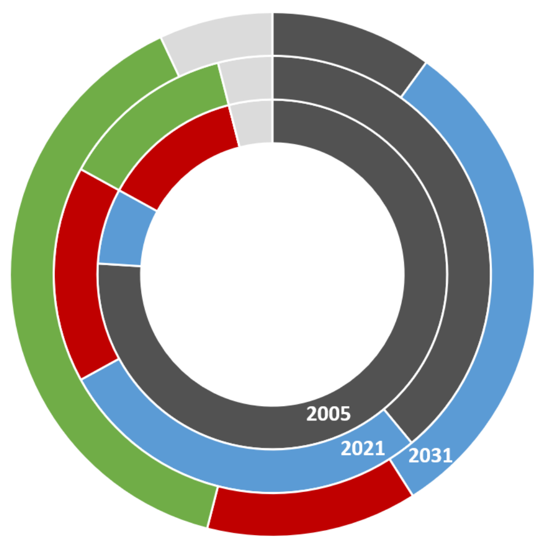
- Battery Storage
- Coal
- Energy Efficiency/ Demand Response
- Hydro Electric
- Natural Gas
- Nuclear
- Wind and Solar

20-year period. Other options include continuation of existing F.B. Culley 3 coal unit, conversion of F.B. Culley 2 and/or 3 coal units to natural gas, various other natural gas resources, conversion of AB Brown combustion turbines to a Combined Cycle Gas Turbine, hydro, landfill gas, and long-duration batteries[9]. Every IRP is a snapshot in time producing a direction based on the best information known at the time. It is helpful to provide some background into significant issues that help shape the IRP analysis, including but not limited to: the passage of the IRA, recent volatile gas prices, high inflation, projected high penetration of intermittent renewable resources, recent increased costs for renewables projects due to demand / supply chain issues, the future of coal resources with more restrictive air regulations, new technologies, and rapid changes in the MISO market to adapt and help ensure reliability.

i. Industry Transition

Within the MISO footprint, energy from gas generation has increased from less than 10% of total electric generation, used primarily to meet the needs during peak demand conditions in 2005, to approximately 28% of total generation in 2021[10]. Meanwhile, the cost of renewable energy has declined dramatically over this time period due to improvements in technology and helped by

MISO Energy Mix Transition from 2005 to 2021 to 2031 (Based on MISO RRA)



[9] Not commercially viable at this time
[10] MISO 2021 State of the Market Report, Potomac Economics, June 2022, page 6 https://cdn.misoenergy.org/2021%20State%20of%20the%20Market%20Report625295.pdf

government incentives in the forms of the PTC and the ITC for renewable energy resources such as wind and solar, both of which have been extended and expanded by the IRA.

The move toward renewable and gas energy has come at the expense of coal generation, which has been rapidly retiring for several reasons. Coal plants have not been able to consistently compete on short term marginal price with renewable and gas energy. Operationally, the move toward intermittent renewable energy requires coal plants to more frequently cycle on and off. These plants were not designed to operate in this manner. The result is increased maintenance costs and more frequent outages. Additionally, older, inefficient coal plants are being retired to avoid spending significant dollars on necessary upgrades to achieve compliance with Environmental Protection Agency ("EPA") regulations. Two recent rule changes are further examples of the continued pressure on coal. EPA finalized revisions to the Cross-State Air Pollution Rule and the Good Neighbor Rule which require further reductions in emissions of NOx during the Ozone Season. EPA has also recently proposed revisions to the Mercury Air Toxics rule that could further ratchet down particulates for F.B. Culley by 2026-2027and on January 6, 2023 EPA proposed a new rulemaking to reduce the National Ambient Air Quality Standard PM2.5 standard and review state's attainment designations. It can be challenging for F.B. Culley to maintain compliance under current regulations and will be more difficult to continue operating the unit on coal in 2027 and beyond. Finally, public and investor pressure, coupled with future cost risk associated with the objective of decreasing carbon emissions, has driven unit retirements. Based on these and other major factors, according to MISO's Regional Resource Assessment, they project wind and solar to contribute up to 42% of the energy in 2031[11]. Some large nuclear plants remain but have also found it challenging to compete on cost.

[11] MISO 2022 Regional Resource Assessment, November 2022, page 6 https://cdn.misoenergy.org/2022%20Regional%20Resource%20Assessment%20Report627163.pdf

ii. Changing Market Rules to Help Ensure Reliability

MISO recognizes these major changes in the way energy is being produced. Traditionally, baseload coal plants produced energy at a constant level around the clock, while peaking gas plants were available to come online as needed to meet peak demand. Gradual increases and decreases in energy demand throughout the day and seasonally were easily managed with these traditional resources. As described above, the energy landscape is continuing its rapid change with increased adoption of more intermittent renewable generation which is available when the sun is shining, or the wind is blowing. This creates much more variability by hour in energy production. Some periods will have over production (more energy produced than is needed at the time) and other periods will have low to no renewable energy production, requiring dispatchable resources to meet real time demand for power. MISO has recognized the region's energy landscape continues to evolve toward a complex, less predictable future. Some of the challenges MISO faces are resources that are primarily weather dependent, less predictable weather, less predictable resource outages, and increasing electric load. To maintain reliability with a changing resource portfolio and the risks MISO faces there is an increased importance of ensuring there are adequate attributes available from the fleet such as ramp capability, long duration energy at high output, and fuel assurance. To ensure reliability is maintained with the changing resource portfolio, MISO implemented a seasonal resource adequacy construct for the 2023/2024 planning year that focuses on meeting system demand in all hours as opposed to planning for meeting the summer peak demand. As part of the seasonal construct thermal resource accreditation has shifted from an Equivalent Forced Outage Rate Demand ("$EFOR_d$") approach to one that accredits resources based on historical availability during tight operating hours. Accreditation for renewable resources has also seen changes with MISO signaling it will continue to revise the accreditation approach for renewables for upcoming planning years. MISO continues to study how this transition will affect the electrical grid and what is needed to maintain reliable service, as renewables penetrations reach 30-50%. Possible ramifications include challenges to the ability to maintain acceptable voltage and thermal limits on the grid.

CEI South has accounted for these changes by incorporating the seasonal construct and accreditation approach into the Encompass model and validating that portfolios in this analysis provide sufficient resources to meets its MISO obligations[12] in all four seasons with limited capacity purchases. Additionally, CEI South analyzed the thermal limits of equipment along with the voltage and reactive power needs of the system for various portfolio options and identified mitigations for each option.

iii. Battery Storage and Transmission Resources

Increasingly, utilities are considering the opportunity to add battery storage to resource portfolios to help provide the availability, flexibility and visibility to support the move to more reliance on intermittent renewable resources. Lithium-ion ("L-ion") batteries have seen significant cost declines over the last several years as the technology begins to mature and as the auto industry creates economies of scale by increasing production to meet the anticipated demand for electric vehicles. However, L-ion batteries continue to evolve. Lithium-ion batteries relying on iron-based cathodes are emerging and are expected to provide nearly 50% of the global demand by 2027. This move is occurring because of the relative abundance and sourcing of iron compared to Cobalt. Large scale batteries for utility applications have begun to emerge around the country, particularly where incentives are available to lower the cost of this emerging technology or for special applications that improve the economics. This technology will continue to evolve over the next decade as competing alternatives are put into operation and evaluated.

There are many applications for this resource, from shifting the use of renewable generation from time of generation to the time of need, to grid support for maintaining

[12] Some portfolios have a heavy reliance on the market for energy.

the reliability of the transmission system. CEI South has installed a 1 MW battery designed to capture energy from an adjacent solar project. This test project has provided information regarding the ability to store energy for use during the evening hours to meet customer energy demand. Along with the benefits provided by this technology, there are some limitations to keep in mind as utility scale battery storage is still evolving. Commercially feasible batteries remain short duration, typically four hours. There are some longer-duration batteries that show promise, such as iron air, but these are still very expensive and not proven on a utility-scale. Future IRPs will continue to monitor for when these technologies become commercially viable. Additionally, safety standards are being developed and fire departments are being trained for the fire risk posed by L-ion batteries. Other chemistries are being developed to account for this issue but are not commercially imminent. Moreover, batteries today are a net energy draw on the system. L-ion can produce about 85-95 percent of the energy that is stored in them. Part of this loss is due to the need to be well ventilated, cool and dry, which takes energy. Batteries are promising and have their place in current and future energy infrastructure, but they do not yet replace the need for other forms of dispatchable generation during extended periods without sun and wind. Recent MISO changes in rules and mechanisms are geared towards meeting the worst week in each season. There is a need for multi-day storage to provide similar benefits to dispatchable generation. Other issues to be followed are how the penetration will affect accreditation based on Effective Load Carrying Capability ("ELCC"), which is expected to go down over time. CEI South conducted a sensitivity analysis to evaluate the cost impact of decreasing accreditation to 75% from 95%. The sensitivity demonstrated that cost to portfolios that rely on batteries would go up as accreditation goes down. Additionally, availability of batteries may not be 95% as modeled within this IRP. Information from California's experience suggests performance of batteries could be much lower. CEI South's All-Source RFP included bids for stand-alone batteries and batteries connected to solar resources and will continue to track developments in this space.

C. Uncertainty/Risk

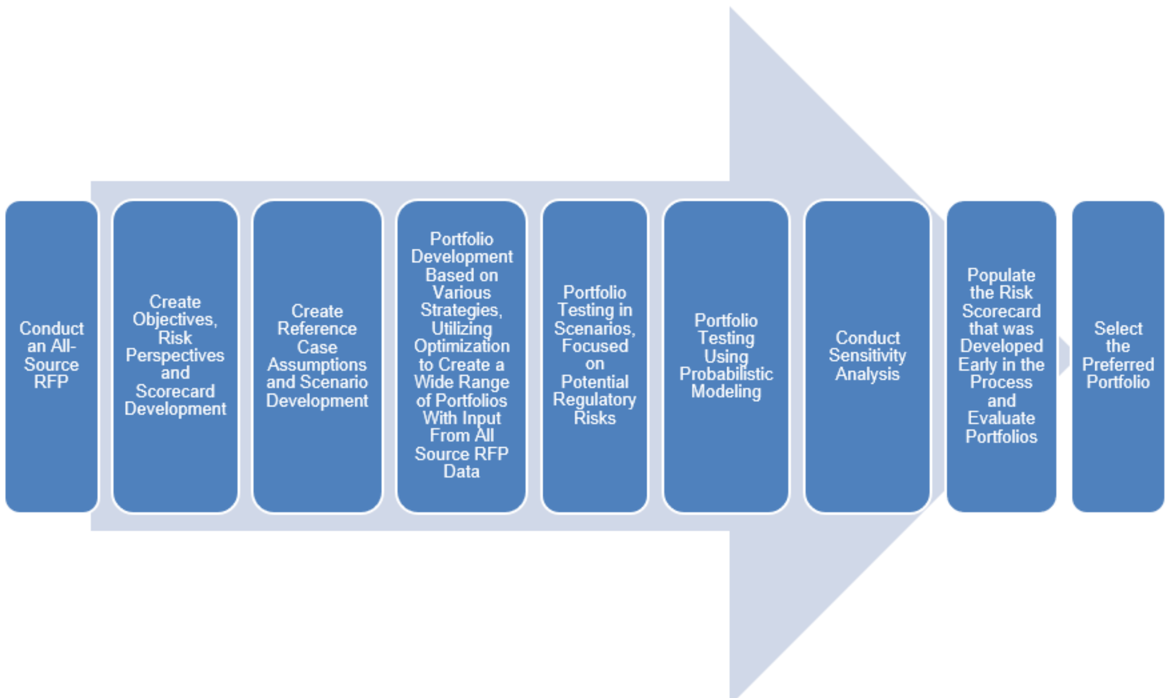
The future is far from certain. Uncertainty creates a risk that a generation portfolio that is reasonable under an anticipated future fails to perform as expected if the future turns out differently. CEI South's IRP analysis was developed to identify the best resource mix of generation and energy efficiency to serve customer energy needs over a wide range of possible future states. CEI South worked with 1898 & Co. to perform two sets of modeling to contribute to the risk analyses, one exposing a defined set of portfolios to a limited number of scenarios and another that exposed the same portfolios to 200 scenarios (stochastic or probabilistic risk assessment). To help better understand the wide range of possibilities for wholesale market dynamics, regulations, technological breakthroughs and shifts in the economy, complex models were utilized with varying assumptions for major inputs (commodity price forecasts, energy/demand forecasts, market power prices, etc.) to develop and test portfolios with diverse resource mixes. Additionally, the risk analysis included sensitivities and qualitative judgement.

IV. Analysis

CEI South's analysis included a step-by-step process to identify the preferred portfolio. The graphic below summarizes the major steps which included the following:

1. Conduct an All-Source RFP to better understand resource cost and availability.
2. Work with stakeholders to develop a scorecard as a tool in the full risk analysis to help highlight several tradeoffs among various portfolios of resources.
3. Work with stakeholders to develop a wide range of future states, called scenarios, to be used for testing of portfolios (mixes of various resource combinations to serve customer power and energy need).
4. Work with stakeholders to develop a wide range of portfolios for testing and evaluation within scenarios, sensitivity analysis and probabilistic analysis. Each of these analyses involves complex modeling.
5. Conduct a risk analysis, including deterministic and probabilistic modeling with sensitivity analysis.

6. Utilize the quantitative scorecard measures and judgment to select the preferred portfolio (the best mix of resources to reliably and affordably serve customer energy needs while minimizing known risks and maintaining flexibility).



V. Stakeholder Process

CEI South continued to improve stakeholder engagement with a series of technical meetings with any stakeholder group willing to sign a Non-Disclosure Agreement ("NDA") and participate with in ongoing tech-to-tech conversations about critical assumptions related to the analysis, including all significant modeling assumptions. The process was reevaluated based on early feedback with stakeholders about what has worked well with other utilities throughout the state. CEI South also reviewed comments in the Director's report on CEI South's last IRP and ongoing Contemporary Issues meetings hosted by the IURC. Careful consideration was taken to ensure that the time spent was mutually beneficial to all parties involved.

As in the last IRP, each of the first three stakeholder meetings began with stakeholder feedback. CEI South would review requests/comments since the last stakeholder meeting and provide feedback. Suggestions were taken, and in instances where suggestions were not acted upon, CEI South made a point to further discuss and explain why not. Notes for each meeting were included in question and answer format, summarizing the conversations. Additionally, feedback was received, and questions were answered via e-mail (irp@centerpointenergy.com) and with one off phone calls/meetings in between each public stakeholder meeting by request, in addition to tech-to-tech meetings mentioned above.

While maintaining the virtual option to participate, CEI South thought it was important to offer face to face meetings post the COVID-19 situation of recent years. All stakeholder meetings were held at CEI South in Evansville, Indiana, with a virtual option for those that could not travel to Southern Indiana or did not wish to participate in person. Dates and topics covered are listed below:

August 18, 2022	October 11, 2022	December 13, 2022	April 26, 2023
• 2022/2023 IRP Process • Objectives and Measures • Encompass Software • All-Source RFP • MISO Update • Environmental Update • Draft Reference Case Market Inputs & Scenarios • Load Forecast Methodology • DSM MPS/ Modeling Inputs • Resource Options	• All-Source RFP Results and Final Modeling Inputs • Draft Resource Inputs • Final Load Forecast • Scenario Modeling Inputs • Portfolio Development • Probabilistic Modeling Approach and Assumptions • Draft Reference Case Modeling Results	• Draft Scenario Optimization Results • Draft Portfolios • Final Scorecard and Risk Analysis • Final Resource Inputs*	• Final Reference Case and Scenario Modeling Results • Probabilistic Modeling Results • Risk Analysis Results • Preview the Preferred Portfolio

*Provided final draft modeling file on December 20, 2022 to stakeholders that signed an NDA as part of the tech-to-tech group. Final deterministic modeling files were provided on March 7, 2023, and final stochastic files were provided on April 21, 2023.

Based on this stakeholder engagement, CEI South made fundamental changes to the analysis in real time to address concerns and strengthen the plan. IRP inputs and several of the evaluation measures used to help determine the preferred portfolio were updated through this process. CEI South held meetings with interested stakeholders willing to sign an NDA ahead of and in between public stakeholder meetings. This along with providing modeling inputs along the way helped to allow for a more productive dialogue throughout the process. CEI South appreciates the time and attention provided by each group that participated in this process. CEI South utilized stakeholder information to create boundary conditions that were wide enough to produce plausible future conditions that would favor opposing resource portfolios. CEI South worked closely with stakeholders to consider relevant risks to be included within the scorecard, adding a metric that highlights risk from exposure to energy generated by coal and gas, and adopting a metric that measures total CO_2 equivalent tons emitted into the atmosphere over the full planning year. Finally, multiple adjustments were made to modeling inputs and assumptions based on direct stakeholder feedback. The table below shows key stakeholder requests made during the process and CEI South's response.

Request	Response
Allow All-Source RFP respondents to update their proposals to account for the IRA	RFP respondents were given the opportunity to update their bids (updated results were incorporated into the IRP)
Use cumulative CO_2 equivalent emissions as a measure of environmental sustainability	Cumulative CO_2 equivalent (stack emissions) were added to the scorecard along with CO_2 intensity
Add a fuel cost risk measure and objective to the scorecard	Cost Risk metric was included in the scorecard, including both fuel risk and 95% percentile cost risk

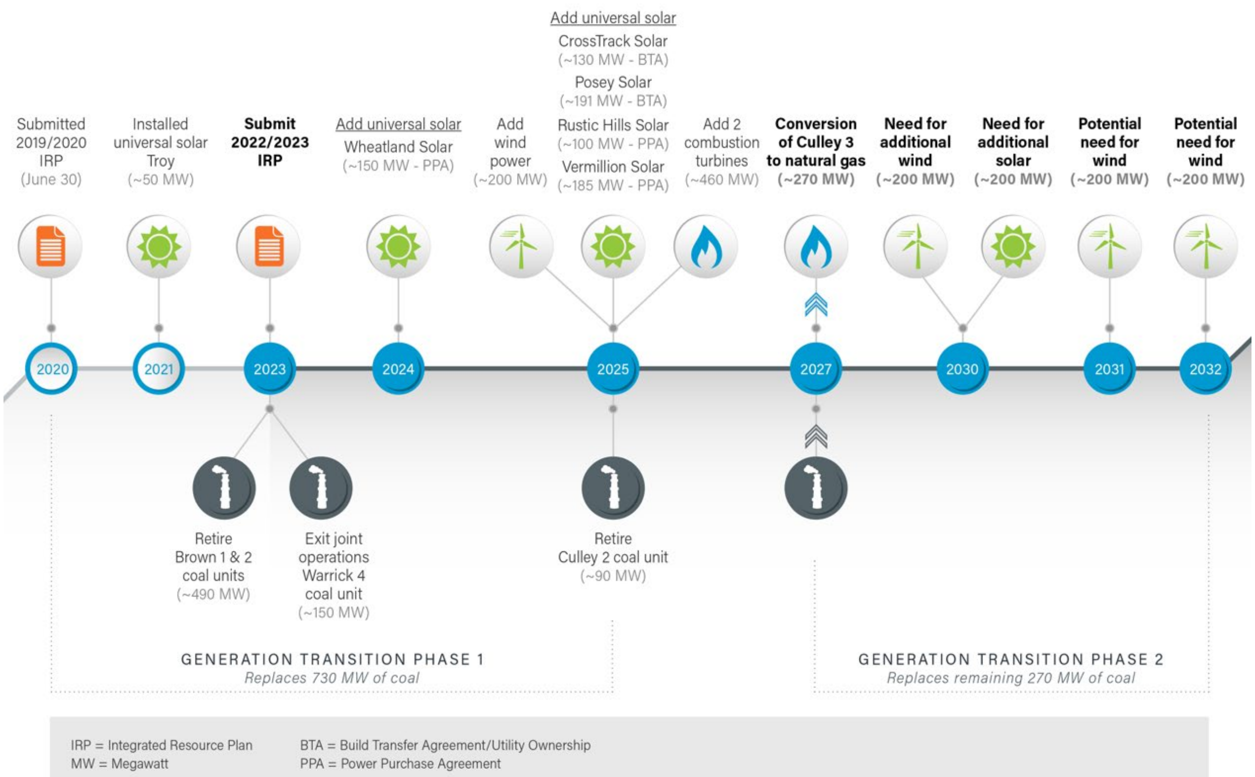
Request	Response
Incorporate more than proposed 10-20 MWs of Industrial DR	CEI South included 25 MWs of industrial DR as a resource. Currently, CEI South does not have any industrial DR registered with MISO. CEI South is engaged in conversations with a demand response aggregator to capture the potential of C&I demand response to further diversify our resource mix
CenterPoint should include demand response using the same methodology as AES. Implement residential rate programs (critical peak pricing, TOU, etc.) soon	CenterPoint has adopted the AES methodology and DR is aligned with peers to incorporate indicative TOU pilots. CEI South is planning to evaluate a TOU rate in the future through a pilot
In the summer of 2022, the reference case forecasts for coal and natural gas prices showed a decline in the near term and do not reflect current pricing	Gas and coal price forecasts were updated as new forecasts became available in late fall of 2022
Coal prices should be higher than the reference case in the high regulatory scenario (not the same as the reference case)	CEI South found it plausible that coal prices could be higher in a high regulatory scenario and updated the price path to be higher than reference case in the high regulatory scenario
Revise the wind profiles being used in the model to differentiate between the output of northern Indiana and southern Indiana wind	The output profiles for wind resources were updated (increased) to better align with the information received from wind resources in the All-Source RFP

Request	Response
Explore alternative retirement dates for Culley 3	Culley 3 will be evaluated in scenarios with a potential retirement date of 2029 (pulled forward from 2030). Also included an alternative that converts F.B. Culley 3 to natural gas by 2027
Update modeling to reflect ITC storage year one	CEI South modeled the ITC benefit for storage in year one
Include full monetization of ITC for hydro resources	Included
Request for continued on-going dialogue following the December public stakeholder meeting	Held a tech-to-tech meeting on February 28, 2023 to provide updated modeling files, additional input files, and portfolios for consideration in the risk analysis to stakeholders for review and comment
Include site -specific assumptions for the energy community bonus for PTC and ITC associated with the IRA	CEI South ran various resource capital costs and tax credit qualification sensitivities to determine the impact of these changes on future resource decisions
Evaluate a portfolio with hydroelectric	Hydroelectric was not selected as a least cost resource within modeling. Several portfolios with hydro were evaluated, but they were higher cost and not included in the risk analysis
Capital costs should not be varied stochastically	An alternate process was used for capital and CO_2
Adjust the scorecard to include near and long-term energy purchases/sales	Adjusted

Meeting materials for each meeting can be found on www.centerpointenergy.com/irp and in Technical Appendix Attachment 3.1 Stakeholder Materials.

VI. The Preferred Portfolio

The Preferred Portfolio is the second evolution to the generation transition plan to move away from coal to a more sustainable portfolio of resources. The recommendation is to convert the remaining 270 MWs of coal generation to natural gas and to provide demand response resources for low-cost capacity and continue to add clean, renewable wind and solar resources by 2030, while maintaining energy efficiency programs at similar levels. Beyond 2030, 400 MWs of additional wind is called for.

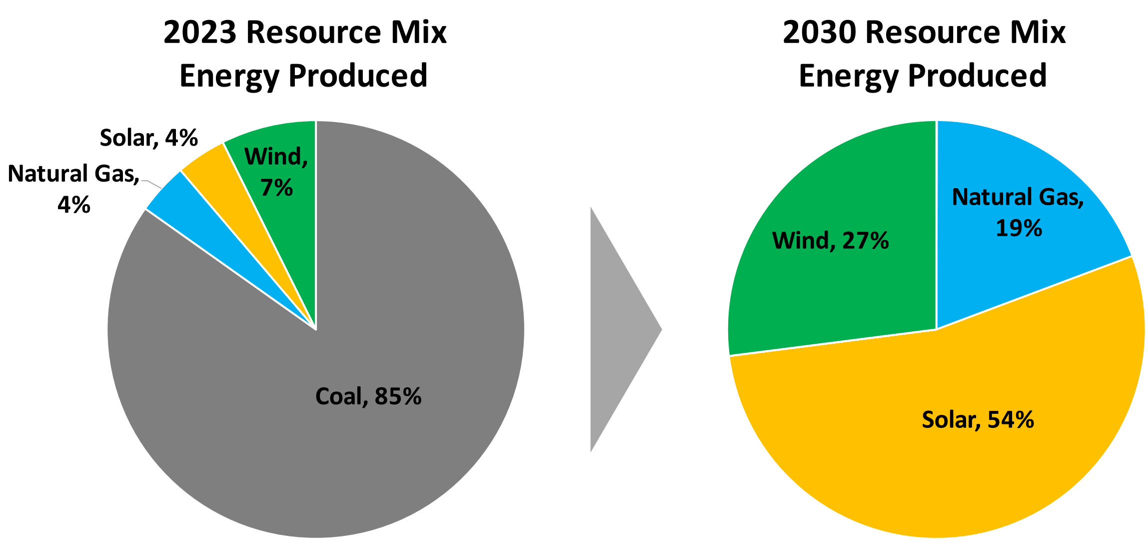


This preferred portfolio:

- Eliminates dependence on coal-fired generation in a prompt timeframe yet provides the flexibility to adapt to changes in technology in the future.
- Maintains reliability and allows customers to enjoy the benefits of renewable energy, while ensuring continued reliable service as CEI South continues to move toward higher levels of intermittent renewable energy in the future. Dispatchable generation with firm gas service at F.B. Culley will allow this resource to be available to meet peak conditions during long duration weather events, providing resiliency.
- Saves customers nearly $80 million over the next 20 years when compared to continued operation of F.B. Culley with coal and avoids $170 million of cost risk over this time period. Eliminates risk of additional cost to comply with currently proposed final environmental rules that become applicable to Culley 3 in 2027 and potential new regulations as EPA continues to focus on environmental concerns associated with coal-fired generation.
- Reduces CO_2 equivalent emissions, which includes methane, by nearly 95% over the next 20 years. Direct carbon emissions are reduced 98% from 2005 levels by 2035. The portfolio prevents over 9 million tons of CO_2 from entering the atmosphere as compared to continuing to run F.B. Culley 3 with coal.
- Includes a diverse mix of resources (solar, wind and energy efficiency, supported by fast-start gas, peaking gas generation, and demand response), mitigates the impacts of extended periods of limited renewable generation and protects against overreliance on the market for energy and capacity.
- Maintains future flexibility with several off ramps to accommodate a rapidly evolving industry, includes a multi-year build out of resources on several sites and maintains the option to replace Culley 3 in the future when appropriate based on continual evaluation of available technology and changing conditions.
- Provides the flexibility to adapt to future environmental regulations or upward shifts in fuel prices relative to Reference Case assumptions. The preferred portfolio

performed consistently well across a wide range of potential future environmental regulations, including CO_2, methane and fracking.

- Maintains tax base in Warrick County, which is particularly important to the local school system in that county.
- Allows for continued use of existing plant assets, helping to avoid potential future stranded assets.
- Continues CEI South's energy efficiency programs with near term energy savings of 1.1% of eligible sales and further long-term energy savings opportunities identified over the next 20 years. CEI South is committed to energy efficiency to help customers save money on their energy bills and will continue to evaluate this option in future IRPs.
- Explores new options to help manage loads in the future with the potential for new demand response resources, working with an aggregator to better partner with commercial and industrial customers to tap additional potential and include a pilot to evaluate the potential of time-based rates, which could provide new resources to help manage loads in the future.



VII. Next Steps

The preferred portfolio calls for CEI South to make additional changes to its generation fleet. Some of these changes require action in the near term. First, CEI South will seek approval from the IURC to convert F.B. Culley 3 from coal to natural gas. Second, the IRP calls for continuation of energy efficiency. CEI South filed a one year continuation of the 2021-2023 plan for 2024 and will file a 2025-2027 plan in early 2024 with the IURC, consistent with the IRP. Third, CEI South plans to issue a new RFP in 2024 to pursue an additional 200 MWs of wind generation and 200 MWs of solar generation to be in service by 2030. CEI South continues to evaluate the potential to work with industrial customers who would like on-site solar generation. CEI South will evaluate including a portion of the new solar for this purpose. Given the long lead times for these projects and the need for energy that they produce, CEI South will begin pursuing these renewable projects ahead of the next IRP. These filings will be consistent with the preferred portfolio. However, the assumptions included in any IRP can change over time, causing possible changes to resource planning. Changes in commodities, regulations, political policies, customer need and other assumptions could warrant deviations from the preferred plan.

CEI South's plan must be flexible, as several items are not certain at this time.

- The timing of exiting joint operations of the Warrick 4 coal plant could change. The plant is jointly owned with Alcoa and as such, CEI South continues to talk to Alcoa about its plans.
- Competition for renewable projects is steep, with multiple, ongoing RFP processes in the state of Indiana and the passage of the IRA. CEI South will continue to actively seek cost competitive projects for the benefit of our customers, consistent with the preferred portfolio.
- Finally, MISO continues to evaluate the accreditation of resources. CEI South will continue to follow developments.

Attachment 1.2 CEI South Technology Assessment Summary Table

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	1x F Class Frame SCGT - Natural Gas		1x G/H Class Frame SCGT - Natural Gas		1x J-Class Frame SCGT - Natural Gas	
BASE PLANT DESCRIPTION	First Unit	Next Unit	First Unit	Next Unit	First Unit	Next Unit
Number of Gas Turbines/Engines/Units	1	1	1	1	1	1
Representative Class Gas Turbine	GE 7F.05		GE 7HA.01		GE 7HA.02	
Capacity Factor, %	Peaking (10%)		Peaking (10%)		Peaking (10%)	
Startup Time to Base Load, min (Note 1)	11		10		10	
Startup Time to MECL, min (Note 2)	8		8		8	
Cold Startup Time to SCR Compliance, min (Note 2)	45		45		45	
Maximum Ramp Rate, MW/min (Online)	40		55		60	
Book Life, Years	35		35		35	
Equivalent Planned Outage Rate, % (Note 3)	5.5%		5.5%		5.5%	
Equivalent Forced Outage Rate, % (Note 3)	0.7%		0.7%		0.7%	
Equivalent Availability Factor, % (Note 3)	93.8%		93.8%		93.8%	
Assumed Land Use, Acres	30	15	30	15	30	15
Fuel Design	Dual Fuel (Natural Gas and Fuel Oil)		Dual Fuel (Natural Gas and Fuel Oil)		Dual Fuel (Natural Gas and Fuel Oil)	
Heat Rejection	Fin Fan Heat Exchanger		Fin Fan Heat Exchanger		Fin Fan Heat Exchanger	
NO_x Control	Dry Low Nox / Nominal 9ppm Nox		Dry Low NOx / SCR		Dry Low NOx / SCR	
CO Control	Good Combustion Practice		Good Combustion Practice		Good Combustion Practice	
Particulate Control	Good Combustion Practice		Good Combustion Practice		Good Combustion Practice	
Technology Rating	Mature		Mature		Mature	
Permitting & Construction Schedule (Years from FNTP)	3		3		3	
ESTIMATED PERFORMANCE (All BASED ON NATURAL GAS OPERATION) (Note 4)						
Nominal Base Load Performance @59° F (ISO Conditions)						
Net Plant Output, kW	228,900	228,900	286,600	286,600	371,700	371,700
Net Plant Heat Rate, Btu/kWh (HHV)	10,010	10,010	9,260	9,260	9,240	9,240
Heat Input, MMBtu/h (HHV)	2,290	2,290	2,650	2,650	3,430	3,430
Nominal Min Load @ 59° F (ISO Conditions)						
Net Plant Output, kW	98,600	98,600	86,000	86,000	111,500	111,500
Net Plant Heat Rate, Btu/kWh (HHV)	13,330	13,330	13,580	13,580	13,630	13,630
Heat Input, MMBtu/h (HHV)	1,310	1,310	1,170	1,170	1,520	1,520
Base Load Performance @ 20° F (Winter Design)						
Net Plant Output, kW	238,400	238,400	295,300	295,300	383,700	383,700
Net Plant Heat Rate, Btu/kWh (HHV)	9,810	9,810	9,160	9,160	9,120	9,120
Heat Input, MMBtu/h (HHV)	2,340	2,340	2,710	2,710	3,500	3,500
Min Load Operational Status @ 20° F (Winter Design)						
Net Plant Output, kW	105,600	105,600	88,600	88,600	115,100	115,100
Net Plant Heat Rate, Btu/kWh (HHV)	13,180	13,180	13,840	13,840	13,840	13,840
Heat Input, MMBtu/h (HHV)	1,390	1,390	1,230	1,230	1,590	1,590
Base Load Performance @ 90° F (Summer Design)						
Net Plant Output, kW	210,500	210,500	265,300	265,300	345,700	345,700
Net Plant Heat Rate, Btu/kWh (HHV)	10,170	10,170	9,450	9,450	9,430	9,430
Heat Input, MMBtu/h (HHV)	2,140	2,140	2,510	2,510	3,260	3,260
Min Load Operational Status @ 90° F (Summer Design)						
Net Plant Output, kW	93,100	93,100	84,000	84,000	109,500	109,500
Net Plant Heat Rate, Btu/kWh (HHV)	13,600	13,600	13,640	13,640	13,650	13,650
Heat Input, MMBtu/h (HHV)	1,270	1,270	1,150	1,150	1,490	1,490
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$163**	**$109**	**$200**	**$150**	**$212**	**$151**
Owner's Costs, 2022 MM$	**$24**	**$9**	**$27**	**$12**	**$27**	**$12**
Owner's Project Development	$0.3	$0.0	$0.3	$0.0	$0.3	$0.0
Owner's Operational Personnel Prior to COD	$0.3	$0.0	$0.3	$0.0	$0.3	$0.0
Owner's Engineer	$0.8	$0.0	$0.8	$0.0	$0.8	$0.0
Owner's Project Management	$1.0	$0.0	$1.0	$0.0	$1.0	$0.0
Owner's Legal Costs	$0.5	$0.0	$0.5	$0.0	$0.5	$0.0
Owner's Start-up Engineering and Commissioning	$1.5	$0.8	$1.6	$0.8	$1.6	$0.8
Land	$0.2	$0.1	$0.2	$0.1	$0.2	$0.1
Construction Power and Water	$0.5	$0.1	$0.5	$0.1	$0.5	$0.1

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	1x F Class Frame SCGT - Natural Gas		1x G/H Class Frame SCGT - Natural Gas		1x J-Class Frame SCGT - Natural Gas	
BASE PLANT DESCRIPTION	First Unit	Next Unit	First Unit	Next Unit	First Unit	Next Unit
Permitting and Licensing Fees	$0.5	$0.0	$0.5	$0.0	$0.5	$0.0
Switchyard	$5.2	$1.7	$5.2	$1.7	$5.2	$1.7
Political Concessions & Area Development Fees	$0.5	$0.0	$0.5	$0.0	$0.5	$0.0
Startup/Testing (Fuel & Consumables)	$2.1	$1.9	$2.7	$2.5	$2.7	$2.5
Initial Fuel Inventory	$3.1	$3.1	$4.3	$4.3	$4.3	$4.3
Site Security	$0.4	$0.0	$0.4	$0.0	$0.4	$0.0
Operating Spare Parts	$5.5	$1.4	$6.5	$1.6	$6.5	$1.6
Permanent Plant Equipment and Furnishings	$0.3	$0.0	$0.3	$0.0	$0.3	$0.0
Builders Risk Insurance (0.45% of Construction Costs)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Owner's Contingency (5% for Screening Purposes)	$1.1	$0.0	$1.3	$1.0	$1.3	$0.6
Total Project Costs, 2022 MM$	**$187**	**$118**	**$227**	**$162**	**$238**	**$163**
Total Project Costs, 2022 MM$ W AFUDC	**$210**	**$133**	**$256**	**$183**	**$268**	**$183**
EPC Cost Per kW, 2022 $/kW (Note 5)	**$710**	**$480**	**$700**	**$520**	**$570**	**$410**
Total Cost Per kW, 2022 $/kW (Note 5)	**$820**	**$520**	**$790**	**$570**	**$640**	**$440**
FIXED O&M COSTS (Note 6)						
Fixed O&M Cost - LABOR, 2022$MM/Yr	$0.9	$0.1	$0.9	$0.1	$0.9	$0.1
Fixed O&M Cost - OTHER, 2022$MM/Yr	$1.0	$0.4	$1.0	$0.4	$1.0	$0.4
LEVELIZED CAPITAL MAINTENANCE COSTS						
Major Maintenance Cost, 2022$/GT-hr or $/engine-hr (Notes 7)	$350	$350	$500	$500	$600	$600.0
Major Maintenance Cost, 2022$/GT-start	$9,500	$9,500	$17,900	$17,900	$26,500	$26,500
Major Maintenance Cost, 2022$/MWh	$1.60	$1.60	$1.80	$1.80	$1.60	$1.60
Catalyst Replacement Cost, 2022$/MWh	$0.00	$0.00	$0.20	$0.20	$0.20	$0.20
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE, Note 8)						
Total Variable O&M Cost, 2022$/MWh	$0.90	$0.90	$1.17	$1.17	$1.19	$1.19
Water Related O&M, $/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SCR Reagent, $/MWh	$0.00	$0.00	$0.27	$0.27	$0.29	$0.29
Other Consumables and Variable O&M, $/MWh	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS (See Note 9)						
Turbine Only (lb/MMBtu, HHV)						
NO_x	0.04	0.04	0.01	0.01	0.01	0.01
SO_2	<0.002	<0.002	<0.002	<0.002	<0.003	<0.003
CO	0.020	0.020	0.014	0.014	0.014	0.014
CO_2	120	120	120	120	120	120

Notes

Note 1: Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available.
Note 2: MECL start time assumes the time for the GT to emissions compliance load (not stack compliance). The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels r
Note 3: Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2006 or later. Reporting period is 2011-2016.
Note 4: New and clean performance assumed for all scenarios. All performance ratings based on NATURAL GAS operation. Minimum loads are based on OEM information at requested ambient conditions.
Note 5: Capital costs are presented in 2022 USD $MM. $/kW values are calculated based on base load performance at ISO conditions.
Note 6: All Gas Turbine FOM costs assume 7 full time personnel for first unit. No additional personnel are included for the next unit(s). FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM
Note 7: Major maintenance costs for frame gas turbines are hours based ($/GT-hr) when average hours per start is >27. When average hours per start over the interval are <27, then major maintenance costs would be starts based.
Note 8: VOM assumes the use of temporarily trailers for demineralized water treatment, where applicable.
Note 9: Emissions estimates are shown for steady state operation at annual average conditions.
Note 10: Performance ratings are based on elevation of 120 ft above msl.
Note 11: Estimated Costs exclude decommissioning costs .

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	**1x1 F Class CCGT - Unfired**	**1x1 F Class CCGT - Fired**	**1x1 G/H Class CCGT - Unfired**	**1x1 G/H Class CCGT - Fired**	**1x1 J Class CCGT - Unfired**	**2x1 J Class CCGT - Fired**
BASE PLANT DESCRIPTION	Unfired	Fired	Unfired	Fired	Unfired	Fired
Number of Gas Turbines	1	1	1	1	1	2
Number of Steam Turbines	1	1	1	1	1	1
Representative Class Gas Turbine	GE 7F.05	GE 7F.05	GE 7HA.01	GE 7HA.01	GE 7HA.02	GE 7HA.02
Steam Conditions (Main Steam / Reheat)	1,050 °F / 1,050 °F	1,050 °F / 1,050 °F	1,050 °F / 1,050 °F	1,050 °F / 1,050 °F	1,050 °F / 1,050 °F	1,050 °F / 1,050 °F
Main Steam Pressure	2,400 psia	2,400 psia	2,400 psia	2,400 psia	2,400 psia	2,400 psia
Steam Cycle Type	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical
Capacity Factor (%)	70%	70%	70%	70%	70%	70%
Startup Time, Minutes (Cold Start to Unfired Base Load) (Note 7, 8)	180	180	180	180	180	180
Startup Time, Minutes (Warm Start to Unfired Base Load) (Note 7, 8)	120	120	120	120	120	120
Startup Time, Minutes (Hot Start to Unfired Base Load) (Note 7, 8)	80	80	80	80	80	80
Startup Time, Minutes (Cold Start to Stack Emissions Compliance) (See note 4)	60	60	60	60	60	60
Maximum Ramp Rate, MW/min (Online)	35	35	40	40	55	110
Book Life (Years)	35	35	35	35	35	35
Equivalent Planned Outage Rate (%)	10.4	10.4	10.4	10.4	10.4	10.4
Equivalent Forced Outage Rate (%)	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%
Equivalent Availability Factor (%)	88.2%	88.2%	88.2%	88.2%	88.2%	88.2%
Assumed Land Use (Acres)	70	70	70	70	70	100
Fuel Design	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Heat Rejection	Wet Cooling Towers	Wet Cooling Towers	Wet Cooling Towers	Wet Cooling Towers	Wet Cooling Towers	Wet Cooling Towers
NO_x Control	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR
CO Control	Oxidation Catalyst	Oxidation Catalyst	Oxidation Catalyst	Oxidation Catalyst	Oxidation Catalyst	Oxidation Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	4	4	4	4	4	4
ESTIMATED PERFORMANCE (See note 1)						
Base Load Performance @59 °F (Nominal)						
Net Plant Output, kW	363,100	360,800	430,700	427,800	551,200	1,101,400
Net Plant Heat Rate, Btu/kWh (HHV)	6,540	6,590	6,200	6,240	6,270	6,280
Heat Input, MMBtu/h (HHV)	2,370	2,380	2,670	2,670	3,460	6,920
Incremental Duct Fired Performance @ 59 °F (Nominal)						
Incremental Duct Fired Output, kW	N/A	57,700	N/A	80,400	N/A	205,400
Incremental Heat Rate, Btu/kWh (HHV)	N/A	8,730	N/A	8,720	N/A	8,690
Incremental Heat Input, MMBtu/h (HHV)	N/A	500	N/A	700	N/A	1,780
Minimum Load (Single Turbine at MECL) @ 59 °F (Nominal)						
Net Plant Output, kW	172,100	171,100	150,000	149,100	202,100	202,100
Net Plant Heat Rate, Btu/kWh (HHV)	7,930	7,970	7,790	7,830	7,520	7,520
Heat Input, MMBtu/h (HHV)	1,360	1,360	1,170	1,170	1,520	1,520
Base Load Performance @ 20 °F (Winter)						
Net Plant Output, kW	364,400	362,000	434,800	431,800	557,300	1,113,700
Net Plant Heat Rate, Btu/kWh (HHV)	6,480	6,530	6,220	6,270	6,280	6,290
Heat Input, MMBtu/h (HHV)	2,360	2,360	2,700	2,710	3,500	7,010
Incremental Duct Fired Performance @ 20 °F (Winter)						
Incremental Duct Fired Output, kW	N/A	57,200	N/A	76,400	N/A	195,100
Incremental Heat Rate, Btu/kWh (HHV)	N/A	8,710	N/A	8,720	N/A	8,700
Incremental Heat Input, MMBtu/h (HHV)	N/A	500	N/A	670	N/A	1,700
Minimum Load (Single Turbine at MECL) @ 20 °F (Winter)						
Net Plant Output, kW	173,200	172,100	151,900	151,000	205,200	204,100
Net Plant Heat Rate, Btu/kWh (HHV)	8,050	8,100	8,070	8,120	7,770	7,810
Heat Input, MMBtu/h (HHV)	1,390	1,390	1,230	1,230	1,590	1,590
Base Load Performance @ 90 °F (Summer)						
Net Plant Output, kW	341,200	339,000	421,000	418,300	535,400	1,070,100
Net Plant Heat Rate, Btu/kWh (HHV)	6,530	6,570	6,100	6,140	6,290	6,290
Heat Input, MMBtu/h (HHV)	2,230	2,230	2,570	2,570	3,370	6,730
Incremental Duct Fired Performance @ 90 °F (Summer)						
Incremental Duct Fired Output, kW	N/A	63,000	N/A	84,200	N/A	218,300
Incremental Heat Rate, Btu/kWh (HHV)	N/A	8,720	N/A	8,720	N/A	8,700
Incremental Heat Input, MMBtu/h (HHV)	N/A	550	N/A	730	N/A	1,900
Minimum Load (Single Turbine at MECL) @ 90 °F (Summer)						
Net Plant Output, kW	162,300	161,400	149,800	149,000	200,500	200,500
Net Plant Heat Rate, Btu/kWh (HHV)	8,000	8,050	7,650	7,690	7,450	7,450
Heat Input, MMBtu/h (HHV)	1,300	1,300	1,150	1,150	1,490	1,490
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$460**	**$478**	**$501**	**$530**	**$538**	**$916**
Owner's Costs, 2022 MM$	**$66**	**$67**	**$69**	**$70**	**$70**	**$95**
Owner's Project Development	$3.5	$3.5	$3.5	$3.5	$3.5	$3.5
Owner's Operational Personnel Prior to COD	$1.7	$1.7	$1.7	$1.7	$1.7	$1.9
Owner's Engineer	$2.3	$2.3	$2.3	$2.3	$2.3	$2.6
Owner's Project Management	$5.9	$5.9	$5.9	$5.9	$5.9	$6.8
Owner's Legal Costs	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0
Owner's Start-up Engineering and Commissioning	$5.7	$5.7	$5.7	$5.7	$5.7	$8.4
Land	$0.4	$0.4	$0.4	$0.4	$0.4	$0.6
Temporary Utilities	$1.6	$1.6	$1.6	$1.6	$1.6	$1.7
Permitting and Licensing Fees	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	1x1 F Class CCGT - Unfired	1x1 F Class CCGT - Fired	1x1 G/H Class CCGT - Unfired	1x1 G/H Class CCGT - Fired	1x1 J Class CCGT - Unfired	2x1 J Class CCGT - Fired
BASE PLANT DESCRIPTION	Unfired	Fired	Unfired	Fired	Unfired	Fired
Switchyard	$9.8	$9.8	$10.8	$10.8	$10.8	$13.5
Political Concessions & Area Development Fees	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Startup/Testing (Fuel & Consumables)	$0.9	$0.9	$0.9	$0.9	$0.9	$1.8
Initial Fuel Inventory	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Site Security	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
Operating Spare Parts	$6.0	$6.0	$6.0	$6.0	$6.0	$7.2
Permanent Plant Equipment and Furnishings	$1.3	$1.3	$1.3	$1.3	$1.3	$1.3
Builders Risk Insurance (0.45% of Construction Costs)	$1.8	$1.9	$1.9	$2.1	$2.1	$3.3
Owner's Contingency	$22.1	$22.8	$23.8	$25.1	$25.3	$39.9
Total Project Costs, 2022 MM$	**$526**	**$545**	**$570**	**$600**	**$608**	**$1,012**
Total Project Costs, 2022 MM$ W AFUDC	**$617**	**$639**	**$668**	**$703**	**$713**	**$1,187**
EPC Cost Per UNFIRED kW, 2022 $/kW	**$1,270**	**$1,330**	**$1,160**	**$1,240**	**$980**	**$830**
Total Cost Per UNFIRED kW, 2022 $/kW	**$1,450**	**$1,510**	**$1,320**	**$1,400**	**$1,100**	**$920**
EPC Cost Per FIRED kW, 2022 $/kW	**N/A**	**$1,140**	**N/A**	**$1,040**	**N/A**	**$700**
Total Cost Per FIRED kW, 2022 $/kW	**N/A**	**$1,300**	**N/A**	**$1,180**	**N/A**	**$770**
FIXED O&M COSTS (See note 9)						
Fixed O&M Cost - LABOR, 2022 $MM/Yr	$2.8	$2.8	$2.8	$2.8	$2.8	$3.2
Fixed O&M Cost - OTHER, 2022 $MM/Yr	$1.7	$1.7	$1.7	$1.7	$1.7	$2.0
LEVELIZED CAPITAL MAINTENANCE COSTS						
Major Maintenance Cost, 2022 $/GT-hr	$350	$350	$500	$500	$600	$600
Major Maintenance Cost, 2022 $/MWh	$1.00	$1.00	$1.20	$1.20	$1.10	$1.10
Catalyst Replacement Cost, 2022 $/MWh	$0.20	$0.20	$0.20	$0.20	$0.10	$0.10
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE)						
Total Variable O&M Cost, Unfired 2022 $/MWh	$1.60	$1.60	$1.60	$1.60	$1.50	$1.40
Water Related O&M ($/MWh)	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20
SCR Reagent, $/MWh	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20
Other Consumables and Variable O&M ($/MWh)	$1.20	$1.20	$1.20	$1.20	$1.10	$1.00
Incremental Duct Fired Variable O&M, 2022 $/MWh (For Incremental Output Only)	N/A	$1.30	N/A	$1.20	N/A	$1.20
CARBON CAPTURE ADD-ON COST						
Carbon Capture Solvlent Based Technology Capital Costs, 2022 MM$	N/A	N/A	$560	N/A	N/A	N/A
Carbon Compression, Transportation, and Sequestration Capital Costs, 2021 MM$	N/A	N/A	$160	N/A	N/A	N/A
Owner's Costs, 2022 MM$	N/A	N/A	$39	N/A	N/A	N/A
CARBON CAPTURE O&M COSTS						
Incremental Fixed O&M Cost, 2022 MM$/Yr	N/A	N/A	$16	N/A	N/A	N/A
Incremental Variable O&M Cost, 2022$/MWh	N/A	N/A	$4	N/A	N/A	N/A
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS, lb/MMBtu (HHV)						
NO_x	0.007	0.007	0.007	0.007	0.007	0.007
SO_2	< 0.002	< 0.002	< 0.002	< 0.002	< 0.002	< 0.002
CO	0.004	0.004	0.004	0.004	0.004	0.004
CO_2	120	120	120	120	120	120

Notes

Note 1: New and clean performance assumed. All performance is based on NATURAL GAS operation. Min load ratings are based on OEM performance information at specified ambient conditions.
Note 2: Base O&M costs are based on performance at annual average conditions.
Note 3: Major maintenance costs for frame gas turbines are hours based ($/GT-hr) when average hours per start is >27. When average hours per start over the interval are <27, then major maintenance costs would be starts based.
Note 4: MECL start time assumes the time for the GT to emissions compliance load (not stack compliance). The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels meet the desired stack emissions.
Note 5: Options with duct firing include a design of firing up to 1,600°F.
Note 6: Outage and availability statistics are collected using the NERC Generating Availability Data System. Combined cycle data is based on North American units that came online in 2006 or later. Reporting period is 2011-2016.
Note 7: For the purpose of startup times, a Cold start is defined as being shutdown for >72 hours. A Hot start is defined as shutdown for <8 hours.
Note 8: Startup times reflect unrestricted, conventional starts for all gas turbines. These start times assume the inclusion of terminal point desuperheaters, full bypass, and associated controls. Fast start packages are not included in CCGT plants.
Note 9: Fixed O&M assumes 22 FTE for 1x1 configurations.
Note 10: Variable O&M costs assume onsite demin treatment system.
Note 11: Emissions estimates are shown for steady state operation at annual average conditions. Estimates account for the impacts of SCR and CO catalysts.
Note 12: Estimated costs exclude decommissioning costs and salvage values.

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
COAL TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	Supercritical Pulverized Coal with Carbon Capture	Ultra-Supercritical Pulverized Coal with Carbon Capture
BASE PLANT DESCRIPTION		
Nominal Output	500 MW Net with CCS	750 MW Net with CCS
Number of Gas Turbines	N/A	N/A
Number of Boilers/Reactors	1	1
Number of Steam Turbines	1	1
Steam Conditions (Main Steam / Reheat)	1050 F/1050F	1100 F/1100F
Main Steam Pressure	3675 psia	3694 psia
Steam Cycle Type	Supercritical	Ultra-Supercritical
Capacity Factor (%)	70%	70%
Startup Time (Cold Start)	10 Hours	10 Hours
Startup Time (Warm Start)	6 Hours	6 Hours
Startup Time (Hot Start)	4 Hours	4 Hours
Book Life (Years)	33	33
Equivalent Planned Outage Rate (%)	9.0%	8.8%
Equivalent Forced Outage Rate (%)	10.9%	8.8%
Equivalent Availability Factor (%)	79.5%	80.8%
Fuel Design	Bituminous Coal	Bituminous Coal
Heat Rejection	Wet Cooling Tower	Wet Cooling Tower
NO_x Control	Low NOx burners / SCR	Low NOx burners / SCR
SO_2 Control	Integrated WFGD and DFGD	Integrated WFGD and DFGD
Acid Gas Control	Integrated WFGD and DFGD	Integrated WFGD and DFGD
CO_2 Control	Advanced Amine	Advanced Amine
Particulate Control	Baghouse	Baghouse
Ash Disposal	Landfill	Landfill
Technology Rating	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	6.5	6.5
ESTIMATED PERFORMANCE		
Base Load Performance @ (Annual Average) w/ Carbon Capture		
Net Plant Output, kW	505,750	747,100
Net Plant Heat Rate, Btu/kWh (HHV)	11,290	10,480
Heat Input, MMBtu/h (HHV)	5,710	7,830
Minimum Load Operational Status @ (Annual Average)		
Net Plant Output, kW	177,010	298,840
Net Plant Heat Rate, Btu/kWh (HHV)	13,410	12,240
Heat Input, MMBtu/h (HHV)	2,370	3,660
ESTIMATED CAPITAL AND O&M COSTS		
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$3,067**	**$4,142**
Owner's Costs, 2022 MM$	**$300**	**$359**
Owner's Project Development	$7.5	$7.5
Owner's Operational Personnel Prior to COD	$7.7	$7.7
Owner's Engineer	$11.5	$11.5
Owner's Project Management	$10.0	$10.0
Owner's Legal Costs	$3.0	$3.0
Owner's Start-up Engineering	$0.4	$0.4
Land	$5.0	$5.0
Operator Training	$0.6	$0.6
Construction Power and Water	$3.6	$3.6
Permitting and Licensing Fees	$4.0	$4.0

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT COAL TECHNOLOGY ASSESSMENT PROJECT OPTIONS PRELIMINARY - NOT FOR CONSTRUCTION AUGUST 2022		
PROJECT TYPE	**Supercritical Pulverized Coal with Carbon Capture**	**Ultra-Supercritical Pulverized Coal with Carbon Capture**
BASE PLANT DESCRIPTION		
Switchyard	$10.1	$10.1
Political Concessions & Area Development Fees	$2.5	$2.5
Startup/Testing (Fuel & Consumables)	$30.1	$30.1
Initial Fuel Inventory	$16.8	$16.8
Site Security	$0.6	$0.6
Operating Spare Parts	$8.2	$8.2
Permanent Plant Equipment and Furnishings	$4.6	$4.6
Builders Risk Insurance (0.45% of Construction Costs)	$13.8	$18.6
Owner's Contingency (5% for Screening Purposes)	$160	$214
Total Project Costs, 2019 MM$	**$3,368**	**$4,501**
Total Project Costs, 2022 MM$ W AFUDC	**$4,390**	**$5,867**
EPC Cost Per kW, 2019 $/kW	**$6,065**	**$5,544**
Total Cost Per kW, 2019 $/kW	**$6,660**	**$6,020**
CO_2 Transportation and Geologic Sequestration (See note 4)		
50 Mile Pipeline Cost, 2022 MM$	$144	$168
CO_2 Pipeline Maintenance ($/MWh)	$4.05	$4.05
CO_2 Storage Cost ($/MWh)	$9.14	$9.14
Fixed O&M Cost, 2022$/kW-Yr	$32.01	$32.01
Fixed O&M Cost, 2022 $MM/Yr	$16.20	$23.90
Major Maintenance Cost, 2022$/MWh	$5.72	$5.72
Variable O&M Cost, 2022$/MWh (excl. major maint.)	$14.85	$14.85
ESTIMATED BASE LOAD OPERATING EMISSIONS (NO CCS), lb/MMBtu (HHV)		
NO_X	0.02	0.02
SO_2	0.02	0.02
CO	0.15	0.15
CO_2	100	100

Notes
Note 1: PC cost and performance are based on net performance inclusive of carbon capture.
Note 2: The PC unit assumes that cooler tower blowdown is recycled in the FGD.
Note 3: The PC unit assumes a spray dry absorber will be used to control acid gases. FGD purge will be recycled in the SDA.
Note 4: Carbon transportation and sequestration assumes 50 mile pipeline to a suitable subterranean reservoir.
Note 5: Outage and availability statistics are collected using the NERC Generating Availability Data System. Reporting period is those units that report

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
NUCLEAR TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
MIDWEST
AUGUST 2022

PROJECT TYPE	**Nuclear**	
BASE PLANT DESCRIPTION	Small Modular Reactor	
Representative Technology	NuScale technology configuration	
Number of Modules	First Module	Next Module
Number of Steam Turbines	1	1
Capacity Factor (%)	95%	95%
Startup Time, Minutes (Cold Start to Unfired Base Load)	96 Minutes (20% to 100%)	96 Minutes (20% to 100%)
Maximum Ramp Rate, %/min	~1%/min or 40%/hr	~1%/min or 40%/hr
Scheduled Outage Factor (SOF), %	2%	2%
Forced Outage Factor (FOF), %	5%	5%
Availability Factor (AF), %	95%	95%
Book Life (Years)	60	60
Fuel Design	≤ 5% Enriched Uranium	≤ 5% Enriched Uranium
Heat Rejection	Dry Cooling	Dry Cooling
Technology Rating	Developing	Developing
Permitting & Construction Schedule (Years from FNTP)	6	6
ESTIMATED PERFORMANCE		
Base Load Performance @ (Annual Average)		
Gross Plant Output, kW	77,000	77,000
Net Plant Output, kW	73,700	73,700
Net Plant Heat Rate, Btu/kWh (HHV)	11,580	11,580
ESTIMATED CAPITAL AND O&M COSTS		
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs) (Note 1)	**$580**	**$570**
Civil/Structural/Architectural	Included in Project Cost	Included in Project Cost
Mechanical	Included in Project Cost	Included in Project Cost
Electrical	Included in Project Cost	Included in Project Cost
Indirects and Fees	Included in Project Cost	Included in Project Cost
Owner's Costs, 2022 MM$ (Note 2)		
Owner's Contingency (Note 6)	$116	$114
Total Project Costs, 2022 MM$	**$696**	**$684**
Total Project Costs, 2022 MM$ W AFUDC	**$888**	**$873**
EPC Cost Per kW, 2022 $/kW	**$7,870**	**$7,734**
Total Cost Per kW, 2022 $/kW	**$9,444**	**$9,281**
Fixed O&M Cost - TOTAL, 2022$MM/Yr (Note 3)	$106	$106
Variable O&M Cost, 2019$/MWh (Note 4)	$0.7	$0.7

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
NUCLEAR TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
MIDWEST
AUGUST 2022

PROJECT TYPE	**Nuclear**	
BASE PLANT DESCRIPTION	Small Modular Reactor	
CASH FLOW PATTERNS (Note 5)		
Total Plant Construction Cost		
Year 1	N/A	N/A
Year 2	N/A	N/A
Year 3	N/A	N/A

Notes
Note 1: Costs based on EPC contracting approach from publically available data produced by NREL. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, a
Note 2: Owner’s costs include project development, studies, permitting, legal, owner’s project management, owner’s engineering, and owner’s startup and commissioning costs. Other owner’s costs i
Note 3: Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.
Note 4: Variable O&M costs include water, water discharge treatment cost, chemicals, and consumables. Fuel is not included.
Note 5: Due to the technology rating for this option, yearly cash flows are unavailable at this time
Note 6: Owner's contingency recommendation is elevated for this technology option to 20% as opposed to the 5% used for other technologies based on historical risks to nuclear technology product c
Note 7: Performance data based on NuScale press releases (NuScale Year in Review 2020, Accessed March 30, 2022).

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
RECIPROCATING ENGINE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	Reciprocating Engine (9 MW Engines) Natural Gas		Reciprocating Engine (18 MW Engines) Natural Gas	
BASE PLANT DESCRIPTION	First Unit	Next Unit	First Unit	Next Unit
Number of Gas Turbines/Engines/Units	6	6	6	6
Representative Class Gas Turbine	Wartsila 20V34SG		Wartsila 18V50SG	
Capacity Factor, %	Peaking (10%)		Peaking (10%)	
Startup Time to Base Load, min (Notes 1)	5		5	
Startup Time to MECL, min	4		4	
Cold Startup Time to SCR Compliance, min	45		45	
Maximum Ramp Rate, MW/min (Online)	55		110	
Book Life, Years	35		35	
Equivalent Planned Outage Rate, % (Note 2)	3.5%		3.5%	
Equivalent Forced Outage Rate, % (Notes 2)	4.3%		4.3%	
Equivalent Availability Factor, % (Notes 2)	92.2%		92.2%	
Assumed Land Use, Acres	30	10	30	10
Fuel Design	Natural Gas Only		Natural Gas Only	
Heat Rejection	Fin Fan Heat Exchanger		Fin Fan Heat Exchanger	
NO_x Control	SCR		SCR	
CO Control	Oxidation Catalyst		Oxidation Catalyst	
Particulate Control	Good Combustion Practice		Good Combustion Practice	
Technology Rating	Mature		Mature	
Permitting & Construction Schedule (Years from FNTP)	3	3	3	3
ESTIMATED PERFORMANCE (All BASED ON NATURAL GAS OPERATION) (Note 3)				
Nominal Base Load Performance @59° F (ISO Conditions)				
Net Plant Output, kW	54,500	54,500	110,100	110,100
Net Plant Heat Rate, Btu/kWh (HHV)	8,440	8,440	8,360	8,360
Heat Input, MMBtu/h (HHV)	460	460	920	920
Nominal Min Load @ 59° F (ISO Conditions) - Single Engine				
Net Plant Output, kW	3,600	3,600	7,300	7,300
Net Plant Heat Rate, Btu/kWh (HHV)	11,110	11,110	9,590	9,590
Heat Input, MMBtu/h (HHV)	40	40	70	70
Base Load Performance @ 20° F (Winter Design)				
Net Plant Output, kW	54,500	54,500	110,100	110,100
Net Plant Heat Rate, Btu/kWh (HHV)	8,440	8,440	8,360	8,360
Heat Input, MMBtu/h (HHV)	460	460	920	920
Min Load Operational Status @ 20° F (Winter Design) - Single Engine				
Net Plant Output, kW	3,600	3,600	7,300	7,300
Net Plant Heat Rate, Btu/kWh (HHV)	11,110	11,110	9,590	9,590
Heat Input, MMBtu/h (HHV)	40	40	70	70
Base Load Performance @ 90° F (Summer Design)				
Net Plant Output, kW	54,500	54,500	110,100	110,100
Net Plant Heat Rate, Btu/kWh (HHV)	8,620	8,620	8,360	8,360
Heat Input, MMBtu/h (HHV)	470	470	920	920
Min Load Operational Status @ 90° F (Summer Design) - Single Engine				
Net Plant Output, kW	3,600	3,600	7,300	7,300
Net Plant Heat Rate, Btu/kWh (HHV)	11,110	11,110	9,590	9,590
Heat Input, MMBtu/h (HHV)	40	40	70	70
ESTIMATED CAPITAL AND O&M COSTS				
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$79**	**$58**	**$150**	**$114**
Engineering	$4.0	$1.2	$6	$1
Gas Turbines/Engines	$30.0	$27.0	$58	$55
GSU (Note 4)	$1.1	$1.1	$2	$2
Environmental Equipment (SCR/CO)	Included	Included	Included	Included
BOP Equipment and Materials	$6.8	$5.1	$23	$18
Construction	$22.3	$13.4	$33	$20
Indirects and Fees	$11.0	$7.3	$22	$15
EPC Contingency	$3.6	$2.6	$7	$5
Owner's Costs, 2022 MM$	**$17**	**$6**	**$22**	**$11**
Owner's Project Development	$0.3	$0.0	$0.3	$0.0
Owner's Operational Personnel Prior to COD	$0.3	$0.0	$0.3	$0.0
Owner's Engineer	$0.8	$0.0	$0.5	$0.0
Owner's Project Management	$1.0	$0.0	$1.0	$0.0

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
RECIPROCATING ENGINE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	Reciprocating Engine (9 MW Engines) Natural Gas		Reciprocating Engine (18 MW Engines) Natural Gas	
Owner's Legal Costs	$0.5	$0.0	$0.5	$0.0
Owner's Start-up Engineering and Commissioning	$0.5	$0.2	$0.9	$0.5
Land	$0.2	$0.0	$0.2	$0.1
Construction Power and Water	$0.5	$0.1	$0.5	$0.1
Permitting and Licensing Fees	$0.5	$0.0	$0.5	$0.0
Switchyard	$5.3	$1.8	$7.1	$3.5
Political Concessions & Area Development Fees	$0.5	$0.0	$0.5	$0.0
Startup/Testing (Fuel & Consumables)	$0.2	$0.1	$0.0	$0.0
Initial Fuel Inventory	$0.0	$0.0	$0.0	$0.0
Site Security	$0.4	$0.0	$0.4	$0.0
Operating Spare Parts	$0.4	$0.1	$0.3	$0.0
Permanent Plant Equipment and Furnishings	$0.3	$0.0	$0.0	$0.0
Builders Risk Insurance (0.45% of Construction Costs)	$0.4	$0.3	$0.7	$0.5
Owner's Contingency (5% for Screening Purposes)	$4.6	$3.0	$8.2	$5.9
Total Project Costs, 2022 MM$	**$96**	**$64**	**$172**	**$125**
Total Project Costs, 2022 MM$ W AFUDC	**$108**	**$72**	**$193**	**$140**
EPC Cost Per kW, 2022 $/kW	**$1,450**	**$1,064**	**$1,362**	**$1,035**
Total Cost Per kW, 2022 $/kW	**$1,756**	**$1,167**	**$1,561**	**$1,132**
FIXED O&M COSTS				
Fixed O&M Cost - LABOR, 2022$MM/Yr	$1.0	$0.4	$1.0	$0.4
Fixed O&M Cost - OTHER, 2022$MM/Yr	$0.5	$0.2	$1.0	$0.4
LEVELIZED CAPITAL MAINTENANCE COSTS				
Major Maintenance Cost, 2022$/GT-hr or $/engine-hr (Notes 6)	$10.80	$10.80	$20.00	$20.00
Major Maintenance Cost, 2022$/GT-start	N/A	N/A	N/A	N/A
Major Maintenance Cost, 2022$/MWh	$1.20	$1.20	$1.10	$1.10
Catalyst Replacement Cost, 2022$/MWh	$0.30	$0.30	$0.10	$0.10
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE)				
Total Variable O&M Cost, 2022$/MWh	$5.60	$5.60	$4.50	$4.50
Water Related O&M, $/MWh	$0.00	$0.00	$0.00	$0.00
SCR Reagent, $/MWh	$0.90	$0.90	$0.90	$0.90
Other Consumables and Variable O&M, $/MWh	$4.70	$4.70	$3.60	$3.60
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS (See Note 8)				
Engine Only (lb/MMBtu, HHV)	N/A	N/A	N/A	N/A
NO_X	N/A	N/A	N/A	N/A
SO_2	N/A	N/A	N/A	N/A
CO	N/A	N/A	N/A	N/A
CO_2				
Engine with SCR and CO Catalyst (lb/MMBtu, HHV)				
NO_X	0.021	0.021	0.021	0.021
SO_2	< 0.002	< 0.002	< 0.002	< 0.002
CO	0.031	0.031	0.032	0.032
CO_2	120	120	120	120

Notes
Note 1: Recip engine start times assume the engines are kept warm when not operational.
Note 2: Outage and availability statistics are collected using the NERC Generating Availability Data System. Note that a unique gas reciprocating engine category does not exist in GADS. Diesel Engine data is used as a proxy.
Note 3: New and clean performance assumed for all scenarios. All performance ratings based on NATURAL GAS operation. Minimum loads are based on OEM information at requested ambient conditions.
Note 4: It is assumed that a maximum of six reciprocating engines tie to one GSU.
Note 5: Capital and fixed O&M costs are presented in 2022 USD $MM.
Note 6: Recip engine FOM assumes 8 FTE for the first 200 MW plant. Major maintenance $/hr is per engine. LTSA costs are split in two categories: major overhauls and catalyst replacements are shown
Note 7: Not Used.
Note 8: Emissions estimates are shown for steady state operation at annual average conditions. Estimates account for the impacts of SCR and CO catalysts, as applicable.
Note 9: Performance ratings are based on elevation of 120 ft above msl.

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
RENEWABLE AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	Wind Energy	Wind Energy	Wind Plus Storage	Solar Photovoltaic	Solar Photovoltaic	Solar Photovoltaic	Solar Plus Storage
BASE PLANT DESCRIPTION	Southern IN	Northern IN	Indiana	Single Axis Tracking	Single Axis Tracking	Single Axis Tracking	Single Axis Tracking
Nominal Output, MW	200	200	50 MW Wind & 10 MW / 40 MWh Storage	10	50	100	50 MW PV & 10 MW / 40 MWh Storage
Number of Turbines	53 x 3.8 MW	53 x 3.8 MW	14 x 3.8 MW	N/A	N/A	N/A	N/A
Capacity Factor (%) (Notes 1,2)	28.1%	38.3%	38.3%	25.2%	25.2%	25.2%	25.2%
Book Life (Years)	30	30	30 Wind / 20 BESS	30	30	30	30 Wind / 20 BESS
Scheduled Outage Factor (SOF), % (Note 5)	< 5%	< 5%	< 5%	<1%	<1%	<1%	<1%
Forced Outage Factor (FOF), % (Note 5)	< 5%	< 5%	< 5%	<1%	<1%	<1%	<1%
Availability Factor (AF), % (Note 5)	95%	95%	95%	99%	99%	99%	99%
Assumed Land Use (Acres)	53	53	16	70	350	700	352
Interconnection Voltage Assumption	230 kV	230 kV	230 kV	115 kV	115 kV	230 kV	115 kV
PV Inverter Loading Ratio (DC/AC)	N/A	N/A	N/A	1.35	1.35	1.35	1.35
PV Degradation (%/yr) (Note 6)	N/A	N/A	N/A	First year: 2% After 1st Year: 0.5%	First year: 2% After 1st Year: 0.5%	First year: 2% After 1st Year: 0.5%	First year: 2% After 1st Year: 0.5%
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	2.5	2.5	2.5	2	2	2	2
ESTIMATED PERFORMANCE							
Base Load Performance @ (Annual Average)							
Net Plant Output, kW	200,000	200,000	50,000	10,000	50,000	100,000	50,000
ESTIMATED CAPITAL AND O&M COSTS							
Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$320**	**$320**	**$108**	**$22**	**$86**	**$159**	**$106**
Wind Capital Cost Breakdown							
Engineering	**$11.5**	**$11.5**	**$3.2**	**N/A**	**N/A**	**N/A**	**N/A**
Equipment and Materials	$215	$215	$59	N/A	N/A	N/A	N/A
Turbine Towers	Included	Included	Included	N/A	N/A	N/A	N/A
Turbine Blades	Included	Included	Included	N/A	N/A	N/A	N/A
Turbine Hubs	Included	Included	Included	N/A	N/A	N/A	N/A
Nacelle and nacelle components	Included	Included	Included	N/A	N/A	N/A	N/A
SCADA Equipment	Included	Included	Included	N/A	N/A	N/A	N/A
Construction	$93	$93	$26	N/A	N/A	N/A	N/A
Turbine Foundation and Erection	Included	Included	Included	N/A	N/A	N/A	N/A
BOP Costs	Included	Included	Included	N/A	N/A	N/A	N/A
Collector Bus	Included	Included	Included	N/A	N/A	N/A	N/A
Indirects and Fees	Included	Included	Included	N/A	N/A	N/A	N/A
EPC Contingency	Included	Included	Included	N/A	N/A	N/A	N/A
PV Capital Cost Breakdown							
Engineering	N/A	N/A	N/A	$1	$1	$2	$1.0
Equipment and Materials	N/A	N/A	N/A	$10	$38	$79	$38.0
Modules	N/A	N/A	N/A	$7	$27	$55	$27.0
Inverters	N/A	N/A	N/A	$1	$2	$5	$2.0
Racking	N/A	N/A	N/A	$2	$9	$19	$9.0
Construction	N/A	N/A	N/A	$8	$35	$60	$35.0
Indirects and Fees	N/A	N/A	N/A	$2	$8	$11	$8.0
EPC Contingency	N/A	N/A	N/A	$1	$4	$7	$4.0
Battery Storage Capital Cost Breakdown			**$20**				**$20**
Batteries	N/A	N/A	$12	N/A	N/A	N/A	$12
Inverters	N/A	N/A	$1	N/A	N/A	N/A	$1
BOP	N/A	N/A	$1	N/A	N/A	N/A	$1
Construction and Indirects	N/A	N/A	$6	N/A	N/A	N/A	$6
Owner's Costs, 2022 MM$	**$48.9**	**$48.9**	**$18**	**$3.6**	**$6.8**	**$18.9**	**$9**
Owner's Project Development	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Engineer	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Project Management	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Startup / Testing / Warranties	Allowance Included	Allowance Included	Included in EPC	Included in EPC	Included in EPC	Included in EPC	Included in EPC
Land (Note 8)	Excluded	Excluded	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease
Permitting and Licensing Fees	Allowance Included	Allowance Included	Included in EPC	Included in EPC	Included in EPC	Included in EPC	Included in EPC
Switchyard / Substation (Notes 7,9)	$5.2 M Allowance Included	$5.2 M Allowance Included	$6.2 M Allowance Included	$1.0M Allowance Included	$1.0M Allowance Included	$5.2 M Allowance Included	$2.0M Allowance Included
Builder's Risk Insurance	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Contingency	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Total Project Costs, 2022 MM$	**$369**	**$369**	**$126**	**$26**	**$93**	**$178**	**$115**
Total Project Costs, 2022 MM$ W AFUDC	**$407**	**$407**	**$139**	**$28**	**$100**	**$192**	**$124**
Fixed O&M Cost - TOTAL, 2022$MM/Yr (Notes 3,4)	**$9.6**	**$9.6**	**$2.9**	**$0.6**	**$0.8**	**$1.1**	**$1.1**
Annual Fixed Labor Cost, 2022$MM/Yr	Allowance Included	Allowance Included	Allowance Included	$0.0	$0.0	$0.0	$0.0
Equipment Maintenance Cost, 2022$MM/Yr	Allowance Included	Allowance Included	$0.3	$0.5	$0.5	$0.5	$0.8
BOP and Other Cost, 2022$MM/Yr	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Land Lease Allowance, 2022$MM/Yr (Notes 8)	Allowance Included	Allowance Included	Allowance Included	Excluded	Excluded	Excluded	Excluded
Property Tax Allowance, 2022$MM/Yr	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded
Capital Replacement Allowance, 2022$/MWh (Notes 3-4)	20% of FOM	20% of FOM	20% of FOM	$0.1	$0.2	$0.5	$0.1
Variable O&M Cost, 2022$/MWh (excl. major maint.) (Note 4)	**Included in FOM**	**Included in FOM**	**Included in FOM**	**Included in FOM**	**Included in FOM**	**Included in FOM**	**Included in FOM**

Note 1: Wind capacity factor represents Net Capacity Factor (NCF), which accounts for typical system losses. Capacity factor is based on General Electric 3.8 MW turbines (GE3.8-137) with 110 meter hub height and 8.0 m/s average wind speed.
Note 2: Solar capacity factor accounts for typical losses. Inverter loading ratios assumed as 1.35. Assumes no inverter overbuild at the POI, 35% Ground Coverage Ratio and bifacial modules.
Note 3: Capital maintenance allowances for onshore wind options are not included in the annual FOM above. A supplemental table in the report shows capital allowances estimated as percentages of annual operating expenses for a 30 year life.
Note 4: PV O&M estimates assume fixed contracts for all maintenance activities. It is assumed the system is remotely controlled. Capital maintenance assumes an inverter replacement allowance levelized over the first 15 years.
Note 5: NERC GADS performance statistics are not available for PV and wind technologies. Availability estimates are based on vendor correspondence and industry publications.
Note 6: PV degradation based on typical warranty information for polycrystalline products. Assuming factory recommended maintenance is performed, PV performance is estimated to degrade ~2% in the first year and 0.5% each remaining year.
Note 7: EPC costs for wind include 34.5 kV collection system and GSU to 230 kV. Owner's costs include 3 position ring bus switchyard for interconnection at 230kV. Owner's costs include 3 position ring bus switchyard for interconnection at 230kV.
Note 8: Onshore wind and PV projects assume that land is leased and therefore land costs are included in O&M, not capital costs. Onshore wind assumes one acre per turbine. PV seven acres per MW for tracking options.
Note 9: PV scope for EPC includes 34.5 kV collection system and GSU. Owner costs include allowance for interconnection at 115 kV including a new 115 kV 3 position ring bus.
Note 10: Note Used
Note 11: Estimated Costs exclude decommisioning costs and salvage values.
Note 12: Sites are assumed to be regularly shaped and designed to allow for CAB BLA and requires minimal vegetation control. Soils, flood hazards, and geotechnical conditions are also assumed to be conducive for cost minimization.
Note 13: Not Used.
Note 14: PV 20% spend in Year 1 is based on 5 month LNTP prior to FNTP spend.

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
RENEWABLE AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	Battery Storage	Battery Storage	Battery Storage	Long Duration Storage
BASE PLANT DESCRIPTION	Lithium Ion	Lithium Ion	Lithium Ion	CAES
Nominal Output, MW	10 MW / 40 MWh	50 MW / 200 MWh	100 MW / 400 MWh	300 MW / 3,000 MWh
Capacity Factor (%)	16.3%	16.3%	16.3%	37.5%
Use Case Assumption	1 discharge/day	1 discharge/day	1 discharge/day	0.5 discharge/day
Book Life (Years)	20	20	20	35
Equivalent Planned Outage Rate (%)	< 2%	< 2%	< 2%	3%
Equivalent Forced Outage Rate (%)	< 2%	< 2%	< 2%	2%
Equivalent Availability Factor (%)	98%	98%	98%	95%
Assumed Land Use (Acres)	3	6	9	43
Heat Rejection	Air Cooled HVAC	Air Cooled HVAC	Air Cooled HVAC	Process Thermal Storage
Total System Cycles	7,300	7,300	7,300	5,300
Interconnection Voltage Assumption	115 kV	230 kV	230 kV	230 kV
Storage System AC Capacity at POI (MWh)	40	200	400	0%
Storage System AC Capacity Installed (MWh)	48	240	480	0%
Storage System Degradation (%/yr)	2%	2%	2%	0%
Storage System AC Roundtrip Efficiency (%)	85%	85%	85%	60%
Technology Rating	Mature	Mature	Mature	Developing
Permitting & Construction Schedule (Years from FNTP)	2	2	2	4.5
ESTIMATED PERFORMANCE				
Base Load Performance @ (Annual Average)				
Net Plant Output, kW	10,000	50,000	100,000	300,000
ESTIMATED CAPITAL AND O&M COSTS				
Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$20**	**$89**	**$173**	**$660**
Battery Storage Capital Cost Breakdown				
Batteries (Assumes Owner Procurement of Battery Integrator Scope)	$12	$64	$122	N/A
Inverters	$1	$3	$5	N/A
BOP	$1	$4	$5	N/A
Construction and Indirects	$6	$18	$41	N/A
Long-Term Storage Capital Cost Breakdown				
Topside	N/A	N/A	N/A	$400
Subsurface	N/A	N/A	N/A	$260
Owner's Costs, 2022 MM$	**$5**	**$19**	**$29**	**$117**
Owner's Project Development	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Engineer	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Project Management	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Startup / Testing / Warranties	Inlcuded in Project Cost	Inlcuded in Project Cost	Inlcuded in Project Cost	Allowance Included
Land	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease
Permitting and Licensing Fees	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Switchyard / Substation	$1.0	$5.2	$5.2	Allowance Included
Builder's Risk Insurance	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Contingency	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Total Project Costs, 2022 MM$	**$25**	**$108**	**$202**	**$777**
Total Project Costs, 2022 MM$ W AFUDC	**$27**	**$117**	**$218**	**$931**
Fixed O&M Cost - TOTAL, 2022$MM/Yr	**$0.4**	**$1.9**	**$3.5**	**$5.8**
Annual Fixed Labor Cost, 2022$MM/Yr	$0	$0	$0	Allowance Included
Equipment Maintenance Cost, 2022$MM/Yr	$0.3	$1.7	$3.2	Allowance Included
BOP and Other Cost, 2022$MM/Yr	Included in FOM	Included in FOM	Included in FOM	Allowance Included
Land Lease Allowance, 2022$MM/Yr (Notes 4)	Excluded	Excluded	Excluded	$0.03
Property Tax Allowance, 2022$MM/Yr	Excluded	Excluded	Excluded	$0.0004
Capital Replacement Allowance, 2022$/MWh (Notes 2)	$0.1	$0.2	$0.3	Excluded
Variable O&M Cost, 2022$/MWh (excl. major maint.)	Included in FOM	Included in FOM	Included in FOM	$2.6

Notes
Note 1: Lithium ion capacity factor calculations assume single daily charge and discharge cycles over the year with allowances for equipment expected availability.
Note 2: Battery FOM assumes the site is remotely controlled. A battery replacement fund (augmentation) is included in the FOM to accommodate for degradation throughout the project life. Variable O&M accounts for the parasitic power draw of the system, including HVAC and efficiency losses.
Note 3: NERC GADS performance statistics are not available for battery storage. Availability estimates are based on vendor correspondence and industry publications.
Note 4: Land lease and property estimate allowances are excluded.
Note 5: Estimated Costs exclude decommisioning costs and salvage values.

CENTERPOINT ENERGY 2022 GENERIC UNIT ASSESSMENT SUMMARY TABLE
SIMPLE CYCLE TO COMBINED CYCLE CONVERSION TECHNOLOGY ASSESSMENT
PRELIMINARY - NOT FOR CONSTRUCTION
INDIANA
August 2022 - Revision 0

PROJECT TYPE	**2x1 F Class SCGT to CCGT Conversion**
BASE PLANT DESCRIPTION	
Number of Gas Turbines	2
Number of Steam Turbines	1
Representative Class Gas Turbine	GE 7F.05
Steam Conditions (Main Steam / Reheat)	1,050 °F / 1,050 °F
Main Steam Pressure	2,400 psia
Steam Cycle Type	Subcritical
Capacity Factor (%)	70%
Startup Time, Minutes (Cold Start to Unfired Base Load) (Note 1)	180
Startup Time, Minutes (Warm Start to Unfired Base Load) (Note 1)	120
Startup Time, Minutes (Hot Start to Unfired Base Load) (Note 1)	80
Startup Time, Minutes (Cold Start to Stack Emissions Compliance) (Note 2)	60
Maximum Ramp Rate, MW/min (Online)	72
Book Life (Years)	35
Scheduled Outage Factor (SOF), % (Note 3)	10.4%
Forced Outage Factor (FOF), % (Note 3)	1.4%
Availability Factor (AF), % (Note 3)	88.2%
Fuel Design	Natural Gas
Heat Rejection	Wet Cooling Towers
NO_x Control	DLN/SCR
CO Control	Oxidation Catalyst
Particulate Control	Good Combustion
Technology Rating	Mature
Permitting & Construction Schedule (Years from FNTP)	2.50
ESTIMATED PERFORMANCE (Note 4)	
Base Load Performance @ 59 °F (Nominal)	
Net Plant Output, kW	716,900
Net Plant Heat Rate, Btu/kWh (HHV)	6,480
Heat Input, MMBtu/h (HHV)	4,650
Minimum Load (Single Turbine at MECL) @ 59 °F (Nominal)	
Net Plant Output, kW	165,300
Net Plant Heat Rate, Btu/kWh (HHV)	7,920
Heat Input, MMBtu/h (HHV)	1,310
Base Load Performance @ 5 °F (Winter)	
Net Plant Output, kW	719,400
Net Plant Heat Rate, Btu/kWh (HHV)	6,570
Heat Input, MMBtu/h (HHV)	4,730
Minimum Load (Single Turbine at MECL) @ 5 °F (Winter)	
Net Plant Output, kW	170,000
Net Plant Heat Rate, Btu/kWh (HHV)	8,210
Heat Input, MMBtu/h (HHV)	1,400
Base Load Performance @ 90 °F (Summer)	
Net Plant Output, kW	686,300
Net Plant Heat Rate, Btu/kWh (HHV)	6,560
Heat Input, MMBtu/h (HHV)	4,500
Minimum Load (Single Turbine at MECL) @ 90 °F (Summer)	
Net Plant Output, kW	153,800
Net Plant Heat Rate, Btu/kWh (HHV)	8,230
Heat Input, MMBtu/h (HHV)	1,270
ESTIMATED STARTUP FUEL USAGE	
Start to Stack Emissions Compliance, MMBtu	1,720
Start to Unfired Base Load, MMBtu	8,530
ESTIMATED WATER USAGE (Note 6)	
Water Consumption (kgal/yr)	1,451,000
Water Consumption with Evap Cooler (kgal/yr)	1,474,000
ESTIMATED REAGENT USAGE (Note 6)	
Ammonia Consumption (tons/yr)	4,530
ESTIMATED CAPITAL AND O&M COSTS (Note 7)	
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	[redacted]
Engineering	
Gas Turbines	
HRSGs	
Steam Turbine	
GSUs	
BOP Equipment and Materials	
Construction	
Indirects and Fees	
EPC Contingency	
Owner's Costs, 2022 MM$	

CENTERPOINT ENERGY 2022 GENERIC UNIT ASSESSMENT SUMMARY TABLE
SIMPLE CYCLE TO COMBINED CYCLE CONVERSION TECHNOLOGY ASSESSMENT
PRELIMINARY - NOT FOR CONSTRUCTION
INDIANA
August 2022 - Revision 0

PROJECT TYPE	2x1 F Class SCGT to CCGT Conversion
Owner's Project Development	[redacted]
Owner's Operational Personnel Prior to COD	
Owner's Engineer	
Owner's Project Management	
Owner's Legal Costs	
Owner's Start-up Engineering and Commissioning	
Land	
Temporary Utilities	
Permitting and Licensing Fees	
Switchyard	
Political Concessions & Area Development Fees	
Startup/Testing (Fuel & Consumables)	
Initial Fuel Inventory	
Site Security	
Operating Spare Parts	
Permanent Plant Equipment and Furnishings	
Builders Risk Insurance (0.45% of Construction Costs)	
Owner's Contingency (5% for Screening Purposes)	
Total Project Costs, 2022 MM$	
Total Project Costs, 2022 MM$ W AFUDC	
EPC Cost Per TOTAL kW, 2022 $/kW	
Total Cost Per TOTAL kW, 2022 $/kW	
EPC Cost Per INCREMENTAL kW, 2022 $/kW	
Total Cost Per INCREMENTAL kW, 2022 $/kW	
FIXED O&M COSTS (Note 8)	
Fixed O&M Cost - LABOR, 2022 $MM/Yr	
Fixed O&M Cost - OTHER, 2022 $MM/Yr	
LEVELIZED CAPITAL MAINTENANCE COSTS (Note 9)	
Major Maintenance Cost, 2022 $/GT-hr	
Major Maintenance Cost, 2022 $/MWh	
Catalyst Replacement Cost, 2022 $/MWh	
NON-FUEL VARIABLE O&M COSTS (EXCLUDES LEVELIZED CAP. MAINT. COST) (Note 10)	
Total Variable O&M Cost, 2022 $/MWh	
Water Related O&M ($/MWh)	
SCR Reagent, $/MWh	
Other Consumables and Variable O&M ($/MWh)	
ESTIMATED BASE LOAD EMISSIONS, ppm @15% O2 (Note 12)	
NO_X (without SCR/CO Catalyst)	25
CO (without SCR/CO Catalyst)	9
NO_X (with SCR/CO Catalyst)	2
CO (with SCR/CO Catalyst)	2
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS, lb/MMBtu (HHV) (Note 12)	
NO_X	0.007
SO_2	< 0.002
CO	0.004
CO_2	120

Notes
Note 1: Startup times reflect unrestricted, conventional starts for all gas turbines. These start times assume the inclusion of t
Note 2: Startup time to stack emissions compliance is not the same as the start time for gas turbine to MECL. Stack emissio
Note 3: Outage and availability statistics are collected using the NERC Generating Availability Data System. Combined cycle
Note 4: New and clean performance assumed. All performance ratings are based on NATURAL GAS operation. Min load ra
Note 5: Not Used.
Note 6: Water and ammonia consumption are based on performance at annual average conditions and the capacity factors s
Note 7: Capital and fixed O&M costs are presented in 2022 USD $MM.
Note 8: Base O&M costs are based on performance at annual average conditions. Fixed O&M labor assumes 17 additional F
Note 9: Major maintenance costs for frame gas turbines are hours based ($/GT-hr) when average hours per start is >27. Wh
Note 10: Variable O&M costs assume onsite demin treatment system.
Note 11: Not used.
Note 12: Emissions estimates are shown for steady state operation at ISO conditions. Estimates account for the impacts of S

Attachment 3.1 Stakeholder Materials

IRP Public Stakeholder Meeting

August 18, 2022

CenterPoint Energy

Welcome and Safety Share

Richard Leger
Senior Vice President Indiana Electric

Safety share

Know your exits

- Whenever you are entering a public area or a guest in a facility such as this, always know your exits. Take note of the signs
- There are two emergency exits, immediately behind me, Additionally, there are exit doors directly behind you – once through the door, to the left is the main entrance into the building. Should the main entrance be blocked there is an exit to the right of this room through a set of doors leading to the loading dock area

Visualize for safety

- When you enter a new space, visualize that an emergency – like a fire, bad weather, or an earthquake – could happen there and consider how you can respond
- The best way is to prepare to respond to an emergency before it happens. Few people can think clearly and logically in a crisis, so it is important to do so in advance, when you have time to be thorough

Fire

- Evacuate the building and move to the back of the CNP Plaza parking lot, near the YWCA

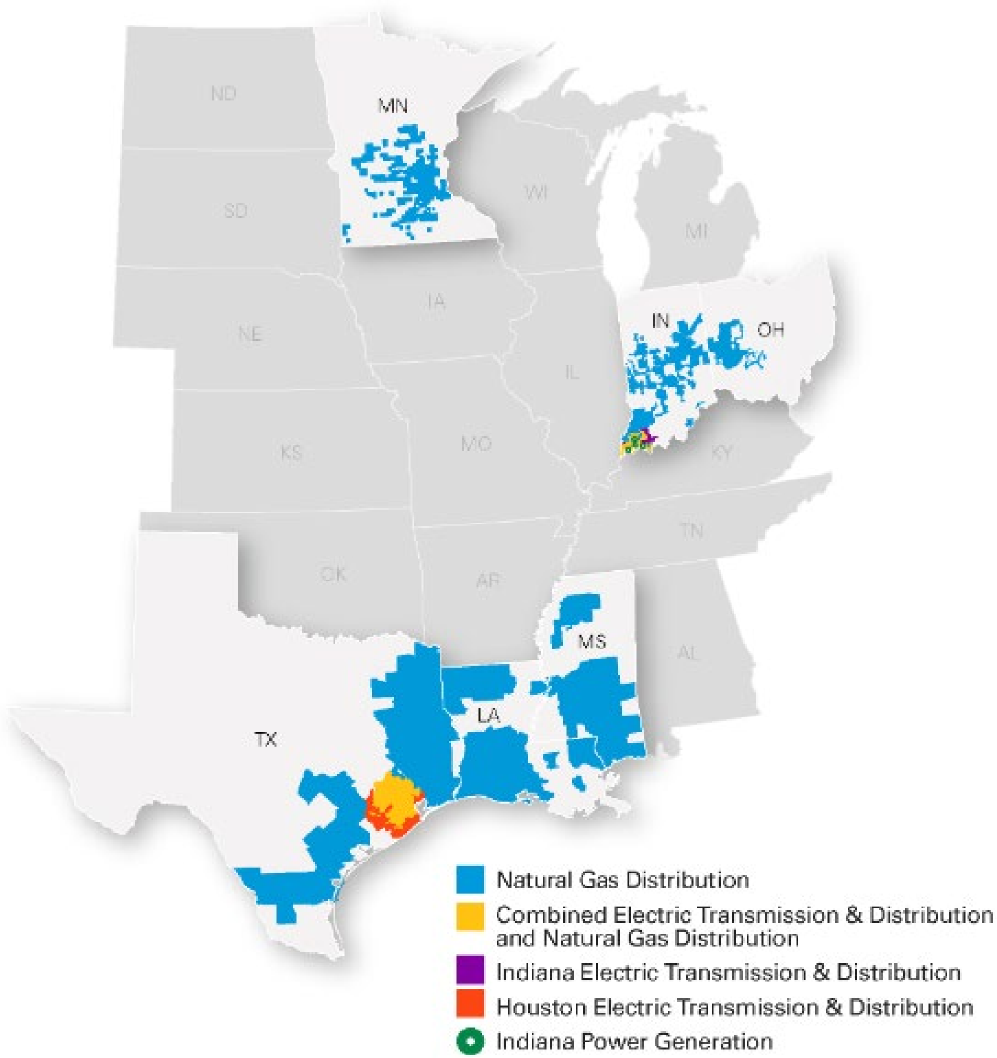
Bad Weather

- During a tornado warning, stay away from windows, glass doors, and outside walls
- Move in an orderly fashion to the stairwell, just outside of the lobby in the main entrance way

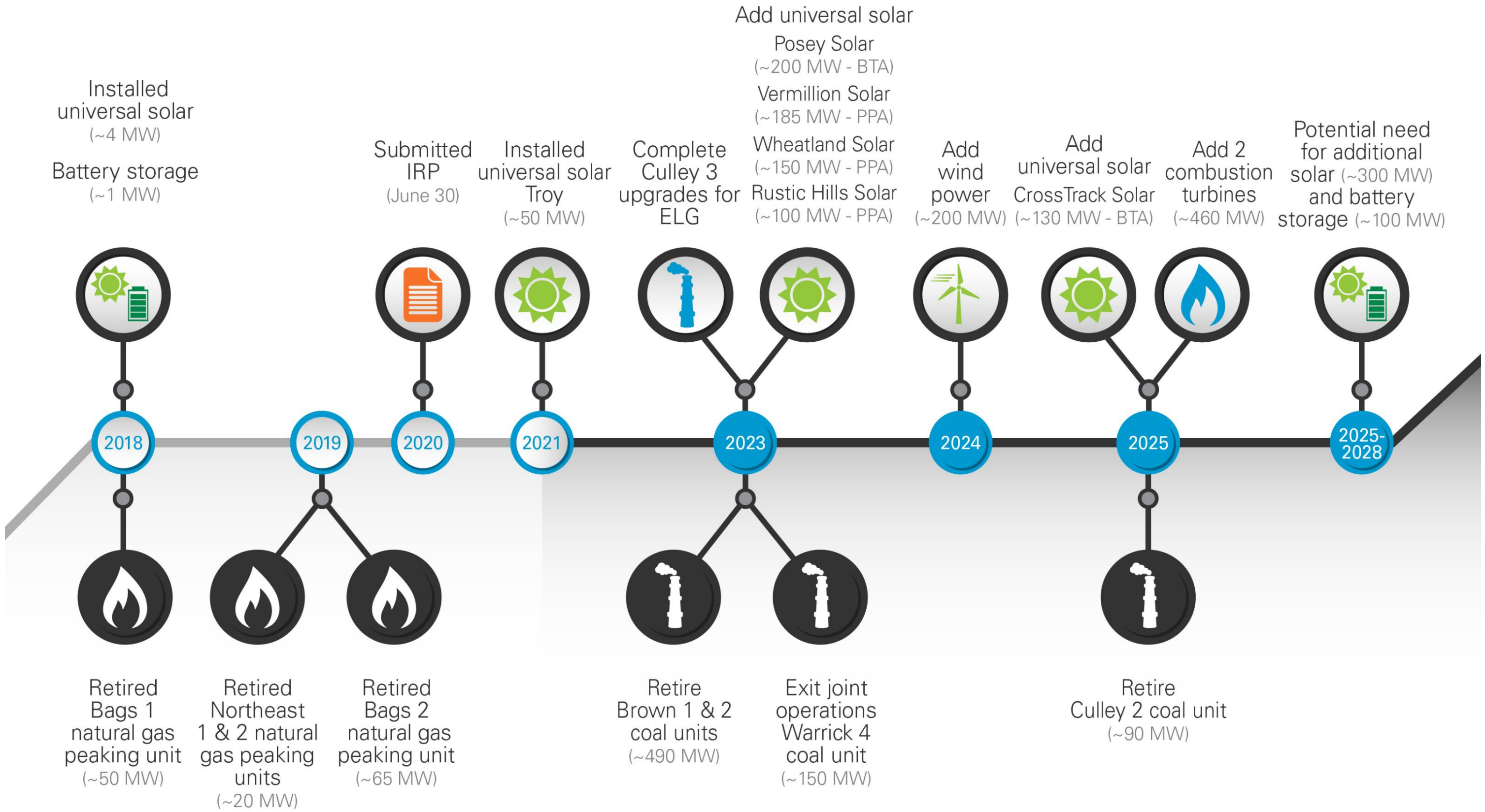
Earthquake

- Move under the desk where you are sitting, facing away from glass, and cover your head and face
- Once shaking has subsided, move in an orderly fashion towards the nearest exit and move to the back of the CNP Plaza parking lot, near the YWCA

Our Businesses



Generation Transition Timeline



Bags = Broadway Avenue Gas Turbines	ELG = Effluent Limitations Guidelines	PPA = Power Purchase Agreement
BTA = Build Transfer Agreement/Utility Ownership	MW = Megawatt	RFP = Request for Proposal

2022/2023 IRP Process

Matt Rice
Director, Regulatory and Rates

Agenda

Time		
9:00 a.m.	Sign-in/Refreshments	
9:30 a.m.	Welcome, Safety Message	Richard Leger, CenterPoint Energy Senior Vice President Indiana Electric
9:40 a.m.	2022/2023 IRP Process	Matt Rice, CenterPoint Energy Director Regulatory & Rates
9:55 a.m.	Draft Objectives & Measures	Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
10:20 a.m.	EnCompass Software	Kyle Combes, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
10:35 a.m.	Break	
10:45 a.m.	All-Source RFP	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
11:20 a.m.	Lunch	
12:00 p.m.	MISO Update	Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
12:35 p.m.	Environmental Compliance Update	Scott Duhon, CenterPoint Energy Director of Environmental Compliance & Policy
1:05 p.m.	DSM Market Potential Study	Jeffrey Huber, Principal, Energy Efficiency, GDS Associates
1:30 p.m.	Break	
1:40 p.m.	Draft Load Forecast Methodology	Michael Russo, Forecast Consultant - Itron
2:00 p.m.	Resource Options	Kyle Combes, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
2:20 p.m.	Draft Reference Case Market Inputs and Scenarios	Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
3:00 p.m.	Stakeholder Questions and Feedback	Moderated by Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
3:30 p.m.	Adjourn	

Meeting Guidelines

1. Please hold most questions until the end of each presentation. Time will be allotted for questions following each presentation. (Clarifying questions about the slides are fine throughout)
2. For those on the webinar, please use the “React” feature in Microsoft Teams (shown at the bottom of this page) to raise your hand if you have a question and we will open your (currently muted) phone line for questions within the allotted time frame. You may also type in questions in the Q&A feature in Microsoft Teams.
3. The conversation today will focus on resource planning. To the extent that you wish to talk with us about other topics we will be happy to speak with you in a different forum.
4. At the end of the presentation, we will open up the floor for “clarifying questions,” thoughts, ideas, and suggestions.
5. There will be a parking lot for items to be addressed at a later time.
6. CenterPoint Energy does not authorize the use of cameras or video recording devices of any kind during this meeting.
7. Questions asked at this meeting will be answered here or later.
8. We will do our best to capture notes but request that you provide written feedback (concepts, inputs, methodology, etc.) at IRP@CenterPointEnergy.com following the meeting. Additional questions can also be sent to this e-mail address.
9. The Teams meeting will be recorded only to ensure that we have accurately captured notes and questions from the meeting. The public meetings are not transcribed, and the recordings will not be posted to the website. However, Q&A summaries of our public meetings will be posted on www.CenterPointEnergy.com/irp.

Directors Report Feedback

- CEI South always utilizes feedback from the Director's report for continuous improvement opportunities

Improvement Opportunities	Positive Comments
One optimization run with a minimum of constraints	Significant improvements in all aspects of the IRP
Break out EE bundles into C&I and residential	Risk and uncertainty analysis and discussion in the IRP are well done
Allow DERs to participate in RFP	Wide range of alternative candidate portfolios
Consider sub-hourly to capture value of ancillary services	

Commitments for 2022/2023 IRP

- Will strive to make every encounter meaningful for stakeholders and for us
- The IRP process informs the selection of the preferred portfolio
- Utilize an All-Source RFP to gather market pricing & availability data
- Utilize EnCompass software to improve visibility of model inputs and outputs
- Will include a balanced risk score card. Draft to be shared at the first public stakeholder meeting
- Work with stakeholders on portfolio development
- Will test a wide range of portfolios in scenario modeling and ultimately in the risk analysis
- Will conduct a sensitivity analysis
- Will conduct technical meetings with interested stakeholders who sign an NDA
- Evaluate options for existing resources
- The IRP will include information presented for multiple audiences (technical and non-technical)
- Will provide modeling data to stakeholders as soon as possible
    - Draft Reference Case results – October 4th to October 31st
    - Draft Scenario results – December 6th to December 20th
    - Full set of final modeling results - March 7th to March 31st

Proposed 2022/2023 IRP Process

Stakeholder input is provided on a timely basis throughout the process, with meetings held in August, October, December, and March

- Conduct an All Source RFP
- Create Objectives, Risk Perspectives and Scorecard Development
- Create Reference Case Assumptions and Scenario Development
- Portfolio Development Based on Various Strategies, Utilizing Optimization to Create a Wide Range of Portfolios With Input From All Source RFP Data
- Portfolio Testing in Scenarios, Focused on Potential Regulatory Risks
- Portfolio Testing Using Probabilistic Modeling
- Conduct Sensitivity Analysis
- Populate the Risk Scorecard that was Developed Early in the Process and Evaluate Portfolios
- Select the Preferred Portfolio

2022/2023 Stakeholder Process

CenterPoint Energy

August 18, 2022	October 11, 2022	December 13, 2022	March 14, 2023
• 2022/2023 IRP Process • Objectives and Measures • Encompass Software • All-Source RFP • MISO Update • Environmental Update • Draft Reference Case Market Inputs & Scenarios • Load Forecast Methodology • DSM MPS/ Modeling Inputs • Resource Options	• All-Source RFP Results and Final Modeling Inputs • Draft Resource Inputs • Final Load Forecast • Scenario Modeling Inputs • Portfolio Development • Draft Reference Case Modeling Results • Probabilistic Modeling Approach and Assumptions	• Draft Scenario Optimization Results • Draft Portfolios • Final Scorecard and Risk Analysis • Final Resource Inputs	• Final Reference Case Modeling • Probabilistic Modeling Results • Risk Analysis Results • Preview the Preferred Portfolio

CenterPoint Energy

Draft Objectives and Measures

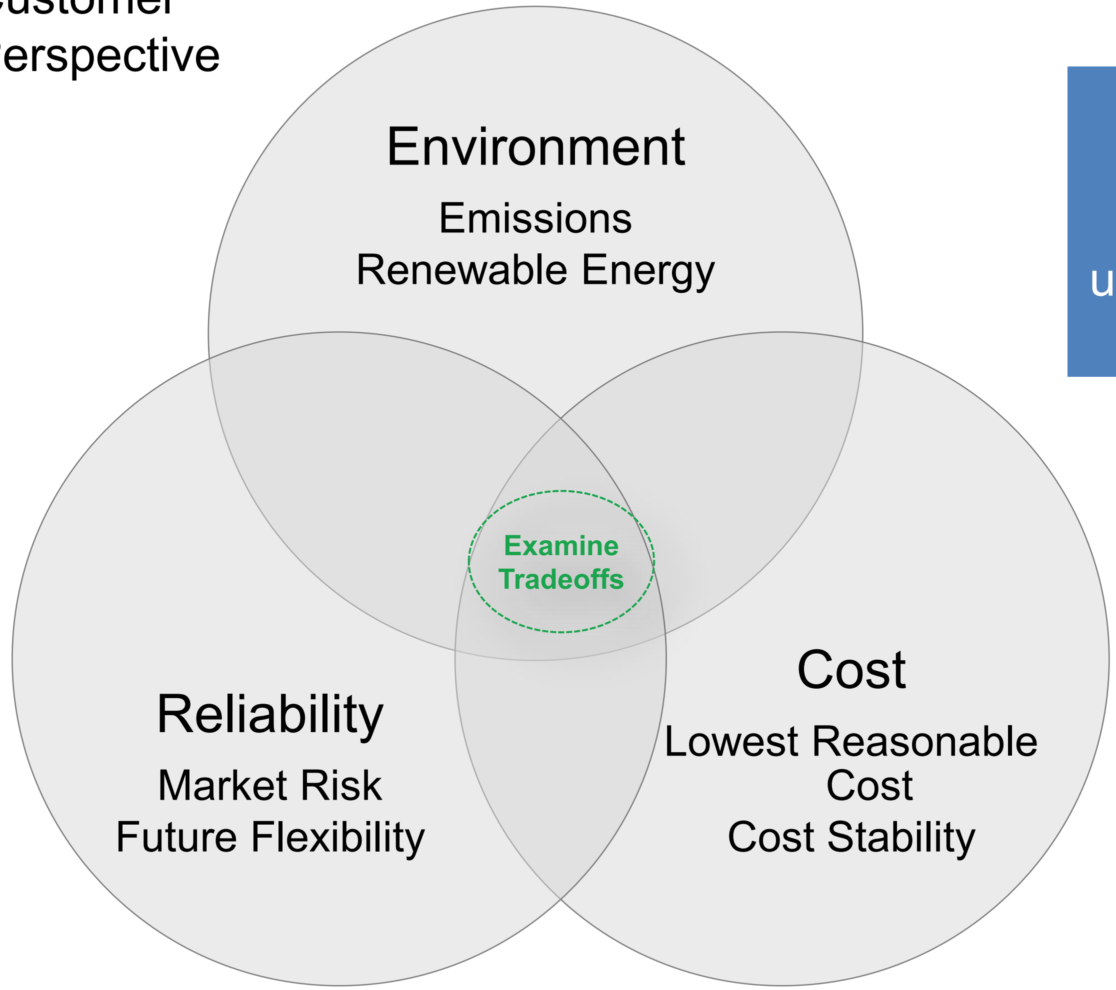
Matt Lind
Director, Resource Planning & Market Assessments
1898 & Co.

IRP Overview

- **Purpose:** Evaluate CenterPoint Energy's current energy resource portfolio and a range of alternative future portfolios to meet customers' electrical energy needs in an affordable, system-wide manner
- **Process:** Evaluate portfolios across many objectives
  - Environmental stewardship
  - Market and price risk, and future flexibility
  - System flexibility to provide backup resources
  - Reliability
  - Resource diversity
- Each objective is important and worthy of balanced consideration in the IRP process, taking into account uncertainty; Some objectives are better captured in portfolio construction than as a portfolio measure
- The measures allow the analysis to compare portfolio performance and potential risk on an equal basis

EACH portfolio will have tradeoffs

Customer Perspective



Each portfolio will be tested against all objectives and metrics. This evaluation will ultimately result in the selection of the preferred portfolio.

IRP Draft Objectives & Measures

CenterPoint Energy

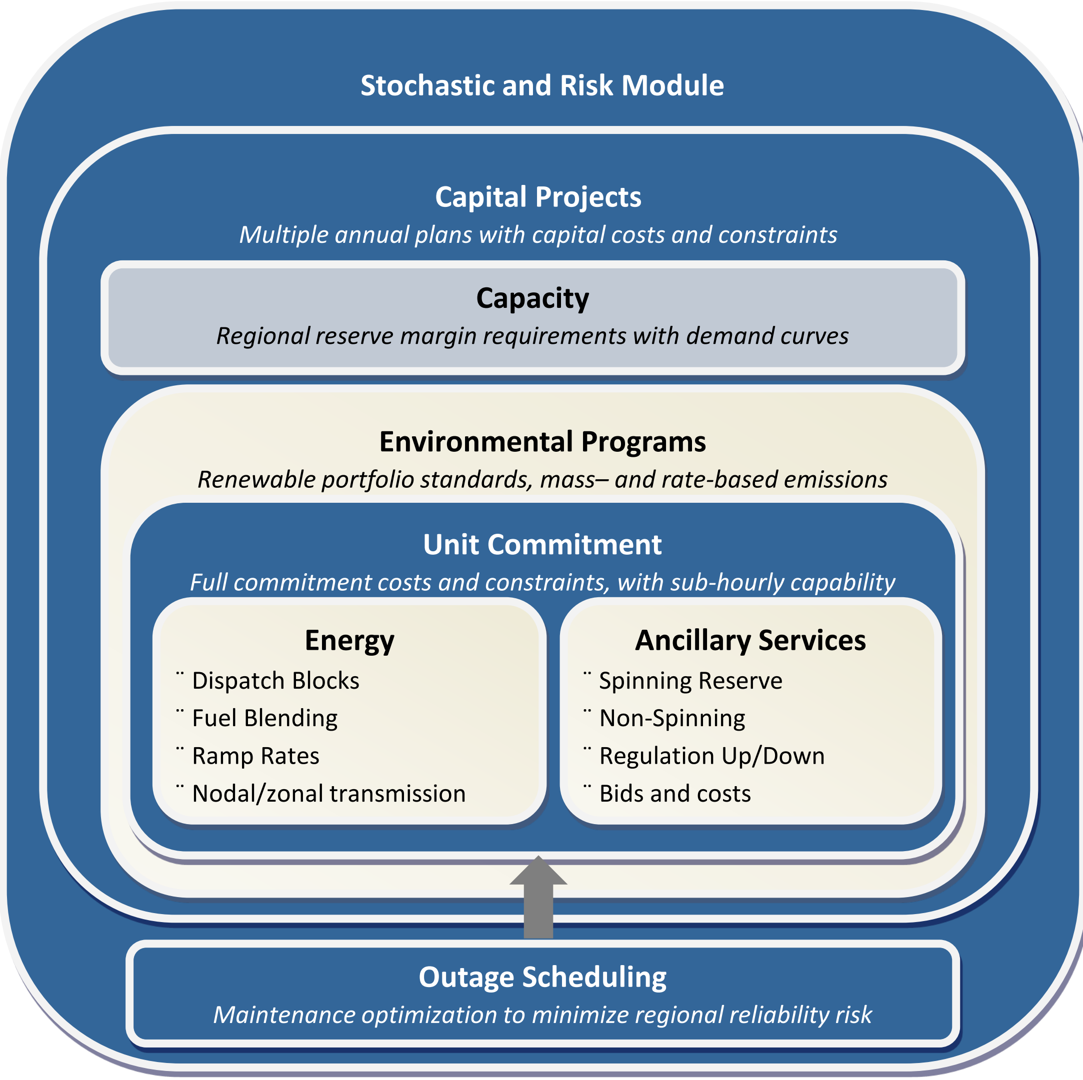
Objective	Potential Measures	Unit
Affordability	20 year NPVRR	$
Environmental Sustainability	CO_2 Intensity	Tons CO_2/kwh
Reliability	Must Meet MISO Planning Reserve Margin Requirement in All Seasons	UCAP MWs
	Spinning Reserve\Fast Start Capability	% of Portfolio MW's That Offer Spinning Reserve\Fast Start
Market Risk Minimization	Energy Market Purchases or Sales	%
	Capacity Market Purchases or Sales	%
Execution	Assess Challenges of Implementing Each Portfolio	Qualitative

EnCompass

Kyle Combes
Project Manager, Resource Planning & Market Assessments
1898 & Co.

What is EnCompass?

- Robust production cost and capacity expansion software developed by Anchor Power Solutions
- Currently serves as the basis for regulatory filings in 17 states
- Combines a time series data model with performance options for managing runtime and complexity, while always maintaining chronological constraints



What are EnCompass' Capabilities?

CenterPoint Energy

- Can import and export data into non-proprietary, easy to read spreadsheets
- Has built-in high-level summaries and detailed dispatch reports that support transparency
- Can solve for seasonal capacity obligations, like those currently proposed by MISO
- Can co-optimize dispatch of storage along with other traditional resource types
- Can perform sophisticated stochastic modeling of variables to assist in evaluating risk
- Can incorporate ramp rates, startup times, and startup costs; data items that most traditional long-term models ignore

ANCHOR POWER SOLUTIONS

ENCOMPASS POWER PLANNING SOFTWARE

Who uses EnCompass?

CenterPoint Energy

- EnCompass is licensed by utilities, consultants, and stakeholders as a powerful and accurate tool

aes Indiana

DAIRYLAND POWER COOPERATIVE

DTE Energy

DUKE ENERGY

GREAT RIVER ENERGY

IMPA
Indiana Municipal Power Agency

minnesota power

OTTER TAIL POWER COMPANY

PNM Resources

TVA

Xcel Energy

1898 & CO
PART OF BURNS & McDONNELL

...and many more!

All-Source RFP

Drew Burczyk
Consultant, Resource Planning & Market Assessments
1898 & Co.

All-Source RFP Overview

- CenterPoint's 2022 All-Source RFP follows a very similar process as the 2019 All-Source RFP
- Sought feedback and incorporated input from stakeholder groups prior to issuing the RFP
- The guiding principles of the RFP are to conduct a process that is:
  - Objective
  - Fair
  - Open
- Issued advanced notice of RFP
- Open to continued feedback for future RFPs

All-Source RFP Purpose

- The All-Source RFP will help inform CenterPoint Energy's 2022/2023 Integrated Resource Plan modeling
- From the proposals received, CenterPoint Energy can better understand and access current market data

All-Source RFP Overview

CenterPoint Energy

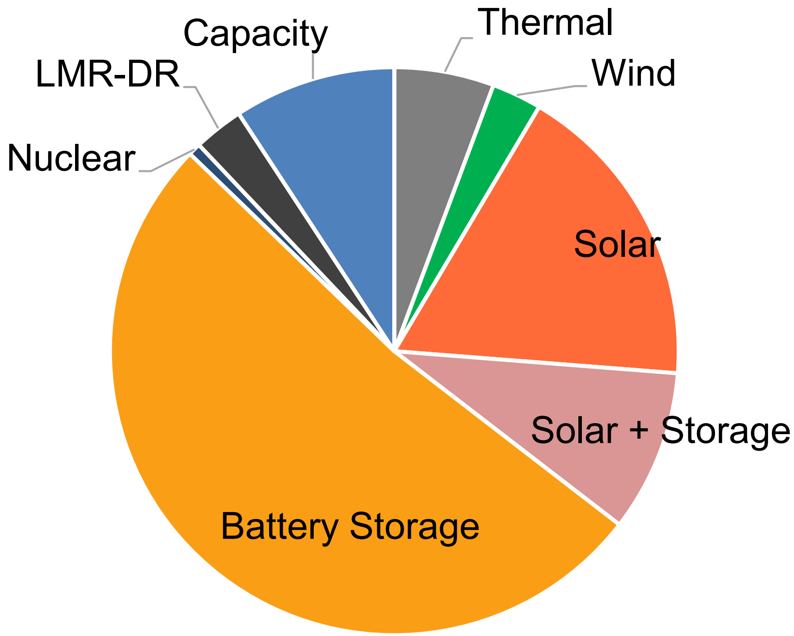
- Open and non-limiting
- Technologies
  - Renewables and storage
  - Thermal
  - Load modifying resources and demand resources
  - Capacity only
- Eligible transaction structures
  - PPA
  - Asset purchase
  - Renewable project in development
  - Demand-side contracts
  - Capacity only contracts
- Resources to be accredited prior to March 1st, 2027

RFP Key Dates

RFP Issued	Wednesday, May 11, 2022
Notice of Intent, NDA, and Respondent Application Due	Friday, May 27, 2022
Pre-Bid Meeting	Wednesday, June 1, 2022
Proposal Submittal Due Date	Tuesday, July 5, 2022
Initial Proposal Review and Evaluation Period	Wednesday, July 6, 2022 – Wednesday August 11, 2022
Proposal Evaluation Completion Target and Short List to CenterPoint For Further Due Diligence	Friday, August 12, 2022

PRELIMINARY RFP STATISTICS

As part of the RFP, we received 129 proposals from 27 different respondents.



Proposal Breakdown

2022 RFP Responses	Proposal Installed Capacity (MW)	Project Installed Capacity (MW)
Thermal	3,087	1,909
Battery Storage	10,149	1,651
Solar + Storage	2,700	1,400
Capacity	632	557
Solar	2,588	1,529
LMR-DR	64	63
Wind	800	400
Total	20,019	7,508

Summary of RFP Responses

- Received significant number of proposals accounting for a diverse set of generation technologies to help inform IRP modeling
- Consistent with industry trend of higher pricing compared to proposals seen in recent years potentially impacted by:
  - Supply chain and COVID impacts
  - Inflation
  - Solar market uncertainty due to Department of Commerce Anti-Dumping/Countervailing Duties Investigation
  - Uyghur Forced Labor Prevention Act (UFLPA)
  - MISO generator interconnection queue
- IRP scenario modeling to help evaluate portfolio replacement decisions under varying future technology costs

MISO Update

Matt Lind
Director, Resource Planning & Market Assessments
1898 & Co.

What is MISO?

- **M**idcontinent **I**ndependent **S**ystem **O**perator
- In 2001, MISO was approved as the first Regional Transmission Organization (RTO)
  - MISO has operational authority: the authority to control transmission facilities and coordinate security for its region to ensure reliability
  - MISO is responsible for dispatch of lowest cost generation units: MISO's energy market dispatches the most cost effective generation to meet load needs
- MISO is divided into 10 Local Resources Zones (LRZ), Indiana is part of Zone 6, which includes northwest Kentucky (Big Rivers Electric Cooperative)
- Each LRZ has its own planning requirements in regard to energy and capacity
- Each Zone's ability to rely on neighboring Zones depends largely on transmission infrastructure. Based on MISO's Local Clearing Requirement (LCR), approximately 70% of CenterPoint's generation must be physically located within MISO Zone 6

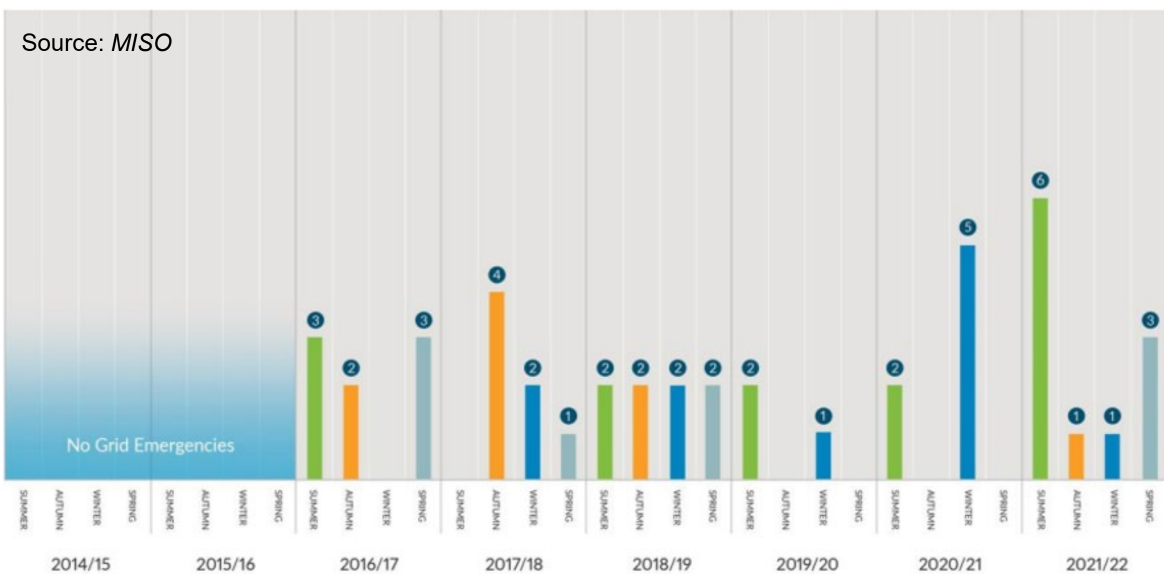
Source: *MISO*

MISO Updates

- New technologies, regulations and policies are changing market dynamics
  - Ongoing power supply fleet transition MISO-wide through resource retirements and increasing intermittent resource additions
  - Corresponding reduction in excess capacity and/or energy during certain periods across MISO is resulting in changes to MISO's Resource Adequacy design
  - In September 2020 FERC issued order 2222, which will allow for distributed energy resources to participate in the market once implemented in MISO

MISO Resource Adequacy

- One of MISO's key functions is to facilitate the availability of adequate and cost-effective resources to reliably meet peak demand in the MISO region
- With MISO's ongoing power supply fleet transition, resource adequacy must evolve to account for new technologies and impacts due to seasonal weather



MISO Resource Adequacy

- MISO's Market Redefinition efforts have led to a proposed[1] seasonal resource adequacy construct with availability-based accreditation
  - Winter - December, January, February
  - Spring - March, April, May
  - Summer - June, July, August
  - Fall - September, October, November

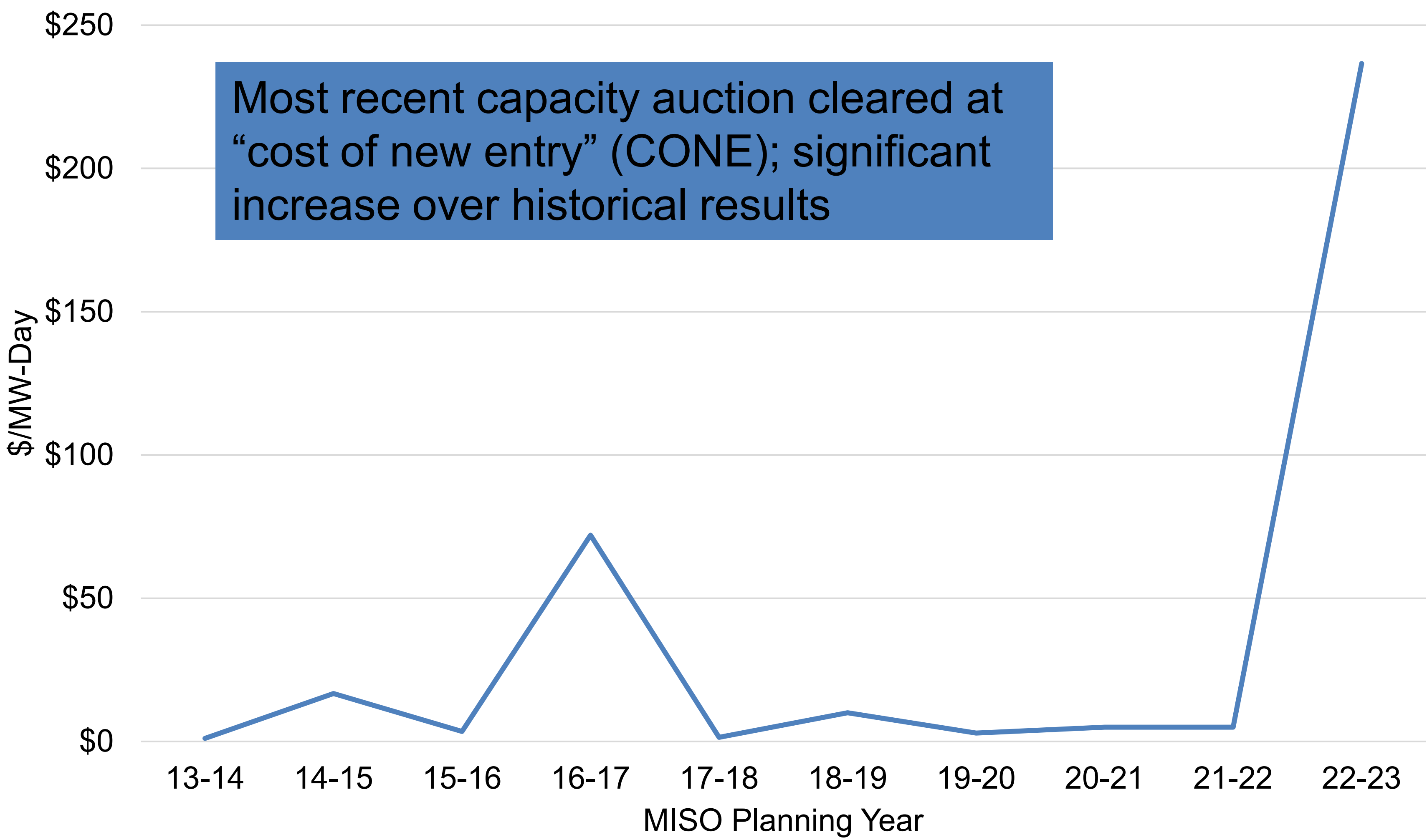
[1]Filed with FERC Nov. 2020 to be effective Sept. 1, 2022 with implementation beginning in PY 2023/24.

Proposed Seasonal Resource Adequacy Construct

MISO's Market Redefinition aims to ensure resources with needed capabilities and attributes will be available in the highest risk periods across the year.

- MISO will calculate sub-annual resource adequacy requirements to align with seasonal needs
  - Loss of load expectation study will calculate the planning reserve margin requirements and local reliability requirements on a seasonal basis
- Accredit resources by season to ensure resources are available when needed, seasonal accredited capacity (SAC)
  - Thermal accreditation will be calculated based on tiered structure within each season, tight hours and non-tight hours
  - Intermittent resource accreditation enhancements are being evaluated; current seasonal accreditation methodology:
    - Wind - Seasonal Effective Load Carrying Capability (ELCC) based on historical performance in 8 peak days per season
    - Non-Wind - based on historical output during hours 15, 16, 17 EST for spring, summer, and fall; Winter accreditation based on hours 8, 9, 19, and 20 EST

MISO Zone 6 Capacity Prices



FERC 2222

- FERC Order No. 2222 removes barriers preventing distributed energy resources (DERs) from participating in organized capacity, energy and ancillary services markets run by regional grid operators such as MISO
- DERs are small-scale power generation or storage resources located on an electric utility's distribution system or behind a customer meter
- Example technologies include solar, storage, demand response, energy efficiency, electric vehicles

FERC 2222

- MISO's proposed approach to 2222 has been submitted for compliance with FERC
  - Proposed implementation date of October 1, 2029
- Planning to incorporate into scenario and/or sensitivity analysis
  - Looking for input and feedback on FERC 2222 in IRP analysis

Environmental Update

Scott Duhon,
Director of Environmental Compliance & Policy

Coal Combustion Residuals Rule

- Final Rule issued April 2015
- Allows continued beneficial reuse of coal combustion residuals
  - Majority of CEI South's fly ash beneficially reused in cement application
  - Scrubber by-product at Culley and Warrick beneficially reused in synthetic gypsum application
- Rule established operating criteria and assessments as well as closure and post-closure care standards
  - Culley West ash pond closure activities were completed in December 2020
  - Culley East ash pond is still operating, with planned closure-by-removal. Closure plan submitted to IDEM in February 2022
  - Brown ash pond is still operating, with planned closure by removal and beneficial reuse. Beneficial reuse activities have commenced
- Part A Rule finalized in August 2020
  - Finalized revised compliance deadline (April 2021) and provided a mechanism to request limited extension for use of ponds. CEI South filed extension requests for A.B. Brown ash pond and F.B. Culley East ash pond in November 2020
    - EPA has not yet issued a decision on either extension request; however, construction of the extension ponds were recently approved by the IURC in Cause No. 45564, and we are proceeding with design and construction per the commitments provided by our submittals to EPA

Effluent Limitation Guidelines

- On September 30, 2015, the EPA finalized its new Effluent Limitation Guidelines (ELGs) for power plant wastewaters, including ash handling and scrubber wastewaters
- The ELGs prohibit discharge of water used to handle fly ash and bottom ash, thereby mandating dry handling of fly ash and bottom ash
- ELG Reconsideration Rule finalized in October 2020 updated the compliance deadline for bottom ash which allows for continued operation of Culley Unit 2 until December 2025, which CNP may do to help support capacity requirements until new combustion turbines and renewables projects are completed; Operation of Culley Unit 2 beyond December 2025 would require completion of a bottom ash handling retrofit
- Culley Unit 3 retrofit of bottom ash to dry handling was completed in 2020; Spray Dryer Evaporator for scrubber wastewater is on schedule for completion in 2023

Clean Water Act 316(b)

- In May 2014 EPA finalized its Clean Water Act 316(b) rule which focuses on impingement and entrainment of aquatic species during water intake
- The final rule did not mandate cooling tower retrofits
- CNP submitted the multi-year entrainment and other required studies for F.B. Culley as required under the rule and proposed modified traveling screens in its NPDES renewal submittal; CEI South is still in discussion with IDEM as to the applicable 316(b) technology
- For purposes of IRP modeling, CEI South is modeling a range of scenarios which would include intake screen modifications and new wedge wire screens for the Culley plant and will assume a 2024 - 2026 deadline for compliance

NOx Ozone Season Allowances

- Revised CSAPR Update Rule finalized in May 2021 significantly reduced amount of ozone season NOx allowances allocated to each state and have significantly increased the cost

Year	Tons Allocated	Tons Purchased	Purchase Cost per Allowance
2018	1,381	350	$200
2019	1,381	1,050	$164
2020	1,379	800	$73
2021*	1,184	600	$2,310
2022**	851	450	$50,000

*2021 – 2022 are Group 3 allowances under the May 2021 rule. 2021 was prorated due to the rule becoming effective after the start of the ozone season, making 2022 the first full season under the Revised CSAPR Update rule.
**2022 purchase quantity is based on generation as of 7/22/2022. Purchase cost is based on market offer price as of 8/4/2022.

Carbon Regulation

- Since 2015 dueling administrations have attempted to finalize carbon regulations under CAA Sect. 111(d)
- The Clean Power Plan (CPP) would have set stringent state emission caps and effectuated a shift in state generation portfolios to significantly increased renewables, which implementation was stayed by the U.S. Supreme Court
- The EPA sought to vacate the CPP and replace it with the Affordable Clean Energy (ACE) rule, which focused on efficiency targets that could be met at an individual unit level
- In June 2022, the U.S. Supreme Court held that the EPA exceeded its authority when it promulgated the CPP's stringent state emission caps that would have required generation shifting within states; While the decision did not go so far as to hold that EPA was explicitly prohibited from promulgating a regulation requiring compliance measures "outside the fence line" for existing units under 111(d), the ACE rule remains the current reference case 111(d) compliance scenario for modeling purposes

Future Regulation - MATS Revisions

- MATS revision – Mercury & Air Toxics (MATS)
  - In May of 2020, the EPA issued its revised finding that it is not *appropriate and necessary* to regulate coal-fired electric generating units under Section 112 of the CAA; However, EPA did <u>not</u> seek at that time to withdraw the currently applicable MATS standards finalized in 2015
  - In May of 2020 EPA also published its residual risk and technology review of MATS, finding that emissions of hazardous air pollutants (HAPs) have been reduced such that residual risk is at acceptable levels, that there are no developments in 2 HAP emissions controls to achieve further cost-effective reductions beyond the current standards, and no changes to the MATS rule are warranted
  - On January 21, 2022, EPA proposed to revoke its finding that it is not *appropriate and necessary* to regulate coal-fired electric generating units under Section 112 of the CAA, and notified of its intent to review the residual risk and technology review of MATS
  - EPA's actions in January 2022 set the stage for potential updates to the existing MATS limits for mercury and acid gases from coal-fired power plants

Future Regulation – Ozone "Good Neighbor SIP"

- On April 6, 2022, EPA proposed to further reduce emissions of NOx from coal-fired power plants under Section 126 (or the "Good Neighbor") provision of the CAA, which requires coal-fired power plants in 26 states (including Indiana) to reduce emissions of NOx that EPA has found to contribute to ozone nonattainment in downwind states for the more stringent 2015 Ozone NAAQS
- Beginning in the 2023 ozone season, EPA is proposing to include Indiana coal-fired power plants in a revised and potentially significantly more stringent Cross-State Air Pollution Rule (CSAPR) "NOx Ozone Season Group 3 Trading Program"

Natural Gas

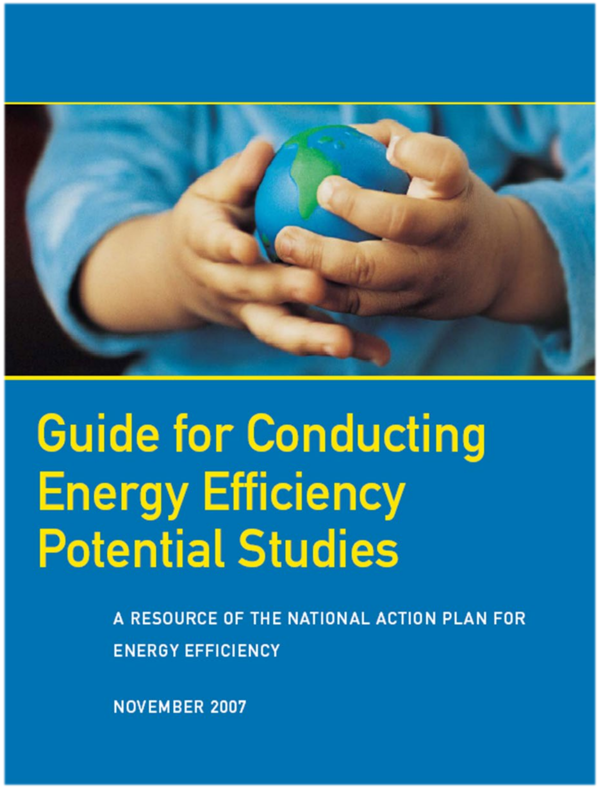
- Clean Water Act Section 401
  - October 2021, the U.S. District Court vacated EPA's 2020 Clean Water Act Section 401 Certification Rule; April 2022, the U.S. Supreme Court stayed the vacatur reinstating the 2020 Rule
- New Source Performance Standards
  - November 2021, the EPA proposed NSPS program rules that would reverse the prior administration's rules and return to the previous methane standards and contain more stringent monitoring requirements and possibly require state specific plans

DSM Market Potential Study

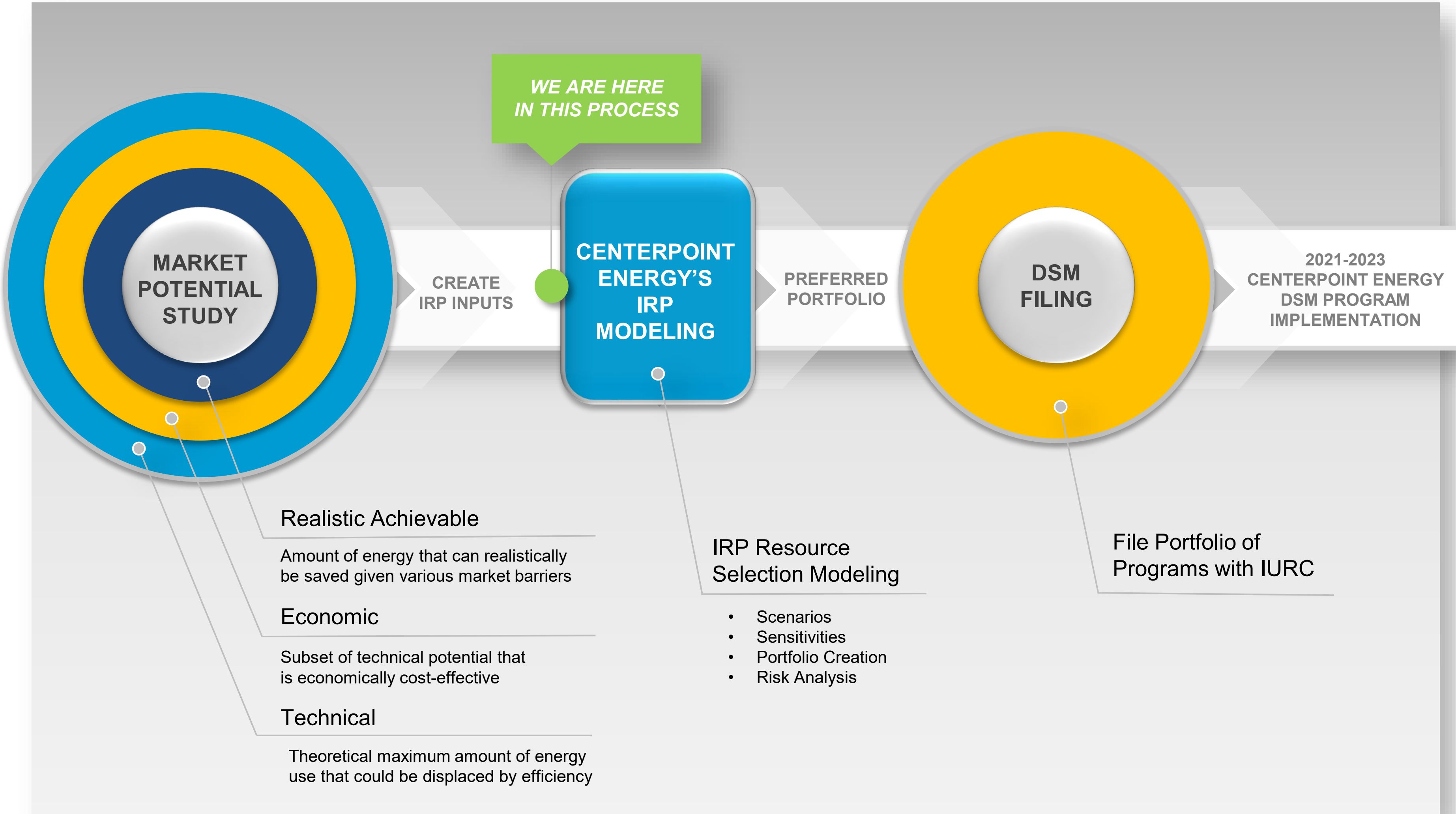
Jeffrey Huber
Principal, Energy Efficiency
GDS Associates, Inc.

Market Potential Studies & IRPs

- What is a Market Potential Study (MPS)?
  - Simply put, a potential study is a quantitative analysis of the amount of energy savings that either exists, is cost-effective, or could be realized through the implementation of energy efficiency programs and policies
- About the CEI South MPS
  - Includes Energy Efficiency (EE) and Demand Response (DR)
  - 2022 MPS is considered a “refresh” and does not include new primary market research
  - MPS analysis covers 2025-2042



Market Potential Studies & IRPs



Types of EE/DR Potential

CenterPoint Energy

TECHNICAL POTENTIAL

All technically feasible measures are incorporated to provide a theoretical maximum potential.

ECONOMIC POTENTIAL

All measures are screened for cost-effectiveness using the UCT Test. Only cost-effective measures are included.

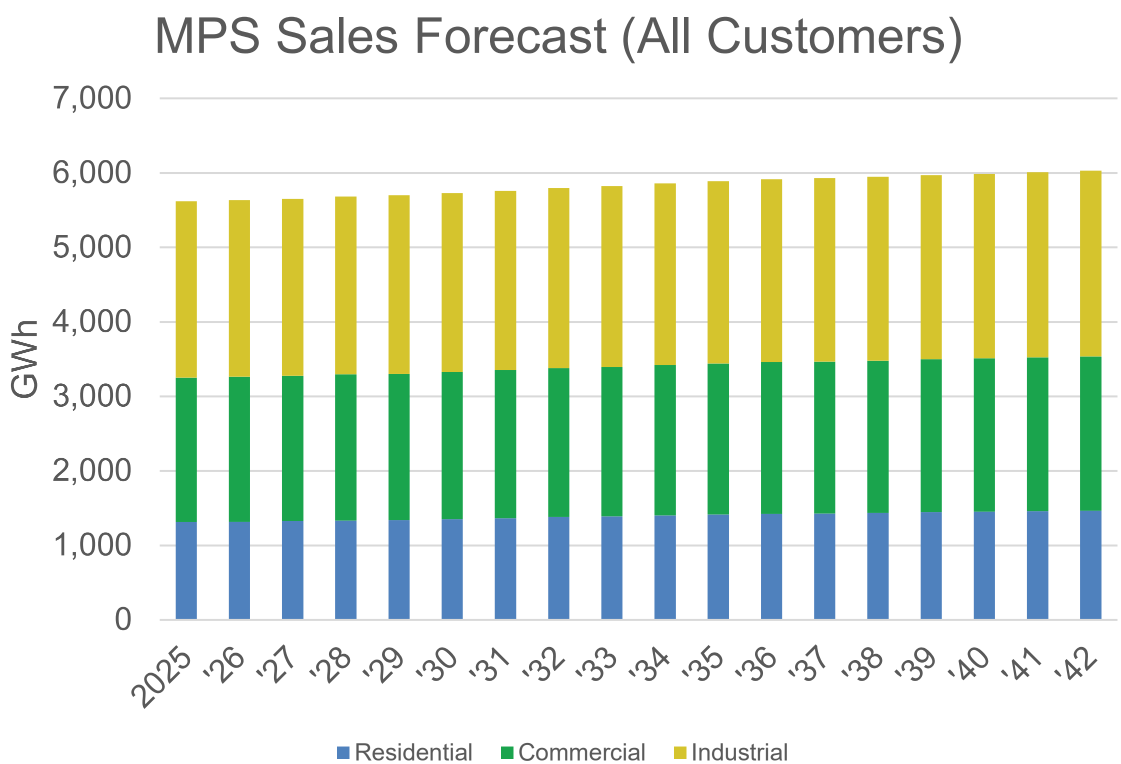
ACHIEVABLE POTENTIAL

Cost-effective energy efficiency potential that can practically be attained in a real-world program delivery case, assuming that a certain level of market penetration can be attained.

Types of Energy Efficiency Potential

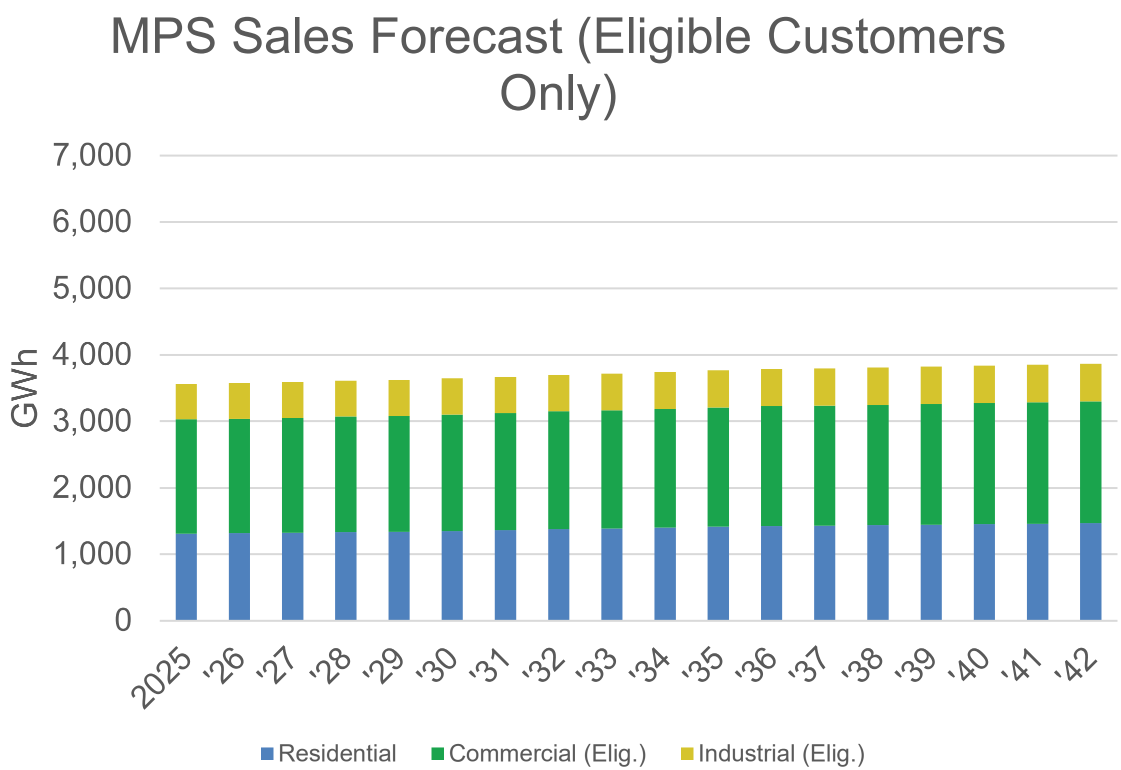
Not Technically Feasible	TECHNICAL POTENTIAL		
Not Technically Feasible	Not Cost-Effective	ECONOMIC POTENTIAL	
Not Technically Feasible	Not Cost-Effective	Market & Adoption Barriers	ACHIEVABLE POTENTIAL

Load Forecast for EE/DR



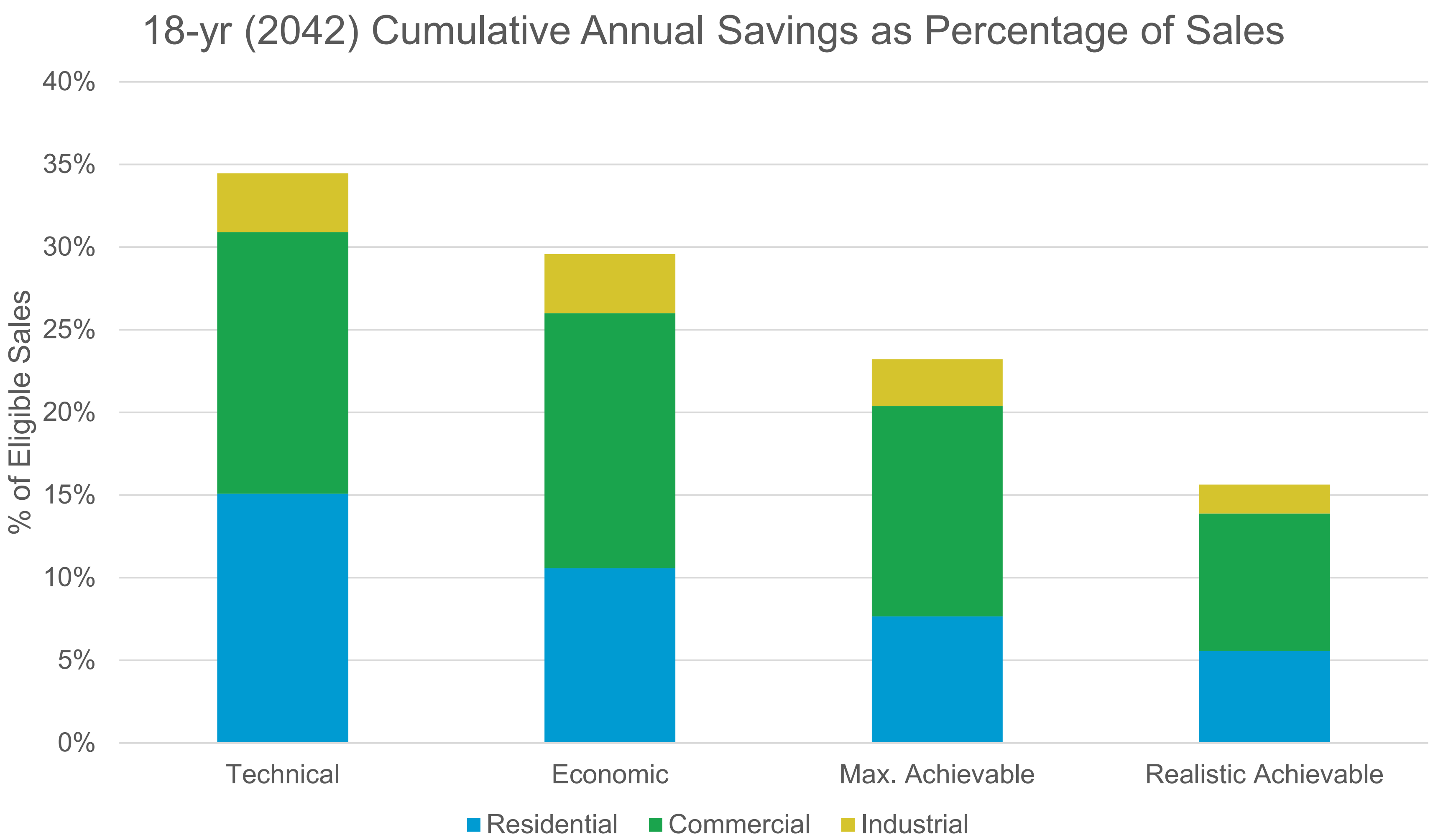
- MPS Sales Forecast reclassifies some load between commercial and industrial to reflect building type vs. rate code
- A substantial portion of the industrial load (and a smaller portion of the commercial load) can opt out of utility DSM programs

Eligible Load for EE/DR

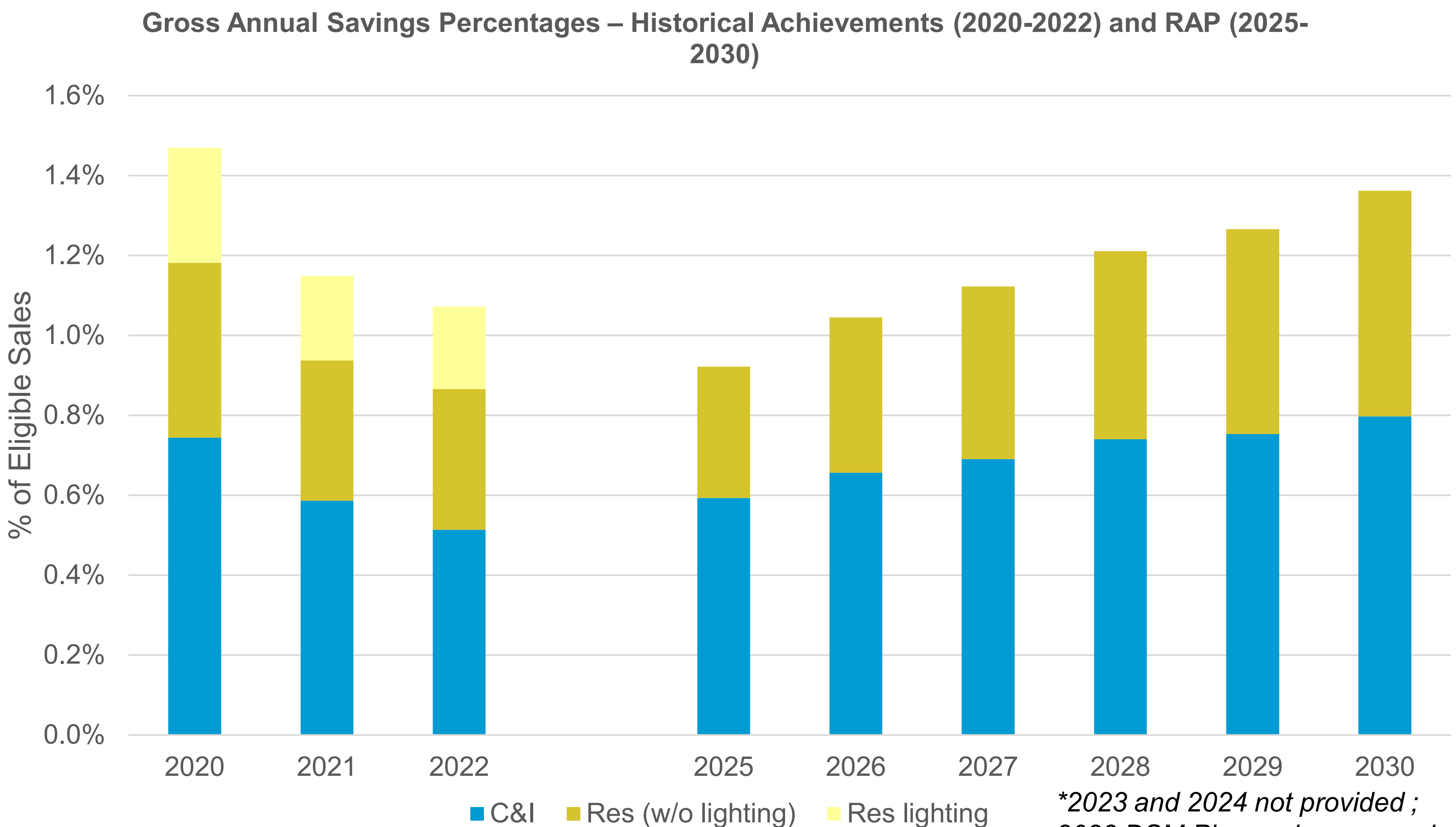


- Opt-out customers are not included in the base case of the MPS

EE Analysis – Summary Results



EE Analysis – Historical Comparison



**2023 and 2024 not provided ;*
2023 DSM Plan under approval
2024 DSM Plan will be extension filing

DR Analysis – Programs Included

- DR programs analyzed include:
  - Direct load control of air conditioning (using thermostats and switches), water heaters, and pool pumps
  - Rate programs include critical peak pricing (with enabling technology and without), peak time rebates, real time pricing, and time of use
- Timing of programs:
  - DLC air conditioning switches expected to fully transition to thermostats by 2029
  - Rate programs starting in 2026 as potential pilots and ramping up starting in 2031

DR Analysis – Summary Results

DR Hierarchy

DR analysis accounts for interactive effects as additional types of demand response programs are added to the mix. The hierarchy places existing DR programs at the top of the list. Rate programs are ordered based on the highest load reduction per customer. The hierarchy for demand response programs is as follows:

1. Direct Load Control
2. Critical Peak Pricing with Enabling Technology (such as a smart thermostat)
3. Critical Peak Pricing without Enabling Technology
4. Real Time Pricing
5. Peak Time Rebate
6. Time of Use

EE/DR Inputs into IRP

- EE Inputs will align with RAP Potential *(but adjusted from gross to net savings)*
- EE Inputs will be provided over three vintages
  - 2025-2027 (3 years)
  - 2028-2030 (3 years)
  - 2031-2042 (12 years)
- For 2025-2027, EE Inputs will be bundled to closely resemble program offerings
  - For remaining vintages, EE inputs will be aggregated at the sector level
- EE Costs will include utility costs (incentives and non-incentive costs)
  - Costs will be adjusted to recognize value of avoided lifetime T&D benefits

EE/DR Inputs into IRP

- Income Qualified Savings will be a going-in resource (i.e. not selectable) as high program costs would likely prohibit selection in the IRP model
  - The cost (and savings) of the income-qualified program will be aligned so that the future income-qualified annual budget maintains the same proportion to the total budget as the current DSM Plan
- Expected Improvements to the DSM Plan
  - Bundles will be sector specific, consistent with request from the prior Director’s Report
  - Within a bundle/vintage, the EE Savings are broken out by end-use
  - Cost adjustment to reflect avoided transmission and distribution benefits
  - Consistent with prior IRP DSM Inputs, model will account for full lifetime savings of DSM bundles

EE/DR Inputs into IRP

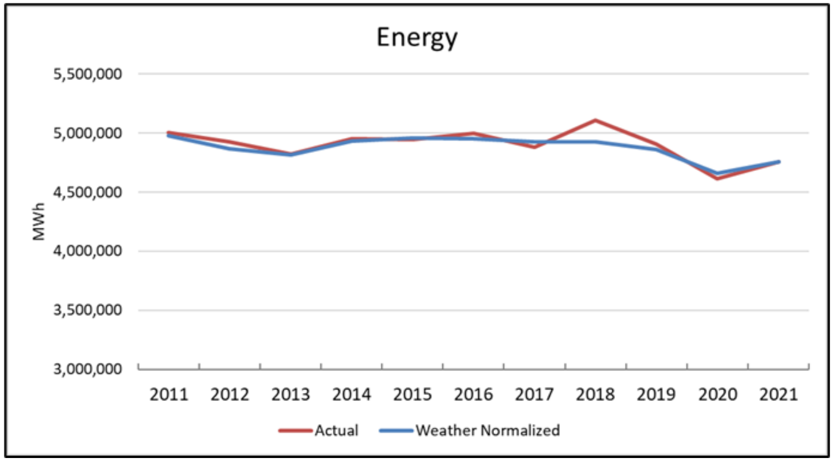
- Bundles for demand response follow the same vintages as Energy Efficiency
- Demand response bundles created for four categories
  - Residential DLC
  - Residential Rates
  - C&I DLC
  - C&I Rates/Interruptible
- DR program provide summer peak savings but expected to provide minimal winter peak and energy value to the portfolio
- Phase out of existing DLC legacy air conditioning switches will be a going-in resource; remaining DR will be modeled as a selectable resource

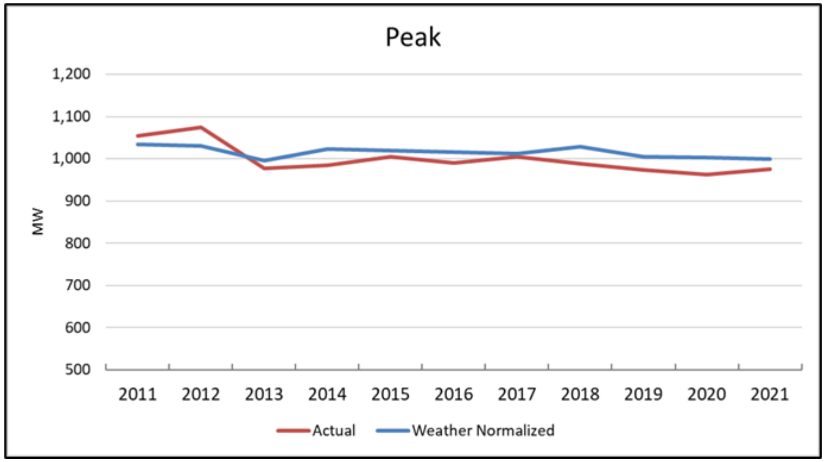
Draft Load Forecast Methodology

Michael Russo
Senior Forecast Consultant - Itron

Historical Energy and Peaks Trends

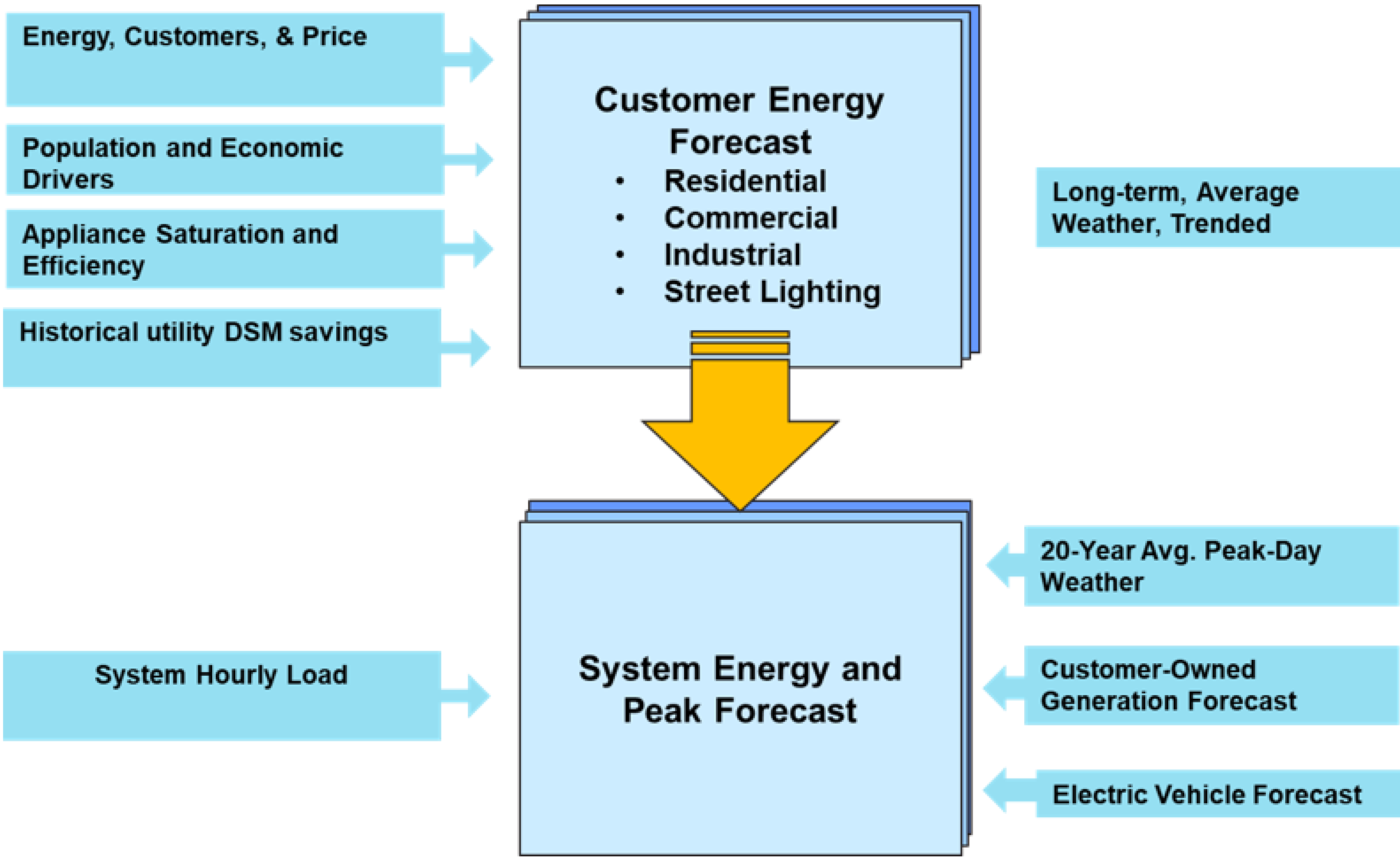
- Historical decline in energy and peaks despite moderate economic and customer growth
  - Strong efficiency gains reflecting new and existing Federal codes and standards as well as utility sponsored energy efficiency program savings
  - 0.4% average annual decline in energy and peaks; 2011-2021, weather normalized





*Excludes the loss of load in 2017 from large customer's cogeneration

Bottom-Up Forecast Approach



Economic Drivers

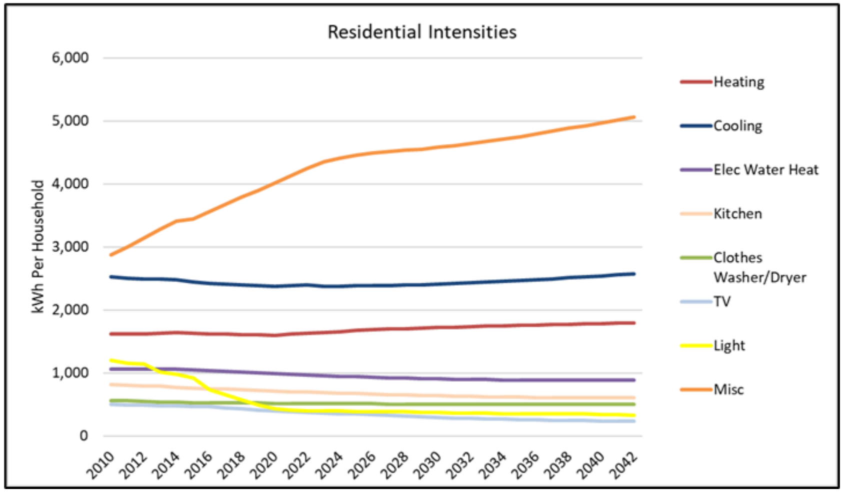
IHS Markit forecast for the Evansville MSA and Indiana

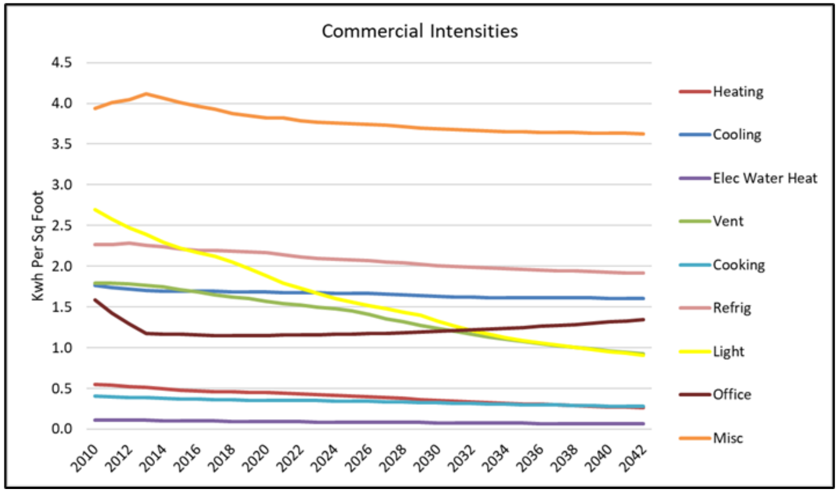
- Residential Sector
    - Households: 0.4% CAGR
    - Real Household Income: 1.6% CAGR
    - Household Size: -0.3% CAGR
- Commercial Sector
    - Non-Manufacturing Output: 1.5% CAGR
    - Non-Manufacturing Employment : 0.3% CAGR
    - Population: 0.4% CAGR
- Industrial Sector
    - Manufacturing Output: 2.2% CAGR
    - Manufacturing Employment: -0.6% CAGR

*CAGR= Compound average growth rate from 2022-2042

End-use intensity Trends

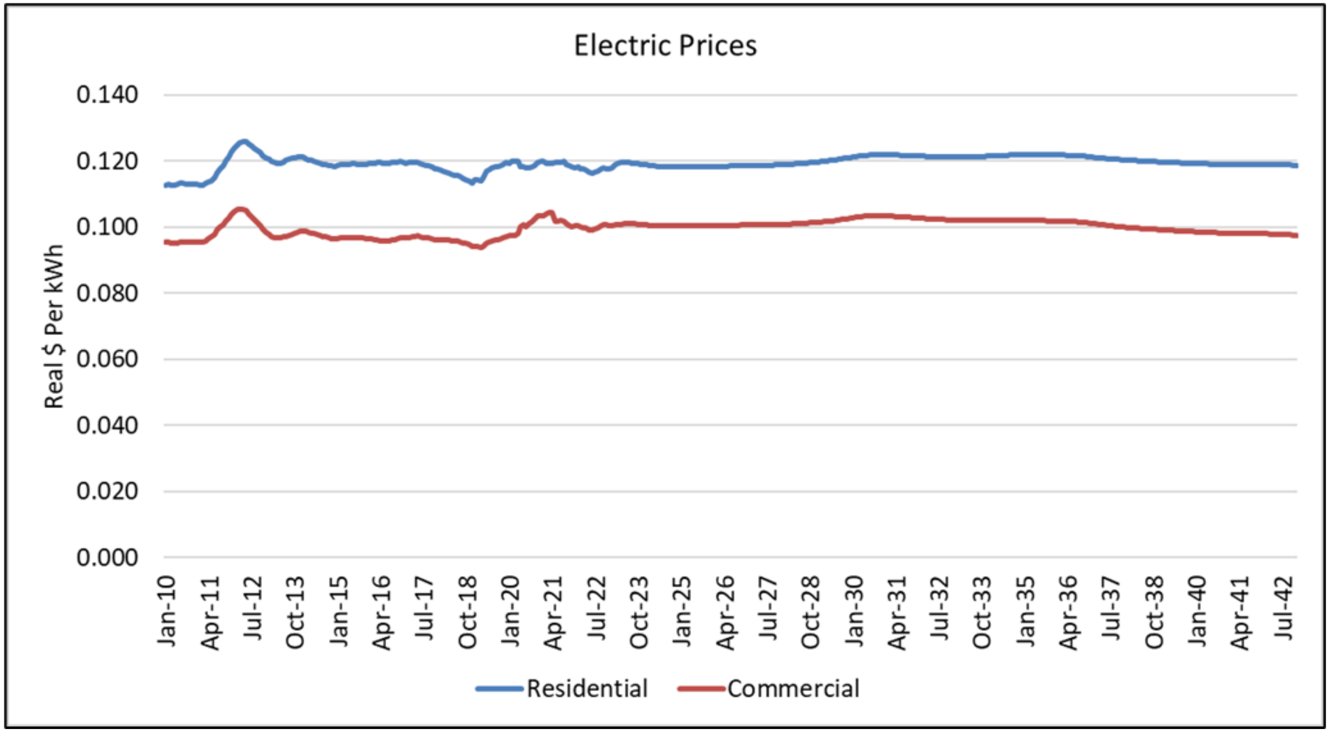
- Residential and Commercial Buildings
  - Reflects change in end-use ownership and efficiency trends
  - Based on the most recent Energy Information Administration's Annual Energy Outlook
    - Calibrated to the Indiana electric service territory
    - Total residential intensity increases at 0.2% CAGR (2022-2042)
    - Total commercial intensity decreases at 0.8% CAGR (2022-2042)





Electricity Prices

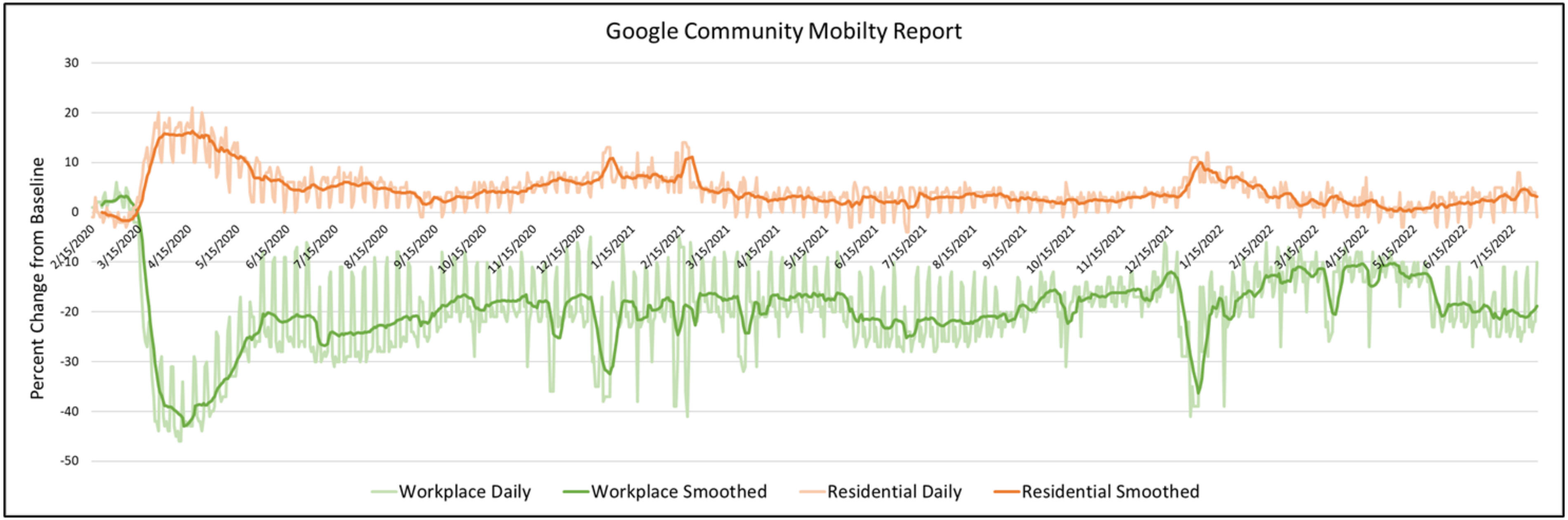
- Historical prices based on 12 month rolling average rate (total revenue $/total kWh), converted from nominal to real dollars
- Forecasted price increase/decrease based on Energy Information Administration's regional forecast



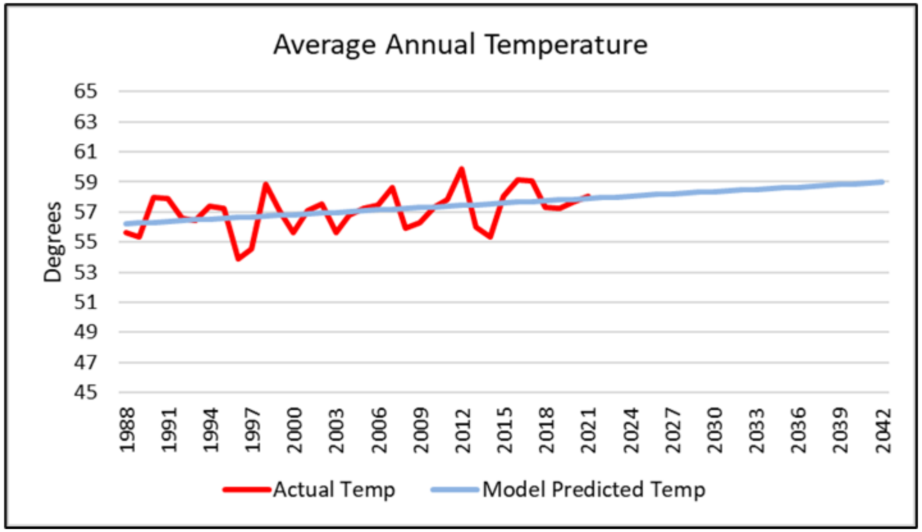
COVID Impact on Electricity Usage

CenterPoint Energy

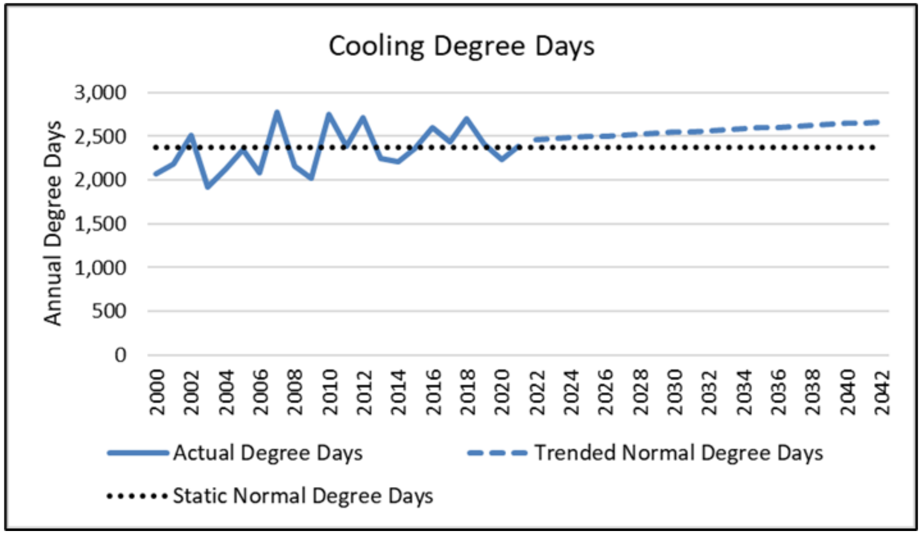
- Increase in residential sales, decrease in commercial sales
- Google Community Mobility Reports data used to explain historical deviations from normal usage
  - Vanderburgh County data
  - Residential and Workplace categories used

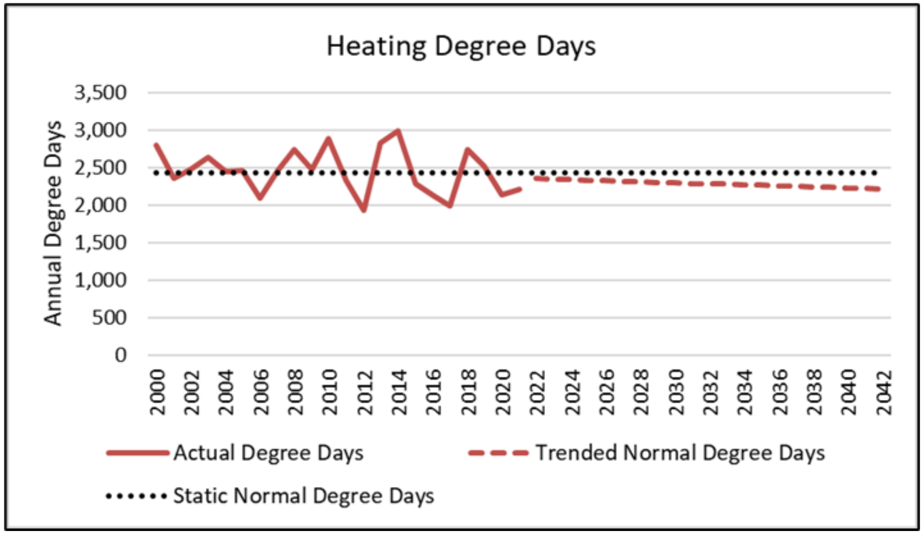


Trended Normal Weather



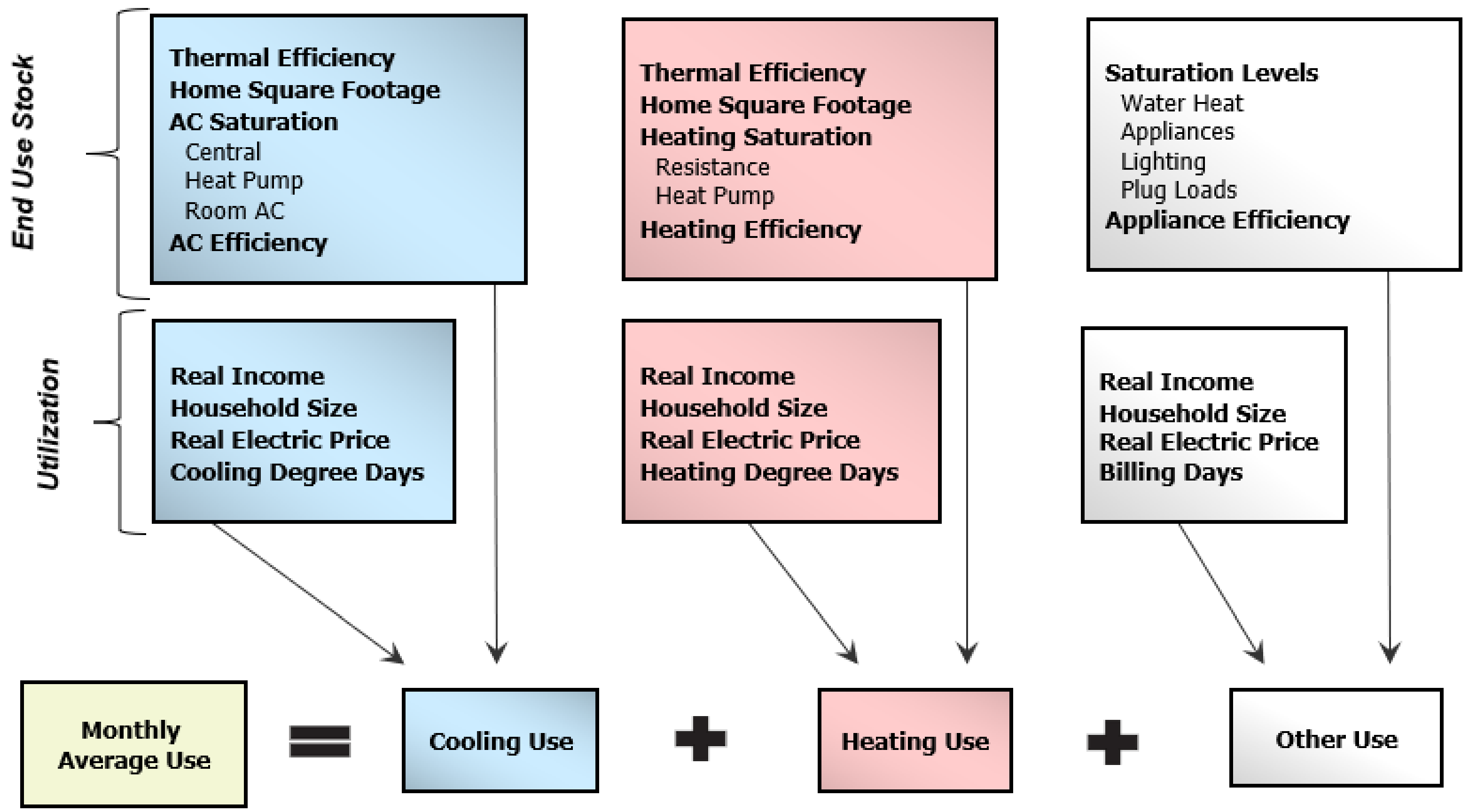
- Average temperature is increasing
  - Trend based on statistical analysis of historical temperature data (1988 to 2021).
  - Average annual temperature increasing 0.5 degrees per decade
  - Decline in HDD (warmer/shorter winters)
  - Increase in CDD (warmer/longer summers)





Residential Average Use model

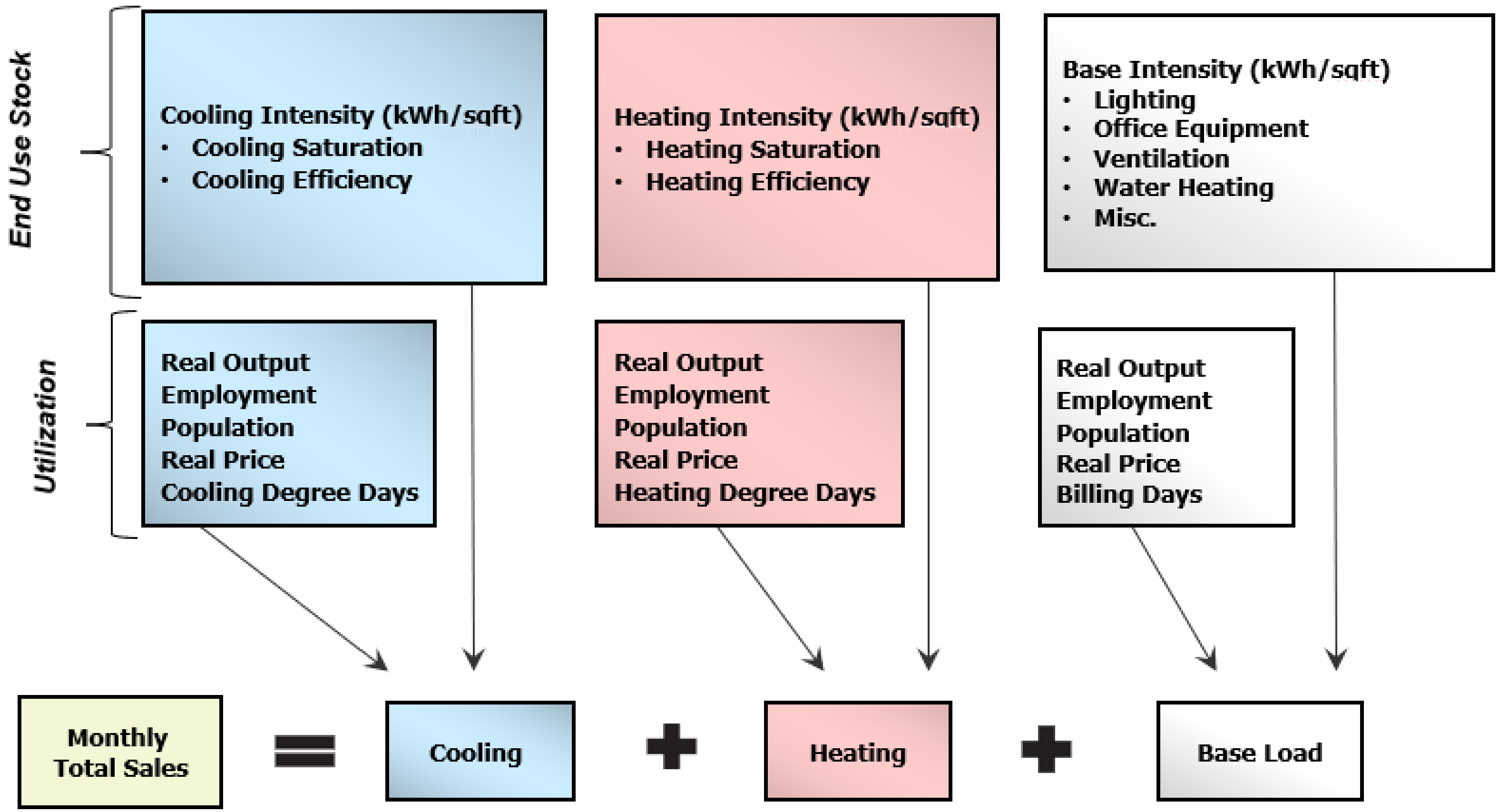
CenterPoint Energy



Electric Vehicles and Customer Owned PV Approach

- Energy Information Administration (EIA) forecast based on share of total registered vehicles; Differentiating between all electric (BEV) and plug-in hybrid electric (PHEV)
- Customer economics defined using simple payback
  - Incorporates declining solar system costs, electric price projections, changes in net metering laws, and federal incentives
  - Monthly adoption based on simple payback

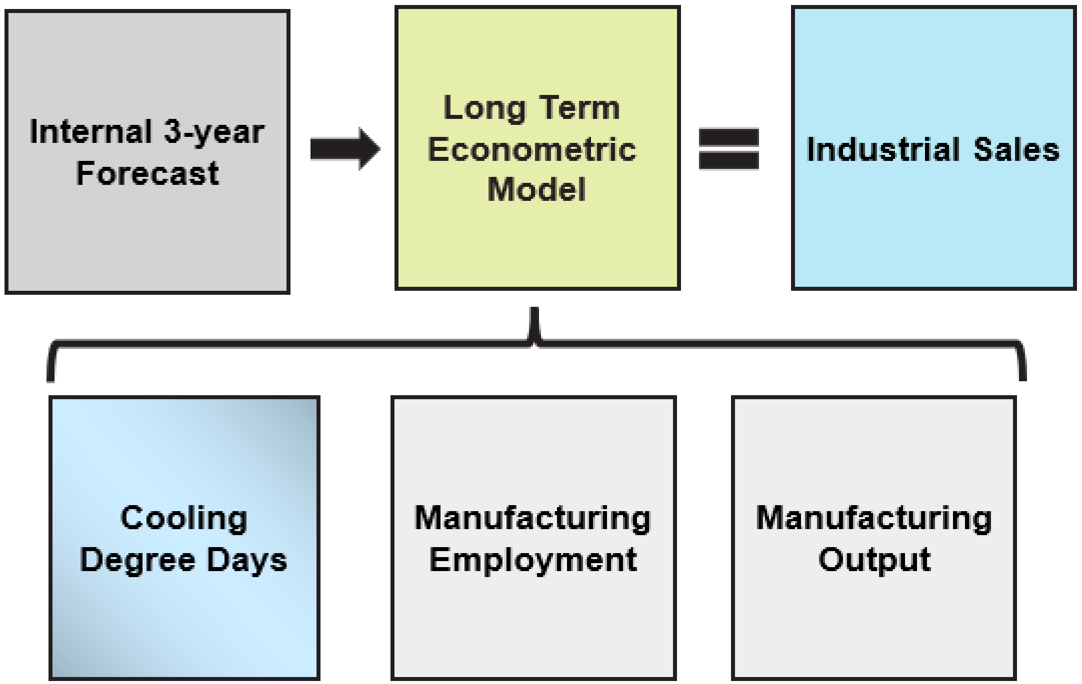
Commercial Sales model



Industrial Forecast

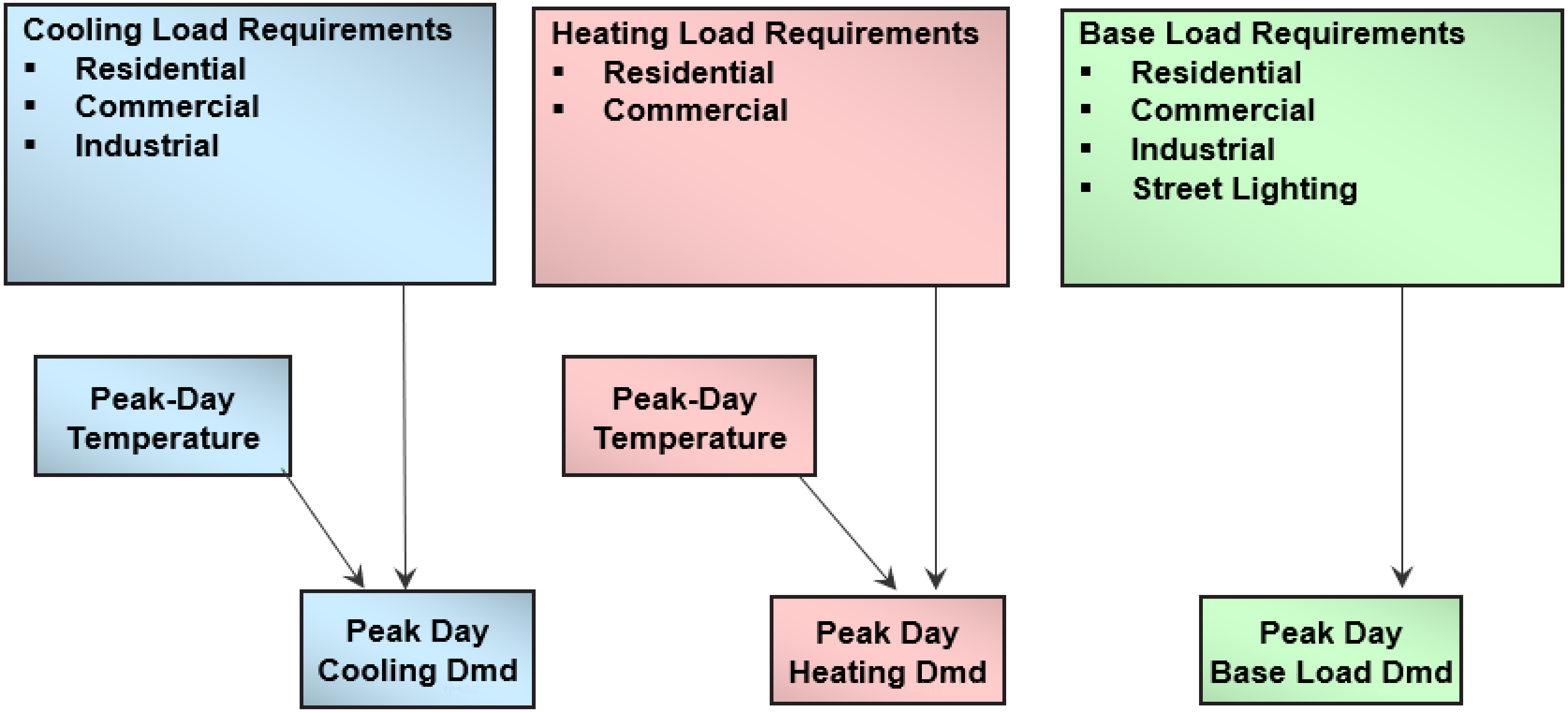
CenterPoint Energy

- The industrial (large customer) forecast is a two-step approach
  - The first 3 years is based on Indiana Electric's internal forecast
  - The long-term growth rate is developed using the econometric model framework



Peak Demand Forecast

- Peak demand is driven by heating, cooling, and base load requirements derived from the customer class forecasts



Portfolio Resource Options

Kyle Combes
Project Manager, Resource Planning & Market Assessments
1898 & Co.

Existing and Planned Thermal Resources

Name	Type	Capacity (MW)	In-Service Date	Retirement / Contract End Date
A.B. Brown 1	Coal	245	1979	2023
A.B. Brown 2	Coal	245	1986	2023
A.B. Brown 3	Natural Gas	80	1991	N/A
A.B. Brown 4	Natural Gas	80	2002	N/A
F.B. Culley 2	Coal	90	1966	2025
F.B. Culley 3	Coal	270	1973	N/A
Warrick 4	Coal	150	1970	2023 or 2025
OVEC	Coal	32	-	N/A
Blackfoot	Landfill Gas	3	2009	N/A
A.B. Brown 5	Natural Gas	230	2025	N/A
A.B. Brown 6	Natural Gas	230	2025	N/A

Planned

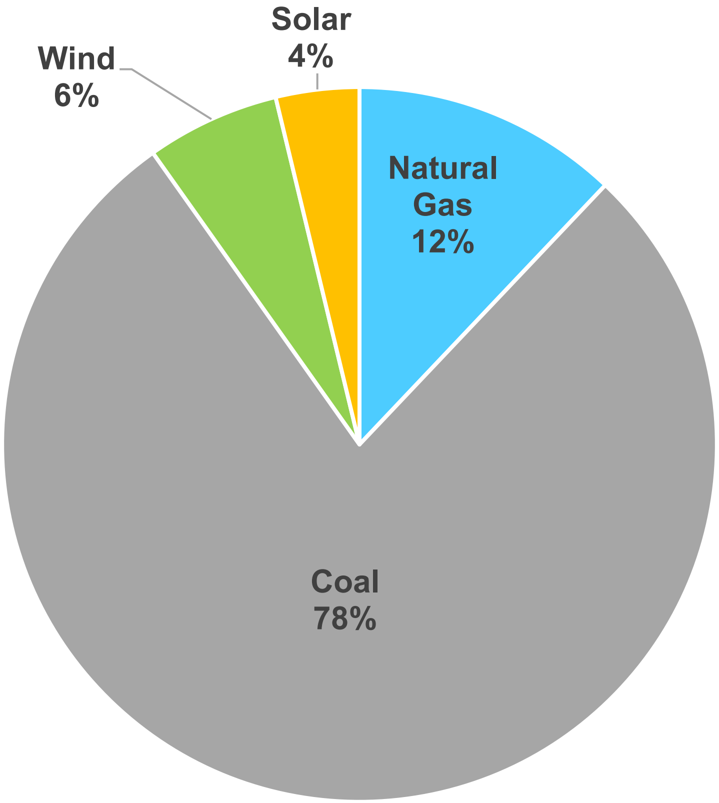
Existing and Planned Non-Thermal Resources

Name	Type	Capacity (MW)	In-Service Date	Retirement / Contract End Date
Benton County	Wind	30	2007	2028
Fowler Ridge	Wind	50	2010	2030
Oakhill	Solar	2	2018	N/A
Volkman Road	Solar\Battery	2\1	2018	N/A
Troy	Solar	50	2021	N/A
Posey	Solar	200	2024	N/A
Vermillion	Solar	185	2024	2038
Wheatland	Solar	150	2024	2044
Rustic Hills	Solar	100	2024	2049
CrossTrack	Solar	130	2025	N/A
Future TBD	Wind	200	2025	N/A

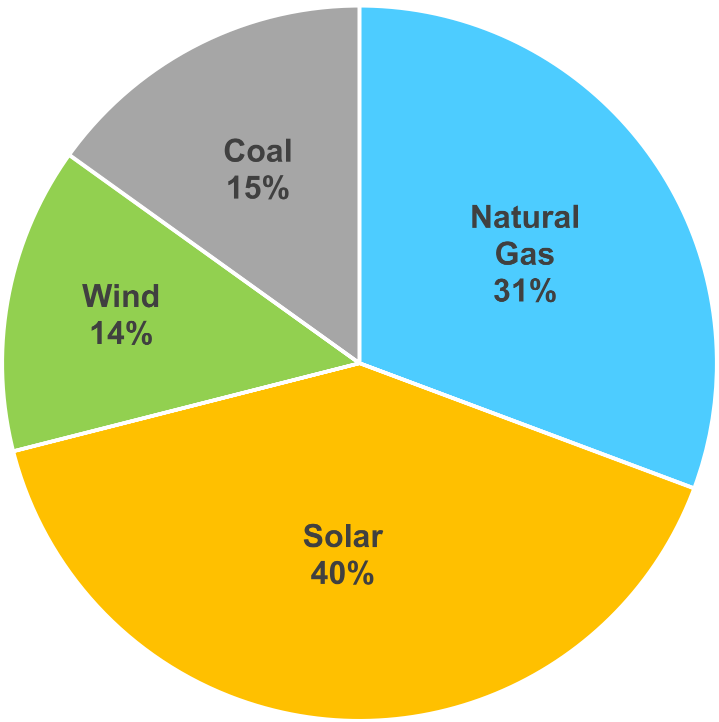
Planned

Existing and Planned Resource Mix

2022 (ICAP MW)



2026 (ICAP MW)



New Thermal Resources Options

CenterPoint Energy

Peaking Natural Gas (~95% Summer & Winter Capacity Accreditation)

- Simple cycle gas turbines
- Reciprocating engines
- F.B. Culley 3 conversion

Combined Cycle Natural Gas (~95% Summer & Winter Capacity Accreditation)

- Fired and unfired
- With and without CCS
- A.B. Brown 5 & 6 conversion

Cogeneration (~95% Summer & Winter Capacity Accreditation)

- Partnership with large industrial customers

Coal (~90% Summer & Winter Capacity Accreditation)

- Supercritical with CCS
- Ultra-supercritical with CCS

Nuclear (~90% Summer & Winter Capacity Accreditation)

- Small modular reactors

New Non-Thermal Resources Options

CenterPoint Energy

Wind (~10% Summer / ~20% Winter Capacity Accreditation*)

- On-shore in northern and southern Indiana
- With and without paired storage

Solar (~50% Summer / ~0% Winter Capacity Accreditation*)

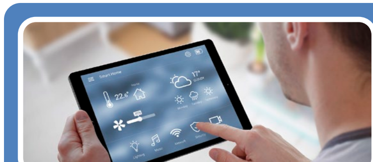
- Utility scale with single axis tracking
- With and without paired storage

Storage (~95% Summer & Winter Capacity Accreditation*)

- Lithium ion (4-hour)
- Long duration (10-hour, compressed air as proxy)

Hydroelectric (To Be Determined)

- At existing Newburgh and J.T. Myers dams on Ohio River



Demand Side

- Energy efficiency
- Demand response

*Accreditation expected to decline over time due to ELCC

Draft Reference Case Inputs and Scenario Discussion

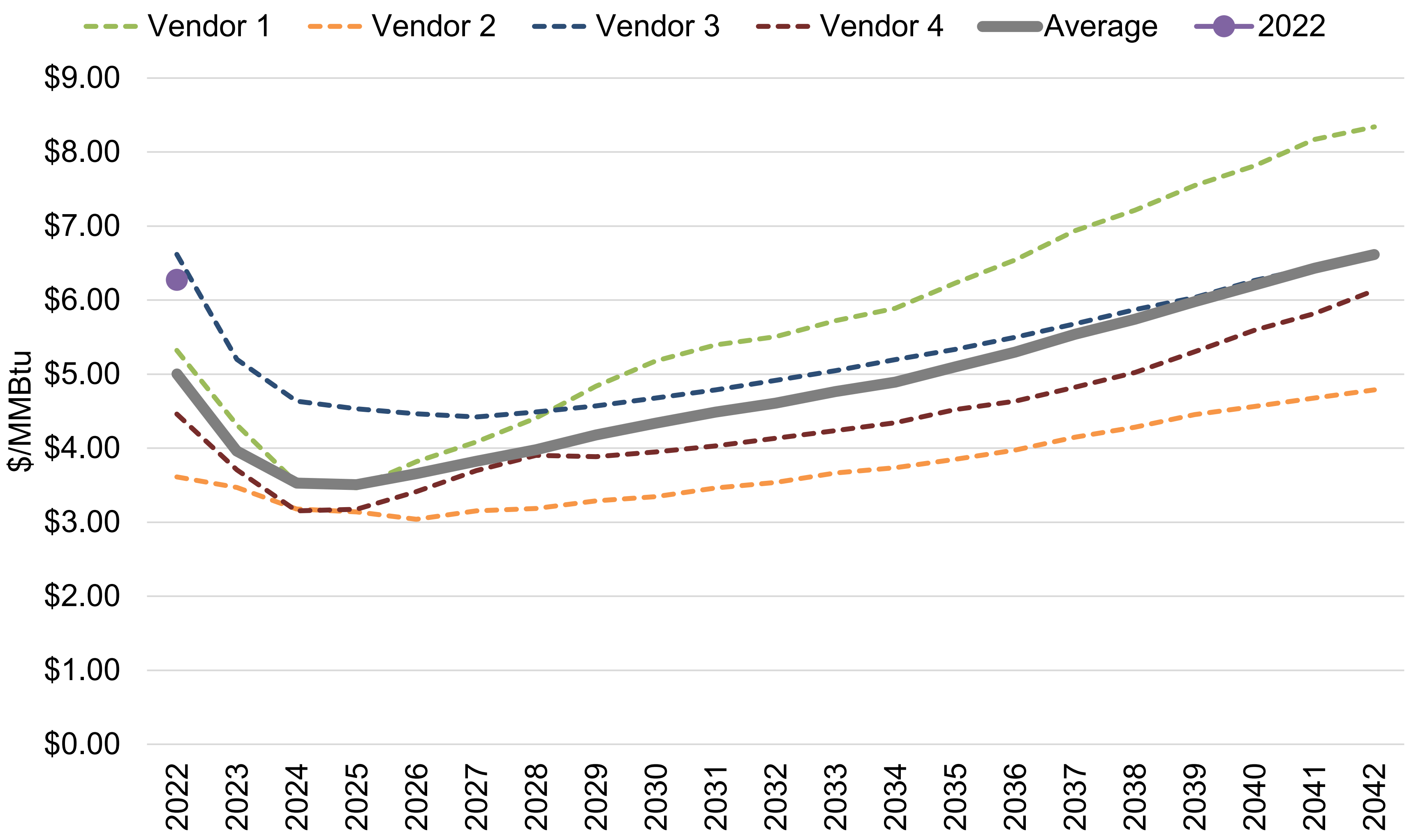
Matt Lind
Director, Resource Planning & Market Assessments
1898 & Co.

Reference Case Inputs

CenterPoint surveyed and incorporated a wide array of sources in developing its Reference Case inputs, which reflect a current consensus view of key drivers in power and fuel markets.

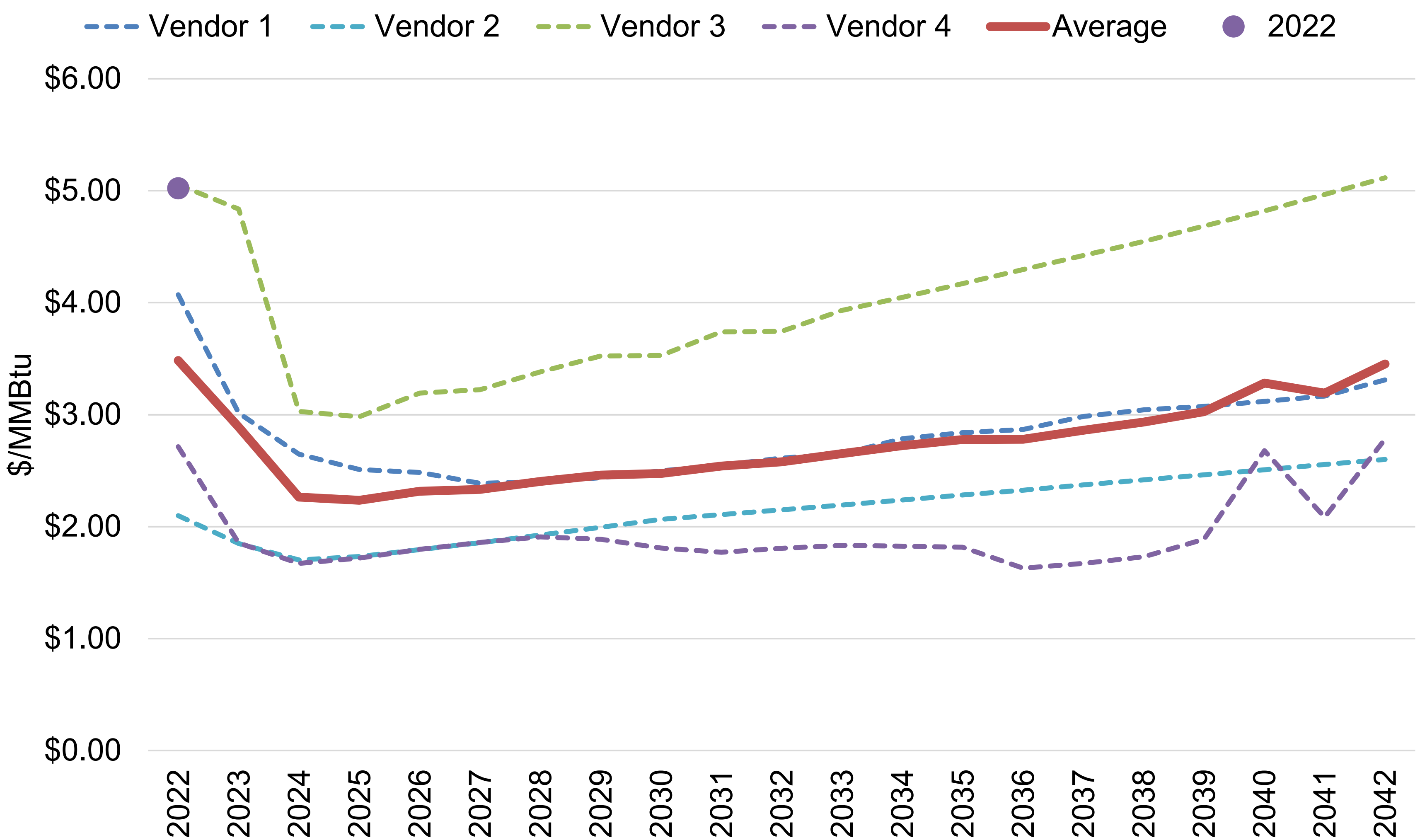
- Reference Case market inputs include forecasts of the following key drivers:
  - Henry Hub and delivered natural gas prices
  - Illinois Basin mine mouth and delivered coal prices
  - MISO Capacity Costs
  - CO_2 ACE Proxy
  - Capital costs for various generation technologies
  - Load forecast
- On- and off-peak power prices are an output of scenario assumptions
- CenterPoint uses a consensus Reference Case view, by averaging forecasts from several sources when available; This ensures that reliance on one forecast or forecaster does not occur

Natural Gas (Henry Hub) Forecast



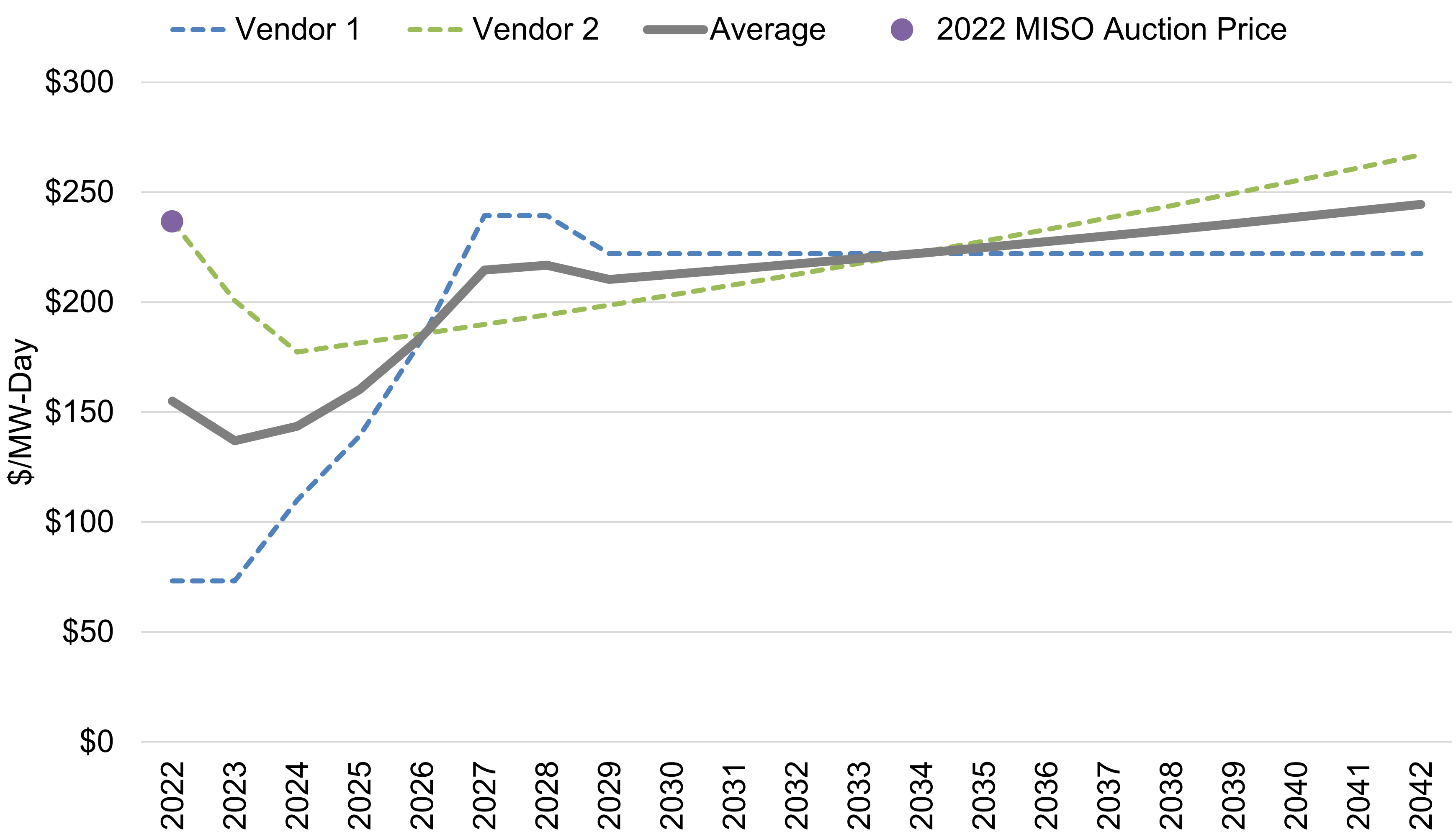
Will be revised as individual forecasts are updated

Coal Forecast



Will be revised as individual forecasts are updated

MISO Capacity Forecast



Will be revised as individual forecasts are updated

Potential Scenarios

	Coal Price	Natural Gas Price	Load	Carbon	Renewables and Storage Cost	Economy	Gas Regulation	Other Environmental Regulations	EE Cost
Reference Case	Base	Base	Base	ACE Proxy	Base	Base	None	None	Base
High Regulatory	↔	↑	↓	↑	↓	↓	Fracking Ban	MATS Update	↑
Market Driven Innovation	↓	↓	↑	↓	↓	↑	None	None	↓
Decarbonization \ Electrification	↑	↔	↑	↑	↔	↔	Methane	None	↓
Continued High Inflation & Supply Chain Issues	↑	↑	↓	↔	↑	↓	None	None	↑

↑ = Higher than Reference Case

↓ = Lower than Reference Case

↔ = Same as Reference Case

Scenario Narratives - High Regulatory – Increased regulations from legislature and government

	Coal Price	Natural Gas Price	Load	Carbon	Renewables and Storage Cost	Economy	Gas Regulation	Other Environmental Regulations	EE Cost
High Regulatory	↔	↑	↓	↑	↓	↓	Fracking Ban	MATS Update	↑

- **Coal** - While there could be regulations that could increase the coal price - demand would be going down, offsetting the increase
- **Natural Gas** – In a high reg environment there will be a ban on fracking which will restrict supply, thus causing gas prices to increase
- **Load** – In high regulatory scenario there is a drag on the economy; Low economic output leads to lower load
- **Carbon** - Legislature passes a high tax on CO_2
- **Renewables and Storage Costs** – Renewables and storage receive increased government incentives reducing their overall cost
- **EE Cost** – Technological innovation is stifled; Lower load leads to less opportunity for cost effective energy efficiency; In addition, a high regulatory environment leads to more codes and standards for equipment; This in turn results in higher incentives for more efficient equipment

Scenario Narratives - Market Driven Innovation – Less government regulation, more free market

	Coal Price	Natural Gas Price	Load	Carbon	Renewables and Storage Cost	Economy	Gas Regulation	Other Environmental Regulations	EE Cost
Market Driven Innovation	↓	↓	↑	↓	↓	↑	None	None	↓

- **Coal Price** – Less government influence drives competition among competing fuels for the increase in load
- **Natural Gas Price -** Less government influence drives competition among competing fuels for the increase in load
- **Load** - Less government influence reduces costs, which drives increased usage
- **Carbon** - No carbon tax nor ACE like requirements
- **Renewables and Storage Costs** – Increased demand for renewable and storage resource options spurs further technological innovation to lowers cost
- **EE Cost** – Technological innovation drives more opportunities for EE programs; Increased load drives more opportunity for cost effective energy efficiency; Less codes and standards changes will allow utility sponsored EE programs more opportunities to transform the market at a lower incentive cost

Scenario Narratives - Decarbonization\Electrification – Consumers are moving to electrify transportation and promotes fuel switching in homes and businesses from natural gas to electricity

	Coal Price	Natural Gas Price	Load	Carbon	Renewables and Storage Cost	Economy	Gas Regulation	Other Environmental Regulations	EE Cost
Decarbonization \ Electrification	↑	↔	↑	↑	↔	↔	Methane	None	↓

- **Coal Price** – Demand for coal decreases as a mid level carbon tax is imposed, supply is constrained causing price to increase
- **Natural Gas Price** – Methane regulation causes the cost of gas to increase but is offset by increased supply due to fuel switching away from natural gas heating
- **Load** – Increased due to fuel switching while economy remains at reference levels
- **Carbon** - Mid level carbon tax imposed
- **Renewables and Storage Costs** – Technological improvements which typically lowers costs are offset by higher demand and rising land and labor costs
- **EE Cost** – Increased load allows more opportunities for EE potential and reduces the cost of EE acquisition; Further, a carbon tax will allow for more cost-effective EE measures

Scenario Narratives - Continued High Inflation & Supply Chain Issues

	Coal Price	Natural Gas Price	Load	Carbon	Renewables and Storage Cost	Economy	Gas Regulation	Other Environmental Regulations	EE Cost
Continued High Inflation & Supply Chain Issues	↑	↑	↓	↔	↑	↓	None	None	↑

- **Coal Price** – Increased costs for delivery and labor with reduced supply drive coal prices higher
- **Natural Gas** – Less new drilling leads to reduced supply and increased demand, resulting in higher cost
- **Load** – High inflation reduces economic output, reducing load demand
- **Carbon -** Reference
- **Renewables and Storage Costs** – Continued disruption in supply chain partnered with high inflation shows continued high cost for renewables and storage
- **EE Cost** – Reduction in load results in less potential and higher cost of EE acquisition both for incentives passed to customers and implementation of programs as implementers experience increased cost; Shortage of EE equipment leads to increased cost of high-efficient measures

Q&A

Appendix

Definitions

Term	Definition
ACE	Affordable Clean Energy (ACE) Rule, establishes emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants
All-Source RFP	Request for proposals, regardless of source (renewable, thermal, storage, demand response)
BAGS	Broadway Avenue Gas Turbine
BTA	Build Transfer Agreement/Utility Ownership
C&I	Commercial and Industrial
CAA	Clean Air Act
CAGR	Compound Annual Growth Rate
Capacity	The maximum output of electricity that a generator can produce under ideal conditions (megawatts)
CCGT	A combined-cycle power plant uses both a gas and a steam turbine together to produce up to 50 percent more electricity from the same fuel than a traditional simple-cycle plant. The waste heat from the gas turbine is routed to the nearby steam turbine, which generates extra power
CCR Rule	Coal Combustion Residuals Rule
CCS	Carbon Capture and Storage
CDD	Cooling Degree Day
CEI South	CenterPoint Energy Indiana South
CO_2	Carbon dioxide

Definitions Cont.

Term	Definition
CONE	Cost of New Entry
CPCN	A Certificate of Public Convenience and Necessity is required to be granted by the Commission for significant generation projects
CSAPR	Cross State Air Pollution Rule
DER	Distributed Energy Resource
Deterministic Modeling	Simulated dispatch of a portfolio in a determined future. Often computer generated portfolios are created by optimizing on cost to the customer
DLC	Direct Load Control
DR	Demand Response
DSM	Demand side management includes both Energy Efficiency and Demand Response programs to reduce customer demand for electricity
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines are U.S. national standards for wastewater discharges to surface waters and publicly owned treatment works
EnCompass	Electric modeling forecasting and analysis software
Energy	Amount of electricity (megawatt-hours) produced over a specific time period

Definitions Cont.

Term	Definition
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GW	Gigawatt (1,000 million watt), unit of electric power
GWh	Gigawatt Hour
HDD	Heating Degree Day
Henry Hub	Point of interconnection of interstate and intrastate natural gas pipelines as well as other related infrastructure in Erath, Louisiana
IDEM	Indiana Department of Environmental Management
Installed Capacity (ICAP)	Refers to generating capacity after ambient weather adjustments and before forced outages adjustments
Intermittent	An intermittent energy source is any source of energy that is not continuously available for conversion into electricity and outside direct control
IRP	Integrated Resource Plan is a comprehensive plan to meet customer load expectations
IURC	The Indiana Utility Regulatory Commission is the public utilities commission of the State of Indiana. The commission regulates electric, natural gas, telecommunications, steam, water and sewer utilities
KWh	Kilowatt Hour

Definitions Cont.

Term	Definition
LCOE	Levelized Cost of Energy, A measure that looks at cost and energy production over the life of an asset so different resources can be compared. Does not account for capacity value.
LMR	Load Modifying Resource
Local Clearing Requirement (LCR)	Capacity needs to be fulfilled by local resource zone
LRZ6	MISO Local Resource Zone 6
MATS	Mercury and Air Toxics Standard
Mine Mouth	At the mine location
MISO	Midcontinent Independent System Operator, an Independent System Operator (ISO) and Regional Transmission Organization(RTO) providing open-access transmission service and monitoring the high-voltage transmission system in the Midwest United States and Manitoba, Canada and a southern United States region which includes much of Arkansas, Mississippi, and Louisiana. MISO also operates one of the world's largest real-time energy markets
MMBTU	Million British Thermal Units
MPS	Market potential study - Determines the total market size (value/volume) for a DSM at a given period of time
MSA	Metropolitan Statistical Area
MW	Megawatt (million watt), unit of electric power
NAAQS	National Ambient Air Quality Standards

Definitions Cont.

Term	Definition
Name Plate Capacity	The intended full-load sustained output of a generation facility
NDA	Non-Disclosure Agreement
NOI	Notice of Intent
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPVRR	Net Present Value Revenue Requirement
NSPS	New Source Performance Standards
OMS	Organization of MISO States, was established to represent the collective interests of state and local utility regulators in the Midcontinent Independent System Operator (MISO) region and facilitate informed and efficient participation in related issues.
Peaking	Power plants that generally run only when there is a high demand, known as peak demand, for electricity
Planning Reserve Margin Requirement (PRMR)	Total capacity obligation each load serving entity needs to meet
Portfolio	A group of resources to meet customer load
PPA	Purchase Power Agreement

Definitions Cont.

Term	Definition
Preferred Portfolio	The IRP rule requires that utilities select the portfolio that performs the best, with consideration for cost, risk, reliability, and sustainability
Probabilistic modeling	Simulate dispatch of portfolios for a number of randomly generated potential future states, capturing performance measures
PV	Photovoltaic
RA (Resource Adequacy)	RA is a regulatory construct developed to ensure that there will be sufficient resources available to serve electric demand under all but the most extreme conditions
RAP	Realistic Achievable Potential
Resource	Supply side (generation) or demand side (Energy Efficiency, Demand Response, Load Shifting programs) to meet planning reserve margin requirements
SAC	Seasonal Accredited Capacity
Scenario	Potential future State-of-the-World designed to test portfolio performance in key risk areas important to management and stakeholders alike
SDE	Spray Dryer Evaporator
Sensitivity Analysis	Analysis to determine what risk factors portfolios are most sensitive to
SIP	State Implementation Plan
Spinning Reserve	Generation that is online and can quickly respond to changes in system load

Definitions Cont.

Term	Definition
T&D	Transmission and Distribution
Technology Assessment	An analysis that provides overnight and all-in costs and technical specifications for generation and storage resources
Unforced Capacity (UCAP)	A unit's generating capacity adjusted down for forced outage rates (thermal resources) or expected output during peak load (intermittent resources)
VAR Support	Unit by which reactive power is expressed in an AC electric power system
ZLD	Zero Liquid Discharge

CenterPoint 2022 IRP
1st Stakeholder Meeting Minutes Q&A
August 18, 2022, 9:30 am – 3:30 pm CDT

Richard Leger (Senior Vice President, CenterPoint Energy) – Welcome, Safety Message, Introduction to CenterPoint Energy, Personal background and CenterPoint team introductions, Updates and Goals for this 2022/2023 IRP

Matt Rice (Director, Regulatory and Rates, CenterPoint Energy) – Discussed the meeting agenda, guidelines for the meeting, discussed directors report feedback, and the proposed 2022/2023 IRP and stakeholder process.

- Slide 5 Generation Transition Timeline:
  - Question: I noticed the retirement date for Culley 2 has changed from 2023 to 2025.
    - Response: Over the last year, capacity market prices in MISO have increased significantly. To keep that capacity value for a plant that doesn't run a lot, we decided to extend it for 2 years.
  - Follow-up: You may extend the agreement with Warrick 4 from 2023 to 2025?
    - Response: We do not have an agreement that runs past 2023 currently.
  - Question: Are you planning to evaluate the cost of the CTs compared to another alternative based on the new federal tax credit in the IRA?
    - We intend to move forward with the CTs. We have the approval from the IURC and are awaiting approval from FERC to move forward.
- Slide 12 2022/2023 Stakeholder Process:
  - Question: Final modeling results will not be done by March 31st. There is a wide gap between the last stakeholder meeting on March 14th and the filing date [June 1, 2023]. Can the portfolio change between those two dates? I'm worried modeling results based on the dates posted might not be done before the final meeting.
    - Response: We don't expect any changes to the portfolio. It takes time to do the analysis and get thoughts on paper. We plan to share the modeling results as soon as possible.
- General Section Questions:
  - Question: What percentage of the Cully ELG compliance work has been completed?
    - Response: It will be in service by March 1st of next year. Probably over 50%.
  - Correction by CenterPoint: Correction. We are negotiating for wind. We currently have not filed for wind, but plan to file in the very near future.

Matt Lind (Director, Resource Planning & Market Assessments. 1898 & Co.) – Discussed Objectives & Measures and gathered stakeholder feedback.

- Slide 16 IRP Draft Objectives and Measures:
  - Question: On your slide, you said measured in carbon dioxide. How will that be measured just CO_2 or CO_2 equivalent?
    - Response: Yes CO_2 and CO_2 equivalents are two possible metrics. Last time we used life cycle CO_2 emissions but the results were very similar to just tons of output so we have decided to move away from life cycle emissions.
  - Question: If the CO_2 intensity is similar to absolute tons of CO_2, why are you changing that metric? Is the appropriate measure not the total tons of CO_2 emitted into the environment?
    - Response: There is an absolute value, the metric was chosen based on intensity as we have different load demand assumptions in a particular portfolio. But that is good feedback and something that we will take into consideration.
  - Question: Are you going to measure thermal accreditation on a UCAP basis or are you going to attempt to translate the seasonal accreditation methodology into the accredited value of your thermal units?
    - Response: It is something we will look at, consider, and evaluate. We do intend to accredit all resources, thermal and otherwise, on a seasonal basis.
- General Section Questions:
  - Question: Will demand response be a part of the portfolio plans? Will CenterPoint expand DR to commercial customers?

- Response: Demand response will be discussed in further detail as we move forward in the process. We are looking at a combination of direct load control and rate programs. This allows us to have customers control different rates at different periods of time. We are looking to fully transitioned to smart thermostats by 2029.
  - Question: What are your plans if FERC doesn't approve the [natural gas] pipeline [needed for the new CTs]?
    - Response: All portfolios assume future FERC approval. If it is not approved, we will refer to the IRP process to guide us in the next steps. The plan is to move forward with the CTs.
  - Question: Is the CT totally dependent on that gas pipeline being approved?
    - Response: There is not enough gas at the site today. We will need the gas pipeline for the CTs to operate. There is a lot of other equipment at that site, such as the substation and the interconnect rights, that make that site favorable for the CTs.
  - Question: What are the new and different technologies in the future coming beyond what we already have?
    - Response: Some of the future technologies both on the demand and supply side will be touched on later in this presentation. The technology mentioned is new in terms of the impact it will have to the supply side. Not necessarily that the technology itself is new.

Kyle Combes (Project Manager, Resource Planning & Market Assessments, 1898 & Co.) – Discussed the 2022 IRP modeling software, EnCompass.

- Slide 19 What are Encompass' Capabilities?
  - Question: Can Encompass model other types of storage beyond chemical storage (e.g., battery)?
    - Response: Yes. It's not specific to just chemical battery storage. Other options may be modeled with the correct input assumptions. Variable costs, capital costs, etc.
  - Follow-Up: Why did the CAC suggest switching to EnCompass?
    - CAC Response: We have some experience licensing several other software's used by MISO. We found that if you are looking at someone else's modeling files, it is important you can digest those modeling files, and understand the constraints to those inputs. Encompass models can be input and exported in an Excel format. Several other models don't have that capability. 1898 and Co. also licenses Encompass, so it was beneficial to use that as the modeling software.
  - Question: Can you compare the gas plant cost to the other technologies mentioned this morning?
    - Response: Based on comments and discussion today, yes, the CTs have been approved and will be part of the plan for the CenterPoint portfolio. We did not suggest that the CTs be built in an alternate location.
- General Section Question:
  - Question: If the modeling files are available in advance, can they be seen earlier by those who have signed the NDA?
    - Response: We will take that into consideration and provide those as soon as we can. [The expected data release schedule is on slide 10.]
  - Question: I would like to formally request that you run the portfolio without the gas turbine to determine least cost.
    - Response: The request has been noted.
  - Question: Why don't you go ahead and evaluate the cost now without the CTs, so you don't have to rerun the evaluation?
    - Response: We will take that into consideration. We should have an answer from FERC later this year [or early next year] regarding the pipeline.

Drew Burczyk (Consultant, Resource Planning & Market Assessments, 1898 & Co.) – Discussed the Request For Proposals (RFP) methodology, scoring, role, and provided high level statistics for CenterPoint's RFP.

- Slide 26 Preliminary RFP Statistics:
  - Question: Would you be getting updated numbers on the people that bid solar?
    - Response: We are still digesting the information to see how the bill [Inflation Reduction Act] impacts our current plan. By the second stakeholder meeting we should have more clarity on how the bill impacts pricing.
  - Question: How will the bids be incorporated into the IRP modeling? And do you know yet how/if they will be used as the basis for future costs?

- Response: We will have the cost curve assumptions ready for the next stakeholder meeting. We do have RFP responses to use as a reference for the next few years to use in IRP modeling.
- Question: Are you surprised on the breakdown percentage for RFP bids (especially storage)?
  - Response: We are not surprised by the type of bids we have received. Over the last few RFP's, there have been more storage projects in the MISO interconnection queue, so it makes sense that we would be seeing more storage proposals now.
- Question: Is the nuclear capacity existing or new build?
  - Response: The nuclear bid is an existing resource.

- General Section Questions:
  - Question: Given the IRA is offering both PTC and ITC which includes storage, when looking at the modeling, will you be assuming the 30-40% cost savings in certain communities outlined in the act?
    - Response: We are still processing the potential impacts of the new legislation. We will have more clarity in the next meeting on how we plan to account for those updates.
  - Question: Will we be able to access the bids for those of us with NDAs?
    - Response: Yes, the plan is to follow a similar process as the 2019 All-Source RFP.
  - Question: In Encompass, are you planning to model renewables as a project or as a resource?
    - Response: We haven't decided on any of the modeling just yet. Any input or feedback that you may provide, we will consider.

Matt Lind – Discussed MISO Updates, Resource Adequacy and key functions, and updates for FERC 2222.

- Slide 34 MISO Zone 6 Capacity Prices:
  - Question: Can you expand on the MISO capacity chart?
    - Response: The chart shows historical numbers of the MISO capacity auction and for the current planning year. The chart shows the historical clearing prices, or the price of capacity purchased specifically for MISO zone 6. The capacity price is associated closely with the demand at that time i.e., market driven. High prices reveal the need to add more capacity to the market.
  - Question: These Peaker plants seem large for the local need. Would CenterPoint be a provider to the grid during these times of high prices? Who would benefit from these high prices, the customers, or the company?
    - Response: This is a capacity price, not a function of energy sales. The CTs were added to meet CenterPoint's own capacity needs, not necessarily to sell into the market as surplus. Different resources and technology types have different characteristics. Seasonally, we look at how those technologies perform in different conditions. Every technology type will receive its own capacity credits, and CenterPoint must meet that capacity demand in all conditions.
- General MISO Questions:
  - Question: In terms of the FERC 2222, do you all have a sense of an approach that you would like to take or are likely to take? Is the question about the adoption rate of those technologies or is it about the things that CenterPoint would do internally to promote the adoption of those technologies and the tradeoffs of those approaches?
    - Response: Ultimately, it's projecting the adoption rates of those technologies and the impact on the load forecasts. The impact of the adoption on portfolios considering how quickly those will come into effect and how quickly the demand will have to be met with those resources coming online. Thoughts and feedback are welcome.
  - Question: Does the model have capabilities to model the FERC 2222?
    - Response: We can see it possibly affecting the load forecasts. We could model the impact based on different assumptions.
  - Question: I wanted to bring attention to an article on vertical solar panels that are bi-facial. They require less battery storage and capture electricity for long periods of the day. Just wanted to bring it up and have CenterPoint look at it as an option.
    - Response: Please send the article to irp@centerpointenergy.com

Scott Duhon (Director, Environmental Compliance & Policy, CenterPoint Energy) – Discussed environmental regulations and policy.

- Slide 41 NO_X Ozone Season Allowances:
    - Question: To calculate how much it would cost to comply with this, would you just multiply the tons purchased by the purchased cost per allowance?
        - Response: Yes.
    - Follow-Up: For 2022, we're looking at over $22M for NOx compliance?
        - Response: As you can see, as time has gone on, allowances allocated to CenterPoint have gone from 1,381 to 851. We have used our selective catalytic reduction equipment to reduce NOx as much as we can without causing other operational issues. With the high capacity factor this year, we project to be about 450 tons short on these NOx allowances. There is a short supply on the market. It is very expensive to purchase NOx allowances in the market.
    - Question: What does high costs of NOx mean regarding keeping Culley 2 online an extra 2 years?
        - Response: Regarding Culley 2, the unit doesn't run a lot due to the high costs. We will extend it through 2025 because we can hold it for capacity which limits the amount of capacity we have to buy on the market. This will help us reduce the cost to customers.
    - Question: Is there anything being done to hedge the cost of NOx allowance purchases? What is being done to reevaluate the cost of these units?
        - Response: To mitigate NOx emissions, we are injecting as much ammonia into our selective catalytic system. Additionally, when bidding these units into the market, accounting for the NOx price is included in our offer price.
    - Follow-Up: How are you currently recovering those allowance costs? Are those tracked and/or embedded in rates?
        - Response: The costs get recovered through the RCRA once a year.
- General Section Questions:
    - Question: Can carbon emissions be also measured in their absolute tonnage?
        - Response: CenterPoint looks at absolute tonnage.
    - Follow-Up: On your website, it says that you take the Paris commitment under serious consideration. Is it talking about carbon intensity, absolute tonnage emissions, or what? Is this part of the planning that you use?
        - Response: When we look at net zero, we look at absolute tonnage. We have modeled the retirement of all coal by 2035. This is an assumption. Since we are moving from coal to primarily renewables, most of the offsets aren't going to the generation side. We aren't anticipating significant need for offsets to the generation emissions.
    - Question: Do the combustion turbines have lower NOx than the coal units?
        - Response: Yes.
    - Question: What is the current retirement on Culley 3?
        - Response: This will be evaluated through the IRP.

Jeffery Huber (Principal, Energy Efficiency, GDS Associates, Inc.) – Discussed Market Potential Studies, Energy Efficiency and Demand response.

- Slide 54 DR Analysis – Programs Included
    - Question: Does CenterPoint have any Demand response programs for residential customers?
        - Response: We do have the legacy smart saver switches. We have a couple of residential demand response programs such as the legacy direct load control program. In 2016, we implemented a pilot program and rolled that out into a smart thermostat program. The goal is to phase out the load control program and ramp up the "bring your own thermostat" program.
    - Follow Up: Recommends implementing residential rate programs [critical peak pricing, TOU, etc.] sooner. Haven't you rolled out the smart meter program?
        - Response: In terms of AMI systems, the meters are out in the field. We are working on incorporating the legacy meter data management system into the CenterPoint system. The system is not ready yet.
- General Section Questions:
    - Question: In the future, will CenterPoint allow users to participate in the program without pre-cooling their home?

        - Response: The intent with the pre-cooling option is to make the customer more comfortable prior to a demand response event. The pre-cooling is only available with certain brands of thermostat.
    - Question: When you are looking at the achievable market share for energy efficiency, would you consider 50-100% rebates on appliance upgrades? Will that impact overall effectiveness and adoption?
        - Response: The analysis was done prior to the IRA passing. The low to moderate income rebates could be affected. We generally model them with high incentives. In the past when there have been similar types of tax credits, we have modeled them in a similar way.
    - Question: How do you determine these incentives?
        - Response: We did research that looked at customers' willingness to participate at certain levels. That research asked customers, both residential and non-residential, what their likelihood would be to participate in this program. We are in the process of evaluating the demand response incentives to get as much participation as possible.

Michael Russo (Senior Forecast Consultant, Itron) – Discussed historical trends, economic drivers, industry trends, and portfolio forecasts.

- Slide 63 End-use Intensity trends:
    - Question: How were you able to determine an increase in the forecast of energy intensity in the residential sector?
        - Response: The total decline in energy intensity from 2010 to now has been in lighting. In the energy outlook in 2022, there were no major improvements in end use efficiency that would change the graph.
- Slide 64 Electricity Prices:
    - Question: Regarding electricity prices, does it matter what the absolute rate is, or does it just matter what the rate of change is? How elastic is demand to price?
        - Response: For the regression model, the important factor is the percent change. Electricity is inelastic: people don't respond that much to changes in electricity prices.
- General Section Questions:
    - Question: Can you help me square the fact that residential use has been declining over time, but intensity appears to be increasing over time?
        - Response: One of the major savings from 2010 until now has been lighting. Lighting is at its lowest point basically now. The one end use that is increasing is the misc. category.

Kyle Combes – Discussed portfolio resource options, both new and existing.

- General Section Questions:
    - Question: Can you talk more about a conversion from CTs to CC? Would that require another Certificate of public convenience and necessity (CPCN)?
        - Response: Yes. The CTs would be the same. You could add heat recovery steam generators. Peaking gas turbines are mainly a capacity resource with a less efficient heat rate, but less expensive on capital investment. Yes, it would require another CPCN.
    - Follow-Up: Why would you pursue a new joint agreement until 2025 for Warrick?
        - Response: We are short on capacity in the 2024/2025 planning year [until the CTs come online]. Our customers will be vulnerable to the capacity price at that time. If we can reach a fair agreement, we can avoid paying for capacity until some of those other units come online, and ultimately, save our customers money.
    - Question: Is this a pre-screening list or the post-screening? Does this mean that new coal passed the screening?
        - Response: No pre-screening has been done at this time. We have not determined if we will do a LCOE or other pre-screening at this time. Usually we would only pre-screen in specific technology groups where there are multiple options, if there were several different peaking gas technologies for example.

Matt Lind – Discussed reference case inputs and scenarios.

- Slide 80 Natural Gas (Henry Hub) Forecast:

- Question: Based on an internet search, the Henry Hub natural gas price today is $9.23/MMBtu. The graph does not reflect this number. Can you explain?
    - Response: The pricing is the 2022 average [consistent with the annual datasets shown]. It is not today's Henry Hub pricing.
- Question: Are the graphs nominal or real?
    - Response: The forecasts are in nominal dollars.
- Question: Expressed concern about forecasts.
    - Response: We are living in a volatile time from normal gas pricing. Going back 10-15 years prices were in the $8/MMBtu range. We have seen price fluctuations before, and there is uncertainty in the price assumption [as with most forecasts today]. We will do a probabilistic stochastic analysis to capture volatility, [and we will update with vendor forecasts as they are updated.]

<u>Open Q&A Session</u>

- Question: Does CenterPoint want to add fuel risk as an objective and measure?
    - Response: NPV largely captures fuel cost and risk inherent to a portfolio. We will consider it.
- Question: What is the implication of the economy assumption for the modeling?
    - Response: The assumption is not a direct input into the model, the economy assumption indirectly or directly effects other metrics across the scenario. But generally, load for example is one that is more directly correlated to the economy.
- Follow-Up: What tool are you using for modeling assumptions?
    - Assumptions will be modeled similar to previous IRPs.
- Question: How much is the new law going to impact the new modeling relative to methane gas?
    - Response: We will be looking into the impacts of the new legislation and provide updates in future scenarios.
- Question: Can we start the process of sharing data to make an interactive process?
    - Response: We will take the feedback into consideration moving forward.
- Question: Do you plan to talk about the metrics at the next meeting or are those decided?
    - Response: We've heard feedback on carbon intensity and other metrics, so we will go back and reassess.

Comments of CAC on CenterPoint's First 2022-2023 IRP Stakeholder Workshop

Submitted to CenterPoint on September 1, 2022

Citizens Action Coalition of Indiana ("CAC") submits these comments on the materials presented and issues discussed during CenterPoint's August 18, 2022, Integrated Resource Plan ("IRP") stakeholder workshop.

1 General Stakeholder Process

CAC appreciates CenterPoint's "Commitments for 2022/2023 IRP." We look forward to working constructively with CenterPoint throughout this process to achieve an IRP that will provide beneficial outcomes to CenterPoint's customers.

Thank you for agreeing to facilitate technical workshops with stakeholders like CAC that execute non-disclosure agreements ("NDAs"). CAC also appreciates the schedule shared by CenterPoint that includes time tables for sharing information with stakeholders at regular intervals throughout the process.

CAC would also like to request that CenterPoint:

- Provide to CAC the full bid proposals received in response to its 2022 request for proposals at its earliest convenience.
- Use an online data sharing platform (e.g., Drop Box, Sharefile, etc.) to provide IRP data files to stakeholders who have executed NDAs.
- Provide direct and clear responses to stakeholder input, such as through additional calls or as part of the technical conferences, so that stakeholders can have an understanding of how their feedback was considered.
- Commit to providing its data inputs and modeling files to stakeholders on a schedule that permits stakeholders to provide feedback and gives CenterPoint sufficient time to be able to incorporate that feedback.

2 Objectives and Measures

CAC thanks CenterPoint for providing these draft metrics early in the process to allow time for stakeholder input and response. CAC has the following concerns and recommendations about the draft Objectives and Measures identified by CenterPoint:

- **Environmental Sustainability:** Best practice is to use total (absolute) CO_2-equivalent emissions, not CO_2 intensity, as the metric for measuring impacts to climate. CO_2 intensity does not indicate whether greenhouse gas ("GHG") emissions are increasing or decreasing. Total GHGs – not the rate of GHG emissions – is what is causing harm to the climate system. If the rationale for using intensity is the ability to compare the electrification portfolios, there are at least two options available to address that concern. One is to enforce an emissions reduction constraint in any electrification based portfolio so that total emissions drop even as load is increased. This would be consistent with the rationale for the electrification – to reduce carbon emissions. Another option is to evaluate the electrification portfolios only against each other. <u>CAC strongly recommends using cumulative CO_2-equivalent emissions over the IRP period as the measure for the Environmental Sustainability objective.</u>

- **Fuel Price Risk:** CAC believes none of the identified metrics would sufficiently measure the risk of different portfolio options to CenterPoint's customers associated with fuel price volatility. Since CenterPoint passes through all fuel costs to its customers, the risk of fuel price spikes is borne entirely by the customer. Therefore, it is critically important that CenterPoint evaluate how various portfolio options compare on the amount of fuel price risk associated with the selected resources. Portfolios that rely more on meeting customer energy needs using technologies that rely on volatile fuel prices are riskier to customers than portfolios that rely less on fuels that have volatile costs. <u>CAC recommends that CenterPoint adopt a Rate Stability objective with three metrics (cost certainty, cost risk, and lower cost opportunity) that NIPSCO used in its most recent IRP</u>. In the alternative, CenterPoint could adopt a "Fuel Price Risk" objective with an associated measure of "Proportion of annual energy generated by resources that rely on fuels that have volatile costs," where fuels with volatile costs includes both coal and natural gas.

- **Reliability:** CAC wishes to better understand what objective CenterPoint will set for this metric and how it will assign "Spinning Reserve/Fast Start Capability" to resources. The stated measure is "% of Portfolio MW's that offering spinning reserve\fast start", but the percentage is not given and it is not clear if that % might change relative to other metrics of the portfolio such as load. CAC's goal in better understanding this metric is to ensure that it is appropriately including the reliability attributes that clean energy solutions can offer. In addition, now that FERC has approved the changes to MISO's thermal accreditation methodology, CAC would strongly recommend that those changes be included in addition to the seasonal reserve margin requirements.

- **Equity:** Given the high proportion of low-income ratepayers in CenterPoint's service territory and the disproportionate impact of emitting industries on its service territory, we would recommend a two-part equity metric that looks at low-income cost burdens and emissions exposure. We would propose the following:
    - First, a metric that measures whether emitting units in each portfolio are located in low-income and/or communities of color and how those overlap with other emitters in Southern Indiana. An example of this as it relates to peaker plants in New Mexico is given below.

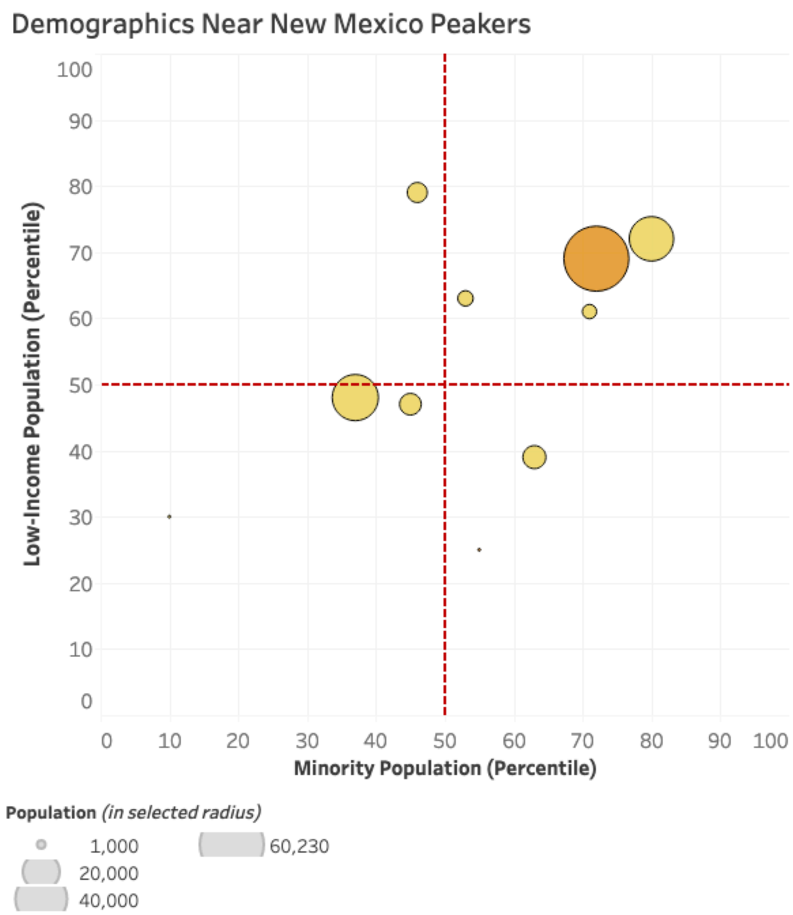


Figure 1. Demographics Near New Mexico Peaker Plants[1]

The circle size indicates the population within a given radius of the plant and the color, in this case, distinguishes between peakers at their own site versus those co-located with a combined cycle plant. For CenterPoint's purposes, we would recommend keeping the low-income and community of color axes, but changing the color coding to reflect the fuel burned at emitting units. We would note that a similar graph, but for all fuel types, could be used to identify some of the positive and negative impacts as well as the equity of those impacts of replacement generation once those locations are identified.

- Second, a metric that looks at the cost burden by census tract and could account for the bill impacts of community-solar projects that could be placed in those communities (since those are now eligible for a bonus Investment Tax Credit)

[1] https://www.psehealthyenergy.org/our-work/energy-storage-peaker-plant-replacement-project/new-mexico/

would be very useful. An example of this is given in a report looking at energy cost burdens as a percent of median household income in the state of Colorado.[2]

3 RFP

CAC appreciated having the opportunity to review and provide feedback on CenterPoint's draft RFP prior to its issuance and CenterPoint's willingness to incorporate our feedback. Given the significant volatility in markets over the past several months, as well as the enactment of the Inflation Reduction Act, which significantly changed tax credits for renewable energy and battery energy storage, <u>we urge CenterPoint allow bidders the opportunity to update their project costs to ensure CenterPoint uses the most up-to-date information on resource costs as inputs in its IRP</u>.

We look forward to reviewing the results of the RFP and the bid proposals submitted.

4 Environmental Update

Given the large cost increase in NOx allowances in 2022, CAC would appreciate hearing additional clarification on how CenterPoint will estimate the cost of NOx allowances in its IRP modeling. What NOx prices will CenterPoint use for future years, and how many purchases of allowances will CenterPoint need to make in future years?

5 DSM

5.1 Energy Efficiency "EE"

5.1.1 Market Potential Study "MPS"

CenterPoint engaged GDS Associates, Inc. ("GDS"), in January 2022 to perform a "refresh" of the most recent CenterPoint Market Potential Study ("MPS"), which was completed in 2019. Due to the nature of the refresh, the opportunities for stakeholder review and input were more limited compared to a full MPS. GDS and CenterPoint provided updates on the MPS development process periodically, but infrequently, at Oversight Board "OSB" meetings. While CenterPoint and GDS were generally receptive to feedback provided during OSB meetings, CAC would have preferred more frequent updates with opportunities for formal review and comment. The draft MPS results were shared publicly by CenterPoint at the IRP Public Stakeholder Meeting held on August 18, 2022, prior to CAC having the opportunity to review or comment on the draft findings. At this time, several CAC concerns remain outstanding regarding the treatment and bundling of EE resources within the IRP.

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[2] *See* PDF page 26 of https://www.psehealthyenergy.org/wp-content/uploads/2022/01/Colorado-Energy-Affordability-Study_Full-Report.pdf

The MPS, once completed, will quantify the technical, economic, maximum achievable, realistic achievable, and program potential savings for the years 2025 through 2042. Each of these MPS scenarios is described as follows:

- **Technical Potential** is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures.
- **Economic Potential** refers to the subset of the technical potential that is economically cost-effective, based on screening with the utility cost test ("UCT") as compared to conventional supply-side energy resources.
- **Achievable Potential** is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. The potential study evaluated two achievable potential scenarios:
    - **Maximum Achievable Potential** ("MAP") estimates achievable potential on paying incentives equal to up to 100% of measure incremental costs and aggressive adoption rates.
    - **Realistic Achievable Potential** ("RAP") estimates achievable potential with CenterPoint paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

5.1.2 MPS Cost-Effectiveness Screening

The MPS economic potential cost-effectiveness screening was performed as described below by GDS:

> *The UCT considers electric energy, capacity, and transmission & distribution (T&D) savings as benefits, and utility incentives and direct install equipment expenses as the cost. Consistent with application of economic potential according to the National Action Plan for Energy Efficiency, the measure level economic screening does not consider non-incentive/measure delivery costs (e.g. admin, marketing, evaluation etc.) in determining cost-effectiveness. Apart from the low-income segment of the residential sector, all measures were required to have a UCT benefit-cost ratio greater than 1.0 to be included in economic potential and all subsequent estimates of energy efficiency potential.*

Utility non-incentive costs were included in the overall assessment of cost-effectiveness in the RAP and MAP scenarios. Non-incentive costs were calibrated to recent CenterPoint levels by sector and program and applied on a per-first year kWh basis.

A notable inconsistency with the IRP is that the MPS does not consider the avoided cost of carbon regulation. Multiple IRP scenarios, as presented by CenterPoint at the August 18 IRP Stakeholder Meeting, include carbon regulation. Had the MPS included a similar assumption for future carbon regulation, the UCT scores for all measures would have improved, thereby enabling additional measures (or programs) to be considered cost-effective. This inconsistency results in a smaller amount of savings being available for selection within the IRP.

5.1.3 MPS Forecasted Cost and Savings

CenterPoint has not yet made available to CAC the MPS modeling files nor the MPS IRP bundling. As such, we are unable to provide any comments on the reasonableness and accuracy of the MPS assumptions and calculations. During MPS development with other Indiana utilities, these resources have been made available to CAC and other stakeholders at multiple stages throughout the development process, and certainly before any draft results are shared publicly.

5.1.4 MPS Bundles for IRP Modeling

Energy Efficiency resources will be bundled and inputted into the IRP according to the following process, as provided by GDS at the August 18 IRP Stakeholder meeting:

1. EE Inputs will align with RAP Potential *(but adjusted from gross to net savings)*
2. EE Inputs will be provided over three vintages
    a. 2025-2027 (3 years)
    b. 2028-2030 (3 years)
    c. 2031-2042 (12 years)
3. For 2025-2027, EE Inputs will be bundled to closely resemble program offerings
    a. For remaining vintages, EE inputs will be aggregated at the sector level
4. EE Costs will include utility costs (incentives and non-incentive costs)
    a. Costs will be adjusted to recognize value of avoided lifetime T&D benefits

Based on discussions with CenterPoint and GDS during an IRP planning meeting held on August 2, CAC was under the impression that CenterPoint would be modeling bundles of savings from the MPS RAP scenario *and* the MPS MAP or an alternative "enhanced" version of RAP with elevated incentive levels. Instead, EE bundles were constructed only from the MPS RAP scenario. With this approach, MAP savings (or an "enhanced" version of the RAP) will be excluded from the IRP model entirely, and therefore will not be a selectable resource within Aurora and will not be allowed to compete with other resource options. This approach is problematic since it imposes limits on future EE potential based on existing program design, budget, and incentive levels. As a result, the MPS forecast as modeled in the IRP will not be independent of existing program constraints such as incentive budget.

5.1.5 Emerging Technology

CAC anticipates that the MPS analysis will include a limited number of emerging technology measures, consistent with the 2019 CenterPoint MPS and with studies completed by GDS for other Indiana utilities. For example, in another recent Indiana MPS, GDS included 32 measures (18 residential, 14 commercial & industrial) that were designated as emerging technology. CAC commends the inclusion of emerging technologies in an MPS, however, the relatively small number of measures results in a very limited impact. Many of the emerging technology measures included by GDS in other studies failed to pass the economic screen and therefore did not contribute to the achievable potential.

The nature of new emerging technology is such that high initial costs tend to fall as production volume and market adoption increase. The MPS analysis makes no accommodation for any emerging technology to be included in the later years of the analysis if/when the measure becomes cost-effective. New technologies are regularly being introduced, and many utility programs contribute to the market readiness of these emerging technologies through pilot programs and incentives. Failure to account for these technologies results in a conservative and unrealistic view of the potential savings.

As a point of comparison, the Consumers Energy 2021 Electric Energy Waste Reduction Potential Study, completed by Cadmus, evaluated over 200 emerging technology measures which were characterized and included in the model.[3] Ultimately, 170 unique measures were included in what Consumers Energy refers to as the "Transformational Scenario." The impact of this scenario was significant on the estimate of future achievable potential, as shown in Figure 2 below.[4] In years 3 through 9, emerging technologies account for roughly 20% of the achievable potential. In the later years of the Consumers Energy study, emerging technologies account for roughly two-thirds of the achievable potential. These results plainly demonstrate the significance of emerging technologies and highlight the importance of adequately accounting for them in a market potential study.

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[3] MPSC Case No. U-21090, Consumers Energy Co. Witness Garth, Exhibit A-81 available at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/EWR_Collaborative/2022/Consumers-Energy-Electric-EWR-EE-Potential-Study-w-TransTech-Scenario-20210610.pdf

[4] Presentation by Consumers Energy, "Creating a Transformational Path to the Future of Energy Efficiency, Together!," available at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/EWR_Collaborative/2022/Transformational-EWR-Together_CE_20220719-final.pdf

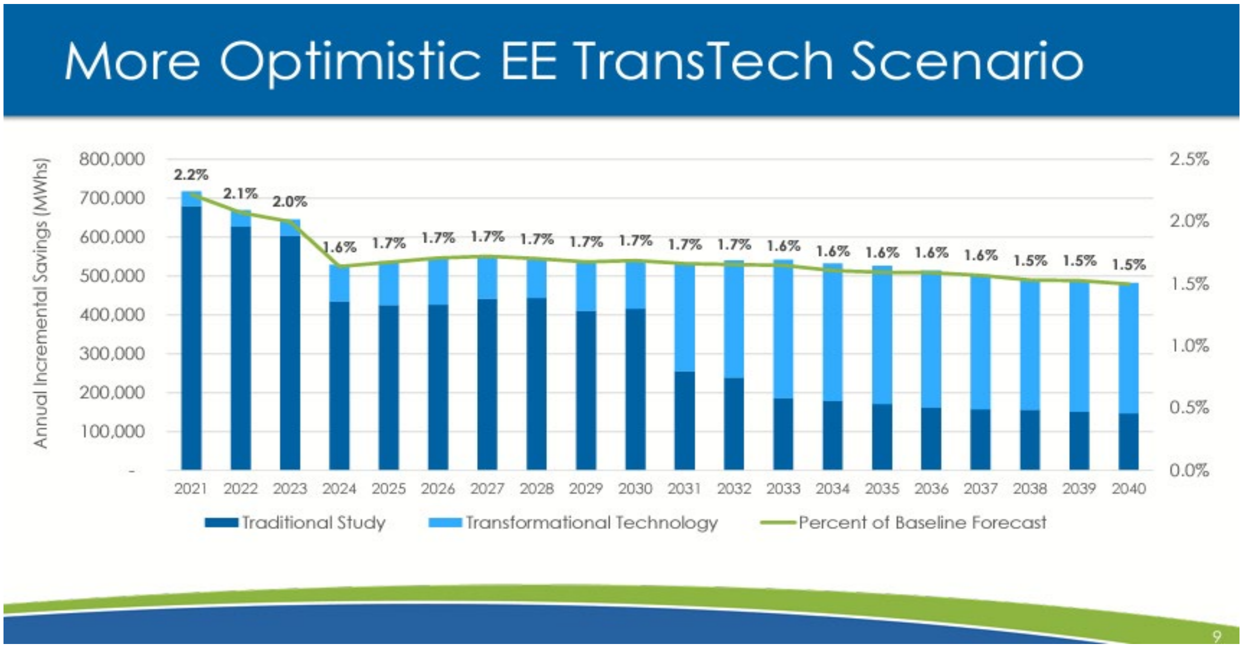

Figure 2. Consumers Energy Transformational Scenario

5.1.6 Demand Response

During a July 13, 2022 meeting with CenterPoint to discuss demand response, CAC asked that CenterPoint/GDS use the same methodology employed for the AES MPS to develop additional demand response options. CAC outlined several reasons why relying on an RFP to characterize DR opportunities would result in little to no meaningful data to use. For example, there is no meaningful DR aggregator community in southern Indiana, and industrial customers could not be expected to be experts in demand response programs themselves. To date, CenterPoint has not responded to this request, and we would reiterate its importance to ensuring that all cost-effective resources are available in the IRP modeling.

6 Load and Commodity Forecasts

6.1 Load Forecast

CAC appreciates CenterPoint's and Itron's presentation to stakeholders of its draft load forecasting methodology before finalizing the load forecast for the 2022-2023 IRP. CAC asks for clarity on the following items ahead of the preparation of the final load forecast:

1. How these data were calibrated to CenterPoint's electric service territory;
2. Have shorter weather periods been evaluated – e.g. 10-year or 15-year historical temperature data?;
3. Transparency on how the EIA electric vehicle forecast will be incorporated into the total energy and peak demand forecasts.; and
4. Whether Itron will incorporate the Inflation Reduction Act tax credits for electric vehicles.

In addition, CAC would like to understand the approach that will be used to forecast industrial load. Will Itron be responsible for that analysis, or will CenterPoint substitute its own forecast as it did in the previous IRP? If the latter, what will CenterPoint's methodology be, and what data will it rely upon?

6.2 Commodities Forecasts

CAC is extremely concerned that the reference case forecasts for natural gas and coal pricing are underestimating the costs of these fuels, as well as their price volatility. The natural gas and coal price forecasts assume a rapid return to low commodity pricing in 2023-2024, followed by a gradual increase in fuel prices, with no significant volatility, from 2025-2042.

The reference case fails to consider the current, record-high prices for both coal and natural gas and overall volatility in pricing that is an attribute of the status quo with these fuels. In that context, sustained high fuel costs are possible, yet it does not appear that CenterPoint will be modeling this. For instance, the U.S. is continuing to expand LNG capacity, which will result in increased exports of natural gas in the future as the U.S. provides larger quantities to places like Europe. The natural gas industry has also proven extremely reluctant to expand production despite high prices due to investor pressures to bring spending down. Likewise, coal mining companies are not opening new mines to meet short-term increased demand due to projected long-term industry decline, and coal transportation problems could continue to hamper deliveries, continuing upwards pressure on coal costs. The near-term natural gas and coal price forecasts predicting dramatic declines in prices therefore lacks credibility under current recognized market dynamics and should be rectified.

6.2.1 Natural Gas

All but one of the vendors is forecasting well below the current spot price for natural gas, which is currently approximately $9.04/MMBtu (see Figure 3).[5] Henry Hub futures are currently trading at approximately $5.00/MMBtu and above through first half of 2024. CAC recommends that CenterPoint update the Henry Hub projections to align more closely with the expected market conditions in the near term. CAC would also appreciate clarity on the methodology used to average the forecasts of the four vendors. For example, are the prices derived from a simple or weighted average?

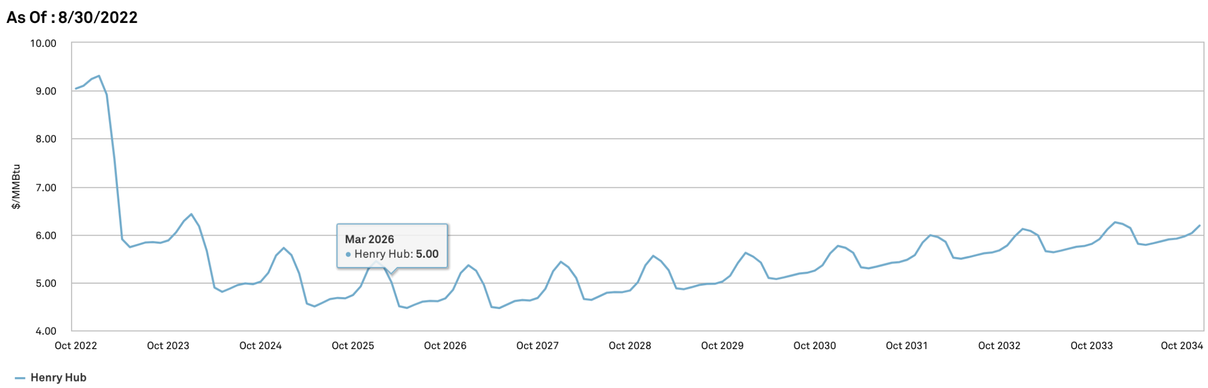

Figure 3. Henry Hub Natural Gas Futures as of 8/30/22

Two of the four coal price forecasts for the 2022-2023 IRP currently project coal prices to be below $3.00/MMBtu for the majority of the forecast horizon. Average weekly Illinois Basin coal traded at $8.04/MMBtu for the week of 8/26/2022.[6] By comparison, CenterPoint states its price for coal in 2022 was approximately $5.00/MMBtu. Three of the coal price forecasts do not exceed $3.00/MMBtu for most, if not all, of the planning horizon. CAC recommends CenterPoint update its coal price forecast to reflect the current state of coal prices.

The forecast for MISO Capacity prices has only two vendors. These forecasts start from different points, however, both forecasts converge on the same point over the forecast horizon. This may give less value to averaging these vendors. CAC ask for clarity on the limited number of vendors for MISO Capacity price forecasts as compared to other commodity projections presented at the stakeholder workshop. If additional forecasts are not available to CenterPoint, CAC recommends that CenterPoint consider scenario analysis rather than the averaging two forecasts. In either event, it may make the most sense to price capacity sales only in the production cost runs, so that the capacity price does not unduly influence the resource build.

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[5] *CME Group. Henry Hub Natural Gas*. https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.html. August 30, 2022.

[6] *Coal Markets. EIA*. https://www.eia.gov/coal/markets/#tabs-prices-2. August 31, 2022.

7 Resources

During the August 18, 2022, stakeholder meeting, CenterPoint presented several thermal and non-thermal resource options that would be modeled as new supply side resources in EnCompass. For new supply side resource options, we recommend that:

1. CenterPoint consider the resource screening analysis to determine if some of the new thermal options, such as supercritical or ultra-supercritical coal with CCS, be offered as a resource in the capacity expansion model.
2. Reflect the tax credits outlined in the Inflation Reduction Act ("IRA").
3. Consider modeling longer duration Lithium-Ion battery storage resources in addition to 4-hour storage resources given the tax credits for standalone battery resources under the IRA.

We would also recommend that in future workshops CenterPoint discuss any resource constraints that will be applied in EnCompass in addition to the declining ELCC values for renewable and battery storage resources that were noted on slide 77 of the stakeholder workshop. Will CenterPoint impose any annual or cumulative build limitations as constraints in its modeling? If so, what are those constraints?

8 Stochastic Modeling

It is our understanding from the information provided in the stakeholder workshop that CenterPoint is planning on replicating the stochastic modeling approach that was used in the 2020 IRP. Given the differences between Aurora and EnCompass, we had several follow-up questions to better understand how the stochastic modeling will be conducted:

1. How many stochastic iterations will be performed in EnCompass?
2. Will the stochastic modeling be applied to the production cost runs only?
3. What topology will be modeled in EnCompass? Will 1898 and CenterPoint be modeling a larger footprint than the CenterPoint system?
4. In the 2020 IRP, the stochastic modeling included capital costs as a stochastic variable but only in areas outside of the CenterPoint system. Is the plan to include capital costs as a stochastic variable? If so, we would strongly encourage CenterPoint remove this variable from the analysis because capital costs are uncertain, e.g., the impact of expanded tax credits are not volatile so it would very difficult to develop an appropriate probability distribution. We would recommend that capital costs be addressed through scenarios or sensitivities.

9 Reference Case

ACE Proxy and Carbon Price

CAC requests additional information on how the CO_2 ACE Proxy will be modeled in the IRP once that information is available. CAC observes that many utility IRPs are modeling the impacts of potential future climate policy through a forecast of escalating carbon prices included in their reference case.

10 Potential Scenarios

10.1 High Regulatory

CAC believes coal prices would be higher (not the same as in the reference case) in a high-regulatory environment. Environmental regulations would likely add costs. While demand for coal might be lower, providing downwards cost pressure, the industry will also be reducing supply by closing mines and reducing output, and transportation issues could persist, which will create upwards cost pressures.

In addition, because this scenario seems to be a high *environmental* regulatory scenario, we do not think that the cost of EE is likely to go up much. A comprehensive environmental policy would not just reduce carbon emissions, but also *incentivize* carbon reducing technologies. The recently passed Inflation Reduction Act is an example of this. While it did not include a carbon constraint, part of the Act's purpose is to reduce the cost of carbon abating technologies including on the demand-side. CAC believes the EE cost should at least be static in this scenario, if not go down and additional EE ought to be available to select (see Section 5).

10.2 FERC Order 2222 Scenarios

Will CenterPoint clarify if it will take efforts to incorporate Distribution System Planning into its IRP planning? FERC Order 2222 permits distribution-level resources (DER) to serve as wholesale capacity on a potentially unprecedented scale. This could have significant impacts on bulk-level system planning, which has been the traditional focus of the IRP process. CAC recommends that CenterPoint incorporate DSP into IRP planning as the penetration of DER increases. In particular, CAC would recommend that CenterPoint examine ways that FERC Order 2222 could encourage or bring additional value to low-income programs, energy efficiency programs, increased customer- and community-sited DER and other behind-the-meter programs across the service territory.

CAC encourages CenterPoint to evaluate the following in 2022 IRP:

- Identify current capacity hosting limits at the substation level
- Evaluate how much distributed capacity could be added at each substation without thermal or voltage violations
- Evaluate three scenarios:
    - Base Case in which the current level of solar and battery DER penetration is held constant,

- Mid Case, in which the current level of solar and battery DER increases to the capacity hosting limit, and
- High Case, in which the current level of solar and battery DER increases by 25% above the capacity hosting limit.

- Estimate the potential attributes of increased DER participation:[7]
  - Avoided capacity value,
  - Energy and ancillary value,
  - Avoided transmission value, and
  - Voltage support value.

If it is not possible to identify a hosting capacity limit, then CAC would welcome an alternative proposal from CenterPoint that would enable the testing of differing levels of DERs. The cost of those DERs should reflect only the utility cost and account for participation impacts of the IRA.

[7] Zhou, Ella; Hurlbut David, and Xu, Kaifeng. *A Primer on FERC Order No. 2222: Insights for International Power Systems*. *NREL.* September 2021. https://www.nrel.gov/docs/fy21osti/80166.pdf

September 22, 2022

Matt Rice, Director, Regulatory and Rates, CenterPoint Energy
211 Northwest Riverside Dr., Evansville, IN, 47708

Dear Mr. Rice,

RE: Sierra Club recommendations in response to CenterPoint's first IRP meeting

Thank you for reaching out to solicit our input in CenterPoint Energy's 2022/2023 IRP Process. Below are our suggestions in response to the public stakeholder meeting on August 18th.

Locking in Coal Retirement Dates

Sierra Club's priority is to secure commitments from CenterPoint for retirement dates by 2030 for all of the Company's coal plants during this IRP process.

Culley Unit 2 and Warrick Unit 4

From the August 18th stakeholder meeting, we understand that CenterPoint pushed back the retirement date of Culley Unit 2 by three years (from 2022 to 2025) as a result of the high capacity clearing prices for MISO Zone 6 in the 2022/2023 Planning Resource Auction (PRA). During the extra years of operation, CenterPoint asserts that Culley Unit 2 will be valuable for its capacity even though it will seldom be dispatched, and that continuing to operate Culley Unit 2 will avoid the need for CenterPoint to pay high costs for additional capacity in the market. The Company presents a similar argument about extending its contract with Alcoa for Warrick Unit 4. We are concerned that this is a superficial analysis, and request that CenterPoint address the following questions before extending the operating dates of either unit:

- Does the Company believe that the recent high-capacity prices in the 2022/2023 PRA are indicative of likely future trends?
- Does the Company plan to issue a request for proposal (RFP) to see if it could meet short-term capacity needs at lower costs to ratepayers?

- Has the Company evaluated the capital and operation and maintenance (O&M) costs required to maintain Culley Unit 2 and Warrick Unit 4 until 2025? If extensive repairs are needed, costs could easily outweigh the capacity benefits of maintaining the plant.
- Will the Company commit to a cap on total funds that may be used for repairs and upgrades at its coal plants, especially the ones with near-term retirement dates?
- What actions is the Company taking to replace the coal capacity from these two units' capacity after the eventual closure of Culley Unit 2 and the end of its contract with Warrick Unit 4 to ensure there are no further delays in the units' retirements dates?

Culley Unit 3

We also request that CenterPoint commit to retiring Culley Unit 3 by no later than 2030, given recent developments in federal energy policy, including the Inflation Reduction Act (IRA), and the rapidly escalating costs of environmental compliance for CenterPoint's coal plants.

The price of NOx allowances under the Cross-State Air Pollution Rule (CSAPR) increased by a factor of 685 between 2020 and 2022, and allowance purchases will cost CenterPoint $22.5 million dollars this year, even as the Company runs its remaining coal units as cleanly as possible. The NOx emissions limits established by CSAPR will continue to tighten in future years, further driving up allowance prices. Because coal combustion is one of the most pollution-intensive methods for generating electricity, future environmental regulations, including regulation of greenhouse gas emissions, are likely to make Culley Unit 3 even more uneconomic.

And as the cost to operate Culley Unit 3 continues to rise, the cost of replacement resources are expected to fall. This is especially true after the enactment of the Inflation Reduction Act (IRA) in August. This will further erode the economics of maintaining Culley Unit 3 such that retirement by 2030, even with the effluent limitation guidelines upgrade costs already spent and sunk, will be the most economic course of action.

Revisiting Decision to Construct Natural Gas Plants

We also urge CenterPoint to reevaluate its plan to build two natural gas combustion turbine plants (CTs). Although CenterPoint has received Commission approval to construct the CTs (but it has not yet received approval for the pipeline needed to fuel them), it is under no obligation to construct them. Conversely, CenterPoint *does* have an obligation to its customers to re-evaluate the reasonableness of a project if market conditions change substantially. While changes in policy and market conditions occur regularly, and there is likely to always be some level of policy change or uncertainty during any resource planning process, the IRA is unique in the magnitude of its impact on renewable costs and the landscape of electricity utility resource planning as shown in Table 1 below.

Table 1: Renewable tax credits available to CenterPoint before and after IRA. Credits are now significantly larger, increasing the cost-competitiveness of renewables relative to coal and gas.

	CenterPoint 2019/2020 IRP tax credit assumptions[1]	**Current IRA tax credits[2]**
Solar PV	ITC: 2019: 30% 2020: 26% 2021: 23% After 2022: 10%	ITC: 30% base PTC: 2.5 cents/kWh 100%
Wind	PTC: 2.5 cents/kWh (in $2017) Stepping down… 2019: 40% 2020: 60% After 2021: 0%	PTC: 2.5 cents/kWh 100%
Battery Storage	-	ITC: 30%

Source: 2019/2020 IRP pages 175-177.

Note 1: Tax credits here reflect those included in the 2019 IRP. Tax credits were subsequently extended through 2025 after the IRP and prior to the IRA.
Note 2: 30% ITC and 2.5 cents/kWh PTC are all the base. Companies can get an extra 10% for siting in an energy community, and another 10% for use of domestic products

Revisiting the decision to construct the CTs is also especially important given the enormous cost and the risks the project places on ratepayers. These risks include the project's large capital cost, which poses a stranded asset risk if the plant becomes uneconomic before it is fully depreciated, the cost of the gas pipeline, and the cost of fuel, which is highly volatile.

Even before the IRA, CenterPoint's justification for the CTs was incomplete at best. The Company's own modeling from its 2019/2020 IRP — despite using unrealistically high renewables costs and low gas prices — showed that a portfolio with no CTs was lower cost than a portfolio that included two CTs (the High Technology Portfolio) in three out of five future scenarios. In all IRP scenarios, the portfolio with one CT was lower cost than the portfolio with two CTs. In four out of five scenarios, the second CT almost never operated, indicating that it is not needed for reliability and is at high risk of becoming a stranded asset.

As discussed above, the cost of NOx allowances has escalated rapidly since the 2019/2020 IRP was conducted. If 2022 prices continue, the net present value of allowances to balance emissions from the two turbines through 2039 ranges from $2.1 million to $46.8 million (depending on the capacity factor of the plants in each scenario). These costs further reduce the economic viability of the plants.

It makes sense that CTs do not appear as the lowest cost option in CenterPoint's modeling, because the availability of energy storage technologies renders them largely obsolete. This was true during the 2019/2020 IRP process and is even more true now. Operationally, battery storage is better suited to serving reliability needs and facilitating the expansion of renewables, because batteries respond to dispatch signals more quickly than CTs and can charge during periods of high renewable availability, reducing the need for curtailment. Now that battery storage is eligible for the investment tax credit (ITC), its capital costs are 30-50% lower than when CenterPoint performed its original analysis, further increasing its advantage over the costly combustion turbines and gas pipeline. Table 2 summarizes the cost of renewable generation (in 2022$) to CenterPoint before and after the IRA, assuming PPA financing for the ITC (and that the tax credit is not normalized over the life of the plant). The current costs would be even lower for projects eligible for tax credit adders under the IRA. We find that project NPVs are expected to fall around 25% for battery storage, 21-22% for solar PV, and 28-38% for wind, depending on capacity factor.

Table 2: Percent reduction in CenterPoint renewable project relative to the 2019/2020 IRP

	NPV (2025-2054) before IRA	**NPV (2025-2054) after IRA**	**IRA tax credit claimed**	**Percent Reduction**
Lithium ion battery (50 MW)*	$99 million NPV	$74 million NPV	Base ITC	25%
Solar photovoltaic (100 MW)	$177 million NPV	$139 million NPV	Base PTC 30% ITC	21.6% for PTC 21.1% for ITC
Wind in northern Indiana (38% CF) (200 MW)	$476 million NPV	$297 million NPV	Base PTC	38%
Wind in southern Indiana (28% CF) (200 MW)	$476 million NPV	$344 million NPV	Base PTC	28%

Source: Calculated from CenterPoint cost parameters provided in the Direct Testimonies of Matthew Rice and Michael Goggin in Indiana Utility Regulatory Commission Cause No. 45564
*Note: Battery storage NPV excludes VOM costs

Because CenterPoint will already be conducting EnCompass modeling as part of its IRP process, it would require minimal extra effort for the Company to include an unconstrained run evaluating the cost of the proposed CTs relative to replacement resources under current cost conditions. During the August 18th Stakeholder meeting, CenterPoint indicated that it would re-run its modeling to find the next optimal resources in the event that the gas pipeline wasn't approved by FERC. We repeat the question we posed at the meeting – why wait to perform the analysis if it could just be done proactively, and incorporate the updated renewable costs that resulted from the extension of the production tax credit (PTC) and ITC in the IRA?

Improving Modeling of Renewables and Climate Policies

With renewable costs lower than ever and the U.S. committed to a 50 percent reduction in greenhouse gas emissions by 2030, CenterPoint should use this IRP as an opportunity to explore a rapid buildout of renewable energy resources. The RFP lays the foundation for this effort, and CenterPoint should request that developers refresh their bids in light of the new tax credits available under the IRA. CenterPoint should also release the results of its RFP to stakeholders who have signed nondisclosure agreements (NDA).

Representing renewables in the IRP modeling

CenterPoint requested feedback on how to represent renewables in the IRP EnCompass modeling. We agree with the Company's plan to use RFP results to model resource cost assumptions in the near-term (provided the bids are refreshed based on the IRA impacts). For later years, CenterPoint should model generic resources, including both PPA and utility-owned projects based on transparent industry standard projections such as those provided by NREL, EIA or Lazard. Updating tax credit assumptions to match the IRA will be crucial to obtaining accurate results; this includes modeling solar and wind as eligible for either the PTC or ITC, and storage as eligible for the ITC, and modeling the incremental 10% adder for resources located in energy communities. The Company should clearly outline the assumptions that it makes regarding bonus credits related to wages, domestic content, and similar criteria. All calculations should be transparent, and CenterPoint should provide workbooks to stakeholders.

Carbon regulation

Regarding assumptions about carbon regulation in the IRP modeling, we are concerned with the Company's decision to use the Affordable Clean Energy (ACE) rule as the reference assumption for policy under Clean Air Act Section 111(d). Even after *West Virginia v. EPA*, the EPA has multiple possible avenues for establishing ambitious emissions limits for existing power plants under 111(d). ACE was a notoriously weak rule developed by a presidential administration that was hostile to climate policy, and it does not align with CenterPoint's stated commitment to align its operations with the Paris Agreement. The current administration is committed to emissions reductions, including a goal of 100 percent clean electricity by 2035, making it very likely that forthcoming power sector regulations will be stronger than ACE. To accurately represent this regulatory environment, CenterPoint should adjust its baseline policy assumptions. Additionally, the reference scenario should include new energy costs established by the IRA, as well as renewable energy builds to which CenterPoint is already committed.

Refining IRP Objectives and Evaluation Metrics

We appreciate CenterPoint's request for feedback on the objectives that it plans to pursue in its IRP, and have several suggestions for refining the metrics used to assess these criteria:

Affordability

CenterPoint lists affordability as its first objective and proposes to assess it using 20-year net present value revenue requirement (NPVRR). We agree that affordability should be a central objective of the IRP process, but NPVRR is an incomplete way to measure this goal. Affordability depends on distributional impacts as well as total cost to ratepayers. But NPVRR measures only aggregate cost, potentially masking impacts on low-income customers and other vulnerable groups. Low-income energy efficiency programs, and rate designs that target specific demographics and focus on bills and not rate can be critical in addressing affordability. To fully grasp the affordability of its portfolio options, CenterPoint should develop a methodology for assessing the impacts on each customer class and type separately.

Environmental sustainability

Similarly, environmental sustainability is a crucial IRP objective, but carbon dioxide intensity is potentially a misleading way to quantify it. What matters from the perspective of climate change is the overall quantity of greenhouse gas emissions added to the atmosphere, which depends both on electricity emissions intensity and the amount of electricity consumed. CenterPoint should quantify tons of carbon dioxide emissions rather than focusing only on emissions intensity. (When relevant, emission from greenhouse gasses besides carbon dioxide should also be included in this total.)

Reliability

For reliability, it appears that CenterPoint is weighing ancillary services (spinning reserve/fast start) equally with overall resource adequacy. Unless CenterPoint has particular reason to think that MISO ancillary service markets will be unable to provide sufficient ancillary services, UCAP obligations should be established as the primary reliability metric.

Risk minimization
Finally, we believe that the risk minimization objective should be expanded to include risks posed by fuel price volatility as well as market risk. Fossil fuel prices are inherently volatile, and portfolios that maintain reliance on natural gas and coal prolong customer exposure to price swings. CenterPoint should take this into account when comparing IRP portfolios.

Emphasizing Community Impacts in IRP Planning

Lastly, we encourage CenterPoint to expand its consideration of the community impacts of the portfolios it evaluates in the IRP. The CenterPoint electric service territory in Southwest Indiana is a sacrifice zone to polluting power, and while CenterPoint is not responsible for all of the emissions from the high concentration of coal-fired power plants in the region, its Brown, Culley and Warrick coal units are local contributors to air and water pollution. At the same time, CenterPoint customers are burdened with the highest electric bills in the state. CenterPoint should retire its fossil plants as soon as possible, rather than delaying retirement dates, and replace those units with affordable clean energy rather than more polluting, price-volatile fossil fuels. As the electric utility for the national hub of Super Polluters, CenterPoint could lead a clean energy transition in Southwest Indiana, and transform an energy sacrifice zone into a clean "energy community" utilizing incentives for coal communities in the IRA.

Devi Glick Senior Principal Associate Synapse Energy Economics dglick@synapse-energy.com	Wendy Bredhold Senior Campaign Representative, Indiana and Kentucky Beyond Coal Sierra Club wendy.bredhold@sierraclub.org
Lucy Metz Research Associate Synapse Energy Economics lmetz@synapse-energy.com	Tony Mendoza Senior Staff Attorney Environmental Law Program Sierra Club tony.mendoza@sierraclub.org
Jean Webb Energy Chair, Hoosier Chapter Sierra Club jeanwebb68@gmail.com	Robyn Skuya-Boss Lead Organizer, Beyond Coal Sierra Club robyn.skuya.boss@sierraclub.org

Cc (via email):

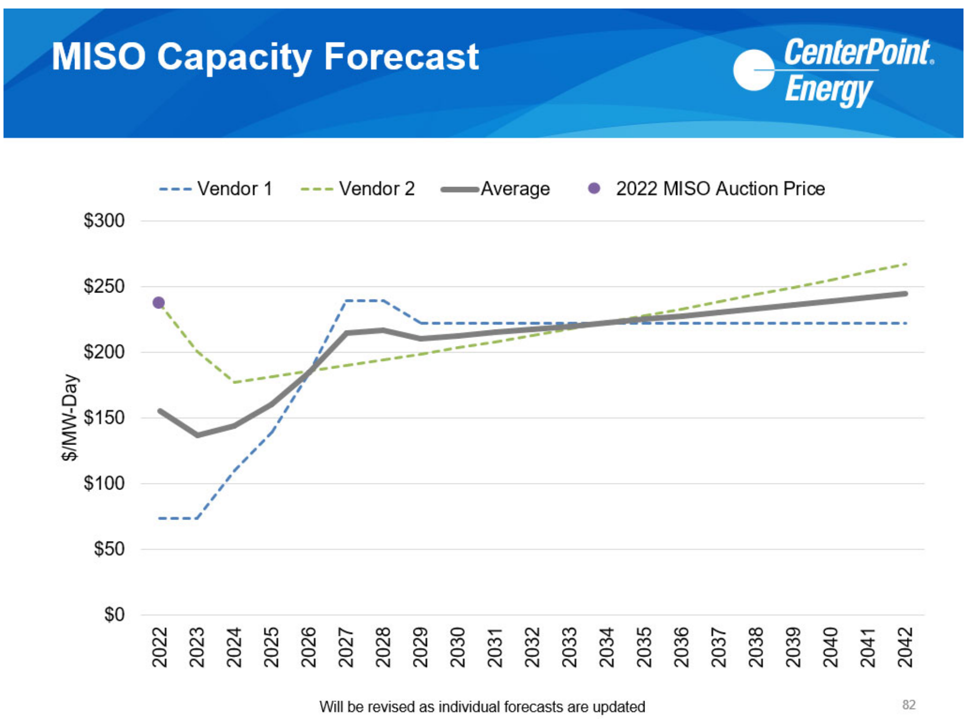
Dr. Bradley Borum, Indiana Utility Regulatory Commission, Director of Research, Policy, and Planning, bborum@urc.in.gov

William Fine, Utility Consumer Counselor, Indiana Office of Utility Consumers Council, wfine@oucc.in.gov

1.1 Does the Company believe that the recent high-capacity prices in the 2022/2023 PRA are indicative of likely future trends?

Response: Yes. MISO released the 2022 OMS-MISO Survey Results on June 10, 2022. MISO pointed out in the survey that the MISO footprint is "projected to have a capacity deficit of 2.6 GW below the 2023 PRMR". Similar to the 2022 PRA results, these deficits are restricted to the North/Central Regions. Capacity deficits are projected to widen in subsequent years primarily driven by demand growth and the continued retirements of coal fired resources. As is described in CEI South's second IRP stakeholder deck and in the IRP Contemporary Issues Meeting on September 22, 2022, in a presentation from MISO, the RTO is seeing increased load and projecting a decline in accredited capacity through the 2040's.

As such, CEI South believes high-capacity prices will continue in future years as shown in the 1st IRP stakeholder presentation.



Sierra Club Data Request Set 1 to CEI South
CEI South 2022/2023 IRP Response
October 12, 2022

1.2 Does the Company plan to issue a request for proposal (RFP) to see if it could meet short-term capacity needs at lower costs to ratepayers?

Response: CNP did issue an RFP in May of 2022. The RFP produced a few capacity-only-bids but were not viable based on timing/pricing. CEI South has acquired capacity to satisfy most of its capacity needs for the 2023/2024 MISO planning year and continues to solicit capacity requests for the 2024/2025 planning year.

1.3 Has the Company evaluated the capital and operation and maintenance (O&M) costs required to maintain Culley Unit 2 and Warrick Unit 4 until 2025? If extensive repairs are needed, costs could easily outweigh the capacity benefits of maintaining the plant.

Response: CEI South has evaluated the projected capital and O&M cost to operate Culley Unit 2 through 2025 vs. purchasing replacement capacity and energy. [redacted]

1.4 Will the Company commit to a cap on total funds that may be used for repairs and upgrades at its coal plants, especially the ones with near-term retirement dates?

Response: No, this is not a commitment that CNP can make.

1.5 What actions is the Company taking to replace the coal capacity from these two units' capacity after the eventual closure of Culley Unit 2 and the end of its contract with Warrick Unit 4 to ensure there are no further delays in the units' retirements dates?

Response: CEI South continues to implement its generation transition plan of operating approximately 700 – 1,000 MWac of solar generation, 300 MWac of wind generation, and 460 MW of natural gas Combustion Turbine generation by the end of 2025 to replace the capacity from the A.B. Brown Units 1& 2 and F.B. Culley Unit 2 retirements in 2023 and 2025, respectively, as well as the exit of the Warrick Unit #4 Joint Operating Agreement to occur between 2023 and 2025.

IRP Public Stakeholder Meeting

October 11, 2022

Welcome and Safety Share

Richard Leger
Senior Vice President Indiana Electric

Safety share

CenterPoint Energy

Tips to Avoid Distractions While Driving

- Make adjustments before your get underway. Address vehicle systems like your GPS, seats, mirrors, climate controls and sound systems before hitting the road. Decide on your route, and check traffic conditions ahead of time.
- Secure children and pets before getting underway. If they need your attention, pull off the road safely to care for them. Reaching into the backseat can cause you to lose control of the vehicle.
- Put aside your electronic distractions. Don’t use cell phones while driving – handheld or handsfree – except in absolute emergencies. Never use text messaging, email functions, video games or the internet with a wireless device, including those built into the vehicle, while driving.
- If another activity demands your attention, instead of trying to attempt it while driving, pull off the road and stop your vehicle in a safe place. To avoid temptation, power down or stow devices before heading out.
- As a general rule, if you cannot devote your full attention to driving because of some other activity, it’s a distraction. Take care of it before or after your trip, not while behind the wheel.

Follow Up Information From First IRP Stakeholder Meeting

Matt Rice
Director, Regulatory and Rates

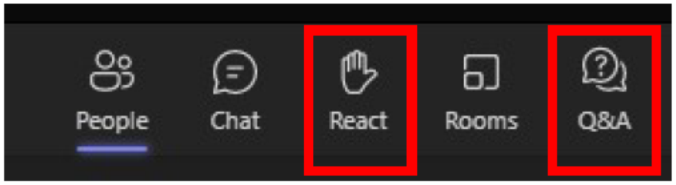
Agenda

Time		
8:30 a.m.	Sign-in/Refreshments	
9:30 a.m.	Welcome, Safety Message	Richard Leger, CenterPoint Energy Senior Vice President Indiana Electric
9:40 a.m.	Follow Up Information From First IRP Stakeholder Meeting	Matt Rice, CenterPoint Energy Director Regulatory & Rates
10:20 a.m.	All-Source RFP Update	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
10:50 a.m.	Break	
11:05 a.m.	Draft Resource Inputs	Kyle Combes, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
11:40 a.m.	Lunch	
12:20 p.m.	Final Load Forecast	Michael Russo, Forecast Consultant - Itron
1:05 p.m.	Probabilistic Modeling Approach and Assumptions	Brian Despard, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
1:50 p.m.	Break	
2:05 p.m.	Portfolio Development	Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
2:35 p.m.	Draft Reference Case Modeling Update	Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
2:45 p.m.	Stakeholder Questions and Feedback	Moderated by Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
3:15 p.m.	Adjourn	

Meeting Guidelines

CenterPoint Energy

1. Please hold most questions until the end of each presentation. Time will be allotted for questions following each presentation. (Clarifying questions about the slides are fine throughout)
2. For those on the webinar, please use the "React" feature in Microsoft Teams (shown at the bottom of this page) to raise your hand if you have a question and we will open your (currently muted) phone line for questions within the allotted time frame. You may also type in questions in the Q&A feature in Microsoft Teams.
3. The conversation today will focus on resource planning. To the extent that you wish to talk with us about other topics we will be happy to speak with you in a different forum.
4. At the end of the presentation, we will open up the floor for "clarifying questions," thoughts, ideas, and suggestions.
5. There will be a parking lot for items to be addressed at a later time.
6. CenterPoint Energy does not authorize the use of cameras or video recording devices of any kind during this meeting.
7. Questions asked at this meeting will be answered here or later.
8. We will do our best to capture notes but request that you provide written feedback (concepts, inputs, methodology, etc.) at IRP@CenterPointEnergy.com following the meeting. Additional questions can also be sent to this e-mail address. **We appreciate written feedback within 10 days of the stakeholder meeting.**
9. The Teams meeting will be recorded only to ensure that we have accurately captured notes and questions from the meeting. The public meetings are not transcribed, and the recordings will not be posted to the website. However, Q&A summaries of our public meetings will be posted on www.CenterPointEnergy.com/irp.

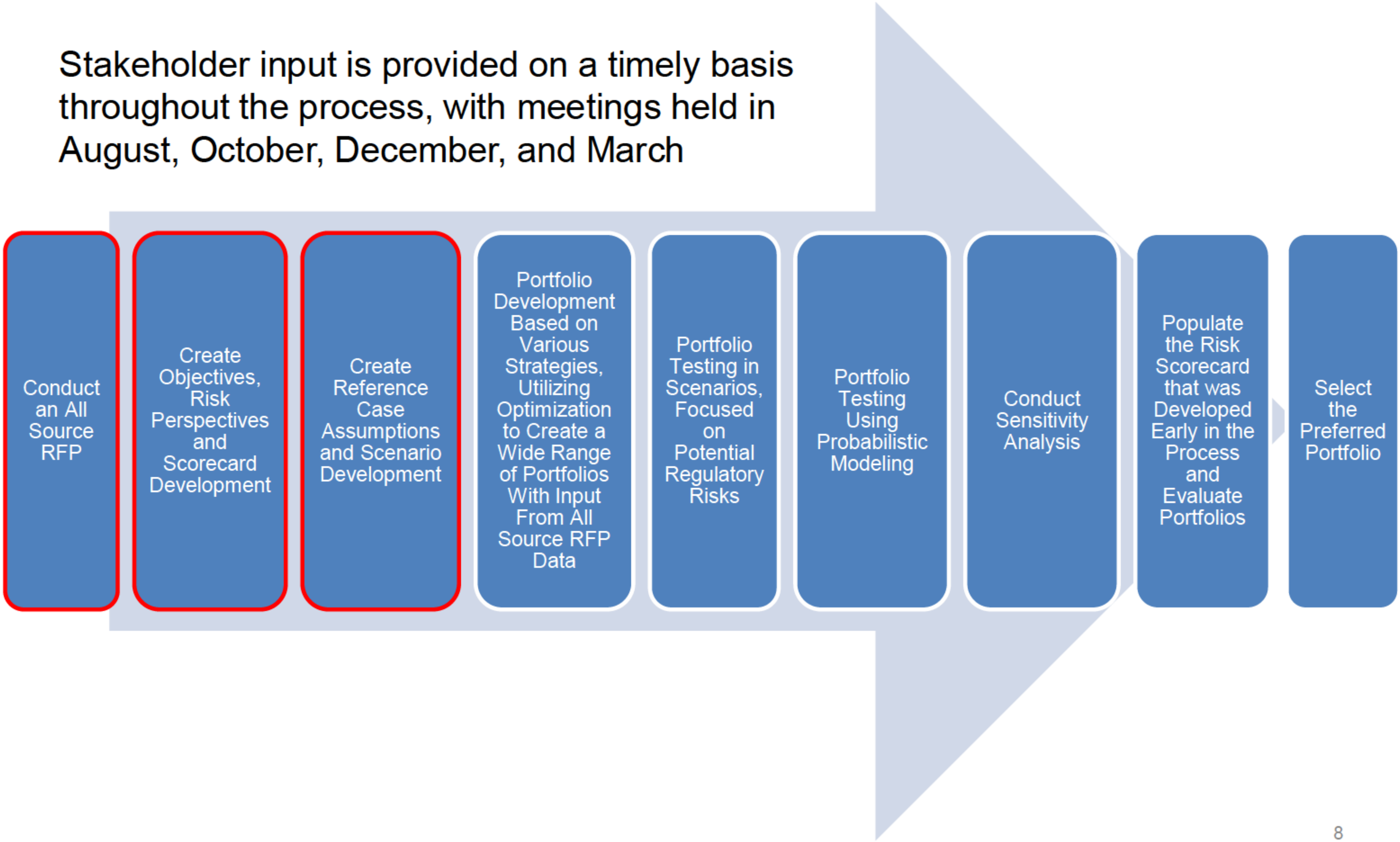


Commitments for 2022/2023 IRP

- ✓ Utilize an All-Source RFP to gather market pricing & availability data
- ✓ Utilize EnCompass software to improve visibility of model inputs and outputs
- ✓ Will include a balanced risk score card. Draft to be shared at the first public stakeholder meeting
- Will strive to make every encounter meaningful for stakeholders and for us
- The IRP process informs the selection of the preferred portfolio
- Work with stakeholders on portfolio development
- Will test a wide range of portfolios in scenario modeling and ultimately in the risk analysis
- Will conduct a sensitivity analysis
- Will conduct technical meetings with interested stakeholders who sign an NDA
- Evaluate options for existing resources
- The IRP will include information presented for multiple audiences (technical and non-technical)
- Will provide modeling data to stakeholders as soon as possible
  - Draft Reference Case results – October 4th to October 31st
  - Draft Scenario results – December 6th to December 20th
  - Full set of final modeling results - March 7th to March 31st

Proposed 2022/2023 IRP Process

Stakeholder input is provided on a timely basis throughout the process, with meetings held in August, October, December, and March



2022/2023 Stakeholder Process

August 18, 2022	October 11, 2022	December 13, 2022	March 14, 2023
• 2022/2023 IRP Process • Objectives and Measures • Encompass Software • All-Source RFP • MISO Update • Environmental Update • Draft Reference Case Market Inputs & Scenarios • Load Forecast Methodology • DSM MPS/ Modeling Inputs • Resource Options	• All-Source RFP Results and Final Modeling Inputs • Draft Resource Inputs • Final Load Forecast • Scenario Modeling Inputs • Portfolio Development • Probabilistic Modeling Approach and Assumptions • Draft Reference Case Modeling Results[1]	• Draft Scenario Optimization Results • Draft Portfolios • Final Scorecard and Risk Analysis • Final Resource Inputs	• Final Reference Case Modeling • Probabilistic Modeling Results • Risk Analysis Results • Preview the Preferred Portfolio

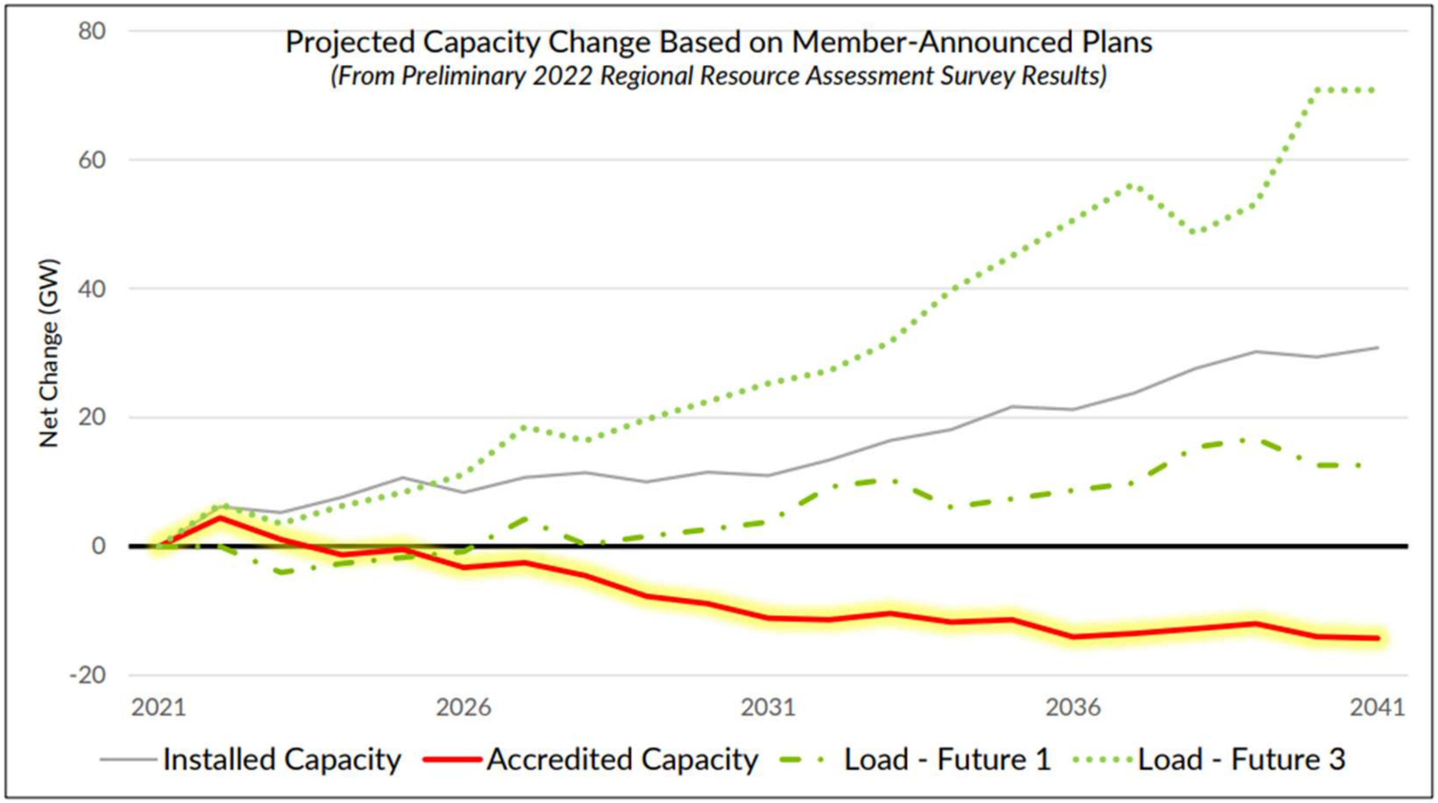
[1] Draft modeling results will be shared on a CenterPoint Energy Technical modeling call on October 31, 2022 and supplemental slides will be posted to www.centerpointenergy.com/irp.

CEI South Expects Capacity Value to Remain High, Based on Recent MISO Communications

CenterPoint Energy

- Aggressive decarbonization strategies and accelerated policies are driving rapid change in our region
- As the evolution of the resource fleet accelerates, variability is increasing, and attributes required to reliably operate the system are diminishing
- Increased complexity is leading to an expanded scope and reprioritization across the elements of MISO's Reliability Imperative
- [MISO] must develop a coordinated transition plan to reliably navigate from the present to the future

A survey of member plans indicates accredited capacity will continue to decline, combined with increasing intermittent resources and demand



*Future projections calculated as change from Future 1 2022 load assumption

Estimated accredited capacity: 16.6% for wind; 35% for solar, 87.5% for battery, 90% for coal, 90% for gas, and 95% for nuclear

4

MISO

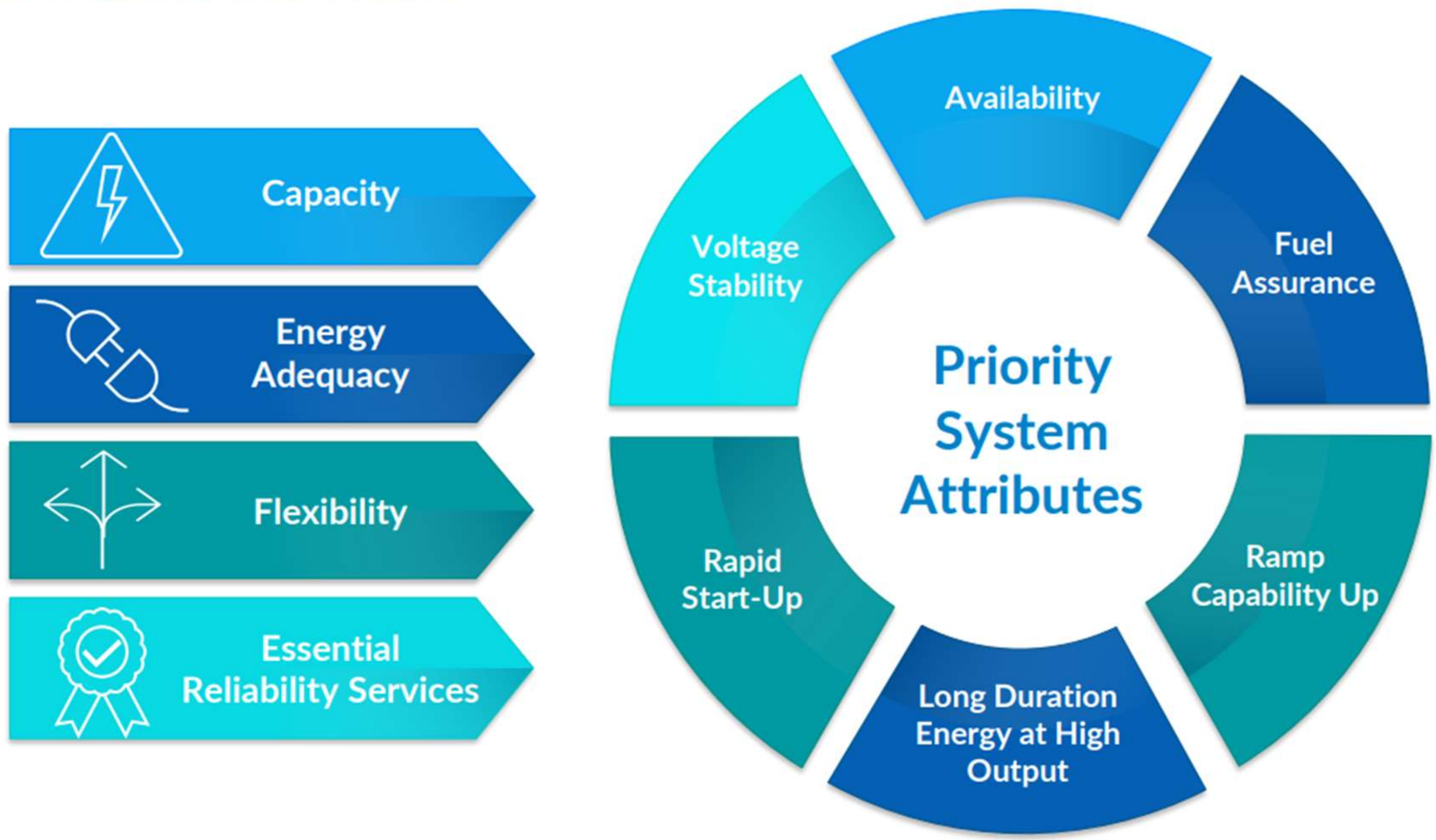
CTs Provide the Priority System Attributes MISO is Seeking

CenterPoint Energy

The region's energy landscape is evolving and will continue to evolve toward a more complex, less predictable future

- Primarily weather-dependent resources
- Risk-adjusted reserve margin requirements
- Less predictable resource outages or unavailability
- Less predictable weather
- Increasing scarcity of essential reliability attributes
- Increasing electric load
- Increasing importance of accurate load and renewable forecasting
- Focus on providing energy for the worst week in each season

Maintaining reliability with the changing resource portfolio and evolving risks also increases the importance of ensuring adequate attributes



9

MISO

Stakeholder Feedback - Resources

Request	Response
Re-evaluate the CT's (combustion turbines) selected in the preferred portfolio of the 2019/2020 IRP	The CTs are the best resource available to ensure the reliability of the CenterPoint system, and the IURC approved their construction for that reason. CenterPoint will move forward with their construction to ensure its system remains reliable during the transition to renewables. Re-evaluating the CTs in this IRP would be a poor use of resources that CenterPoint believes could be better redirected to most efficiently perform the IRP
Allow the IRP to determine if Culley 2 retires in 2023 vs 2025	Culley 2 extension is contingent on IDEM NPDES approval. The capacity value Culley 2 is approximately $8 million at MISO Cost of New Entry (CONE). The unit is not expected to run much but helps CEIS to meet its MISO capacity obligation while new solar projects and CTs are brought online

Stakeholder Feedback - Resources cont.

Stakeholder Request	Response
Allow RFP respondents to update their proposals to account for the Inflation Reduction Act (IRA)	RFP respondents were given the opportunity to update their bids (updated results will be incorporated into the IRP)
Recommend that tax credits outlined in the Inflation Reduction Act are reflected in modeling assumptions	Updated RFP responses will be used to inform IRP assumptions
The MISO capacity price forecast only averages two vendors that converge over the planning period. Suggest scenario analysis rather than averaging the two forecasts so capacity price doesn't influence the resource build	Capacity prices are expected to remain high. During the portfolio development and capacity expansion phases of the modeling, the model will not allow revenues for excess capacity sales.
Provide stakeholders with access to RFP bid information	RFP bids will be shared using a process similar to past RFPs (requires NDA)
Provide a better understanding of how ACE proxy will be included	BAU Culley 3 assumes about $30M in efficiency upgrades. Based on efficiency studies conducted for the 2019/2020 IRP

Stakeholder Feedback - Resources cont.

Stakeholder Request	Response
Incorporate MISO's seasonal construct into the modeling analysis	The seasonal construct will be the basis for resource adequacy requirements, including seasonal accreditation for resources and seasonal planning reserve margin requirement
Consider the resource screening analysis to determine if some thermal options (supercritical and ultra-supercritical coal) should be removed as resource options to the model	CenterPoint will consider pending additional feedback from other stakeholders and model runtime. Screening may include more than coal resources
Consider modeling longer duration lithium ion (longer than 4 hours)	The tech assessment includes a long duration storage option. Also, the model will have the ability to select multiple blocks of 4-hour lithium-ion storage. There are limited economies of scale associated with moving from 4-hour to longer duration lithium-ion

Stakeholder Feedback - Resources cont.

Stakeholder Request	Response
Provide a better understanding of how ACE proxy will be included	BAU Culley 3 assumes about $30M in efficiency upgrades. Based on efficiency studies conducted for the 2019/2020 IRP

Stakeholder Feedback - Score Card

CenterPoint Energy

Stakeholder Request	Response
Use cumulative CO_2 equivalent emissions as a measure of environmental sustainability	CO_2 equivalent (stack emissions) will be added to the scorecard along with CO_2 intensity
Include a metric on the scorecard that quantifies whether resources in each portfolio are located in low-income or communities of color	New generation resources in the IRP analysis are not typically location specific; This is outside the scope of the IRP analysis
Add a fuel cost risk measure and objective to the scorecard	Cost Risk will be included in the scorecard, including both fuel risk and 95% percentile cost risk

Stakeholder Feedback - Score Card cont.

CenterPoint Energy

Request	Response
Add a metric to the scorecard that looks at the cost burden by census tract and could account for the bill impacts of community solar projects that could be placed in those communities	The IRP does consider energy cost by evaluating PVRR and fuel cost risk. Project location is generally outside the scope of the IRP analysis but is considered during project selection during which site-specific benefits are vetted. While outside the scope of the IRP, community solar should be compared with other potential assistance programs to determine which is more effective for providing bill assistance to low-income customers. Note that RFP responses did not include any community solar bids

Updated IRP Draft Objectives & Measures

CenterPoint Energy

Updates from the last meeting are shown in red

Objective	Potential Measures	Unit
Affordability	20 Year NPVRR	$
Cost Risk	Proportion of Energy Generated by Resources With Exposure to Coal and Gas Markets and Market Purchases 95% Value of NPVRR	% $
Environmental Sustainability	CO_2 Intensity CO_2 Equivalent Emissions (Stack Emissions)	Tons CO_2e/kwh Tons CO_2e
Reliability	Must Meet MISO Planning Reserve Margin Requirement in All Seasons Spinning Reserve\Fast Start Capability	UCAP MWs % of Portfolio MW's That Offer Spinning Reserve\Fast Start
Market Risk Minimization	Energy Market Purchases or Sales	%
	Capacity Market Purchases or Sales	%
Execution	Assess Challenges of Implementing Each Portfolio	Qualitative

Stakeholder Feedback - DSM

Request	Response
In the high regulatory scenario EE costs shouldn't increase but should be equal to the reference case or go down and additional EE should be available to select	A high regulatory scenario in which either codes & standards or carbon prices increase, this erodes away savings and increases the acquisition costs of energy efficiency savings. Decarbonization / Electrification scenario will potentially capture high-cost EE bins
Several questions regarding MPS and DSM	Will be addressed in separate meetings with CAC
Incorporate more than proposed 10-20 MWs of Industrial DR	CEI South will include 25 MWs of industrial DR as a resource. Currently, CEI South does not have any industrial DR customers.

Stakeholder Feedback - DSM cont.

Request	Response
MPS was inconsistent with the IRP in that the avoided cost of carbon regulation was not included which results in lower savings	Although including carbon cost in cost-effectiveness test may increase the savings potential, Indiana only recognizes the TRC (Total Resource Cost) as the cost-effectiveness test to implement non-low-income programs.
CenterPoint has not made available MPS & IRP modeling files	All modeling files were provided after incorporating feedback from CAC on 9/23/22
CenterPoint should include EE bundles that included an "enhanced RAP"	CenterPoint has now included an "enhanced RAP" for commercial

Stakeholder Feedback - DSM cont.

CenterPoint Energy

Request	Response
CenterPoint should adjust inflation for low-income bundles to allow this non-selectable bundle to include higher short-term inflation rates	CenterPoint has made this adjustment
CenterPoint should include more emerging technology in MPS similar to Consumers Energy	CenterPoint MPS does include emerging technology and will also leverage flex funding to capture emerging technology in future action plans
CenterPoint should include demand response using the same methodology as AES	CenterPoint has adopted the AES methodology and DR is now aligned with peers to incorporate indicative TOU pilots
Implement residential rate programs (critical peak piecing, TOU, etc.) soon	Plan to evaluate in the future through a pilot

Stakeholder Feedback - Inputs

CenterPoint Energy

Stakeholder Request	Response
Several questions regarding load forecast	Will be addressed later in this presentation
Provide data inputs and modeling files to stakeholders	CenterPoint is targeting to provide modeling information according to the schedule outlined in the first stakeholder meeting
Stakeholder concern that the reference case forecasts for natural gas and coal prices are underestimating the cost of these fuels and their potential volatility	The stochastic analysis will vary coal and natural gas prices to capture potential volatility
The reference case forecasts for coal and natural gas prices show a decline in the near term	These assumptions will be updated as new forecasts are available. Included in appendix
Recommendation to utilize Henry Hub futures in the near term to better align with current market conditions	CenterPoint is considering using NYMEX futures in the near term and will adjust long-term forecasts as available. See appendix for forecast schedule and NYMEX.

Stakeholder Feedback - Inputs cont.

Stakeholder Request	Response
In future meetings discuss resource constraints applied to the EnCompass model and ELCC curves for renewables and battery storage resources	Development of ELCC curves will be discussed in this meeting along with constraints
Coal prices should be higher than the reference case in the high regulatory scenario (not the same as the reference case)	Coal prices will be updated to be higher than reference case in the high regulatory scenario
Stakeholder concern that sustained high fuel costs are possible but the reference case does not take this into consideration	This will be captured in the scenario analysis. The Continued High Inflation & Supply Chain Issues scenario includes a coal and natural gas price forecast higher than the reference case

Stakeholder Feedback - Analysis

Stakeholder Request	Response
Several questions were asked around stochastic modeling	Will be discussed later in today's presentation
Implement distribution system planning (FERC Order 2222) into IRP modeling	CenterPoint continues to monitor the level of distributed resources on its distribution system. The current level of penetration does not warrant this level of detailed analysis at this time but could be evaluated in a future IRP analysis. Additionally, MISO is currently planning to incorporate FERC Order 2222 into its processes in 2030 pending FERC approval. As more information becomes available from MISO it can help shape how this analysis should be performed

Q&A

All-Source RFP Update

Drew Burczyk
Consultant, Resource Planning & Market Assessments
1898 & Co.

RFP IRA Updates

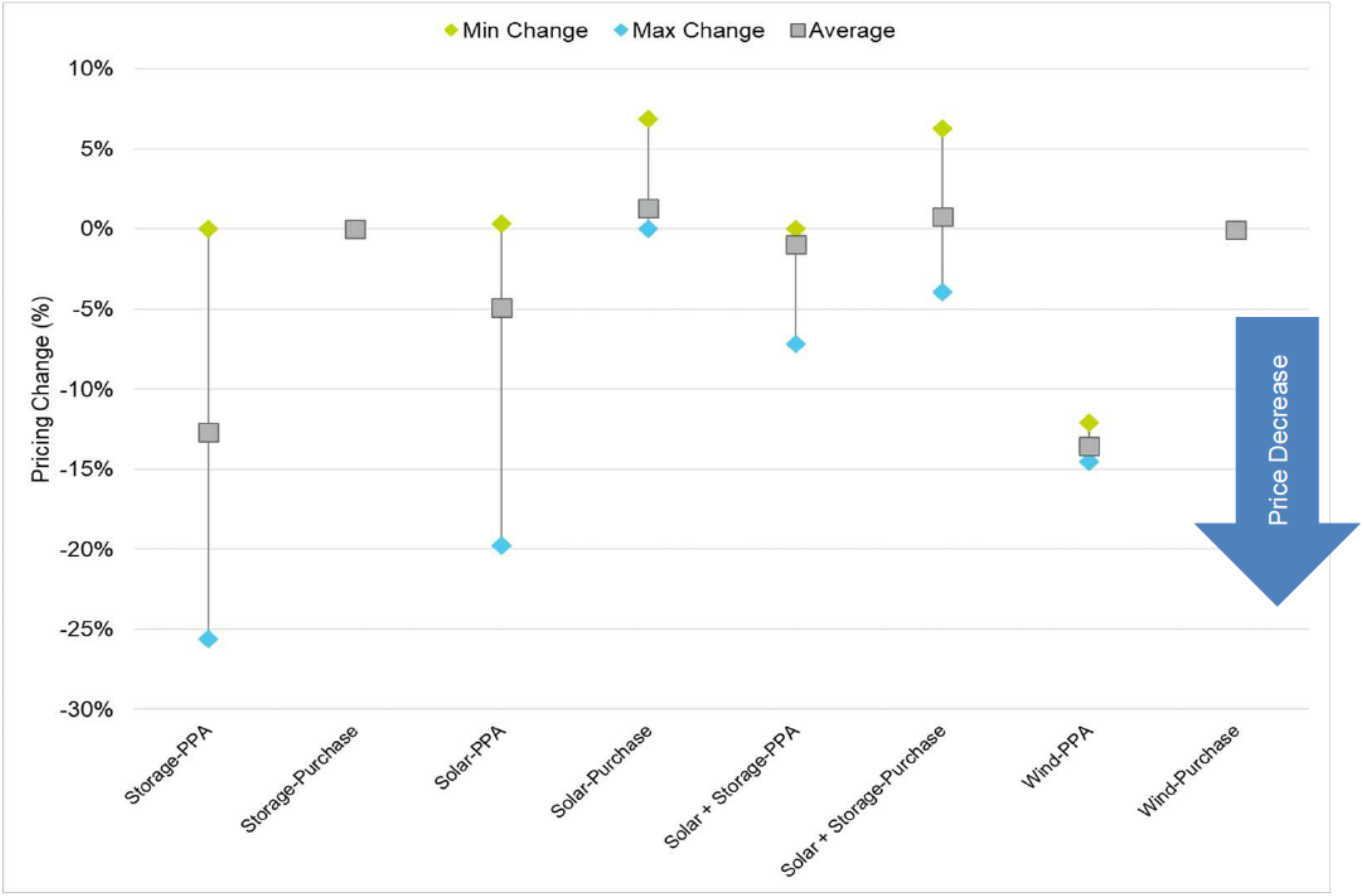
- The Inflation Reduction Act was signed into law August 16th.
- Stakeholder Meeting 1 occurred August 18th.
- Agreed with feedback and comments made during the Stakeholder meeting that updated costs from IRA could impact IRP modeling.
- August 23rd reached back out to bidders asking for updated pricing.
- This has delayed draft modeling results; A technical call to discuss draft results has been scheduled for October 31st with those that have signed a NDA. Supplemental slides will be posted to the www.CenterPointEnergy.com/irp

RFP IRA Updates

- 9 of 27 bidders submitted updated pricing to account for IRA changes.
- 77 Bids were returned with updated pricing.
  - 22 Solar bids
  - 46 Storage bids
  - 4 Wind bids
  - 5 Solar + Storage bids
- Example reasoning from bidders who did not update pricing:
  - Not applicable to proposal technology
  - Proposal pricing remains the same, offer was a BTA, tax credit would be monetized by CenterPoint
  - Benefits of IRA are offset by inflation and shortage in labor market

Pre vs Post IRA Pricing

Wide range of changes within certain technology groups. At a high level, the updated pricing received is not a 1:1 equivalent of IRA tax credit qualification.



Purchase prices do not account for tax benefits

Q&A

CenterPoint Energy

Draft Resource Inputs

Kyle Combes
Project Manager, Resource Planning & Market Assessments
1898 & Co.

MISO Seasonal Resource Adequacy

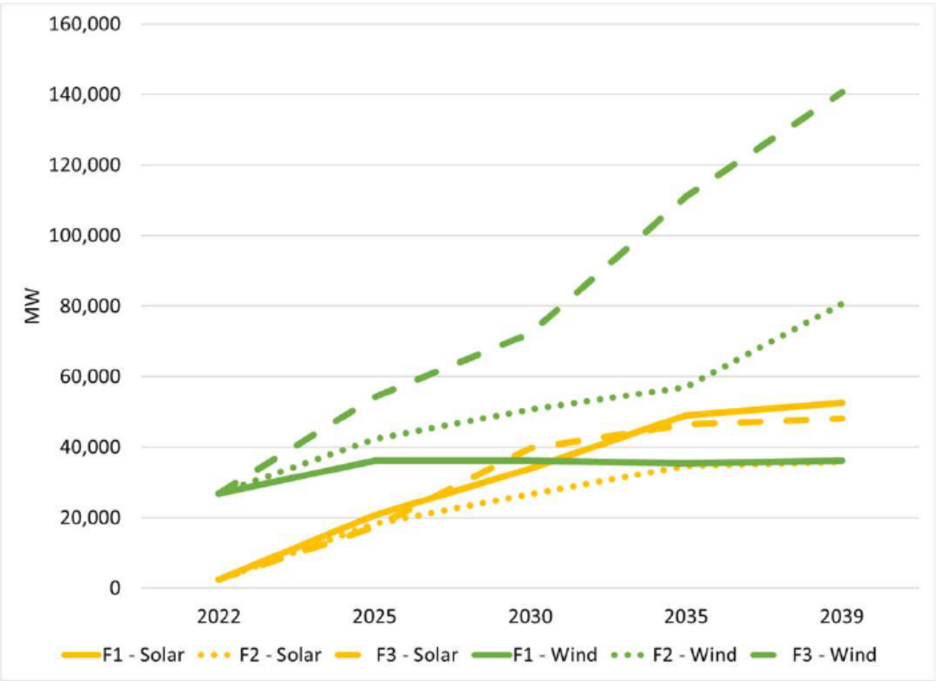
CenterPoint Energy

- MISO is moving to a seasonal resource adequacy construct.
  - Winter - December, January, February
  - Spring - March, April, May
  - Summer - June, July, August
  - Fall - September, October, November
- Implementation beginning in MISO Planning Year 2023/24.
- This is new, and dynamic, we are working through these impacts and changes as more information becomes available.

MISO Renewable Penetration Trends

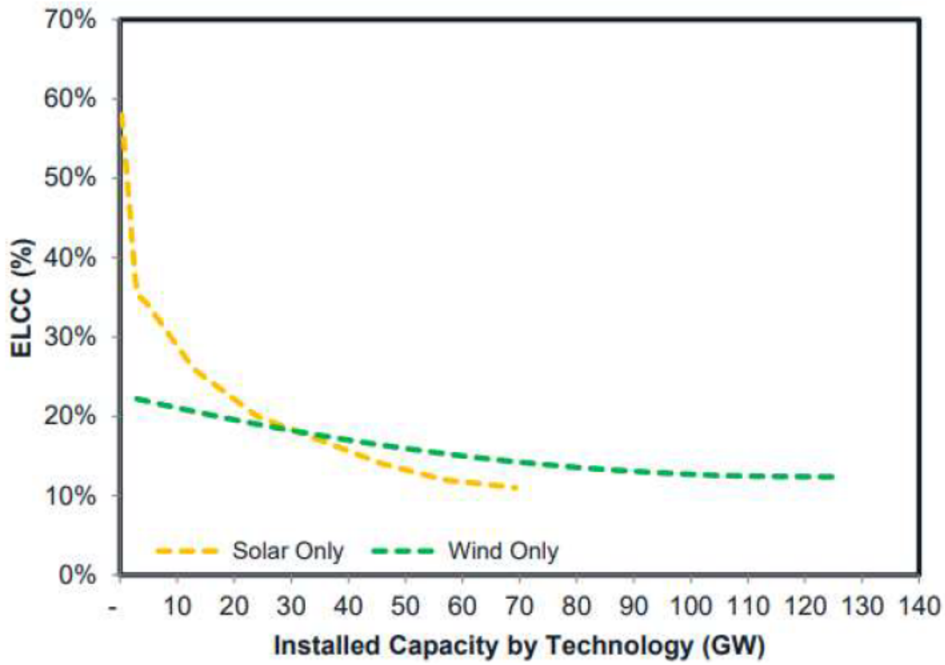
CenterPoint Energy

MISO Installed Renewable Capacity



https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf

Effects of increasing installations

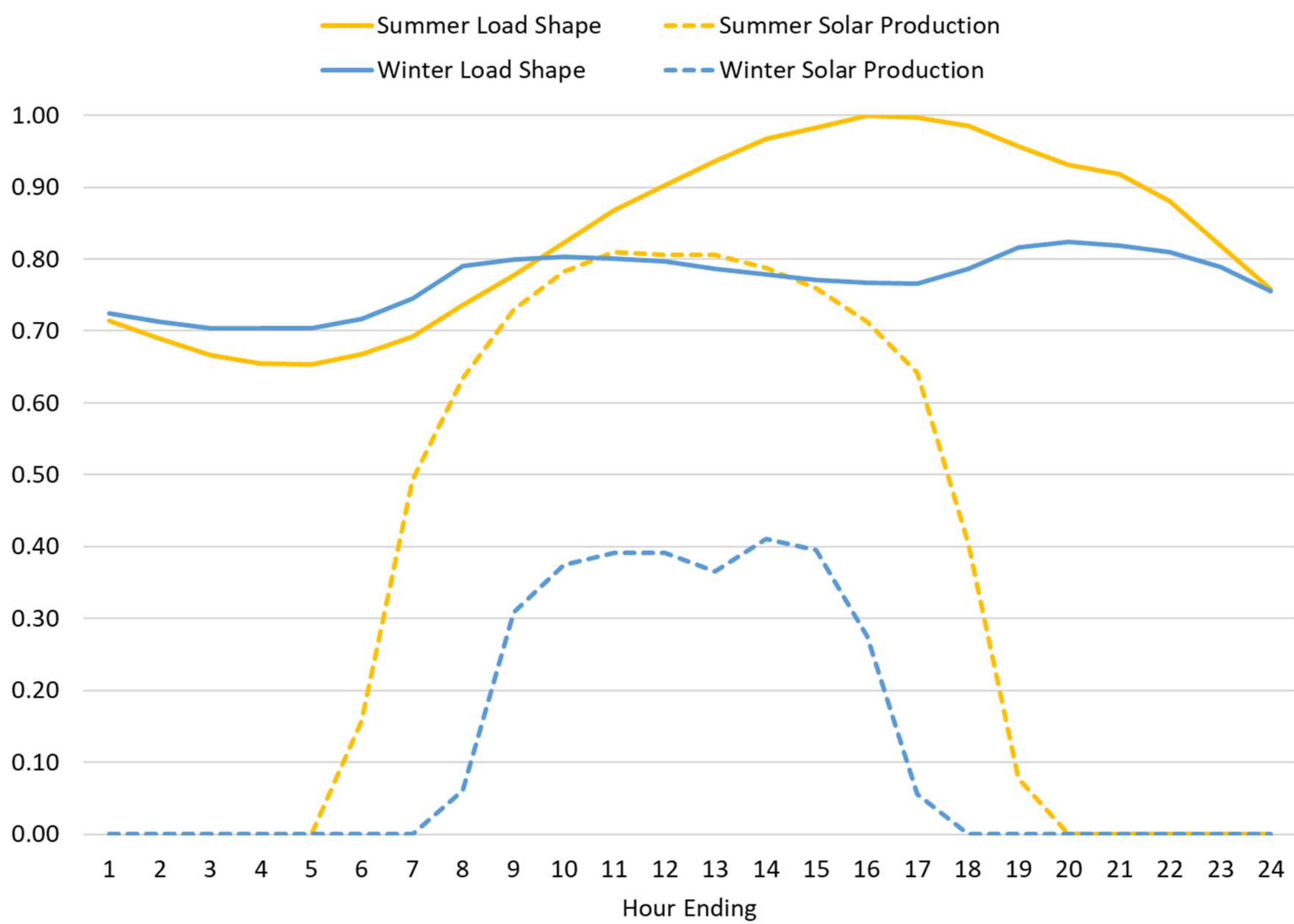


https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

As installed capacity (ICAP) goes ⬆… Accreditable capacity (UCAP) goes ⬇

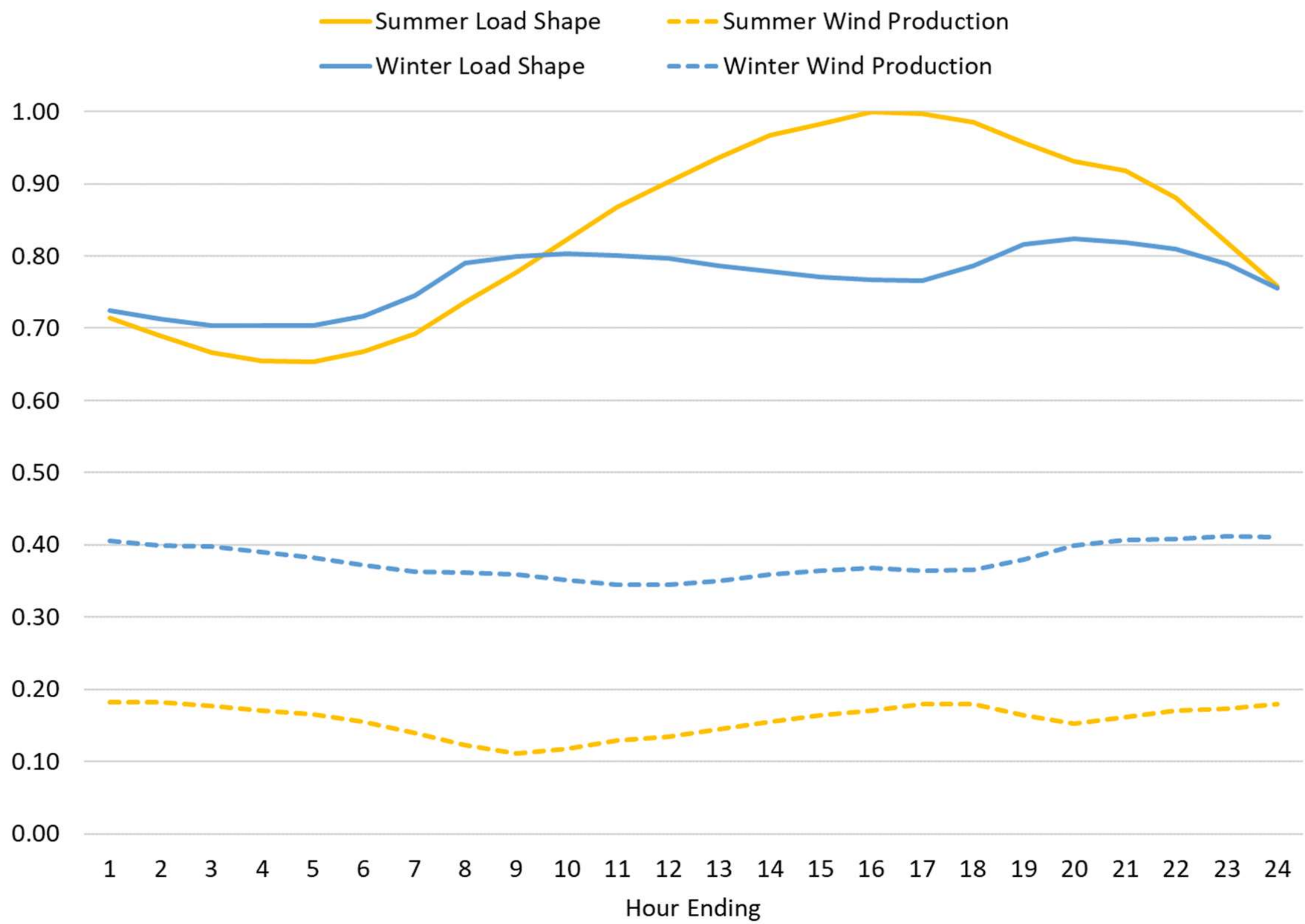
ELCC – Effective Load Carrying Capability

Solar Seasonal Differences

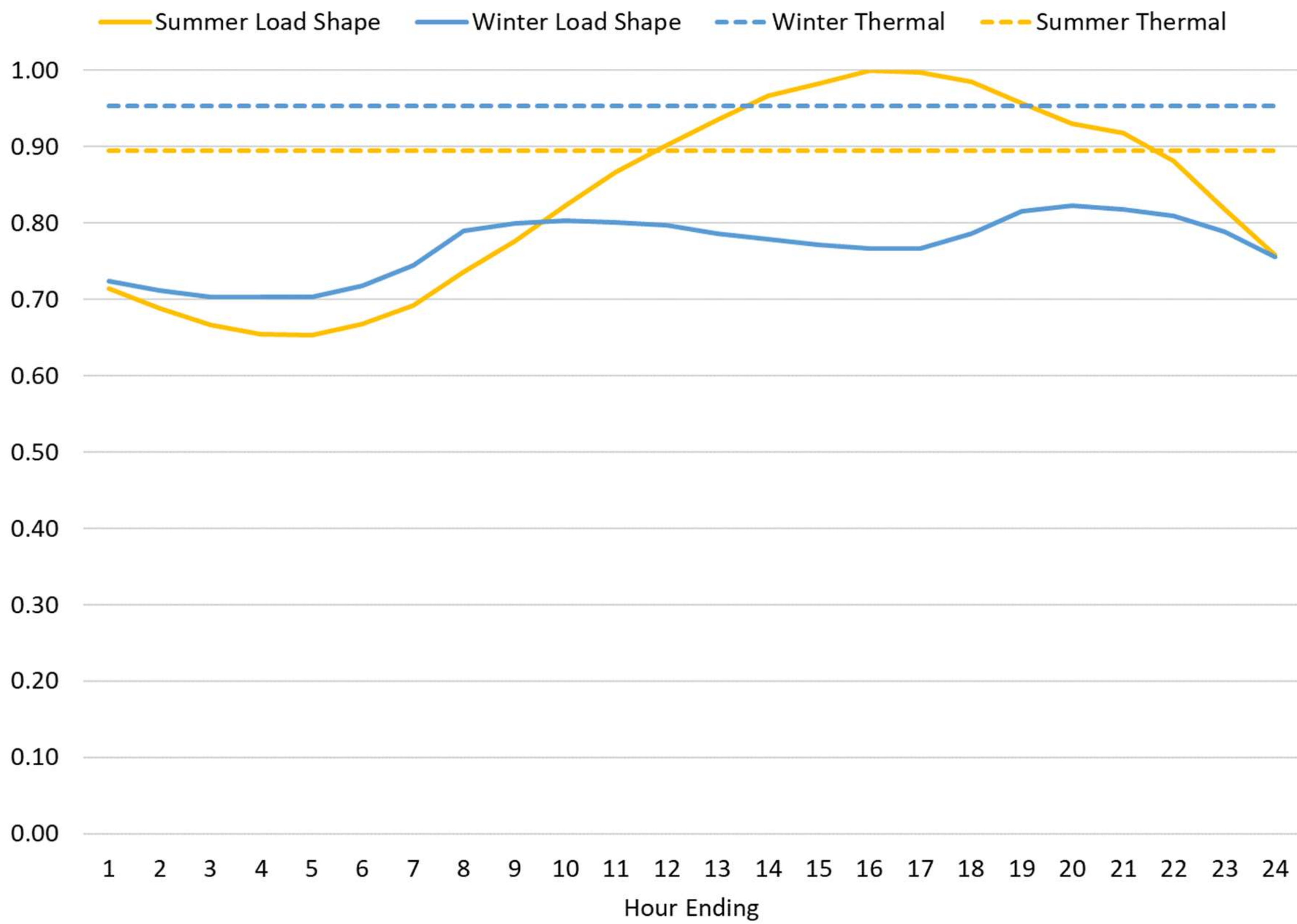


Wind Seasonal Differences

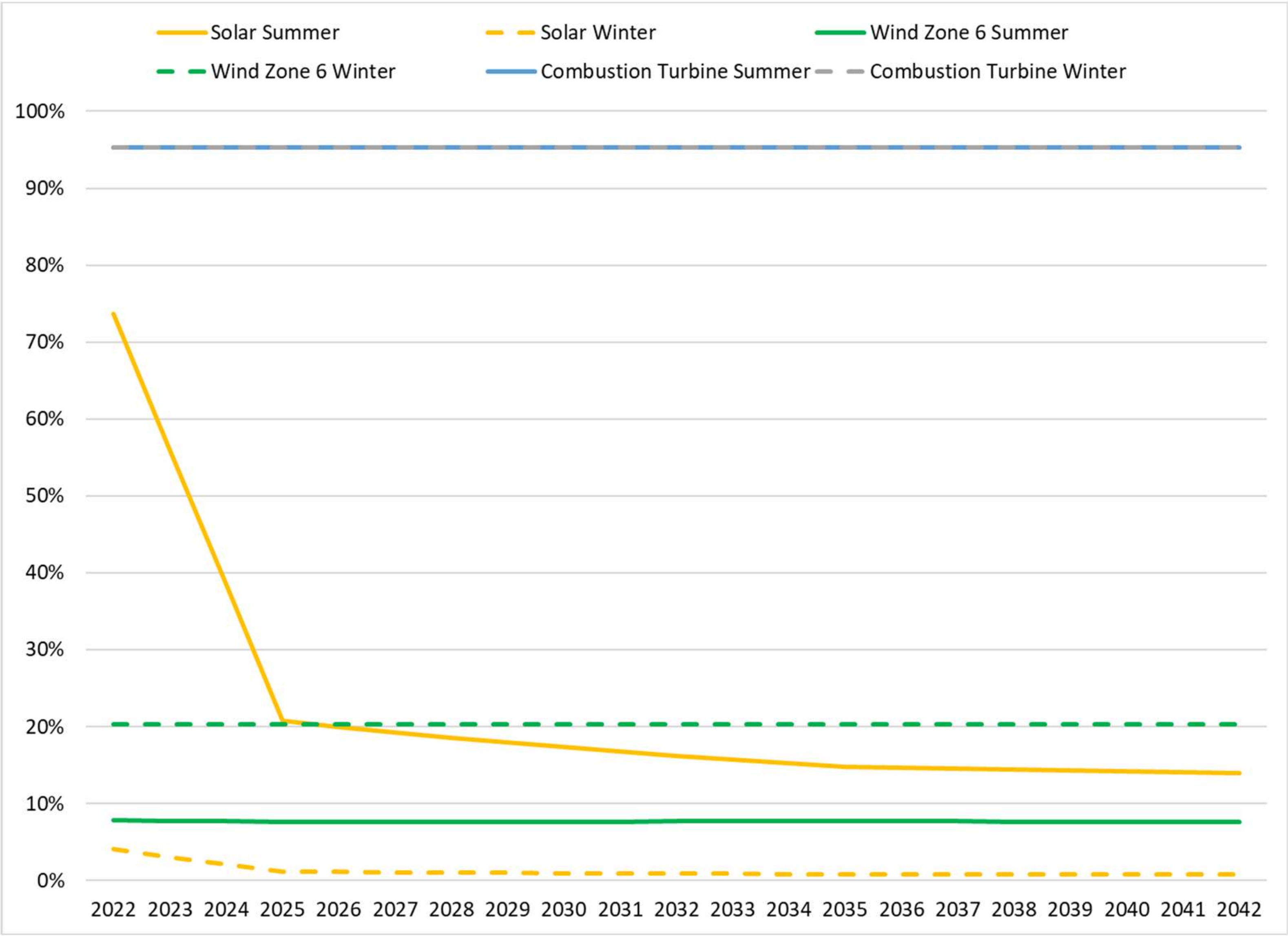
CenterPoint Energy



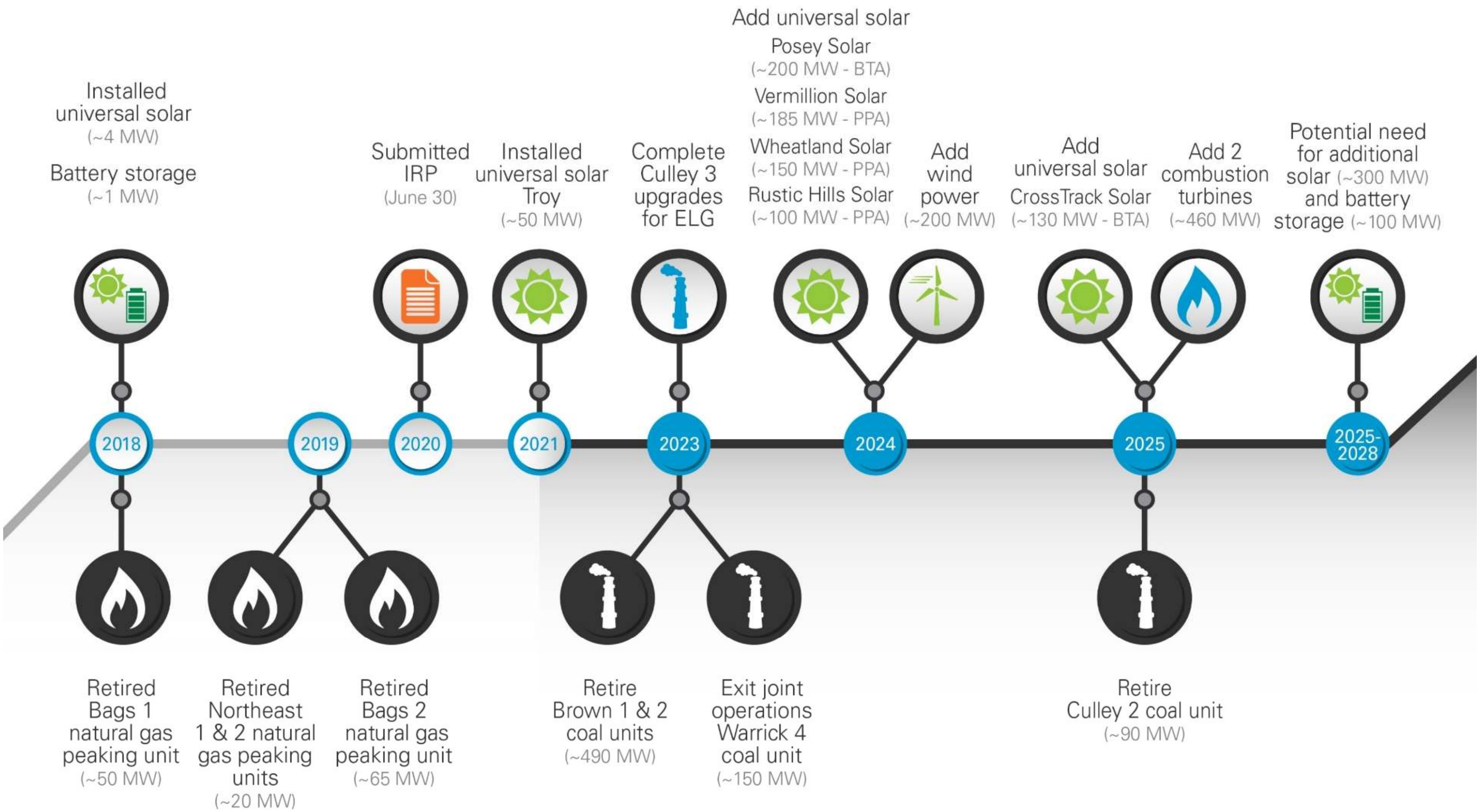
Thermal Seasonal Differences



Draft Projected Seasonal Accreditation



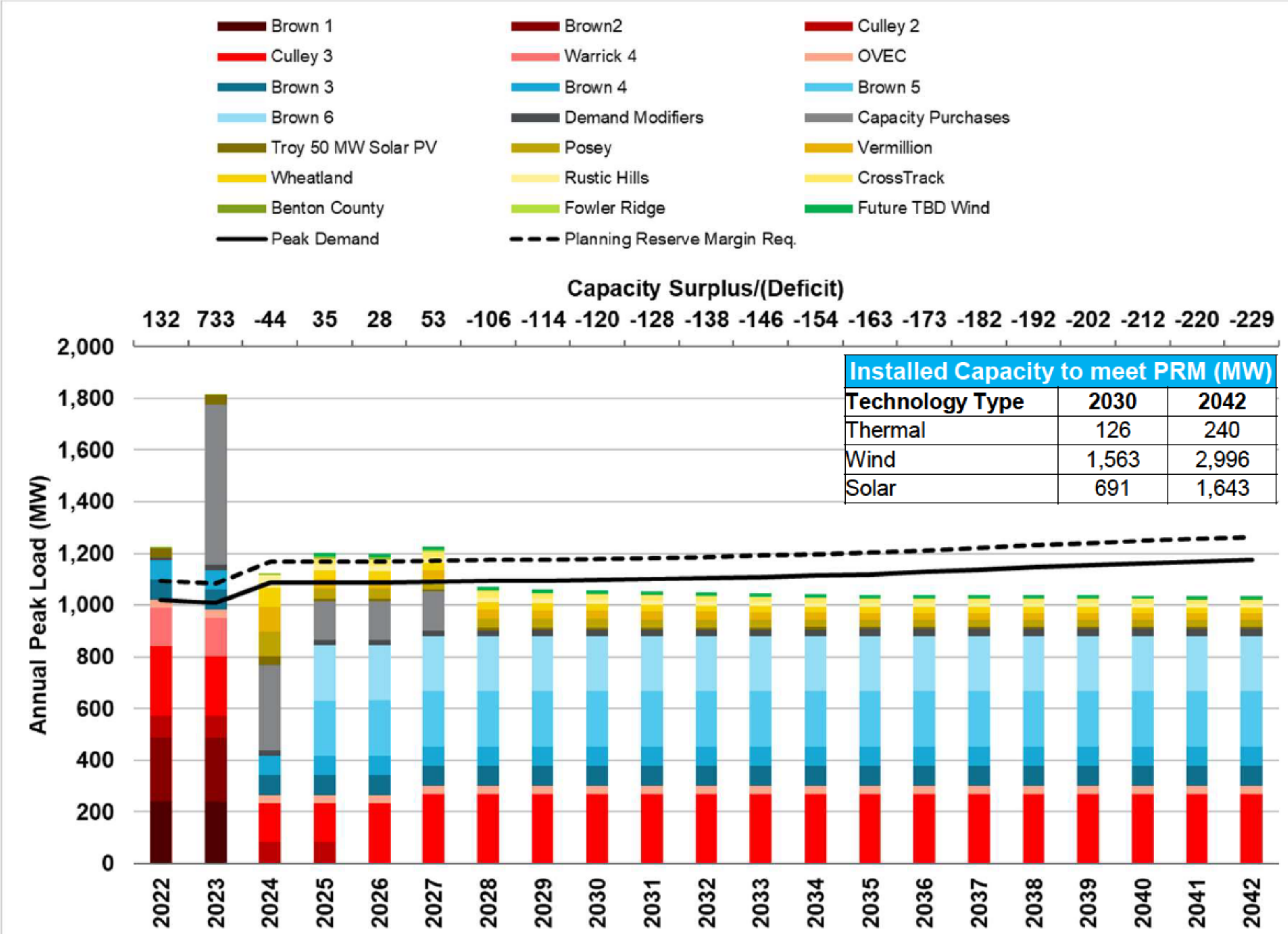
Generation Transition Timeline



Bags = Broadway Avenue Gas Turbines
BTA = Build Transfer Agreement/Utility Ownership
ELG = Effluent Limitations Guidelines
MW = Megawatt
PPA = Power Purchase Agreement
IRP = Integrated Resource Plan

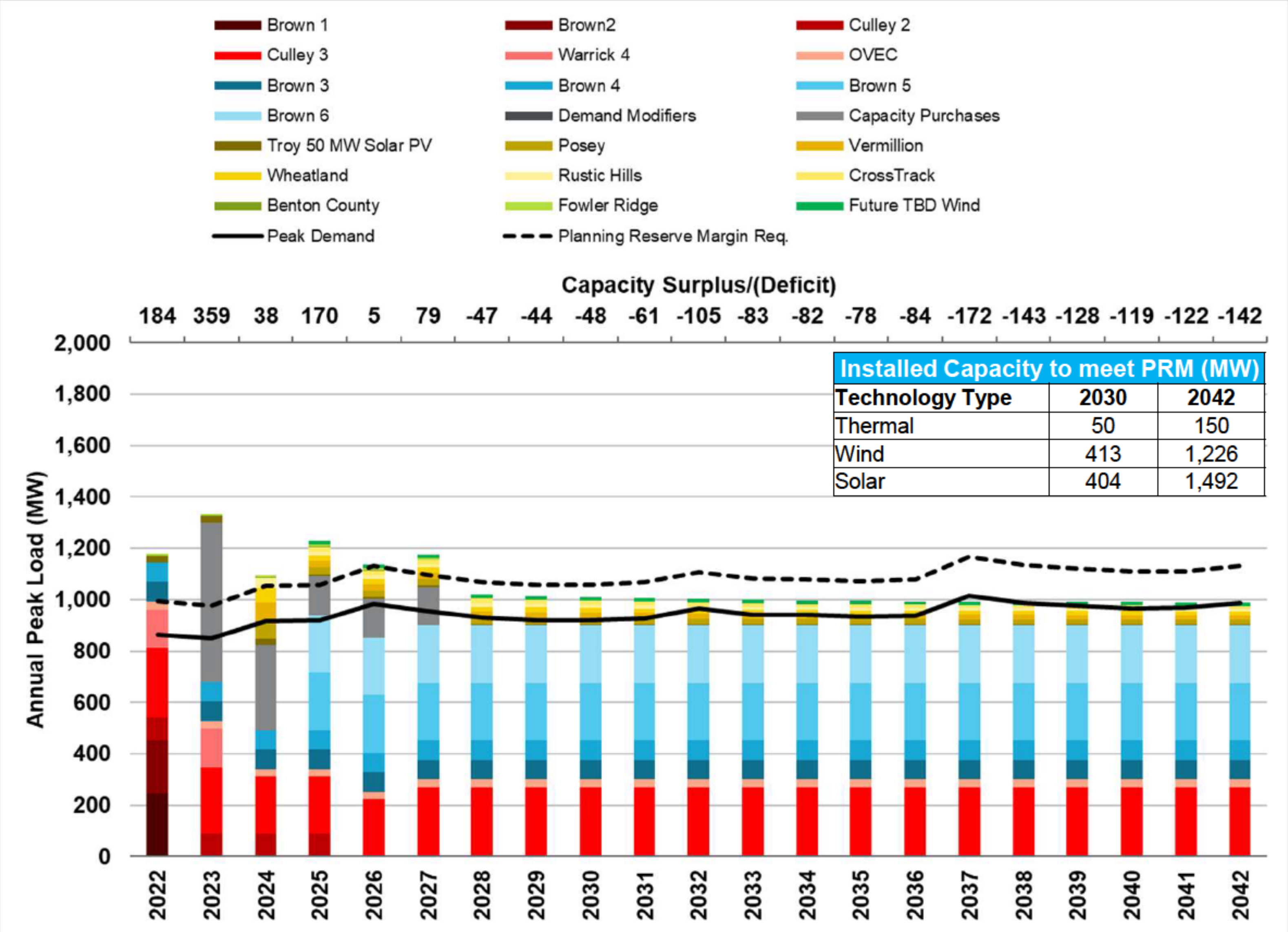
Balance of Loads and Existing & Planned Resources Summer

CenterPoint Energy



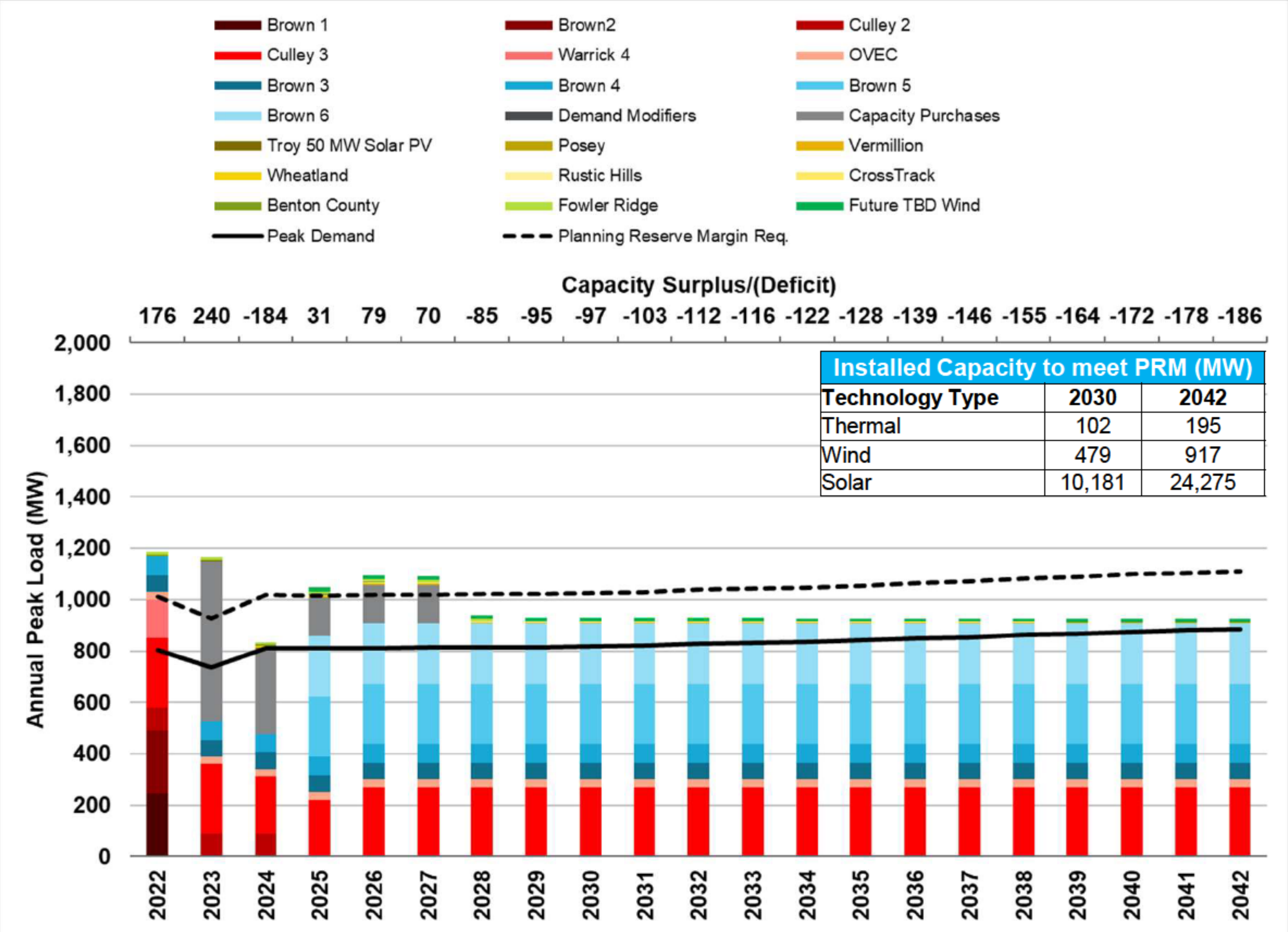
Installed Capacity to meet PRM (MW)		
Technology Type	2030	2042
Thermal	126	240
Wind	1,563	2,996
Solar	691	1,643

Balance of Loads and Existing & Planned Resources Fall



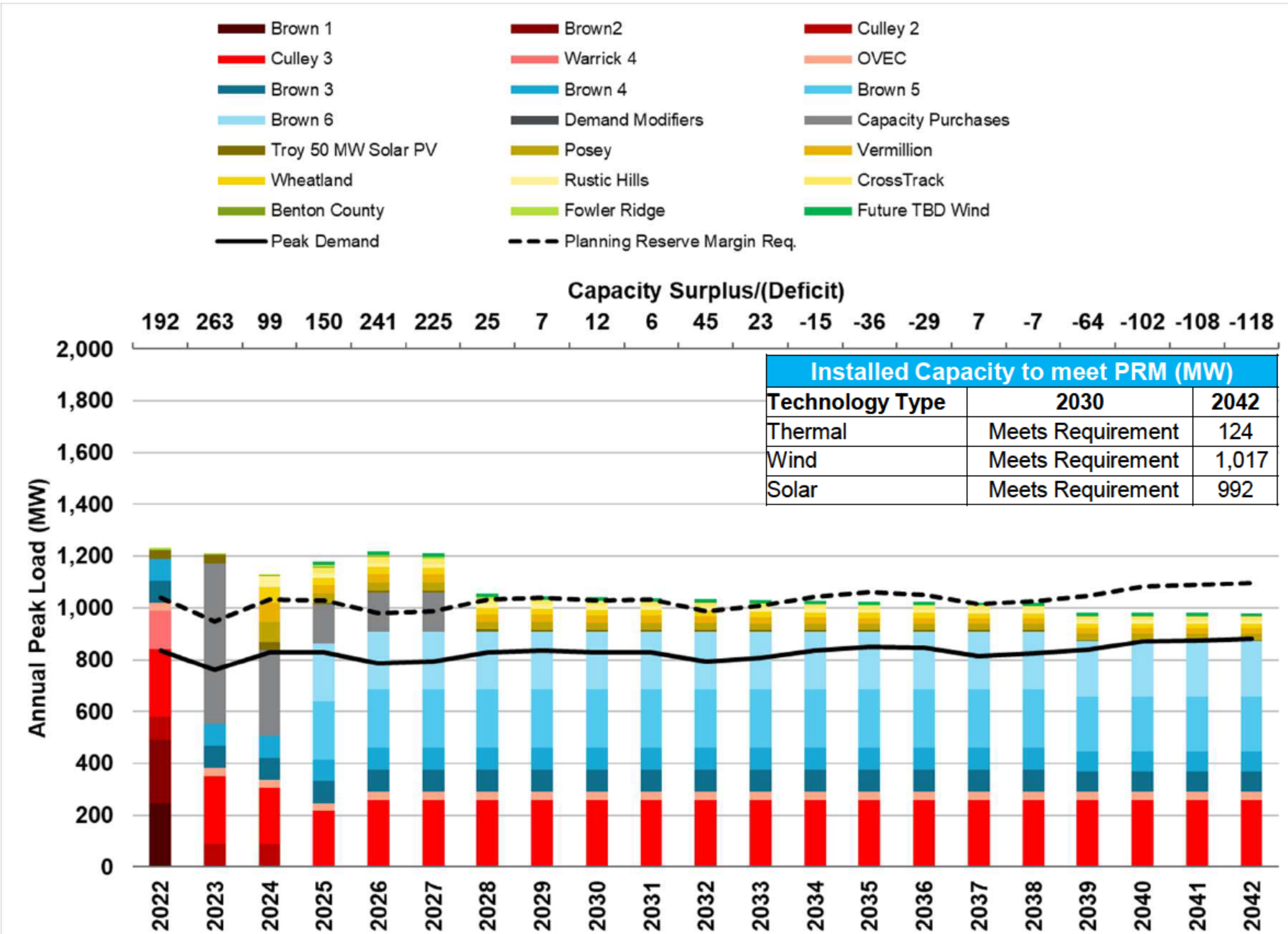
Installed Capacity to meet PRM (MW)		
Technology Type	2030	2042
Thermal	50	150
Wind	413	1,226
Solar	404	1,492

Balance of Loads and Existing & Planned Resources Winter



Installed Capacity to meet PRM (MW)		
Technology Type	**2030**	**2042**
Thermal	102	195
Wind	479	917
Solar	10,181	24,275

Balance of Loads and Existing & Planned Resources Spring



Installed Capacity to meet PRM (MW)		
Technology Type	**2030**	**2042**
Thermal	Meets Requirement	124
Wind	Meets Requirement	1,017
Solar	Meets Requirement	992

Technology Assessment

- RFP bids were used to inform cost assumptions for near term resources.
- Technology Assessment was developed for future generation options.
- The costs from the Technology Assessment in combination with cost curve estimates are used for modeling resources out beyond the period where we have RFP bid data available.
- If no bid was received for a resource, TA costs are used as the default.

Technology Assessment Details

CenterPoint Energy

Examples of candidates for natural gas peaking generation:

Peaking	F-Class SCGT	G/H-Class SCGT	J-Class SCGT	6 x 9 MW Recip Engines	6 x 18 MW Recip Engines
Capacity (MW)	238	295	384	54	110
Fixed O&M (2022 $/kW-Yr)	$8	$7	$5	$28	$18
Total Project Costs (2022 $/kW)	$712	$699	$569	$1,756	$1,561

Examples of candidates for natural gas combined cycle generation:

Combined Cycle - Unfired	1x1 F-Class[1]	1x1 G/H-Class[1]	1x1 J-Class[1]
Capacity (MW)	363	431	551
Fixed O&M (2022 $/kW-Yr)	$12	$11	$8
Total Project Costs (2022 $/kW)	$1,278	$1,162	$962

Combined Cycle - Fired	1x1 F-Class[1]	1x1 G/H-Class[1]	2x1 J-Class[1]
Capacity (MW)	419	508	1,307
Fixed O&M (2022 $/kW-Yr)	$11	$9	$4
Total Project Costs (2022 $/kW)	$1,146	$1,036	$641

[1] 1x1 Combined Cycle Plant is one combustion turbine with heat recovery steam generator and one steam turbine utilizing the unused exhaust heat. 2x1 is two combustion turbines and 1 steam turbine.

Technology Assessment Details

CenterPoint Energy

Examples of candidate for nuclear generation:

Nuclear	Small Modular Reactor
Size (MW)	TBD
Fixed O&M (2022 $/kW-Yr)	TBD
Total Project Costs (2022 $/kW)	TBD

Examples of candidate for coal fired generation:

Coal	Supercritical Pulverized Coal with 90% Carbon Capture	Ultra-Supercritical Pulverized Coal with 90% Carbon Capture
Size (MW)	506	747
Fixed O&M (2022 $MM/kW-Yr)	$32	$32
Total Project Costs (2022 $/kW)	$6,659	$6,024

Examples of other thermal:

Other Thermal	Co-Gen Steam Turbine	2x1 F-Class CCGT Conversion	FB Culley 2 Gas Conversion	FB Culley 3 Gas Conversion
Size (MW)	22	717 / 257 incremental	100 / 0 incremental	287 / 0 incremental
Fixed O&M (2022 $/kW-Yr)	$323	$12	TBD	TBD
Total Project Costs (2022 $/kW)	$2,832	$691 / $1,990	$247	$107

Technology Assessment Details

CenterPoint Energy

Examples of candidate for wind generation:

Wind	Indiana Wind Energy	Indiana Wind + Storage
Base Load Net Output	200 MW	50 MW + 10 MW / 40 MWh
Fixed O&M (2022 $/kW-Yr)	$48	$49
Total Project Costs (2022 $/kW)	$1,845	$2,107

Examples of candidate for solar generation:

Solar	Solar Photovoltaic	Solar Photovoltaic	Solar Photovoltaic	Solar PV + Storage
Base Load Net Output	10 MW	50 MW	100 MW	50 MW + 10 MW / 40 MWh
Fixed O&M (2022 $/kW-Yr)	$60	$16	$11	$19
Total Project Costs (2022 $/kW)	$2,560	$1,856	$1,779	$1,910

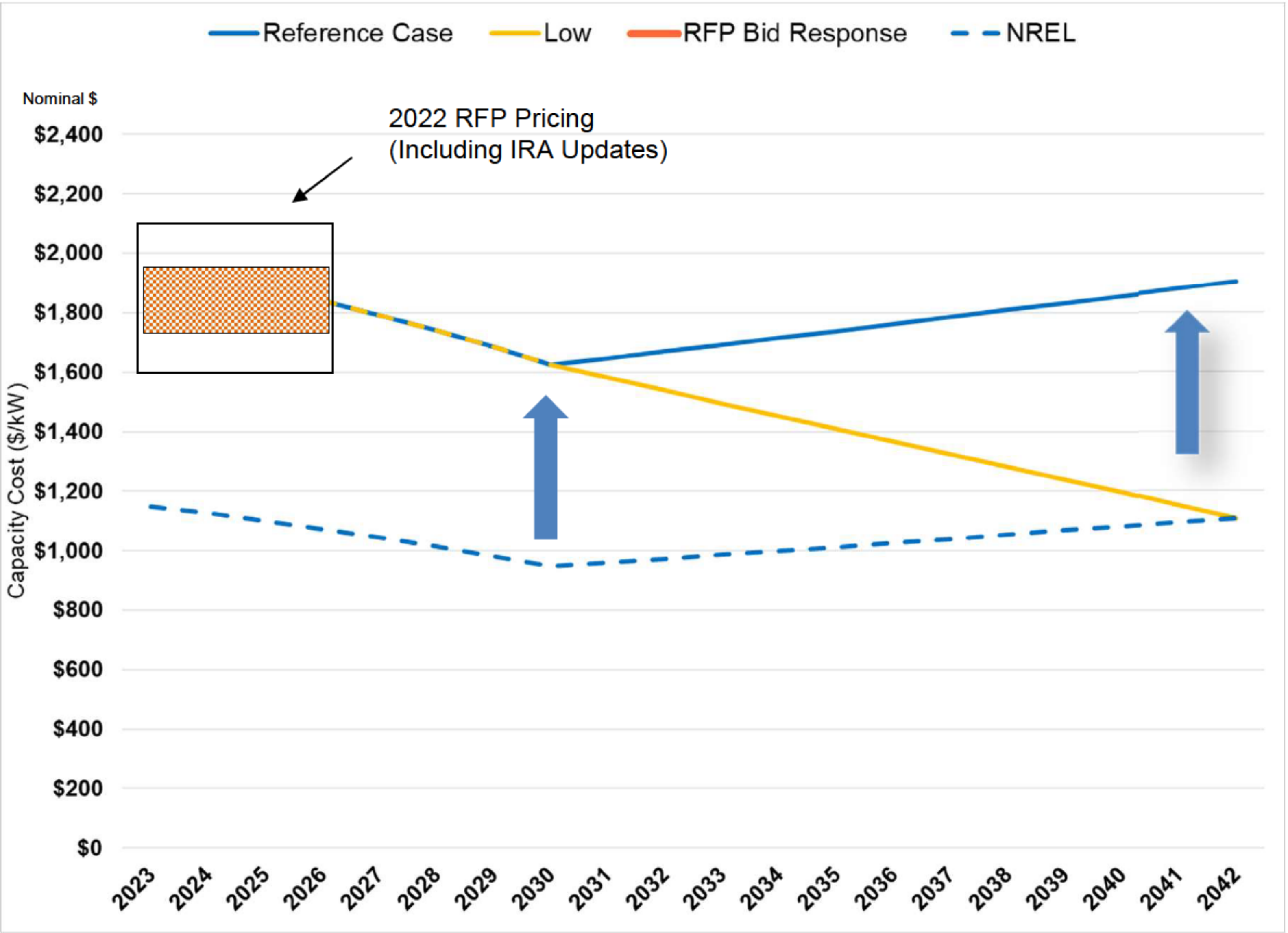
Examples of storage:

Storage	Lithium-Ion Battery Storage	Lithium-Ion Battery Storage	Lithium-Ion Battery Storage	Long Duration Storage
Base Load Net Output	10 MW / 200 MWh	50 MW / 200 MWh	100 MW / 400 MWh	300 MW / 3,000 MWh
Fixed O&M (2022 $/kW-Yr)	$40	$38	$35	$19
Total Project Costs (2022 $/kW)	$2,500	$2,160	$2,020	$2,590

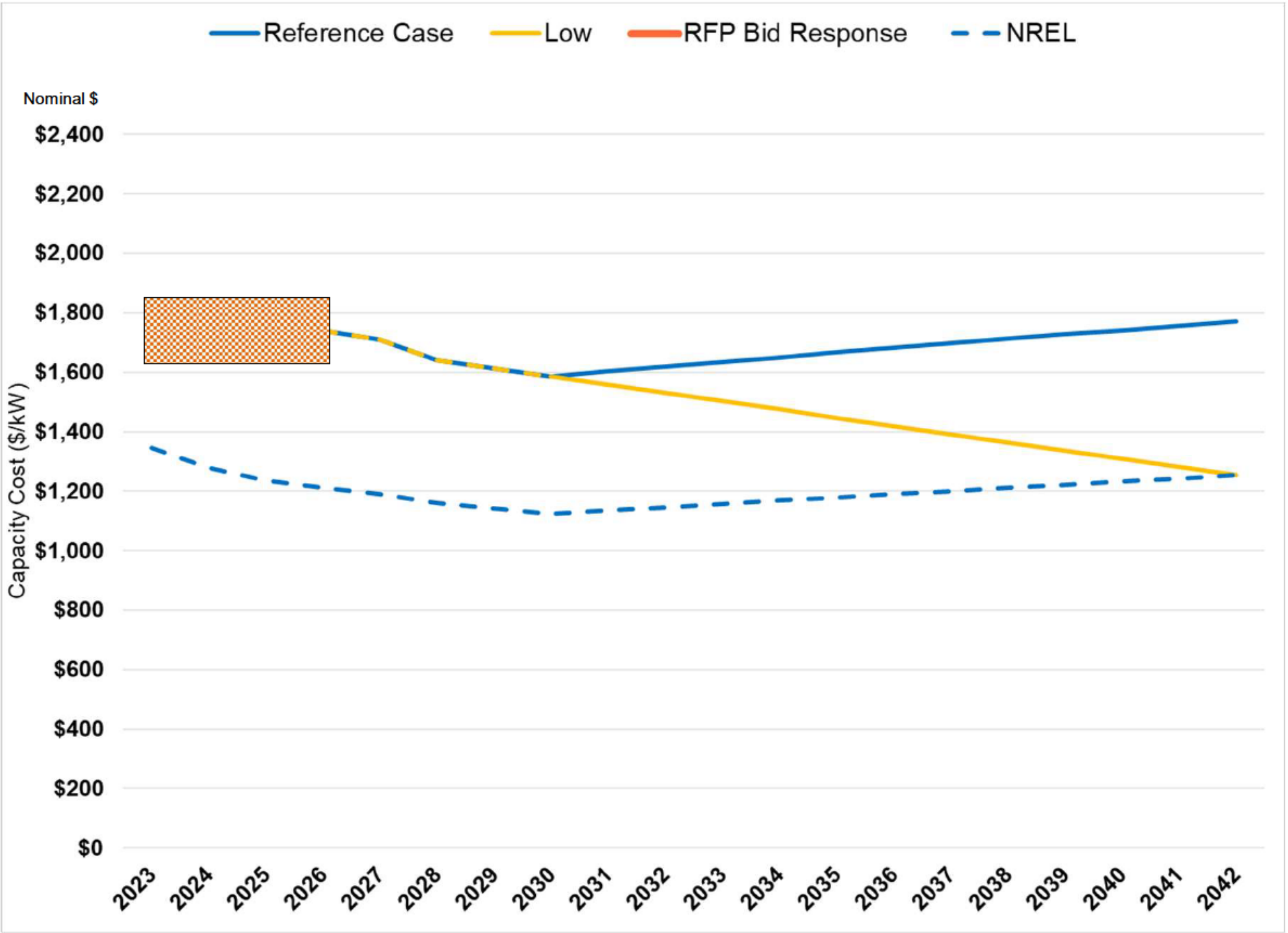
Capacity Cost Curve Summary

- Initial curve modeled from 2022 Annual Technology Baseline from NREL.
- Pricing of all RFP purchase options taken per technology type.
  - Pricing includes updates from the Inflation Reduction Act.
- Reference case follows the NREL curve shifted to match the aggregate bid pricing.
- The ‘Low’ curve is the interpolation from the reference case to the moderate NREL curve.

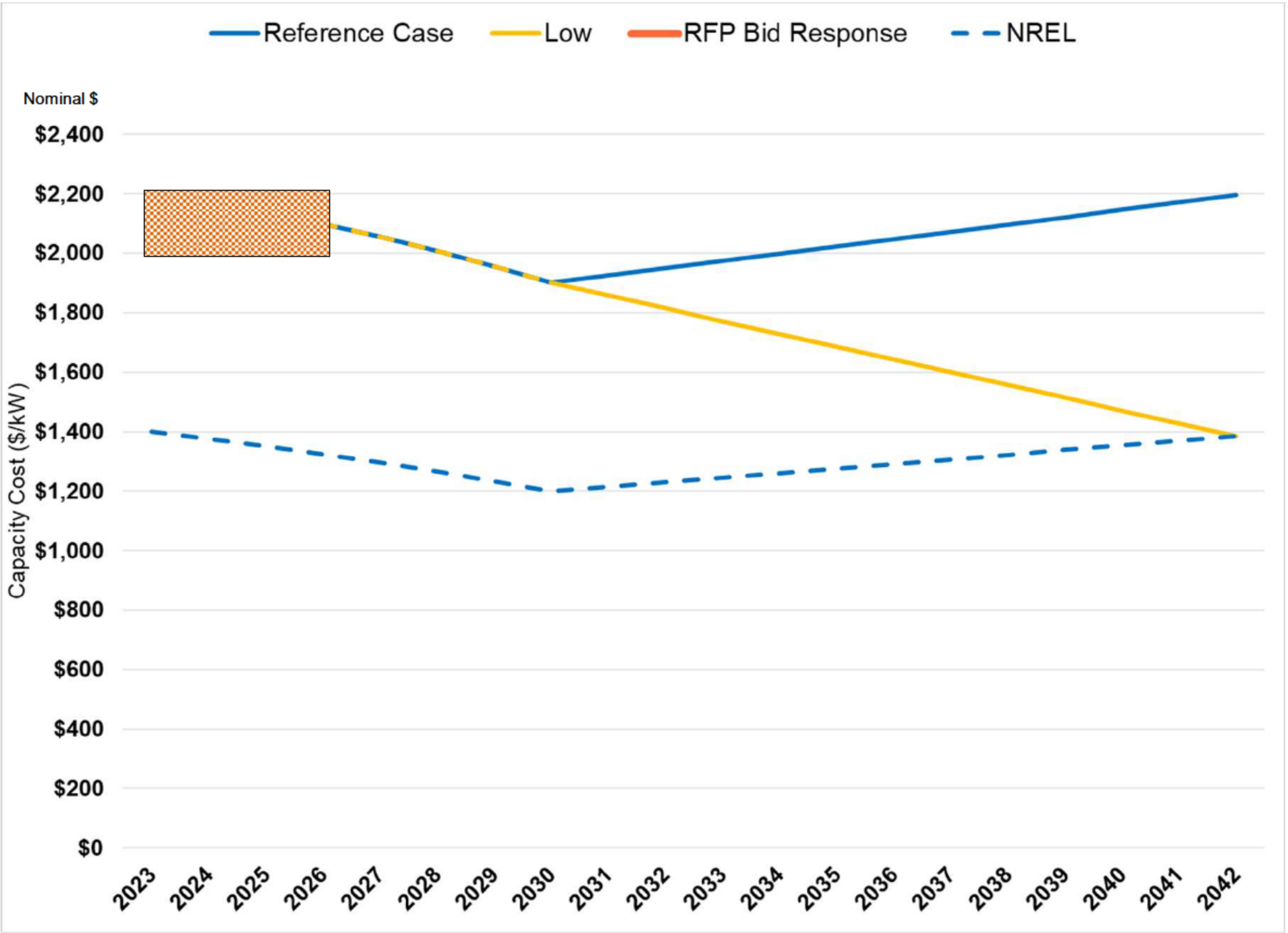
Capacity Cost Curves - Solar



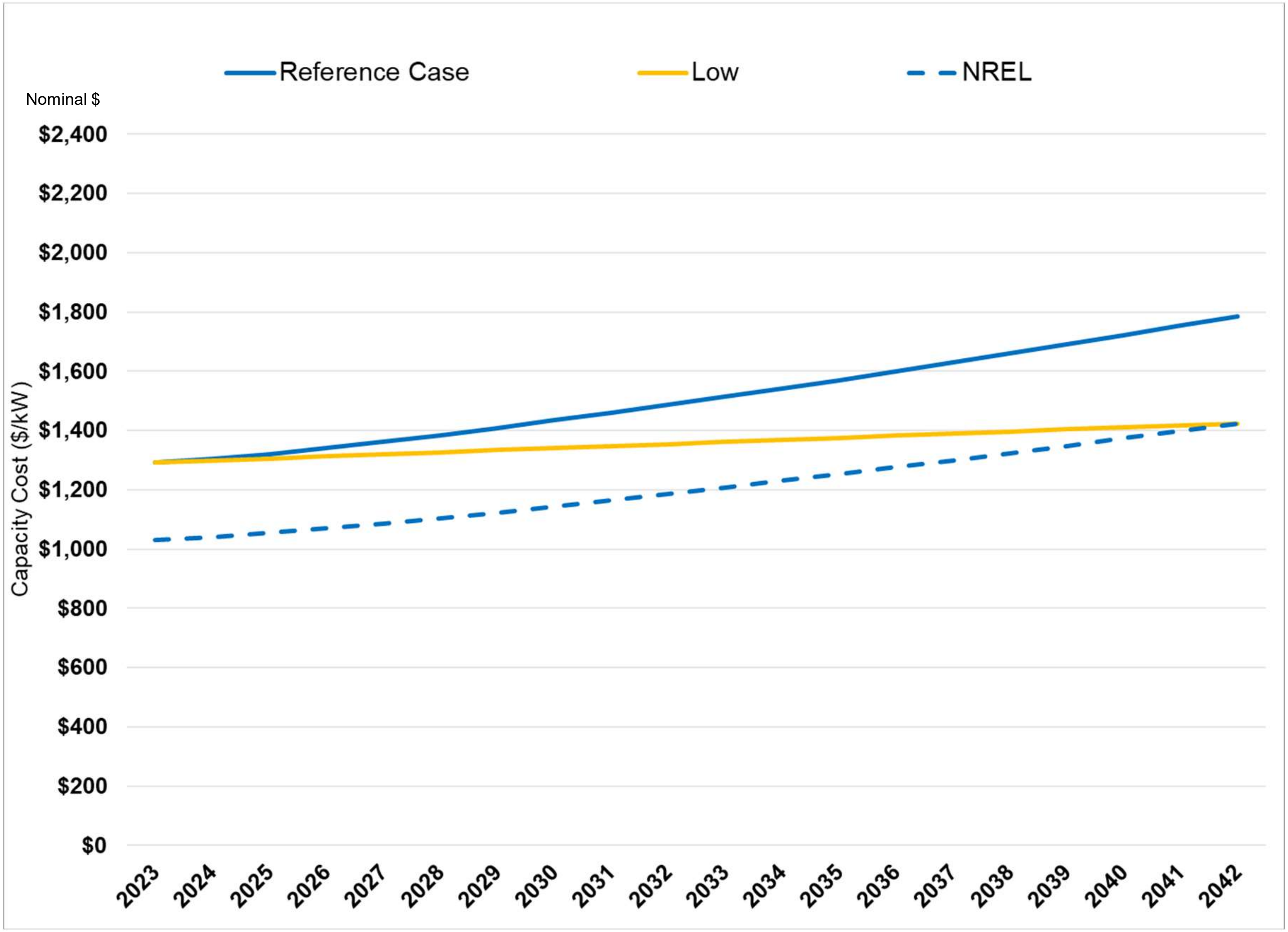
Capacity Cost Curves - Storage



Capacity Cost Curves – Wind



Capacity Cost Curves – Combined Cycle



CenterPoint Energy

Q&A

CenterPoint Energy

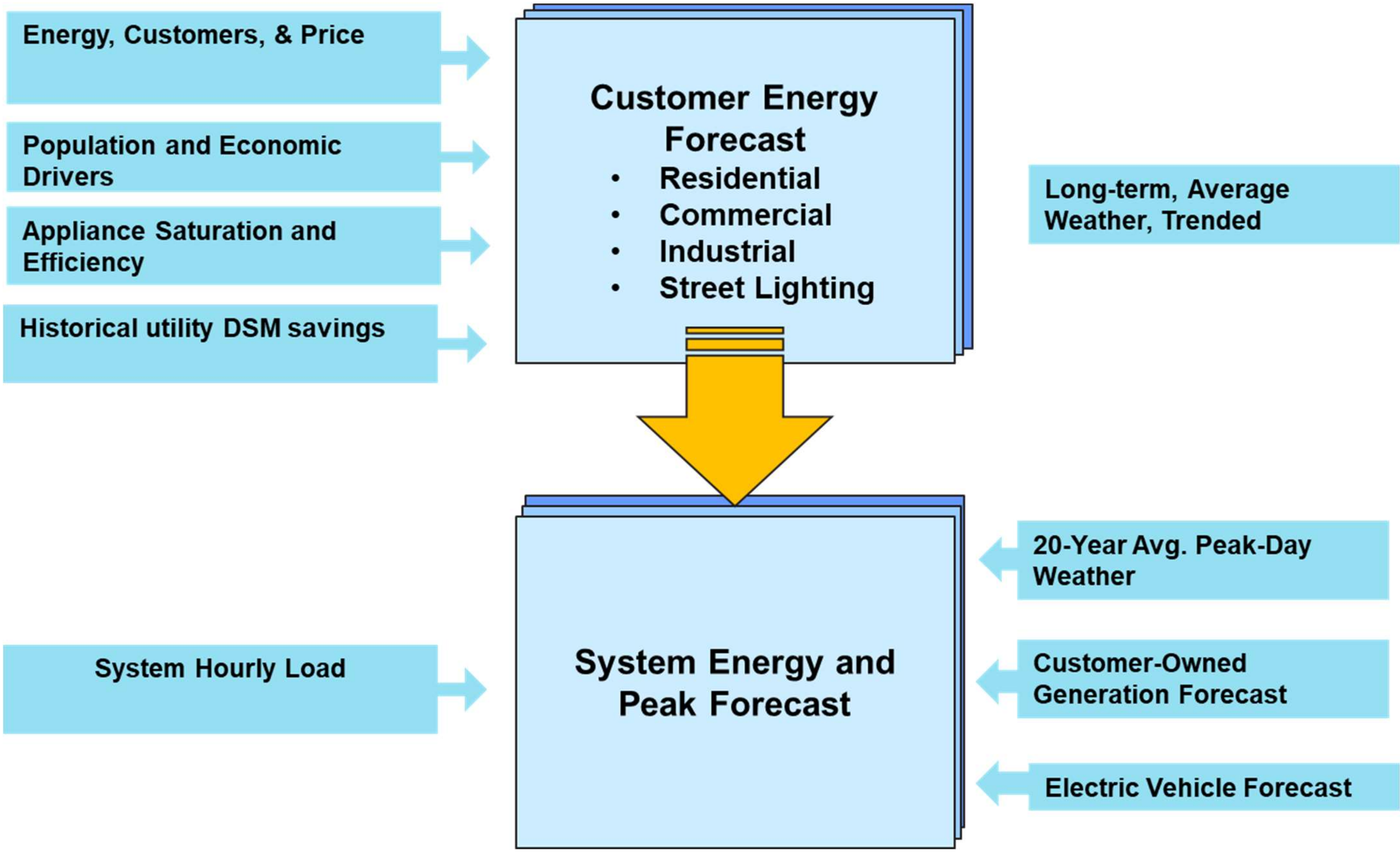
Final Load Forecast

Michael Russo
Senior Forecast Consultant - Itron

Forecast Summary

- Forecast excludes the impact of additional CenterPoint sponsored energy efficiency program savings
- Forecast includes the impact of customer owned photovoltaics and electric vehicles
- Average annual growth of 0.7% on energy and peaks, over the 2022-2042 forecast period
  - Includes the addition of a large industrial customer in 2024
  - Excluding this addition, average annual growth would be 0.3% on energy and 0.4% on peaks.

Baseline Bottom-Up Forecast Approach

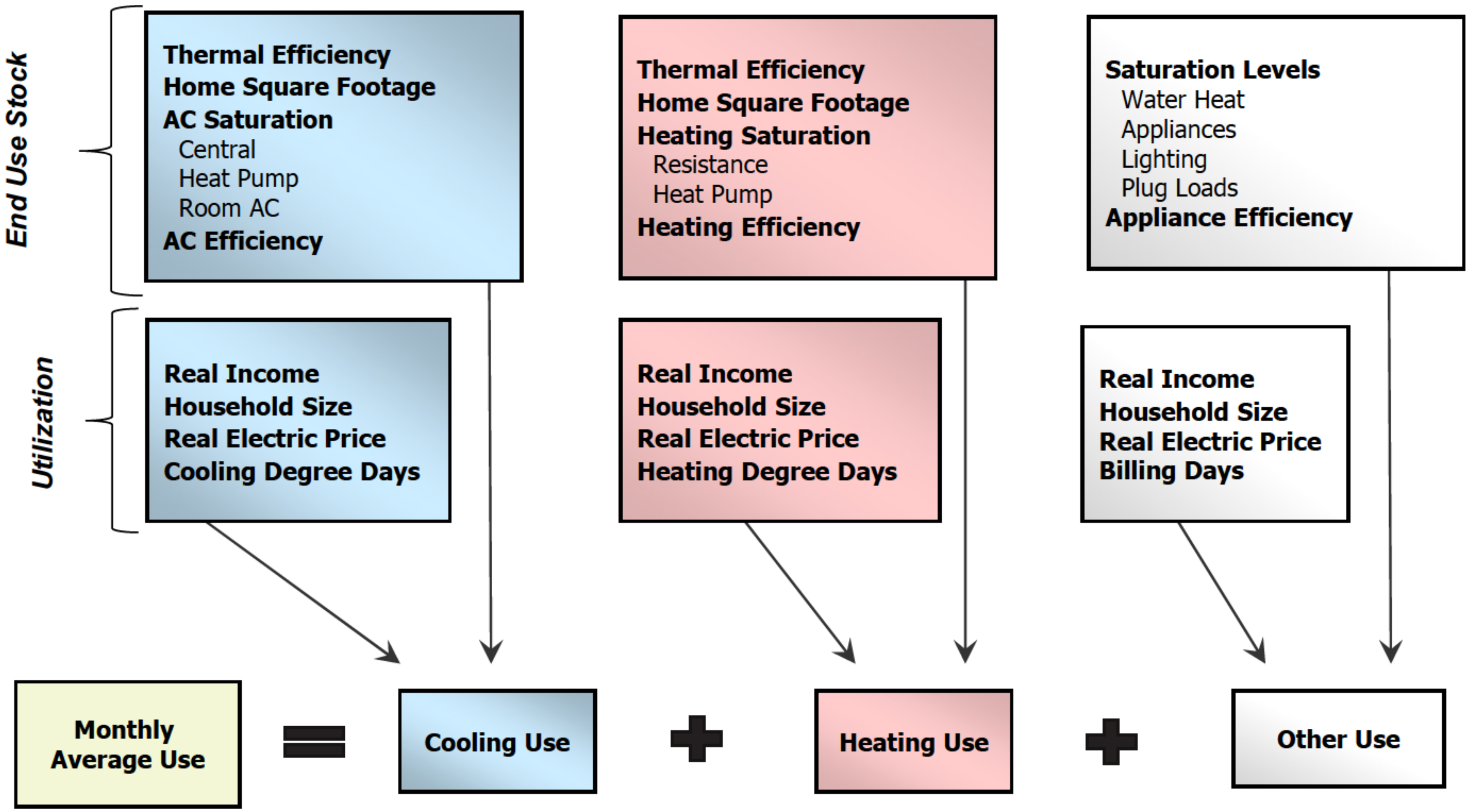


Model Estimation

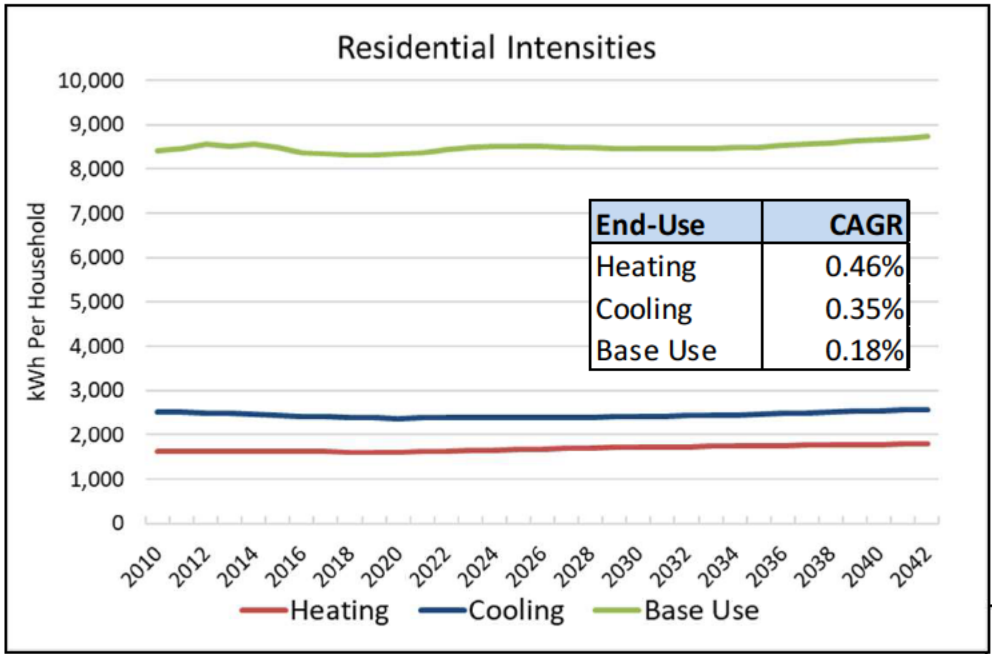
- Models estimated using rate class billed sales and customer data
- Monthly models, estimated for the period January 2011 to June 2022
- Rate class models:
  - Residential average use
  - Residential customers
  - Commercial total sales
  - Industrial total sales
  - Street lighting total sales (estimated from January 2014)
  - System peak

Residential Average Use model

CenterPoint Energy



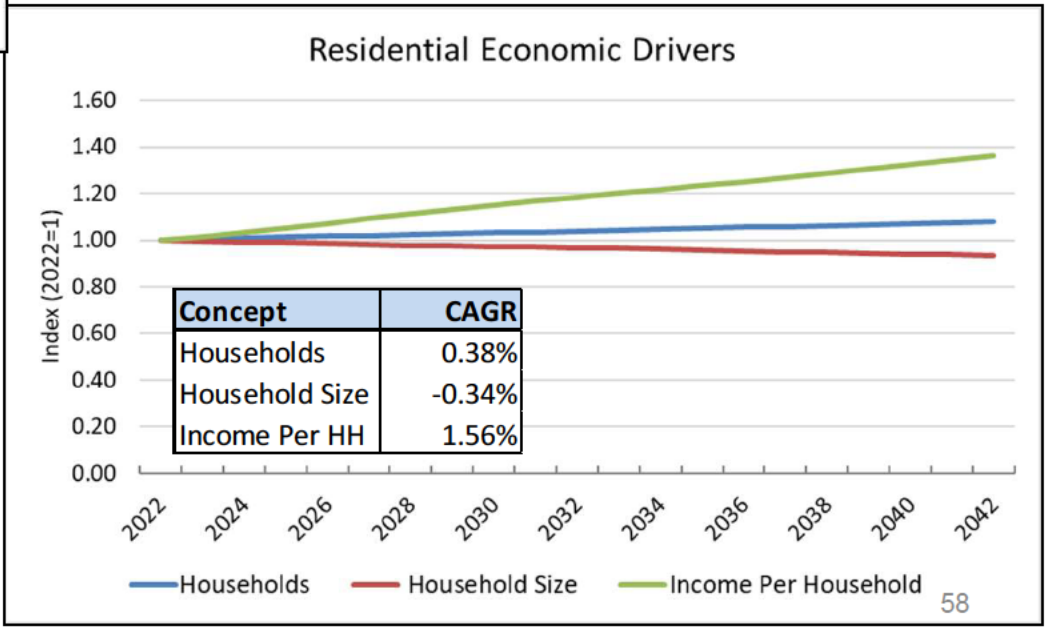
Residential Forecast Drivers



End-Use	CAGR
Heating	0.46%
Cooling	0.35%
Base Use	0.18%

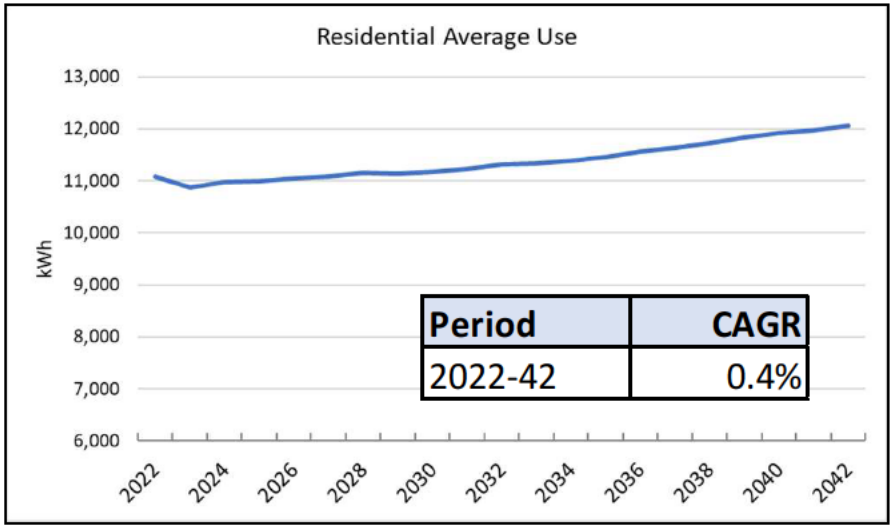
- Residential intensities based on the 2022 Annual Energy Outlook from the Energy Information Administration (EIA)
  - Reflects changes in end-use ownership, efficiency trends, and home thermal shell efficiency
  - Calibrated to CenterPoint's service territory using end-use saturations from 2016 study

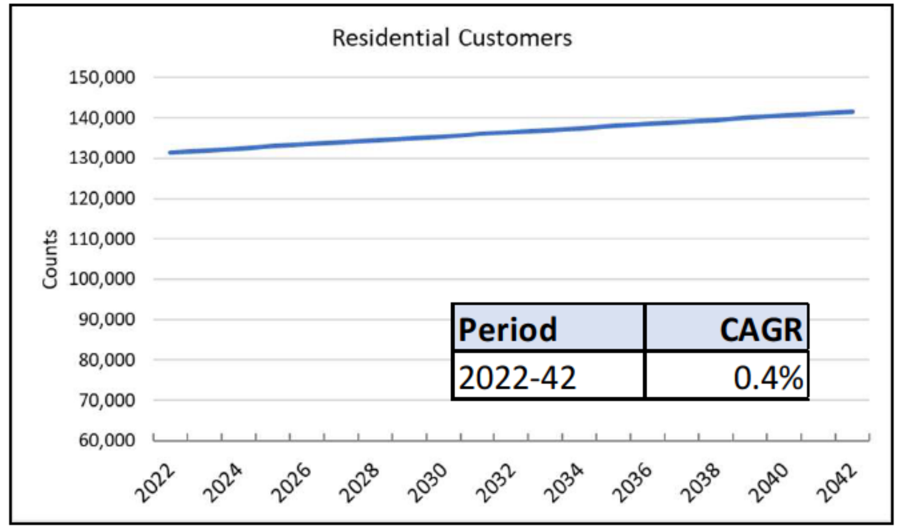
- Economic drivers from IHS Markit for Evansville MSA



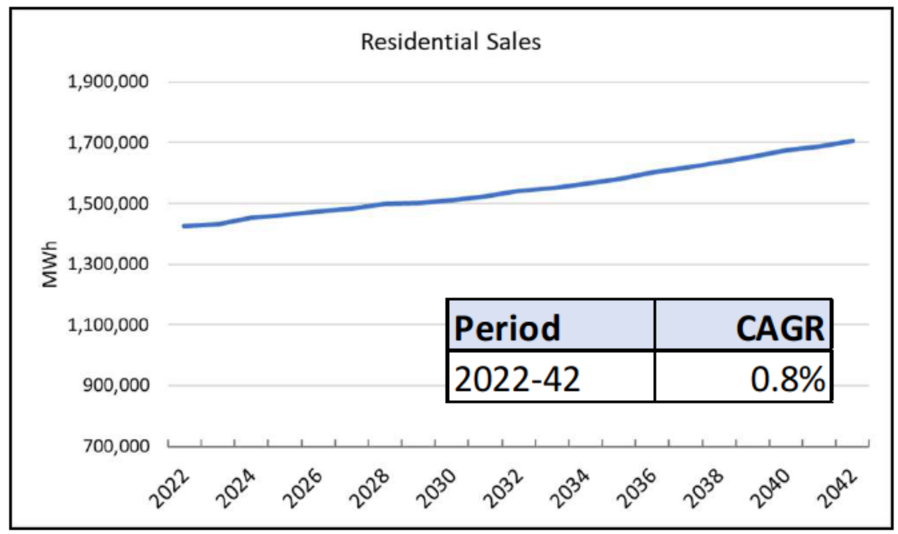
Concept	CAGR
Households	0.38%
Household Size	-0.34%
Income Per HH	1.56%

Residential Class Forecast

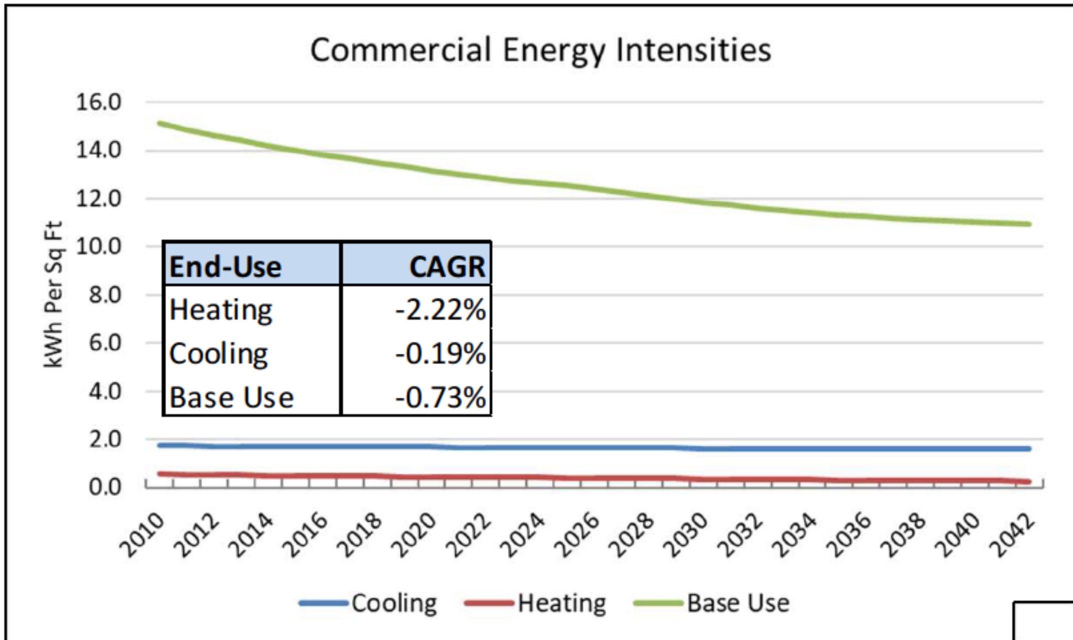




- Does not include the impact of future CenterPoint efficiency program savings
- Flattening of federal efficiency improvements results in average use growth over the forecast period



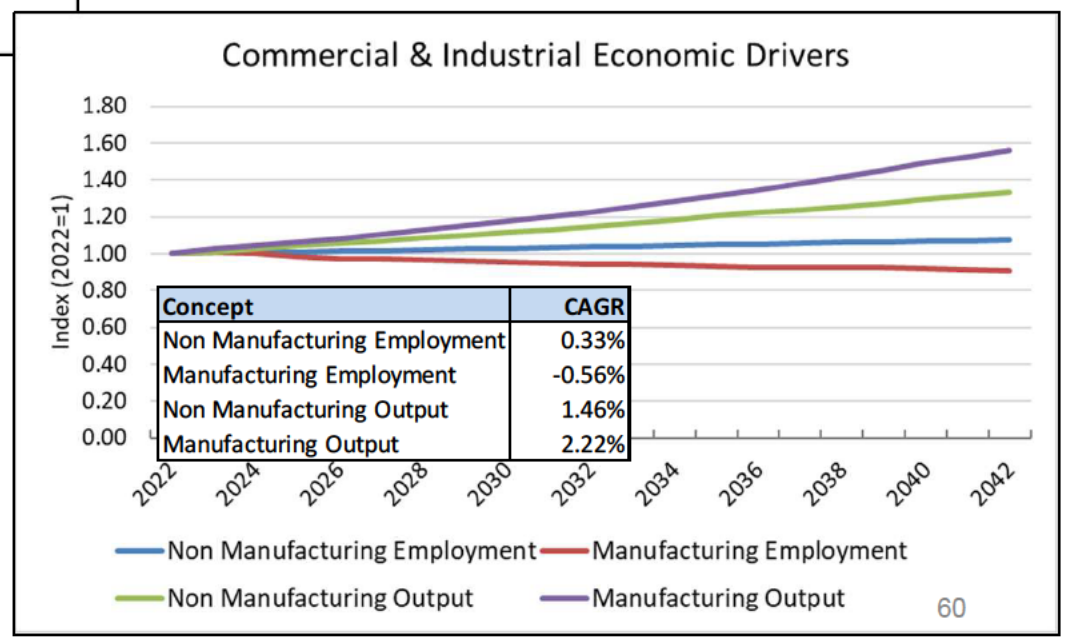
Commercial & Industrial Class Forecast Driver



End-Use	CAGR
Heating	-2.22%
Cooling	-0.19%
Base Use	-0.73%

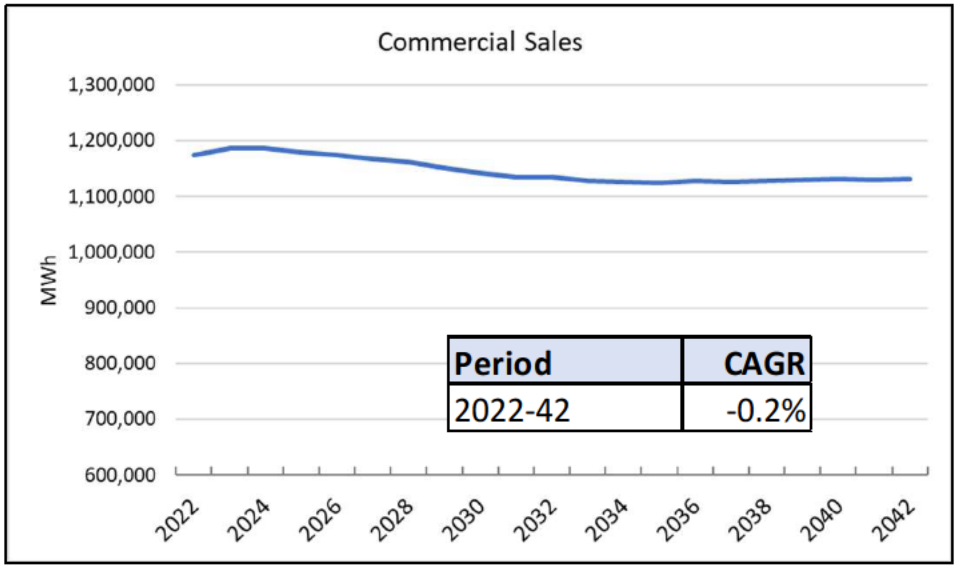
- Commercial intensities based on the 2022 Annual Energy Outlook from the Energy Information Administration (EIA)
  - Reflects efficiency trends and square footage estimates by building type and end-use
  - Calibrated to CenterPoint's annual commercial sales

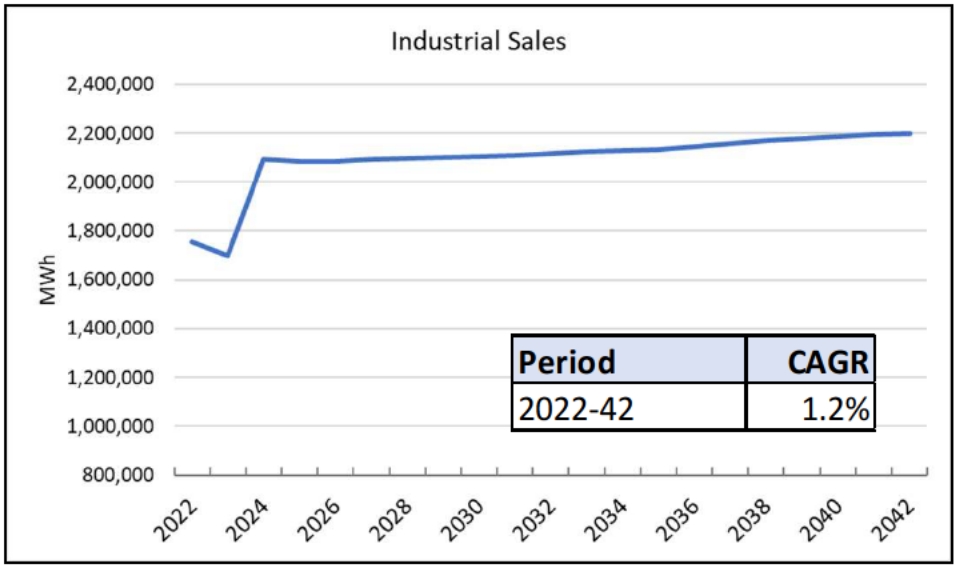
- Economic drivers from IHS Markit for Evansville MSA and Indiana



Concept	CAGR
Non Manufacturing Employment	0.33%
Manufacturing Employment	-0.56%
Non Manufacturing Output	1.46%
Manufacturing Output	2.22%

Commercial & Industrial Class Forecast

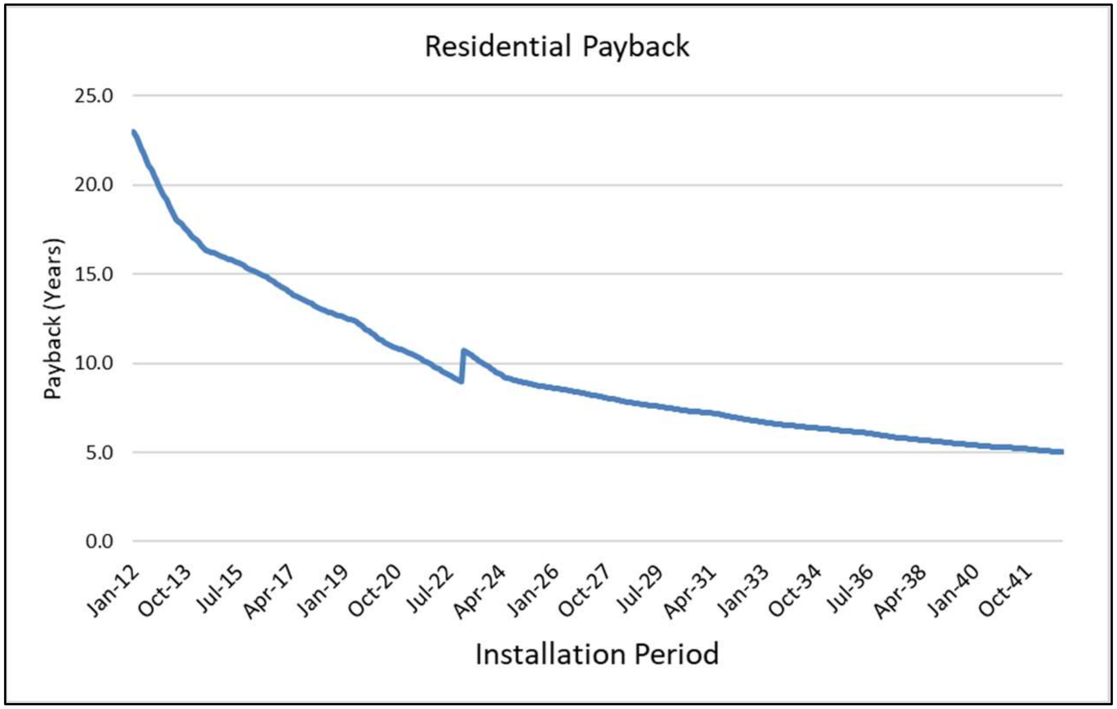




- Does not include the impact of future CenterPoint efficiency program savings
- Strong continued federal efficiency gains in commercial buildings, driven by lighting and ventilation
- Large new industrial customer will be added in 2024

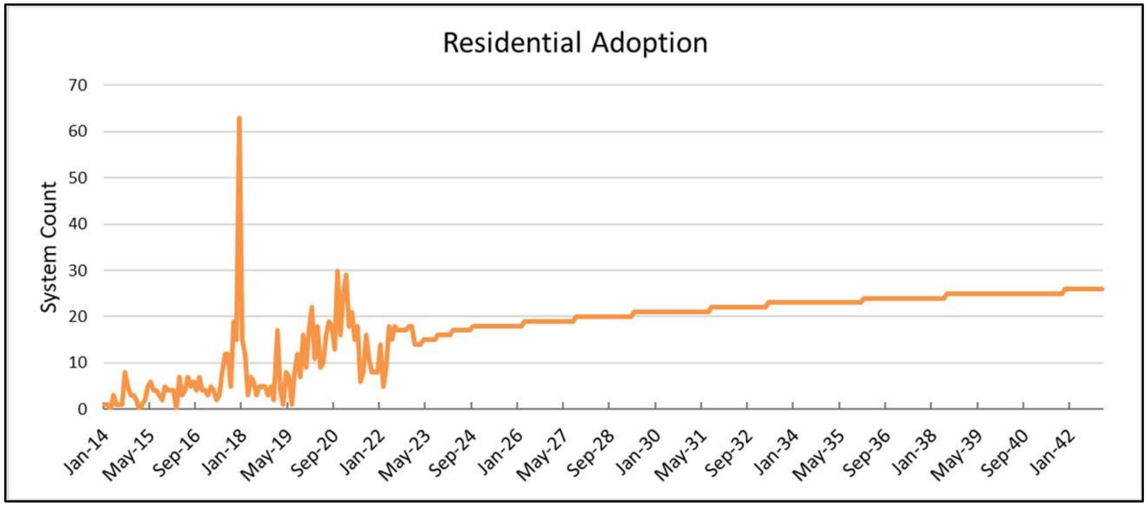
Customer Owned Photovoltaics: Customer Economics

- Monthly adoption modeled as a function of simple payback
  - Incorporates declining solar system costs, electric price projections, changes in net metering laws, and federal incentives
    - Switch from net metering to Excess Distributed Generation (EDG)
    - Continuation of ITC under the Inflation Reduction Act (IRA)
    - Continued decline in solar costs



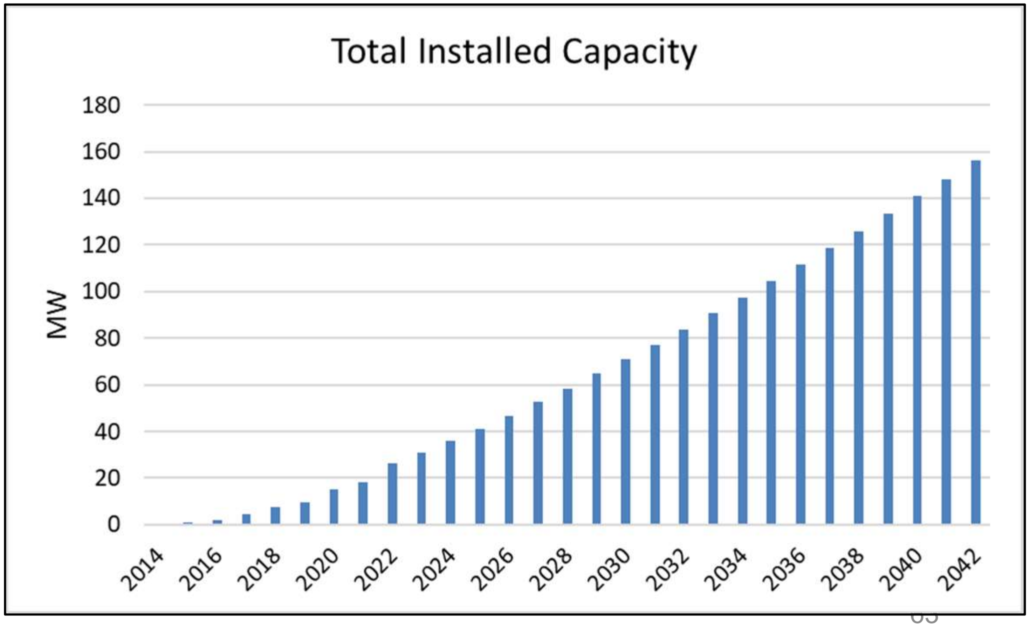
Customer Owned Photovoltaics: Forecast

CenterPoint Energy



- Commercial adoption based on historical relationship between residential and commercial installations.

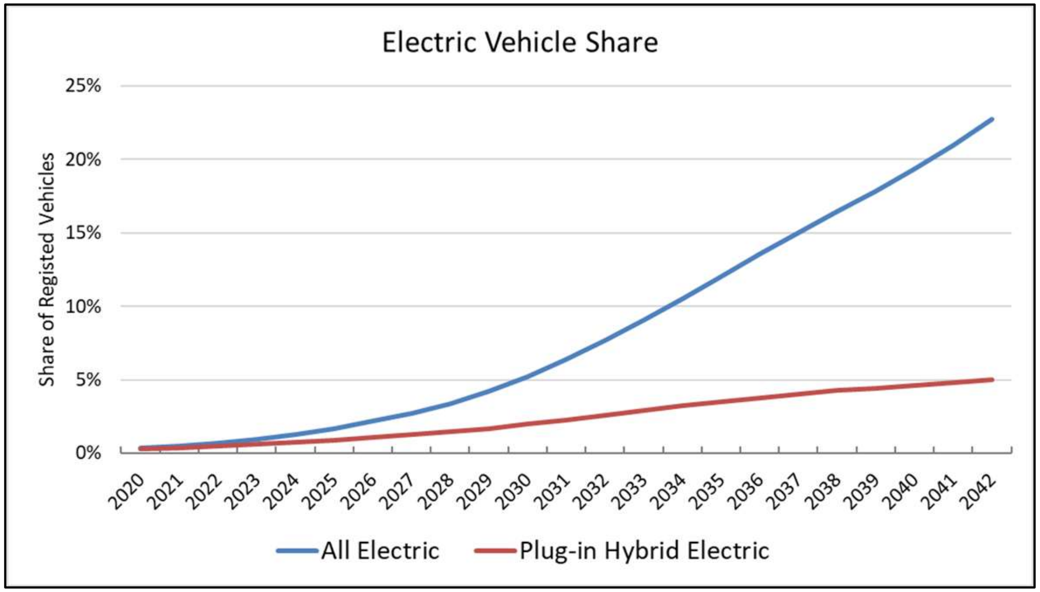
- Total installed capacity derived by combining monthly adoptions with average (kW) system size
- NREL PVWatts hourly solar profile is used to calculate monthly load factors and estimate monthly solar generation
- The load forecast is only adjusted for incremental new solar capacity



Electric Vehicle Forecast:

CenterPoint Energy

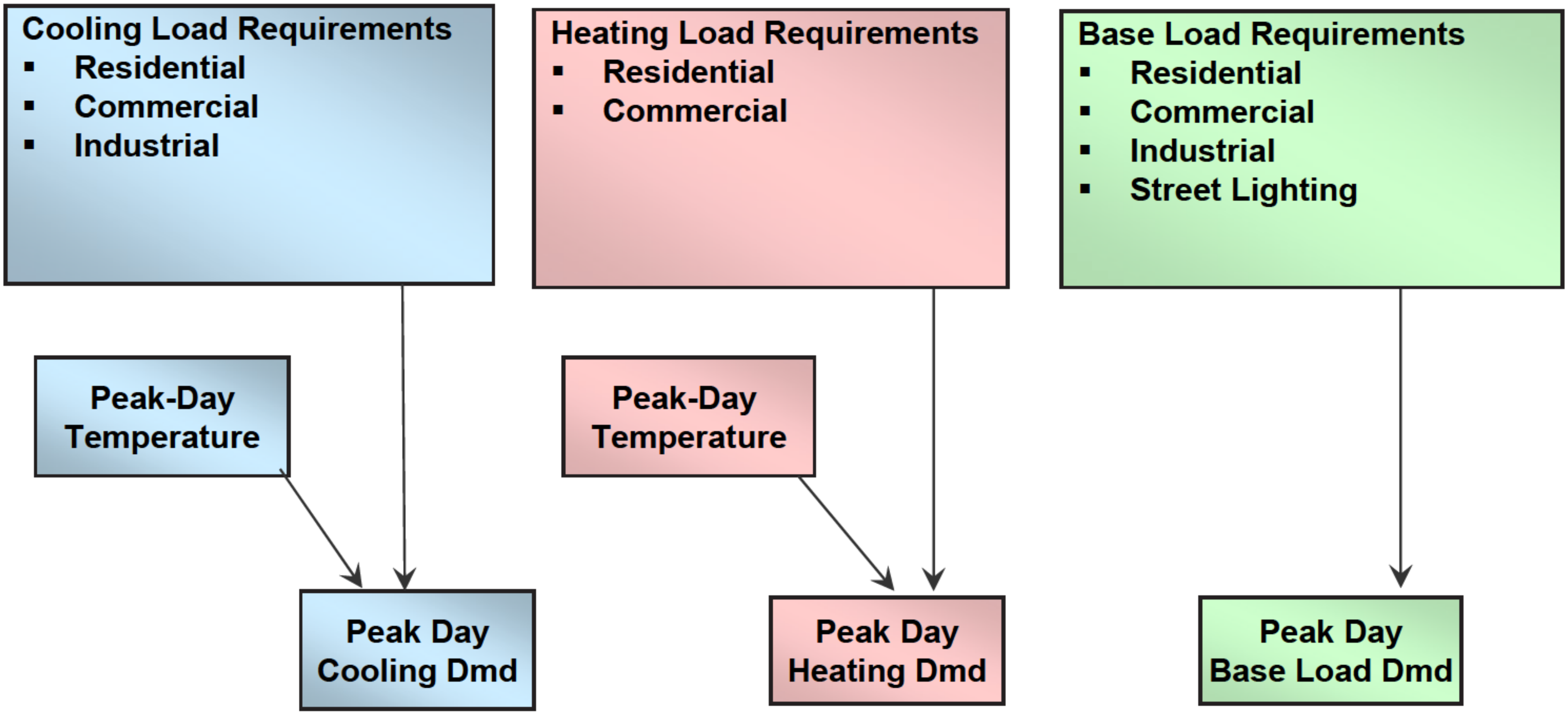
- There are approximately 700 electric vehicles currently registered in CenterPoint's service territory.
  - This is below the implied number of electric vehicles based on U.S. average electric vehicle share which would be approximately 2,200 electric vehicles.
- The forecast is based on the average of the Energy Information Administration and BloombergNEF forecasts
- The forecast is calibrated into the number of electric vehicles in CenterPoint's territory
- Incorporates assumptions regarding vehicles per household and miles traveled per year



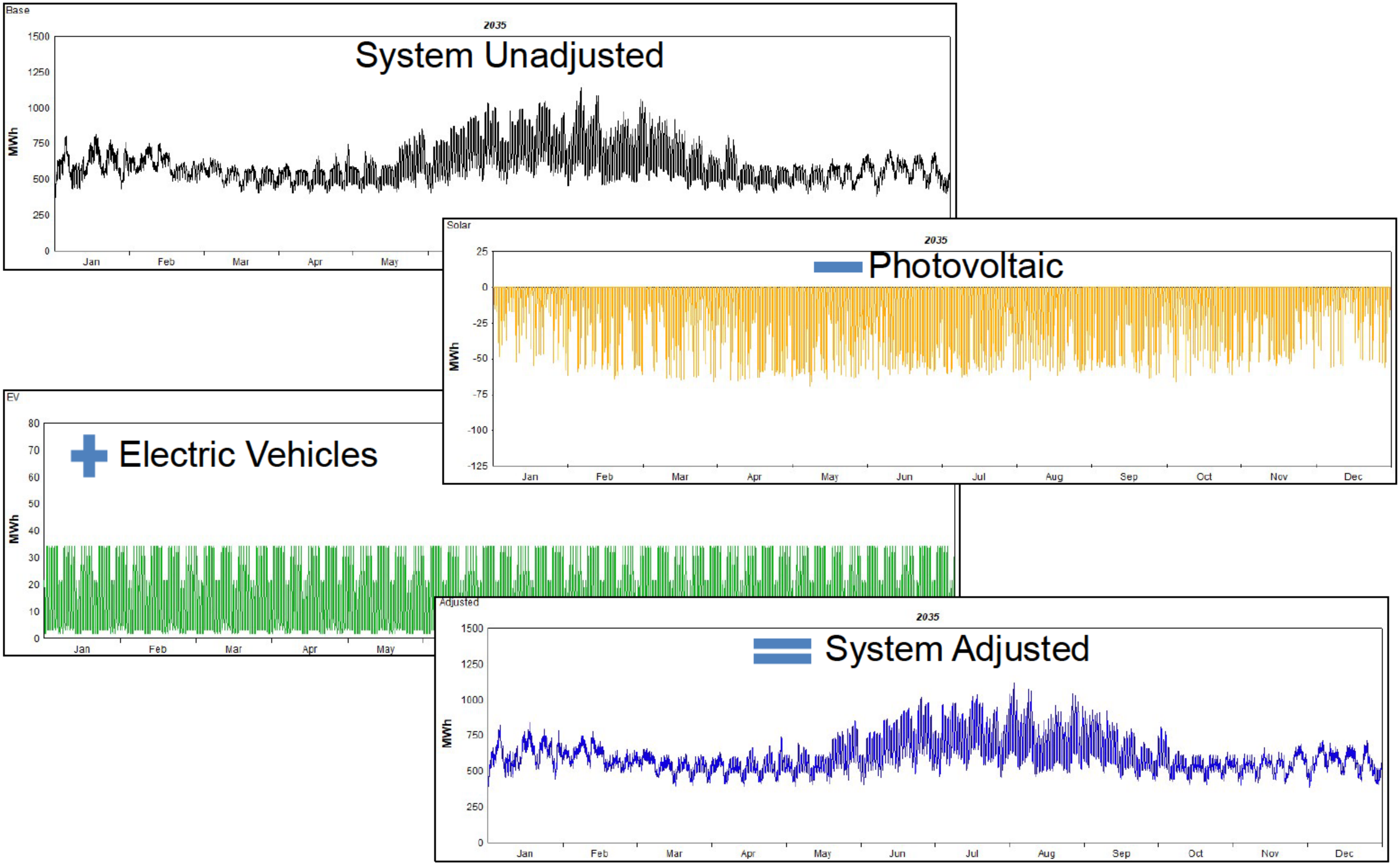
Peak Demand Model Forecast

CenterPoint Energy

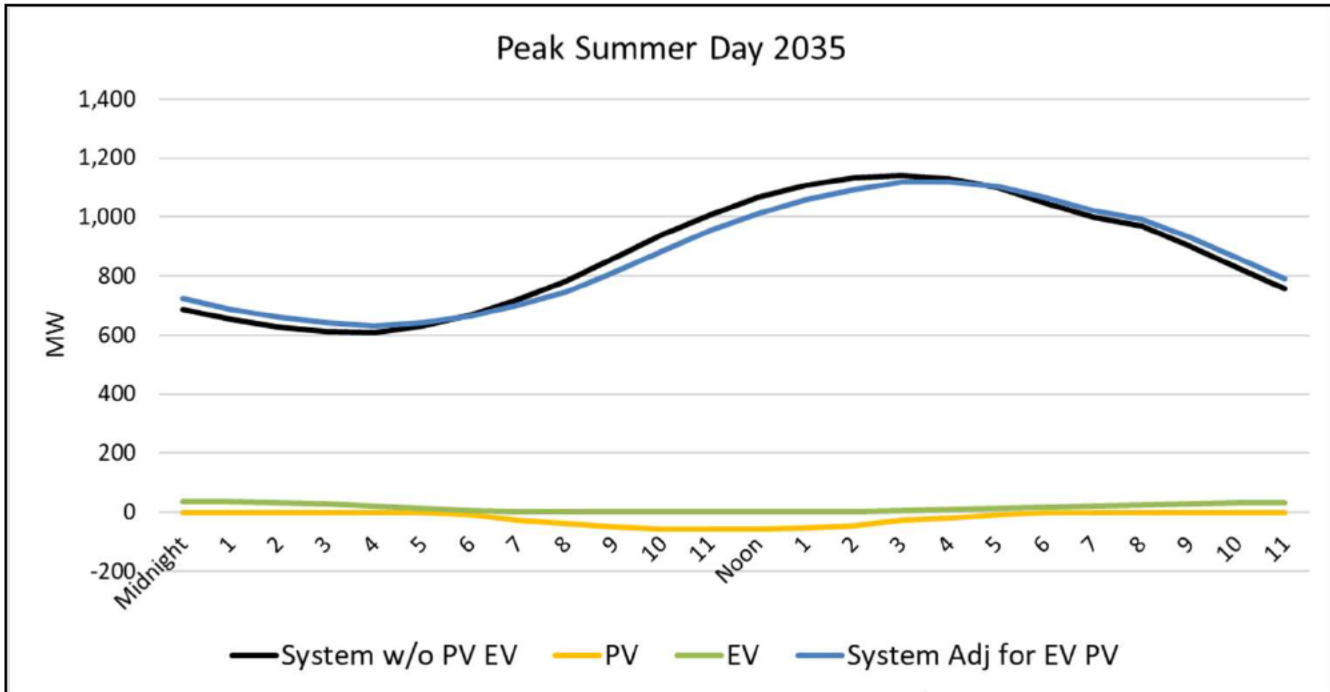
- Peak demand is driven by heating, cooling, and base load requirements derived from the customer class forecasts

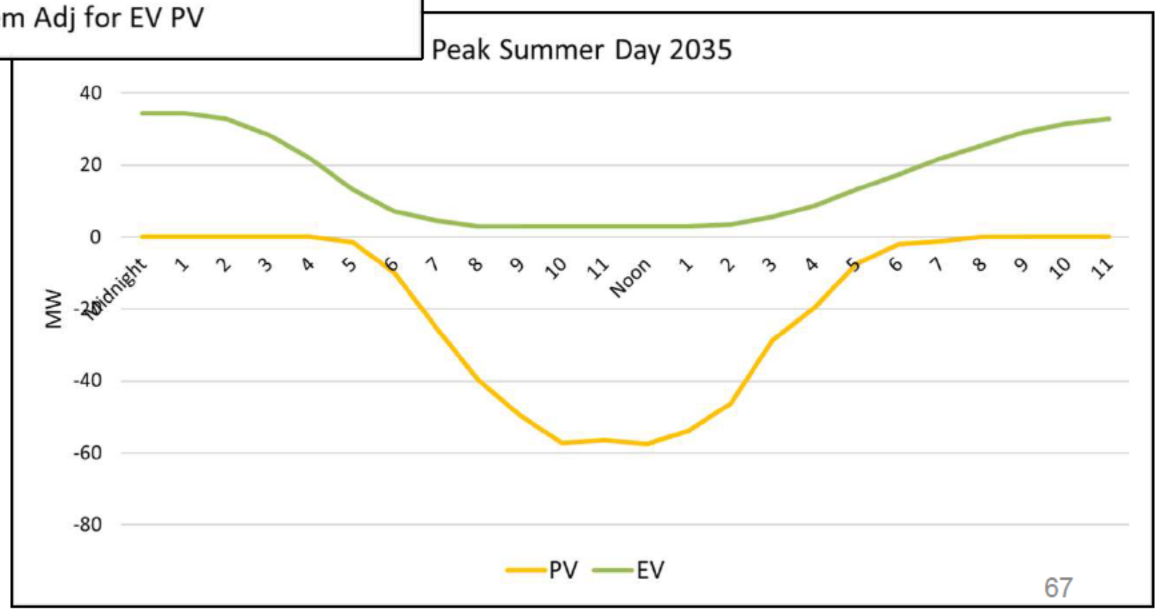


Combine Energy and Hourly Profiles



Hourly Shapes: Impact on Peak

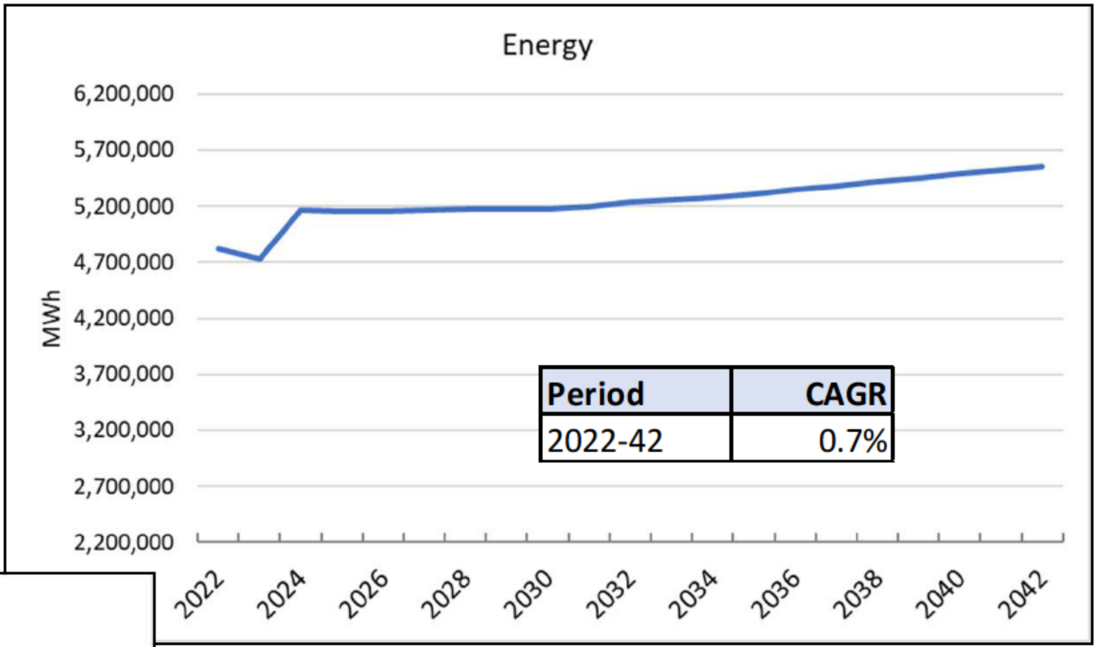


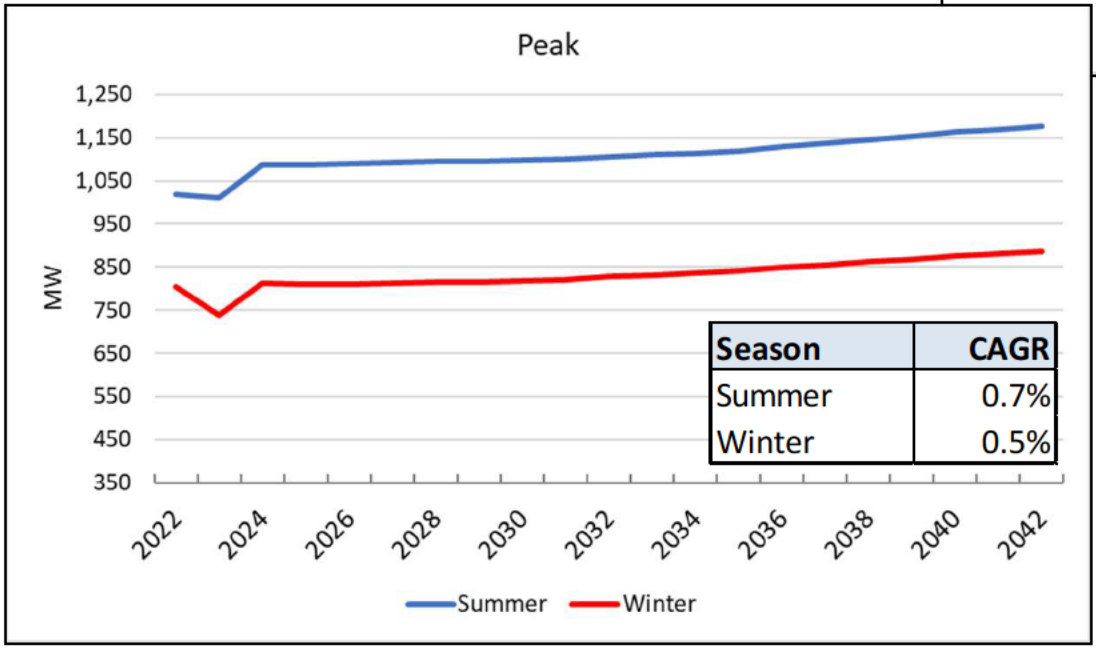


- PV and EV adoption will reshape system load over time
- Timing and level of peak impacted by change in system hourly load profile

Energy and Peak Forecast

- Does not include the impact of future CenterPoint efficiency program savings
- Includes the impact of photovoltaics and electric vehicles



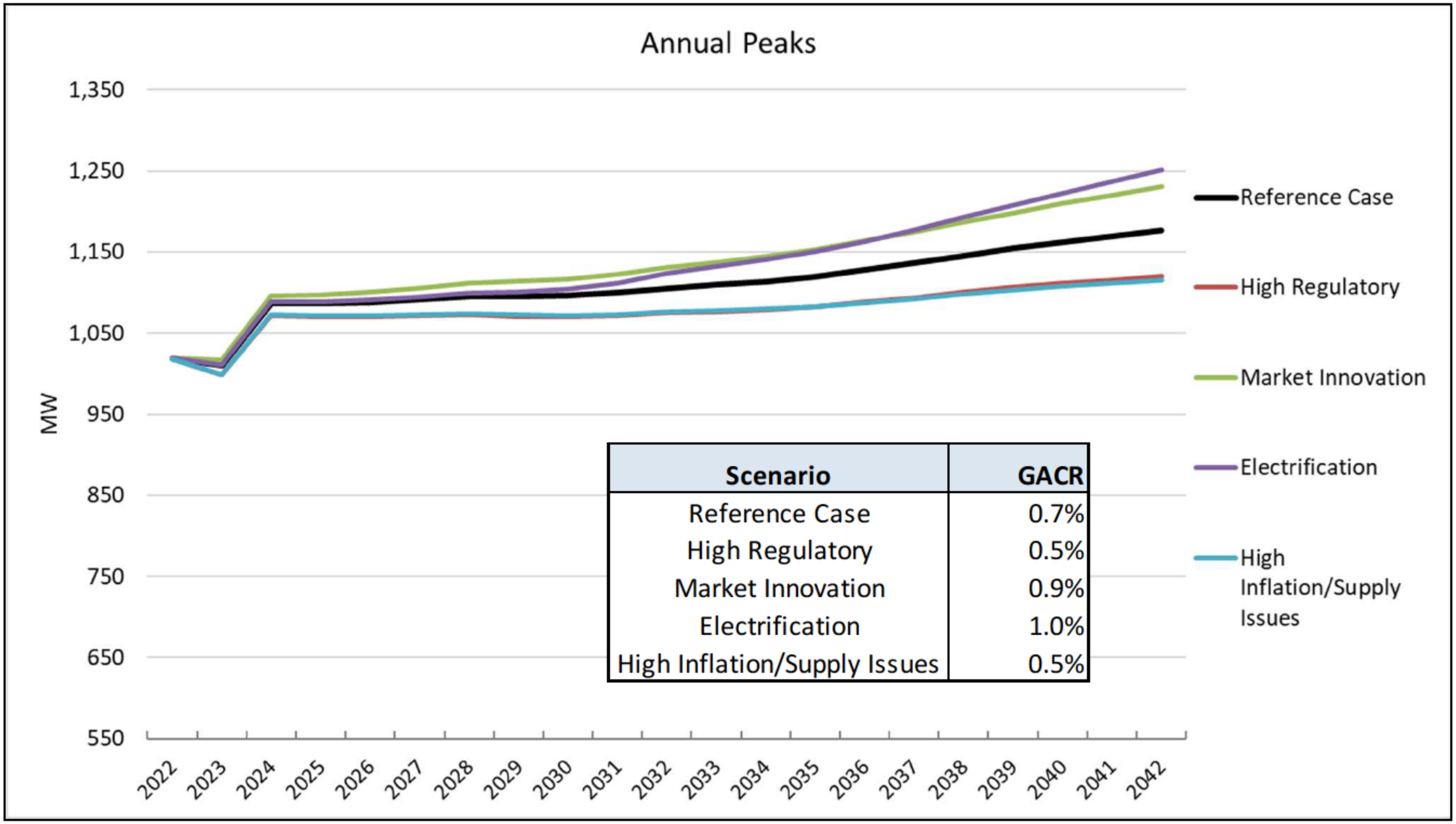


Scenario Assumptions

CenterPoint Energy

- **High Regulatory**= Lower load forecast driven by lower economic forecast
- **Market Driven Innovation**= Higher load forecast driven by higher economic forecast
- **Decarbonization\Electrification**= Higher load driven by increased adoption of electric water heaters, clothes dryers, and heat-pump heaters. Higher electric vehicle and solar forecast.
- **High Inflation & Supply Chain Issue**= Lower load forecast driven by lower economic forecast, lower electric vehicles and solar forecasts.

Scenario Peak Load Forecast



Scenario	GACR
Reference Case	0.7%
High Regulatory	0.5%
Market Innovation	0.9%
Electrification	1.0%
High Inflation/Supply Issues	0.5%

Q&A

Scenario and Probabilistic Modeling Approach and Assumptions

Brian Despard
Project Manager, Resource Planning & Market Assessments
1898 & Co.

Approach Overview

CenterPoint Energy

Objective: Utilize stochastic analysis around key IRP inputs to measure uncertainty around power supply portfolio costs.

Two Purposes:

1. Evaluate results of stochastic inputs analysis to inform on what inputs to use for various scenarios; and
2. Stochastically develop 200 “families” of correlated inputs to run through PCM – result will be probability distribution around power supply costs.

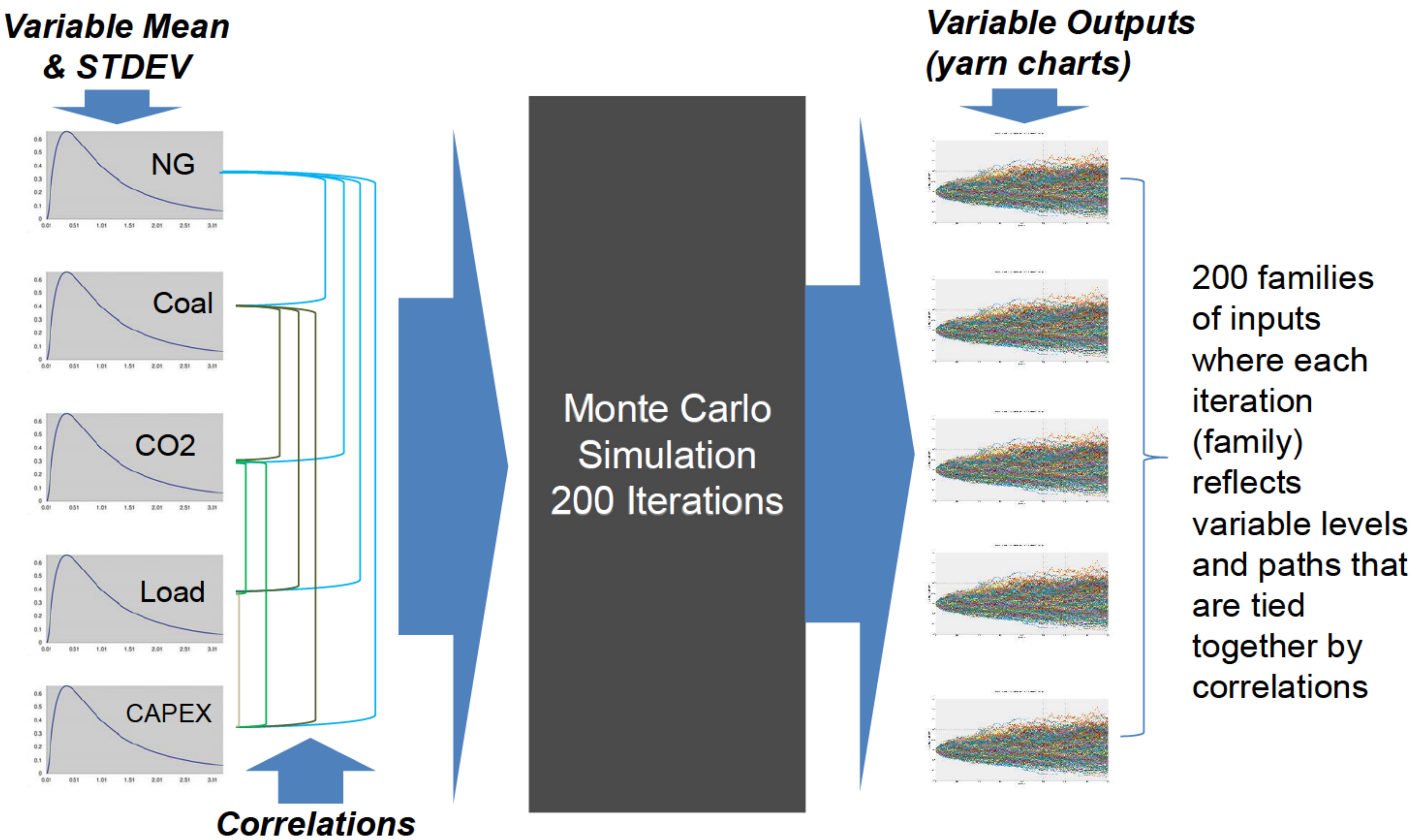
Uncertainty Variables

- Peak Demand
- Natural Gas (NG) Prices
- Coal Prices
- CO_2 Costs
- Renewable Development Costs

Stochastics Process Overview

1. Develop uncertainty variable parameters by month – expected value, volatility, correlations
2. Input variables into Monte Carlo simulation model
3. Run simulations with uncertainty variables being the output
4. Evaluate output implied distributions for each variable
5. Identify 200 sets of uncertainty variable “families”

Stochastics Process Overview



Uncertainty Variable Parameters Expected Values & Volatilities

CenterPoint Energy

Expected values (mean values): Reference Case forecasts for each variable

Volatilities (standard deviations):

- **Demand:** From various Itron demand scenarios
- **Natural gas pricing:** From ABB forecast Base/High/Low forecast
- **Coal pricing:** From variation in consensus forecasts
- **CO_2 Costs:** Reference case of zero and 2 high cases
- **Newbuild CAPEX**: NREL ATB range of costs

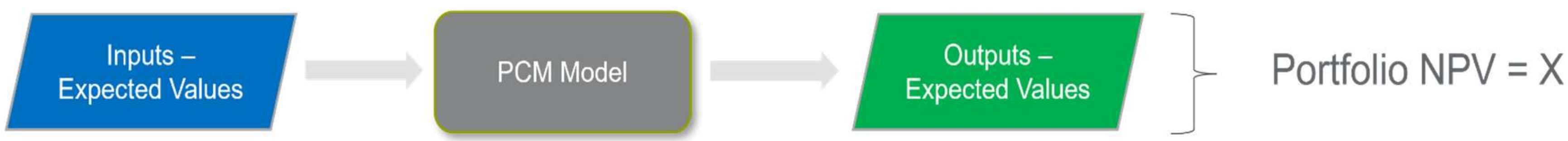
Uncertainty Variable Parameters Expected Correlations

Variable	Demand	NG Price	Coal Price	CO_2 Cost	Dev CAPEX
Demand		Slightly Positive	Zero	Zero	Zero
NG Price	Slightly Positive		Slightly Negative	Negative	Positive
Coal Price	Zero	Slightly Negative		Negative	Zero
CO_2 Cost	Zero	Negative	Negative		Positive
Dev CAPEX	Zero	Positive	Zero	Positive	

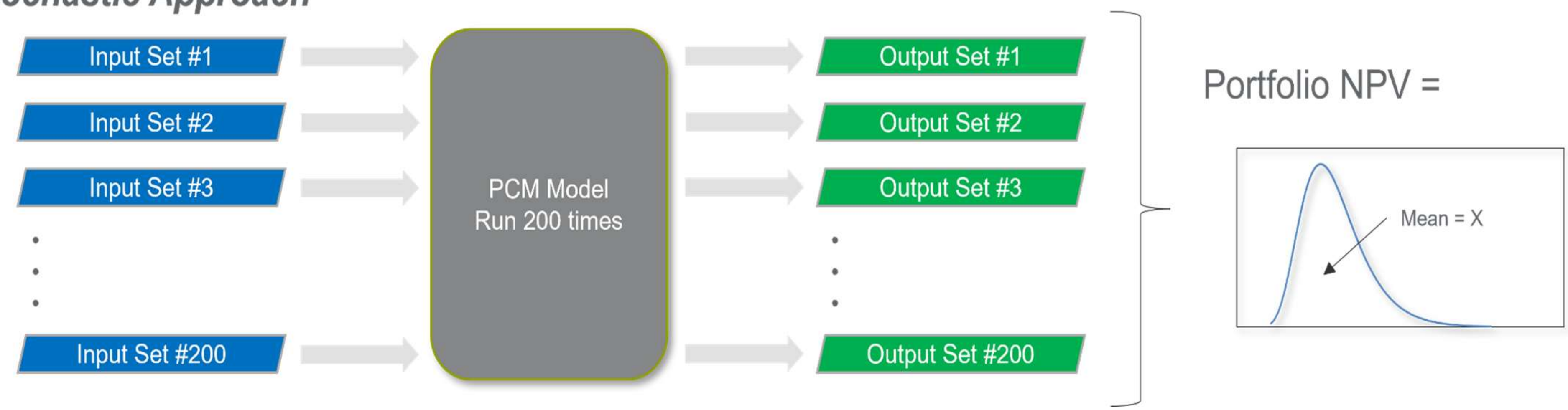
Production Cost Modeling Stochastics Process Overview

CenterPoint Energy

Typical Deterministic Approach

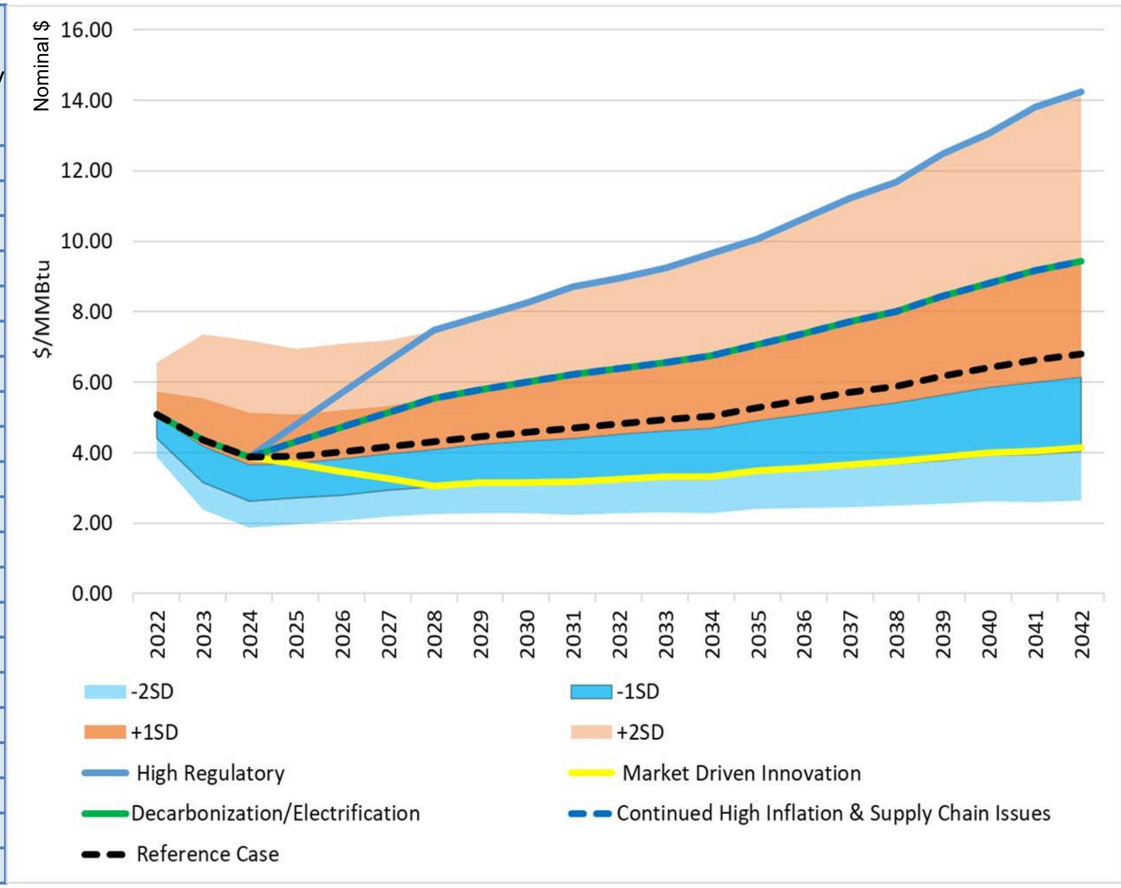


Stochastic Approach



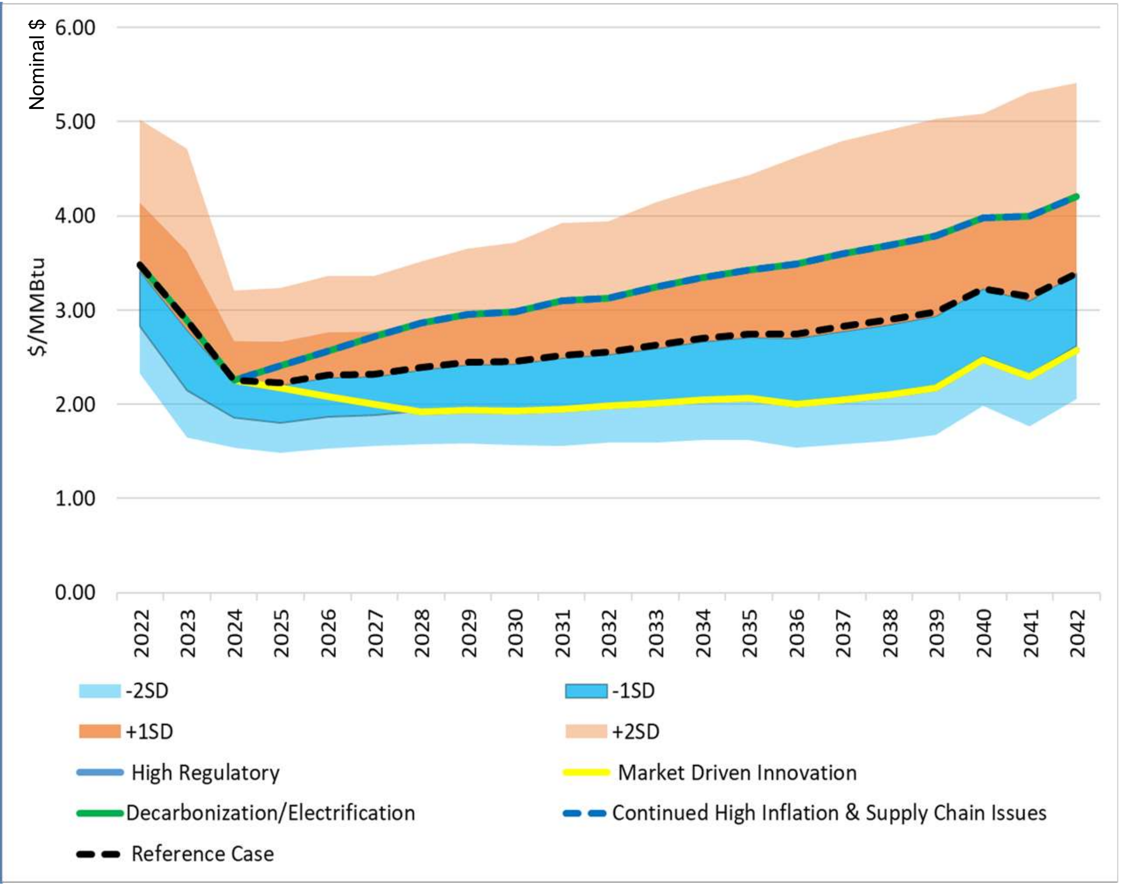
Scenario Inputs: Natural Gas Henry Hub ($/MMBtu)

Year	Reference Case	High Regulatory	Market Driven Innovation	Decarbonization/ Electrification	Continued High Inflation & Supply Chain Issues
2022	$5.08	$5.08	$5.08	$5.08	$5.08
2023	$4.36	$4.36	$4.36	$4.36	$4.36
2024	$3.89	$3.89	$3.89	$3.89	$3.89
2025	$3.90	$4.78	$3.68	$4.30	$4.30
2026	$4.02	$5.68	$3.47	$4.72	$4.72
2027	$4.16	$6.58	$3.27	$5.14	$5.14
2028	$4.31	$7.48	$3.06	$5.55	$5.55
2029	$4.47	$7.85	$3.14	$5.79	$5.79
2030	$4.58	$8.25	$3.16	$5.99	$5.99
2031	$4.71	$8.70	$3.18	$6.22	$6.22
2032	$4.83	$8.95	$3.26	$6.39	$6.39
2033	$4.94	$9.23	$3.32	$6.56	$6.56
2034	$5.05	$9.64	$3.32	$6.76	$6.76
2035	$5.29	$10.07	$3.49	$7.07	$7.07
2036	$5.49	$10.63	$3.57	$7.39	$7.39
2037	$5.70	$11.22	$3.66	$7.73	$7.73
2038	$5.89	$11.68	$3.76	$8.01	$8.01
2039	$6.17	$12.49	$3.87	$8.45	$8.45
2040	$6.42	$13.06	$4.00	$8.81	$8.81
2041	$6.63	$13.81	$4.05	$9.18	$9.18
2042	$6.81	$14.23	$4.15	$9.44	$9.44



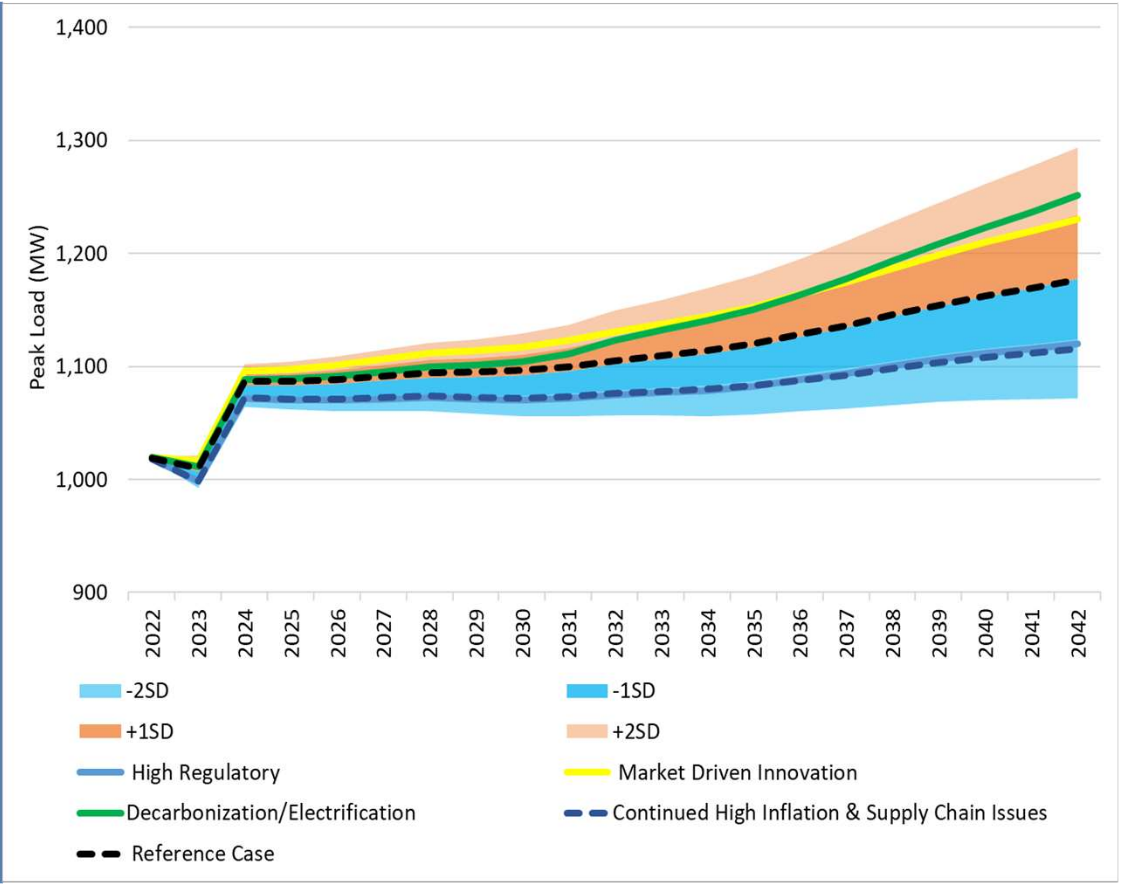
Scenario Inputs: Coal Illinois Basin fob Mine ($/MMBtu)

Year	Reference Case	High Regulatory	Market Driven Innovation	Decarbonization/ Electrification	Continued High Inflation & Supply Chain Issues
2022	$3.48	$3.48	$3.48	$3.48	$3.48
2023	$2.89	$2.89	$2.89	$2.89	$2.89
2024	$2.26	$2.26	$2.26	$2.26	$2.26
2025	$2.23	$2.41	$2.17	$2.41	$2.41
2026	$2.31	$2.56	$2.09	$2.56	$2.56
2027	$2.32	$2.71	$2.00	$2.71	$2.71
2028	$2.39	$2.87	$1.91	$2.87	$2.87
2029	$2.44	$2.95	$1.94	$2.95	$2.95
2030	$2.46	$2.98	$1.93	$2.98	$2.98
2031	$2.52	$3.10	$1.94	$3.10	$3.10
2032	$2.56	$3.13	$1.98	$3.13	$3.13
2033	$2.63	$3.25	$2.01	$3.25	$3.25
2034	$2.70	$3.34	$2.04	$3.34	$3.34
2035	$2.75	$3.43	$2.06	$3.43	$3.43
2036	$2.75	$3.49	$2.00	$3.49	$3.49
2037	$2.83	$3.60	$2.05	$3.60	$3.60
2038	$2.90	$3.69	$2.10	$3.69	$3.69
2039	$2.98	$3.79	$2.18	$3.79	$3.79
2040	$3.23	$3.98	$2.48	$3.98	$3.98
2041	$3.14	$4.00	$2.29	$4.00	$4.00
2042	$3.39	$4.21	$2.58	$4.21	$4.21



Scenario Inputs: Peak Load

Year	Reference Case	High Regulatory	Market Driven Innovation	Decarbonization/ Electrification	Continued High Inflation & Supply Chain Issues
2022	1,019	1,018	1,020	1,019	1,018
2023	1,010	999	1,017	1,011	999
2024	1,087	1,072	1,096	1,088	1,072
2025	1,087	1,070	1,097	1,089	1,071
2026	1,088	1,070	1,101	1,091	1,071
2027	1,092	1,071	1,106	1,095	1,073
2028	1,095	1,072	1,111	1,099	1,074
2029	1,095	1,071	1,114	1,101	1,073
2030	1,096	1,070	1,117	1,104	1,072
2031	1,100	1,072	1,123	1,111	1,073
2032	1,105	1,075	1,131	1,123	1,076
2033	1,110	1,077	1,137	1,132	1,078
2034	1,114	1,079	1,144	1,141	1,080
2035	1,120	1,082	1,153	1,151	1,083
2036	1,128	1,088	1,164	1,163	1,088
2037	1,136	1,094	1,174	1,178	1,092
2038	1,145	1,100	1,187	1,193	1,098
2039	1,154	1,106	1,198	1,208	1,103
2040	1,162	1,112	1,210	1,223	1,108
2041	1,169	1,116	1,220	1,237	1,112
2042	1,177	1,120	1,230	1,252	1,116



Scenario Inputs: CO2 Price ($/TON)

Year	Reference Case	High Regulatory	Market Driven Innovation	Decarbonization/ Electrification	Continued High Inflation & Supply Chain Issues
2022	$0	[redacted]	$0	$0	$0
2023	$0	[redacted]	$0	$0	$0
2024	$0	[redacted]	$0	$0	$0
2025	$0	[redacted]	$0	[redacted]	$0
2026	$0	[redacted]	$0	[redacted]	$0
2027	$0	[redacted]	$0	[redacted]	$0
2028	$0	[redacted]	$0	[redacted]	$0
2029	$0	[redacted]	$0	[redacted]	$0
2030	$0	[redacted]	$0	[redacted]	$0
2031	$0	[redacted]	$0	[redacted]	$0
2032	$0	[redacted]	$0	[redacted]	$0
2033	$0	[redacted]	$0	[redacted]	$0
2034	$0	[redacted]	$0	[redacted]	$0
2035	$0	[redacted]	$0	[redacted]	$0
2036	$0	[redacted]	$0	[redacted]	$0
2037	$0	[redacted]	$0	[redacted]	$0
2038	$0	[redacted]	$0	[redacted]	$0
2039	$0	[redacted]	$0	[redacted]	$0
2040	$0	[redacted]	$0	[redacted]	$0
2041	$0	[redacted]	$0	[redacted]	$0
2042	$0	[redacted]	$0	[redacted]	$0

[redacted]

Reference Case
High Regulatory
Market Driven Innovation
Decarbonization/Electrification
Continued High Inflation & Supply Chain Issues

Q&A

Portfolio Development

Matt Lind
Director, Resource Planning & Market Assessments
1898 & Co.

Existing Resource Options

CenterPoint Energy

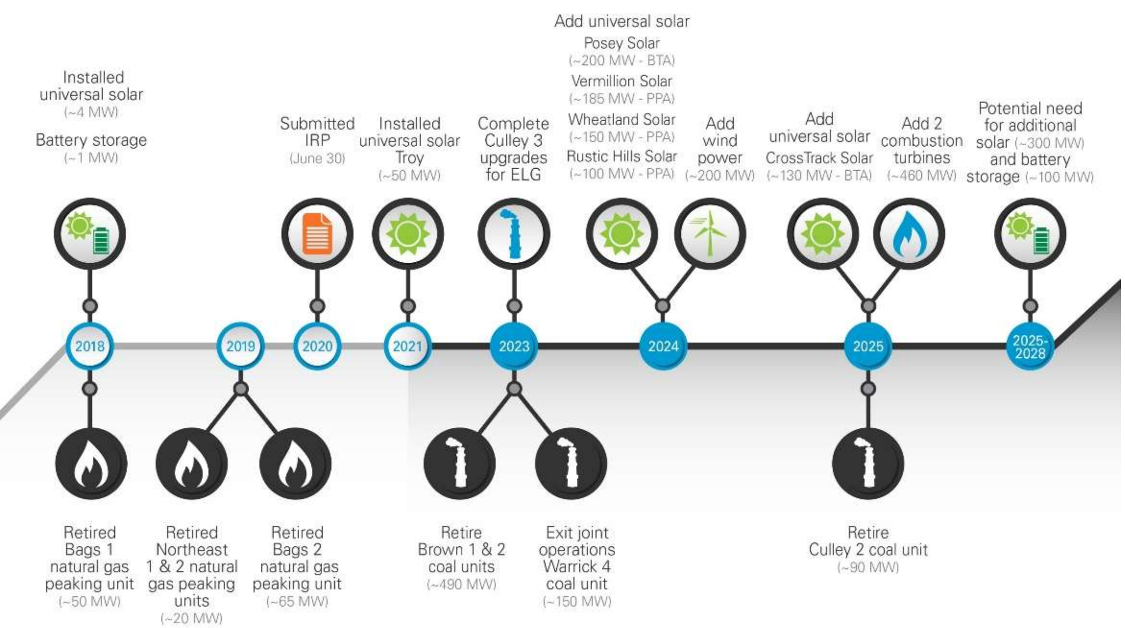
	Unit	Fuel	Retire 2023	Retire 2025	Retire 2030	Retire 2034	Natural Gas Conversion	BAU	PPA Expires 2028	PPA Expires 2030	PPA Expires 2038
Owned Resources	A.B. Brown 1	Coal	X								
	A.B. Brown 2	Coal	X								
	F.B. Culley 2	Coal		X*			X				
	F.B. Culley 3	Coal			X	X	X	X			
	Warrick 4	Coal	X	X							
	OVEC	Coal						X			
	A.B. Brown 3	Natural Gas			X	X		X			
	A.B. Brown 4	Natural Gas			X	X		X			
	A.B. Brown 5	Natural Gas						X			
	A.B. Brown 6	Natural Gas						X			
	Troy Solar	Solar						X			
	Posey Solar - BTA	Solar						X			
	Crosstrack Solar - BTA	Solar						X			
	Future Wind (200 MW) - BTA	Wind						X			
PPA's	Rustic Hills Solar -PPA	Solar						X			
	Knox County Solar - PPA	Solar						X			
	Vermillion County Solar - PPA	Solar									X
	Benton County Wind	Wind							X		
	Fowler Ridge Wind	Wind								X	

*Pending Indiana Department of Environmental Management approval

Draft Reference Case New Resource Options

Type	Resource	Start year	Model Starting Point Limitations	Installed Capacity
RE and Storage	Hydroelectric	TBD	2 units	
	Wind	2026	600 MW per year	200 MW
	Wind Plus Storage	2026	600 MW per year	50 MW wind (10 MW/40 MWh Battery)
	Solar Photovoltaic	2025	600 MW per year	10,50,100 MW
	Solar Plus Storage	2025	600 MW per year	50 MW PV (10 MW/40 MWh Battery)
	Lithium-Ion Battery Storage	2025	600 MW per year	10 MW / 40 MWh, 50 MW / 200 MWh, 100 MW / 400 MWh
	Long Duration Storage	2027	600 MW per year	300 MW / 3,000 MWh
Demand Side Management	V1 - Bundles broken by sector	2025-2027		
	V2 - Bundles broken by sector	2028-2030		
	V3 - Bundles broken by sector	2031-2042		
Coal	Supercritical with CCS	2030	Max 1 unit	500 MW
	Ultra supercritical with CCS	2030	Max 1 unit	750 MW
Combined Cycle	1x1 F Class CCGT Unfired	2027	Max 2 units	365 MW
	1x1 F Class CCGT Fired	2027	Max 2 units	363 MW
	1x1 G/H Class CCGT Unfired	2027	Max 2 units	431 MW
	1x1 G/H Class CCGT Fired	2027	Max 2 units	428 MW
	1x1 J Class CCGT Unfired	2027	Max 1 unit	551 MW
	2x1 J Class CCGT Fired	2027	Max 1 unit	1,101 MW
	Brown 5 & 6 Retrofit	2027	Max 1 unit	257 MW
Gas Turbine	1x F Class Frame SCGT	2026	Max 3 units	229 MW
	1x G/H Class Frame SCGT	2026		287 MW
	1x J-Class Frame SCGT	2026		372 MW
	Wartsila 20V34SG	2026	Max 3 units	54 MW
	Wartsila 18V50SG	2026	Max 3 units	108 MW
Co-Gen	22 MW Cogen	2026	Max 1 unit	22 MW
Nuclear	Small Modular Reactor	2029	TBD	TBD

IRP Portfolio Decisions



Bags = Broadway Avenue Gas Turbines
BTA = Build Transfer Agreement/Utility Ownership
ELG = Effluent Limitations Guidelines
MW = Megawatt
PPA = Power Purchase Agreement
IRP = Integrated Resource Plan

- FB Culley 2 & 3 conversion or retirement decision is a key part of this IRP.
- With MISO's shift to seasonal construct there is a capacity shortfall in 2024 prior to the CTs coming online and then in 2028 into the future.
- Will analyze a wide range of portfolios that provide insights around the FB Culley decision and the future resource mix.

Range of IRP Portfolios

- Business as Usual (Continue to run FB Culley 3 through 2042)
- Scenario Based Portfolios
  - Reference Case
  - High Regulatory
  - Market Driven Innovation
  - Decarbonization/Electrification
  - Continued High Inflation & Supply Chain Issues
- Replacement of FB Culley 2 & 3
  - Retire FB Culley 3 by 2030
    - Replace with non-thermal (Wind, Solar, Storage)
    - Replace with thermal (CCGT, CT)
  - Retire FB Culley 3 by 2034
    - Replace with non-thermal (Wind, Solar, Storage)
    - Replace with thermal (CCGT, CT)
  - FB Culley 2 or 3 gas conversion
  - FB Culley 2 & 3 gas conversion

Q&A

Draft Reference Case Modeling Results

Matt Lind
Director, Resource Planning & Market Assessments
1898 & Co.

Draft Modeling Results

- The incorporation of the IRA has delayed draft modeling results.
- A technical call has been scheduled for October 31st with those that have signed a NDA.
- Supplemental slides will be posted to the www.CenterPointEnergy.com/irp

Q&A

Appendix

Definitions

CenterPoint Energy

Term	Definition
ACE	Affordable Clean Energy (ACE) Rule, establishes emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants
All-Source RFP	Request for proposals, regardless of source (renewable, thermal, storage, demand response)
BAGS	Broadway Avenue Gas Turbine
BTA	Build Transfer Agreement/Utility Ownership
C&I	Commercial and Industrial
CAA	Clean Air Act
CAGR	Compound Annual Growth Rate
Capacity	The maximum output of electricity that a generator can produce under ideal conditions (megawatts)
CCGT	A combined-cycle power plant uses both a gas and a steam turbine together to produce up to 50 percent more electricity from the same fuel than a traditional simple-cycle plant. The waste heat from the gas turbine is routed to the nearby steam turbine, which generates extra power
CCR Rule	Coal Combustion Residuals Rule
CCS	Carbon Capture and Storage
CDD	Cooling Degree Day
CEI South	CenterPoint Energy Indiana South
CO_2	Carbon dioxide

Definitions Cont.

Term	Definition
CONE	Cost of New Entry
CPCN	A Certificate of Public Convenience and Necessity is required to be granted by the Commission for significant generation projects
CSAPR	Cross State Air Pollution Rule
DER	Distributed Energy Resource
Deterministic Modeling	Simulated dispatch of a portfolio in a determined future. Often computer generated portfolios are created by optimizing on cost to the customer
DLC	Direct Load Control
DR	Demand Response
DSM	Demand side management includes both Energy Efficiency and Demand Response programs to reduce customer demand for electricity
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines are U.S. national standards for wastewater discharges to surface waters and publicly owned treatment works
EnCompass	Electric modeling forecasting and analysis software
Energy	Amount of electricity (megawatt-hours) produced over a specific time period

Definitions Cont.

Term	Definition
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GW	Gigawatt (1,000 million watt), unit of electric power
GWh	Gigawatt Hour
HDD	Heating Degree Day
Henry Hub	Point of interconnection of interstate and intrastate natural gas pipelines as well as other related infrastructure in Erath, Louisiana
IDEM	Indiana Department of Environmental Management
Installed Capacity (ICAP)	Refers to generating capacity after ambient weather adjustments and before forced outages adjustments
Intermittent	An intermittent energy source is any source of energy that is not continuously available for conversion into electricity and outside direct control
IRP	Integrated Resource Plan is a comprehensive plan to meet customer load expectations
IURC	The Indiana Utility Regulatory Commission is the public utilities commission of the State of Indiana. The commission regulates electric, natural gas, telecommunications, steam, water and sewer utilities
KWh	Kilowatt Hour

Definitions Cont.

CenterPoint Energy

Term	Definition
LCOE	Levelized Cost of Energy, A measure that looks at cost and energy production over the life of an asset so different resources can be compared. Does not account for capacity value.
LMR	Load Modifying Resource
Local Clearing Requirement (LCR)	Capacity needs to be fulfilled by local resource zone
LRZ6	MISO Local Resource Zone 6
MATS	Mercury and Air Toxics Standard
Mine Mouth	At the mine location
MISO	Midcontinent Independent System Operator, an Independent System Operator (ISO) and Regional Transmission Organization(RTO) providing open-access transmission service and monitoring the high-voltage transmission system in the Midwest United States and Manitoba, Canada and a southern United States region which includes much of Arkansas, Mississippi, and Louisiana. MISO also operates one of the world's largest real-time energy markets
MMBTU	Million British Thermal Units
MPS	Market potential study - Determines the total market size (value/volume) for a DSM at a given period of time
MSA	Metropolitan Statistical Area
MW	Megawatt (million watt), unit of electric power
NAAQS	National Ambient Air Quality Standards

Definitions Cont.

Term	Definition
Name Plate Capacity	The intended full-load sustained output of a generation facility
NDA	Non-Disclosure Agreement
NOI	Notice of Intent
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPVRR	Net Present Value Revenue Requirement
NSPS	New Source Performance Standards
OMS	Organization of MISO States, was established to represent the collective interests of state and local utility regulators in the Midcontinent Independent System Operator (MISO) region and facilitate informed and efficient participation in related issues.
Peaking	Power plants that generally run only when there is a high demand, known as peak demand, for electricity
Planning Reserve Margin Requirement (PRMR)	Total capacity obligation each load serving entity needs to meet
Portfolio	A group of resources to meet customer load
PPA	Purchase Power Agreement

Definitions Cont.

Term	Definition
Preferred Portfolio	The IRP rule requires that utilities select the portfolio that performs the best, with consideration for cost, risk, reliability, and sustainability
Probabilistic modeling	Simulate dispatch of portfolios for a number of randomly generated potential future states, capturing performance measures
PV	Photovoltaic
RA (Resource Adequacy)	RA is a regulatory construct developed to ensure that there will be sufficient resources available to serve electric demand under all but the most extreme conditions
RAP	Realistic Achievable Potential
Resource	Supply side (generation) or demand side (Energy Efficiency, Demand Response, Load Shifting programs) to meet planning reserve margin requirements
SAC	Seasonal Accredited Capacity
Scenario	Potential future State-of-the-World designed to test portfolio performance in key risk areas important to management and stakeholders alike
SDE	Spray Dryer Evaporator
Sensitivity Analysis	Analysis to determine what risk factors portfolios are most sensitive to
SIP	State Implementation Plan
Spinning Reserve	Generation that is online and can quickly respond to changes in system load

Definitions Cont.

Term	Definition
T&D	Transmission and Distribution
Technology Assessment	An analysis that provides overnight and all-in costs and technical specifications for generation and storage resources
Unforced Capacity (UCAP)	A unit's generating capacity adjusted down for forced outage rates (thermal resources) or expected output during peak load (intermittent resources)
VAR Support	Unit by which reactive power is expressed in an AC electric power system
ZLD	Zero Liquid Discharge

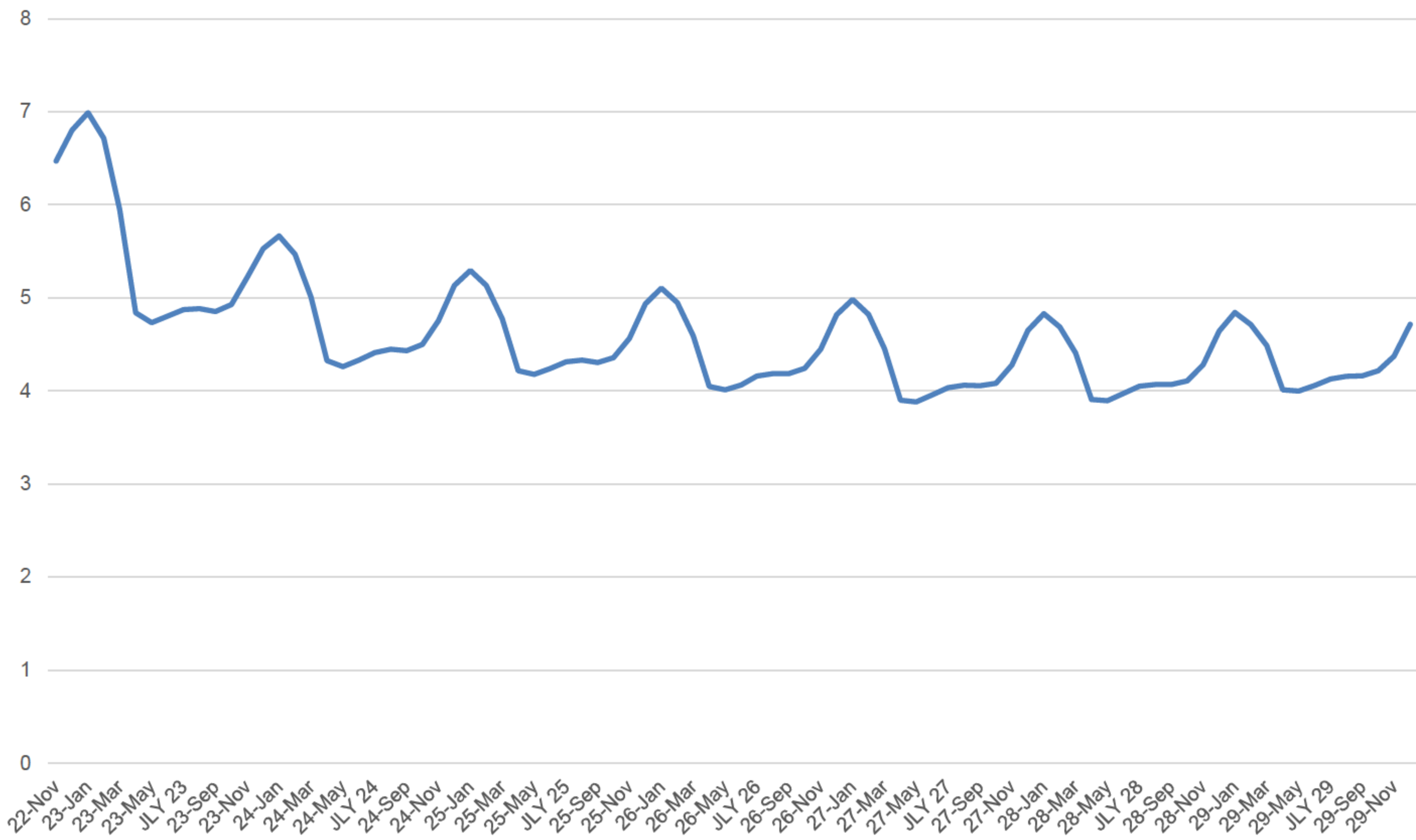
Timeline for Updating Forecasts

CenterPoint Energy

- CEI South will incorporate updates into the modeling that are received by mid November. Additionally, CEI South is considering updating near term gas costs based on NYMEX per stakeholder feedback.

Vendor Name	Future Updates
ABB Hitachi	Hitachi is currently targeting a mid-Nov release for the Fall 2022 Power Reference Case that will incorporate major clean energy and transportation related provisions under the Inflation Reduction Act of 2022.
EVA Inc	Updates were delivered in September.
S&P Global	The Q3 2022 Power Forecast will be available on October 19th, 2022.
Wood Mac	The next LTO will be in November 2022.

NYMEX Futures as of 10/3/22



CenterPoint 2022 IRP
2nd Stakeholder Meeting Minutes Q&A
October 11, 2022, 9 am – 3 pm CDT

Richard Leger (Senior Vice President, CenterPoint Energy) – Welcome, Safety Message

Matt Rice (Director, Regulatory and Rates, CenterPoint Energy) – Discussed the meeting agenda, guidelines for the meeting, discussed updates from the last stakeholder meeting including feedback, and the proposed 2022/2023 IRP and stakeholder process.

- Slide 10 Capacity Change:
  - Question: How are the capacity factors for renewable energy resources being incorporated? What are the capacity factors in the model considering projected capacity shortfall?
    - Response: When we get to the ELCC conversation, we will see how these numbers are projected. We will work to incorporate new information into our model as it is provided from MISO.
- Slide 18 Updated IRP Draft Objectives & Measures:
  - Question: Does that CO_2 include all the upstream emissions of methane?
    - Response: We are considering stack emissions. This does not include any potential upstream. We looked at this in the last IRP, and the differentiation among competing portfolio results was not meaningful. For this reason, we chose not to do a lifecycle analysis again.
  - Question: Are you going to include non-CO_2 GHG emissions in your total emissions count?
    - We will model CO_2 equivalent to capture those additional emissions.
- Slide 18 Industrial DR:
  - Question: Could we figure out a sensitivity to see if other economical Demand Response potential could be picked up?
    - Response: We will continue to have this conversation. Our team has been actively talking to our industrial customers asking what it would take to "move the needle" for participation. We do feel that 25 MW may be pushing the envelope, but we can talk about adding another sensitivity to the analysis.
- General Section Questions:
  - Question: Will CenterPoint reconsider the CTs or the decision made to extend the life of the coal plant(s)? Will the scorecard and cost risk reflect the inclusion of the CTs and the coal units?
    - Response: Yes. The measure calculations on the score card will reflect the full resource portfolio. We have made the decision to move forward with the CTs.

Drew Burczyk (Consultant, Resource Planning & Market Assessments, 1898 & Co.) – Discussed the Request For Proposals (RFP) update including the impact of the IRA on pricing for CenterPoint's RFP.

- Slide 27 – 28 IRA Updates:
  - Question: There is a conflict on October 31st. Can we move the draft results discussion on that day?
    - Response: Yes. We will update the timing.
  - Question: Regarding cost savings due to tax credits, is that for CenterPoint or the bidder? How is the savings reflected in the process?
    - Response: If the bid was a purchase option, the purchase price would remain essentially the same. Any changes to the tax credit would result in a savings for CenterPoint's customers. If we model a purchase option, we would plan on CenterPoint fully monetizing that tax credit which would result in a tax decrease. [The savings would be passed back to customers.]

Kyle Combes (Project Manager, Resource Planning & Market Assessments, 1898 & Co.) – Discussed the 2022 IRP Draft Resource Inputs, seasonal accreditation, technical assessment, and cost curves.

- Slide 34 Solar Seasonal Shapes
  - Question: Regarding the solar curve, is that fixed south facing? I would like to suggest that it would match up much better if you modeled west facing panels and bi-facial.

- Response: This profile is actual data from the Troy solar farm which does have single axis tracking. There is always a balance or tradeoff depending on the orientation of panels.

- Slide 36 Thermal Seasonal Shapes
  - Question: Can we consider how often thermal units are offline when considering thermal units? Possibly consider MISO data on thermal units.
    - Response: MISO uses a class average EFOR (Equivalent Forced Outage Rate) for new resources. If existing resources are called on and cannot meet demand, they will get docked for that. If you have a major outage that lasts several months, that will affect your accreditation for years to come until you can prove reliability. This will be considered with the planning reserve margin. There is a distinction in the availability due to a planned or unplanned outage. We are focused on the unplanned outage in our modeling.
- Slide 40 Balance of Loads and Resources (BLR)
  - Question: Do you plan to keep Culley 2/3 online until 2042?
    - Response: Not necessarily. [We plan to retire Culley 2 in 2025.] We will consider Culley 3 retirement at different junctions, as well as a natural gas conversion. This slide includes a representation of resources without retirements included and is not indicative of our plan.
- Slide 45 Technology Assessment
  - Question: A number of the thermal bids are for existing plants, and we did not get bids for all types of alternatives. How will you create cost assumptions for those?
    - Response: A technology assessment was developed for this IRP. We will utilize costs from this assessment for technologies where we did not receive bids in the RFP.
- Slide 46 Technology Assessment
  - Question: Have we considered iron oxide batteries?
    - Response: There are a couple pilot projects we are following. We will incorporate that in future IRPs as it becomes more proven and feasible.

<u>Michael Russo</u> (Senior Forecast Consultant, Itron) – Discussed portfolio forecasts.

- Slide 56 Model Estimation:
  - Question: I was under the impression that Evansville is moving to LED streetlights. Is that the case and how far along are they on this plan? Why are we using 8-year-old data if we are transitioning to LEDs?
    - Response: Streetlighting sales are declining in the model, which reflects the gradual incorporation of LEDs. There are certain sections that have been replaced. Relative to other forecasts, street lighting is a very small load. Each year, we replace a set number of streetlights with LEDs as they need to be replaced.
- Slide 57 Residential Average Use Model:
  - Question: Are you taking the IRA into account in the residential model? Does the utility have any plans to promote or encourage customers to take advantage of these IRA incentives?
    - Response: Currently, we do not have a way of accounting for the IRA in the residential use model until next year when the EIA updates their model. We are still trying to figure out exactly how this process will look in the future.
- Slide 58 Residential Forecast Drivers:
  - Question: The Annual Energy Outlook (AEO) 2022 incorporated impacts of demand side efficiency, and it was prepared before the IRA. How are you thinking about that prior to the release of the AEO 2023?
    - Response: Those estimates do not include the impact of the IRA. They don't do any midterm update. This information wouldn't capture the IRA's effects until next year's release. [We are using the best information that we have available for the forecast.]
- Slide 62 Customer Photovoltaics:
  - Question: Can we see the methodology behind the Residential Payback graph?
    - Response: We can follow-up on a Tech-to-Tech call or an individual meeting.
  - Slide 69 Assumptions:
  - Question: Do you know if the assumptions for increased adoption on clothes dryers and electric water heater also captures some assumptions about heat pump variance?

- Response: There is not a specific heat pump electric water heater in the information we receive from the federal government.

- General Section Questions:
  - Question: How do emerging technologies affect our evaluation of energy use (specifically from EVs)?
    - Response: We don't make a distinction of the vehicle and how it will be charged. We include an estimated kWh per vehicle, and we don't make a distinction as to where those kWh's come from.
  - Question: The heating efficiency on the electric side is based on resistance heating. Is that the case?
    - Response: In the AEO, there is resistance heat which has no efficiency improvement. There are efficiency improvements for air-source and ground-source heat pump. The saturations are growing faster than intensity.

Brian Despard (Project Manager, Resource Planning & Market Assessments, 1898 & Co.) – Discussed the probabilistic modeling approach and assumptions including inputs.

- General Section Question:
  - Question: How do you come up with standard deviations around the load forecast? Are each of the cases equally probable?
    - Response: We are taking the standard deviation from a mix of the various runs.

Matt Lind (Director, Resource Planning & Market Assessments, 1898 & Co.) – Discussed portfolio development including existing resources and draft alternatives resources.

- Slide 86 Existing Resource Options:
  - Question: Did you think about repowering Benton County?
    - Response: CenterPoint has a PPA for this location. Since CenterPoint does not own Benton County, the decision to repower it is out of our control.
- Slide 87 Draft New Resource Options:
  - Question: How are you coming up with the capacity for the new coal resources?
    - Response: We didn't receive a bid for coal with carbon capture from the RFP. The Technology Assessment, developed by 1898 at Burns & McDonnell will be utilized for this option.
  - Question: Regarding hydroelectric, there has never been any discussion of that. Is there any discussion that we are unaware of?
    - Response: Hydroelectric was considered in the last IRP. Hydroelectric is still an option that will be selectable for portfolio development.
  - Question: Is the long duration storage option you have included the compressed air proxy?
    - Response: Correct.
  - Question: There is a start year of 2027 for long duration storage. What made you choose that?
    - Response: Development time. Making sure it would be available. We didn't receive any RFP bids prior to that year.
- General Section Questions:
  - Question: Are you all taking into consideration the cost of OVEC to CenterPoint customers? What's the plan to get rid of OVEC?
    - Response: From a modeling standpoint, the cost associated with OVEC is included. However, under the agreement, we are not obligated to cover any additional costs. The contract doesn't provide for us to have to bear additional costs. We have evaluated the contract, but we do have contractual commitments.
  - Question: Are the costs that you are modeling include transportation of the pipeline and to the point of injection for carbon capture and storage (CCS)? Are you talking about any potential areas of injection?
    - Response: Yes, that would be the equipment to have those units capture and store the carbon emissions. Not additional pipelines. We will write that down as a topic for discussion.

Matt Lind – Discussed when draft modeling results will be presented.

Open Q&A Session

- Question: Regarding methane emissions, there's a substantial fee for those from the IRA. Have you figured this into your methane cost projections?
    - Response: We are working to get updated assumptions from multiple vendors. We will be leveraging newer gas price forecast over the next few months for inclusion in final modeling.
- Comment: Stakeholders wants to see a portfolio where there are no CTs being built in the future.
- Question: How can we sign the NDA?
    - Response: Please send an email to the IRP@centerpointenergy.com, and CenterPoint will send the NDA to be signed by the stakeholder.

Comments of CAC on CenterPoint's Second 2022-2023 IRP Stakeholder Workshop

Submitted to CenterPoint on October 26, 2022

Comments on CenterPoint's Second 2022 IRP Stakeholder Workshop and Technical Meeting

Citizens Action Coalition of Indiana ("CAC") submits these comments on the materials presented and issues discussed during CenterPoint's October 11, 2022, Integrated Resource Plan ("IRP") stakeholder workshop.

1 General Stakeholder Process

CAC would like reiterate its request that CenterPoint:

- Provide to CAC the full bid proposals received in response to its 2022 request for proposals at its earliest convenience.
- Use an online data sharing platform (e.g., Drop Box, Sharefile, etc.) to provide IRP data files to stakeholders who have executed NDAs.
- Commit to providing its data inputs and modeling files to stakeholders on a schedule that permits stakeholders to provide feedback and gives CenterPoint sufficient time to be able to incorporate that feedback.

We would like to provide feedback on the stochastic modeling and the translation of the RFP data into new build inputs but we need access to the spreadsheets underlying the information presented at the stakeholder meeting to do so.

2 New Resources Modeled

Solar and Battery Storage Resources

In the workshop, CenterPoint presented information related to the candidate resources that would be offered for selection within EnCompass. We would like to offer a recommendation to CenterPoint related to the number of solar and battery storage resources offered to the model. Table 1 below shows the different solar and battery storage resources with the corresponding MW sizes that CenterPoint indicated would be offered within EnCompass.

Table 1. Candidate Solar and Battery Storage Resources Presented by CenterPoint

	MW Size
Solar	10
Solar	50
Solar	100
Battery Storage	10
Battery Storage	50
Battery Storage	100

We recommend that CenterPoint select one solar and one battery storage resource (i.e. the 100 MW solar and the 100 MW battery) for modeling in EnCompass. Rather than set up six different resources, CenterPoint could utilize the partial unit project input within EnCompass to allow the model to select partial units to determine the optimal size of any new solar or battery storage resources. This would also benefit the run time of the model by reducing the number of new resources evaluated.

If CenterPoint would like to evaluate the addition of smaller scale solar and battery storage resources, we recommend that CenterPoint consider modeling these as specific projects under 5 MW that could qualify for the Low Income Communities projects under the IRA.

Multiday Storage and SMR

During the stakeholder workshop held on October 11, 2022, CenterPoint was asked by a stakeholder about modeling iron air battery storage for this IRP. It is our understanding that CenterPoint is not moving forward with modeling multiday storage, such as Form Energy's iron air battery, due to CenterPoint's concerns about commercial viability. However, this seems to be in contrast with the reported first year available date for the SMR resources, which CenterPoint indicated would be 2029. There are significant hurdles for the SMR resources to overcome to be commercially viable, and we see that technology as having substantially more risk when compared to the iron air battery technology. Furthermore, 2029 is an implausible date for SMR resources to come online to serve CenterPoint customers, given NuScale's first-of-its-kind SMR deployment is not planned to come online in Idaho until 2029 at the earliest. We recommend that CenterPoint consider modeling multiday storage as a selectable resource within EnCompass and push back the year by which SMRs could be selected to 2035 or later. We are happy to provide feedback on information we have used to represent multiday storage within EnCompass.

Long Duration Storage

During the workshop, we heard 1898 say that compressed air storage is the proxy technology for the long-duration option that is being modeled. Why is CenterPoint chosing that technology over lithium ion for the duration being modeled?

3 Build Constraints

During the workshop, we heard 1898 staff say that no annual or lifetime binding build constraints will be used in the capacity expansion modeling. We think this is a good approach that recognizes how very difficult it is to predict the pipeline of potential projects available to CenterPoint throughout the entirety of the planning period.

4 Demand-Side Impacts of the IRA

As CenterPoint knows, the availability of income-qualified rebates enacted through the IRA depends on the state of Indiana writing the appropriate rules governing their eligibility. Given the rate of poverty in CenterPoint's service territory, e.g., Evansville's rate of 21%, there are significant numbers of CenterPoint ratepayers who would depend on the state's ability to write these rules to benefit from the efficiency, heat pump, and other measure rebates in the law. Has CenterPoint begun talking with the Office of Energy Development about writing those rules? Has CenterPoint offered to help, i.e., by providing technical assistance?

5 Wind Repowering

Given the long delays in the generation interconnection process in MISO, we would strongly recommend that CenterPoint evaluate the option of repowering the Benton County and Fowler Ridge wind farms rather than assuming they are rolled off the system. Repowering can involve just increasing rotor length or increasing rotor length *and* hub height. The former may not increase the capacity of the projects, but it can increase the capacity factor, can be PTC-eligible, and could be more cost-effective than building a new wind project while the latter would increase nameplate capacity as well. We understand that CenterPoint does not own these farms, but if their lives are extended, an offtaker will still be needed and CenterPoint, as one of the current offtakers, is an obvious candidate. Evaluating this option would be consistent with the purpose of evaluating new build options in the IRP and we would not expect that new wind builds could substitute because of the difference in cost.

6 Coal with CCS

To recap comments that were offered during the workshop, if the modeling happens to pick coal with CCS, we would ask CenterPoint to give broad indications of where the captured CO_2 would be stored, and whether it can acquire much larger quantities of coal and cooling water to accommodate similar levels of generation given the large parasitic loads associated with capture, solvent regeneration, compression, and heating of the CO_2 stream and the increased cooling needs those loads imply.

7 Capacity Cost Curves

The capacity cost curves for solar, wind, and battery storage show the same assumed pricing for both the Reference and Low cases through approximately 2030 (slides 48-50) but not for natural gas combined cycle (slide 51), which shows distinguishable cost trajectories under the Low and Reference cases. CAC requests that CenterPoint model faster cost declines through 2030 in the Low case compared to the Reference case for solar, wind, and battery storage, as it is definitely possible (as the past decade has illustrated) for these technologies to have cost declines that are much more rapid than analyst projections. For instance, recent cost increases experienced in 2022 could be alleviated in the near to mid-term if supply chain pressures are alleviated or based on other macroeconomic factors.

Furthermore, if these curves include the IRA rebates we would expect that cost to increase in roughly 2035 given the 2032 sunset date for these incentives and the ability to safe harbor project costs and extend the online date eligibility for these incentives. However, we question whether project costs would simply stabilize in real terms after this time. Deployment-led innovation has demonstrated that mass deployment of modular generating technologies over time leads to continued cost declines, absent external shocks (e.g., the COVID-19 pandemic contributing to short-term supply chain constraints; the Russian invasion of Ukraine impacting global energy markets). It is not realistic to assume in this IRP that historic trends of large cost declines in solar, wind, and battery storage technologies will not continue past 2030 or even 2035, particularly given the Reference case prices in the 2030s selected by CenterPoint significantly exceeds the moderate NREL ATB scenario.

8 OVEC

CAC requests that CenterPoint model options for exiting the OVEC contract at earlier dates, such as 2025 and 2030, and to model only economic commitment of the plants (i.e., no must-run designation). CenterPoint should take action to protect its customers from the continued uneconomic purchases from the OVEC contract, including reaching out to other OVEC parties to explore options to retiring the plants early, exiting the agreement, or reducing plant operations. This IRP is the appropriate venue to model alternatives to OVEC and the potential benefits of those alternatives to CenterPoint customers. CenterPoint should clearly state its basis for assumed exit costs, with reference to contractual provisions and actual cost data underlying its assumptions.

CAC Data Request Set 1 to CEI South
CEI South 2022/2023 IRP Response
November 16, 2022

1.1 During the workshop, we heard 1898 say that compressed air storage is the proxy technology for the long-duration option that is being modeled. Why is CenterPoint choosing that technology over lithium ion for the duration being modeled?

Response: The energy storage market is rapidly evolving. Long duration is not a defined term, but it is generally assumed to be >4 hour discharge duration. Several non-lithium technologies may become competitive for long duration energy storage(LDES) in the future. While it is technically achievable for multiple 4-hour lithium-ion battery systems to be controlled to behave similarly to a longer duration technology, the unit cost ($/kWh) for lithium-ion remains relatively flat for longer duration applications. For this IRP we are modeling 4-hour lithium-ion batteries but are not limiting the number of resources selected, therefore multiple 4-hour lithium-ion batteries could be selected if a need for longer durations was identified by the model.

There are numerous technologies of varying commercial and technical maturity, and while CenterPoint recognizes the desire for technology diversity, a single representative technology was selected to represent the broader category of LDES. Compressed air energy storage (CAES) is a maturing technology that is suitable for large, utility scale projects. While CAES will be limited in implementation depending on certain geologic characteristics, it generally represents the lower end of today's LDES capital cost range and is therefore a suitable technology for resource planning models. CAES is generally considered a more commercially and technically mature technology than other known long duration storage options. CenterPoint will continue to evaluate emerging technologies and may include other technology(ies) in future resource planning cycles.

CAC Data Request Set 1 to CEI South
CEI South 2022/2023 IRP Response
November 16, 2022

1.2 Has CenterPoint begun talking with the Indiana Office of Energy Development about writing the rules that would govern eligibility for income-qualified rebates offered via the IRA? Has CenterPoint offered technical assistance?

Response: CEI South has not had discussions with the Indiana Office of Energy Development about income-qualified rebates regarding the IRA.

Sierra Club Data Request Set 1 to CEI South Dated November 16, 2022
CEI South 2022/2023 IRP Response
December 8, 2022

1.1 Please provide the forced outage rate for existing generation units for the last ten years.

Response:

	A.B. Brown 1	A.B. Brown 2	A.B. Brown 3	A.B. Brown 4	F.B. Culley 2	F.B. Culley 3	Warrick 4[1]
2013	3%	5%	0%	0%	1%	2%	11%
2014	4%	11%	7%	6%	10%	1%	12%
2015	2%	11%	0%	0%	5%	1%	5%
2016	35%	2%	2%	12%	3%	32%	17%
2017	1%	1%	14%	0%	7%	1%	13%
2018	4%	1%	2%	26%	1%	4%	12%
2019	1%	2%	0%	0%	2%	4%	13%
2020	3%	6%	24%	69%	4%	1%	6%
2021	1%	1%	1%	17%	10%	0%	10%
2022	6%	4%	9%	1%	13%	56%	16%

Note: 2022 values through November

1 – Warrick 4 is operated by Alcoa

1.2 Please explain why, in the EnCompass input files, Culley unit 3 is de-rated from 100% capacity accreditation to lower capacity accreditation values during 2023-2026.

Response: When calculating values for seasonal accreditation for Culley 3 it was assumed that the current outage for boiler feed pump repairs would be 6 months in duration. When determining seasonal accreditation MISO utilizes the 3 most recent years of historical information (September 1st ending August 31st) leading up to the upcoming planning year so this event will impact the accreditation of Culley 3 to varying degrees for the next 4 planning years.

Sierra Club Data Request Set 1 to CEI South Dated November 16, 2022
CEI South 2022/2023 IRP Response
December 8, 2022

1.3 Please explain why, other than years 2023-2026, Culley unit 3 is assigned 100% capacity credit for its 270 MW of nameplate capacity.

Response: As MISO has worked to implement the seasonal construct information\processes have been updated and evolved. Many of these changes have occurred during the time period that CEI South is conducting its IRP analysis. When accreditation assumptions were initially developed for IRP modeling the latest available information\processes from MISO were utilized which resulted in full accreditation for Culley 3. Accreditation assumptions are currently being updated for IRP modeling using the latest information from MISO and will be updated within the EnCompass model.

1.4 Please provide the workbook the Company used to calculate fixed costs in EnCompass for coal and natural gas resources (ABB5+6, ABB7, FBC2, FBC2 on gas, FBC3, FBC3 on gas).

Response: The file used to calculate fixed costs is still in draft format but CEI South is targeting a release of this information to stakeholders that have signed an NDA on December 20th. This information will be provided at that time. Note that modeling inputs, including cost information, are updated as modeling progresses and could change moving forward.

1.5 Please provide the workbook the Company used to calculate the overnight capital costs for ABB7.

Response: Please see file 2022.12.07 - SC CC Conversion TA.xlsx. Note that technology assessment data is an estimate for modeling purposes and is not a detailed bid for construction.

CenterPoint IRP Tech to Tech Modeling Update

October 31, 2022

Tech to Tech Overview

- Content presented today, or provided following this meeting as part of this Tech to Tech series, is confidential and cannot be shared with individuals who have not signed an **NDA** as part of this IRP process.
- A summary of non-confidential slides presented today will be posted to the IRP website.
- These are DRAFT results. These files are being provided to facilitate ongoing modeling discussions and gather input.

Agenda

- Purpose
- Timeline
- Model setup
- Updates to be made
- Preliminary Reference Case Portfolio

Tech to Tech Meeting Purpose

- The intent of this meeting is to:
  - Share the status of the IRP modeling process
  - Provide draft EnCompass Modeling files following the meeting
  - Demonstrate and gather feedback on model setup or big picture modeling assumptions
- The content shared as part of this meeting is NOT:
  - Final - there are numerous updates to be made to the model
  - The preferred portfolio. The resources being selected will likely change as inputs are refreshed and before draft scenario results are presented at the next stakeholder meeting.

Modeling Timeline

Begin Modeling

Gather draft inputs and begin inputting data into model

Q3 2022

We are here

Draft Portfolios

Draft scenario optimization runs and updated inputs for 3rd stakeholder meeting

Dec. 2022

Preview Preferred Portfolio

Final reference case modeling, risk analysis results, and preferred portfolio presented at final stakeholder meeting

March 2023

File IRP

IRP to be filed in June 2023

June 2023

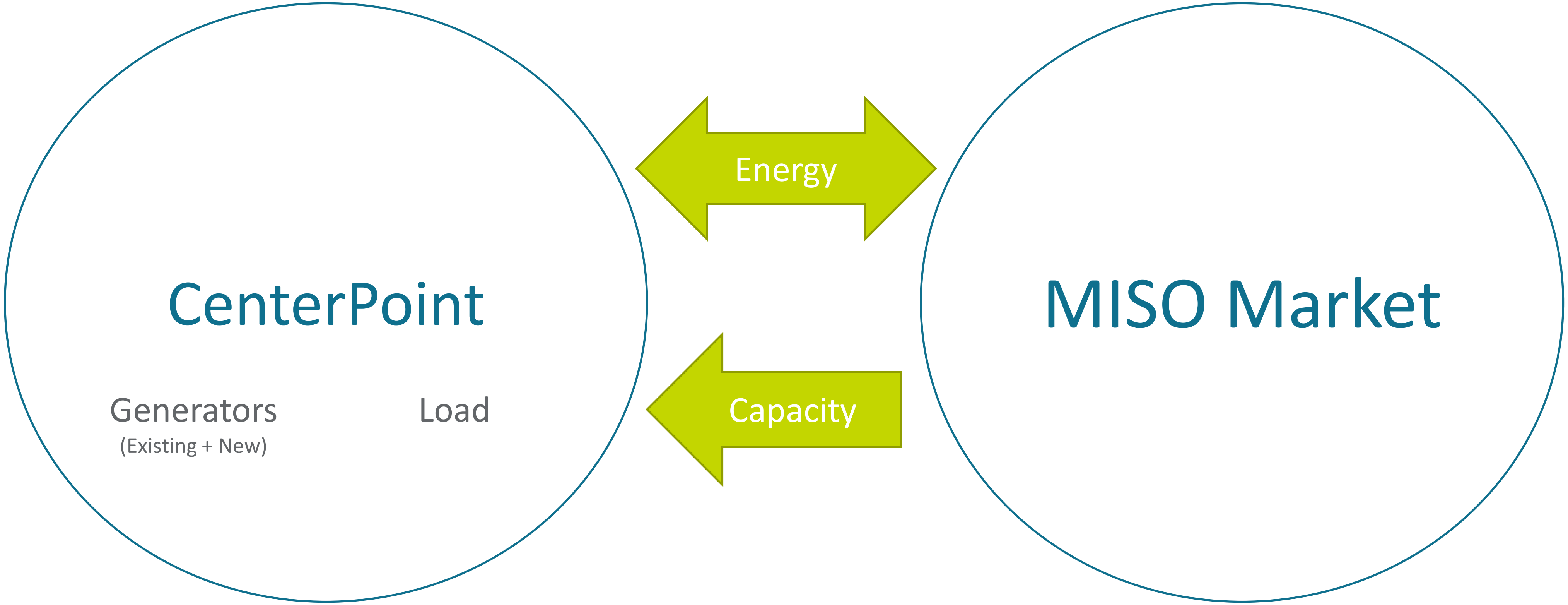
Model sharing

We are sharing the model earlier in the process to get input and feedback. However, there will be updates, we are early in modeling process.

Main Modeling Updates Coming

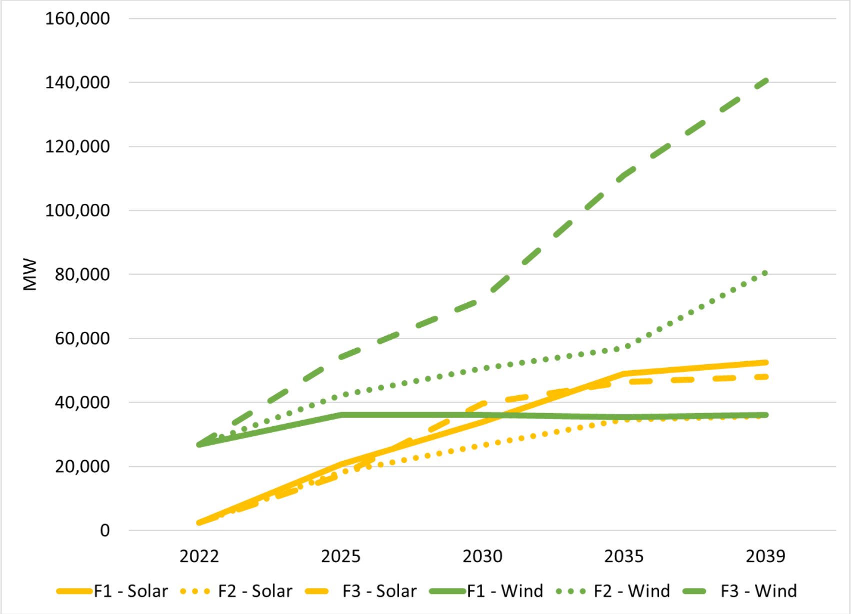
- Commodity/pricing updates
  - Gas
  - Coal
  - Technology assessment
  - Natural gas conversion estimates
- Development of updated market prices
- Renewable tax credit monetization
- Continued input review
- Feedback from stakeholders
- Scenario optimization runs

System Overview - During Capacity Expansion



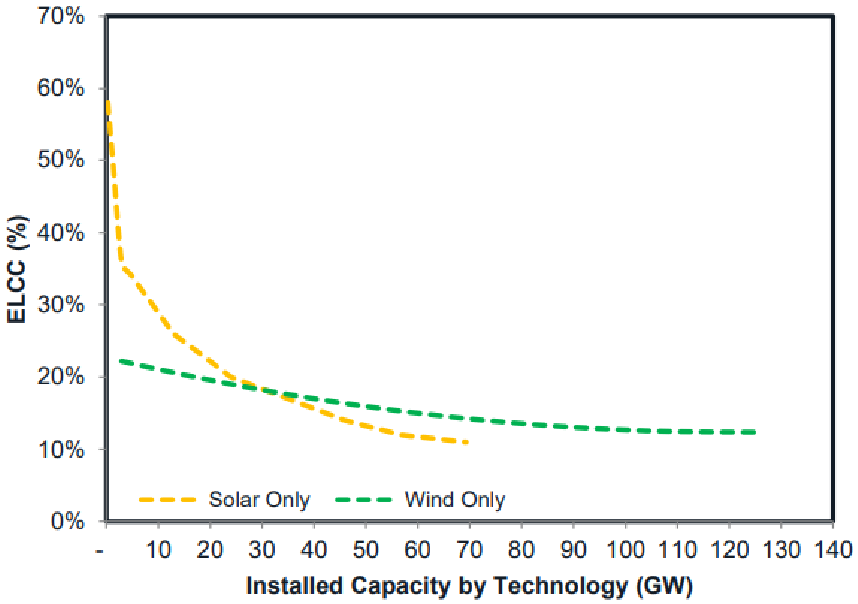
MISO Renewable Penetration Trends

MISO Installed Renewable Capacity



https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf

Effects of increasing installations

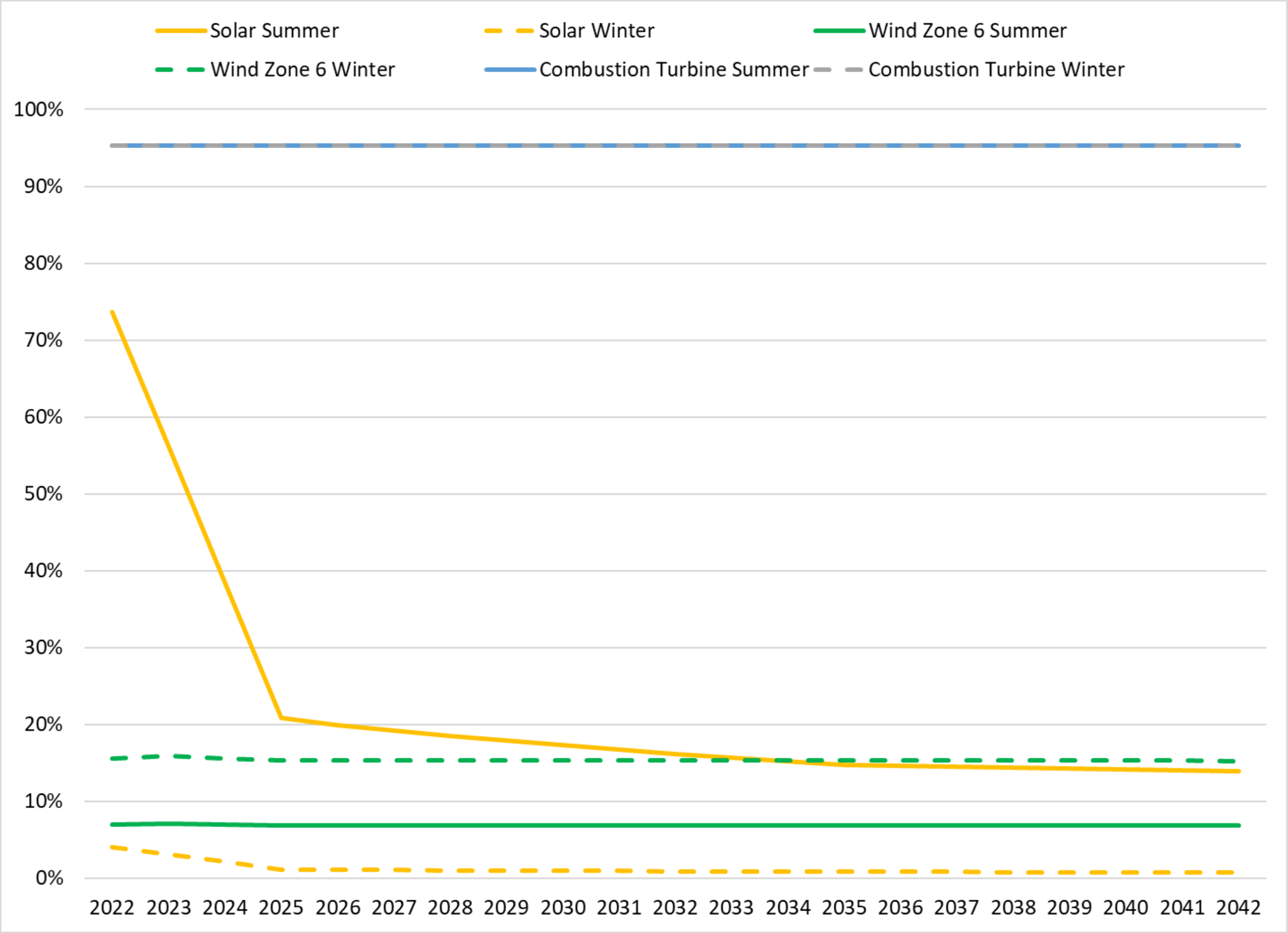


https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v6301579.pdf

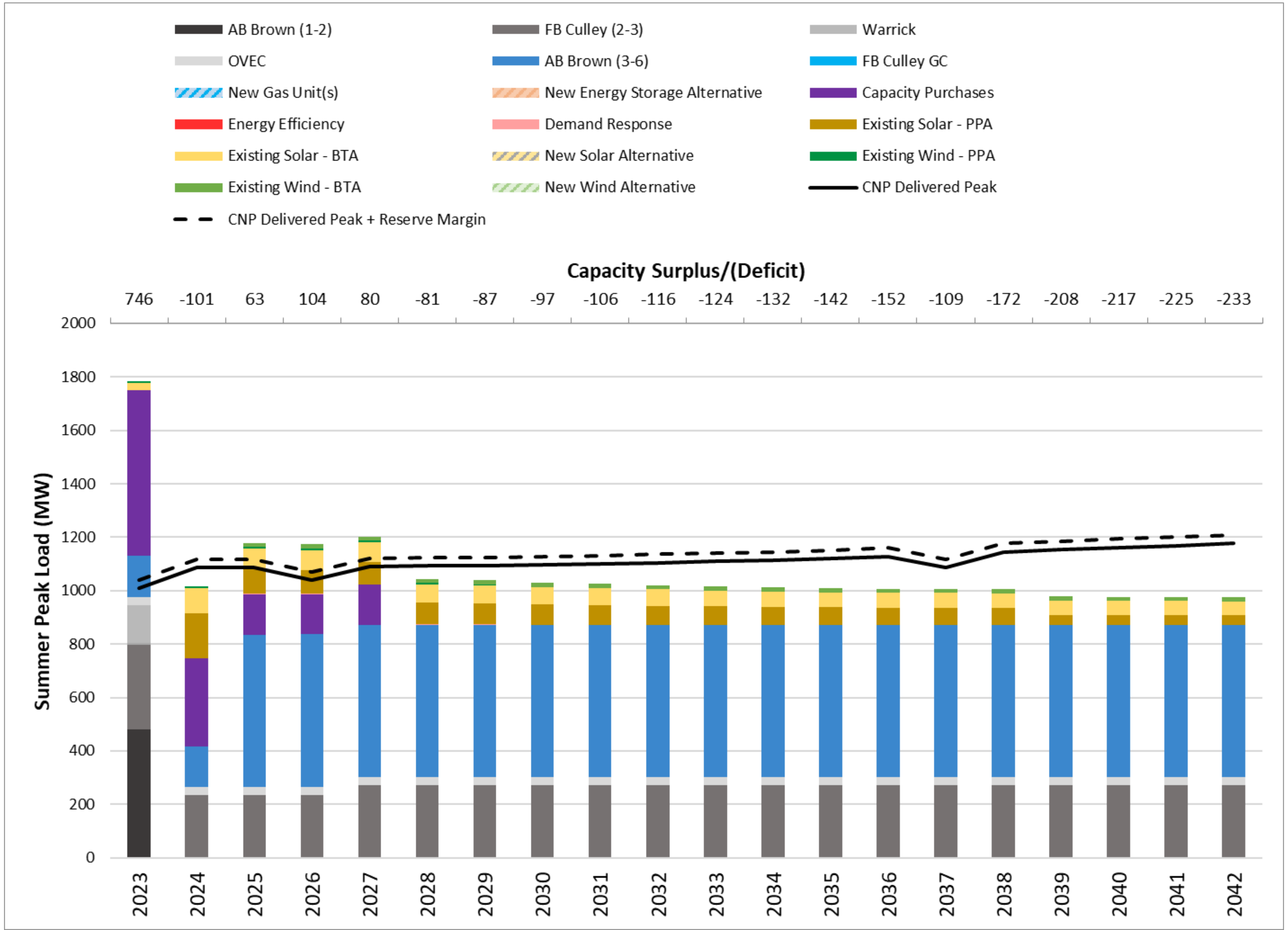
As installed capacity (ICAP) goes … Accreditable capacity (UCAP) goes

ELCC – Effective Load Carrying Capability

Draft Projected Seasonal Accreditation

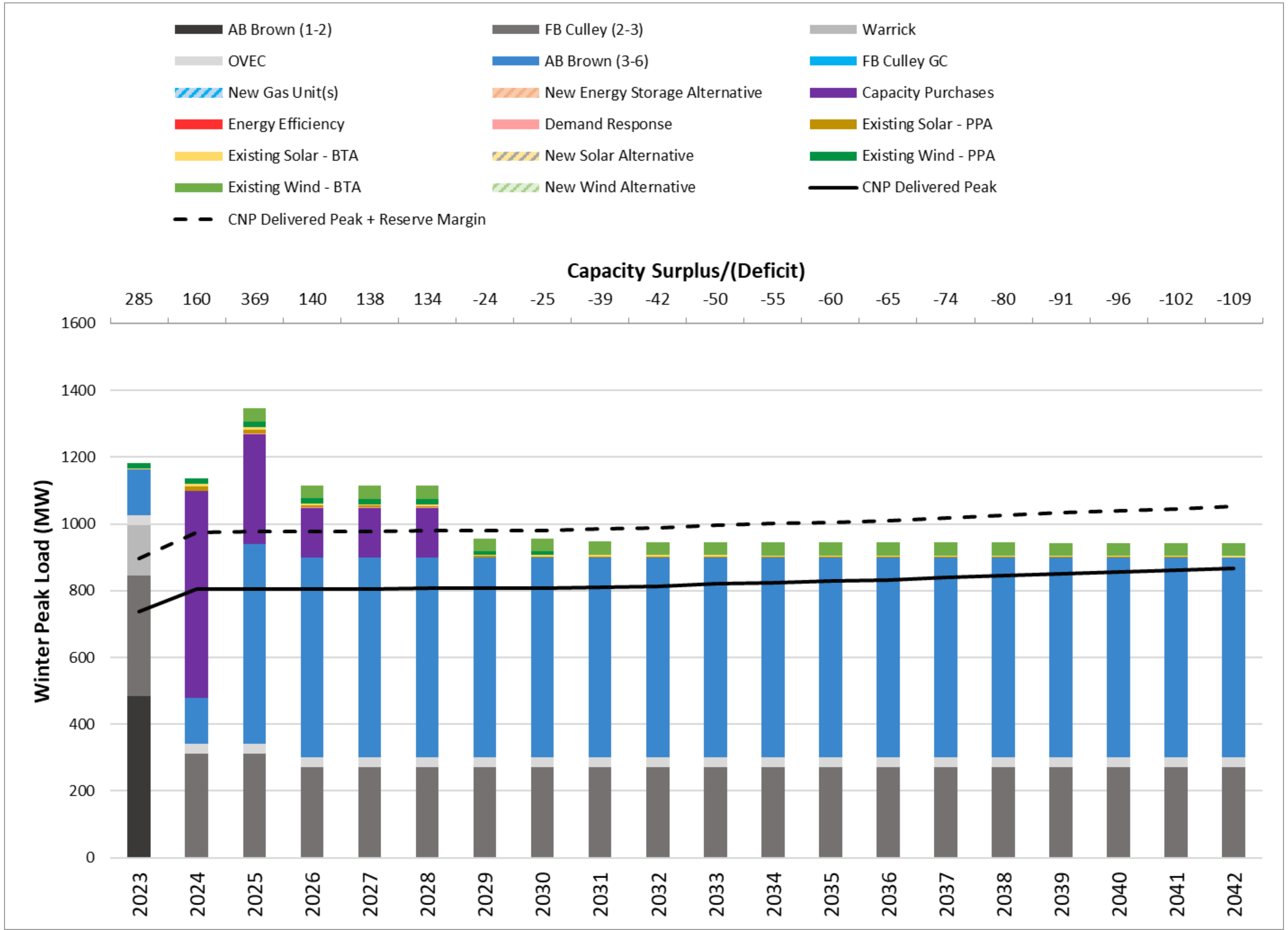


Existing Resource Summer BLR



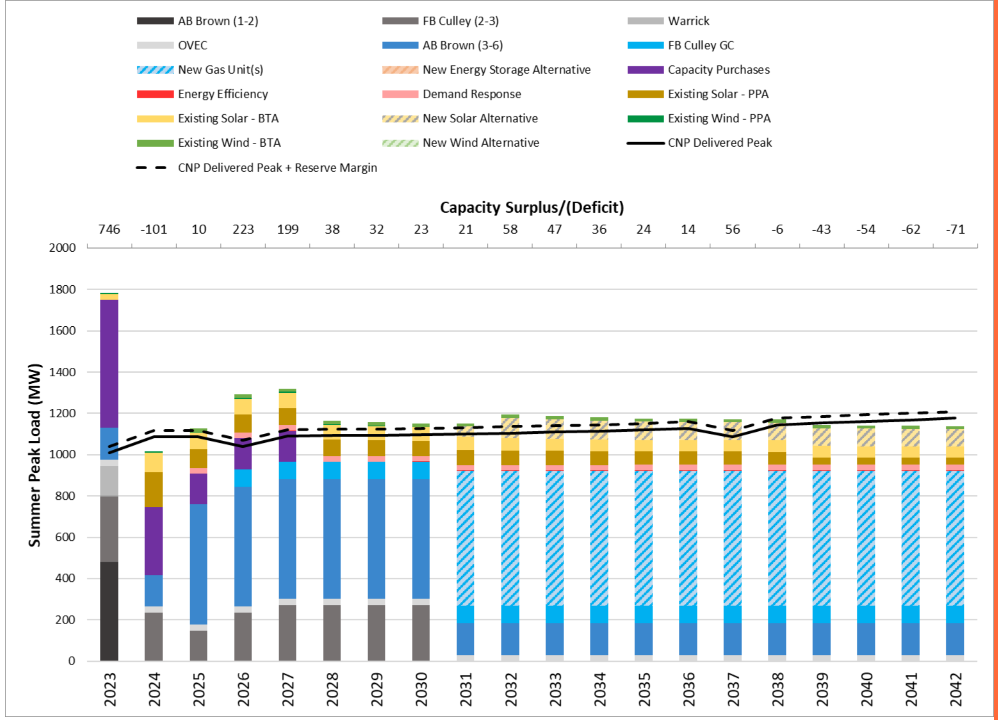
1898 & co.

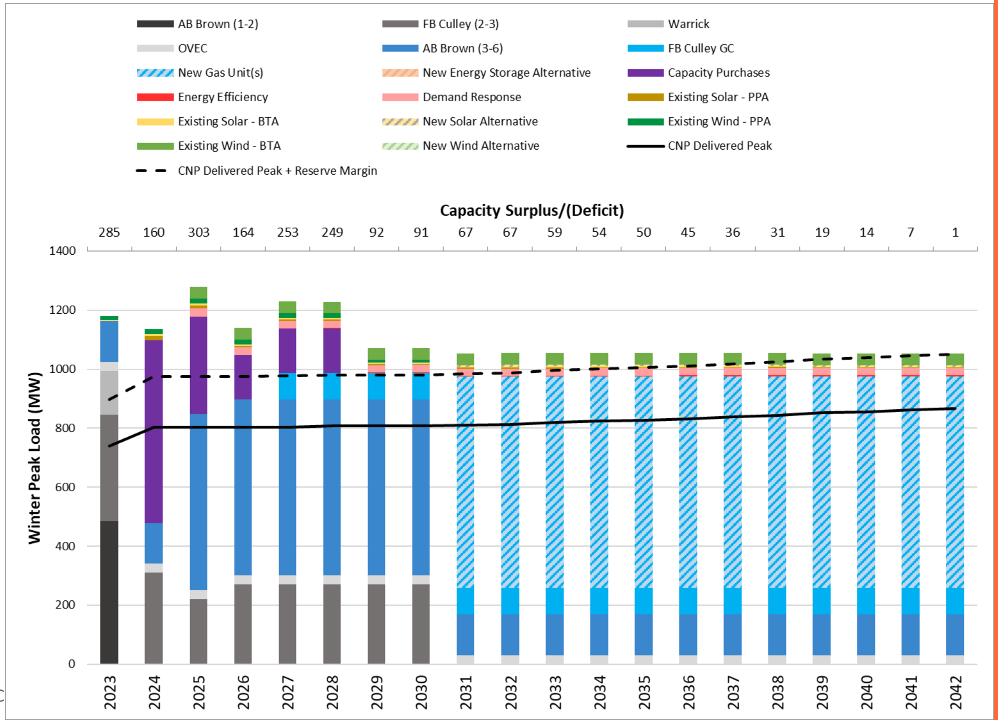
Existing Resource Winter BLR



Preliminary Model Selections

- 2030 retirement of FB Culley 3
- FB Culley 2 GC
- Conversion of CTs to CCGT
- Additional solar in 2030s





Timeline of Next Steps

- Provide EnCompass scenario export following this meeting
- Model feedback requested by November 14th, 2022
- Next Tech to Tech will be the week of December 5th prior to stakeholder meeting

Questions on EnCompass Modeling Input File Discussed During November 7, 2022 Tech to Tech Call:

1. What costs are being represented in the “OtherCosts” column for the following projects: 1x1 F CC F, 1x1 F CC UF, 1x1 GH CC F, 1x1 GH CC UF, 1x1 J CC UF, 1xF CT, 1xGH CT, 1xJ CT, 2x1 J CC F?

2. Is the project named “ABB7” representing the conversion of the new CTs coming online in 2025 (460 MW capacity)? For the project constraints connected to this project:
    a. It looks like the constraint named “ABB7 CMin” is set to 1 for the year 2031. Are you assuming that the conversion is a forced decision in 2031?
    b. Are all of the conversion costs contained in the time series “AB BrownGT – ABB7 Overnight Capital Cost” or are some of the costs in the time series “AB BrownGT – ABB7 Fixed O&M”?
        i. If some of the conversion costs are in the “AB BrownGT – ABB7 Fixed O&M” time series, will there be a disconnect since the time series is starting in 2023 and the conversion would be happening in 2031 or another year? It looks like the time series has significantly higher costs for 2024 and 2025 compared to the other years in the time series.

3. It looks like the constraint named “FBC3 Cumulative Min” is set to 1 starting in 2036 and is connected to all the project options for FBC3 (“Retire FBC3 in 2030”, “Base FBC3”, “Retire FBC3 2034”, and “Convert FBC3 to NG 2025”). Is this constraint representing having the model select one of the four different paths starting in 2036? And if so, will this cause a problem for the FBC3 project options available prior to 2036?

4. Are the FB Culley 2 and 3 conversion to natural gas options only being modeled for the year 2025?

5. How will the projects “ABB5/6 Continue” and “FBC3 Continue” be used to evaluate the decision to continue to operate instead of retire or convert if these resources have no inputs specified?

6. Are the conversion costs for converting FB Culley 2 or FB Culley 3 to natural gas in the “FB Culley: 3 GC Fixed O&M” or “FB Culley: 2 GC Fixed O&M” time series? If not, where are the conversion costs modeled?

7. Are capital expenditures being incorporated into the model for FB Culley 3 continuing to operate on coal?

8. For the FB Culley 3 retirement projects with “OtherCosts” set to “Retire FBC3 2030 Book Cost” or “Retire FBC3 2034 Book Cost”, are these time series representing the plant balance for FB Culley 3 or something else?

9. Are the resources with the names “Capacity Purchase 1” through “Capacity Purchase 5” confirmed bilateral contracts or do they represent something else?

10. It looks like the two Demand Response projects/resources (“DR Industrial” and “DR Legacy”) seem to be forced online in 2025 based on the project constraints. Do these programs represent the existing Demand Response, new Demand Response, or a combination of existing and new?

11. Will the time series “DR Industrial Incremental Block Cost” and “DR Legacy Incremental Block Cost” remain at a value of 0 or will this be modified in future modeling runs?

12. It looks like the EE resources having the naming convention of “IQW1” offered between 2025 to 2027, “IQW2” offered between 2028 and 2030, and then “IQW3” offered between 2031 to 2042. Based on the cost and name, it seems like these are income qualified programs, but I do not see any other selectable EE resources. It looks like there are some time series names related to new EE resources, but I do not see them in the Project or Resource tabs. Will there be selectable EE modeled?

13. Is the hourly profile set for the OVEC resource based on historical operations, contract terms, or something else?

14. Are renewable and battery storage projects and resources with “NT” included intended to represent the RFP bids? And the projects and resources without “NT” the generic resources available outside of the RFP? Can you confirm if the RFP projects do have the IRA assumptions reflected in the cost and what ITC/PTC level is being assumed?

15. It looks like all of the solar and storage projects that do not have “NT” in the name are being modeled with an ITC input. Are CenterPoint and 1898 assuming normalization of the ITC? Was the PTC considered for new solar projects under the IRA?

16. How will you control for the PTC for new wind with the PTC being a time series? Will the model include the PTC outside of a ten year window for projects that come online during the planning period? (If the model adds a new wind project in 2027, won’t it continue to model the PTC at an escalating rate until the PTC time series ends?)

17. How were the hourly profiles developed for the new wind and solar resources? Also, will you be modeling different profiles to distinguish between the North and South Indiana wind resources. (We typically see the other Indiana utilities model a higher capacity factor for Northern Indiana wind).

18. How are any curtailment costs being modeled for new wind and solar resources without “NT” in the name and have a positive “CurtailOrder” set?

19. It looks like there are no dependency connections to represent the charging for the hybrid resources. Are the hybrid resources being modeled with hybrid costs but then modeled as individual projects? Also, the project named “Hybrid_StorageS” is missing inputs for “PaybckReq” and “MaxStorage”.

20. Based on the capex time series for the flow battery, are you assuming that there will be no cost reductions during the planning period?

21. Does the time series “CNPResMargReg” reflect the coincidence factor for each month? If so, appears that a different coincidence factor was applied each month or at least each season, what was the basis for that?

22. Will values be added to the CO_2 price time series?

23. How was the Uranium price determined for modeling the fuel price for the SMR resource?

24. Is there an advantage to modeling CenterPoint and MISO as two individual companies instead of putting the Area Connection as an asset for CenterPoint?

25. The “NG Price High” time series has the repeat set to 13. Is this meant to be set to 12?

IRP Public Stakeholder Meeting

December 13, 2022

Welcome and Safety Share

Richard Leger
Senior Vice President Indiana Electric

Safety share

CenterPoint Energy

Holiday Safety Tips

- Inspect electrical decorations for damage before use. Cracked or damaged sockets, loose or bare wires, and loose connections may cause a serious shock or start a fire
- Do not overload electrical outlets. Overloaded electrical outlets and faulty wires are a common cause of holiday fires
- Use battery-operated candles. Candles start almost half of home decoration fires (National Fire Protection Association - NFPA)
- Keep combustibles at least three feet from heat sources. Heat sources that are too close to a decoration are a common factor in home fires
- Stay in the kitchen when something is cooking. Unattended cooking equipment is the leading cause of home cooking fires (NFPA
- Turn off, unplug, and extinguish all decorations when going to sleep or leaving the house. Half of home fire deaths occur between the hours of 11pm and 7am (NFPA)

Follow Up Information From Second IRP Stakeholder Meeting

Matt Rice
Director, Regulatory and Rates

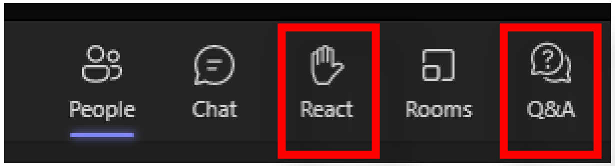
Agenda

Time		
8:30 a.m.	Sign-in/Refreshments	
9:30 a.m.	Welcome, Safety Message	Richard Leger, CenterPoint Energy Senior Vice President Indiana Electric
9:40 a.m.	Follow Up Information From Second IRP Stakeholder Meeting	Matt Rice, CenterPoint Energy Director Regulatory & Rates
10:20 a.m.	Final Scorecard and Scenarios	Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
10:50 a.m.	Break	
11:05 a.m.	Scenario and Probabilistic Modeling Update	Brian Despard, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
11:25 a.m.	Lunch	
12:05 p.m.	Final Resource Inputs	Kyle Combes, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
12:45 p.m.	Draft Scenario Optimization Results	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
1:30 p.m.	Break	
1:45 p.m.	Draft Deterministic Portfolio Results	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
2:20 p.m.	Stakeholder Questions and Feedback	Moderated by Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
3:00 p.m.	Adjourn	

Meeting Guidelines

CenterPoint Energy

1. Please hold most questions until the end of each presentation. Time will be allotted for questions following each presentation. (Clarifying questions about the slides are fine throughout)
2. For those on the webinar, please use the "React" feature in Microsoft Teams (shown at the bottom of this page) to raise your hand if you have a question and we will open your (currently muted) phone line for questions within the allotted time frame. You may also type in questions in the Q&A feature in Microsoft Teams.
3. The conversation today will focus on resource planning. To the extent that you wish to talk with us about other topics we will be happy to speak with you in a different forum.
4. At the end of the presentation, we will open up the floor for "clarifying questions," thoughts, ideas, and suggestions.
5. There will be a parking lot for items to be addressed at a later time.
6. CenterPoint Energy does not authorize the use of cameras or video recording devices of any kind during this meeting.
7. Questions asked at this meeting will be answered here or later.
8. We will do our best to capture notes but request that you provide written feedback (concepts, inputs, methodology, etc.) at IRP@CenterPointEnergy.com following the meeting. Additional questions can also be sent to this e-mail address. **We appreciate written feedback within 10 days of the stakeholder meeting.**
9. The Teams meeting will be recorded only to ensure that we have accurately captured notes and questions from the meeting. The public meetings are not transcribed, and the recordings will not be posted to the website. However, Q&A summaries of our public meetings will be posted on www.CenterPointEnergy.com/irp.



Commitments for 2022/2023 IRP

- ✓ Utilize an All-Source RFP to gather market pricing & availability data
- ✓ Utilize EnCompass software to improve visibility of model inputs and outputs
- ✓ Will include a balanced risk score card. Draft to be shared at the first public stakeholder meeting
- ✓ Will conduct technical meetings with interested stakeholders who sign an NDA
- ✓ Evaluate options for existing resources
- ✓ Will strive to make every encounter meaningful for stakeholders and for us
- The IRP process informs the selection of the preferred portfolio
- Work with stakeholders on portfolio development
- Will test a wide range of portfolios in scenario modeling and ultimately in the risk analysis
- Will conduct a sensitivity analysis
- The IRP will include information presented for multiple audiences (technical and non-technical)
- Will provide modeling data to stakeholders as soon as possible
  - ✓ Draft Reference Case results – October 4th to October 31st
  - Draft Scenario results – December 6th to December 20th
  - Full set of final modeling results - March 7th to March 31st

Proposed 2022/2023 IRP Process

CenterPoint Energy

Stakeholder input is provided on a timely basis throughout the process, with meetings held in August, October, December, and March

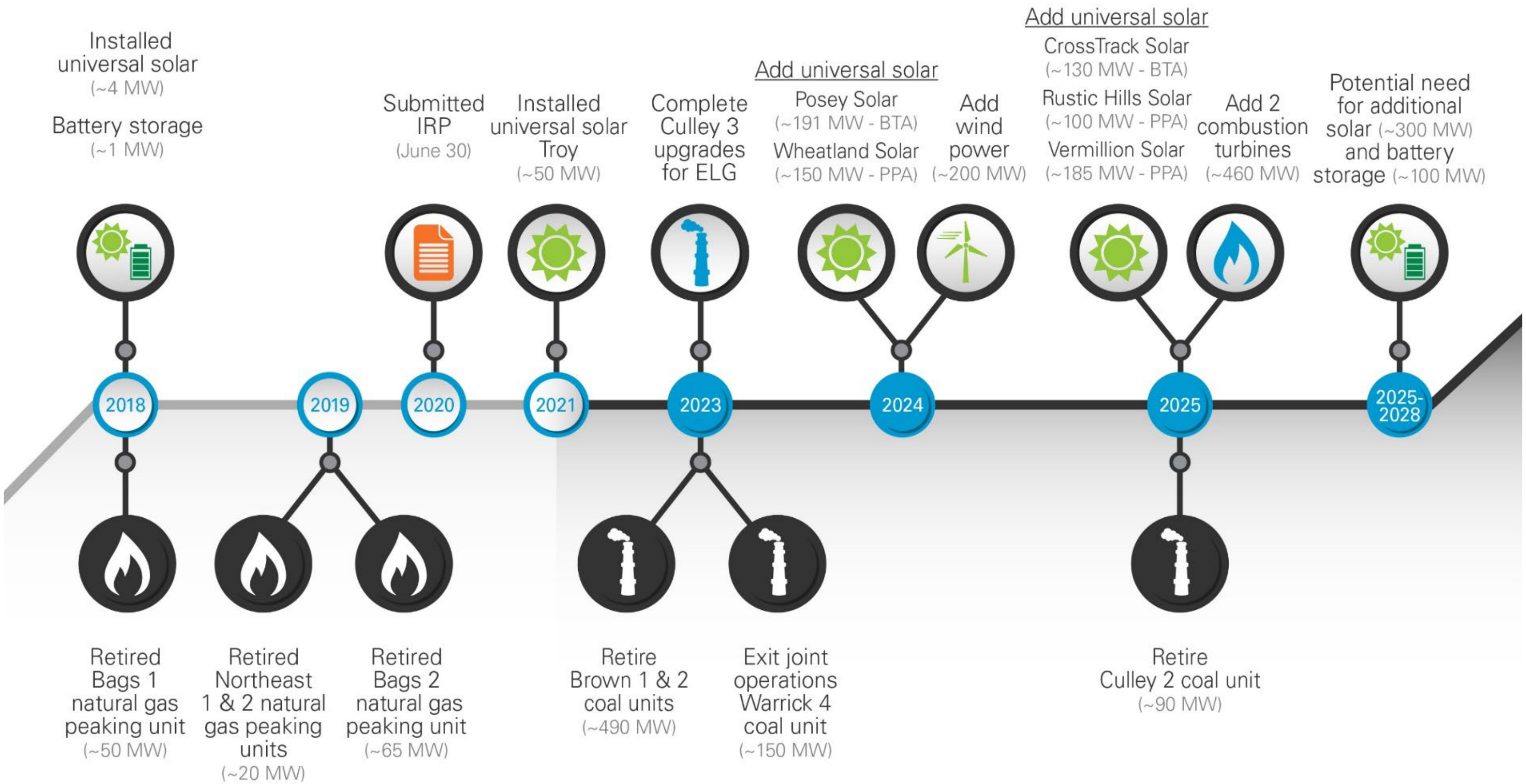
- Conduct an All Source RFP
- Create Objectives, Risk Perspectives and Scorecard Development
- Create Reference Case Assumptions and Scenario Development
- Portfolio Development Based on Various Strategies, Utilizing Optimization to Create a Wide Range of Portfolios With Input From All Source RFP Data
- Portfolio Testing in Scenarios, Focused on Potential Regulatory Risks
- Portfolio Testing Using Probabilistic Modeling
- Conduct Sensitivity Analysis
- Populate the Risk Scorecard that was Developed Early in the Process and Evaluate Portfolios
- Select the Preferred Portfolio

2022/2023 Stakeholder Process

August 18, 2022	October 11, 2022	December 13, 2022	March 14, 2023
• 2022/2023 IRP Process • Objectives and Measures • Encompass Software • All-Source RFP • MISO Update • Environmental Update • Draft Reference Case Market Inputs & Scenarios • Load Forecast Methodology • DSM MPS/ Modeling Inputs • Resource Options	• All-Source RFP Results and Final Modeling Inputs • Draft Resource Inputs • Final Load Forecast • Scenario Modeling Inputs • Portfolio Development • Probabilistic Modeling Approach and Assumptions • Draft Reference Case Modeling Results	• Draft Scenario Optimization Results • Draft Portfolios • Final Scorecard and Risk Analysis • Final Resource Inputs[1]	• Final Reference Case Modeling • Probabilistic Modeling Results • Risk Analysis Results • Preview the Preferred Portfolio

[1] Still finalizing. Plan to provide to those with an NDA by December 20th along with final draft modeling.

Generation Transition Update



Bags = Broadway Avenue Gas Turbines
BTA = Build Transfer Agreement/Utility Ownership
ELG = Effluent Limitations Guidelines
MW = Megawatt
PPA = Power Purchase Agreement
IRP = Integrated Resource Plan

Stakeholder Feedback - Resources

Request	Response
Select one solar and one storage resource (100 MW solar and 100 MW battery) for modeling in Encompass and allow the model to select partial units to determine the optimal size of new resources	The model has the option to select 10 MW, 50 MW, and 100 MW solar and/or storage resources at their respective price points. Allowing the model to select partial units based on the cost of a 100 MW resource does not recognize economies of scale, introducing artificially low pricing for smaller resources. Additionally, this would introduce partial units for all other resources, where partnerships may not be available.
Consider modeling multi-day storage as a selectable resource	Compressed air storage (10 hour) is being used as a proxy for long duration storage within the Encompass model. The model has the option to select multiple compressed air storage resources (as well as lithium ion) to expand the duration of storage resources.
Explore the use of capital and fixed O&M costs for either a 10 hour lithium-ion battery or a flow battery	Economies of scale for lithium-ion batteries currently level off at 4 hours of duration but the model can select multiple 4 hour resources to achieve long duration if this is the most economical choice. Flow battery technology isn't technical viable so compressed air energy storage is being used as a proxy for all long term storage solutions

Stakeholder Feedback - Resources cont.

Stakeholder Request	Response
It appears that generic battery storage resources available starting in 2027 have a project life of 20 years. We assume this was modeled based on the RFP results, but the NREL ATB assumes a project life of 30 years in its development of costs and it appears that CenterPoint and 1898 may have based their fixed O&M cost on the ATB which would include higher augmentation costs. We recommend that the life and the fixed O&M assumptions be aligned to the same lifetime	Project life and cost for resources selectable in the long term are both based on the technology assessment (TA) received from 1898 & Co. The TA estimates a book life of 20 years and the costs are aligned with this book life estimate. EIA uses 10 years
Adjust the capital costs for new generic solar, wind, and storage downward to better align with the assumed cost trends of thermal resources. Thermal costs are not immune to inflationary pressures	Capital costs for new solar, wind, and storage resources (starting in 2027) are based on tech assessment information and NREL ATB cost curves. If stakeholders have alternative sources that could be used CenterPoint will consider them. The cost assumptions for thermal resources have been adjusted upward to reflect recent increases in market pricing
Evaluate the option of repowering the Benton County and Fowler Ridge wind farms (Current PPA's)	CenterPoint has reached out to the owners of these wind farms and is waiting for a reply

Stakeholder Feedback - Resources cont.

Stakeholder Request	Response
In scenarios that have a "Low" cost for renewables and storage (compared to the reference case), update cost decline curves to differentiate between the "Low" scenario and the reference case in the near term	The cost decline curves for solar, wind, and storage have been updated to use the lowest bid incorporated into each group's average as the starting point for the "Low" scenario, which provides cost separation with the reference case in the near term
Adjust the cost decline curves for renewables and storage to continue cost declines until 2035 (currently decline until 2030)	Information from NREL's annual technology bulletin (ATB) is being utilized to create the shape of the cost decline curves for renewables and storage. If stakeholders have alternative sources that could be used CenterPoint will consider them
Revise the wind profiles being used in the model to differentiate between the output of northern Indiana and southern Indiana wind	The output profiles for wind resources have been updated (increased) to better align with the information received from wind resources in the RFP

Stakeholder Feedback - Resources cont.

Stakeholder Request	Response
IRA Energy Community Bonus Adder – Include the impact of the energy community bonus adder for the ITC and the PTC as a base case assumption	Resource selection in the near term is based on updated RFP bid pricing and reflect the results of the passage of IRA. The energy community bonus adder is site specific and does not apply to all resources
Request for a DR sensitivity of 204 MW of C&I DR	The customer makeup of CEI South's service territory does not lend itself to achieving this level of DR. Currently, there are only 7 customers who have more than 10 MW of load and many of these customers are not in an industry that readily allows idle manufacturing operations for curtailment. CEI South will model the promised 25 MWs of Industrial DR at the all-source RFP bid price and engage with the DR aggregation bidder

Stakeholder Feedback - Resources cont.

Stakeholder Request	Response
For SMR (Small Modular Reactor) resources, push back the year that the model can first select this resource to 2035	This adjustment has been made in Encompass. Likewise, we plan to not allow long-duration storage before 2032
Model options for exiting the OVEC contract early (i.e. 2025 and 2030) and model only economic commitment of the plants (i.e. no must run designation)	CenterPoint has contractual commitments associated with the OVEC units. CenterPoint's small, 1.5% ownership (~30 MWs) will be included within IRP modeling
Explore alternative retirement dates for Culley 3	Culley 3 will be evaluated in scenarios with a potential retirement date of 2029 (pulled forward from 2030)

Stakeholder Feedback - Resources cont.

Stakeholder Request	Response
Do not link the remaining book value of the units to the retirement decision within EnCompass. Assume that the remaining book value is recovered from ratepayers regardless of retirement date	Remaining book value is a factor within a retirement decision and thus should be reflected within the modeling. The retirement date of the unit helps determine the remaining book value to be recovered from customers
Assume that the remaining book value of Culley 3 be securitized	There currently is no Indiana statute that allows for securitization of Culley 3
ITC storage year one	CEI South will model the ITC benefit for storage in year one. This will be discussed further on the sensitivities slide

Stakeholder Feedback - Resources cont.

Stakeholder Request	Response
Access to files so feedback can be provided on: • The translation of the RFP data into new build inputs • The assumed conversion costs for converting either FB Culley 2 or FB Culley 3 to operate on natural gas • Supporting workbooks that show a breakout of costs that include both fixed O&M and capital expenditures for thermal resources • The selectable energy efficiency and resource inputs	CenterPoint has been actively working to finalize these files and will provide this information to stakeholders that execute a NDA once it is in final draft format. We plan to provide this information by December 20^{th}
Access to updated modeling files	CenterPoint will share the latest files with those that have signed an NDA and plans to another update to stakeholders in Q1 2023 and hold another tech-to-tech discussion

Stakeholder Feedback - Resources cont.

Stakeholder Request	Response
Access to supporting calculations for seasonal accreditation for existing and new thermal resources	Seasonal accreditation for new thermal resources is based on MISO EFORd Class averages. Seasonal accreditation for existing thermal resources is being updated as MISO provides additional information in preparation for the 2023/2024 planning year. This information will be shared once it has been updated / validated

Stakeholder Feedback – CO_2

Stakeholder Request	Response
CO_2 tax is falling out of favor. Can you explore alternative ways to model CO_2?	CO_2 tax is meant to be a cost proxy for CO_2 regulation, regardless of form

Q&A

Final Scorecard and Scenario Review

Matt Lind
Director, Resource Planning & Market Assessments
1898 & Co.

Updated IRP Draft Objectives & Measures

CenterPoint Energy

Objective	Potential Measures	Unit
Affordability	20 Year NPVRR	$
Cost Risk	Proportion of Energy Generated by Resources With Exposure to Coal and Gas Markets and Market Purchases 95% Value of NPVRR	% $
Environmental Sustainability	CO_2 Intensity CO_2 Equivalent Emissions (Stack Emissions)	Tons CO_2e/kwh Tons CO_2e
Reliability	Must Meet MISO Planning Reserve Margin Requirement in All Seasons Spinning Reserve\Fast Start Capability	UCAP MWs % of Portfolio MW's That Offer Spinning Reserve\Fast Start
Market Risk Minimization	Energy Market Purchases or Sales	%
	Capacity Market Purchases or Sales	%
Execution	Assess Challenges of Implementing Each Portfolio	Qualitative

Updates from first stakeholder meeting are shown in red

Sensitivities

- Storage ITC
- Unconstrained Reference case
- Understanding how price variation has an impact on model selection
- NSPS 111B cost risk
- EE cost
- ELCC
- Large load addition (Reference case w/ large load addition)

Scorecard Purpose

- Scorecard used to help evaluate and compare portfolio attributes and risks on consistent basis
- Not all risks can be quantified and captured in capacity expansion models
- There are other qualitative considerations which can help inform the selection of the preferred portfolio (not all inclusive):
  - Resource diversification
  - System flexibility
  - Economic development
  - Transmission/distribution
  - Potential resource locations (where applicable)

Scenarios

CenterPoint Energy

	Coal Price	Natural Gas Price	Load	Carbon	Renewables and Storage Cost	Economy	Gas Regulation	Other Environmental Regulations	EE Cost
Reference Case	Base	Base	Base	ACE Proxy	Base	Base	None	None	Base
High Regulatory	↑	↑	↓	↑	↓	↓	Fracking Ban	MATS Update	↑
Market Driven Innovation	↓	↓	↑	↓	↓	↑	None	None	↓
Decarbonization \ Electrification	↑	↔	↑	↑	↔	↔	Methane	None	↓
Continued High Inflation & Supply Chain Issues	↑	↑	↓	↔	↑	↓	None	None	↑

↑ = Higher than Reference Case Case

↓ = Lower than Reference Case

↔ = Same as Reference

Updates from first stakeholder meeting are shown in red

Q&A

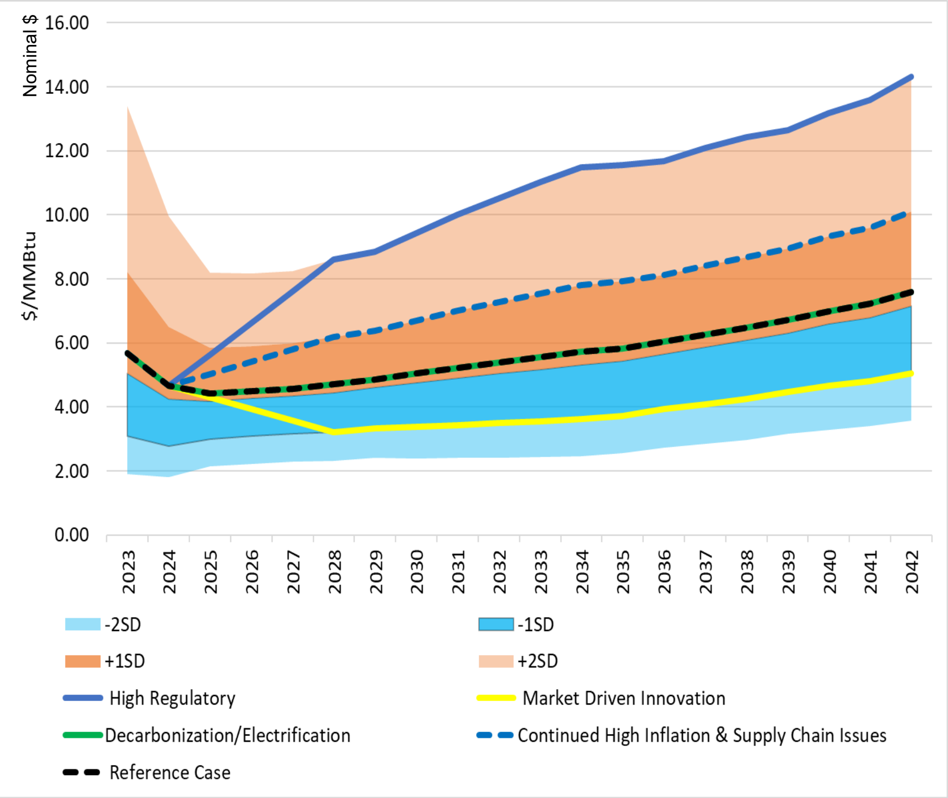
CenterPoint Energy

Scenario and Probabilistic Modeling Update

Brian Despard
Project Manager, Resource Planning & Market Assessments
1898 & Co.

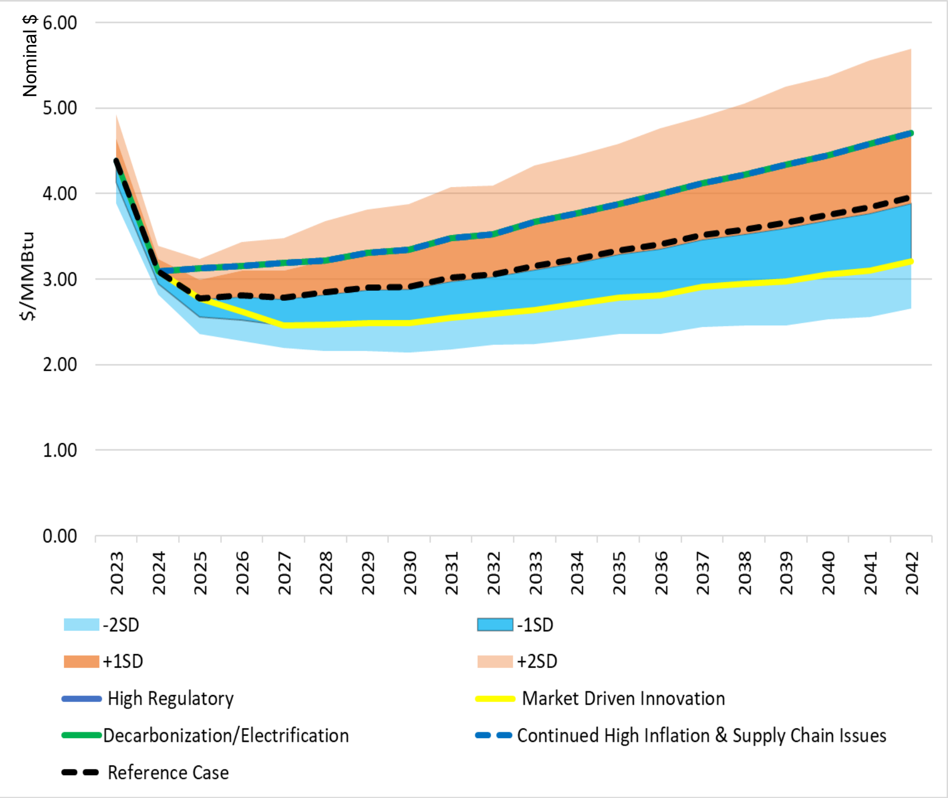
Scenario Inputs: Natural Gas Henry Hub ($/MMBtu)

Year	Reference Case	High Regulatory	Market Driven Innovation	Decarbonization/ Electrification	Continued High Inflation & Supply Chain Issues
2022	$5.82	$5.82	$5.82	$5.82	$5.82
2023	$5.68	$5.68	$5.68	$5.68	$5.68
2024	$4.65	$4.65	$4.65	$4.65	$4.65
2025	$4.43	$5.64	$4.29	$4.43	$5.04
2026	$4.50	$6.63	$3.93	$4.50	$5.42
2027	$4.57	$7.62	$3.57	$4.57	$5.80
2028	$4.70	$8.61	$3.21	$4.70	$6.19
2029	$4.87	$8.85	$3.34	$4.87	$6.39
2030	$5.05	$9.44	$3.38	$5.05	$6.70
2031	$5.23	$10.00	$3.44	$5.23	$7.01
2032	$5.39	$10.51	$3.49	$5.39	$7.28
2033	$5.55	$11.01	$3.55	$5.55	$7.55
2034	$5.72	$11.47	$3.62	$5.72	$7.81
2035	$5.83	$11.55	$3.73	$5.83	$7.92
2036	$6.03	$11.68	$3.93	$6.03	$8.12
2037	$6.26	$12.09	$4.08	$6.26	$8.42
2038	$6.48	$12.42	$4.26	$6.48	$8.69
2039	$6.71	$12.64	$4.47	$6.71	$8.94
2040	$7.00	$13.19	$4.66	$7.00	$9.32
2041	$7.22	$13.58	$4.81	$7.22	$9.60
2042	$7.59	$14.31	$5.06	$7.59	$10.11



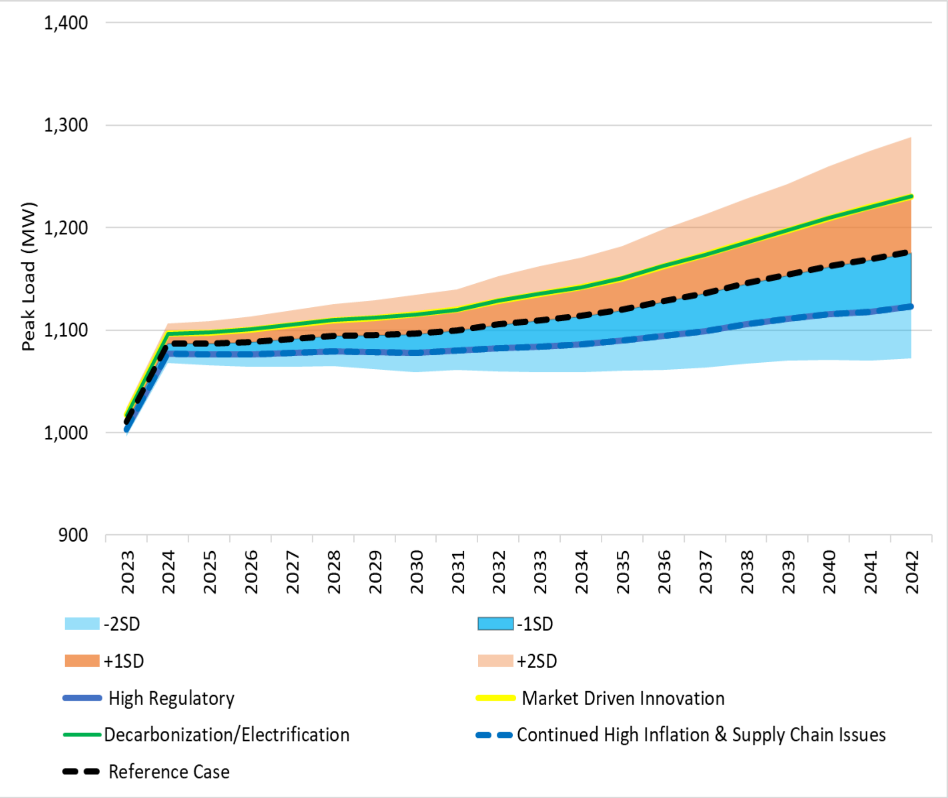
Scenario Inputs: Coal Illinois Basin fob Mine ($/MMBtu)

Year	Reference Case	High Regulatory	Market Driven Innovation	Decarbonization/ Electrification	Continued High Inflation & Supply Chain Issues
2022	$2.89	$2.89	$2.89	$2.89	$2.89
2023	$4.39	$4.39	$4.39	$4.39	$4.39
2024	$3.09	$3.09	$3.09	$3.09	$3.09
2025	$2.77	$3.13	$2.77	$3.13	$3.13
2026	$2.81	$3.16	$2.62	$3.16	$3.16
2027	$2.78	$3.19	$2.46	$3.19	$3.19
2028	$2.85	$3.22	$2.47	$3.22	$3.22
2029	$2.90	$3.31	$2.49	$3.31	$3.31
2030	$2.91	$3.34	$2.48	$3.34	$3.34
2031	$3.02	$3.48	$2.55	$3.48	$3.48
2032	$3.06	$3.52	$2.60	$3.52	$3.52
2033	$3.16	$3.67	$2.64	$3.67	$3.67
2034	$3.24	$3.77	$2.71	$3.77	$3.77
2035	$3.33	$3.88	$2.79	$3.88	$3.88
2036	$3.41	$4.00	$2.81	$4.00	$4.00
2037	$3.51	$4.12	$2.91	$4.12	$4.12
2038	$3.58	$4.22	$2.94	$4.22	$4.22
2039	$3.66	$4.34	$2.97	$4.34	$4.34
2040	$3.75	$4.45	$3.05	$4.45	$4.45
2041	$3.84	$4.58	$3.10	$4.58	$4.58
2042	$3.96	$4.71	$3.21	$4.71	$4.71



Scenario Inputs: Peak Load

Year	Reference Case	High Regulatory	Market Driven Innovation	Decarbonization/ Electrification	Continued High Inflation & Supply Chain Issues
2022	1,010	996	1,017	1,017	996
2023	1,010	996	1,017	1,017	996
2024	1,087	1,068	1,097	1,097	1,068
2025	1,087	1,066	1,098	1,098	1,066
2026	1,088	1,064	1,101	1,101	1,064
2027	1,092	1,065	1,105	1,105	1,065
2028	1,095	1,065	1,110	1,110	1,065
2029	1,095	1,062	1,112	1,112	1,062
2030	1,096	1,059	1,115	1,115	1,059
2031	1,100	1,061	1,120	1,120	1,061
2032	1,105	1,060	1,128	1,128	1,060
2033	1,110	1,059	1,135	1,135	1,059
2034	1,114	1,059	1,142	1,142	1,059
2035	1,120	1,060	1,150	1,150	1,060
2036	1,128	1,061	1,162	1,162	1,061
2037	1,136	1,063	1,174	1,174	1,063
2038	1,145	1,067	1,185	1,185	1,067
2039	1,154	1,071	1,197	1,197	1,071
2040	1,162	1,071	1,209	1,209	1,071
2041	1,169	1,070	1,220	1,220	1,070
2042	1,177	1,072	1,231	1,231	1,072



CenterPoint Energy

Final Resource Inputs

Kyle Combes
Project Manager, Resource Planning & Market Assessments
1898 & Co.

Technology Details

CenterPoint Energy

Examples of candidates for natural gas peaking generation:

Peaking Gas[2]	F-Class SCGT	G/H-Class SCGT	J-Class SCGT	6 x 9 MW Recip Engines	6 x 18 MW Recip Engines
Capacity (MW)	229	287	372	55	110
Fixed O&M (2022 $/kW-Yr)[3]	$8	$7	$5	$28	$18
Total Project Costs (2022 $/kW)[4]	$940	$910	$740	$1,760	$1,560

~30% capital cost increase for gas turbines

Examples of candidates for natural gas combined cycle generation:

Gas Combined Cycle (Base/ Intermediate Load Units) - Unfired[2]	1x1 F-Class[1]	1x1 G/H-Class[1]	1x1 J-Class[1]
Capacity (MW)	363	431	551
Fixed O&M (2022 $/kW-Yr)[3]	$12	$10	$8
Total Project Costs (2022 $/kW)[4]	$1,450	$1,320	$1,100

~15% capital cost increase for unfired combined cycle gas turbines

Gas Combined Cycle (Base/ Intermediate Load Units) - Fired[2]	1x1 F-Class[1]	1x1 G/H-Class[1]	2x1 J-Class[1]
Capacity (MW)	419	508	1,307
Fixed O&M (2022 $/kW-Yr)[3]	$11	$9	$4
Total Project Costs (2022 $/kW)[4]	$1,300	$1,180	$770

~15% capital cost increase for fired combined cycle gas turbines

[1] 1x1 Combined Cycle Plant is one combustion turbine with heat recovery steam generator and one steam turbine utilizing the unused exhaust heat. 2x1 is two combustion turbines and 1 steam turbine.

[2] Combined Cycle and Gas Turbine Capacity (MW) are shown for nominal base performance @59°F (ISO Conditions).

[3] Firm gas service costs considered separately within the production cost model.

[4] Allowance for Funds Used During Construction (AFUDC) considered separately within the production cost model.

Technology Details

CenterPoint Energy

Examples of candidate for nuclear generation:

Nuclear	Small Modular Reactor
Capacity (MW)	74
Fixed O&M (2022 $/kW-Yr)	$1,440
Total Project Costs (2022 $/kW)[1]	$9,440

Examples of candidate for coal fired generation:

Coal	Supercritical Pulverized Coal with 90% Carbon Capture	Ultra-Supercritical Pulverized Coal with 90% Carbon Capture
Capacity (MW)	506	747
Fixed O&M (2022 $/kW-Yr)	$32	$32
Total Project Costs (2022 $/kW)[1]	$6,660	$6,020

Examples of other thermal:

Other Thermal	Co-Gen Steam Turbine	2x1 F-Class CCGT Conversion	FB Culley 2 Gas Conversion	FB Culley 3 Gas Conversion
Capacity (MW)	22	717 / 257 incremental	90 / 0 incremental	270 / 0 incremental
Fixed O&M (2022 $/kW-Yr)	$323	$12	$80	$33
Total Project Costs (2022 $/kW)[1]	$2,832	$770 / $2,230	$462	$196

12% capital cost increase for CCGT Conversion

[1] Allowance for Funds Used During Construction (AFUDC) considered separately within the production cost model.

Technology Details

CenterPoint Energy

Examples of candidates for wind generation :

Wind	Indiana Wind Energy	Indiana Wind + Storage
Base Load Net Output	200 MW	50 MW+10 MW/40 MWh
Fixed O&M (2022 $/kW-Yr)	$48	$58
Total Project Costs (2022 $/kW)[1]	$1,840	$2,130

Examples of candidates for solar generation :

Solar	Solar Photovoltaic	Solar Photovoltaic	Solar Photovoltaic	Solar PV + Storage
Base Load Net Output	10 MW	50 MW	100 MW	50 MW+10 MW/40 MWh
Fixed O&M (2022 $MM/kW-Yr)	$60	$16	$11	$19
Total Project Costs (2022 $/kW)[1]	$2,560	$1,860	$1,780	$1,910

Examples of candidates for Storage :

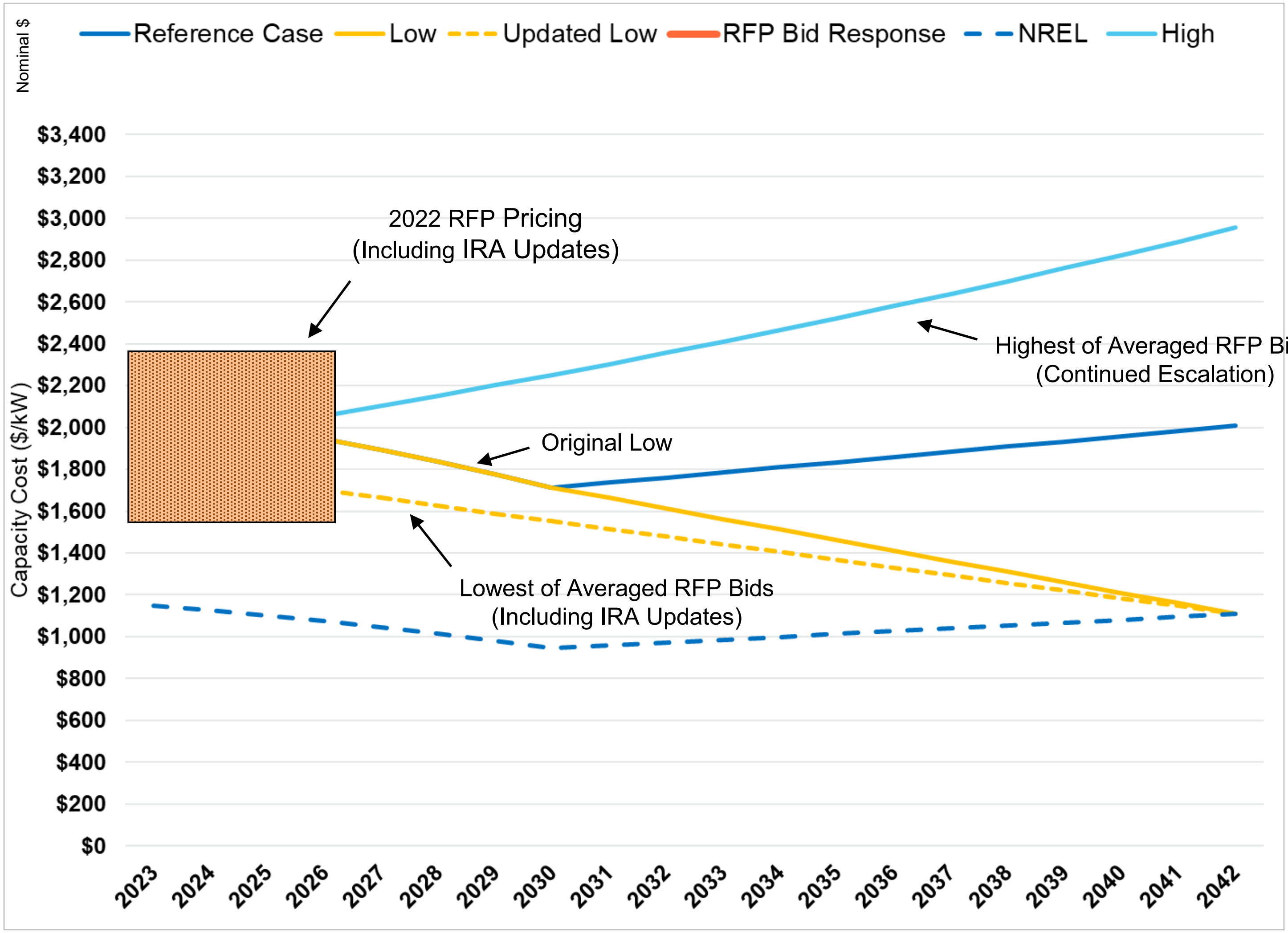
Storage	Lithium-Ion Battery Storage	Lithium-Ion Battery Storage	Lithium-Ion Battery Storage	Long Duration Storage (Represented by Compressed Air)
Base Load Net Output	10 MW / 40 MWh	50 MW / 200 MWh	100 MW / 400 MWh	300 MW / 3,000 MWh
Fixed O&M (2022 $MM/kW-Yr)	$40	$38	$35	$19
Total Project Costs (2022 $/kW)[1]	$2,500	$2,160	$2,020	$2,590

[1] Allowance for Funds Used During Construction (AFUDC) considered separately within the production cost model.

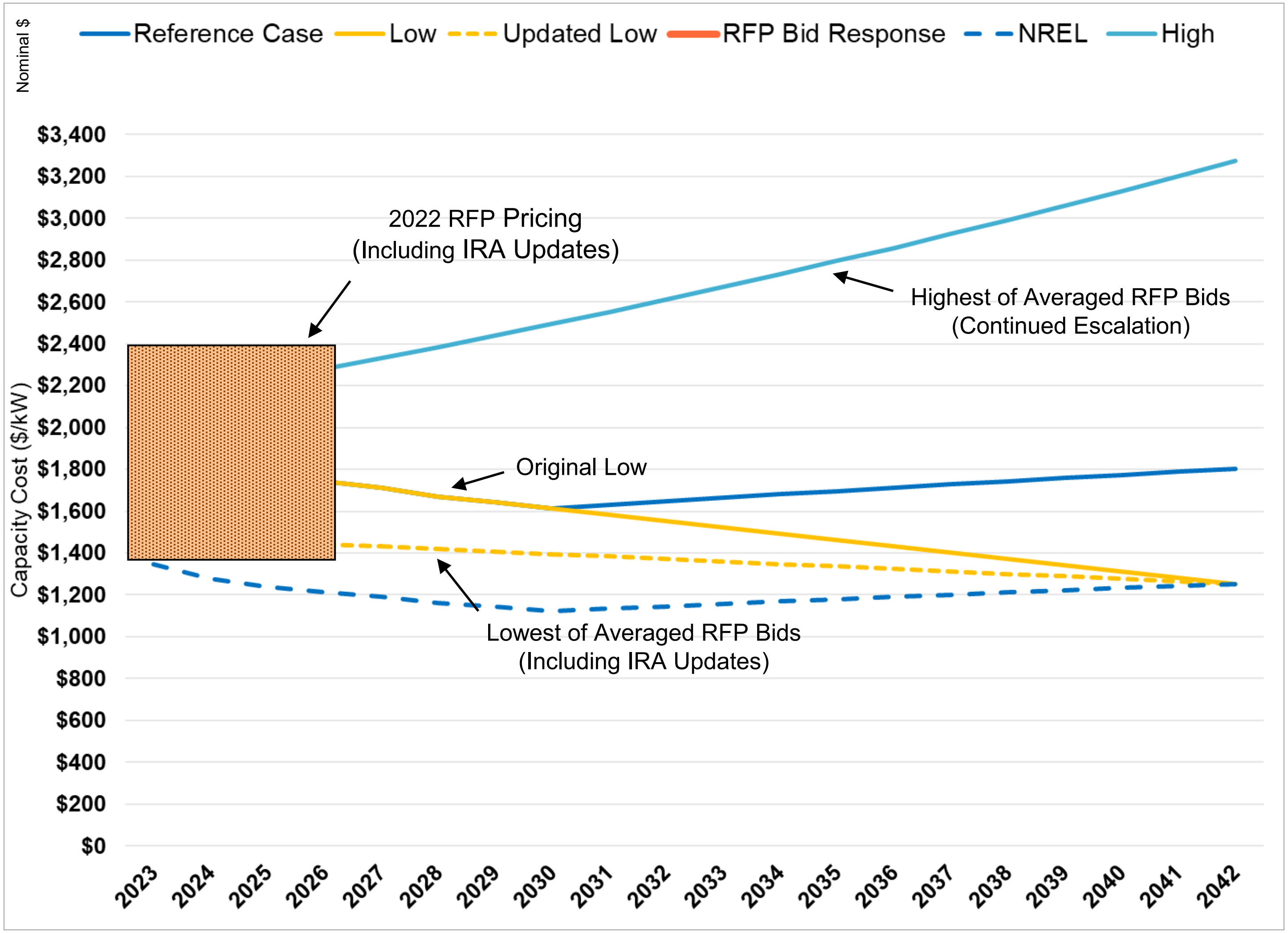
Capacity Cost Curve Summary

- Initial curve modeled from 2022 Annual Technology Baseline from NREL
- Pricing of all RFP purchase options taken per technology type
  - Pricing includes updates from the Inflation Reduction Act
- Reference case follows the NREL curve shifted to match the aggregate bid pricing
- The ‘Low’ curve is the interpolation from the lowest RFP option to the moderate NREL curve (adjusted per stakeholder request)
- The “High” curve begins at the Highest RFP option and is escalated through 2042

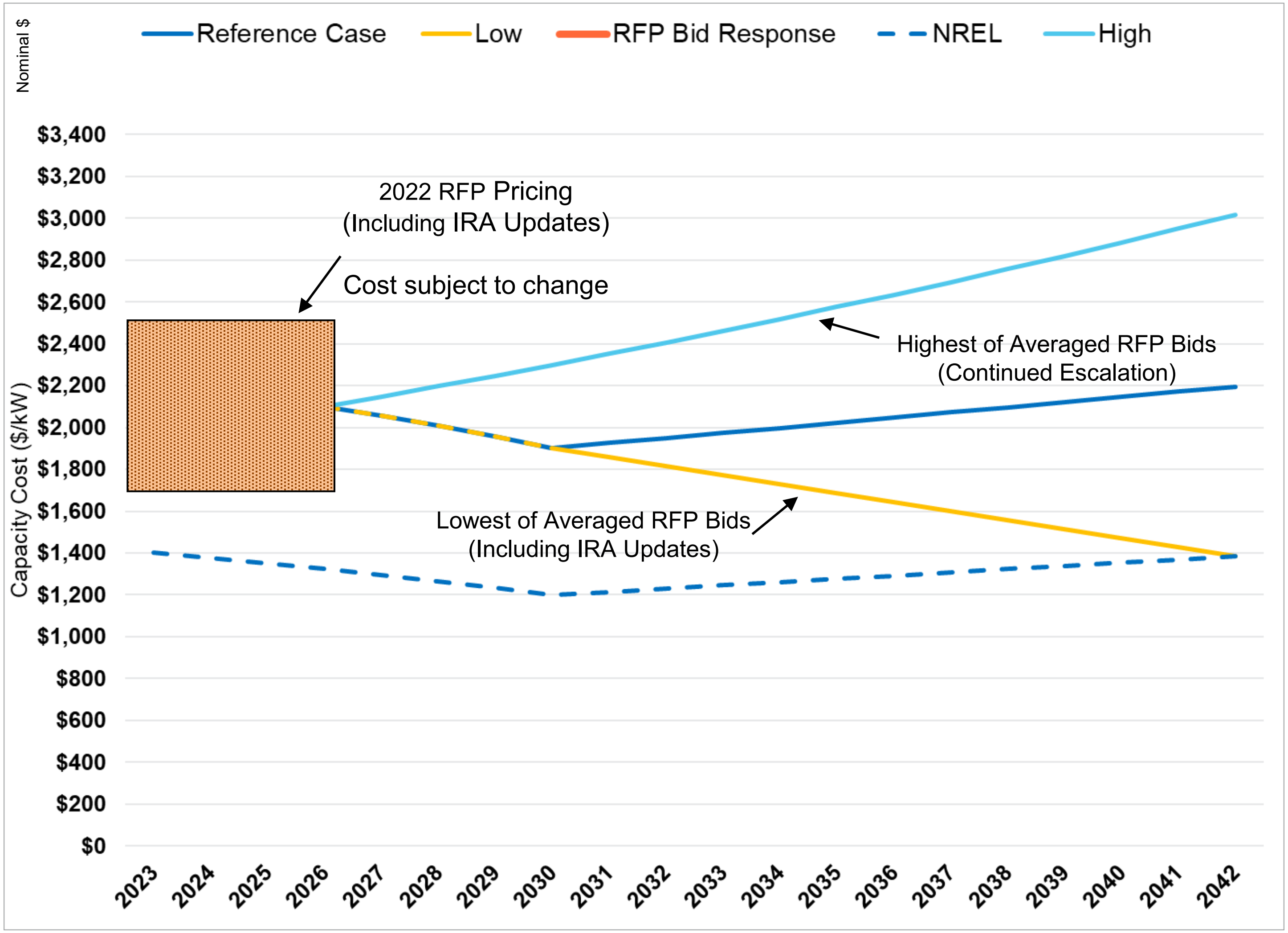
Capacity Cost Curves – Solar



Capacity Cost Curves – Li-ion Storage



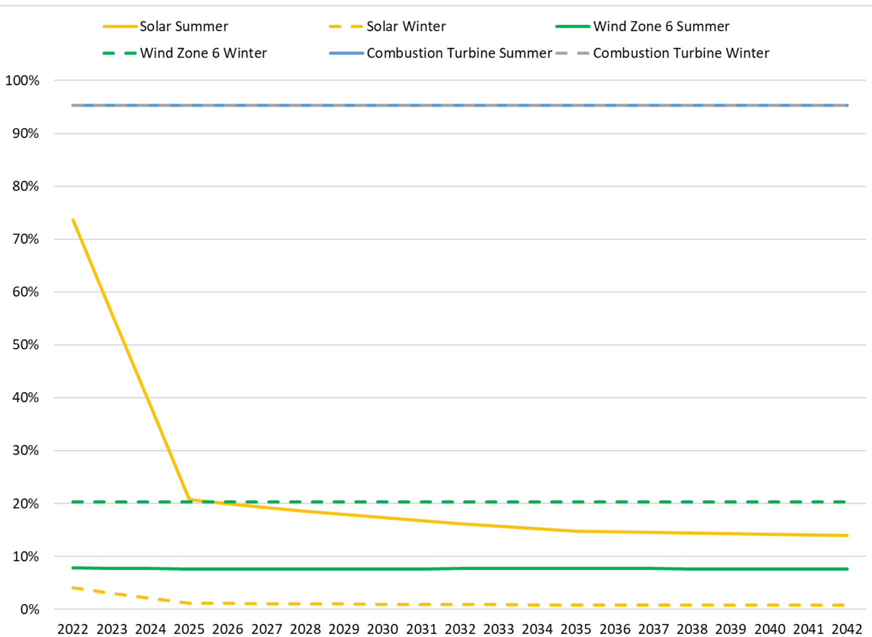
Capacity Cost Curves – Wind



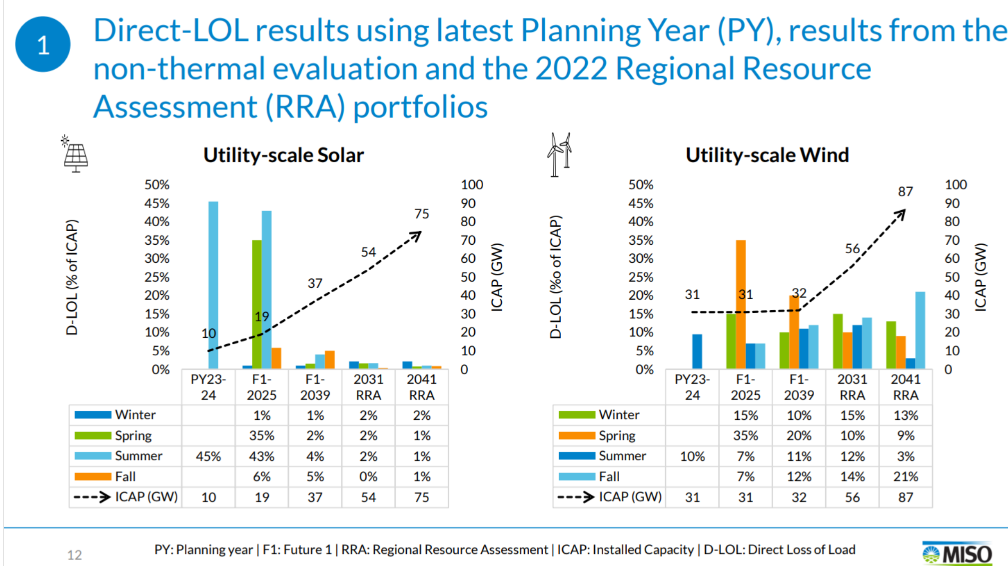
MISO Update

MISO recently provided an updated projection of wind and solar accreditation. The projection for solar is lower than what has been included within the model thus far. In the long-term, wind is projected to have a higher capacity accreditation percentage than solar in all seasons

First stakeholder meeting:



MISO Update:



Utility-scale Solar

	PY23-24	F1-2025	F1-2039	2031 RRA	2041 RRA
Winter		1%	1%	2%	2%
Spring		35%	2%	2%	1%
Summer	45%	43%	4%	2%	1%
Fall		6%	5%	0%	1%
ICAP (GW)	10	19	37	54	75

Utility-scale Wind

	PY23-24	F1-2025	F1-2039	2031 RRA	2041 RRA
Winter		15%	10%	15%	13%
Spring		35%	20%	10%	9%
Summer	10%	7%	11%	12%	3%
Fall		7%	12%	14%	21%
ICAP (GW)	31	31	32	56	87

12 PY: Planning year | F1: Future 1 | RRA: Regional Resource Assessment | ICAP: Installed Capacity | D-LOL: Direct Loss of Load

MISO Resource Adequacy Subcommittee – November 30, 2022: https://cdn.misoenergy.org/20221130%20RASC%20Item%2007b%20Non-Thermal%20Accreditation%20Presentation%20(RASC-2020-4%202019-2)627100.pdf

Q&A

Draft Portfolios and Optimized Results

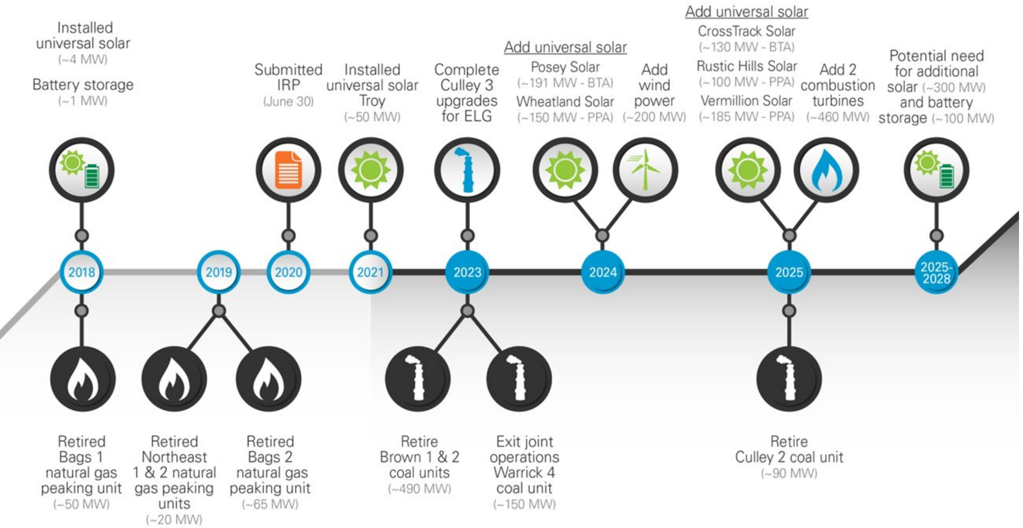
Drew Burczyk
Consultant, Resource Planning & Market Assessments
1898 & Co.

Draft Portfolios and Optimized Results Overview

- During this section we will review:
  - Range of IRP portfolios
  - Optimized Portfolio resource selections
  - Results from Deterministic Portfolio modeling
- The Preferred Portfolio has not been selected at this time; there is a lot of work to be done, including the risk analysis, scorecard comparison, and other considerations before we get to that point
- CEI South continues to refine and add deterministic and optimized portfolios presented today to ensure a diverse set of portfolios are evaluated during risk analysis

IRP Portfolio Decisions

CenterPoint Energy



Bags = Broadway Avenue Gas Turbines
BTA = Build Transfer Agreement/Utility Ownership
ELG = Effluent Limitations Guidelines
MW = Megawatt
PPA = Power Purchase Agreement
IRP = Integrated Resource Plan

- FB Culley 2 & 3 conversion or retirement decision is a key part of this IRP
- With MISO's shift to seasonal construct there is a capacity shortfall in 2024 prior to the CTs coming online and then into the 2030s
- Will analyze a wide range of portfolios that provide insights around the FB Culley decision and the future resource mix

Range of IRP Portfolios

Portfolio Strategy Group	Portfolio
Reference	Optimized Portfolio in Reference Case conditions
Scenario-Based	Optimized Portfolio using High Regulatory scenario assumptions
	Optimized Portfolio using Market Driven Innovation scenario assumptions
	Optimized Portfolio using Decarbonization/Electrification scenario assumptions
	Optimized Portfolio using High Inflation and Supply Chain Issues scenario assumptions
Deterministic	Business as Usual (Continue to run FB Culley 3 through 2042)
	AB Brown CTs with and without CCGT conversion
	FB Culley 2 or 3 gas conversion
	FB Culley 2 and 3 gas conversion
	Retire FB Culley 2 by 2025 • Replace with non-thermal (Wind, Solar, Storage) • Replace with thermal (CCGT, CT)
	Retire FB Culley 3 by 2029 • Replace with non-thermal (Wind, Solar, Storage) • Replace with thermal (CCGT, CT)
	Retire FB Culley 3 by 2034 • Replace with non-thermal (Wind, Solar, Storage) • Replace with thermal (CCGT, CT)

Note: Red text indicates changes made per stakeholder feedback

Draft Scenario Optimization Results

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1898 & Co.

Draft Optimized Portfolios

CenterPoint Energy

Year	Reference Case	Continued High Inflation & Supply Chain Issues	Market Driven Innovation	High Regulatory	Decarbonization/ Electrification
2024	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (200MW) Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Wind (600MW) Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)
2026				Wind (200MW) Solar + Storage (60 MW)	
2027	CCGT Conversion	Wind North (200MW)	CCGT Conversion		CCGT Conversion
2028				Storage (100MW)	
2029	Retire FB Culley 3	Retire FB Culley 3	Retire FB Culley 3	Retire FB Culley 3 Storage (100MW)	Retire FB Culley 3
2030		Storage (50 MW) Wind North (400MW)			Wind North (200MW)
2031		Storage (10MW)			
2032		Long Duration Storage (300MW)		Long Duration Storage (300MW)	Long Duration Storage (300MW) Wind North (200MW)
2033	Wind North (600MW)	Wind North (400MW)		Wind North (400MW)	Wind North (600MW)
2041			Storage (10MW)	Solar (100MW)	
2042			Storage (10MW)	Solar (200MW)	

Note: CEI South's latest RFP only resulted in 2 bids for wind projects. As other utilities pursue wind projects it may become increasingly difficult to execute on wind heavy portfolios if there are not enough viable projects to meet demand.

Draft Optimized Portfolios – EE & DR

CenterPoint Energy

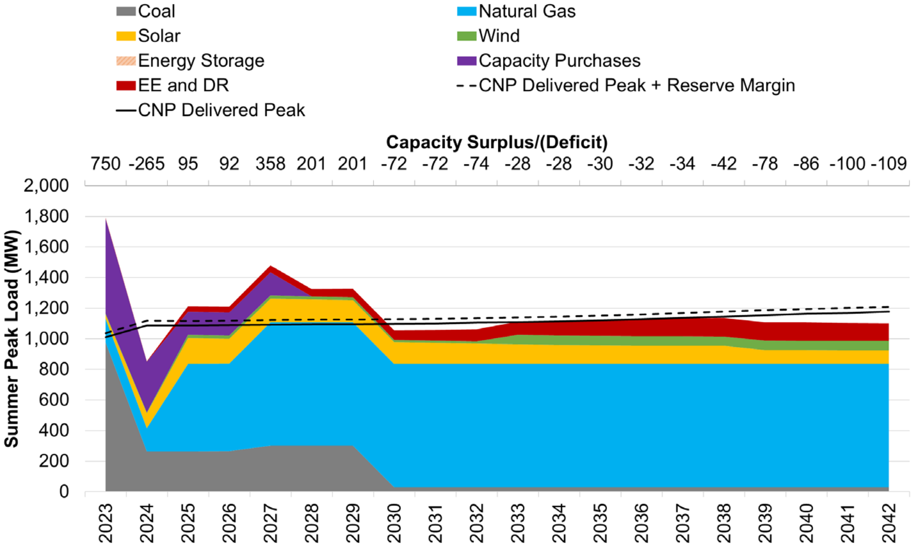
	Reference Case	Continued High Inflation & Supply Chain Issues	Market Driven Innovation	High Regulatory	Decarbonization/ Electrification
Vintage 1 2025 - 2027	DR Legacy - 2023	DR Legacy - 2023	DR Legacy - 2023	DR Legacy - 2023	DR Legacy - 2023
	DR Industrial	DR Industrial	DR Industrial	DR Industrial	DR Industrial
	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced
	HER	HER	IQW	HER	HER
	IQW	IQW		IQW	IQW
				Residential Low & Medium	
Vintage 2 2028 - 2030	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced
	IQW	HER	IQW	HER	HER
		IQW		IQW	IQW
		DR CI DLC		Residential Low & Medium	DR CI Rates
				DR CI Rates	
Vintage 3 2031 - 2042	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced
	DR CI Rates	DR CI Rates	DR CI Rates	DR CI Rates	DR CI Rates
	IQW	IQW	IQW	HER	IQW
				IQW	
				Residential Low & Medium	

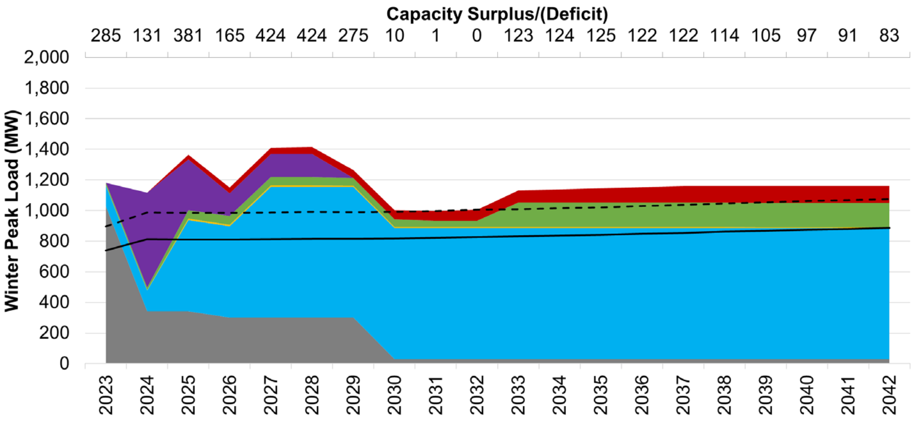
IQW = Income Qualified Weatherization
HER = Home Energy Reports
C&I = Commercial & Industrial

Reference Case Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Conversion of CTs to CCGT
- EE & DR
- Wind in 2033

Balance of Loads and Resources



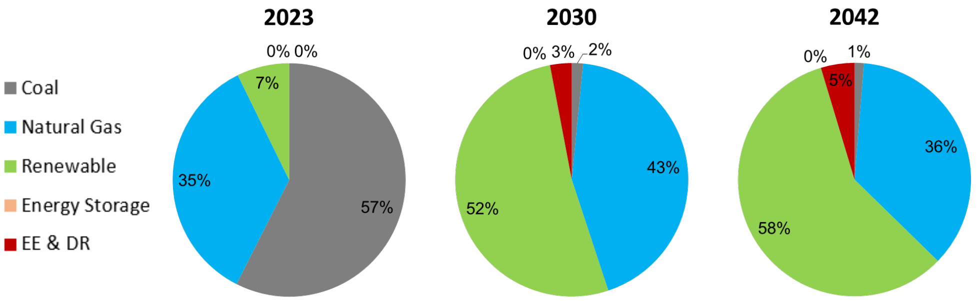


Reference Case Portfolio Selection

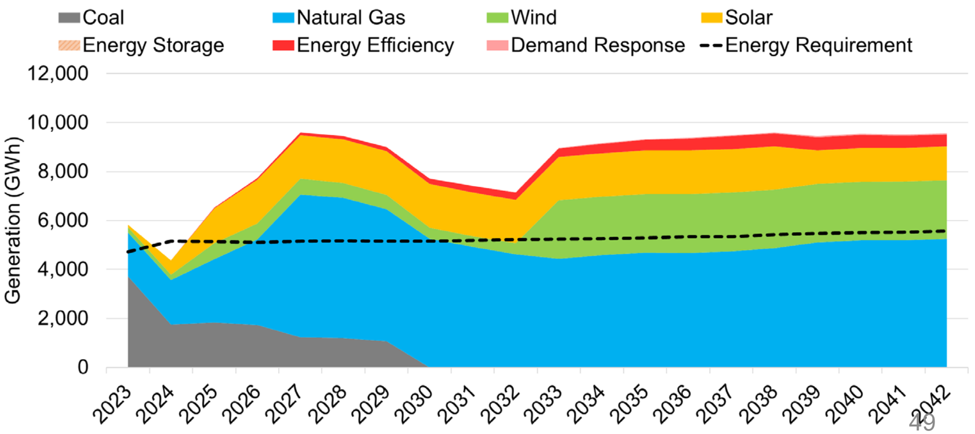
CenterPoint Energy

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Conversion of CTs to CCGT
- EE & DR
- Wind in 2033

Installed Capacity



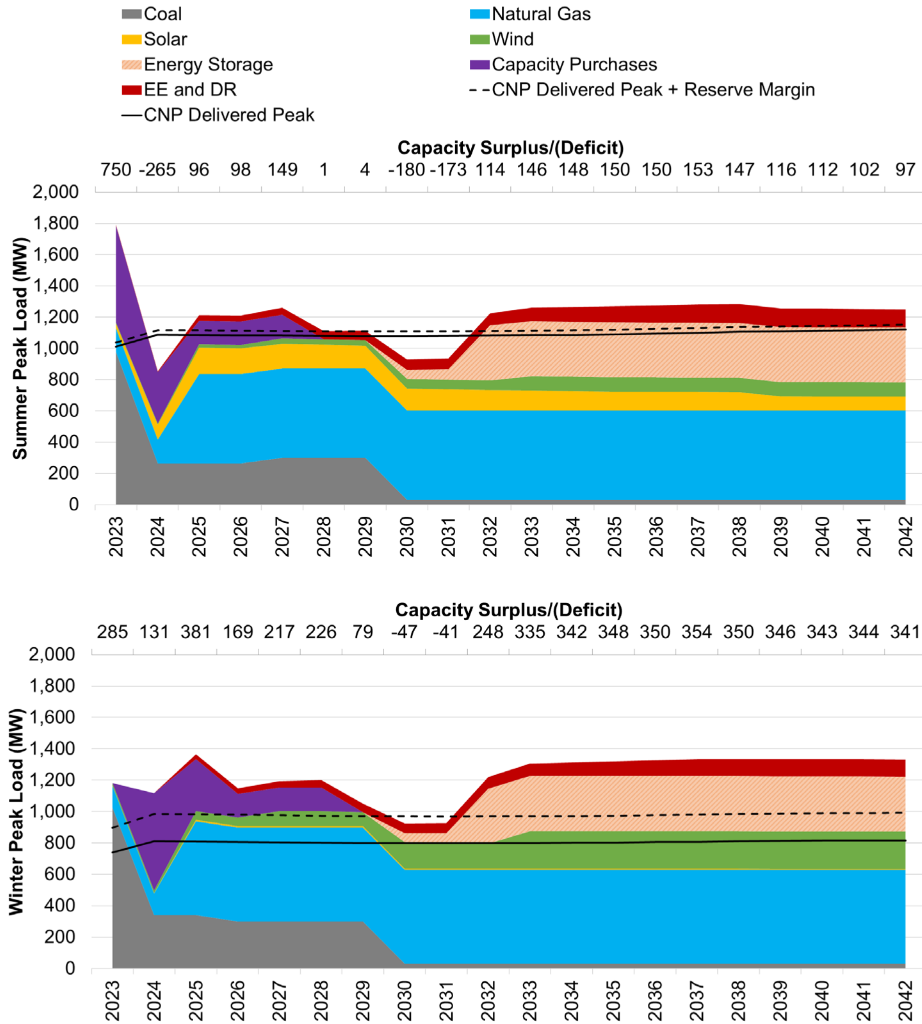
Energy Generation Mix



Continued High Inflation & Supply Chain Issues Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Additional wind and storage in 2027 – 2030s
- Long Duration Storage in 2032

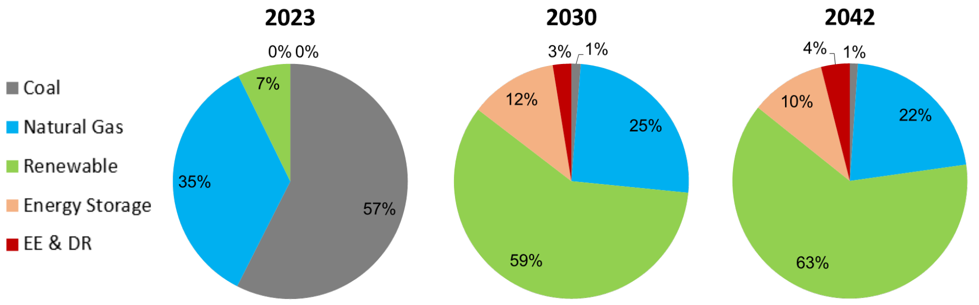
Balance of Loads and Resources



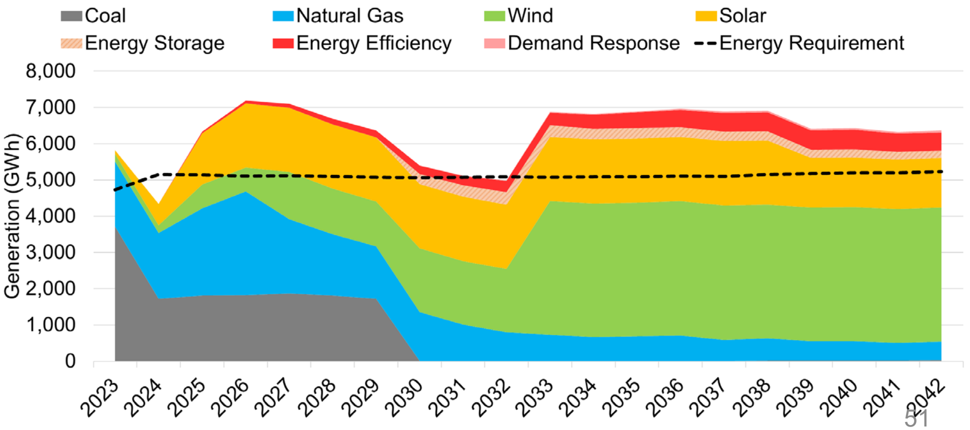
Continued High Inflation & Supply Chain Issues Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Additional wind and storage in 2027 – 2030s
- Long Duration Storage in 2032

Installed Capacity

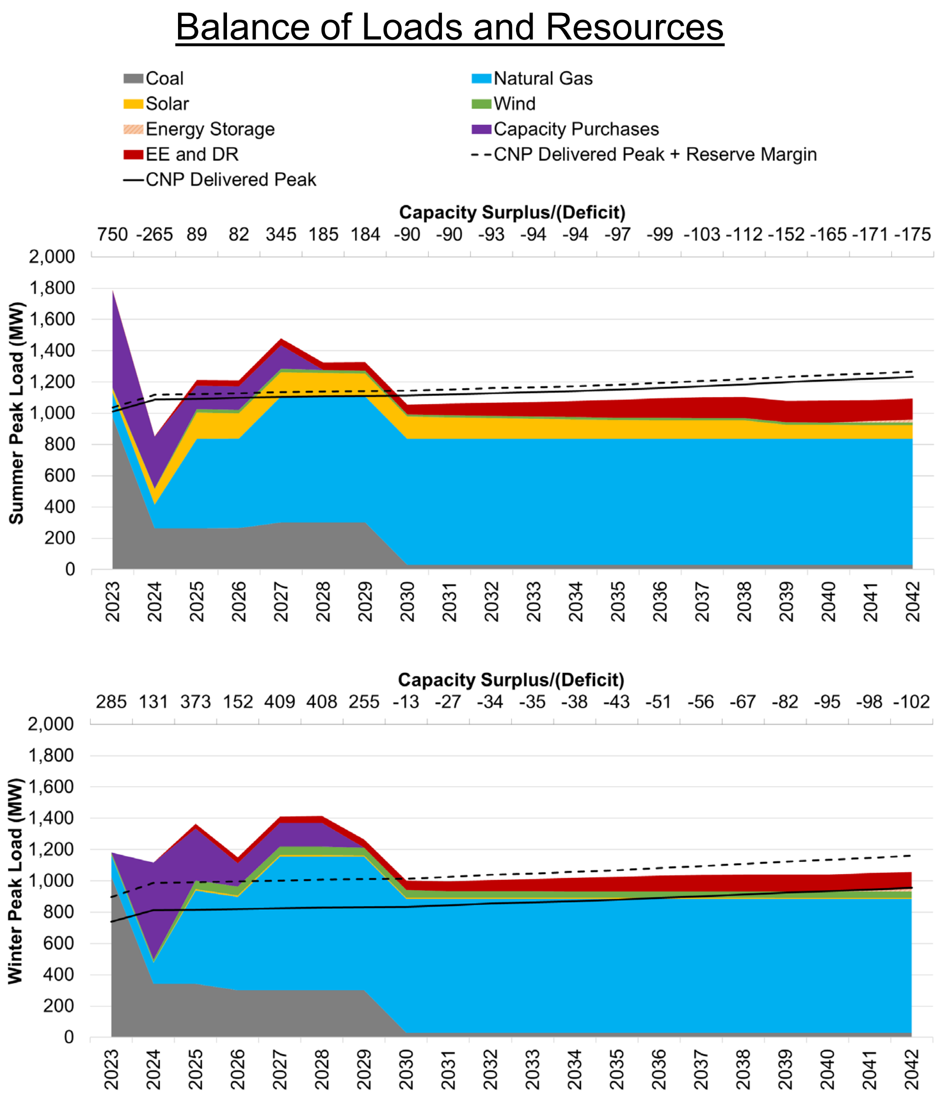


Energy Generation Mix



Market Driven Innovation Portfolio Selection

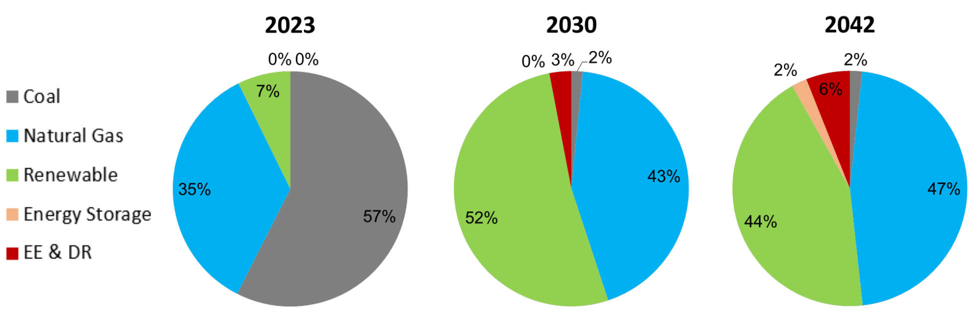
- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Conversion of CTs to CCGT
- Additional storage in 2032 and 2040s



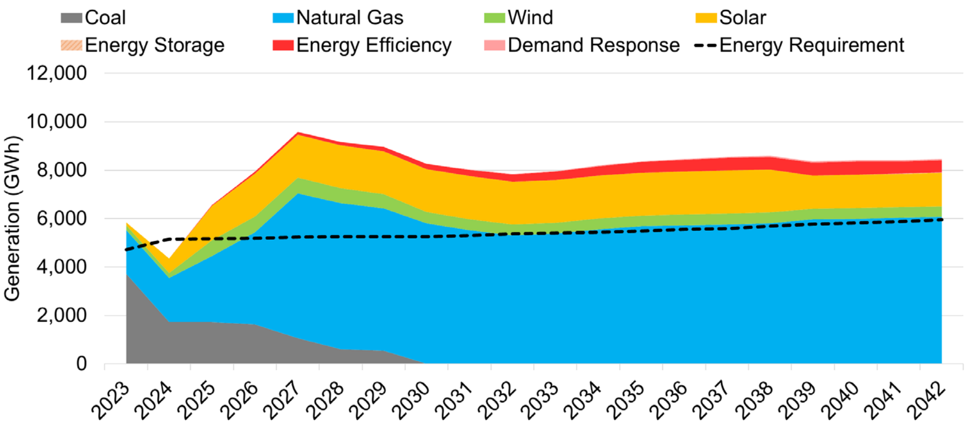
Market Driven Innovation Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Conversion of CTs to CCGT
- Additional storage in 2032 and 2040s

Installed Capacity



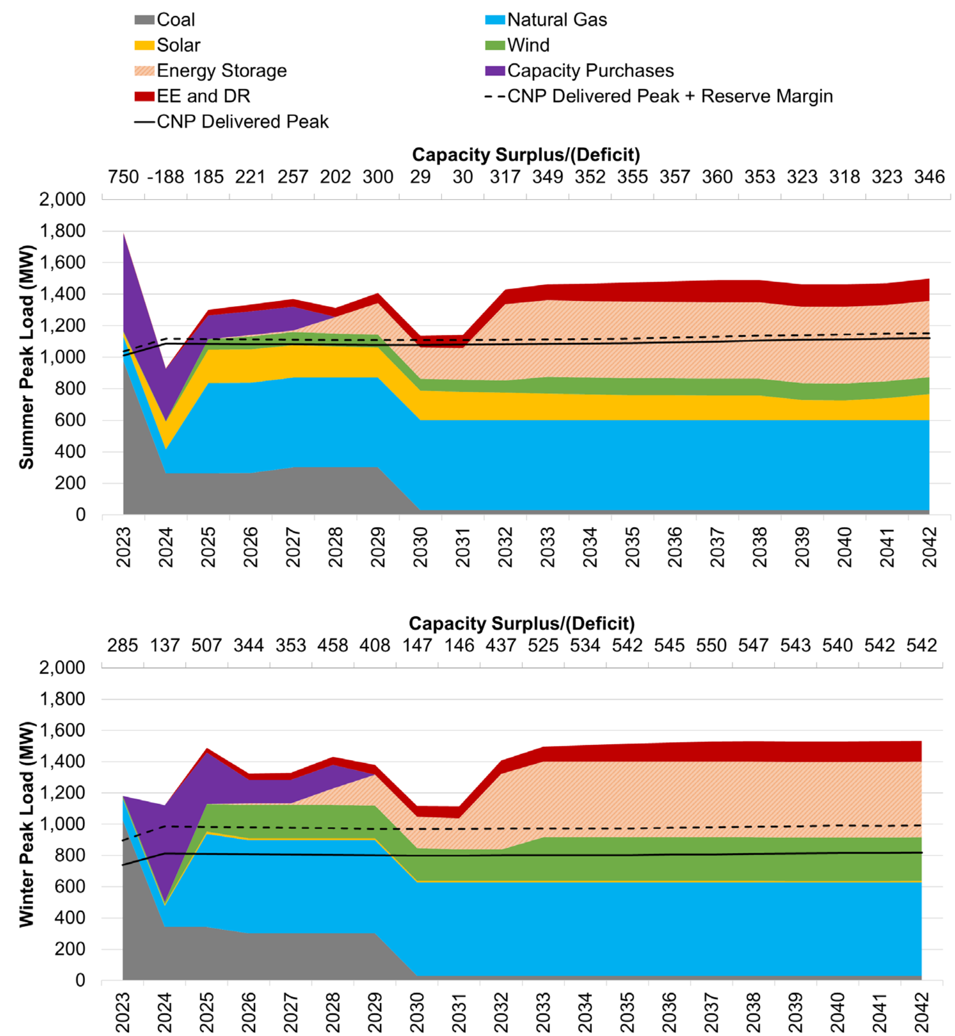
Energy Generation Mix



High Regulatory Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- High renewable additions
  - Wind and solar additions throughout study period
  - Solar + Storage
  - Long Duration Storage

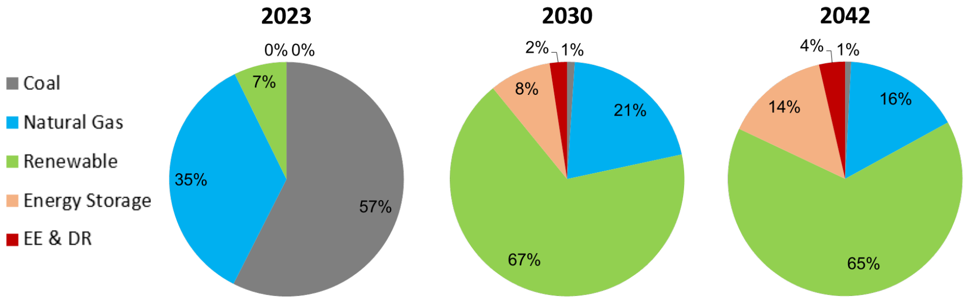
Balance of Loads and Resources



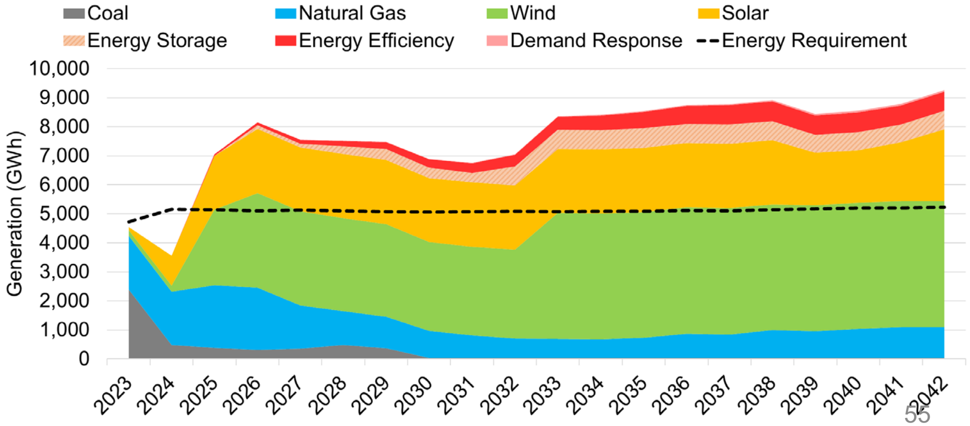
High Regulatory Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- High renewable additions
  - Wind and solar additions throughout study period
  - Solar + Storage
  - Long Duration Storage

Installed Capacity



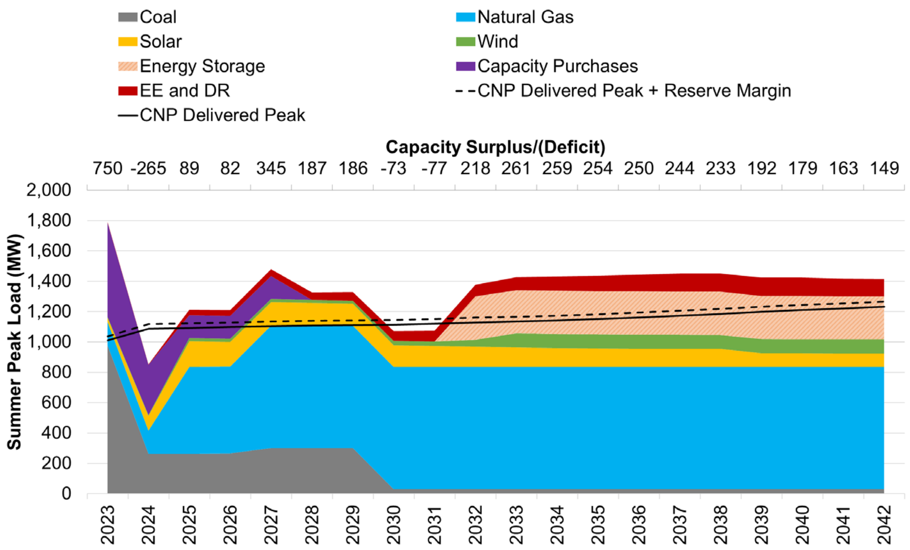
Energy Generation Mix

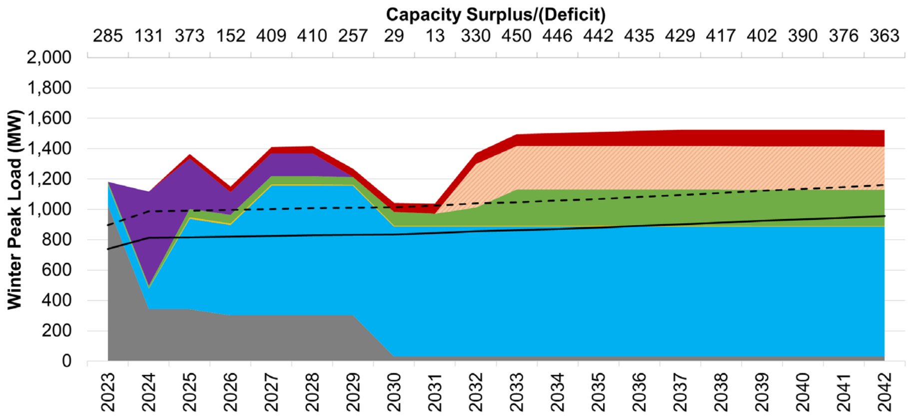


Decarbonization/Electrification Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Conversion of CTs to CCGT
- Wind in the 2030s
- Long Duration Storage

Balance of Loads and Resources

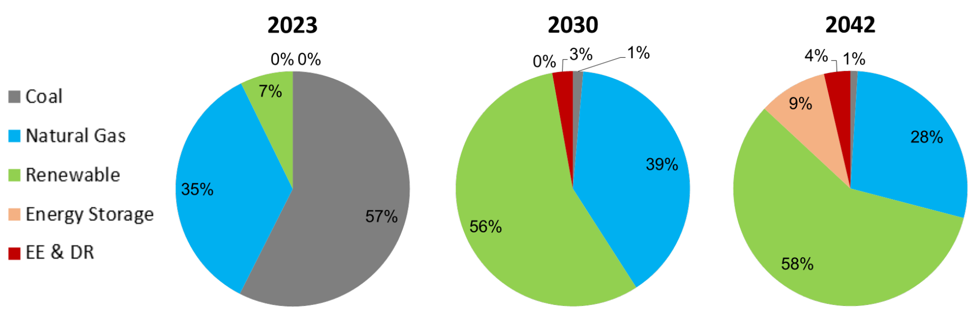




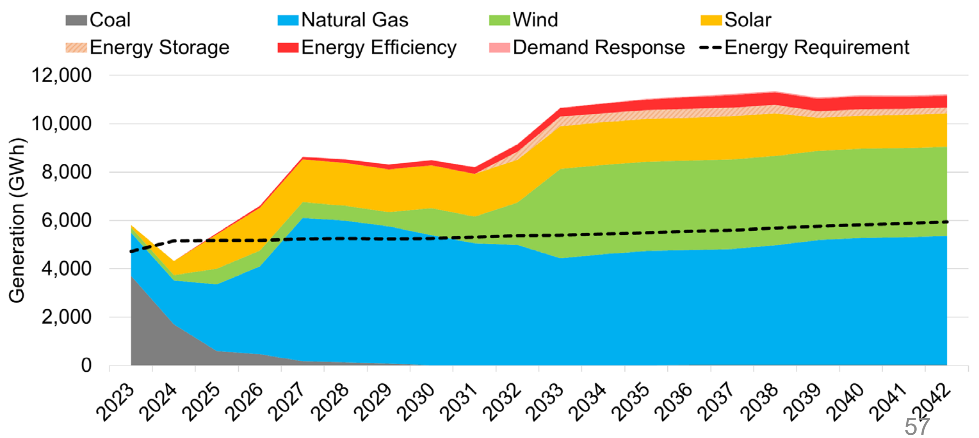
Decarbonization/Electrification Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Conversion of CTs to CCGT
- Wind in the 2030s
- Long Duration Storage

Installed Capacity



Energy Generation Mix



Draft Deterministic Portfolio Results

Drew Burczyk
Consultant, Resource Planning & Market Assessments
1898 & Co.

Draft Deterministic Portfolios

Year	Reference Case	BAU	Replace Culley With Storage	Convert Culley to Natural Gas	High Renewables & Storage by 2035	J-Class CCGT	F-Class CT	No AB Brown CCGT Conversion
2024	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Continue FB Culley 3 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)
2026				Covert FB Culley 2 & 3 to Natural Gas				
2027	CCGT Conversion							
2028								
2029	Retire FB Culley 3		Retire FB Culley 3			Retire FB Culley 3	Retire FB Culley 3	Retire FB Culley 3
2030			Storage (300MW)			1x1 J CC UF	1 x F CT	Storage (150MW)
2031								
2032		Wind North (100MW) Long Duration Storage (300MW)		Wind North (200MW)	Wind North (400MW) Long Duration Storage (300MW)		Wind North (200MW) Long Duration Storage (300MW)	Wind North (200MW)
2033	Wind North (600MW)	Wind North (600MW)		Wind North (600MW)	Wind North (600MW)	Wind North (600MW)	Wind North (600MW)	Wind North (600MW)
2034					Retire FB Culley 3			
2042								Storage (10MW)
NPV ($M)								
% Difference From Reference Case								

Note: CEI South's latest RFP only resulted in 2 bids for wind projects. As other utilities pursue wind projects it may become increasingly difficult to execute on wind heavy portfolios if there are not enough viable projects to meet demand.

Draft Deterministic Portfolios – EE & DR

CenterPoint Energy

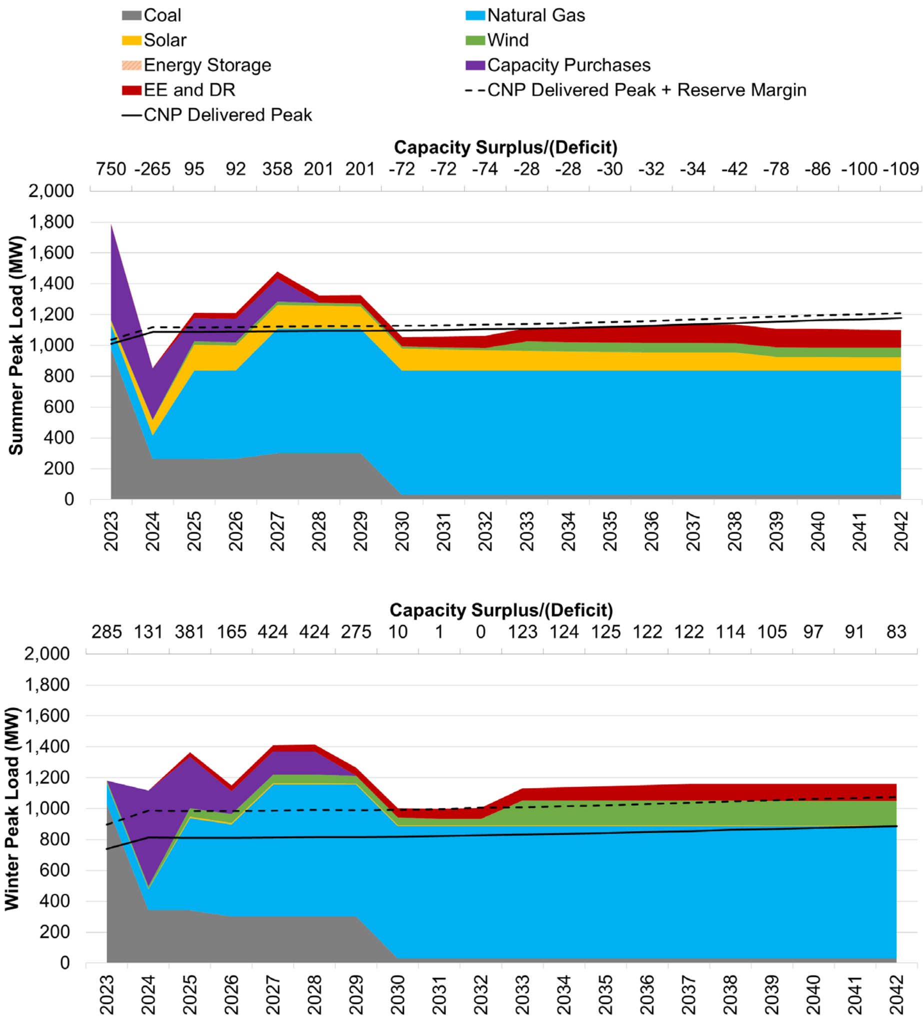
	Reference Case	BAU	Replace Culley With Storage	Convert Culley to Natural Gas	High Renewables & Storage by 2035	J-Class CCGT	F-Class CT	No AB Brown 7 Option
Vintage 1 2025 - 2027	DR Legacy - 2023	DR Legacy - 2023	DR Legacy - 2023	DR Legacy - 2023	DR Legacy - 2023	DR Legacy - 2023	DR Legacy - 2023	DR Legacy - 2023
	DR Industrial	DR Industrial	DR Industrial	DR Industrial	DR Industrial	DR Industrial	DR Industrial	DR Industrial
	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced
	HER	HER	HER	HER	HER	HER	HER	HER
	IQW	IQW	IQW	IQW	IQW	IQW	IQW	IQW
Vintage 2 2028 - 2030	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced
	IQW	HER	HER	HER	HER	IQW	HER	HER
		IQW	IQW	IQW	IQW		IQW	IQW
Vintage 3 2031 - 2042	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced
	DR CI Rates	DR CI Rates	DR CI Rates	DR CI Rates	DR CI Rates	DR CI Rates	DR CI Rates	DR CI Rates
	IQW	IQW	IQW	IQW	IQW	IQW	IQW	IQW
			HER					
			Residential Low & Medium					

IQW = Income Qualified Weatherization
HER = Home Energy Reports
C&I = Commercial & Industrial

Reference Case Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Conversion of CTs to CCGT
- EE & DR
- Wind in 2033

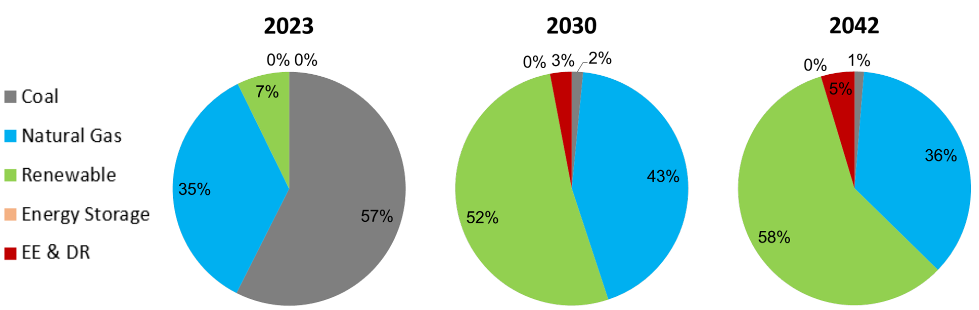
Balance of Loads and Resources



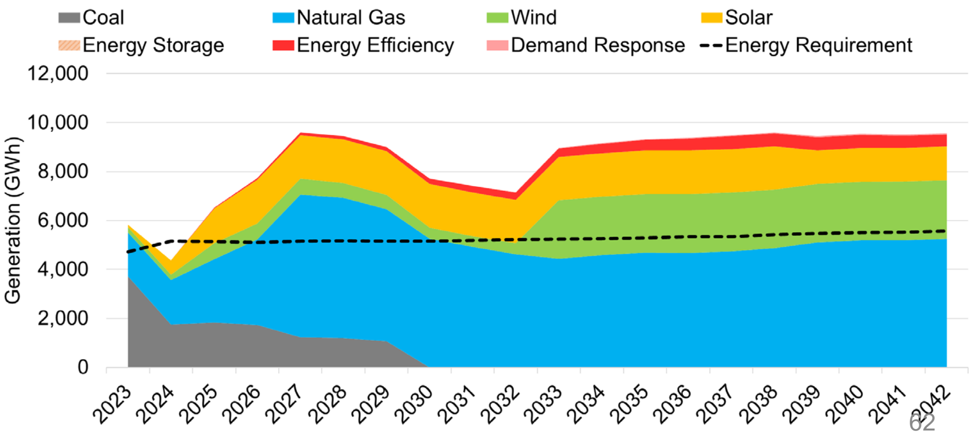
Reference Case Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Conversion of CTs to CCGT
- EE & DR
- Wind in 2033

Installed Capacity



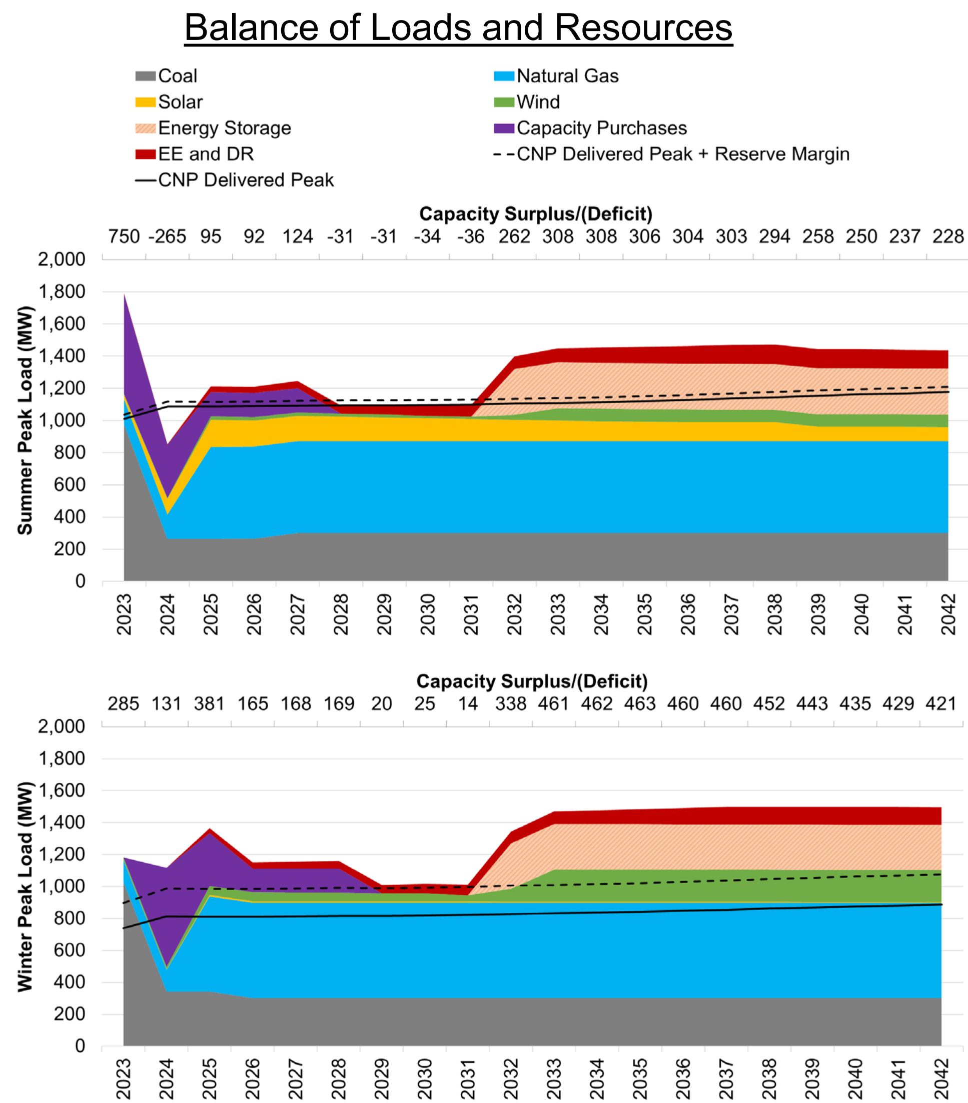
Energy Generation Mix



Business as Usual Portfolio Selection

CenterPoint Energy

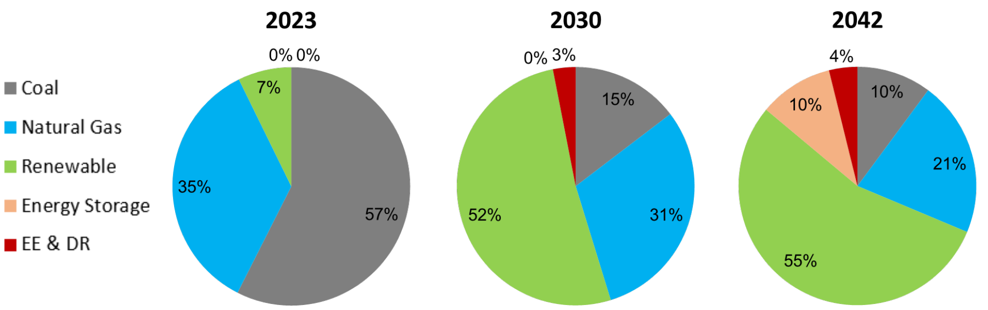
- 2025 retirement of FB Culley 2
- Continue FB Culley 3 operations through study period
- Wind in the 2030s
- Long Duration Storage in 2032



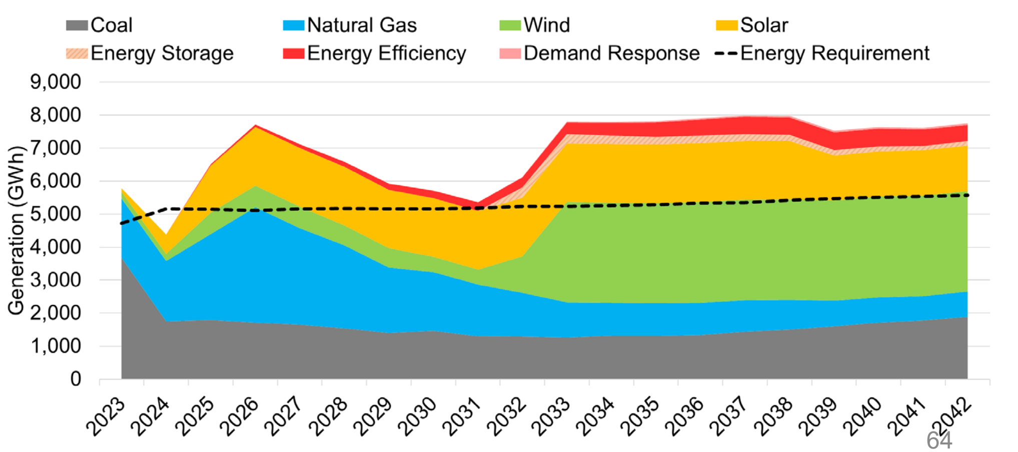
Business as Usual Portfolio Selection

- 2025 retirement of FB Culley 2
- Continue FB Culley 3 operations through study period
- Wind in the 2030s
- Long Duration Storage in 2032

Installed Capacity



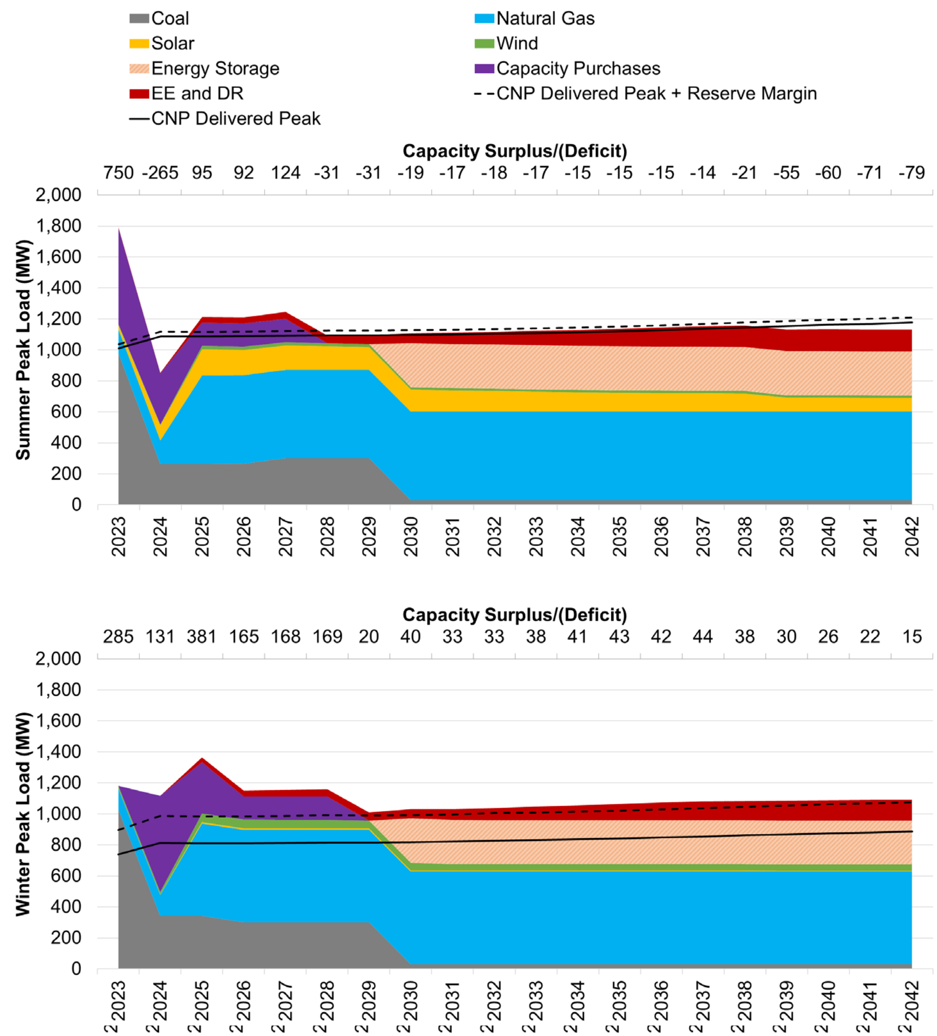
Energy Generation Mix



Replace Culley With Storage Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Storage in 2030

Balance of Loads and Resources



Replace Culley With Storage Portfolio Selection

- 2025 retirement of FB Culley 2
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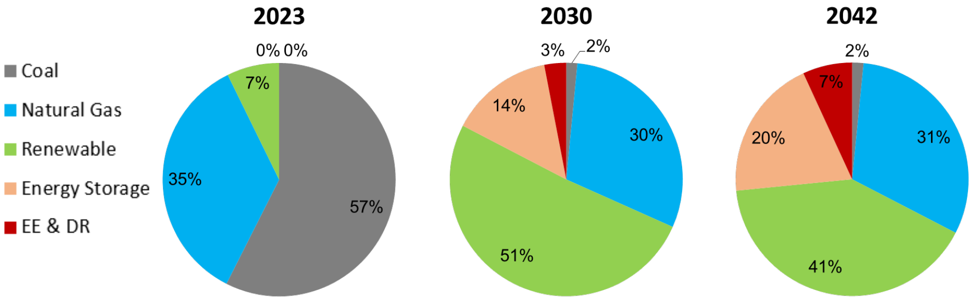
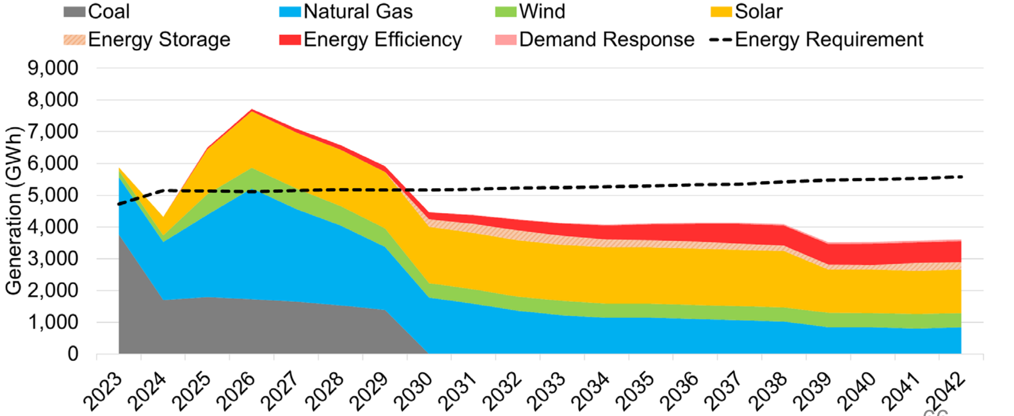
- Storage in 2030

Installed Capacity



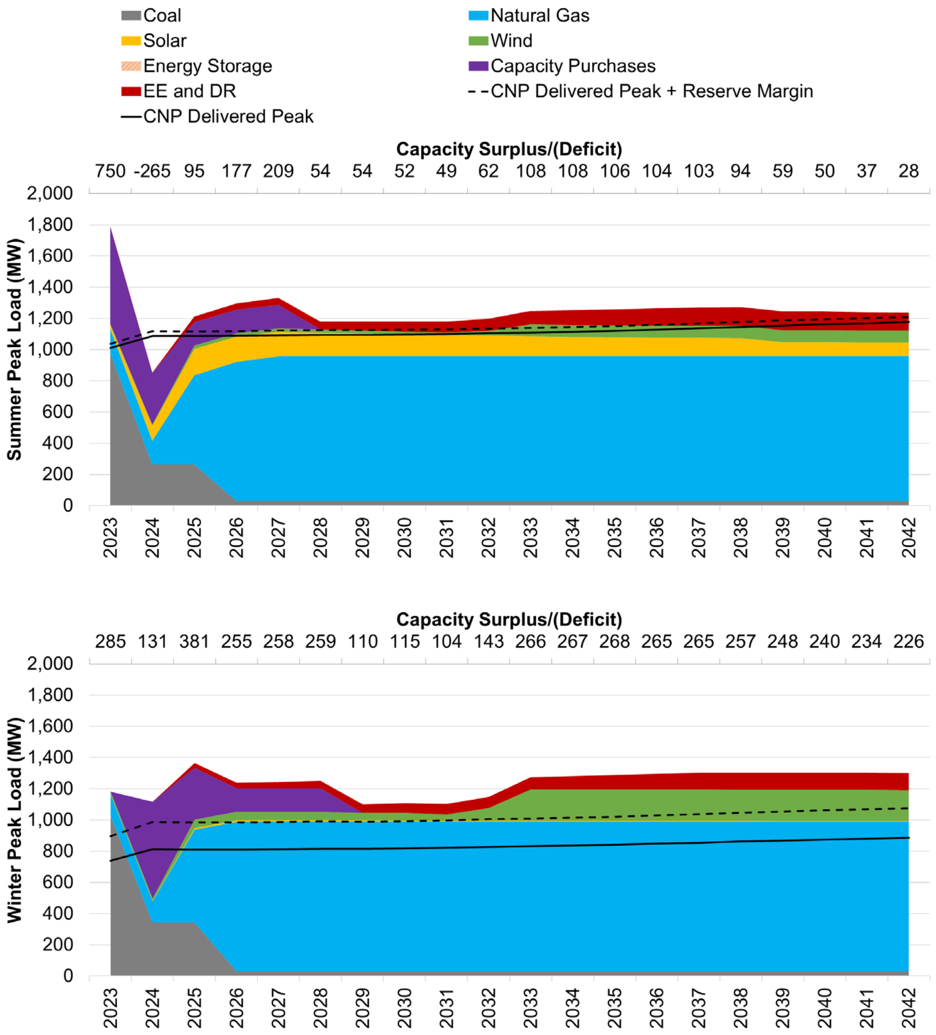
Energy Generation Mix



Convert Culley to Natural Gas Portfolio Selection

- Convert FB Culley 2 & 3 to gas in 2026
- Wind in the 2030s

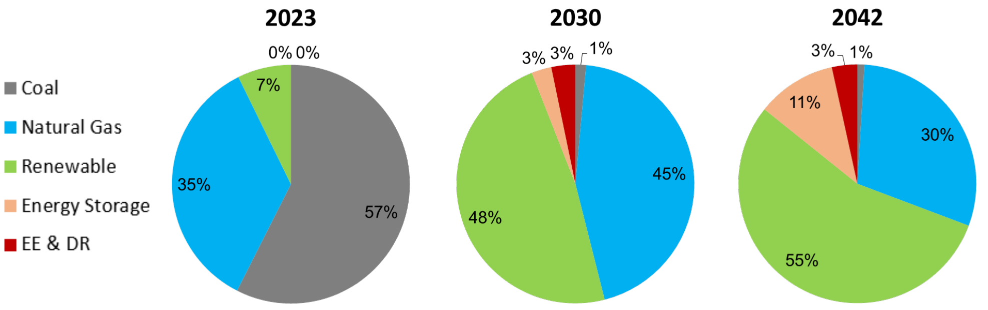
Balance of Loads and Resources



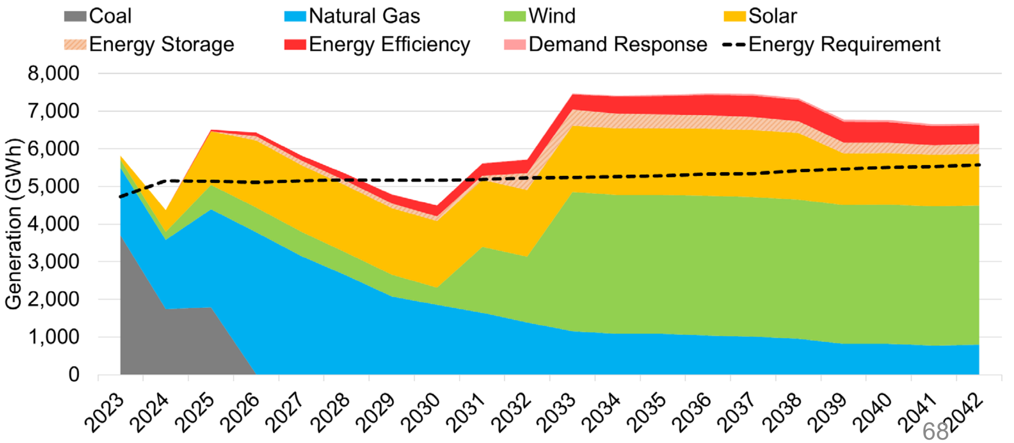
Convert Culley to Natural Gas Portfolio Selection

- Convert FB Culley 2 & 3 to gas in 2026
- Wind in the 2030s

Installed Capacity



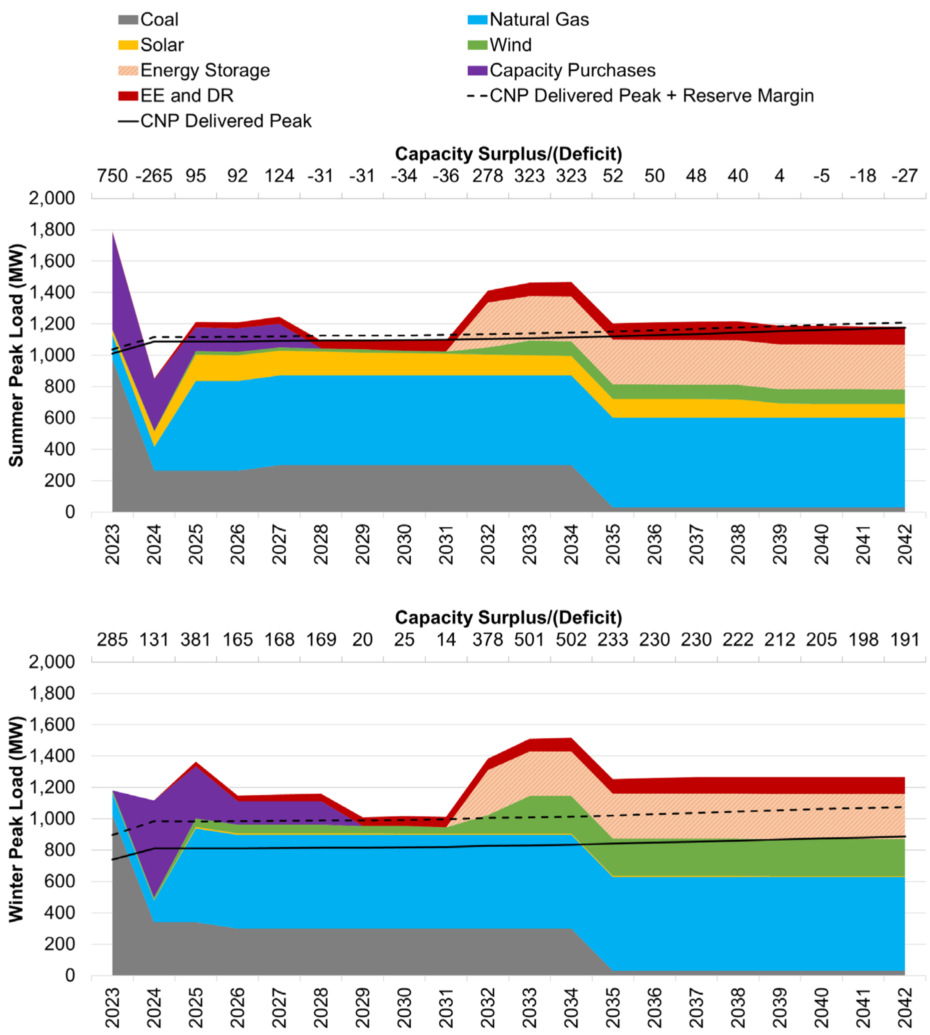
Energy Generation Mix



High Renewables & Storage by 2035 Portfolio Selection

- 2025 retirement of FB Culley 2
- 2034 retirement of FB Culley 3
- Additional wind and storage in the 2030s

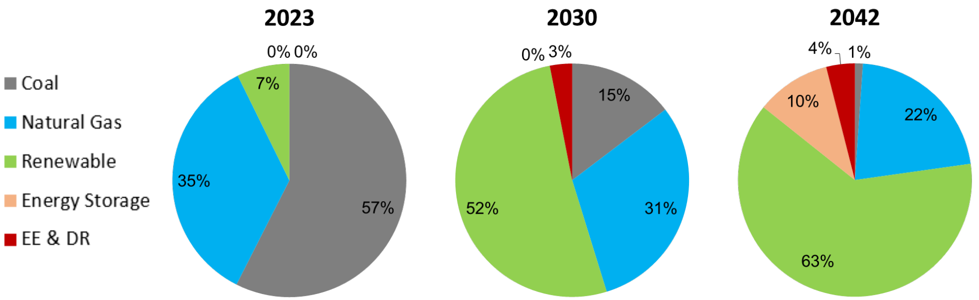
Balance of Loads and Resources



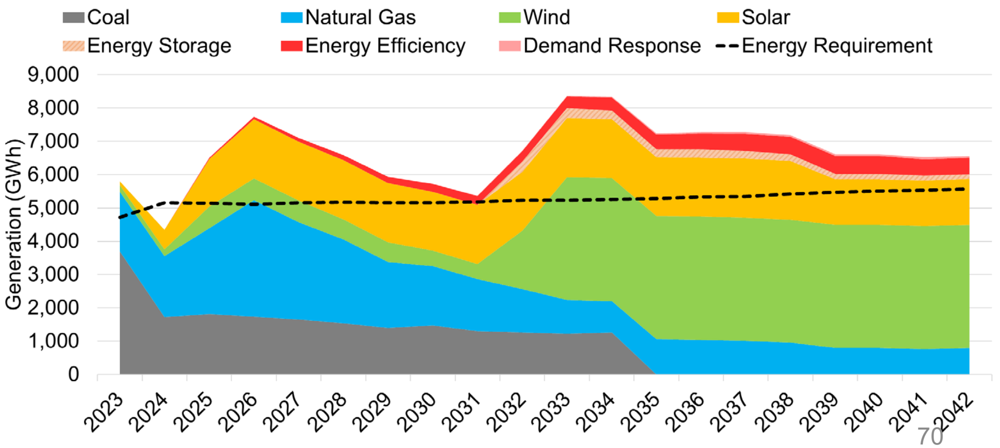
High Renewables & Storage by 2035 Portfolio Selection

- 2025 retirement of FB Culley 2
- 2034 retirement of FB Culley 3
- Additional wind and storage in the 2030s

Installed Capacity



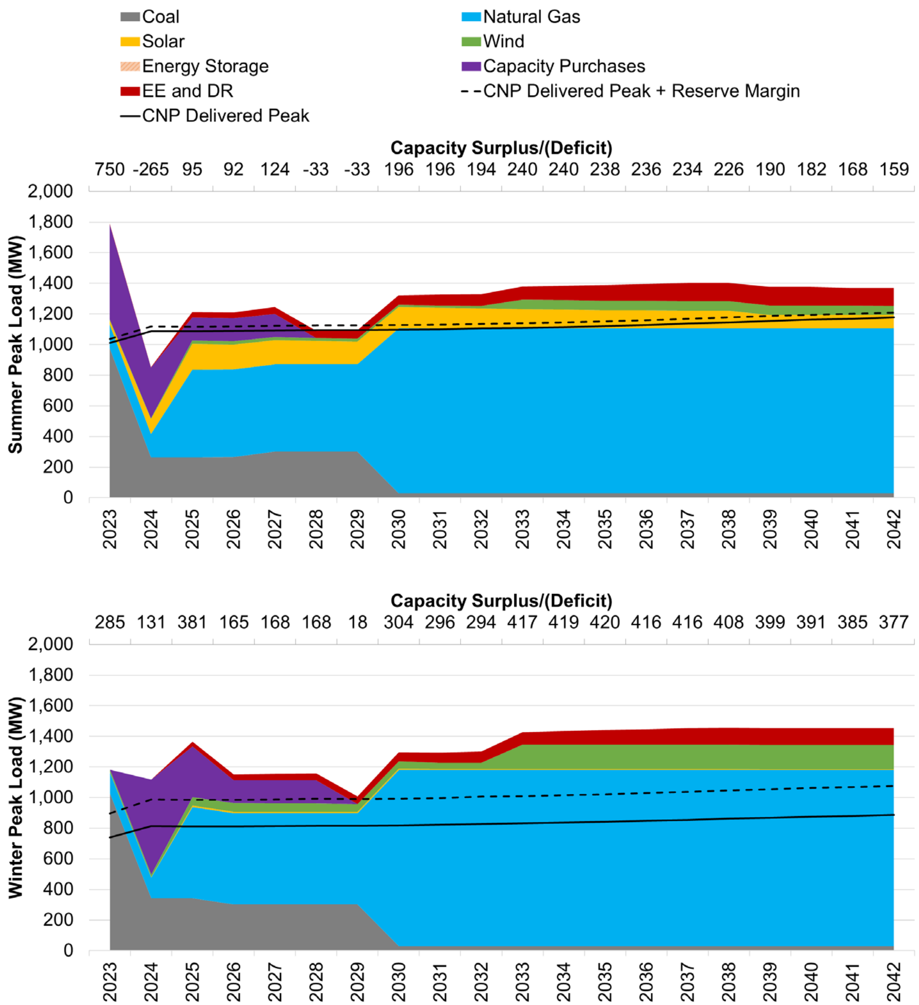
Energy Generation Mix



J-Class CCGT Portfolio Selection

- J-Class Combined Cycle in 2030
- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Additional wind in the 2030s

Balance of Loads and Resources

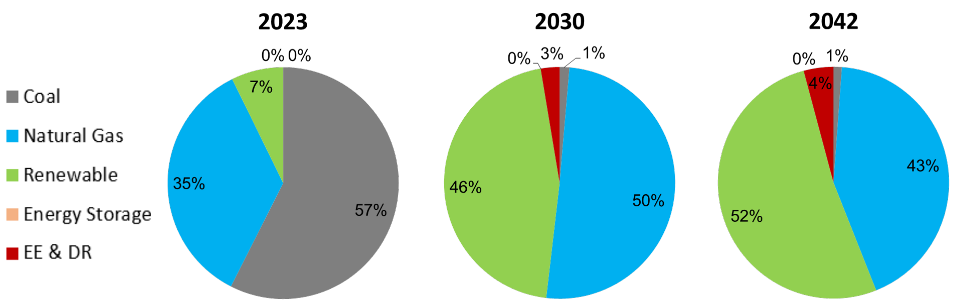


J-Class CCGT Portfolio Selection

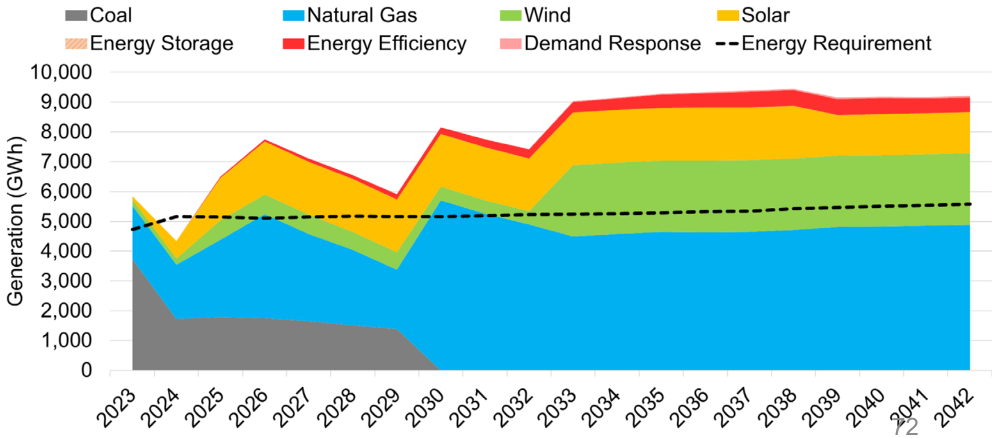
CenterPoint Energy

- J-Class Combined Cycle in 2030
- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Additional wind in the 2030s

Installed Capacity



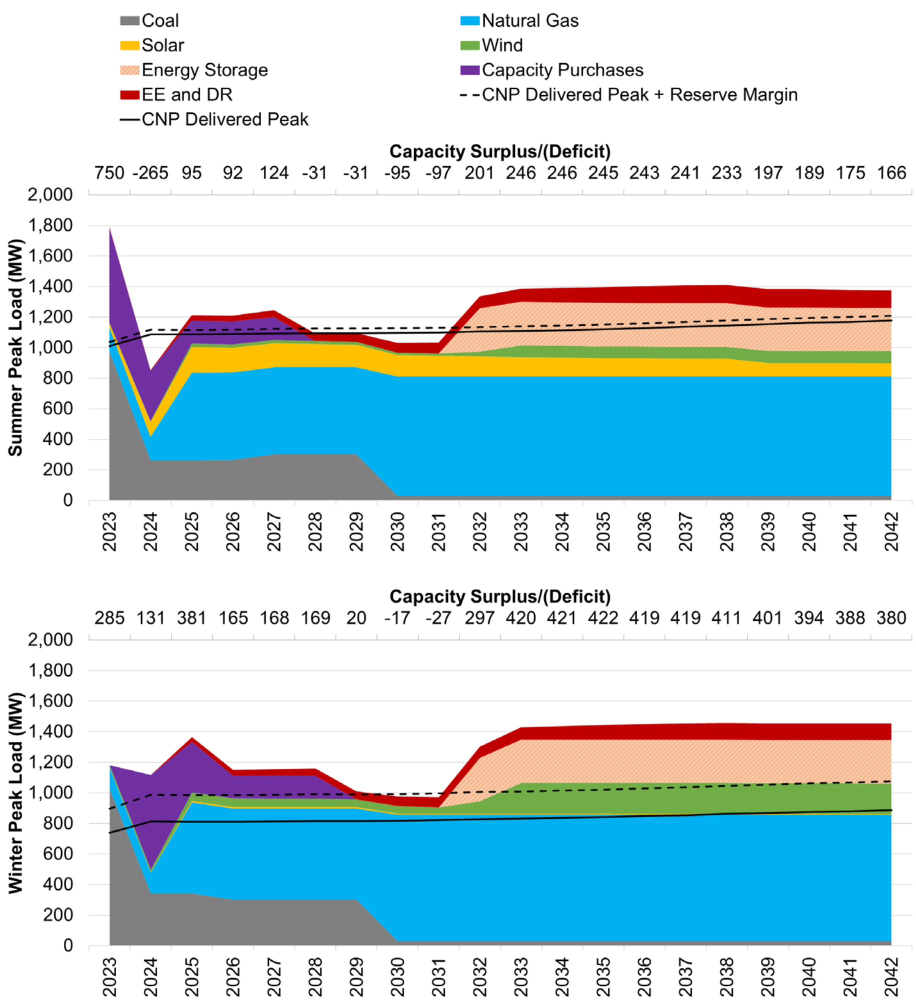
Energy Generation Mix



F-Class CT Portfolio Selection

- F-Class CT in 2030
- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Additional wind and storage in the 2030s

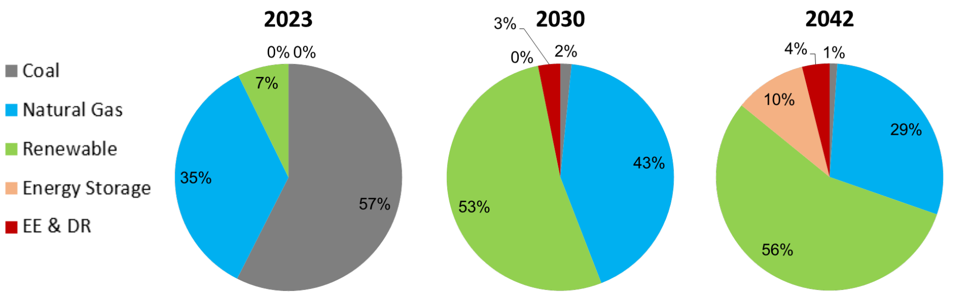
Balance of Loads and Resources



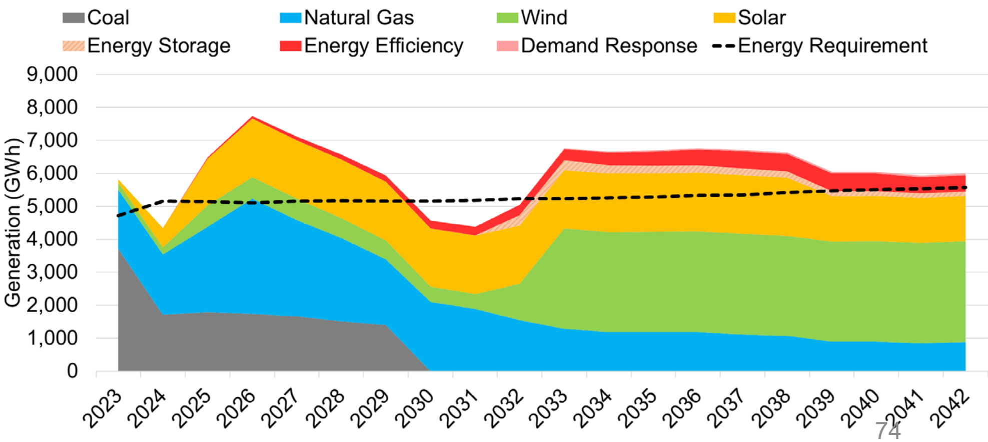
F-Class CT Portfolio Selection

- F-Class CT in 2030
- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Additional wind and storage in the 2030s

Installed Capacity

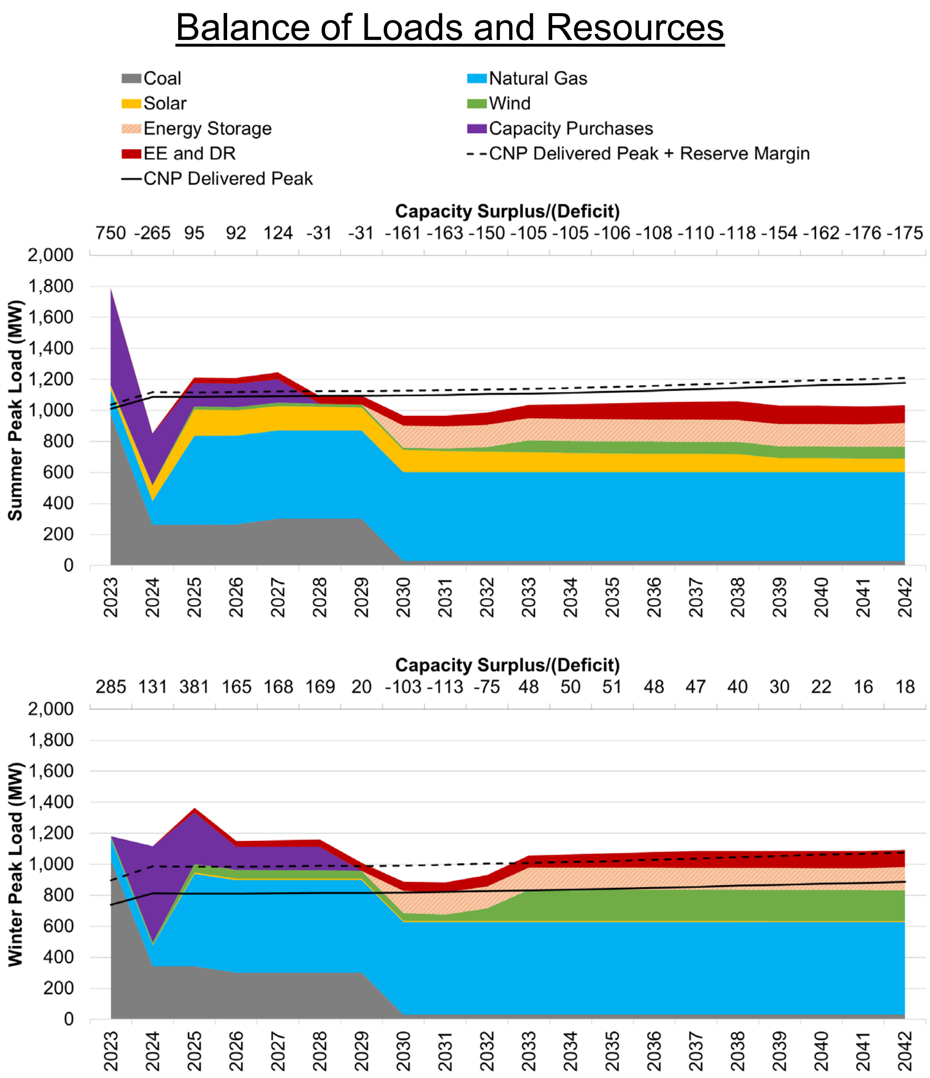


Energy Generation Mix



No AB Brown CCGT Conversion Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Additional wind and storage in the 2030s
- 10 MW storage in 2042



No AB Brown CCGT Conversion Portfolio Selection

- 2025 retirement of FB Culley 2
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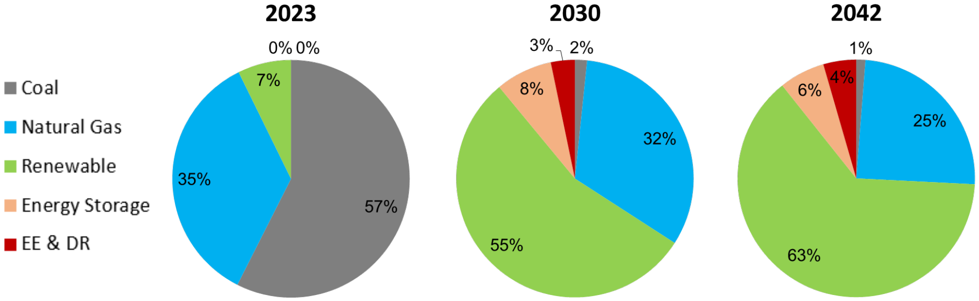
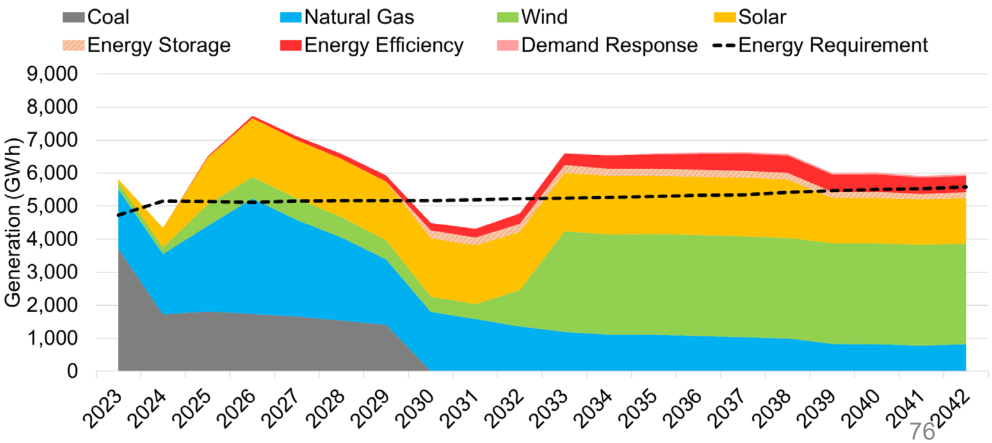
- 10 MW storage in 2042

Installed Capacity



Energy Generation Mix



Scorecard

Scorecard		Affordability	Cost Risk		Environmental Sustainability		Reliability		Market Risk Minimization		Execution
Portfolio Strategy Group	Portfolio	20 Year NPVRR ($M)	Proportion of Energy Generated by Resources With Exposure to Coal and Gas Markets and Market Purchases (%)	95% Value of NPVRR ($)	CO2 Intensity (Tons CO_2e/kwh)	CO2 Equivalent Emissions (Stack Emissions) (Tons CO_2e)	Must Meet MISO Planning Reserve Margin Requirement in All Seasons (MW)	Spinning Reserve\ Fast Start Capability (%)	Energy Market Purchases or Sales (%)	Capacity Market Purchases or Sales (%)	Assess Challenges of Implementing Each Portfolio
Reference	Reference Case										
BAU	Business as Usual										
Scenario Based	Market Driven Innovation										
	High Regulatory										
	Decarbonization/Electrification										
	Continued High Inflation & Supply Chain Issues										
Replacement of FB Culley	Convert Culley to Natural Gas										
	J-Class CCGT										
	F-Class CT										
	Replace Culley with Storage										
	High Renewables & Storage by 2035										
	No AB Brown CCGT Conversion										

Q&A

Appendix

Draft Reference Case Inputs

Input	Unit	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal (ILB)	$/MMBtu	4.39	3.09	2.77	2.81	2.78	2.85	2.90	2.91	3.02	3.06	3.16	3.24	3.33	3.41	3.51	3.58	3.66	3.75	3.84	3.96
CO2	$/short ton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas (Henry Hub)	$/MMBtu	5.68	4.65	4.43	4.50	4.57	4.70	4.87	5.05	5.23	5.39	5.55	5.72	5.83	6.03	6.26	6.48	6.71	7.00	7.22	7.59
Peak Load	MW	1,010	1,087	1,087	1,088	1,092	1,095	1,095	1,096	1,100	1,105	1,110	1,114	1,120	1,128	1,136	1,145	1,154	1,162	1,169	1,177
Wind (200 MW)	$/kW	[redacted]				2,056	2,008	1,956	1,901	1,925	1,949	1,974	1,998	2,023	2,047	2,072	2,097	2,121	2,146	2,171	2,196
Solar (100 MW)	$/kW	[redacted]				1,891	1,836	1,777	1,714	1,737	1,761	1,785	1,809	1,834	1,858	1,883	1,908	1,933	1,958	1,983	2,009
Storage (100 MW)	$/kW	[redacted]				1,711	1,669	1,643	1,614	1,632	1,648	1,664	1,680	1,696	1,712	1,727	1,743	1,758	1,773	1,788	1,802

All values are Nominal $'s

Draft High Regulatory Case Inputs

CenterPoint Energy

Input	Unit	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal (ILB)	$/MMBtu	4.39	3.09	3.13	3.16	3.19	3.22	3.31	3.34	3.48	3.52	3.67	3.77	3.88	4.00	4.12	4.22	4.34	4.45	4.58	4.71
CO2	$/short ton	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas (Henry Hub)	$/MMBtu	5.68	4.65	5.64	6.63	7.62	8.61	8.85	9.44	10.00	10.51	11.01	11.47	11.55	11.68	12.09	12.42	12.64	13.19	13.58	14.31
Peak Load	MW	1,010	1,087	1,085	1,083	1,081	1,080	1,078	1,077	1,080	1,082	1,084	1,086	1,090	1,094	1,099	1,105	1,111	1,115	1,118	1,123
Wind (200 MW)	$/kW	[redacted]				2,056	2,008	1,956	1,901	1,858	1,815	1,772	1,729	1,686	1,643	1,600	1,557	1,514	1,471	1,428	1,385
Solar (100 MW)	$/kW	[redacted]				1,663	1,626	1,589	1,552	1,515	1,478	1,442	1,405	1,368	1,331	1,294	1,257	1,220	1,183	1,146	1,109
Storage (100 MW)	$/kW	[redacted]				1,431	1,419	1,407	1,395	1,383	1,372	1,360	1,348	1,336	1,324	1,312	1,300	1,289	1,277	1,265	1,253

All values are Nominal $'s

Draft Market Driven Innovation Case Inputs

CenterPoint Energy

Input	Unit	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal (ILB)	$/MMBtu	4.39	3.09	2.77	2.62	2.46	2.47	2.49	2.48	2.55	2.60	2.64	2.71	2.79	2.81	2.91	2.94	2.97	3.05	3.10	3.21
CO2	$/short ton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas (Henry Hub)	$/MMBtu	5.68	4.65	4.29	3.93	3.57	3.21	3.34	3.38	3.44	3.49	3.55	3.62	3.73	3.93	4.08	4.26	4.47	4.66	4.81	5.06
Peak Load	MW	1,010	1,087	1,093	1,098	1,104	1,110	1,112	1,115	1,120	1,128	1,135	1,142	1,150	1,162	1,174	1,185	1,197	1,209	1,220	1,231
Wind (200 MW)	$/kW	[redacted]				2,056	2,008	1,956	1,901	1,858	1,815	1,772	1,729	1,686	1,643	1,600	1,557	1,514	1,471	1,428	1,385
Solar (100 MW)	$/kW	[redacted]				1,663	1,626	1,589	1,552	1,515	1,478	1,442	1,405	1,368	1,331	1,294	1,257	1,220	1,183	1,146	1,109
Storage (100 MW)	$/kW	[redacted]				1,431	1,419	1,407	1,395	1,383	1,372	1,360	1,348	1,336	1,324	1,312	1,300	1,289	1,277	1,265	1,253

All values are Nominal $'s

Draft Decarbonization/Electrification Case Inputs

Input	Unit	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal (ILB)	$/MMBtu	4.39	3.09	3.13	3.16	3.19	3.22	3.31	3.34	3.48	3.52	3.67	3.77	3.88	4.00	4.12	4.22	4.34	4.45	4.58	4.71
CO2	$/short ton	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas (Henry Hub)	$/MMBtu	5.68	4.65	4.43	4.50	4.57	4.70	4.87	5.05	5.23	5.39	5.55	5.72	5.83	6.03	6.26	6.48	6.71	7.00	7.22	7.59
Peak Load	MW	1,010	1,087	1,093	1,098	1,104	1,110	1,112	1,115	1,120	1,128	1,135	1,142	1,150	1,162	1,174	1,185	1,197	1,209	1,220	1,231
Wind (200 MW)	$/kW	[redacted]				2,056	2,008	1,956	1,901	1,925	1,949	1,974	1,998	2,023	2,047	2,072	2,097	2,121	2,146	2,171	2,196
Solar (100 MW)	$/kW	[redacted]				1,891	1,836	1,777	1,714	1,737	1,761	1,785	1,809	1,834	1,858	1,883	1,908	1,933	1,958	1,983	2,009
Storage (100 MW)	$/kW	[redacted]				1,711	1,669	1,643	1,614	1,632	1,648	1,664	1,680	1,696	1,712	1,727	1,743	1,758	1,773	1,788	1,802

All values are Nominal $'s

Draft Continued High Inflation and Supply Chain Issues Case Inputs

Input	Unit	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal (ILB)	$/MMBtu	4.39	3.09	3.13	3.16	3.19	3.22	3.31	3.34	3.48	3.52	3.67	3.77	3.88	4.00	4.12	4.22	4.34	4.45	4.58	4.71
CO2	$/short ton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas (Henry Hub)	$/MMBtu	5.68	4.65	5.04	5.42	5.80	6.19	6.39	6.70	7.01	7.28	7.55	7.81	7.92	8.12	8.42	8.69	8.94	9.32	9.60	10.11
Peak Load	MW	1,010	1,087	1,085	1,083	1,081	1,080	1,078	1,077	1,080	1,082	1,084	1,086	1,090	1,094	1,099	1,105	1,111	1,115	1,118	1,123
Wind (200 MW)	$/kW	[redacted]				2,148	2,198	2,248	2,299	2,352	2,406	2,461	2,518	2,575	2,634	2,695	2,757	2,820	2,884	2,951	3,018
Solar (100 MW)	$/kW	[redacted]				2,104	2,152	2,201	2,252	2,303	2,356	2,410	2,465	2,522	2,580	2,639	2,699	2,761	2,825	2,889	2,956
Storage (100 MW)	$/kW	[redacted]				2,331	2,385	2,439	2,495	2,553	2,611	2,671	2,732	2,795	2,859	2,924	2,991	3,060	3,130	3,202	3,275

All values are Nominal $'s

Definitions

Term	Definition
ACE	Affordable Clean Energy (ACE) Rule, establishes emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants
All-Source RFP	Request for proposals, regardless of source (renewable, thermal, storage, demand response)
BAGS	Broadway Avenue Gas Turbine
BTA	Build Transfer Agreement/Utility Ownership
C&I	Commercial and Industrial
CAA	Clean Air Act
CAGR	Compound Annual Growth Rate
Capacity	The maximum output of electricity that a generator can produce under ideal conditions (megawatts)
CCGT	A combined-cycle power plant uses both a gas and a steam turbine together to produce up to 50 percent more electricity from the same fuel than a traditional simple-cycle plant. The waste heat from the gas turbine is routed to the nearby steam turbine, which generates extra power
CCR Rule	Coal Combustion Residuals Rule
CCS	Carbon Capture and Storage
CDD	Cooling Degree Day
CEI South	CenterPoint Energy Indiana South
CO_2	Carbon dioxide

Definitions Cont.

Term	Definition
CONE	Cost of New Entry
CPCN	A Certificate of Public Convenience and Necessity is required to be granted by the Commission for significant generation projects
CSAPR	Cross State Air Pollution Rule
DER	Distributed Energy Resource
Deterministic Modeling	Simulated dispatch of a portfolio in a determined future. Often computer generated portfolios are created by optimizing on cost to the customer
DLC	Direct Load Control
DR	Demand Response
DSM	Demand side management includes both Energy Efficiency and Demand Response programs to reduce customer demand for electricity
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines are U.S. national standards for wastewater discharges to surface waters and publicly owned treatment works
EnCompass	Electric modeling forecasting and analysis software
Energy	Amount of electricity (megawatt-hours) produced over a specific time period

Definitions Cont.

Term	Definition
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GW	Gigawatt (1,000 million watt), unit of electric power
GWh	Gigawatt Hour
HDD	Heating Degree Day
Henry Hub	Point of interconnection of interstate and intrastate natural gas pipelines as well as other related infrastructure in Erath, Louisiana
IDEM	Indiana Department of Environmental Management
Installed Capacity (ICAP)	Refers to generating capacity after ambient weather adjustments and before forced outages adjustments
Intermittent	An intermittent energy source is any source of energy that is not continuously available for conversion into electricity and outside direct control
IRP	Integrated Resource Plan is a comprehensive plan to meet customer load expectations
IURC	The Indiana Utility Regulatory Commission is the public utilities commission of the State of Indiana. The commission regulates electric, natural gas, telecommunications, steam, water and sewer utilities
KWh	Kilowatt Hour

Definitions Cont.

Term	Definition
LCOE	Levelized Cost of Energy, A measure that looks at cost and energy production over the life of an asset so different resources can be compared. Does not account for capacity value.
LMR	Load Modifying Resource
Local Clearing Requirement (LCR)	Capacity needs to be fulfilled by local resource zone
LRZ6	MISO Local Resource Zone 6
MATS	Mercury and Air Toxics Standard
Mine Mouth	At the mine location
MISO	Midcontinent Independent System Operator, an Independent System Operator (ISO) and Regional Transmission Organization(RTO) providing open-access transmission service and monitoring the high-voltage transmission system in the Midwest United States and Manitoba, Canada and a southern United States region which includes much of Arkansas, Mississippi, and Louisiana. MISO also operates one of the world's largest real-time energy markets
MMBTU	Million British Thermal Units
MPS	Market potential study - Determines the total market size (value/volume) for a DSM at a given period of time
MSA	Metropolitan Statistical Area
MW	Megawatt (million watt), unit of electric power
NAAQS	National Ambient Air Quality Standards

Definitions Cont.

Term	Definition
Name Plate Capacity	The intended full-load sustained output of a generation facility
NDA	Non-Disclosure Agreement
NOI	Notice of Intent
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPVRR	Net Present Value Revenue Requirement
NSPS	New Source Performance Standards
OMS	Organization of MISO States, was established to represent the collective interests of state and local utility regulators in the Midcontinent Independent System Operator (MISO) region and facilitate informed and efficient participation in related issues.
Peaking	Power plants that generally run only when there is a high demand, known as peak demand, for electricity
Planning Reserve Margin Requirement (PRMR)	Total capacity obligation each load serving entity needs to meet
Portfolio	A group of resources to meet customer load
PPA	Purchase Power Agreement

Definitions Cont.

Term	Definition
Preferred Portfolio	The IRP rule requires that utilities select the portfolio that performs the best, with consideration for cost, risk, reliability, and sustainability
Probabilistic modeling	Simulate dispatch of portfolios for a number of randomly generated potential future states, capturing performance measures
PV	Photovoltaic
RA (Resource Adequacy)	RA is a regulatory construct developed to ensure that there will be sufficient resources available to serve electric demand under all but the most extreme conditions
RAP	Realistic Achievable Potential
Resource	Supply side (generation) or demand side (Energy Efficiency, Demand Response, Load Shifting programs) to meet planning reserve margin requirements
SAC	Seasonal Accredited Capacity
Scenario	Potential future State-of-the-World designed to test portfolio performance in key risk areas important to management and stakeholders alike
SDE	Spray Dryer Evaporator
Sensitivity Analysis	Analysis to determine what risk factors portfolios are most sensitive to
SIP	State Implementation Plan
Spinning Reserve	Generation that is online and can quickly respond to changes in system load

Definitions Cont.

Term	Definition
T&D	Transmission and Distribution
Technology Assessment	An analysis that provides overnight and all-in costs and technical specifications for generation and storage resources
Unforced Capacity (UCAP)	A unit's generating capacity adjusted down for forced outage rates (thermal resources) or expected output during peak load (intermittent resources)
VAR Support	Unit by which reactive power is expressed in an AC electric power system
ZLD	Zero Liquid Discharge

CenterPoint 2022 IRP
3rd Stakeholder Meeting Minutes Q&A
December 13, 2022, 9:30 am – 3:00 pm CDT

Richard Leger (Senior Vice President, CenterPoint Energy) – Welcome, Safety Message

Matt Rice (Director, Regulatory and Rates, CenterPoint Energy) – Discussed the meeting agenda, guidelines for the meeting, discussed updates from the last stakeholder meeting including feedback, and the 2022/2023 IRP status update.

- Slide 10 Generation Transition Update:
  - Question: You mentioned the solar panel supply is the reason the solar project was pushed back a bit. Have you experienced any bottlenecks or roadblocks from MISO on these projects?
    - Response: Our projects are in the MISO 2020 queue, and it has been delayed a few times. It has pushed the Rustic Hill and Vermillion projects into 2025, and we don't expect to see an interconnection agreement until mid-2023.
- Slide 11 Stakeholder Feedback – Resources:
  - Question: I don't recall which technology was modeled for flow batteries in the last IRP. What is the preference for compressed air storage vs iron-air batteries?
    - Response: There's a lot of multi-day storage technologies being discussed in the market, but the viability of those is still being questioned and understood. Trying to balance commercial viability effectiveness is why we chose to model Compressed Air Storage.
  - Question: What about the new technology being created by FORM energy?
    - Response: We have heard of FORM energy, but everything that is being announced is in pilot and is several years out from being viable. We don't know if those technologies will come to fruition, and we cannot count on something that may not even be available.
- Slide 12 Stakeholder Feedback – Resources:
  - Question: For the repowering of the wind farms, is there a different or easier way to get a cost estimate for repowering wind farms?
    - Response: At this point, we don't have the cost estimate to repower the wind farm. We are in initial discussion on what we can do given our existing contracts. These contracts don't expire for a few years. If wind is selected in the model, it could be used as proxy for these existing wind contracts.
  - Question: You mentioned you would adjust up the capacity factor of wind because they are proving more resilient. Are you adjusting down the capacity factor of FB Culley 3 as it has been offline since June?
    - Response: When we looked at accreditation of existing units, we look at historical performance. We adjusted the accreditation of FB Culley 3 down for the next several years based on the current outage, but historically FB Culley has been a very reliable unit.
- Slide 16 Stakeholder Feedback – Resources:
  - Question: Can you clarify the decision to include the remaining book value of units in a retirement decision and to exclude inputting book value in units that continue to operate?
    - Response: We can discuss this offline to gain a better understanding of your feedback.
- General Questions:
  - Questions: For the FB Culley 3 gas conversion scenario, would that be a new gas pipeline? Are we bringing that pipeline in because there is not enough gas to supply this new peaking plant?
    - Response: It would be a new pipeline. The pipeline costs being modeled for a potential gas unit at FB Culley is separate from the line going to serve AB Brown for the new, approved CTs.[1]
  - Question: Why are the CTs at AB Brown being listed as Peaker plants? Are there black start capabilities?
    - Response: They are there to back up renewable resources when they are not providing enough energy to serve our customers. There are black start capabilities at that AB Brown.

[1] Other questions were posed about gas pipelines that were outside of the scope of this IRP.

Matt Lind (Director, Resource Planning & Market Assessments, 1898 & Co.) – Discussed scorecard metrics and reviewed modeling scenarios.

- Slide 22 Updated IRP Draft Objectives and Measures:
  - Question: Is spinning reserve/ fast start referring to black start capability?
    - Response: Those are more in line with MISO. Spinning reserve would be for a plant that is already online. Black start is for units that can help bring the grid back online. I would not define that as black start.
- General Questions:
  - Question: Do you have any updates on when the repairs for FB Culley 3 are expected to be completed?
    - Response: They are expected to be done sometime between the end of February and early March. We are going to see what the capacity accreditation for all resources within CenterPoint's portfolio and reflect that in the modeling. We do expect for units like FB Culley that its capacity accreditation will be accounted for in the modeling. We are waiting for MISO's numbers. Resource reliability is important to CenterPoint, MISO, and everyone to keep the lights on.
  - Question: Where will we see a final accounting of what the unplanned outage of FB Culley is going to cost customers? Are those repair costs going to be passed on to customers?
    - Response: A sub-docket is expected to be opened with the IURC which will provide that information. The commission will set it up, and the public information will be on their website.
  - Question: Is the RFP final for this IRP cycle?
    - Response: The RFP is closed, and the information received from that RFP is reflected in the modeling assumptions. However, we are still receiving market information for wind projects through on-going negotiations for a wind project.

Brian Despard (Project Manager, Resource Planning & Market Assessments, 1898 & Co.) – Discussed updates to the probabilistic modeling approach and assumptions including inputs.

Kyle Combes (Project Manager, Resource Planning & Market Assessments, 1898 & Co.) – Discussed the final 2022/2023 IRP resource inputs, seasonal accreditation, technical assessment, and cost curves.

- Slide 39 MISO Update:
  - Question: How is MISO treating storage? Is that still to be determined? How do you see them addressing storage accreditation?
    - Response: MISO has not said how they are treating storage; for now, we are giving it the 95% accreditation for 4-hour storage across the entire time period.
  - Question: Are these accreditation values marginal, not average? MISO derives them basically by taking out all renewables, performing a LOLE study and then adding them back in to rerun the analysis. These values are very different than the values finalized the week before. It seems like you are treating these as average values.
    - Response: These numbers are still not finalized. If you see anything that's not shared publicly from MISO, please let us know.
- General Questions:
  - Question: Can you talk at a high level about where the cost numbers for SMR's come from?
    - Response: Those cost come from our engineering department at Burns & McDonnell and their involvement in front end development in a few SMR projects.

Drew Burczyk (Consultant, Resource Planning & Market Assessments, 1898 & Co.) – Discussed the 2022/2023 draft portfolios.

Drew Burczyk – Presented draft scenario optimization results including project selections, and portfolio breakdowns.

- Slide 47 Draft Optimized Portfolios:
  - Question: There is a difference in the 2024 makeup for the solar selections, why is that?
    - Response: There are different assumptions going into each scenario. Solar is selectable in each portfolio, but only being picked up in certain portfolios.

- Question: For the potential CT conversion to a Combined Cycle at AB Brown, what were the dates in which the model could choose that conversion? Is it correct that you cannot reuse injection rights and it would have to go through the whole MISO queue process?
  - Response: 2027 – 2042. Correct.

- General
  - Question: Hydroelectric is never mentioned in your predictions. There are two dams on the river that haven't been used. If there is federal funding available, would that make up for the cost factor?
    - Response: Hydroelectric technology is a selectable option, and it is not being picked up as the best option. We will be happy to add a portfolio or two that add hydroelectric.
  - Question: Can you talk briefly about how you developed the cost and performance assumptions for the hydroelectric resources? Is it a run of river plant?
    - Response: The information came from the US Corps of Engineers study and costs associated with Cannelton. We can double check that second question [Confirmed Cannelton is a run-of-the-river hydro power plant].
  - Question: What do you expect for the next iteration of portfolios in regard to limiting sales?
    - Response: That is more focused on deterministic portfolios and less on optimized portfolios. We are using 15% of peak load for purchases and sales on the capacity expansion step. Once we step into the 8760 dispatch of the model, we increase that to 750 MW to be aligned with CenterPoint's import/export capabilities.
  - Question: Are you planning to update these assumptions for the proposed enhancement to the Planning Resource Auction (PRA) construct? They are changing the way that maximum capacity price would be assigned.
    - Response: We have not made any of those adjustments, but if you have any feedback, we are open to that.
  - Question: How would the Combined Cycle conversion work? Are you going to build them with the approved Certificate of Public Convenience and Necessity (CPCN) and then later convert them? Would you need a 2nd CPCN and then convert them?
    - Response: It's just an option with all the portfolios. If we were to go down that path, we would need another CPCN to go on and install the Heat Recovery Steam Generator(s) to be considered a Combined Cycle. Just like any new generation resource selected in the IRP.

<u>Drew Burczyk</u> – Presented draft deterministic portfolio results including project selections, and portfolio breakdowns.

- General
  - Question: Could you share information about exiting the Warrick 4 plant? What is involved with exiting Warrick 4?
    - Response: Our intent is to exit our agreement with Warrick at the end of 2023. We do have a capacity need in 2024/2025. If we can come to an agreement and at a reasonable cost compared to capacity purchases, there's a possibly that we can continue the Warrick 4 agreement until 2025 when the CTs come online.

<u>Open Q&A Session</u>

No questions.

Comments of CAC on CenterPoint's EnCompass Modeling Files

Submitted to CenterPoint Energy Indiana South on January 6, 2023

Comments on CenterPoint's EnCompass Modeling Files

Citizens Action Coalition of Indiana ("CAC") submits these comments on CenterPoint Energy Indiana South's ("CenterPoint") EnCompass modeling files that were provided to stakeholders on December 22, 2022. We appreciate the opportunity to review the latest version of modeling files. Our consultants' review of the files has led to additional questions on the inputs. We would like to submit the following feedback and questions to CenterPoint on the EnCompass modeling files.

1 Access to Supporting Information for Modeling Inputs

We appreciate the opportunity to review and provide feedback on important modeling inputs. We believe there are still a few outstanding items that would assist us in providing additional feedback to CenterPoint and 1898 on the modeling. We ask that CenterPoint share the following information with technical stakeholders:

- Supporting workbooks for the development of the seasonal coincidence factors that were incorporated into the development of the reserve margin requirement input.
- Seasonal accreditation values for CenterPoint's thermal units. At this time, it is unclear how some of the seasonal firm capacity values were developed.
- CenterPoint's thermal units. It is our understanding that some of the time series in the model may have a mixture of capital expenditures and fixed O&M together. It is challenging to provide feedback on those inputs if we are not sure what the allocation is for the costs (i.e., breakdown between capital, fixed O&M, and any costs for pipelines or firm gas transportation). For instance, it is not clear what costs are being modeled specific to the consideration of converting the Culley units to gas. Additional information to support these time series would be extremely helpful for us to understand how the costs are developed for the time series in EnCompass.

1.1 Timing of Remaining Workshops and Stakeholder Input

During the December meeting, CenterPoint seemed to be saying that the modeling inputs would largely be finalized after comments were received on January 6th. Because of the volume of missing data and the numerous questions we have about the data provided so far, we are concerned that there is not enough time being allocated to allow for thorough stakeholder input. Given that there is still nearly five months before CenterPoint submits its IRP, we hope that CenterPoint will provide additional flexibility to allow for continued stakeholder input after answering our questions and providing the requested information. If that is not what CenterPoint intended to communicate at the December meeting then we would welcome clarification of that as well.

2 EnCompass Modeling Files

We have reviewed the EnCompass modeling inputs and offer the following comments and questions to CenterPoint related to the modeling inputs shared with stakeholders.

2.1 New Resources

Renewable and Battery Storage

1. How are the Inflation Reduction Act ("IRA") tax credits incorporated into the costs of new generic solar resources? It looks the time series named "PTC" is only applied as a negative $/MWH cost for the new wind resources; changes to Sections 45 and 45Y of the Internal Revenue Code now allow the Production Tax Credit to apply to solar projects.
2. How is the IRA reflected for the hybrid resources? Is there an allocation for the Investment Tax Credit ("ITC") for the battery portion of the project or a full ITC applied to the project?
3. Did CenterPoint and 1898 considered modeling the solar hybrid resources with two distinct resources for the battery portion of the hybrid project to reflect the ability for the storage resource to not be restricted to only charging from the solar resource?
4. For the dataset named "SES - Renewable High," how did CenterPoint and 1898 determine the increase to apply to the resources modeled to reflect the RFP bids?

Hydro

We appreciate CenterPoint and 1898 taking the time to set up and offer new hydro resources in the model. After reviewing the inputs, we have several questions and would like to request additional information on the input assumptions.

1. Are any tax credits from the Inflation Reduction Act incorporated into the capital expenditures modeled for the hydro resources?
2. During the last stakeholder IRP meeting, it was our understanding that 1898 and CenterPoint referenced an Army Corps of Engineers Report that was used to develop the cost estimates for the resources. Is this 2013 report[1] the document that was referenced? If not, which report was used? Either way, can CenterPoint provide the spreadsheet(s) used to develop the cost inputs?
3. How did CenterPoint and 1898 develop the hourly shape for the hydro resources?

Capacity Purchases

1. Will any of the resources with the name "Capacity Purchase" need adjustments to their Firm Capacity in order to reflect MISO's new seasonal RA construct or will CenterPoint still receive the same firm capacity for these purchases in all seasons?

2.2 Energy Efficiency and Demand Response

1. Are the currently approved energy efficiency programs incorporated into the model as a reduction to the load forecast? If not, how are they accounted for?

[1] https://www.hydro.org/wp-content/uploads/2014/01/Army-Corps-NPD-Assessment.pdf

2. Would CenterPoint and 1898 be able to provide a description for some of the energy efficiency resources in EnCompass so that stakeholders can map them to the information from the Market Potential Study? (For example, the resources named "CI Enhanced," "HER V1," "RES High," and "RES LowMed.")
3. Since the EnCompass inputs only seem to have three resources for C&I energy efficiency savings, will this be the only level of savings for C&I included in the modeling?
4. Could CenterPoint and 1898 provide stakeholders with the supporting workbooks used to develop the levelized costs modeled for the new energy efficiency and demand response resources?

2.3 ELCC Values of Wind and Solar

The accredited values of solar and wind will likely have significant implications for whether those resources are chosen in the resource optimization. CenterPoint stated in the December 13, 2022, Public Stakeholder meeting that it will base the capacity value for solar and wind resources on a proposed change to non-thermal accredited values, the Direct-LOL approach, under discussion at MISO. While MISO has not yet even filed for approval of this proposal at FERC, the proposal has not been met with support amongst stakeholders. Of the seventeen parties or coalitions who submitted comment[2] to MISO last month, all either opposed MISO's proposal or raised concerns about it. For example, Xcel Energy stated, "LOL hours favor the very peak hours so this method would accredit wind and solar resource based only on a few hours where the modeled generation supply is inadequate to serve the modeled load. This is not in alignment with the PRM which is calculated across all hours. We consider the Direct-LOL methodology to be a marginal accreditation approach."

We have heard indirectly from MISO that the 2022 Regional Resource Assessment[3] accredited capacity values represent the official forward looking projection from MISO, whereas other capacity accreditation values, such as those projected in MISO's November 30, 2022 presentation,[4] should be used as sensitivities. We would recommend that CenterPoint adopt this approach here as well.

The values presented at CenterPoint's December 13th stakeholder meeting, shown below, would then become a sensitivity.

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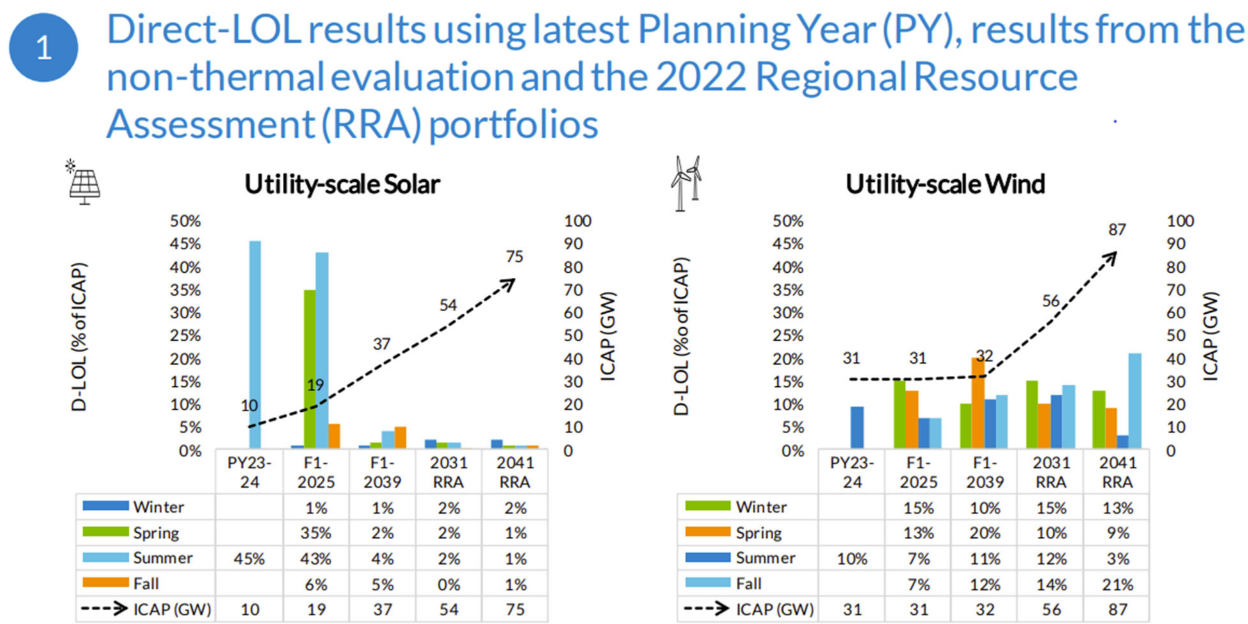
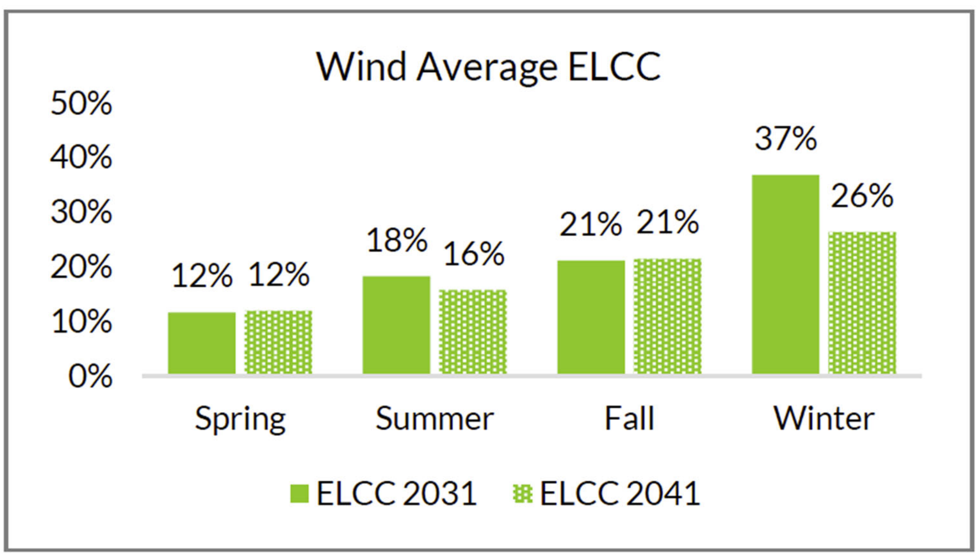
[2] All of the December 2022 stakeholder comments may be found at https://www.misoenergy.org/stakeholder-engagement/stakeholder-feedback/2022/rasc-wind-solar-accreditation-recommendation-rasc-2020-4-rasc-2019-2-20221130.

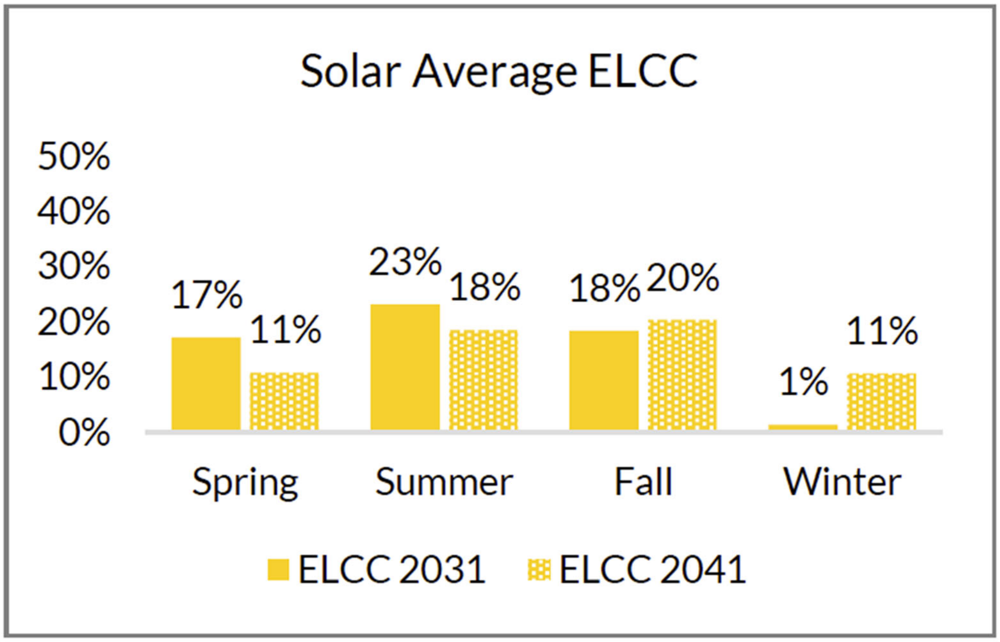
[3] See https://cdn.misoenergy.org/20221110%20RRA%20Workshop%20Presentation626925.pdf, slides 33-36.

[4] See https://cdn.misoenergy.org/20221130%20RASC%20Item%2007b%20Non-Thermal%20Accreditation%20Presentation%20(RASC-2020-4%202019-2)627100.pdf, slide 12.



The RRA values would then become the base case assumptions. They are provided below.





2.4 Additional Questions and Comments

We also have the following additional questions and comments on the modeling files provided:

1. Fixed O&M time series for Warrick 4
    - Does the Fixed O&M time series for "Warrick: 4 Fixed O&M" include costs that will continue after the unit is offline? It looks like the Fixed O&M values for Warrick are reported even after the unit goes offline since that time series continues to have values and EnCompass will continue to see that resource since it is taken offline for maintenance, but not explicitly retired within EnCompass. Is this approach used so that any ongoing costs can be reflected in the model results?
2. Maintenance time series for FB Culley 3
    - The time series named "FB Culley:3 Maintenance" does not contain any values. We were not sure if there were supposed to be any values input for this time series.
3. Curtailments and Battery Resources
    - For modeling runs that select battery storage resources, are there large levels of curtailments for these resources because of the curtailment group order that is specified for them?
4. Market Prices
    - Were the power prices for the scenarios purchased from a third party or was the Horizons National Database used to develop them?
5. Modeling the Book Value of the Coal Resources
    - We would like to reiterate the comments that we previously submitted to CenterPoint on modeling the book value of the FB Culley units in EnCompass for

the retirement scenarios. As we noted during the December 13th workshop, it does not make sense to include remaining book value in the scenarios where coal units are retired but not in the scenarios where they are retained. In order to provide the most accurate revenue requirements comparison, they should be included in both unless CenterPoint has some reason to believe it will not recover those costs.

3 Request for Proposal ("RFP") Files

We appreciate that some of our team members received access to the RFP bid information that was used to develop the inputs for the RFP resources modeled within EnCompass. We have a couple of questions with regard to the updated pricing that CenterPoint and 1898 received from the developers:

1. Did the updated pricing information submitted by the developers for projects only reflect the incorporation of the revised Investment Tax Credit or Production Tax Credit under the IRA, or did some or all of the bidders also refresh the underlying capital costs?
2. Could CenterPoint please provide access to the RFP bid information to Ben Inskeep (binskeep@citact.org)? This request made by email to 1898 on January 3, 2023, has gone unanswered to date.

4 Stochastic Modeling Files

We would also like to submit the following questions on how the stochastic modeling will be utilized within EnCompass and ask that information be provided to stakeholders:

1. Will CenterPoint and 1898 be using the functionality within EnCompass to perform the draws on each variable or will an outside statistical package be used to determine the values for each stochastic variable across the draws?
    a. If the functionality within EnCompass will be used, what will be specified for the draw frequency, mean reversion, and deviation inputs?
    b. Will correlation be specified between any of the stochastic variables?
    c. How many draws will be run in EnCompass? Will the sampling be set to Latin Hypercube?
    d. Which distribution will be applied to each of the stochastic variables?

CAC Data Request Set 3 to CEI South
CEI South 2022/2023 IRP Response
January 30, 2023

3-1. Provide access to supporting workbooks for:

a) Seasonal coincidence factors
b) Seasonal accreditation values for CEI South thermal units
c) A breakdown between capital and fixed O&M for CEI South thermal units

Response:

a) See the files “MISO CP model v2 fall.xlsx”, “MISO CP model v2 spring.xlsx”, “MISO CP model v2 summer.xlsx”, and “MISO CP model v2 winter.xlsx”.
b) See “SAC calculation Central North” files for each existing thermal unit and “ABB 5+6 Accreditation” for future F class CTs. Note that in some cases MISO is showing accreditation greater than the installed capacity (ICAP) of a unit but these values have been capped at ICAP in the EnCompass model.
c) The file “CONFIDENTIAL - O&M and Capex Projections for Existing Units - Draft December 20, 2022.xlsx” that was provided to stakeholders on December 20, 2022 contains this information but an updated version is being provided that addresses a couple typos that have been recently identified.

3-2. During the December meeting, CenterPoint seemed to be saying that the modeling inputs would largely be finalized after comments were received on January 6th. Because of the volume of missing data and the numerous questions we have about the data provided so far, we are concerned that there is not enough time being allocated to allow for thorough stakeholder input. Given that there is still nearly five months before CenterPoint submits its IRP, we hope that CenterPoint will provide additional flexibility to allow for continued stakeholder input after answering our questions and providing the requested information. If that is not what CenterPoint intended to communicate at the December meeting then we would welcome clarification of that as well.

Response: CEI South plans to provide updated modeling files, additional input files, and portfolios for consideration in the risk analysis to stakeholders for review and comment. CEI South plans to provide the preferred portfolio in our fourth stakeholder meeting, ahead of submitting the IRP on June 1, 2023.

3-3. How are the Inflation Reduction Act ("IRA") tax credits incorporated into the costs of new generic solar resources? It looks the time series named "PTC" is only applied as a negative $/MWH cost for the new wind resources; changes to Sections 45 and 45Y of the Internal Revenue Code now allow the Production Tax Credit to apply to solar projects.

Response:

The intent in the modeling was to include the PTC for both new solar and wind resources. This input was missing in the version of the model shared with stakeholders and has since been fixed in the model.

3-4. How is the IRA reflected for the hybrid resources? Is there an allocation for the Investment Tax Credit ("ITC") for the battery portion of the project or a full ITC applied to the project?

Response:

The ITC is used to reduce the capital cost by the full amount for storage and hybrid resources.

3-5. Did CenterPoint and 1898 considered modeling the solar hybrid resources with two distinct resources for the battery portion of the hybrid project to reflect the ability for the storage resource to not be restricted to only charging from the solar resource?

Response:

The hybrid resources were modeled as hybrids where the storage would charge from the solar. There are several options for stand alone storage and solar resources.

3-6. For the dataset named "SES - Renewable High," how did CenterPoint and 1898 determine the increase to apply to the resources modeled to reflect the RFP bids?

Response:

The high cost curves were calculated using the highest cost RFP option included within the average and escalated at the assumed inflation rate over the study period.

3-7. Are any tax credits from the Inflation Reduction Act incorporated into the capital expenditures modeled for the hydro resources?

Response:

The modeling has been updated to reduce capital costs of hydro resources based on full monetization of the ITC.

3-8. During the last stakeholder IRP meeting, it was our understanding that 1898 and CenterPoint referenced an Army Corps of Engineers Report that was used to develop the cost estimates for the resources. Is this 2013 report[1] the document that was referenced? If not, which report was used? Either way, can CenterPoint provide the spreadsheet(s) used to develop the cost inputs?

Response:

Costs escalated but consistent with the 2019 IRP were used for this analysis. See file "Hydro TA.xlsx". These costs were developed as part of the 2019 Technology Assessment – see excerpt from 2019 TA:

This Assessment assumes that low head turbines would be integrated with an existing dam that does not currently generate electricity. The turbines are assumed to be based on either the Kaplan or Bulb type technologies.

The Kaplan turbine is a propeller type, vertical axis machine in which water enters radially and exits the turbine axially. The propeller is immersed in the water flow, but is coupled to an electric generator above the turbine blades, outside of the water. Kaplan turbine designs typically include adjustable vanes and inlet gates to accommodate variable flow.

The Bulb type turbine design is also propeller driven, but water both enters and exits the turbine axially. Horizontal and vertical designs are available. On a bulb turbine, the generator is encased in a bulb shaped casing which is immersed in the water and connected to the electric distribution system above ground.

It should be noted that hydroelectric cost and performance expectations are difficult to generalize because they are entirely dependent on-site specific details. Flow characteristics and construction requirements are not consistent between different water sources and are likely inconsistent even at different points in the same source. The information presented in this Assessment is estimated based on BMcD experience and publicly available information. If hydroelectric generation technology is chosen for further development, a more detailed study shall be performed to evaluate the hydrology, geology, wildlife, and safety characteristics (in addition to cost and performance studies) of hydropower implementation.

1 - https://www.hydro.org/wp-content/uploads/2014/01/Army-Corps-NPD-Assessment.pdf

3-9. How did CenterPoint and 1898 develop the hourly shape for the hydro resources?

Response:

Historical capacity factors from Cannelton were used as a basis for the hourly shape for the hydro resources.

3-10. Will any of the resources with the name “Capacity Purchase” need adjustments to their Firm Capacity in order to reflect MISO’s new seasonal RA construct or will CenterPoint still receive the same firm capacity for these purchases in all seasons?

Response:

Capacity purchases will receive the same firm capacity in all seasons.

3-11. Are the currently approved energy efficiency programs incorporated into the model as a reduction to the load forecast? If not, how are they accounted for?

Response:

The existing income qualified energy efficiency is included in the model (IQW); These are not netted out of load outside of the model.

3-12. Would CenterPoint and 1898 be able to provide a description for some of the energy efficiency resources in EnCompass so that stakeholders can map them to the information from the Market Potential Study? (For example, the resources named “CI Enhanced,” “HER V1,” “RES High,” and “RES LowMed.”)

Response:

See file EE Resource Mapping.xlsx

3-13. Since the EnCompass inputs only seem to have three resources for C&I energy efficiency savings, will this be the only level of savings for C&I included in the modeling?

Response:

The C&I energy efficiency savings from the MPS are included as a single bundle across three different vintages (time periods). This single bundle represents an “enhanced” level of potential that was slightly higher than the MPS realistic achievable potential. This enhanced scenario was created based on feedback requests from the CAC to prioritize C&I savings, which are assumed to be less costly than savings from the residential sector. Based on the overall costs and savings, it was assumed that it would be unnecessary to breakout the overall C&I savings into additional bundles to increase the likelihood of being selected in the IRP.

3-14. Could CenterPoint and 1898 provide stakeholders with the supporting workbooks used to develop the levelized costs modeled for the new energy efficiency and demand response resources?

Response:

The workbooks used develop levelized costs were provided to the OSB on September 23, 2022.

The following link is available to download the supporting workbooks used to develop the levelized cost models for energy and demand response resources in the MPS. These provide the annual savings, annual costs, and average bundle effective useful lives (EULs), as well as estimated hourly impacts. Please download the files by February 7, 2023 when the link expires.

https://filesender.gdsassociates.com/receive/42285580-cbdd-4b7a-a8cb-5d181c18f5cf

3-15. Does the Fixed O&M time series for "Warrick: 4 Fixed O&M" include costs that will continue after the unit is offline? It looks like the Fixed O&M values for Warrick are reported even after the unit goes offline since that time series continues to have values and EnCompass will continue to see that resource since it is taken offline for maintenance, but not explicitly retired within EnCompass. Is this approach used so that any ongoing costs can be reflected in the model results?

Response:

Correct, these are potential stranded costs associated with Warrick 4.

3-16. The time series named “FB Culley:3 Maintenance” does not contain any values. CAC is not sure if there were supposed to be any values input for this time series.

Response:

At one point this input was being used for various retirement options, similar to question 3-15 about Warrick, but is currently not being used in the modeling.

3-17. For modeling runs that select battery storage resources, are there large levels of curtailments for these resources because of the curtailment group order that is specified for them?

Response:

No. The model is only curtailing storage less than .25% of the time.

3-18. Were the power prices for the scenarios purchased from a third party or was the Horizons National Database used to develop them?

Response:

The Horizon National Database was used as a starting point for the development of the power prices in the model.

3-19. Did the updated pricing information submitted by the developers for projects only reflect the incorporation of the revised Investment Tax Credit or Production Tax Credit under the IRA, or did some or all of the bidders also refresh the underlying capital costs?

Response:

We provided an opportunity for bidders to provide us updated pricing after the passage of the IRA. For Purchase options it did appear that there were pricing updates outside of tax credits and updated pricing to the underlying capital costs were made, there is less granularity behind the incremental changes in underlying capital costs that went into PPA updates. See email sent to bidders below:

"Thank you for your participation in the CenterPoint 2022 All-Source RFP. With the passage of the Inflation Reduction Act, the CenterPoint RFP team is aware that this may impact proposals that were submitted to the RFP and CenterPoint is accepting proposal updates to reflect impacts from the newly enacted law. Please submit any updates you wish to make concerning pricing or other terms affected by the Inflation Reduction Act no later than 5PM CDT, September 7th, 2022. Please submit any updates on the form attached along with any new documents via the All Source RFP website http://centerpoint2022asrfp.rfpmanager.biz/. If your proposal has not been affected by the new law, please confirm by responding directly to this email. If you have any questions or concerns, please let us know."

3-20. Could CenterPoint please provide access to the RFP bid information to Ben Inskeep (binskeep@citact.org)? This request made by email to 1898 on January 3, 2023, has gone unanswered to date.

Response:

It has been confirmed with Mr. Inskeep that he received an email on December 20, 2022 granting him access to the RFP bid information.

3-21. Will CenterPoint and 1898 be using the functionality within EnCompass to perform the draws on each variable or will an outside statistical package be used to determine the values for each stochastic variable across the draws?

a) If the functionality within EnCompass will be used, what will be specified for the draw frequency, mean reversion, and deviation inputs?
b) Will correlation be specified between any of the stochastic variables?
c) How many draws will be run in EnCompass? Will the sampling be set to Latin Hypercube?
d) Which distribution will be applied to each of the stochastic variables?

Response:

a) Yes, Encompass will be used to perform the draws. 200 iterations will be performed on monthly data. Mean reversion setting has not yet been decided (currently set to 100%). Standard deviations are based on implied uncertainty from vendor quotes. CAPEX (base, high and low) and CO_2 (base, medium-high and high-high) will be assigned to iterations separately.

b) Yes, between load and NG, and NG and coal (we are still evaluating correlations between NG and CO_2).

c) 200 iterations will be performed for the development of stochastic inputs. EnCompass' Latin hypercube feature will be used for the iterations.

d) Load, NG, and coal will use lognormal distributions. CAPEX and CO_2 will be discrete distributions.

Comments of CAC on CenterPoint's EnCompass Modeling Files

Submitted to CenterPoint Energy Indiana South on March 17, 2023

CAC Comments on CenterPoint's EnCompass Modeling Files

Citizens Action Coalition of Indiana ("CAC") submits these comments on CenterPoint Energy Indiana South's ("CenterPoint") EnCompass modeling files that were provided to stakeholders on March 7, 2023. We appreciate the opportunity to review the latest version of modeling files. Our consultants' review of the files has led to additional questions on the inputs. We would like to submit the following feedback and questions to CenterPoint on the EnCompass modeling files and provide some comments on the Technical Workshop held on February 28, 2023.

Comments on EnCompass Modeling Files

Firm Capacity of ABB Brown Conversion

Table 1 below shows the Schedule 53 Class Averages of seasonal capacity accreditation that MISO has released for the upcoming (2023-2024) planning year. CenterPoint suggested during the February 28th workshop that it has used these values for the firm capacity that is modeled for the new thermal resources, but that does not appear to be the case especially for conversion of the CTs at AB Brown and the coal to gas conversions at FB Culley 2 and 3. Can CenterPoint confirm and explain why it used the values it used?

Table 1. MISO Schedule 53 Class Average[1]

Row Labels	Summer ISAC/ICAP	Fall ISAC/ICAP	Winter ISAC/ICAP	Spring ISAC/ICAP	Count of Units
Combined Cycle	88.17%	76.50%	80.06%	74.07%	106
Combustion Turbine 0-20MW	83.32%	82.79%	77.35%	79.01%	40
Combustion Turbine 20-50MW	87.51%	82.45%	81.64%	81.75%	118
Combustion Turbine 50+MW	91.41%	80.85%	79.78%	84.32%	174
Diesels	90.34%	85.34%	82.95%	86.77%	66
Fluidized Bed Combustion	[redacted]	[redacted]	[redacted]	[redacted]	8
Fossil Steam 0-100MW	81.90%	78.39%	77.60%	75.55%	52
Fossil Steam 100-200MW	[redacted]	[redacted]	[redacted]	[redacted]	28
Fossil Steam 200-400MW	84.15%	72.85%	76.08%	74.34%	33
Fossil Steam 400-600MW	79.45%	75.36%	80.57%	75.10%	34
Fossil Steam 600-800MW	[redacted]	[redacted]	[redacted]	[redacted]	24
Fossil Steam 800+MW	[redacted]	[redacted]	[redacted]	[redacted]	4
Hydro 0-30MW	[redacted]	[redacted]	[redacted]	[redacted]	14
Hydro 30+MW	[redacted]	[redacted]	[redacted]	[redacted]	8
Nuclear	[redacted]	[redacted]	[redacted]	[redacted]	17
Pump Storage	[redacted]	[redacted]	[redacted]	[redacted]	14
FleetWide Schedule 53 ISAC/ICAP	85.93%	78.48%	79.25%	78.53%	740

Demand Side Management Resources

Would CenterPoint be able to provide supporting workbooks and a description of the approach used to determine the seasonal firm capacity to model for energy efficiency and demand response resources?

[1] https://cdn.misoenergy.org/20221215%20Schedule%2053%20Class%20Average627347.pdf

Constraints on the AB Brown CTs

Was the maximum annual energy limit specified for the new CTs because the model was over-dispatching them? If not, please explain why this limit was specified.

Can CenterPoint confirm that the project constraint named "ABB7 CMin" is forcing the model to select the CT to CC conversion between 2027 and 2041 in the Reference Portfolio?

Constraint on the Northern Wind Projects

Can CenterPoint explain why the Northern wind projects were not allowed to be selected until 2033? It also looks like there is a constraint called "Wind_NT AM" that does not allow the project "Wind_NT" to be selected. It was our understanding that this represented a project from the RFP. Has CenterPoint received information that the project is no longer viable or was this not a presentation of an RFP bid and just a holdover project as CenterPoint has gone through the modeling process?

Fixed O&M and Capex Workbook

We had a few questions on the workbook named "CONFIDENTIAL O&M and Capex Projections for Existing Units – DRAFT February 8, 2023":

- Is the information for the ABB7 unit contained in this workbook? If not, would CenterPoint be able to provide that to stakeholders?
- What do the "stranded cost" rows in the workbook include?
- We compared a few of the inputs in EnCompass (FBC3 convert 2027 and FBC2 convert) to the underlying workbook and there seem to be some differences in cost starting in 2026 (FB Culley 2 convert) and 2027 (FB Culley 3 convert) that we have not been able to reconcile. What do these cost differences represent? And can we find them in the underlying workbook? If not, please provide a workbook showing how these inputs in EnCompass were calculated.
- Which EnCompass input is used to represent the Capex projections?

Recommendations from Prior Comments

We would also like to reiterate the previous comments that have been submitted to CenterPoint on renewable accreditation and the repowering of wind projects. These recommendations include modeling the Direct-LOL approach as a sensitivity instead of a base assumption and evaluating the repowering instead of retirement of CenterPoint's existing wind resources. CAC observes that Indiana Michigan Power ("I&M") recently filed a petition with the Commission associated with unspecified "technology upgrades" to Fowler Ridge that I&M has represented will maintain its 100 MW capacity offtake from this facility while lowering the PPA cost to I&M's ratepayers.[2]

[2] Cause No. 45859

Comments on Scorecard and Stochastic Modeling

We would also like to submit comments on the information provided in the Technical Stakeholder meeting held on February 2, 2023.

On the Scorecard, we would like to reiterate the comments and recommendations that were made during the call on the Reliability metrics and the coloring of the scorecard. For the Reliability metric, the "Must Meeting MISO Planning Reserve Margin Requirement in All Seasons (MW)," the Scorecard indicates that there are capacity purchases happening in the summer for each of the portfolios, but the level of the purchase varies between portfolios. Since CenterPoint is allowing the model the option to choose a capacity purchase, this metric seems confusing to present with the coloring, especially since the level of purchase amongst the portfolio is not greater than 50 MW. In addition, the scorecard already captures capacity purchases with the category "Capacity Market Purchases," so these two metrics would seem to be counting the same variable just with slightly different variations in color shading.

In addition, the "Fast Start Capability" and "Spinning Reserve" metrics indicate that the larger the MW, the greater that is for the portfolio under the coloring scheme assigned. We would recommend that the coloring be changed for these metrics to reflect whether minimum needs in these categories are met or not.

On the stochastic modeling approach, we would recommend that capital costs not be included as a stochastic model and CenterPoint use the low and high forecasts for renewable and battery storage resources as a sensitivity to the portfolios. If CenterPoint does not agree and continues to include capital costs as a stochastic variable, then we would recommend that CenterPoint include new thermal resources along with the renewable and battery storage resources. While we understand that the renewables and storage are in more portfolios, there are still several portfolios that include either the conversion of FB Culley 3 or new thermal resources ("Reference Case" and "CT Portfolio"). In addition, the risks of increased cost for thermal resources has increased since the start of the stakeholder process as inflation expectations have gone from short-term concerns to longer length expectations and more utilities announce plans to build gas units in the 2026-2028 timeframe.

We would ask that when the information is available and ready to share, that CenterPoint provide stakeholders with the stochastic inputs for the Capex and CO_2 variables.

CAC Data Request Set 4 to CEI South
CEI South 2022/2023 IRP Response
April 7, 2023

4-1. Table 1 below shows the Schedule 53 Class Averages of seasonal capacity accreditation that MISO has released for the upcoming (2023-2024) planning year. CenterPoint suggested during the February 28th workshop that it has used these values for the firm capacity that is modeled for the new thermal resources, but that does not appear to be the case especially for conversion of the CTs at AB Brown and the coal to gas conversions at FB Culley 2 and 3. Can CenterPoint confirm and explain why it used the values it used?

Table 1. MISO Schedule 53 Class Average[1]

Row Labels	Summer ISAC/ICAP	Fall ISAC/ICAP	Winter ISAC/ICAP	Spring ISAC/ICAP	Count of Units
Combined Cycle	88.17%	76.50%	80.06%	74.07%	106
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Nuclear	[redacted]	[redacted]	[redacted]	[redacted]	17
Pump Storage	[redacted]	[redacted]	[redacted]	[redacted]	14
FleetWide Schedule 53 ISAC/ICAP	85.93%	78.48%	79.25%	78.53%	740

Response:

Capacity accreditation for new thermal resources was developed using MISO posted seasonal historical class average forced outage rates (https://cdn.misoenergy.org/PY%202023%202024%20LOLE%20Study%20Report626798.pdf). Capacity accreditation for the conversion of FB Culley 2 and 3 aligns with the capacity accreditation projections for FB Culley 2 and 3 on coal as the switch to natural gas is not expected to decrease the reliability of these units. Changes to the MISO accreditation for all resource types are still ongoing as MISO is in the process of moving to the seasonal construct. On March 17, 2023 FERC has issued a notice for MISO to review their UCAP/ISAC ratio. The accreditation of new CTs and CCGTs outside of the summer months under the new SAC accreditation methodology are likely to be higher than the existing averages, not only because they are new, but also as unit owners/operators adjust to the new seasonal accreditation methodology attempting to maximize accreditation in all seasons.

It should be noted that the class averages in table 1 would need the UCAP/ISAC conversion ratio applied to them to identify the final season accreditation for each resource. The example below illustrates this for a CCGT unit.

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	Summer ISAC/ICAP	Fall ISAC/ICAP	Winter ISAC/ICAP	Spring ISAC/ICAP
Combined Cycle[2]	89.50%	83.80%	83.90%	81.20%

UCAP/ISAC Ratio[3]	1.049	1.078	1.059	1.087

Final Accreditation	93.9%	90.3%	88.9%	88.3%

1 https://cdn.misoenergy.org/20221215%20Schedule%2053%20Class%20Average627347.pdf

2 https://cdn.misoenergy.org/20230328%20Schedule%2053%20Class%20Average_Posted627347.pdf

3 https://cdn.misoenergy.org/202303281500%20UCAP%20ISAC%20Ratio%20for%20PY23-24627342.pdf

4-2. Provide supporting workbooks and a description of the approach used to determine the seasonal firm capacity to model for energy efficiency and demand response resources?

Response: The EE/DR MPS models provided annual estimates of annual savings as well as summer peak capacity impacts. For IRP modeling purposes these annual estimates were provided at an 8,760 level. For EE, we determined the annual savings by end-use, and then used the 8,760 end-use load shapes from the NREL dataset (for Indiana) to break out the annual energy savings at the hourly level. Inevitably, the result of the hourly disaggregation from the NREL load-shapes did not produce an identical summer peak reduction that was equivalent to the summer peak capacity savings from the MPS (which was determined from deemed savings algorithms, technical reference manuals, evaluation studies, etc.). To help align the hourly IRP inputs with the estimated summer peak reductions in the MPS, we forced in the MPS summer peak capacity impacts over a three hour window (including HE 16) for all peak days in July/August. Any difference in savings during that window between the original hourly estimates and the MPS-adjusted impacts were spread out evenly over all remaining hours so that the overall annual hourly shape was consistent. Any non-summer seasonal impacts can be derived from this resulting shape. To account for MISO's shift to a seasonal accreditation construct, accreditation for EE in the different seasons was determined based on the program's output compared to seasonal peak hours based on CenterPoint's load shape.

For DR, the MPS-determined peak impacts were included in the same 3-hour window during peak days in July/August as EE. Surrounding hours were used to show snapback so that the overall energy impacts remained zero.

The hourly approach is consistent with what GDS provided to CNP for prior IRP (except that there are additional end-use load shapes now that they are based on the NREL data, and not our own building simulation models).

The supporting file “Confidential IRP Template v.FINAL – Seasonal Accreditation” is being provided in response to this DR.

For other supporting workbooks please see the files listed below that were provided in the response to CAC DR3-14.

CAC DR2 – EE Resource Mapping

CAC DR 4 - Commercial_Annual_IO_v.03

CAC DR 4 – Residential_Annual_IO_v.04_$70 Mwh

DR CenterPoint Summary Tables v2

IRP EE Summary Template v.FINAL

4-3. Was the maximum annual energy limit specified for the new CTs because the model was over-dispatching them? If not, please explain why this limit was specified.

Response:

The CTs have an annual hours limitation due to their air permit. The 40% annual capacity factor limit was included to make sure that our modeling respected these permit limitations.

4-4. Can CenterPoint confirm that the project constraint named "ABB7 CMin" is forcing the model to select the CT to CC conversion between 2027 and 2041 in the Reference Portfolio?

Response:

The models provided as part of the tech to tech were set up in preparation for the risk analysis; the reference case portfolio was based on results from the reference case optimization. During the optimization process and the selection of the reference case portfolio by the model, the constraints around AB Brown were set up to force EnCompass to choose to either continue AB Brown 5/6 as CTs or to convert the unit to AB Brown 7. Since the reference case optimization selected the CCGT conversion, that option was included as part of the portfolio carried into the risk analysis.

4-5. Can CenterPoint explain why the Northern wind projects were not allowed to be selected until 2033? It also looks like there is a constraint called "Wind_NT AM" that does not allow the project "Wind_NT" to be selected. It was our understanding that this represented a project from the RFP. Has CenterPoint received information that the project is no longer viable or was this not a presentation of an RFP bid and just a holdover project as CenterPoint has gone through the modeling process?

Response:

The models provided as part of the tech to tech were developed for the risk analysis. It is not an optimization run. Optimization runs were conducted for all 5 scenarios. The reference case was pulled into the risk analysis based on optimized results. Other portfolios were developed with the aid of optimization, but locked down prior to conducting the risk analysis. The Wind_NT was not selected during optimizations, and therefore was not included in portfolios that are being carried forward into risk analysis.

4-6. We had a few questions on the workbook named "CONFIDENTIAL O&M and Capex Projections for Existing Units – DRAFT February 8, 2023":

a) Is the information for the ABB7 unit contained in this workbook? If not, would CenterPoint be able to provide that to stakeholders?
b) What do the "stranded cost" rows in the workbook include?
c) We compared a few of the inputs in EnCompass (FBC3 convert 2027 and FBC2 convert) to the underlying workbook and there seem to be some differences in cost starting in 2026 (FB Culley 2 convert) and 2027 (FB Culley 3 convert) that we have not been able to reconcile. What do these cost differences represent? And can we find them in the underlying workbook? If not, please provide a workbook showing how these inputs in EnCompass were calculated.
d) Which EnCompass input is used to represent the Capex projections?

Response:

a) No. Please see the file "CenterPoint 2022 IRP Technology Assessment (Combined) - Draft December 20, 2022" that was provided to stakeholders on December 20, 2022.
b) Stranded costs include the undepreciated value of assets that will no longer be used and useful following the closure of the units.
c) Please see CONFIDENTIAL 2023.04.06 - FBC Revenue Requirement.xlsx. This adds in costs associated with a NG pipeline to the fixed costs.
d) Ongoing O&M and capital associated with the gas conversion are included in the "CONFIDENTIAL O&M and Capex Projections for Existing Units – DRAFT February 8, 2023" workbook. Capital and O&M cost are included in the "The Fixed O&M" input in Encompass.

Sierra Club Data Request Set 3 to CEI South
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3.1 It's not clear to us what assumptions CenterPoint has adopted for modeling solar, wind, and battery storage. We understand from the earlier slide decks that you relied on the results from your RFPs, refreshed the bids, and then applied the NREL ATB cost decline assumptions. But in those initial RFP bids that you used as a starting point, did any of the respondents assume that the projects were to be located in an energy community or not?

Response:

Near-term modeling of wind, solar, and storage relied on using PPA prices from the RFP; all potential tax credits which RFP projects would qualify for would be included in the PPA prices provided. Beyond the near-term modeling and executable window for projects received as part of the RFP, site-specific assumptions to include energy community adders for the PTC were not included. However, as part of the sensitivity analysis of the reference case and portfolio decisions, various resource capital costs and tax credit qualification sensitivities were performed to determine the impact of these changes on future resource decisions.

3.2 Are the assumptions CenterPoint made about NOx allowance limits, projected NOx emissions for your units, and costs consistent with the updated rules that just came out this week? If not, will CenterPoint be updating its assumptions to reflect this rule? Does CenterPoint anticipate that the final rule will significantly change any of its results?

Response: After preliminary review, Indiana's allocation of NOx allowances does not look significantly different from the most recent CSAPR allocation which was modeled in the current IRP. We will continue to review, but do not expect the updated Good Neighbor SIP allowance allocations to significantly differ from our assumptions in the IRP.

3.3 Cost associated with other environmental regulations:

a) Has the CCR Extension at AB Brown been ruled on yet? How is that cost potential being modeled?

b) Cost of FGD wastewater system at Culley 3 – is that assumed to be a sunk cost? Are there ongoing O&M costs? If so, what are those and where are they being modeled?

c) Other Clean Water Act costs for Compliance at Culley 3 – What are the projected costs associated with compliance and where are those being modeled? Are the capital costs separated from the O&M costs?

Response:

a) CEI South has received conditional approval on the CCR extension at AB Brown but the EPA is yet to finalize. Since these are fixed costs and are consistent across all portfolios they do not impact IRP modeling.

b) Yes. Ongoing O&M costs for the FGD wastewater system are estimated to be $50,000 in year one and escalate 2.3% annually. This is included in the fixed costs in the modeling.

c) All O&M and capex assumptions are shown in the O&M and Capex projection spreadsheet provided to stakeholders on March 7th.

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3.4 Is 2023 the final date for Warrick 4 retirement or is there a possibility that the contract will be extended?

Response: Currently CEI South expects to exit out of the Warrick 4 Joint Operating Agreement (JOA) at the end of 2023; however, CEI South continues to discuss with Alcoa the possibility of contract extension.

3.5 Did you do any modeling with lower costs for storage? Do you know what assumptions you would need for battery storage for more of it to be selected by the model (i.e., how much do storage costs have to fall below what CenterPoint assumed for the model to select more battery storage earlier in the planning period).

Response:

Yes. Storage costs were varied within the scenarios and within the probabilistic model to reflect higher and lower costs relative to the base case. Additionally, various sensitivity analysis is being performed to test the impact of different costs for battery storage, along with sensitivities associated with how much accreditation a battery may receive in the future from MISO.

3.6 Has CenterPoint considered the possibility of securitization in its modeling both for retirement of Culley 3 and replacement with alternatives?

Response: No legislation currently exists that allows for securitization of any assets beyond the A.B. Brown units.

3.7 Did CenterPoint figure out why the NPVRR of the Reference case, which is by far the most carbon intensive of any case, still has the lowest cost under the Decarbonization/Electrification and High Regulatory scenarios that both include a Carbon Price?

Response:

The NPVRR of the reference case under different scenarios still benefits from the ability to dispatch an efficient gas combined cycle and sell energy into the market to lower the portfolio NPVRR under scenarios where there is a carbon price.

Sierra Club Data Request Set 3 to CEI South
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3.8 U.S. Energy Information Administration just published its Annual Energy Outlook this week - the EIA's natural gas price current forecast differed from its forecast last year in that it is projects (1) slightly higher prices in the near term (i.e., this year into next), followed by lower gas prices over the next few years. Has CenterPoint received Spring 2023 gas price forecasts? If not, is planning to update its gas price assumptions using spring 2023 numbers?

Response: No. Based on stakeholder feedback, CEI South updated the gas price forecast following our first stakeholder meeting in the summer of 2022 to fall forecasts from various venders. Gas prices have since come down dramatically. CEI South is including probabilistic modeling that is designed to capture the effects of gas price volatility.

3.9 What utilization levels does CenterPoint model or assume for Culley 3 after it is converted to operate on gas? Generation levels for coal + gas combined (pre-conversion) look very similar to generation levels for just gas after the conversion. Does CenterPoint assume the capacity factor for Culley 3 on gas will be similar to Culley 3 on coal?

Response:

The capacity factors for Culley 3 on gas are much lower than the capacity factor for Culley 3 on coal.

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3.10 Replace FB Culley 3 with Solar and Storage has higher market purchases – Did CenterPoint test any sensitivities where it hard-coded in more renewables to reduce the purchases to understand how it would impact the cost to reduce purchases down to the levels seen in the other scenarios?

Response:

Yes. Several portfolios, including the diversified renewables portfolio, were tested where additional renewables were included in the portfolio to reduce market purchases.

3.11 Reference case with CCGT conversion in 2027 has really high market sales – Did CenterPoint test sensitivities where it assumed lower market prices or capped market sales? How much of the NPVRR delta between scenarios can be explained by the large amount of market sales.

Response:

In order to avoid portfolios that were developed due to excess market sales, market sales were capped during the portfolio development step of the analysis. The Reference case portfolio does sell more energy into the market than other portfolios and relies less on market purchases for energy. Market purchases and sales percentages are included in the scorecard and are being analyzed to determine potential risks for different portfolios.

Sierra Club Data Request Set 3 to CEI South
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3.12 Convert FBC3 to Natural gas by 2027- Why are there capacity purchases in 2025-2028 when the Company doesn't have a capacity shortfall?

Response: In securing capacity for the 2023/2024 MISO Planning Year to bridge the gap between the coal-fired unit shutdowns and exit and the CT and renewable resources, CEI South secured several bilateral capacity agreements. One contract in particular was only willing to negotiate a multiyear bilateral contract and, with the concern of limited capacity, availability, CEI South entered into this agreement.

3.13 Diversified Renewables scenario: Did CenterPoint do any analysis to understand how much its renewable cost assumptions would have to fall for the scenario to be economically competitive with some of the others?

Response:

The diversified renewables portfolio was created for the risk analysis. It is not a scenario. CEI South did model scenarios where prices for renewable and storage resources were lower relative to base case.

IRP Public Stakeholder Meeting

April 26, 2023

CenterPoint Energy

Welcome and Safety Share

Richard Leger
Senior Vice President Indiana Electric

April 26, 2023

Safety Share
Family Emergency Plan

CenterPoint Energy

The National Safety Council recommends every family have an emergency plan in place in the event of a natural disaster or other catastrophic event. Spring is a great time to review that plan with family members. Have a home and car emergency kit. The Federal Emergency Management Agency says an emergency kit should include one gallon of water per day for each person, at least a three-day supply of food, flashlight and batteries, first aid kit, filter mask, plastic sheeting and duct tape, and medicines. Visit the FEMA website for a complete list. The emergency plan also should include:

- A communications plan to outline how your family members will contact one another and where to meet if it's safe to go outside
- A shelter-in-place plan if outside air is contaminated; FEMA recommends sealing windows, doors and air vents with plastic sheeting
- A getaway plan including various routes and destinations in different directions
- Also, make sure your first aid kit is updated.

For more information, visit the National Safety Council website at www.nsc.org

CenterPoint Energy

Meeting Guidelines, Agenda, and Follow-Up Information

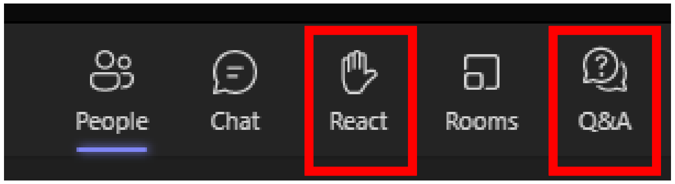
Matt Rice
Director, Regulatory and Rates

Agenda

Time	Topic	Presenter
12:00 – 1:00	Sign-in/Refreshments	
1:00 – 1:10	Welcome, Safety Message	Richard Leger, CenterPoint Energy Senior Vice President Indiana Electric
1:10 – 1:30	Follow Up Information From Third IRP Stakeholder Meeting	Matt Rice, CenterPoint Energy Director Regulatory & Rates
1:30 – 2:00	Preferred Portfolio	Matt Rice, CenterPoint Energy Director Regulatory & Rates
2:00 – 2:25	Risk Analysis Modeling and Portfolios	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
2:25 – 2:45	Risk Analysis Scorecard	Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
2:45 – 3:00	Next Steps	Matt Rice, CenterPoint Energy Director Regulatory & Rates

Meeting Guidelines

1. Please hold most questions until the end of each presentation. Time will be allotted for questions following each presentation. (Clarifying questions about the slides are fine throughout)
2. For those on the webinar, please use the "React" feature in Microsoft Teams (shown at the bottom of this page) to raise your hand if you have a question and we will open your (currently muted) phone line for questions within the allotted time frame. You may also type in questions in the Q&A feature in Microsoft Teams.
3. The conversation today will focus on resource planning. To the extent that you wish to talk with us about other topics we will be happy to speak with you in a different forum.
4. At the end of the presentation, we will open the floor for "clarifying questions," thoughts, ideas, and suggestions.
5. There will be a parking lot for items to be addressed at a later time.
6. CenterPoint Energy does not authorize the use of cameras or video recording devices of any kind during this meeting.
7. Questions asked at this meeting will be answered here or later.
8. We will do our best to capture notes but request that you provide written feedback (concepts, inputs, methodology, etc.) at IRP@CenterPointEnergy.com following the meeting. Additional questions can also be sent to this e-mail address. **We appreciate written feedback within 10 days of the stakeholder meeting.**
9. The Teams meeting will be recorded only to ensure that we have accurately captured notes and questions from the meeting. The public meetings are not transcribed, and the recordings will not be posted to the website. However, Q&A summaries of our public meetings will be posted on www.CenterPointEnergy.com/irp.



Commitments for 2022/2023 IRP

CenterPoint Energy

- ✓ Utilize an All-Source RFP to gather market pricing & availability data
- ✓ Utilize EnCompass software to improve visibility of model inputs and outputs
- ✓ Will include a balanced risk score card. Draft to be shared at the first public stakeholder meeting
- ✓ Will conduct technical meetings with interested stakeholders who sign an NDA
- ✓ Evaluate options for existing resources
- ✓ Will strive to make every encounter meaningful for stakeholders and for us
- ✓ The IRP process informs the selection of the preferred portfolio
- ✓ Work with stakeholders on portfolio development
- ✓ Will test a wide range of portfolios in scenario modeling and ultimately in the risk analysis
- ✓ Will conduct a sensitivity analysis
- ✓ The IRP will include information presented for multiple audiences (technical and non-technical)
- ✓ Will provide modeling data to stakeholders as soon as possible
  - ✓ Draft Reference Case results – October 4th to October 31st
  - ✓ Draft Scenario results – December 6th to December 20th
  - ✓ Full set of final modeling results - March 7th to March 31st*

* Stochastic files to be provided following the final stakeholder meeting

2022/2023 IRP Process

Stakeholder input is provided on a timely basis throughout the process, with meetings held in August, October, December, and April

- Conduct an All Source RFP
- Create Objectives, Risk Perspectives and Scorecard Development
- Create Reference Case Assumptions and Scenario Development
- Portfolio Development Based on Various Strategies, Utilizing Optimization to Create a Wide Range of Portfolios With Input From All Source RFP Data
- Portfolio Testing in Scenarios, Focused on Potential Regulatory Risks
- Portfolio Testing Using Probabilistic Modeling
- Conduct Sensitivity Analysis
- Populate the Risk Scorecard that was Developed Early in the Process and Evaluate Portfolios
- Select the Preferred Portfolio

2022/2023 Stakeholder Process

August 18, 2022	October 11, 2022	December 13, 2022	April 26, 2023
• 2022/2023 IRP Process • Objectives and Measures • Encompass Software • All-Source RFP • MISO Update • Environmental Update • Draft Reference Case Market Inputs & Scenarios • Load Forecast Methodology • DSM MPS/ Modeling Inputs • Resource Options	• All-Source RFP Results and Final Modeling Inputs • Draft Resource Inputs • Final Load Forecast • Scenario Modeling Inputs • Portfolio Development • Probabilistic Modeling Approach and Assumptions • Draft Reference Case Modeling Results	• Draft Scenario Optimization Results • Draft Portfolios • Final Scorecard and Risk Analysis • Final Resource Inputs[1]	• Final Reference Case Modeling • Probabilistic Modeling Results[2] • Risk Analysis Results • Preview the Preferred Portfolio

[1]Provided results to those with an NDA by December 20, 2022 Updated modeling results were provided to stakeholders on March 7, 2023
[2] Stochastic files to be provided following the final stakeholder meeting

Stakeholder Collaboration

During this IRP cycle we have had additional communication with stakeholders through a series of tech-to-tech meetings. These have allowed additional opportunity for stakeholders to provide helpful input and participate in this process

Tech to Tech Modeling Feedback		
Meeting Dates	**General Notes and Feedback**	**Data Requested**
October 5th, 2022	• Discussed model inputs and assumptions • Evaluated model constraints • Discussed CO_2 forecast assumptions	• Stochastic modeling information • CO_2 price curves
October 31st, 2022	• Discussed Energy Efficiency and Demand Response model inputs • Discussed optimization of conversion options	• Reference case model outputs • Energy Efficiency and Demand Response model inputs
December 7th, 2022	• Reviewed optimized portfolios • Discussed assumptions surrounding optimized model outputs and portfolio buildouts	• Commodity forecasts • RFP PPA and Purchase pricing inputs • Stochastic results • Draft EnCompass model
February 28th, 2023	• Gathered input before running the risk analysis • Discussed accreditation, capital, and O&M projection updates • Evaluated final approach for the risk analysis	• Final capital cost curve estimates • Final IRP resource accreditation • Final near term PPA pricing

Stakeholder Feedback

Stakeholder Feedback	Response
Stakeholder request for continued dialogue following the public stakeholder meeting in December	Held a tech-to-tech meeting on February 28, 2023, to provide updated modeling files, additional input files, and portfolios for consideration in the risk analysis to stakeholders for review and comment
Include full monetization of Investment Tax Credit (ITC) for hydro resources	Included
Include the same style energy and capacity graphs that were included in the final tech-to-tech meeting when displaying risk analysis portfolios	Included
Beyond the near-term modeling, did you include site-specific assumptions to include energy community bonus for the Production Tax Credit and ITC	CEI South ran various resource capital costs and tax credit qualification sensitivities to determine the impact of these changes on future resource decisions

Stakeholder Feedback

Stakeholder Feedback	Response
Please evaluate a portfolio with hydro electric	Hydro was not selected in any of the 5 optimized modeling runs. Several portfolios were considered with hydro. These portfolios resulted in higher costs and were screened out of the risk analysis
Color coding in the score card is not helpful	The color coding is assigned by Excel based on rank order. We believe it is useful in helping discern a lot of information quickly. The scorecard is just a tool used to assimilate trade offs; we use judgement and reason to select a preferred portfolio
Capital costs should not be varied stochastically	An alternate process was used for capital and CO_2. The process will be described today
Adjust the scorecard to include near and long-term energy purchases/sales	Adjusted

Q&A

Preferred Portfolio

Matt Rice

2022/2023 IRP Background

CenterPoint Energy

- Since the 2020 IRP, there has been unprecedented change in multiple areas that effect generation planning:
  - Disruption in the solar market (supply chain issues stemming from COVID, threat of tariffs, and an investigation by the Commerce Department on forced labor in China) that has driven costs much higher than expected
  - Dispatchable generation is rapidly retiring and replaced with intermittent generation, causing a capacity shortage in MISO. The market reached the max price of Cost of New Entry (CONE) for the 2022/2023 planning year
  - Passage of the Inflation Reduction Act (IRA) which accelerated the demand for renewables projects at a time of supply chain constrains is fueling near term price increases
  - Rising energy costs that have helped drive high inflation throughout the economy
  - Fundamental changes to MISO rules and mechanisms (to ensure reliability for the worst week across four seasons rather than planning for the one peak hour of the year in summer) results in lower capacity accreditation for solar in the long term, while wind has benefited from these changes
  - EPA continues to ratchet down on air emissions, targeting coal

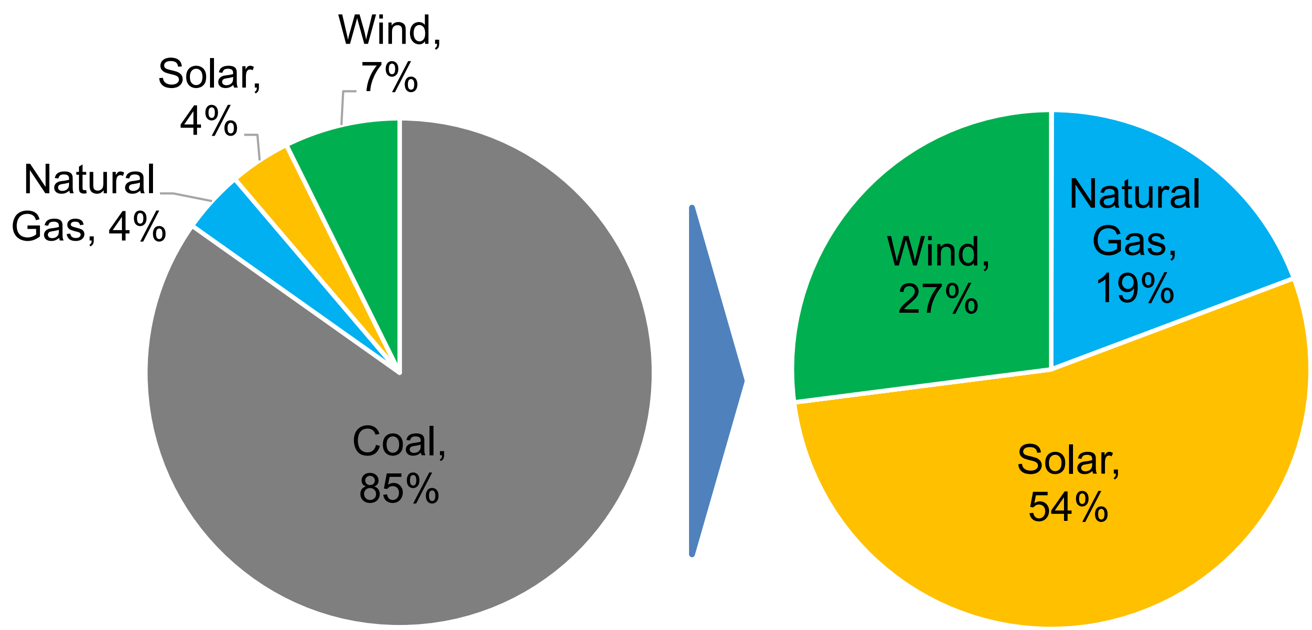
Why Was This Portfolio Chosen?

CenterPoint Energy

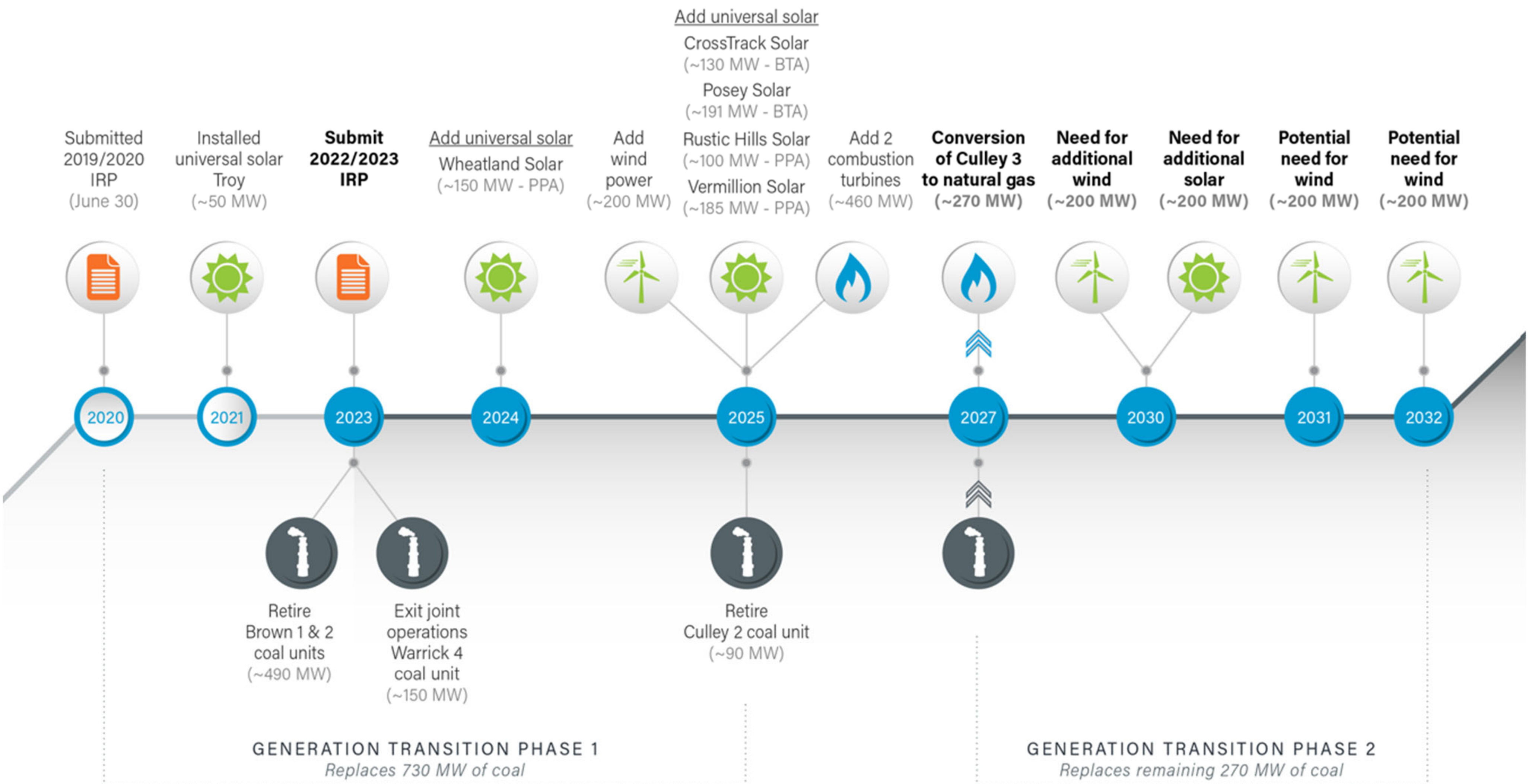
The preferred portfolio converts FB Culley 3 from coal to natural gas by 2027 and adds 200 MW of solar and 200 MW of wind by 2030. An additional 400 MW of wind is called for by 2032.

- **Preferred Portfolio Benefits**
  - Maintains reliability, preserving 270 MW of capacity
  - Saves customers nearly $80 million vs continuation of F.B. Culley 3 on coal
  - Lowers CO_2 output by more than 95%
  - Avoids future customer cost risk by preserving interconnection at Culley 3
  - Preserves tax base in Warrick County
  - Maintains ability to ramp if needed for economic development

2023 to 2030 Energy Production



CenterPoint Energy IRP Preferred Portfolio[1]



IRP = Integrated Resource Plan
MW = Megawatt
BTA = Build Transfer Agreement/Utility Ownership
PPA = Power Purchase Agreement

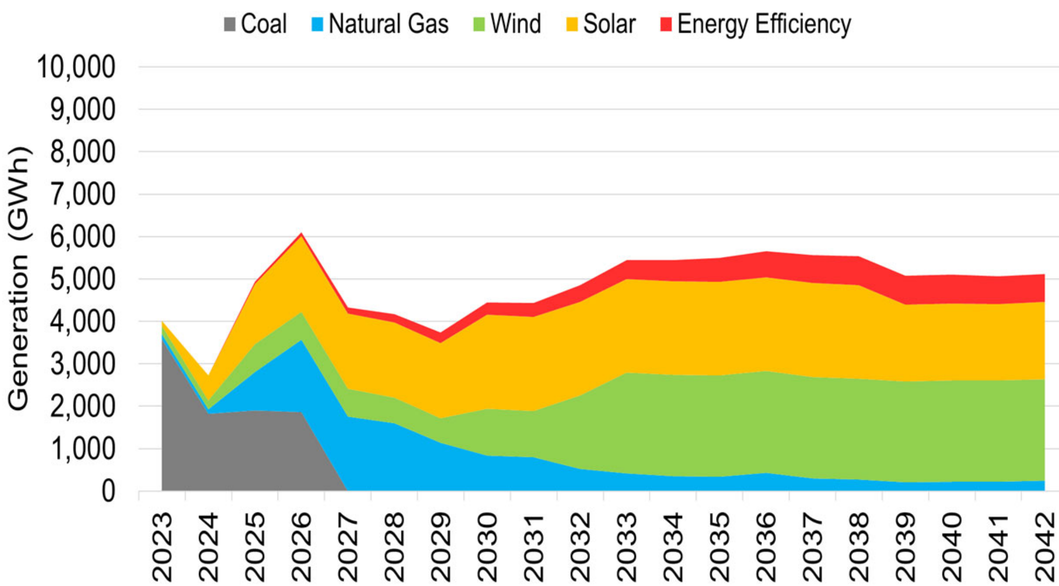
[1] Subject to change based on availability and approval

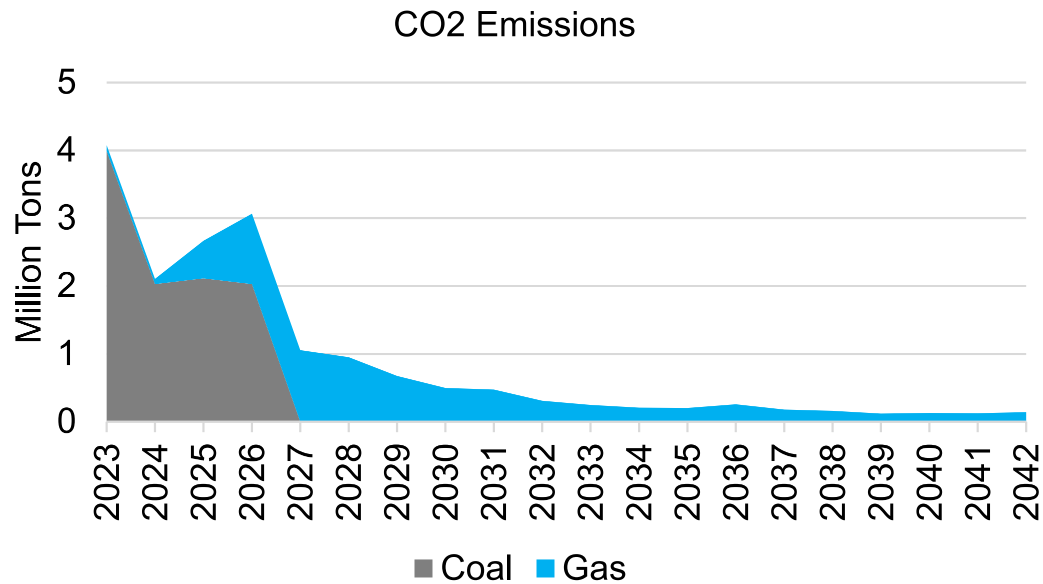
Benefits of FB Culley 3 Conversion

- Reliability and affordability
  - Dispatchable resource supports continued transition to renewable energy by providing energy during peak hours where energy prices are at their highest
  - Hedge against future capacity costs that are expected to remain high in the MISO market
  - Low up front capital cost, reduced O&M and reduced fuel cost results in savings for customers when compared to continuing to run on coal
  - Able to run during times of long duration renewables drought
  - More certainty on future accreditation
- CO_2 emissions nearly the same to storage and renewable portfolios with reduced SO_2 and NO_x emissions
  - Runs approx. 1% of the time
- Provides off ramp in the future
  - Allows for new alternatives to maintain reliability when they become available and affordable in the future
- Maintains existing resource
  - Maintain resource interconnection, reducing future cost and timing risk with MISO interconnection queue
  - Reduces stranded asset cost risk
- Resource diversity
  - Resilient\Diverse firm gas supply to different plants to supporting peaking operation
  - Reduced firm gas cost due to 8-12 hour start time
- Provides ancillary services for stability
- Maintains tax base in community

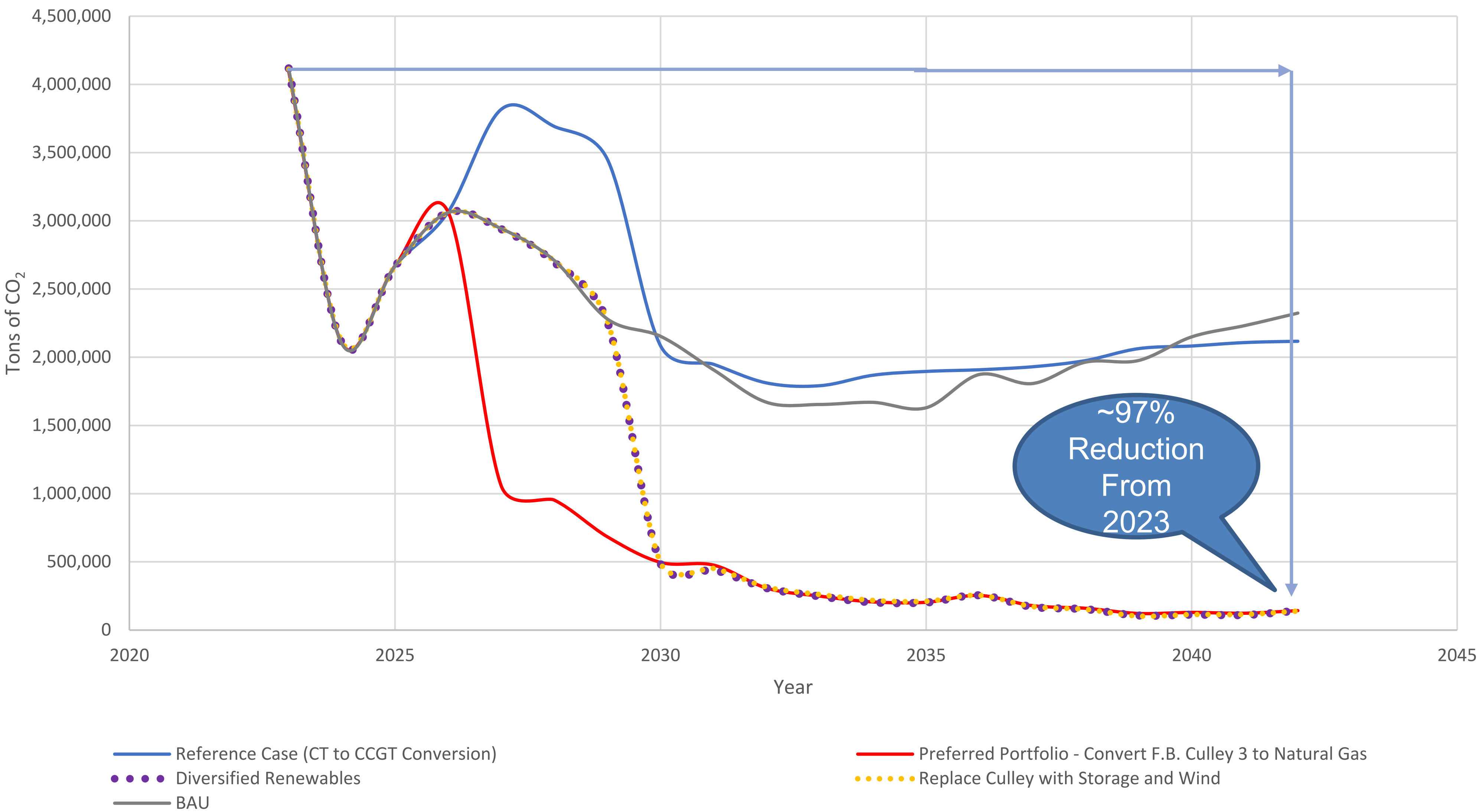
Preferred Portfolio Annual Generation and Emissions

- Generation will shift from coal to renewables and gas in the near term with a long-term shift from natural gas to mostly renewables
- By 2030 80% of energy produced will be from wind and solar resources
- From 2023 to 2030 CO_2 emissions drop by 88% and 97% by the end of the period



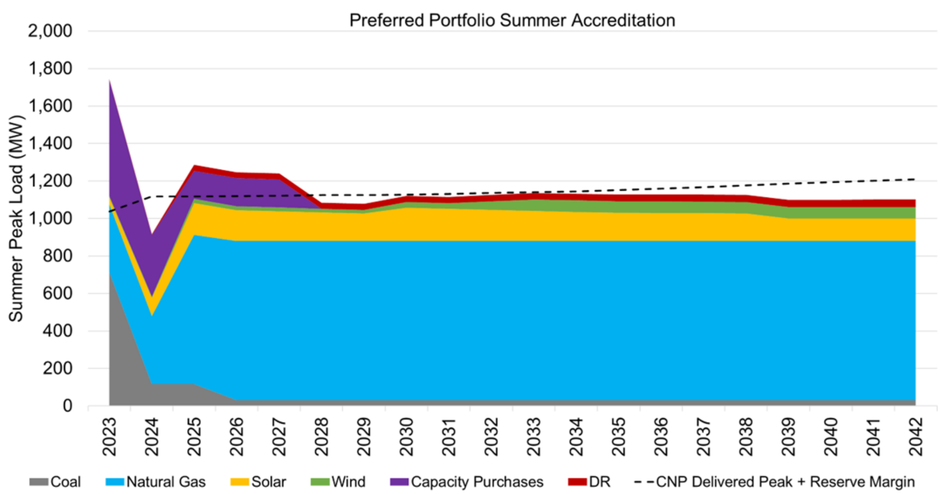


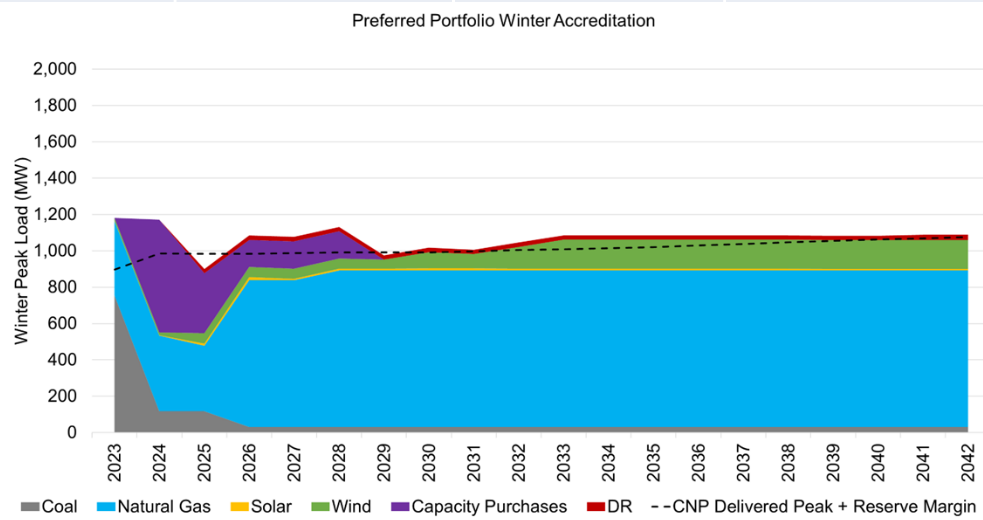
Portfolio CO_2 Emissions



Preferred Portfolio Additions and Retirements

2030-2031 Planning Year	2030-2031 Summer UCAP (MW)	Summer Accreditation %	% Summer UCAP	2030-2031 Winter UCAP (MW)	Winter Accreditation %	% Winter UCAP
Coal	30	94%	2%	30	95%	3%
Natural Gas	851	94%	76%	862	95%	85%
Solar	176	17%	16%	10	1%	1%
Wind	31	7%	3%	90	20%	9%
DR	33	100%	3%	24	100%	2%
Total Resources	1,121	N/A	100%	1,016	N/A	100%





Demand Side Resources in the Preferred Portfolio[1]

CenterPoint Energy

- Consistent with the 2019 IRP, the framework for the 2021-2023 EE Plan was modeled at a savings level of 1.2% of retail sales adjusted for an opt-out rate of 77% of eligible load.
  - CEI South used the realistic achievable potential identified in a Market Potential Study (MPS) as a starting point and worked closely with stakeholders on their suggested process
  - Residential sector savings were segmented into two tiers (High-Cost & Low/Mid Cost) due to stakeholder and CEI South concerns that aggregated residential sector bundles would not get selected
  - To maximize the amount of residential energy efficiency that could be selected, bundles were redrawn, shifting higher cost measures from Tier 1 into Tier 2
  - This process was utilized instead of altering EE pricing utilizing the standard deviations described in prior stakeholder meetings. Results were built into all portfolios for risk analysis modeling
  - Income Qualified Weatherization (IQW), the transition of Legacy DLC (Summer Cycler), and the Industrial DR programs were applied to all scenarios[2]

Vintage	Portfolio Selection
Vintage 1 2025 - 2027	DR Legacy - 2023
	DR Industrial
	C&I Enhanced
	HER
	IQW
	Res LowMed
Vintage 2 2028 - 2030	C&I Enhanced
	IQW
	HER
	Res LowMed
	DR CI Rates
Vintage 3 2031 - 2042	C&I Enhanced
	DR CI Rates
	IQW
	Res LowMed

[1]CEI South's DSM programs have been approved by the Commission and implemented pursuant to various IURC orders over the years

[2]CEI South is currently in discussion with a C&I aggregator to help realize the Industrial DR included in the preferred portfolio

Q&A

Risk Analysis Modeling and Portfolios

Drew Burczyk, 1898

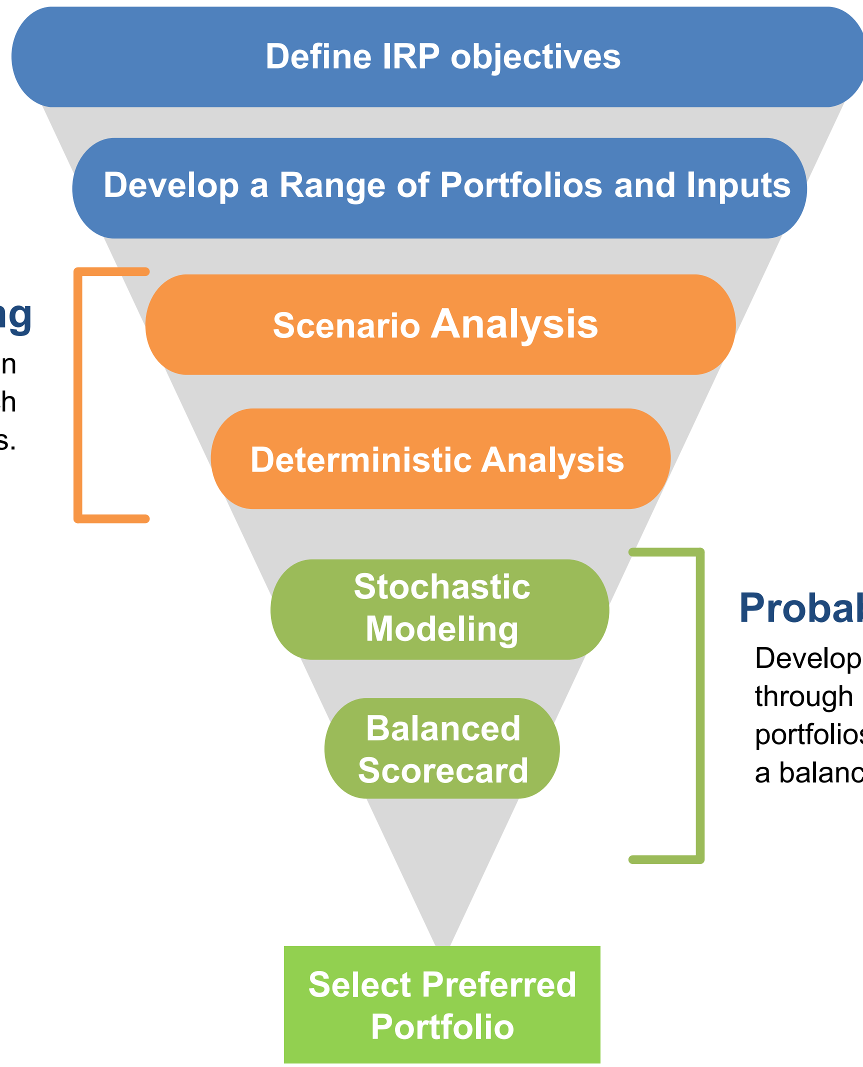
IRP Portfolio Evaluation and Selection Process

Initial Modeling Phase

Outline the customer requirements and project options/constraints within the model.

Deterministic Modeling

Optimize the least cost capacity expansion plan for each portfolio. Run hourly dispatch modeling on all portfolios.



Probabilistic Modeling

Develop 200 unique families of modeling inputs through Monte Carlo simulation. Run selected portfolios through 200 families of inputs to achieve a balanced scorecard.

Probabilistic Modeling Approach

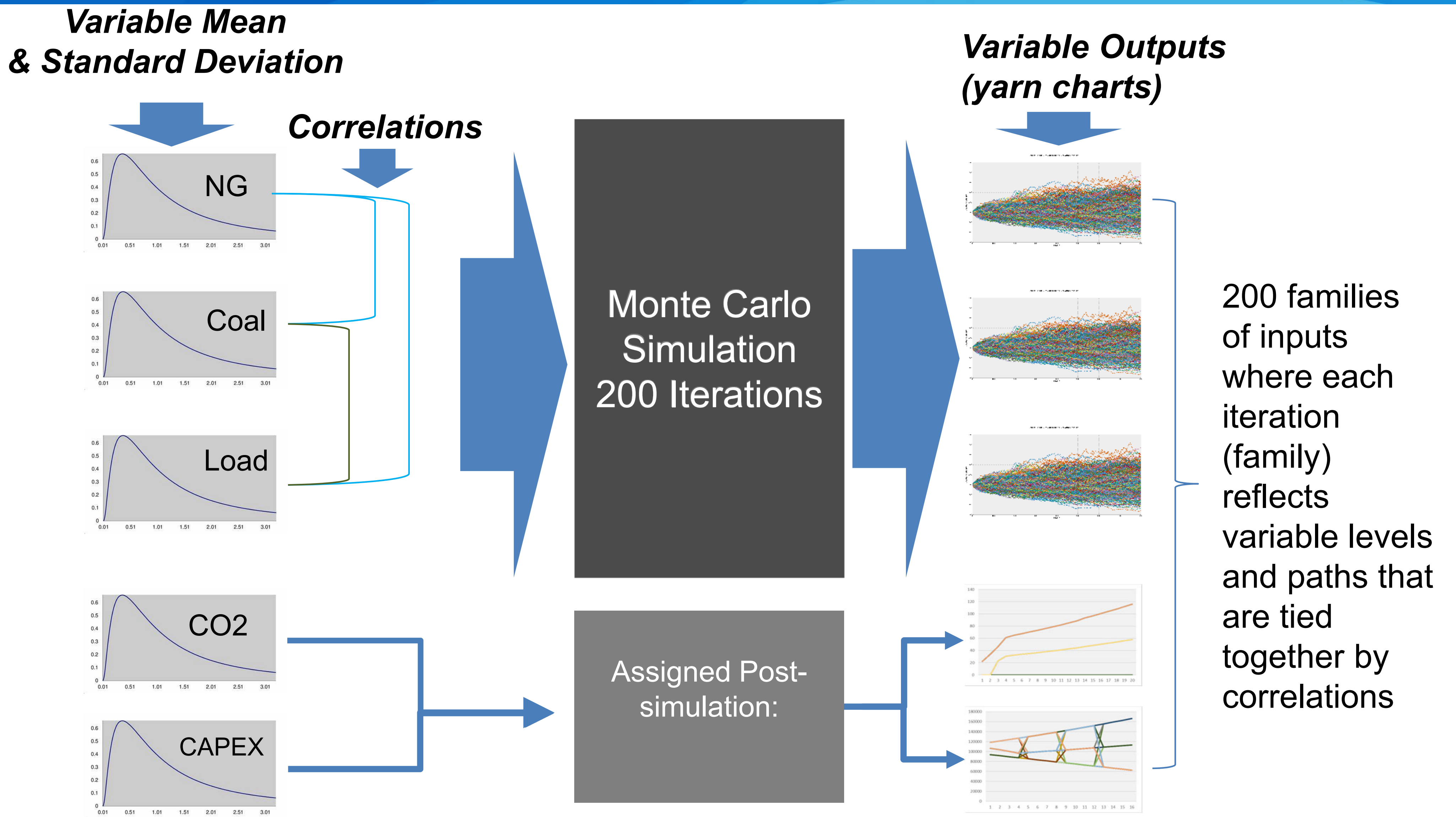
CenterPoint Energy

Objective: Utilize stochastic analysis around key IRP inputs to measure uncertainty around power supply portfolio costs

<u>Two Purposes:</u>

1. Evaluate results of stochastic inputs analysis to inform on what inputs to use for various scenarios; and
2. Stochastically develop 200 “families” of correlated inputs to run through PCM – result will be probability distribution around power supply costs

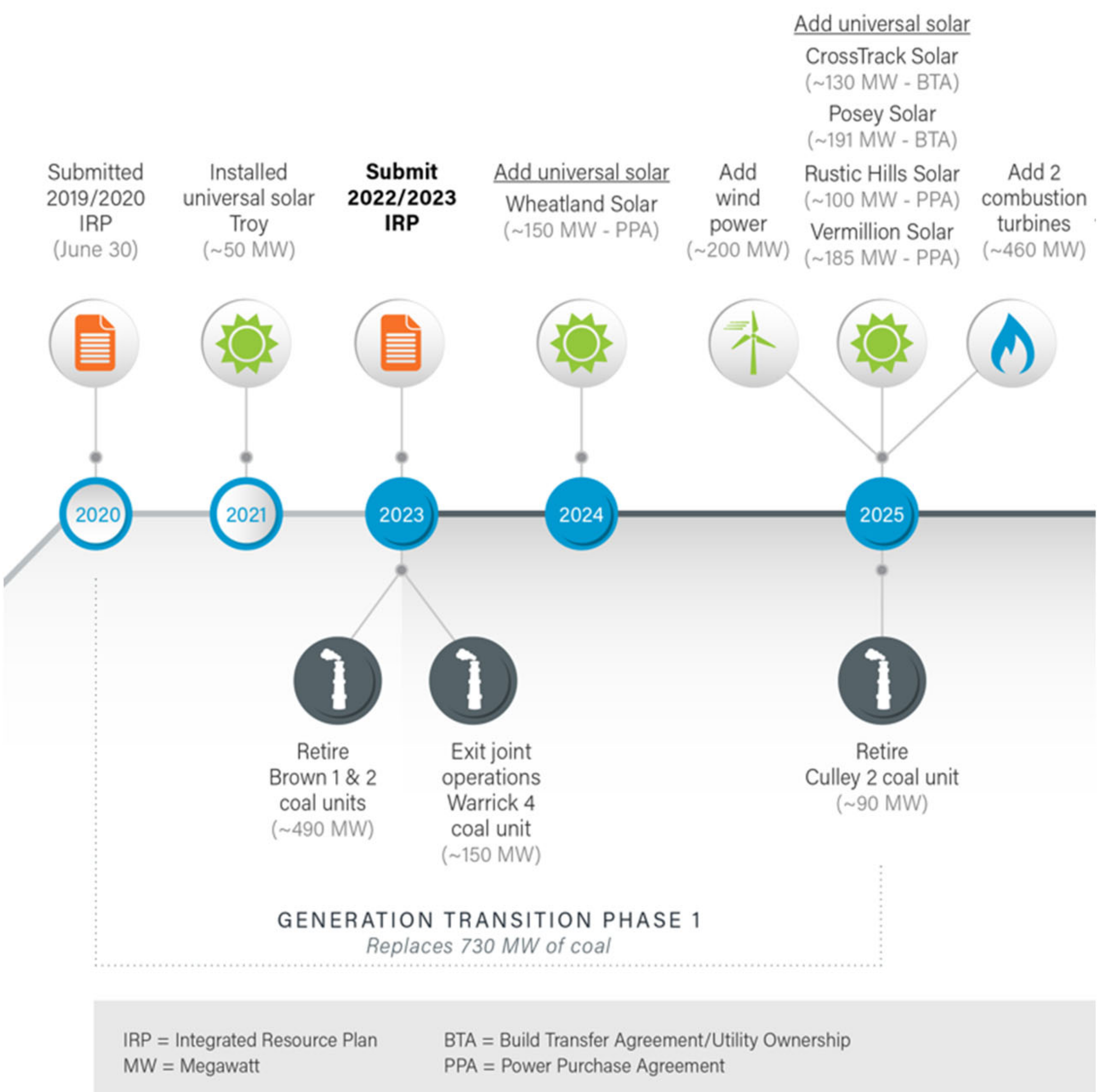
Risk Analysis Process Overview



Risk Analysis Methodology

- Utilize 200 draws from Scenario inputs for Gas, Coal, Load
- Renewable + storage capital cost variation in risk analysis
  - Assigned to 200 EnCompass draws based on:
    - First 50 draws - Low forecast
    - Next 100 draws - Reference case forecast
    - Last 50 draws - High forecast
  - Every 4 years, draws randomly “reshuffled” and above assignments are made
- CO_2 forecast variation in risk analysis - Assigned to 200 EnCompass draws based on:
    - First 120 draws use Reference case forecast ($0/Ton)
    - Next 40 draws use Medium forecast
    - Last 40 draws use High forecast

IRP Portfolio Decisions



- FB Culley 2 & 3 conversion or retirement decision is a key part of this IRP
- With MISO's shift to seasonal construct there is a capacity shortfall in 2024 prior to the CTs coming online and then into the 2030s
- Analyzed a wide range of portfolios that provide insights around the F.B. Culley decision and the future resource mix

Range of IRP Portfolios

Portfolio Strategy Group	Portfolio
Reference	Optimized Portfolio in Reference Case conditions
Scenario-Based	Optimized Portfolio using High Regulatory scenario assumptions
	Optimized Portfolio using Market Driven Innovation scenario assumptions
	Optimized Portfolio using Decarbonization/Electrification scenario assumptions
	Optimized Portfolio using High Inflation and Supply Chain Issues scenario assumptions
Deterministic	Business as Usual (Continue to run FB Culley 3 through 2042)
	AB Brown CTs with and without CCGT conversion
	FB Culley 2 or 3 gas conversion
	FB Culley 2 and 3 gas conversion
	Retire FB Culley 2 by 2025 • Replace with non-thermal (Wind, Solar, Storage) • Replace with thermal (CCGT, CT)
	Retire FB Culley 3 by 2029 • Replace with non-thermal (Wind, Solar, Storage) • Replace with thermal (CCGT, CT)
	Retire FB Culley 3 by 2035 • Replace with non-thermal (Wind, Solar, Storage) • Replace with thermal (CCGT, CT)

Range of Portfolios

- Starting from the 12 portfolios that were presented at the third stakeholder meeting, additional portfolios and iterations of portfolios were developed based on:
  - Continue right sizing portfolios on both for capacity and energy
  - To examine tradeoffs in different existing resource decision timing
  - Stakeholder feedback
  - Lessons learned from preliminary portfolio optimization results

Portfolio Screening

- After iterative portfolio development and testing, portfolios were screened in order to maintain a reasonable number of portfolios to run through risk analysis
- Portfolios were screened primarily based on the following
  - Portfolio similarities and overlap
    - Desire portfolios that are included in risk analysis to be different enough to provide insights between different options (not have 10 portfolios that include the same resource types)
  - Right sizing for CNP and customers
    - Meets seasonal capacity requirements, while not significantly over built
    - Does not over rely on the market for energy sales or energy purchases
  - Cost

Portfolio Screening For Risk Analysis -
12.13.22 Stakeholder Meeting Draft Optimized Portfolios

CenterPoint Energy

Year	Reference Case	Market Driven Innovation	Decarbonization/ Electrification
2024	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)
2026			
2027	CCGT Conversion	CCGT Conversion	CCGT Conversion
2028			
2029	Retire FB Culley 3	Retire FB Culley 3 Storage (1 x 10MW)	Retire FB Culley 3
2030			Wind North (1 x 200MW)
2031			
2032			Long Duration Storage (300MW) Wind North (1 x 200MW)
2033	Wind North (3 x 200MW)		Wind North (3 x 200MW)
2036			
2041		Storage (1 x 10MW)	
2042		Storage (2 x 10MW)	

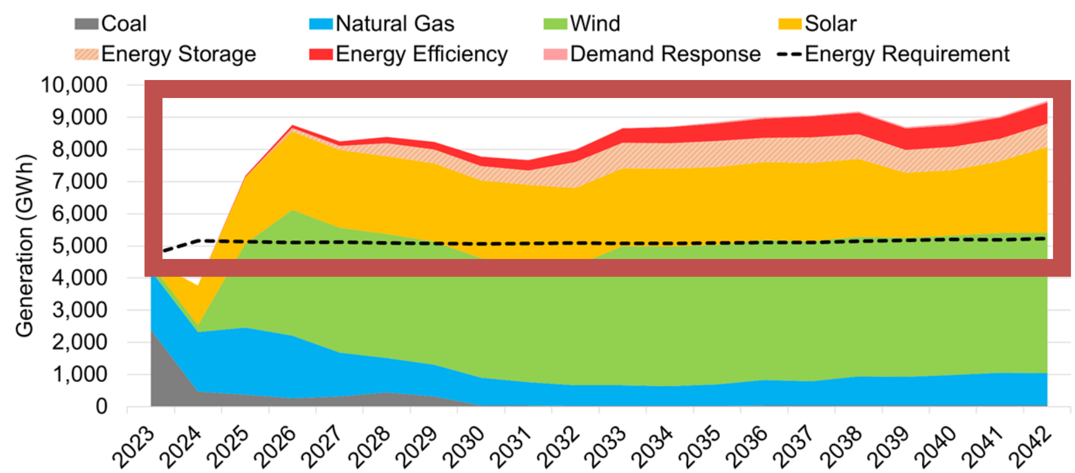
Common themes across several portfolios:

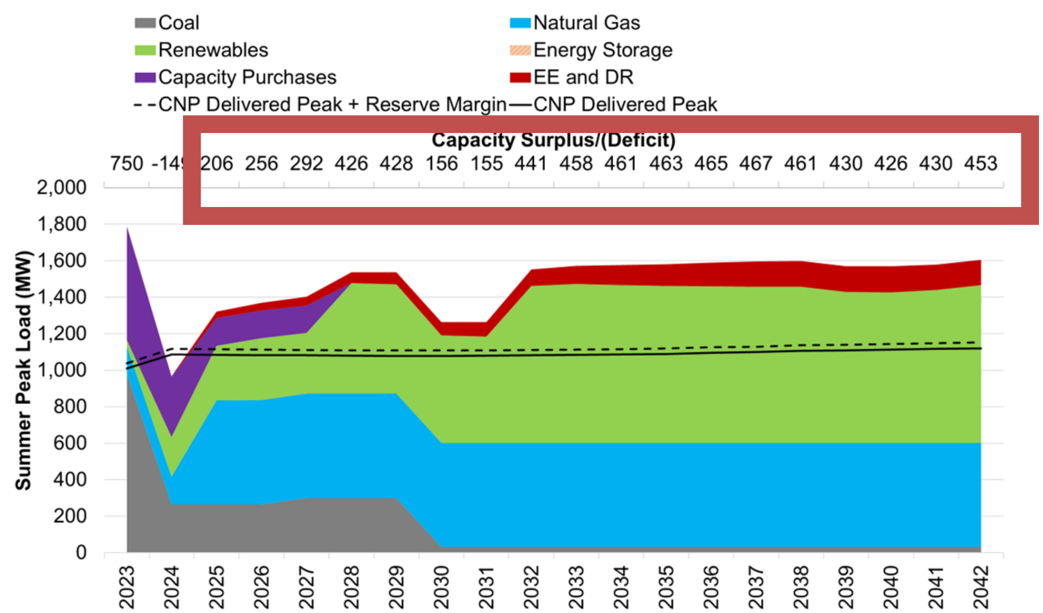
- AB Brown CT to CCGT Conversion
- Retire Culley 3 in 2029
- New wind resources being added

Portfolio Screening - Right sizing CenterPoint and Customer needs

- Several portfolios which were hundreds of MW long on capacity and/or over generated energy compared to CNP need throughout study period were screened out
- Resource mixes and portfolio concepts learned were included in deterministic portfolios at smaller scale

Energy Generation Mix





Portfolio Screening - Cost

Year	Diversified Renewables	Diversified Renewables (With Hydro)
2023	Exit Warrick 4	Exit Warrick 4
2024	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)
2026		
2027		
2028		
2029	Retire FB Culley 3 Wind (200MW)	Retire FB Culley 3
2030	Storage (200MW) Solar (200MW) Wind (200MW)	Storage (200MW) Hydro (58MW)
2031		
2032		Wind (200MW)
2033	Wind (200MW)	Wind (600MW)
2041		
2042		

- Portfolios which were significantly higher on cost when run through the reference case were screened prior to the risk analysis
- Portfolios which tested adding/replacing a specific resource(s) that decreased portfolio performance were also screened

Balanced Portfolio Buildouts (1 of 2)

Year	Reference Case	Business as Usual (BAU) Cont. FB Culley 3 on Coal	Convert F.B. Culley 3 to Natural Gas by 2030	Convert F.B. Culley 3 to Natural Gas by 2027	Convert F.B. Culley 3 to Natural Gas by 2027 with Wind and Solar
2023	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4
2024	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Continue FB Culley 3 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)
2026					
2027	CCGT Conversion			Covert FB Culley 3 to Natural Gas	Covert FB Culley 3 to Natural Gas Wind (200MW) Solar (200MW)
2028					
2029	Retire FB Culley 3	Storage (10 MW)			
2030		Wind (200MW)	Covert FB Culley 3 to Natural Gas Wind (200MW) Solar (200MW)	Wind (200MW) Solar (200MW)	
2031					
2032			Wind (200MW)	Wind (200MW)	Wind (200MW)
2033	Wind (400MW)		Wind (200MW)	Wind (200MW)	Wind (200MW)
2041	Storage (10MW)				
2042		Storage (10 MW)			

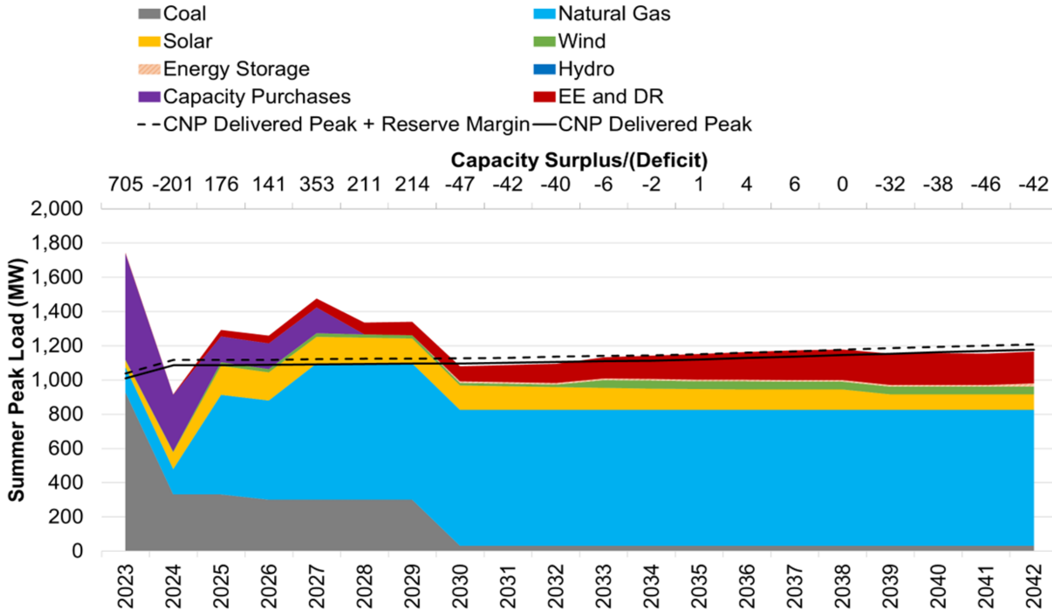
Balanced Portfolio Buildouts (2 of 2)

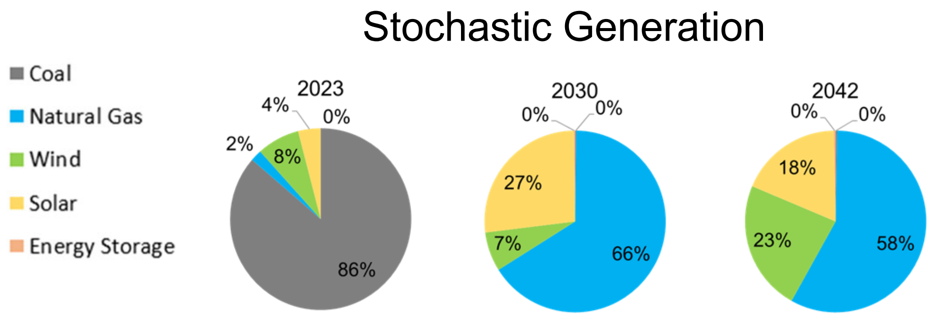
CenterPoint Energy

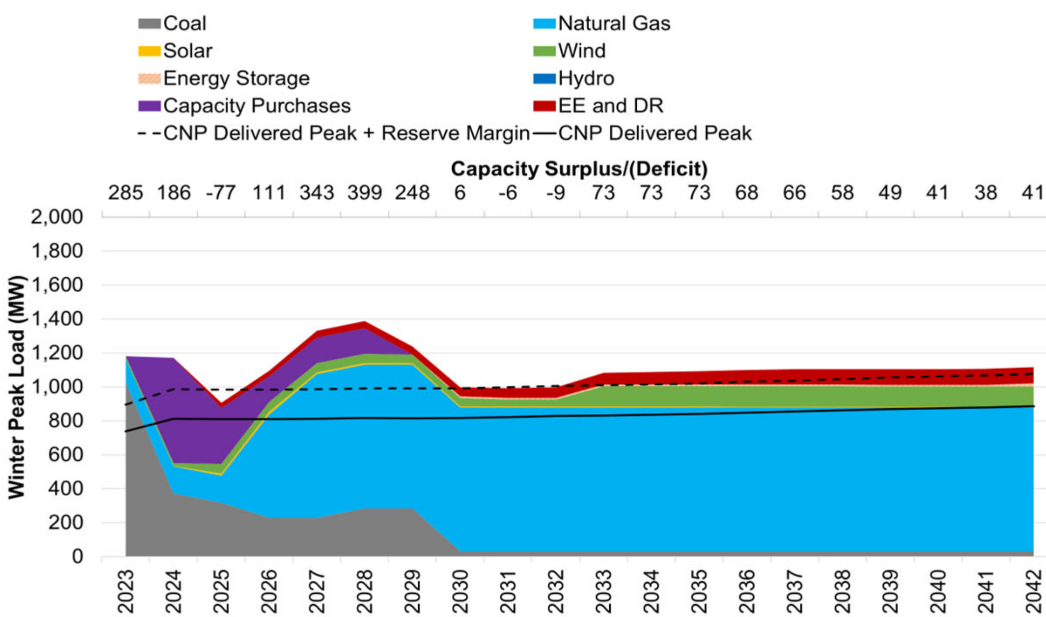
Year	CT Portfolio (Replace FB Culley 3 with F Class CT)	Diversified Renewables	Diversified Renewables (Early Storage & DG Solar)	Replace FB Culley 3 with Storage and Wind	Replace FB Culley 3 with Storage and Solar
2023	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4
2024	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)
2026					
2027			Solar (60MW)		
2028			Storage (90MW)		
2029	Retire FB Culley 3	Retire FB Culley 3 Wind (200MW)	Retire FB Culley 3	Retire FB Culley 3	Retire FB Culley 3
2030	F-Class CT Storage (60MW)	Storage (200MW) Solar (200MW) Wind (200MW)	Storage (100MW) Wind (400MW) Solar (100MW)	Storage (300MW) Wind (400MW)	Storage (250MW)
2031					
2032					
2033	Wind (600 MW)	Wind (200MW)	Wind (200MW)	Wind (200MW)	Solar (300MW)
2041			Solar (100MW)		
2042			Solar (100MW)		Storage (10MW)

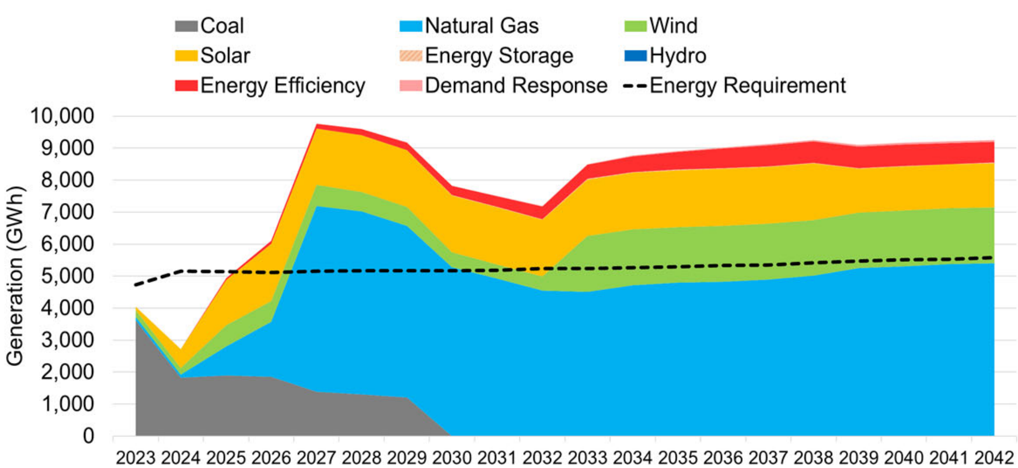
Reference Case (Unconstrained)

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Conversion of CTs to CCGT
- Wind in 2033 and Storage in 2041



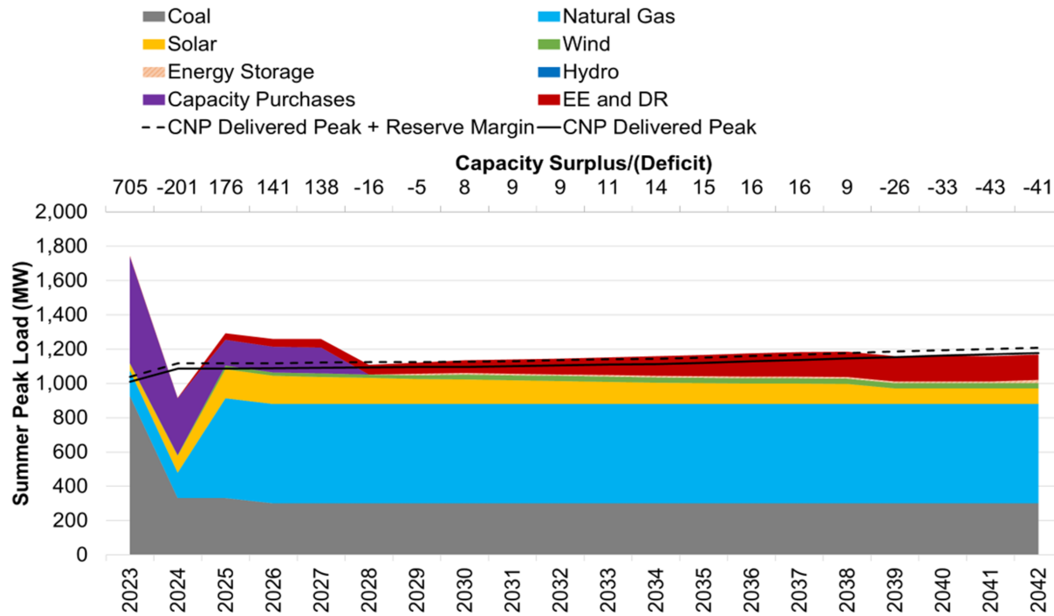


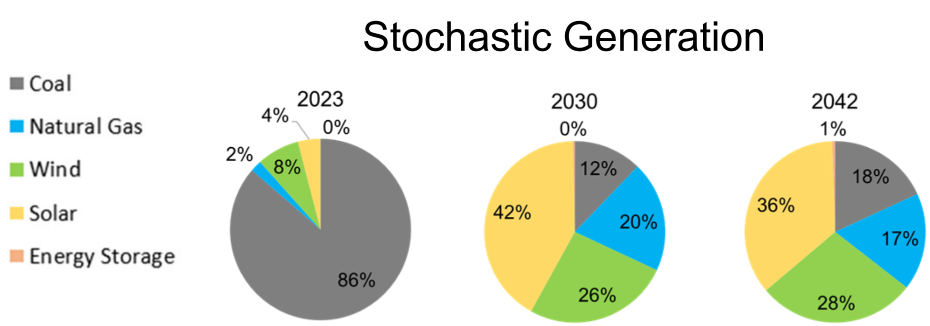


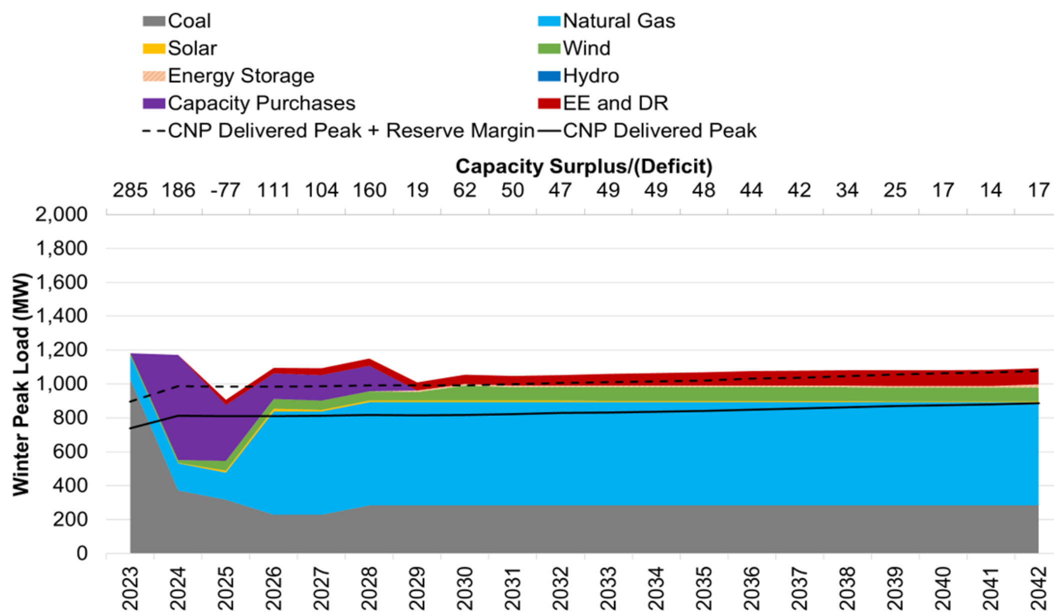


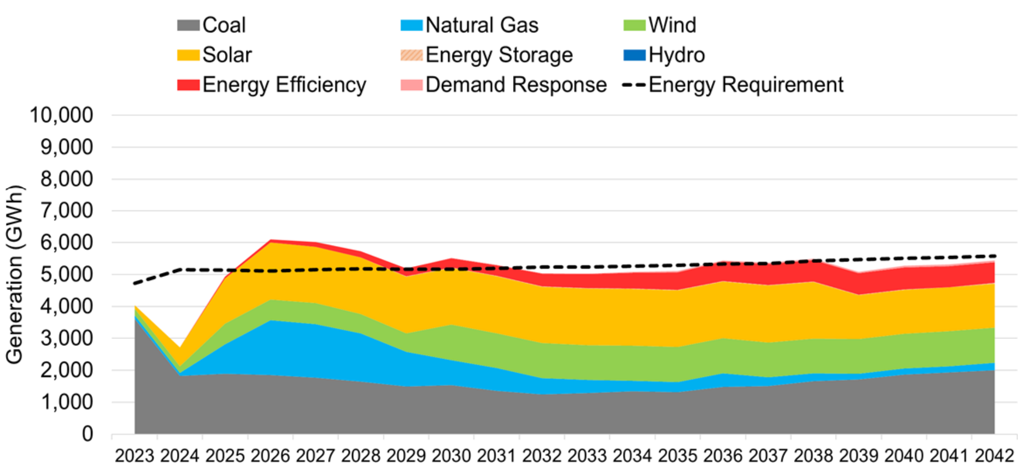
Business as Usual (BAU) Cont. FB Culley 3 on Coal

- 2025 retirement of FB Culley 2
- Continue FB Culley 3 on coal
- Wind in 2030
- 10 MW Storage in 2029 and 2042



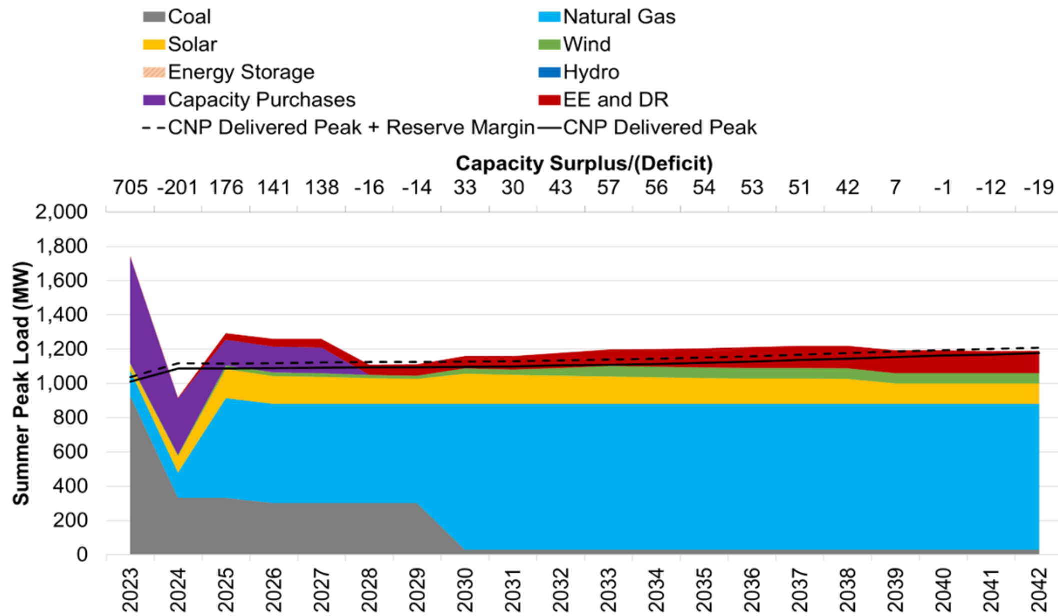




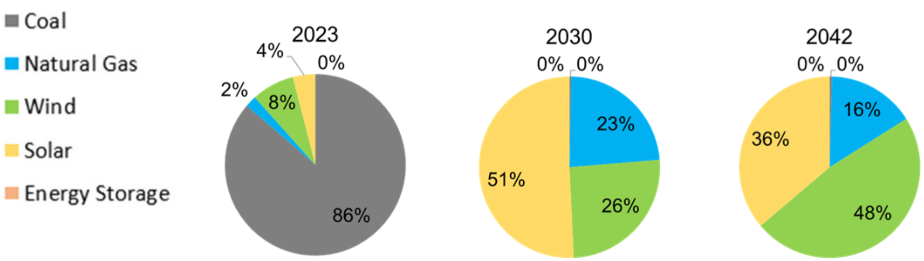


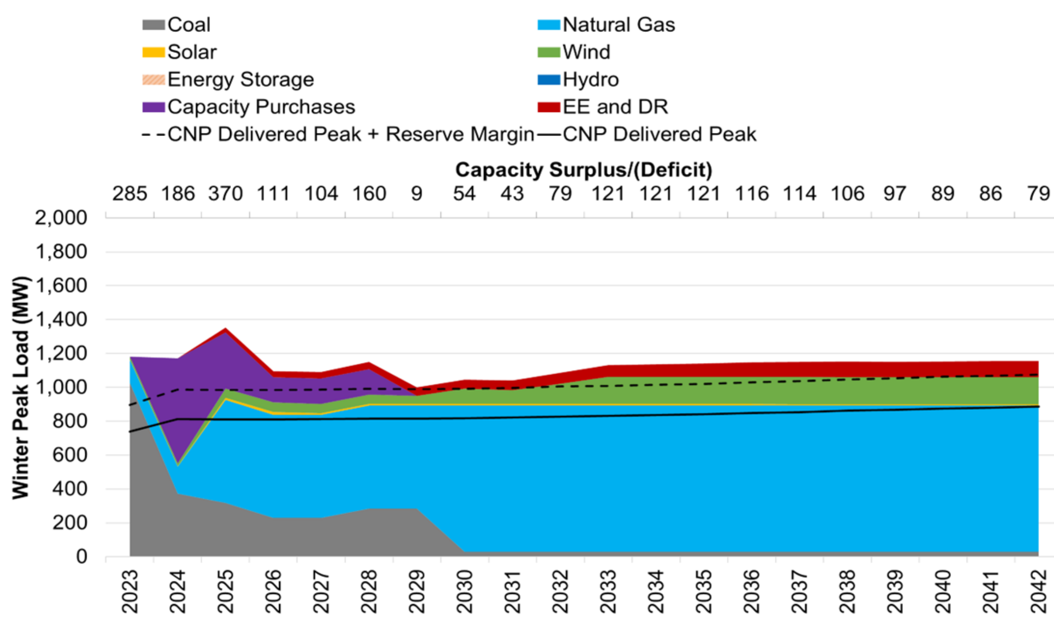
Convert F.B. Culley 3 to Natural Gas by 2030

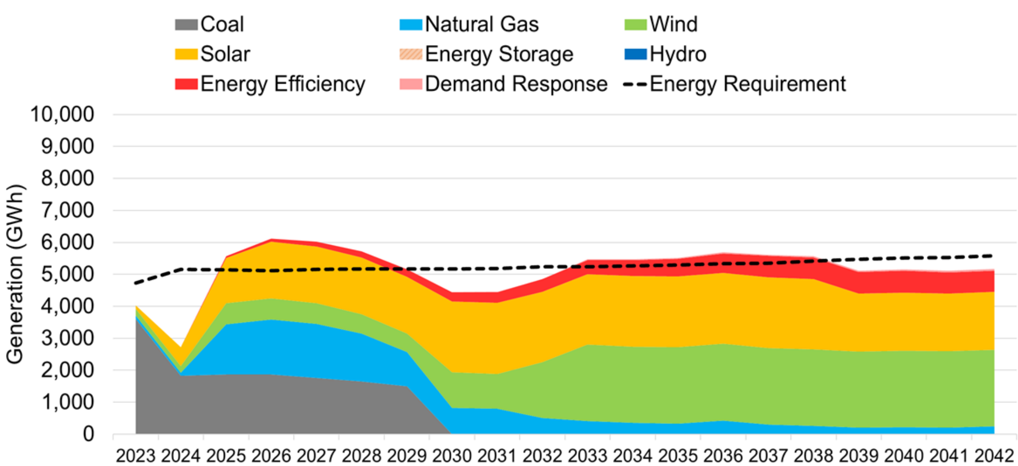
- 2025 retirement of FB Culley 2
- 2030 conversion of FB Culley 3 to NG
- Wind in early 2030s
- Solar in 2030



Stochastic Generation

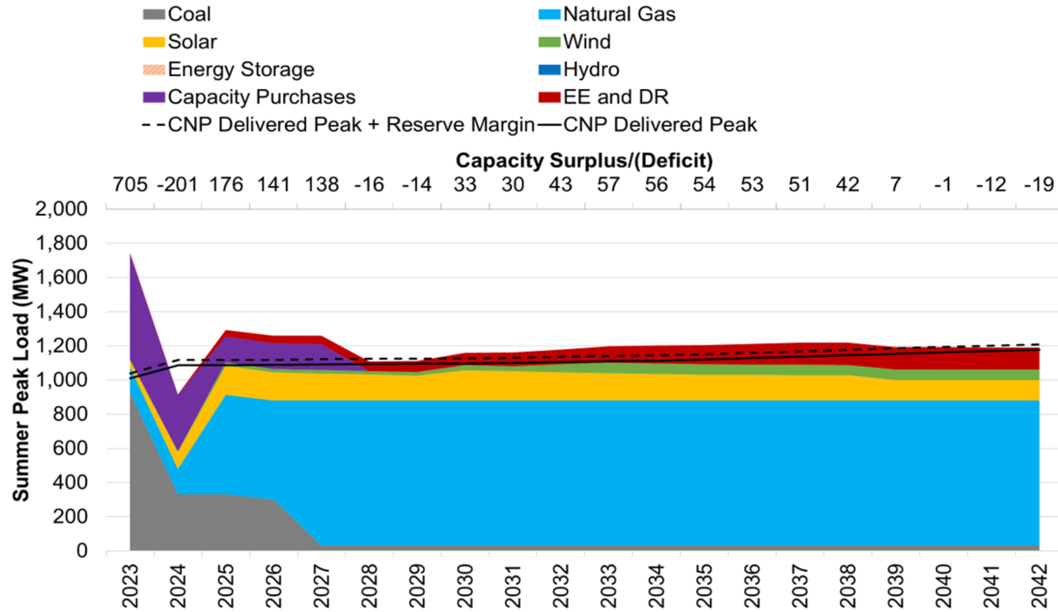




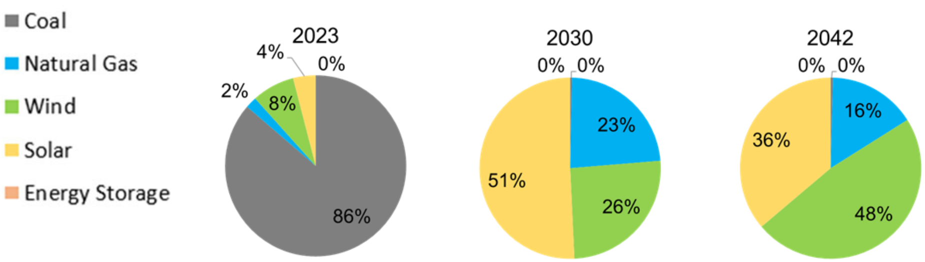


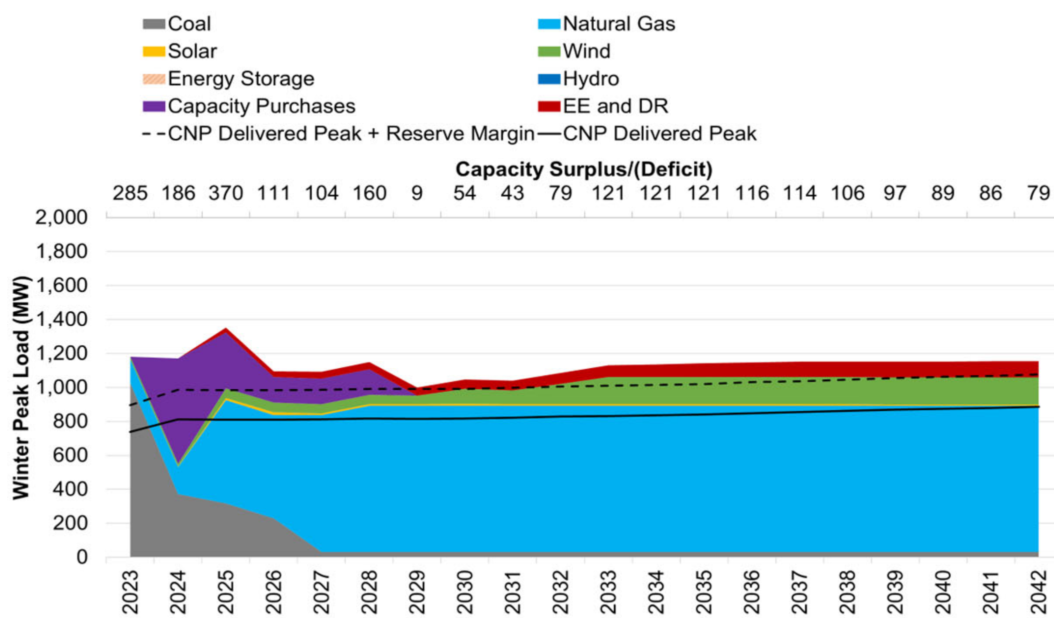
Convert F.B. Culley 3 to Natural Gas by 2027

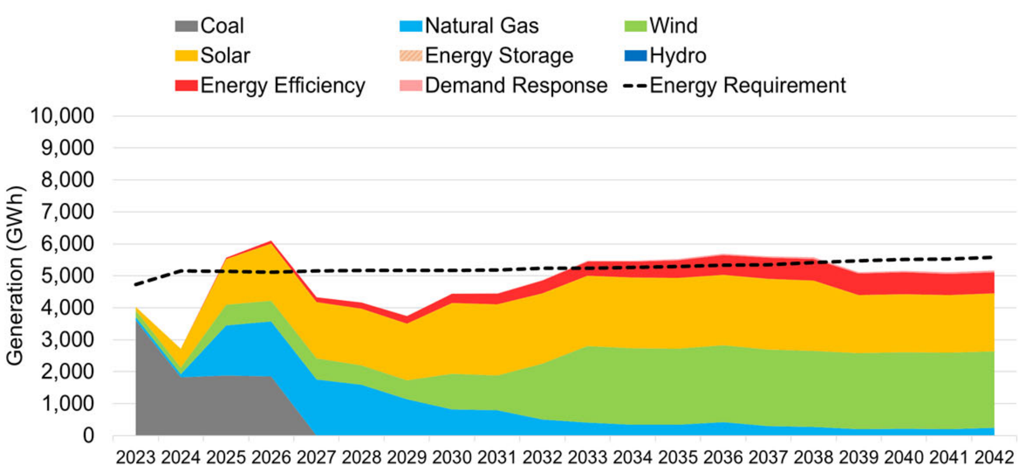
- 2025 retirement of FB Culley 2
- 2027 conversion of FB Culley 3 to NG
- Wind in early 2030s
- Solar in 2030



Stochastic Generation





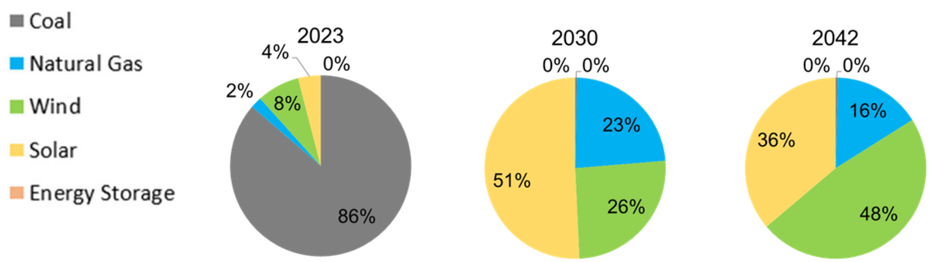


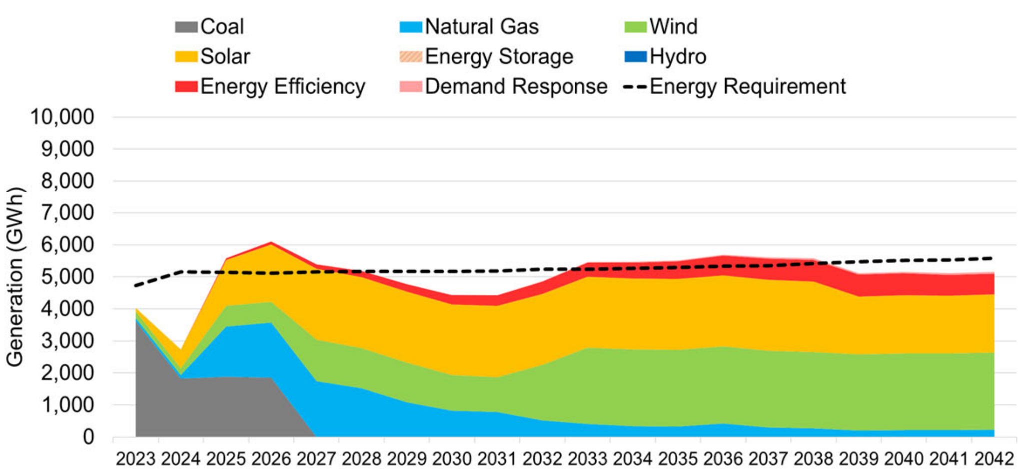
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 Wind and Solar

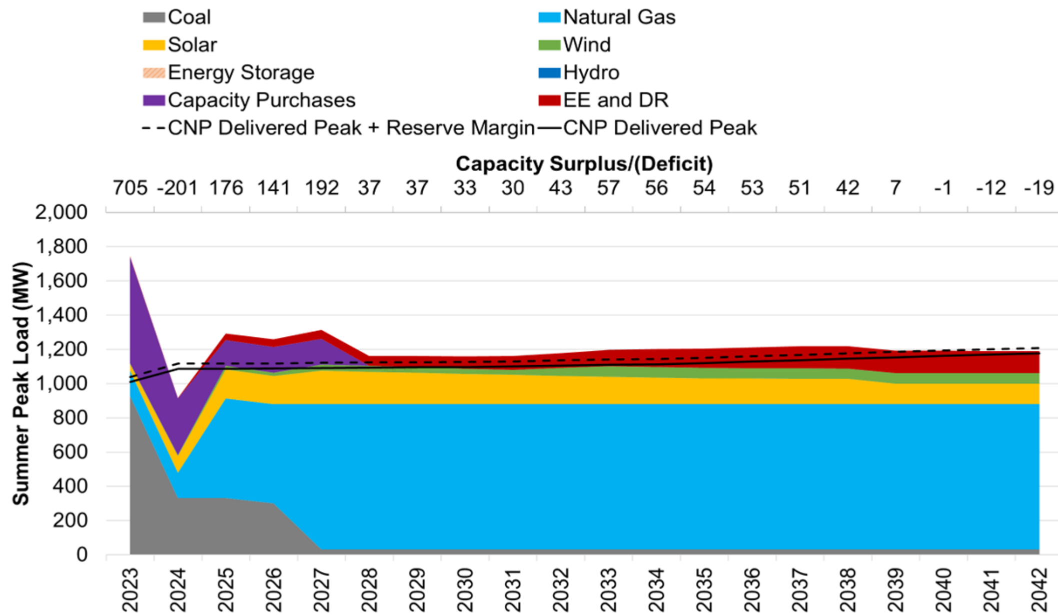
CenterPoint Energy

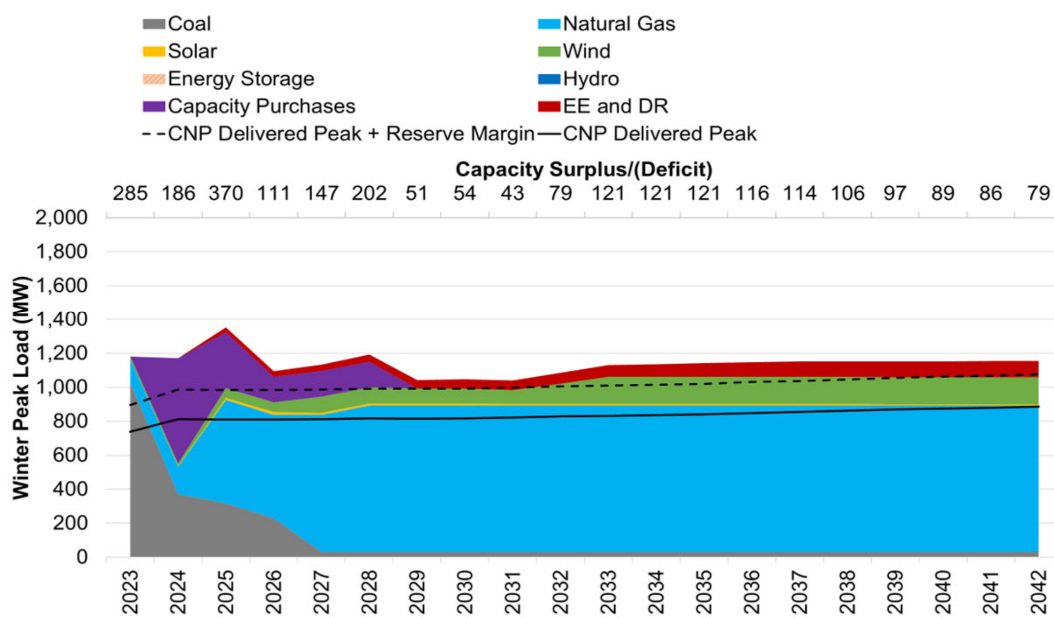
- 2025 retirement of FB Culley 2
- 2027 conversion of FB Culley 3 to NG
- Wind and solar in 2027
- Additional wind in early 2030s

Stochastic Generation



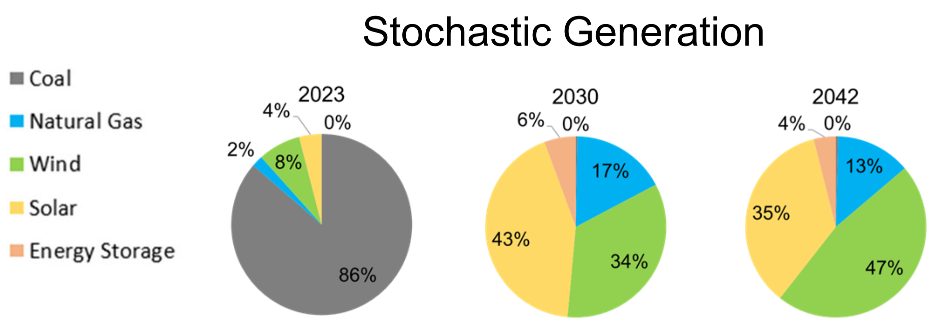


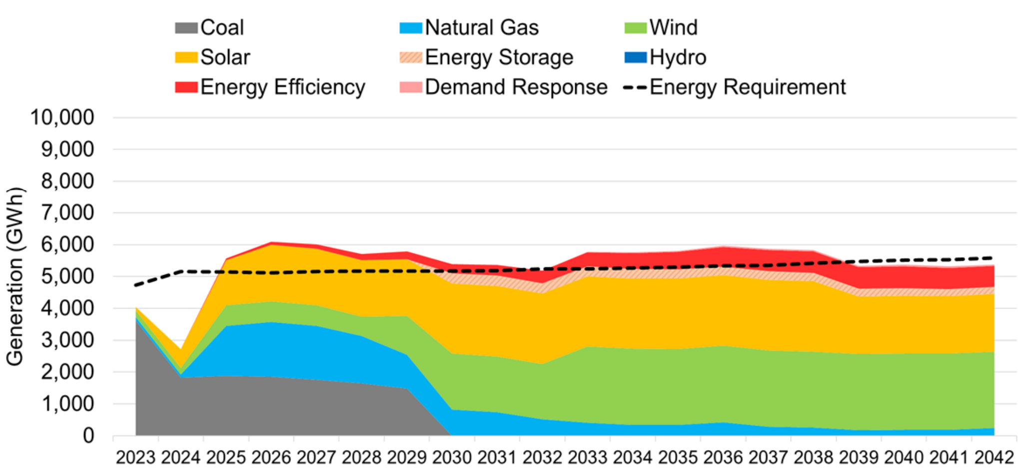


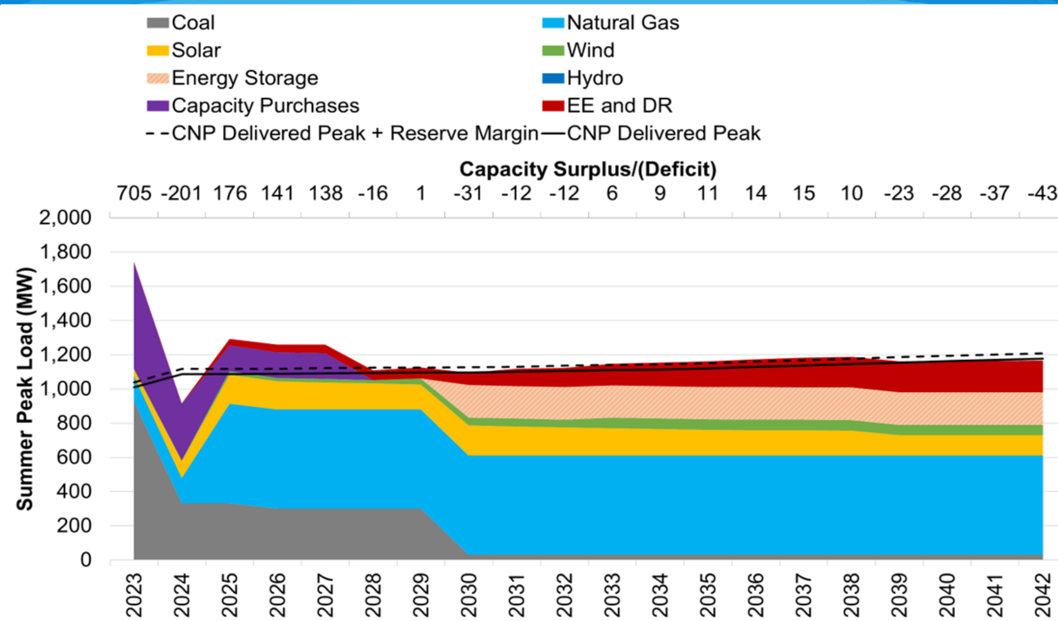


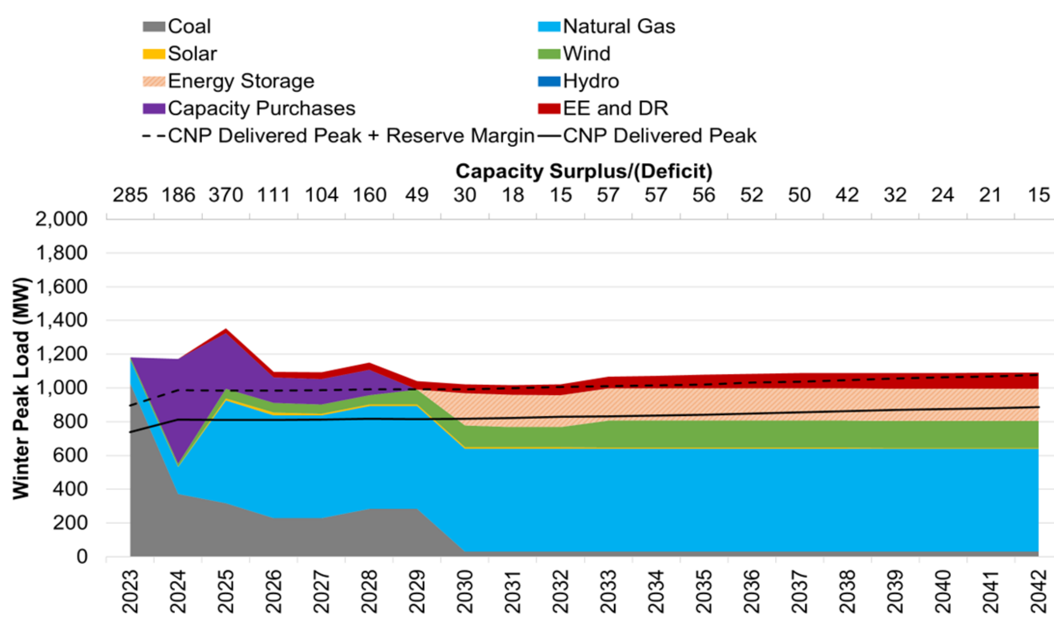
Diversified Renewables

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Wind in 2029 and 2030s
- Solar and Storage in 2030



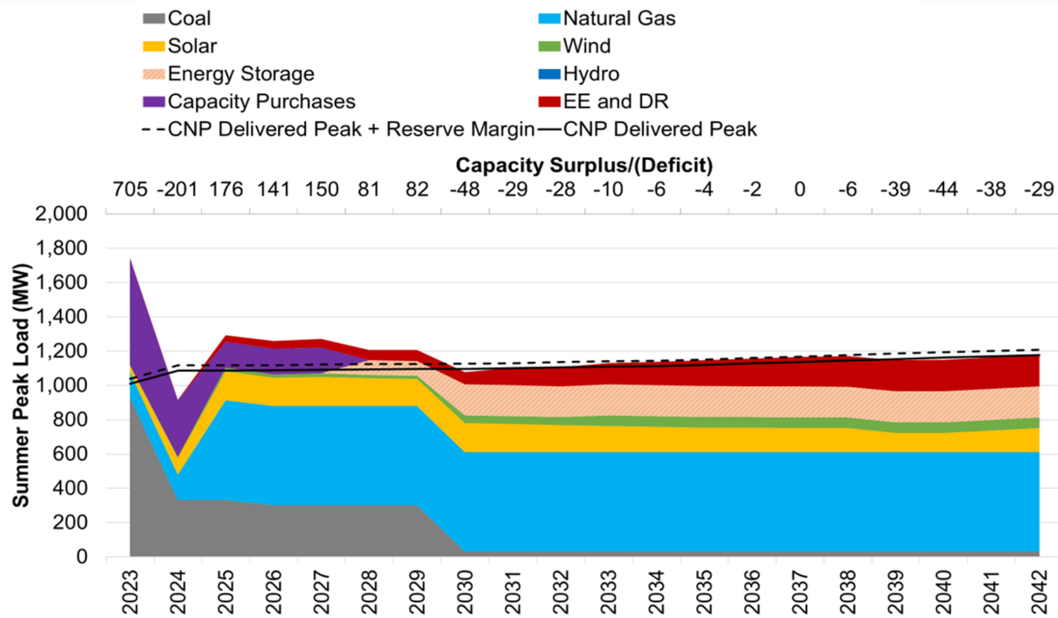






Diversified Renewables (Early Storage & DG Solar)

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- DG Solar + Solar through study period
- Storage in 2028 and 2030
- Wind in 2030s



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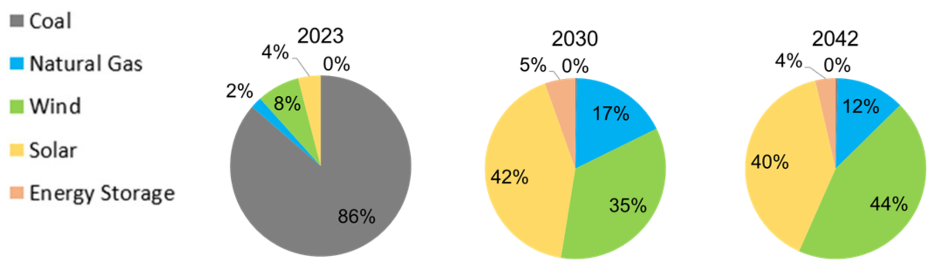
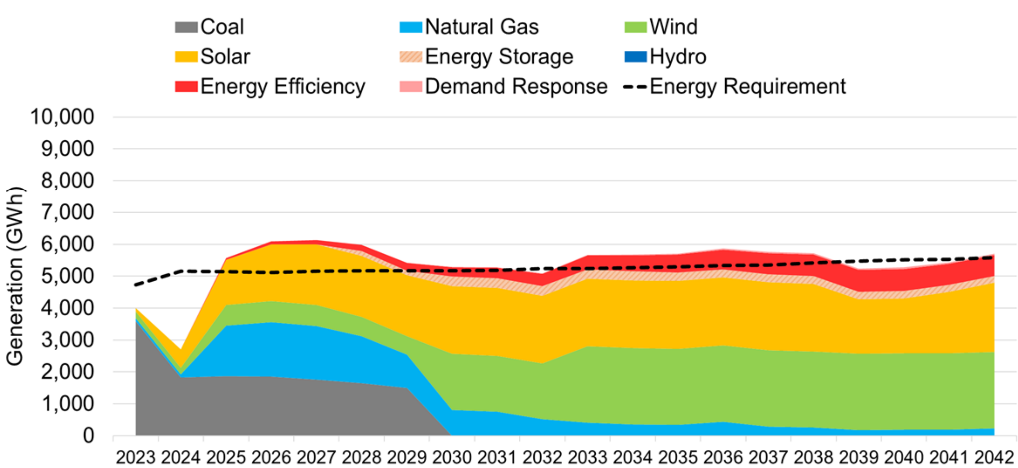
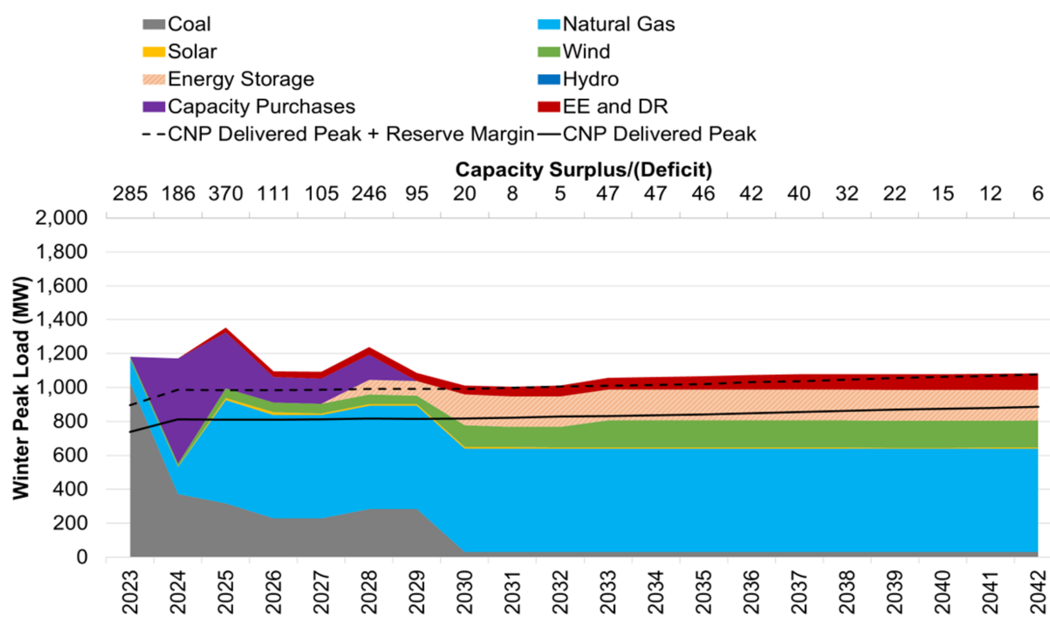


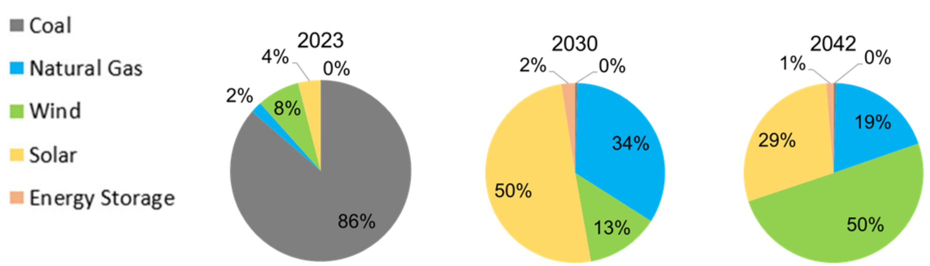


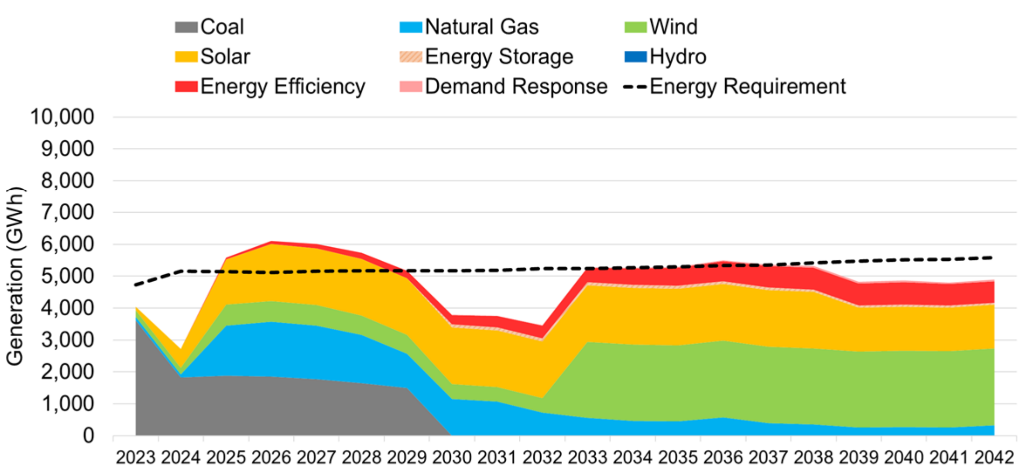


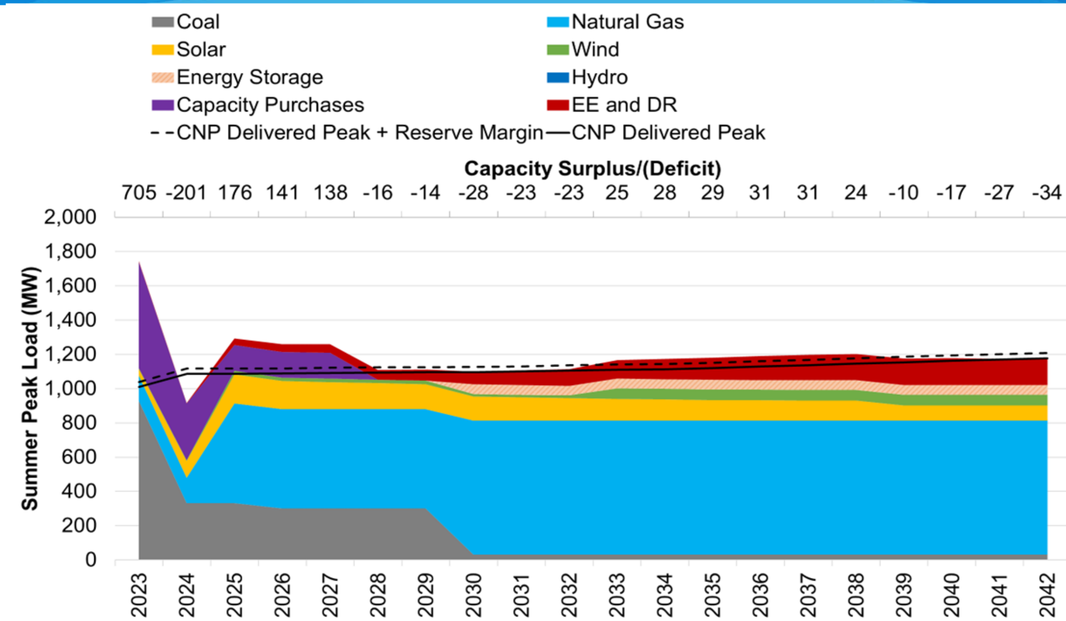
CT Portfolio (Replace FB Culley 3 with F Class CT)

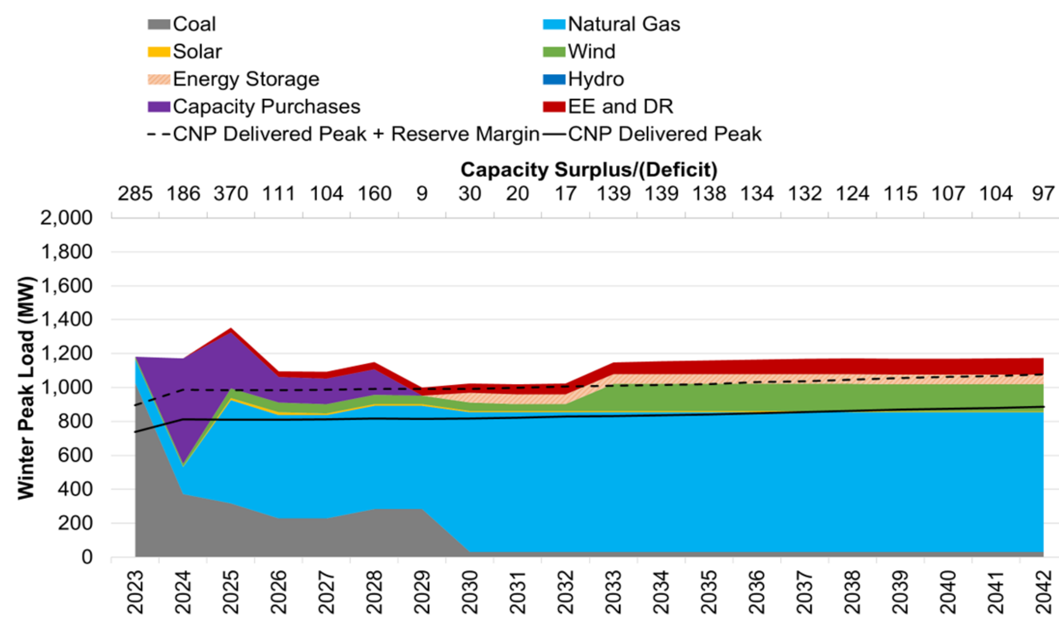
- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- F-Class CT in 2030
- Storage in 2030
- Wind in 2033

Stochastic Generation



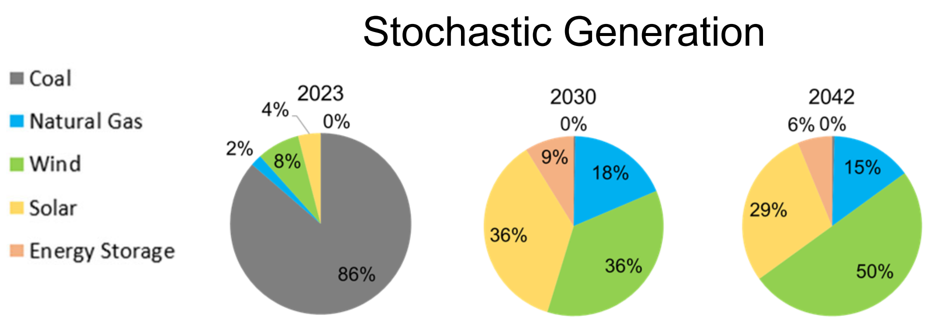


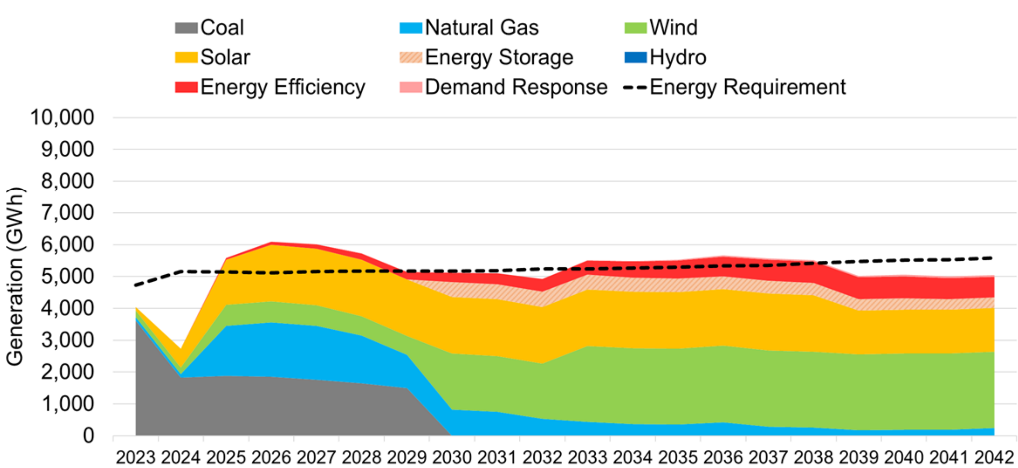


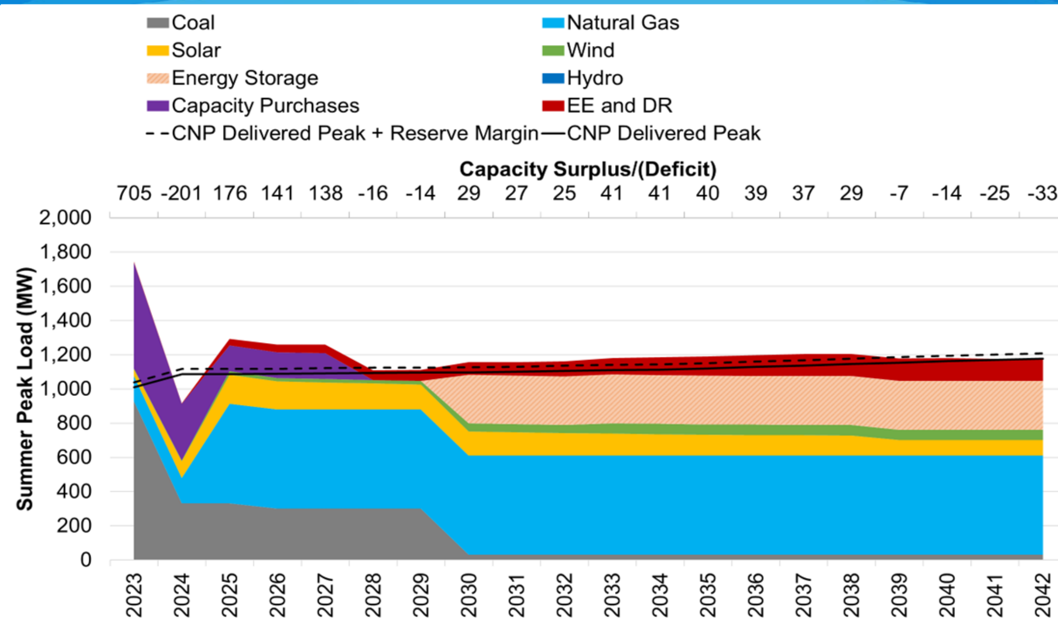


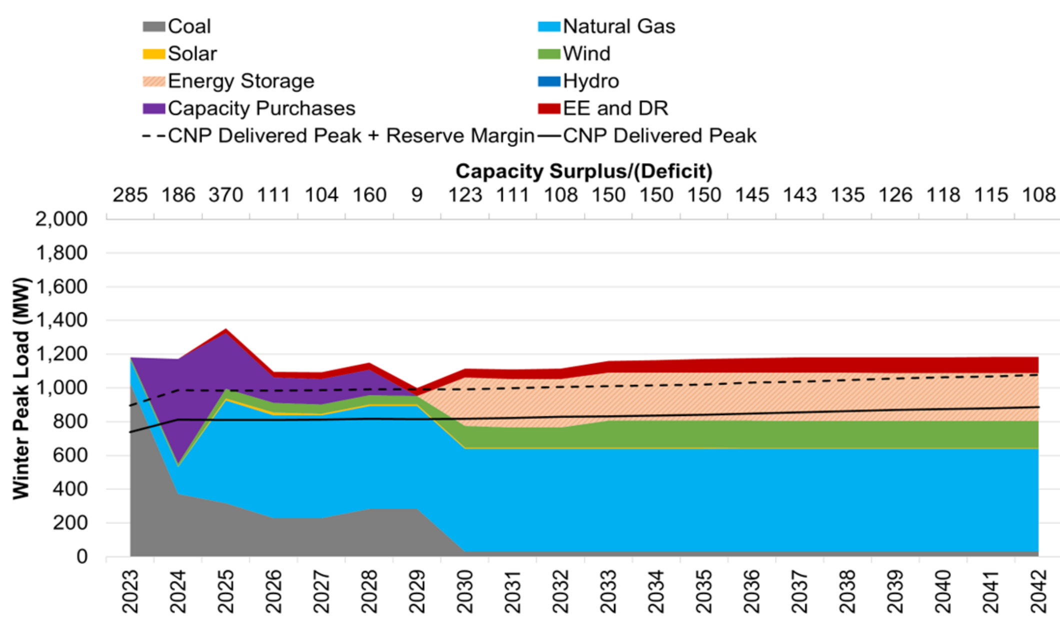
Replace FB Culley 3 with Storage and Wind

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Wind in 2030s
- Storage in 2030



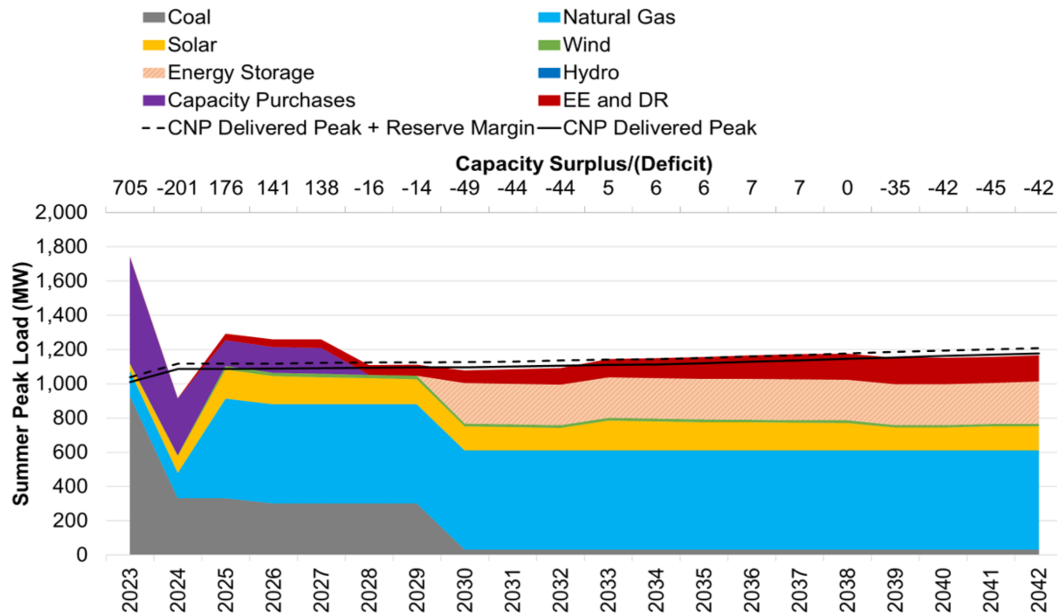


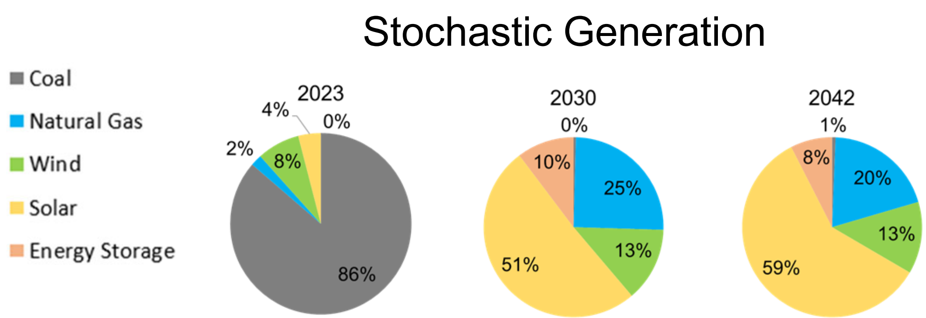


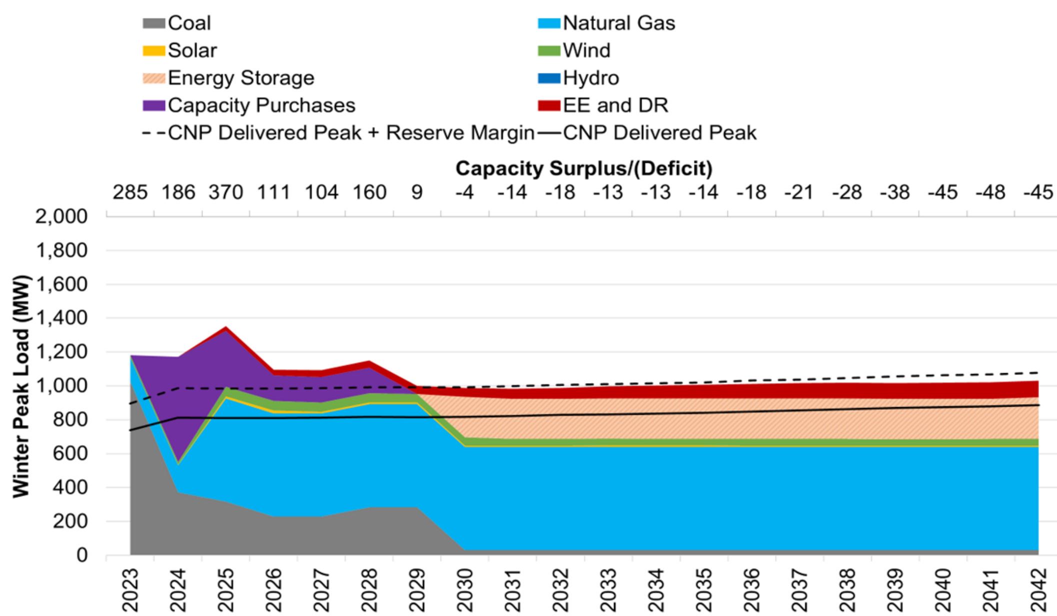


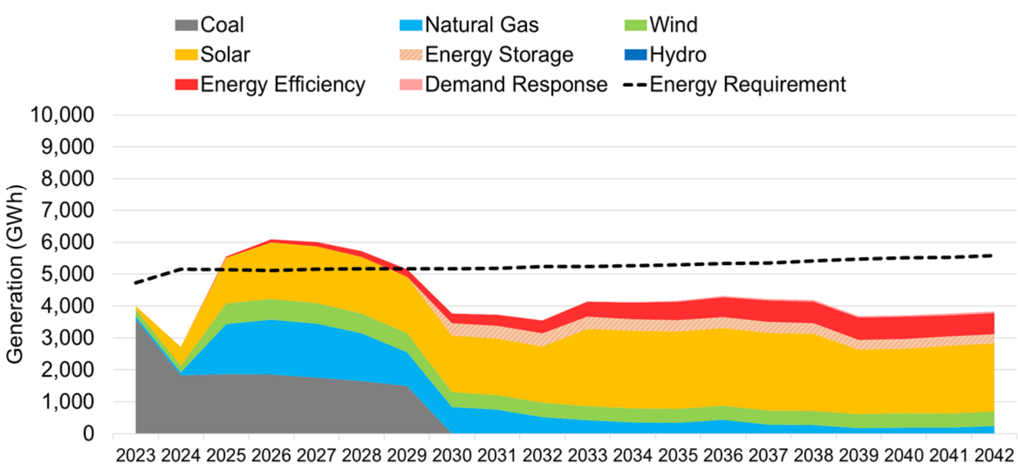
Replace FB Culley 3 with Storage and Solar

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Storage in 2030
- Solar in 2033









Q&A

Risk Analysis Scorecard

Matt Lind, 1898

Balanced Scorecard Affordability/Cost Risk

CenterPoint Energy

Portfolio	20 Year NPVRR ($M)	Delta From Reference (%)	Proportion of Energy Generated by Resources With Exposure to Coal and Gas Markets and Market Purchases (%)[1]	95% Value of NPVRR ($)
Reference Case	$4,214	0.0%	56%	$4,952
F-Class CT	$4,499	6.7%	30%	$5,413
Convert F.B. Culley 3 to Natural Gas by 2027	$4,503	6.8%	27%	$5,316
Convert F.B. Culley 3 to Natural Gas by 2030	$4,508	7.0%	27%	$5,332
Replace FB Culley 3 with Storage and Solar	$4,539	7.7%	29%	$5,416
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	$4,559	8.2%	25%	$5,347
Replace FB Culley 3 with Storage and Wind	$4,580	8.7%	26%	$5,328
Business as Usual	$4,581	8.7%	35%	$5,486
Diversified Renewables	$4,583	8.8%	25%	$5,313
Diversified Renewables (Early Storage & DG Solar)	$4,676	11.0%	25%	$5,408

1: Total energy generation from coal and gas / total fleet generation from 2023 - 2042

Balanced Scorecard
Environmental Sustainability

CenterPoint Energy

Portfolio	CO2 Intensity (Tons CO_2/kwh)[2]	CO2 Equivalent Emissions (Stack Emissions Tons CO_2e)[3]
Reference Case	0.00024	33,199,947
F-Class CT	0.00018	17,975,167
Convert F.B. Culley 3 to Natural Gas by 2027	0.00015	15,506,174
Convert F.B. Culley 3 to Natural Gas by 2030	0.00016	16,953,911
Replace FB Culley 3 with Storage and Solar	0.00018	15,917,099
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	0.00014	15,382,405
Replace FB Culley 3 with Storage and Wind	0.00015	15,931,427
Business as Usual	0.00025	23,897,336
Diversified Renewables	0.00015	15,763,426
Diversified Renewables (Early Storage & DG Solar)	0.00015	15,766,880

2: Average CO_2e from generation / average fleet generation from 2030 - 2042

**CO_2e shown in metric tons*

3: Sum of CO_2e emissions from 2023 - 2042

Balanced Scorecard Reliability

CenterPoint Energy

Portfolio	Must Meet MISO Planning Reserve Margin Requirement in All Seasons (MW)[4] Summer	Winter	Fast Start Capability (MW)[5]	Dispatchable Resource with Spinning Reserve Capability (MW)[6]
Reference Case	97	62	11	919
F-Class CT	80	22	758	900
Convert F.B. Culley 3 to Natural Gas by 2027	60	21	469	941
Convert F.B. Culley 3 to Natural Gas by 2030	60	21	469	941
Replace FB Culley 3 with Storage and Solar	101	137	720	671
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	60	21	469	941
Replace FB Culley 3 with Storage and Wind	74	9	769	671
Business as Usual	90	74	480	941
Diversified Renewables	89	71	669	671
Diversified Renewables (Early Storage & DG Solar)	94	81	659	671

4: Maximum seasonal capacity deficit in summer/winter from 2030 - 2042

5: Average MW of installed battery, CT, recip capacity from 2030 - 2042

6: Average MW of dispatchable resources from 2030 - 2042

Balanced Scorecard
Market Risk Minimization

Portfolio	Energy Market Purchases[7]			Energy Market Sales[7]			Capacity Market Purchases/Sales (%)[8]	
	Average	Near Term Max	Long Term Max	Average	Near Term Max	Long Term Max	Purchases	Sales
Reference Case	12%	24%	18%	33%	42%	41%	1.2%	12%
F-Class CT	28%	40%	46%	17%	21%	24%	0.8%	11%
Convert F.B. Culley 3 to Natural Gas by 2027	26%	39%	32%	19%	22%	27%	0.6%	12%
Convert F.B. Culley 3 to Natural Gas by 2030	25%	35%	32%	19%	22%	27%	0.6%	12%
Replace FB Culley 3 with Storage and Solar	38%	43%	49%	13%	21%	17%	1.7%	8%
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	24%	31%	32%	20%	24%	27%	0.6%	13%
Replace FB Culley 3 with Storage and Wind	27%	35%	33%	15%	21%	21%	0.7%	12%
Business as Usual	31%	35%	36%	14%	21%	19%	0.9%	10%
Diversified Renewables	25%	31%	30%	18%	22%	24%	1.1%	9%
Diversified Renewables (Early Storage & DG Solar)	25%	34%	30%	18%	22%	24%	1.2%	9%

7: Average GWh energy market interaction / total energy + sales from 2023 - 2042

Near Term: 2026 - 2030

Long Term: 2031 - 2042

8: Average capacity market purchases / coincident peak demand from 2023 - 2042

Balanced Scorecard Results

CenterPoint Energy

Scorecard - Ranked	Affordability / Cost Risk				Environmental Sustainability		Reliability				Market Risk Minimization							
Portfolio	20 Year NPVRR ($M)	Delta From Reference (%)	Proportion of Energy Generated by Resources With Exposure to Coal and Gas Markets and Market Purchases (%)[1]	95% Value of NPVRR ($)	CO2 Intensity (Tons CO_2/kwh)[2]	CO2 Equivalent Emissions (Stack Emissions) (Tons CO_2)[3]	Must Meet MISO Planning Reserve Margin Requirement in All Seasons (MW)[4] Summer	Winter	Fast Start Capability (MW)[5]	Dispatchable Resource with Spinning Reserve Capability (MW)[6]	Energy Market Purchases[7] Average	Near Term Max	Long Term Max	Energy Market Sales[7] Average	Near Term Max	Long Term Max	Capacity Market Purchases or Sales (%)[8] Purchases	Sales
Reference Case	$4,214	0.0%	56%	$4,952	0.00024	33,199,947	97	62	11	919	12%	24%	18%	33%	42%	41%	1.2%	12%
F-Class CT	$4,499	6.7%	30%	$5,413	0.00018	17,975,167	80	22	758	900	28%	40%	46%	17%	21%	24%	0.8%	11%
Convert F.B. Culley 3 to Natural Gas by 2027	$4,503	6.8%	27%	$5,316	0.00015	15,506,174	60	21	469	941	26%	39%	32%	19%	22%	27%	0.6%	12%
Convert F.B. Culley 3 to Natural Gas by 2030	$4,508	7.0%	27%	$5,332	0.00016	16,953,911	60	21	469	941	25%	35%	32%	19%	22%	27%	0.6%	12%
Replace FB Culley 3 with Storage and Solar	$4,539	7.7%	29%	$5,416	0.00018	15,917,099	101	137	720	671	38%	43%	49%	13%	21%	17%	1.7%	8%
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	$4,559	8.2%	25%	$5,347	0.00014	15,382,405	60	21	469	941	24%	31%	32%	20%	24%	27%	0.6%	13%
Replace FB Culley 3 with Storage and Wind	$4,580	8.7%	26%	$5,328	0.00015	15,931,427	74	9	769	671	27%	35%	33%	15%	21%	21%	0.7%	12%
Business as Usual	$4,581	8.7%	35%	$5,486	0.00025	23,897,336	90	74	480	941	31%	35%	36%	14%	21%	19%	0.9%	10%
Diversified Renewables	$4,583	8.8%	25%	$5,313	0.00015	15,763,426	89	71	669	671	25%	31%	30%	18%	22%	24%	1.1%	9%
Diversified Renewables (Early Storage & DG Solar)	$4,676	11.0%	25%	$5,408	0.00015	15,766,880	94	81	659	671	25%	34%	30%	18%	22%	24%	1.2%	9%

1: Total energy generation from coal and gas / total fleet generation from 2023 - 2042

2: Average CO_2e from generation / average fleet generation from 2030 - 2042

CO_2e shown in metric tons

3: Sum of CO_2e emissions from 2023 - 2042

4: Maximum seasonal capacity deficit in summer/winter from 2030 - 2042

5: Average MW of installed battery, CT, recip capacity from 2030 - 2042

6: Average MW of dispatchable resources from 2030 - 2042

7: Average GWh energy market interaction / total energy + sales from 2023 - 2042

*Near Term: 2026 - 2030

*Long Term: 2031 - 2042

8: Average capacity market purchases / coincident peak demand from 2023 - 2042

Sensitivities

- Sensitivities were performed to further understand how portfolios cost or resource selection may be impacted by changes in the future
- Base modeling assumed CenterPoint would be able to fully monetize 100% of the ITC
  - Based on sensitivity analysis the impact to portfolio NPVs by adjusting the ITC monetization is minimal
- Due to uncertainty about future resources ability to capitalize on the IRA energy community bonus, it was not included in base modeling assumptions.
  - Based on the sensitivity analysis this adder would have a limited impact on portfolio NPV
- If storage capacity accreditation decreases, portfolios which include storage as a resource must either rely more on market capacity or add additional resources. The costs associated with storage capacity accreditation declining from 95% to 75% over the study period would increase portfolios that include 200MW+ of storage by at least 2%
- To evaluate the cost risk of increased emissions regulations set by the New Source Performance Standards 111(B), all 10 portfolios were run through 200 different simulations, of which 80 included a carbon tax, each of the portfolios saw a 16% - 26% increase in NPV with the inclusion of additional emissions regulation

Q&A

Next Steps

Matt Rice

Short Term Action Plan

CenterPoint Energy

- Near-Term:
  - File for 2021-2023 DSM Extension for 2024
  - Submit IRP
  - Begin class 1 engineering study
- Mid-term:
  - File 2025-2027 DSM Plan
  - Issue Renewable RFP for renewable projects
  - File Certificate of Public Convenience and Necessity (CPCN) for F.B. Culley 3 conversion
  - Bring Generation Transition Phase 1 projects online
  - File Certificate of Public Convenience and Necessity (CPCN) for renewables

CenterPoint Energy

Q&A

CenterPoint 2022 IRP
4th Stakeholder Meeting Minutes Q&A
April 26, 2023, 1:00 pm – 3:00 pm CDT

Richard Leger (Senior Vice President, CenterPoint Energy) – Welcome, Safety Message

Matt Rice (Director, Indiana Electric Regulatory and Rates, CenterPoint Energy) – Discussed the meeting agenda, guidelines for the meeting, discussed updates from the last stakeholder meeting including feedback, and the 2022/2023 IRP status update.

Matt Rice - Presented the preferred portfolio.

- Slide 20 Portfolio CO_2 Emissions:
    - Question: Do you know if those numbers on gas take adequate account for methane leakage in the production?
        - Response: The numbers in the scorecard account for CO_2 Equivalent coming from the stack based on a recommendation in a previous meeting. This slide specifically is just looking at CO_2 stack emissions not CO_2 equivalent. There is not a big difference in these numbers.
- General Questions:
    - Questions: Is the option to convert CTs to Combined Cycle in reference to AB Brown?
        - Response: Yes.
    - Question: Will you file a Certificate of Public Convenience and Necessity (CPCN) to convert FB Culley to gas before the next IRP?
        - Yes.
    - Question: Is the conversion of FB Culley 3 to a combined cycle natural gas plant?
        - No. It will be the same steam turbine; however, it will be fired with natural gas instead of coal.

Drew Burczyk (Project Manager, Resource Planning & Market Assessments, 1898 & Co.) – Discussed the risk analysis modeling and portfolio creation and selection during the analysis.

- General Questions:
    - Question: For Warrick 4, which is being exited, are there going to be any power purchase agreements with it going forward? How about OVEC?
        - Response: We still plan to exit Warrick 4 at the end of the year. There's currently no contract or PPA beyond 2023. We are contractually bound for OVEC for another 15 to 20 years.
    - Question: Is the price of the wholesale market affected in the stochastic analysis?
        - Response: Yes, the different scenarios all had a different price forecast, and then within the stochastics the price forecasts were further varied depending on the scenario and input drivers.
    - Question: With regulations at the federal level expected to tighten natural gas emissions, have you figured emissions costs into this analysis?

- Response: We have scenarios that include CO_2 tax. There are risks associated with future regulations, and those are captured by the CO_2 tax in the stochastics.

<u>Matt Lind</u> (Director, Resource Planning & Market Assessments, 1898 & Co.) – Discussed the risk analysis scorecard along with the metrics and results.

- Slide 51 Balanced Scorecard Environmental Sustainability:
    - Question: Is this slide showing the CO_2e emissions only when CenterPoint is burning it, or does this include a full life cycle of the emissions?
        - Response: It is just the direct emissions from the generation in the scenario.

<u>Matt Rice</u> – Discussed the next steps of the IRP process including the short-term action plan.

- General Questions and comments:
    - Question: Do you have a figure or percentage to show how much renewables have increased, in terms of portion of the portfolio, from the last IRP to this one?
        - Response: By 2030, 80% of energy produced will be from wind and solar resources.
- Feedback From Tech-to-Tech Participant:
    - Comment: Thank you for the data sharing you have done throughout this process, and for the willingness to answer our questions. I felt like this process was much improved over the last IRP.

Attachment 4.1 2022-2023 CEI South Long-Term Electric Energy and Demand Forecast Report

CEI SOUTH CENTERPOINT ENERGY INDIANA SOUTH

2022 Long-Term Electric Energy and Demand Forecast Report

Submitted to:
CEI CenterPoint Energy Indiana South

Prepared by:

Itron

20 Park Plaza
4th Floor
Boston, MA 02116
USA
www.itron.com/forecasting

May 15, 2023

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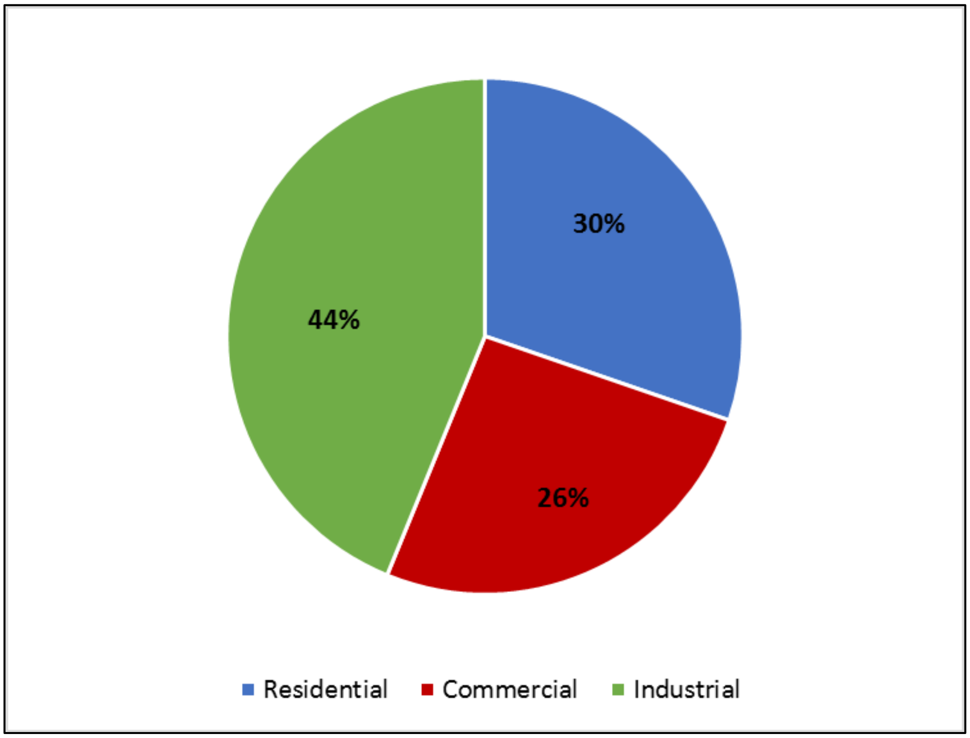
1 OVERVIEW

Itron, Inc. was contracted by CEI South to develop a long-term load forecast to support the 2022/2023 Integrated Resource Plan. The energy and demand forecasts extend through 2042. The forecast is based on a bottom-up approach that starts with residential, commercial, industrial, and street lighting load forecasts that then drive system energy and peak demand. This forecast is then adjusted for behind-the-meter (BTM) solar and electric vehicle load projections. This report presents the results, assumptions, and overview of the forecast methodology.

1.1 CEI SOUTH SERVICE AREA

CEI South serves approximately 150,000 electric customers in Southwest Indiana; Evansville is the largest city within the service area. The service area includes a large industrial base with industrial customers accounting for approximately 44% of sales in 2021. The residential class accounts for 30% of sales with approximately 131,000 customers and the commercial class 26% of sales; there are approximately 19,000 nonresidential customers. System 2021 energy requirements are 4,822 GWh with system peak reaching 1,003MW. Figure 1 shows 2021 class-level sales distribution.

FIGURE 1: 2021 ANNUAL SALES BREAKDOWN



CEI South has seen moderate customer growth with residential customer growth averaging 0.6% per year since 2011. Despite COVID-19's impact, customer growth has continued to increase with 2020 and 2021 showing the strongest growth of the last ten years; since 2018, customer growth has averaged 0.8% per year. Residential customer growth averaged 0.6% since 2011, and 0.8% since 2018.

Commercial customer annual growth averaged 0.4% since 2011, and 0.6% since 2018. Prior to the economic slowdown brough on by the COVID-19 pandemic, GDP averaged 1.9% annual growth, following the 2020 drop and subsequent 2021 rebound, long-term GDP growth is forecasted at 1.4% average annual rate with employment growth of 0.4% per year.

Despite moderate economic and customer growth, system energy and peaks demand have been declining. Energy requirements and demand have declined 0.4% annually since 2011. Energy efficiency gains have been a big factor. COVID-19 had a significant impact resulting in an 8.0% drop in 2020 commercial sales.

Since 2011 weather-normalized residential average use has declined on average 1.2% per year resulting in 0.6% annual decline in residential sales. Commercial sales have also been falling; normalized sales have declined 1.3% per year, this is heavily impacted by the drop in 2020 sales. The industrial sector is the only sector showing growth with industrial sales averaging 0.7% average annual growth[1].

1.2 FORECAST SUMMARY

While DSM activity has had a significant impact on sales, for the IRP filing, the energy and demand forecasts do not include future DSM energy savings; DSM savings are treated as a resource on a consistent and comparable basis to supply side resources in as part of the integrated resource planning process. Excluding DSM but including the impact of future customer-owned generation and electric vehicles results in energy requirements and summer peak demand increases of 0.7% per year and winter peak demand growth of 0.5% per year. Most of the growth is after 2030 as electric vehicles begin to have a significant impact on load. Table 1-1 shows the CEI South energy and demand forecasts. CEI South's utility scale solar and other distributed generation are not included in this report but are accounted for within the IRP.

[1] Excludes a large customer with cogeneration

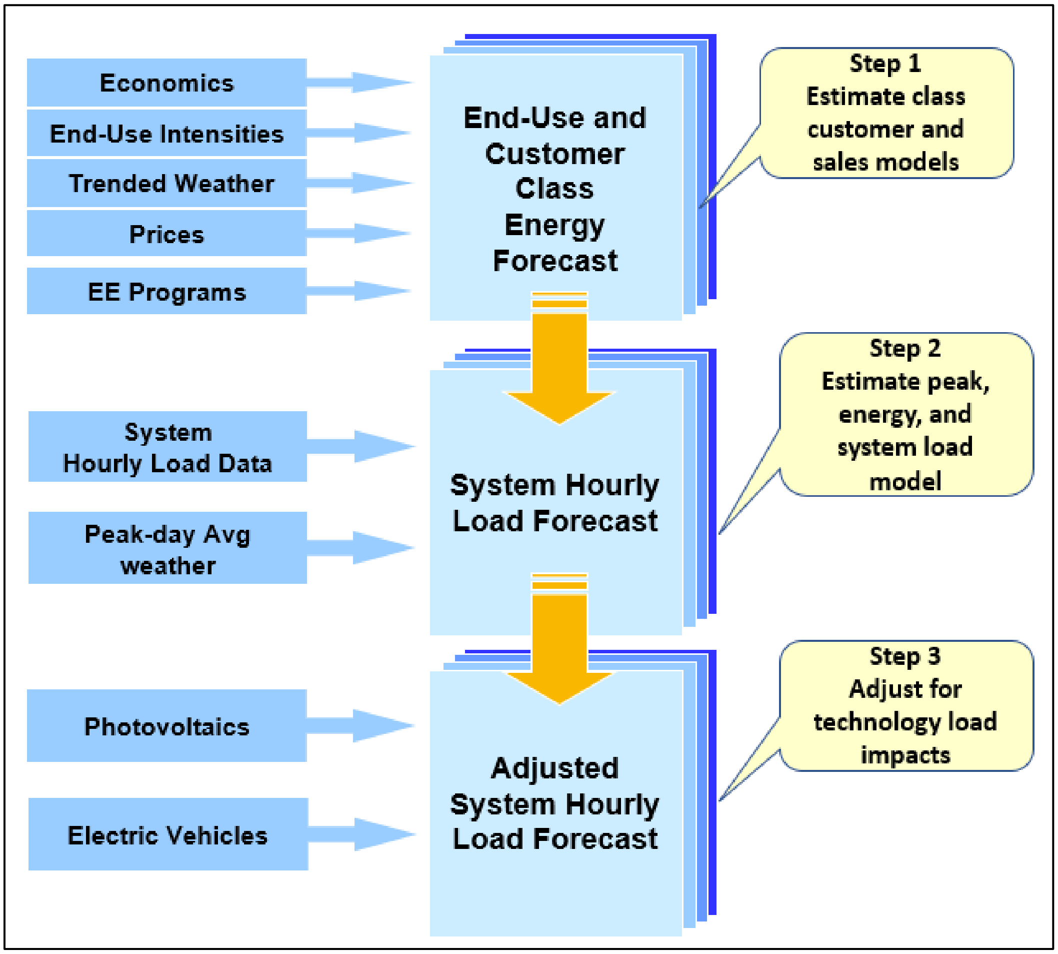
TABLE 1-1: ENERGY AND DEMAND FORECAST (EXCLUDING DSM PROGRAM SAVINGS)

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2022	4,815,801		1,019		802	
2023	4,725,478	-1.9%	1,010	-0.9%	738	-8.0%
2024	5,163,907	9.3%	1,087	7.6%	812	10.0%
2025	5,152,172	-0.2%	1,087	0.0%	810	-0.2%
2026	5,153,363	0.0%	1,088	0.1%	811	0.1%
2027	5,164,632	0.2%	1,092	0.3%	813	0.3%
2028	5,178,436	0.3%	1,095	0.3%	816	0.4%
2029	5,175,063	-0.1%	1,095	0.0%	816	0.0%
2030	5,178,761	0.1%	1,096	0.1%	817	0.2%
2031	5,199,311	0.4%	1,100	0.3%	821	0.5%
2032	5,238,099	0.7%	1,105	0.5%	828	0.9%
2033	5,254,460	0.3%	1,110	0.4%	831	0.4%
2034	5,277,650	0.4%	1,114	0.4%	836	0.5%
2035	5,304,282	0.5%	1,120	0.6%	841	0.6%
2036	5,345,573	0.8%	1,128	0.7%	849	1.0%
2037	5,377,724	0.6%	1,136	0.7%	855	0.7%
2038	5,418,448	0.8%	1,145	0.8%	862	0.9%
2039	5,455,497	0.7%	1,154	0.8%	869	0.8%
2040	5,493,803	0.7%	1,162	0.7%	875	0.8%
2041	5,518,739	0.5%	1,169	0.6%	880	0.5%
2042	5,551,532	0.6%	1,177	0.6%	886	0.7%
CAGR 22-42		0.7%		0.7%		0.5%

2 FORECAST APPROACH

The long-term energy and demand forecasts are based on a build-up approach. End-use sales derived from the customer class sales models (residential, commercial, industrial, and street lighting) drive system energy and peak demand. Energy requirements are calculated by adjusting sales forecast upwards for line losses. Peak demand is forecasted through a monthly peak-demand linear regression model that relates peak demand to peak-day weather conditions and end-use energy requirements (heating, cooling, and other use). System energy and peak are adjusted for residential and commercial PV adoption and EV charging impacts. Figure 2 shows the general framework and model inputs.

FIGURE 2: CLASS BUILD-UP MODEL



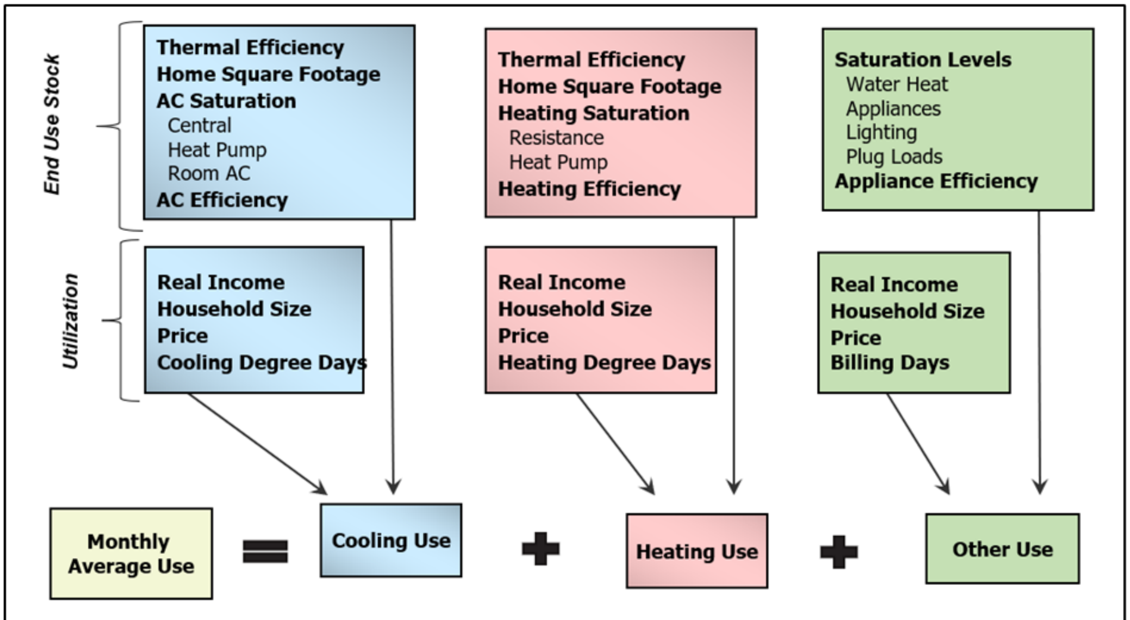
In the long-term, both economic growth and structural changes drive energy and demand requirements. Structural changes include the impact of residential appliance saturation and efficiency trends, housing square footage and thermal shell efficiency, and commercial building end-use intensity trends. The long-term structural drivers are captured in the residential and commercial sales forecast models through a specification that combines economic drivers with structural drivers. This type of model is known as a Statistically Adjusted End-Use (SAE) model. The SAE model variables explicitly incorporate end-use saturation and efficiency projections, as well as changes in population, economic conditions, price, and weather. Both residential average use and commercial sales are forecasted using an SAE specification.

Industrial sales are forecasted using a two-step approach, which includes a generalized econometric model that relates industrial sales to seasonal patterns and industrial economic activity. Streetlight sales are forecasted using a simple trend and seasonal model.

2.1 RESIDENTIAL MODEL

Residential average use and customers are modeled separately. The residential sales forecast is then generated as the product of the average use and customer forecasts. Average use is defined in terms of the average customer's heating (XHeat), cooling (XCool), and other use (XOther) electricity requirements. Figure 3 shows the residential average use model.

FIGURE 3: RESIDENTIAL SAE MODEL



$$AvgUse_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_e \times EE_m$$

The end-use model variables XCool, XHeat, and XOther are constructed by integrating the end use intensity trends with weather, economics, and price. For XOther, it is the monthly number of billing days that impacts much of the monthly short-term variation. The model coefficients – $\mathbf{b_c}$, $\mathbf{b_h}$ and $\mathbf{b_o}$ are estimated using linear regression; the model is estimated over the period January 2011 to June 2022. The model also includes a separate DSM variable (EE) to capture the historical DSM savings that are not captured in the primary model variables. Figure 4 to Figure 6 show the constructed monthly heating, cooling, and other end-use variables. Appendix B shows the end-use variable calculations.

FIGURE 4: RESIDENTIAL XHEAT

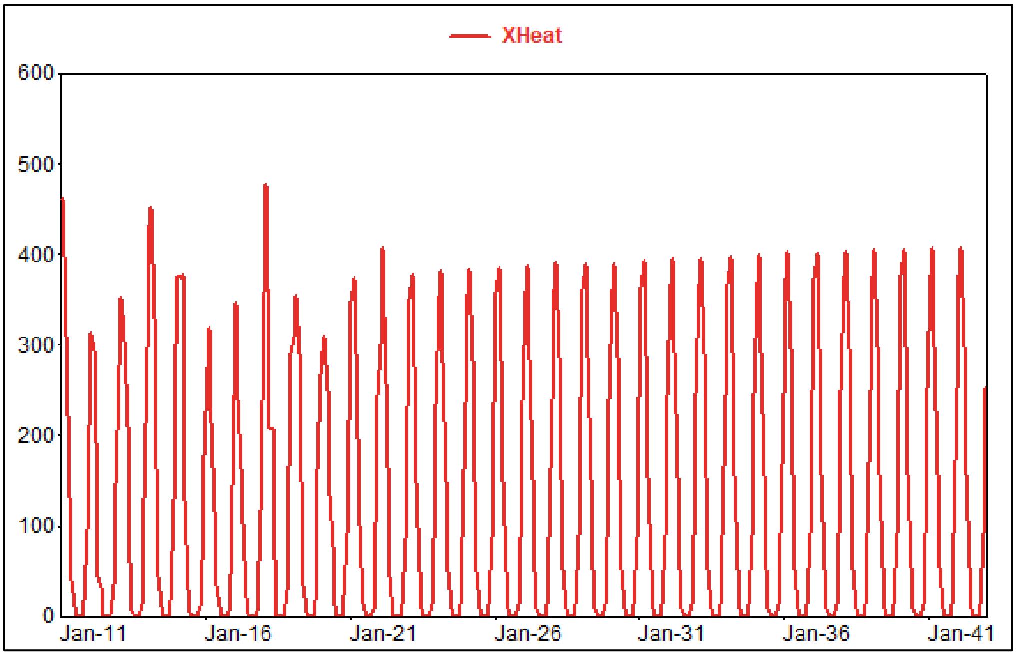


FIGURE 5: RESIDENTIAL XCOOL

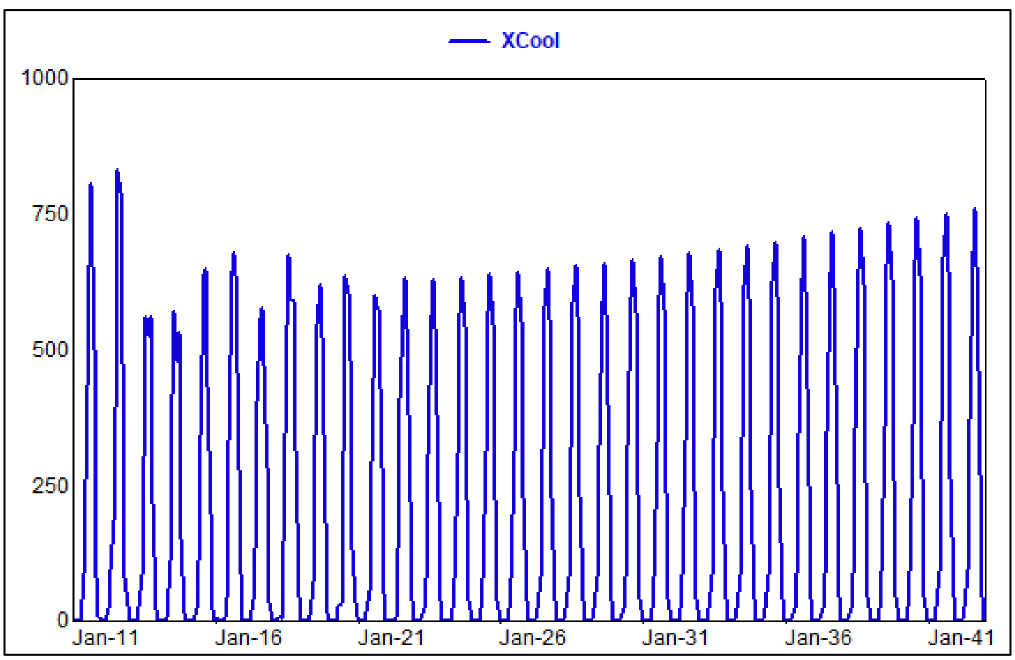


FIGURE 6: RESIDENTIAL XOTHER

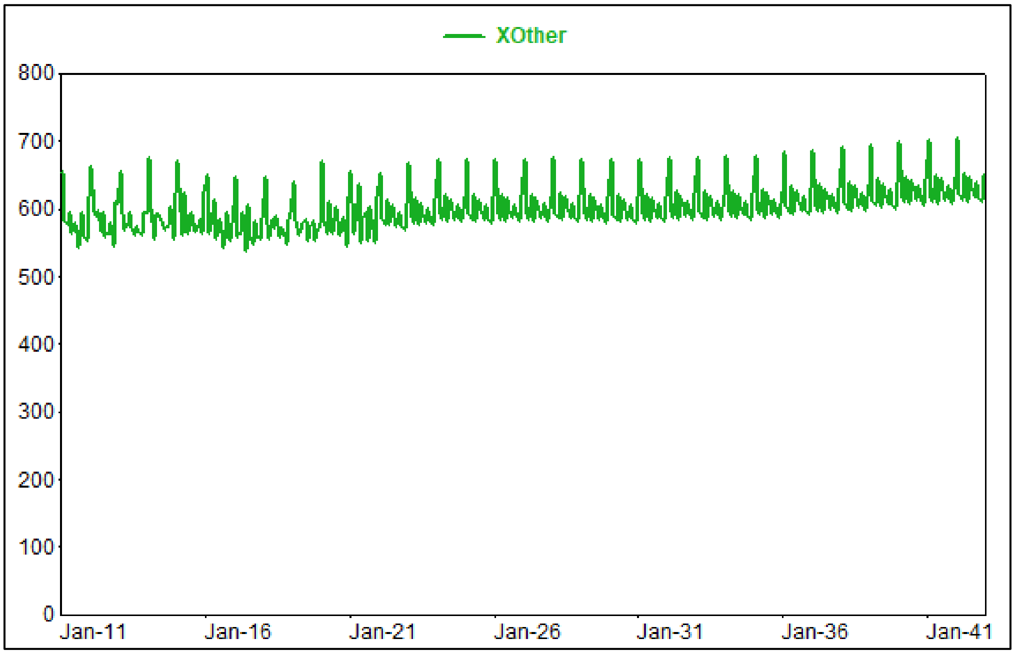
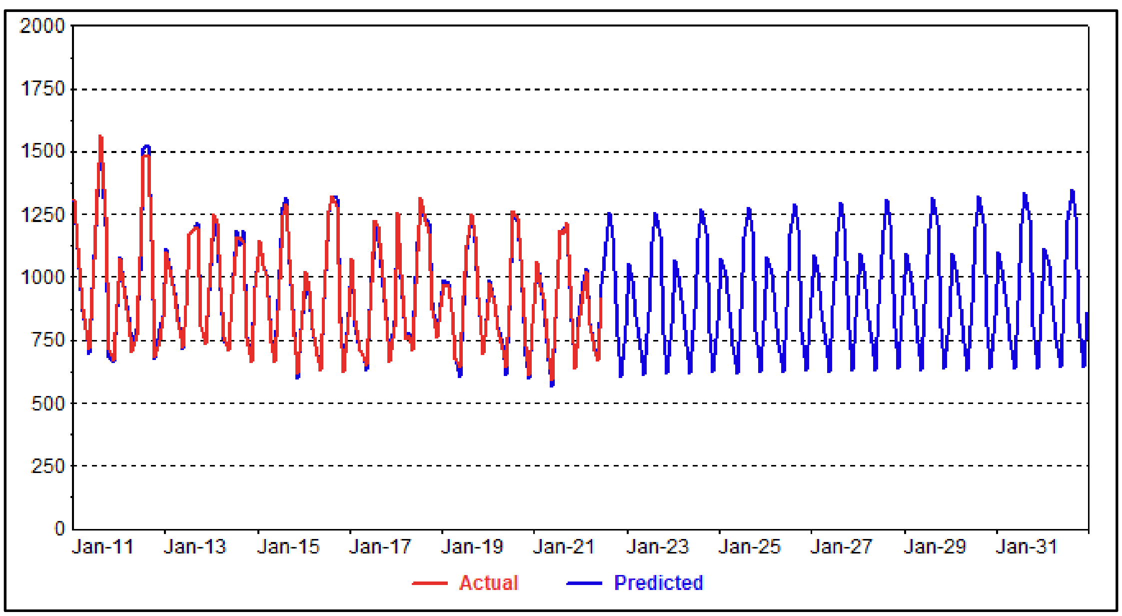


Figure 7 shows the model results.

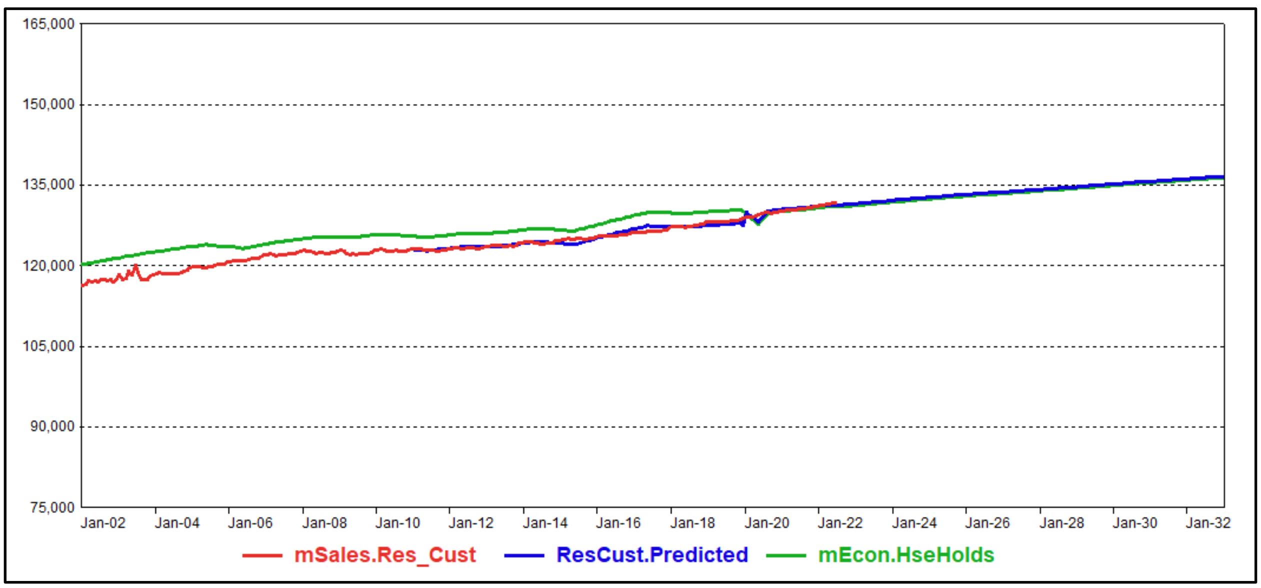
FIGURE 7: RESDENTIAL AVERAGE USE – BASELINE FORECAST



The model also includes a COVID variable to account for the jump in residential average use in 2020. The variable is based on Google Mobility Data that measured cell phone activity near the home. Average use has trended back to pre-COVID levels with businesses and schools reopening. Customer use remains slightly elevated as some households continue to work at home either fulltime or as part of new Hybrid work schedules. Overall, the SAE model explains historical average use variation and trend well with an Adjusted R^2 of 0.98 and in-sample Mean Absolute Percent Error (MAPE) of 1.9%. Model coefficients are statistically significant at the 95% level of confidence and higher. Model coefficients and statistics are provided in Appendix A. Excluding DSM, Baseline average use increases 0.4% annually through the forecast period.

The customer forecast is based on a monthly regression model that relates the number of customers to Evansville MSA (Metropolitan Statistical Area) household projections. We assume that over the long-term, service area customer growth will track household growth in the larger MSA. Figure 8 shows actual and predicted and the number of households in the MSA.

FIGURE 8: CUSTOMER FORECAST



Not surprisingly, there is a strong correlation between MSA level households and the Company. Through the COVID period, however, the Company continued to add customers while the number of households dropped slightly. Given CEI South serves most of the MSA, we assume that customer growth will continue to track household projections with 0.4% long-term annual customer growth.

With 0.4% customer and average use growth, sales average 0.8% annual growth. Table 2-1 shows the residential sales forecast before solar and EV adjustments.

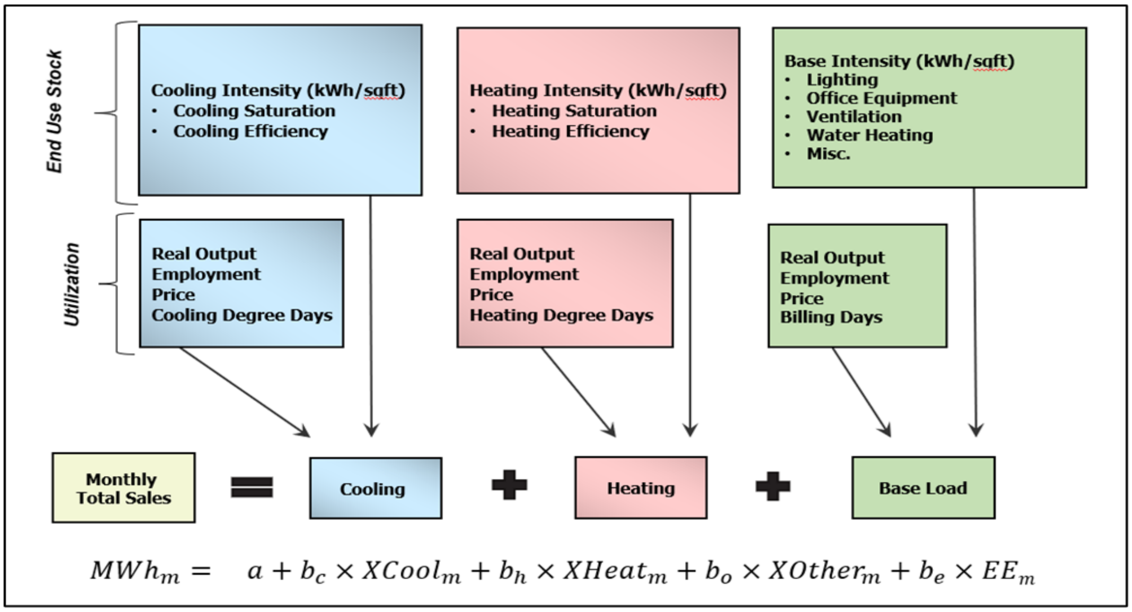
TABLE 2-1: RESIDENTIAL BASELINE FORECAST (EXCLUDES FUTURE DSM)

Year	Sales (MWh)		Customers		AvgUse (kWh)	
2022	1,457,502		131,442		11,089	
2023	1,432,970	-1.7%	131,833	0.3%	10,870	-2.0%
2024	1,453,295	1.4%	132,438	0.5%	10,973	1.0%
2025	1,463,031	0.7%	133,003	0.4%	11,000	0.2%
2026	1,474,875	0.8%	133,494	0.4%	11,048	0.4%
2027	1,484,864	0.7%	133,957	0.3%	11,085	0.3%
2028	1,498,661	0.9%	134,431	0.4%	11,148	0.6%
2029	1,502,827	0.3%	134,931	0.4%	11,138	-0.1%
2030	1,511,813	0.6%	135,435	0.4%	11,163	0.2%
2031	1,524,392	0.8%	135,908	0.3%	11,216	0.5%
2032	1,542,615	1.2%	136,393	0.4%	11,310	0.8%
2033	1,551,854	0.6%	136,899	0.4%	11,336	0.2%
2034	1,566,061	0.9%	137,470	0.4%	11,392	0.5%
2035	1,581,042	1.0%	137,981	0.4%	11,458	0.6%
2036	1,601,937	1.3%	138,451	0.3%	11,570	1.0%
2037	1,616,478	0.9%	138,926	0.3%	11,636	0.6%
2038	1,636,273	1.2%	139,494	0.4%	11,730	0.8%
2039	1,655,551	1.2%	140,052	0.4%	11,821	0.8%
2040	1,675,499	1.2%	140,549	0.4%	11,921	0.8%
2041	1,688,869	0.8%	141,009	0.3%	11,977	0.5%
2042	1,705,768	1.0%	141,424	0.3%	12,061	0.7%
CAGR 22-42		0.8%		0.4%		0.4%

2.2 COMMERCIAL MODEL

The commercial sales model is also estimated using an SAE specification. Figure 9 shows the commercial SAE model.

FIGURE 9: COMMERCIAL SAE MODEL



Commercial end-use intensities are mapped to cooling (XCool), heating (XHeat), and other use (XOther). A linear regression model is used to estimate a set of coefficients that calibrate the end-use variables to commercial monthly sales. The model includes historical cumulative DSM savings (EE) to account for EE savings above captured by the model and a COVID model variable based on Google Mobility Data.

The model input variables include end-use intensities, HDD, CDD, number of billing days, price, and economic deriver that incorporates MSA GDP, employment, and number of households. Figure 10 to Figure 12 show the model variables. The specific variable construction is provided in Appendix C.

FIGURE 10: COMMERCIAL XHEAT

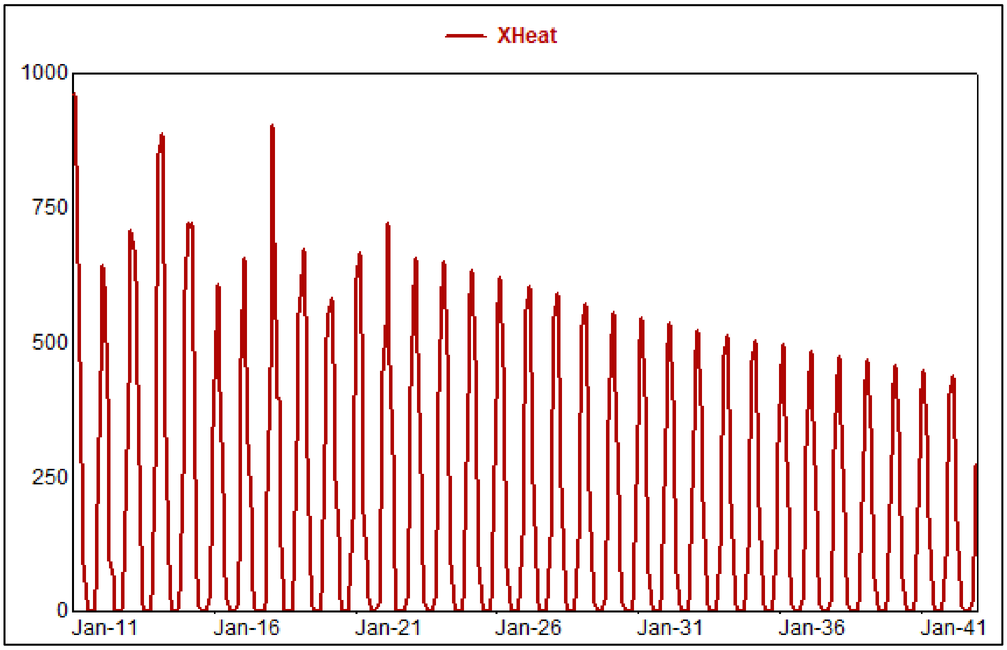


FIGURE 11: COMMERCIAL XCOOL

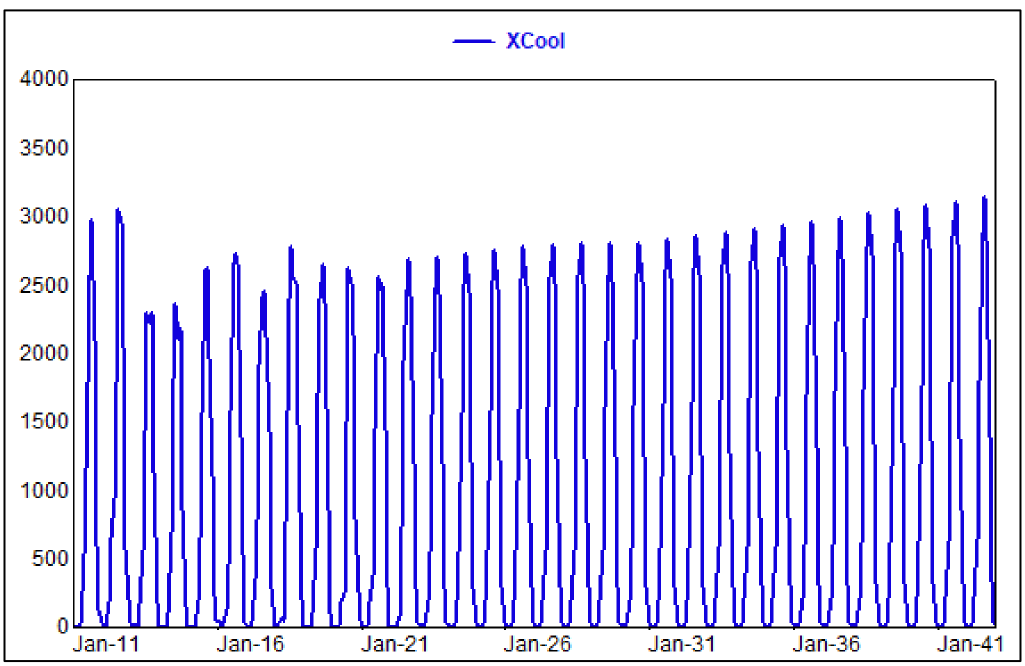


FIGURE 12: COMMERCIAL XOTHER

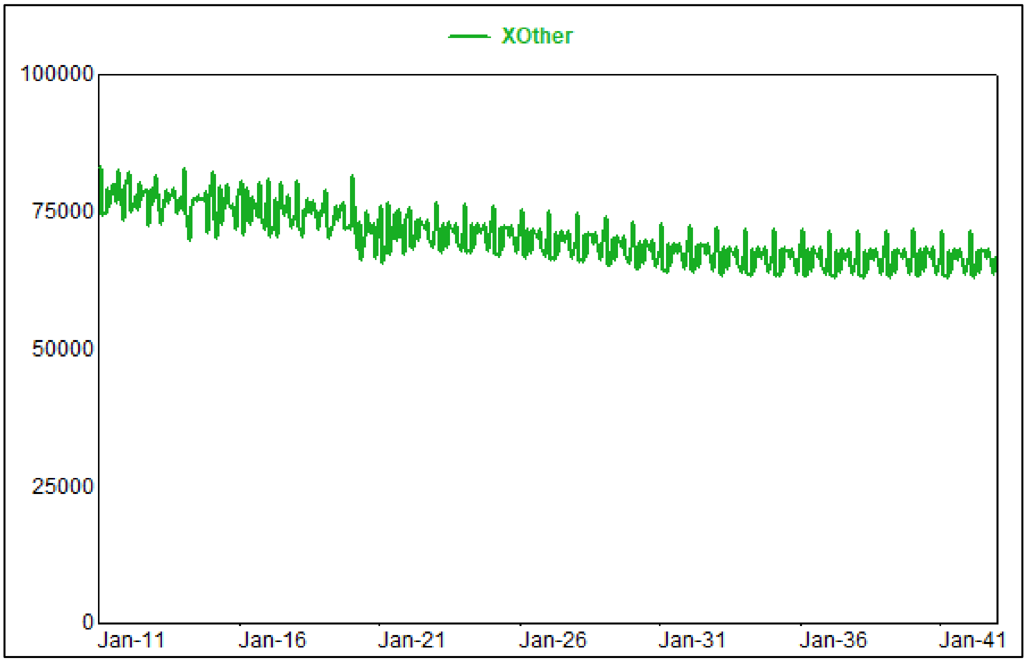
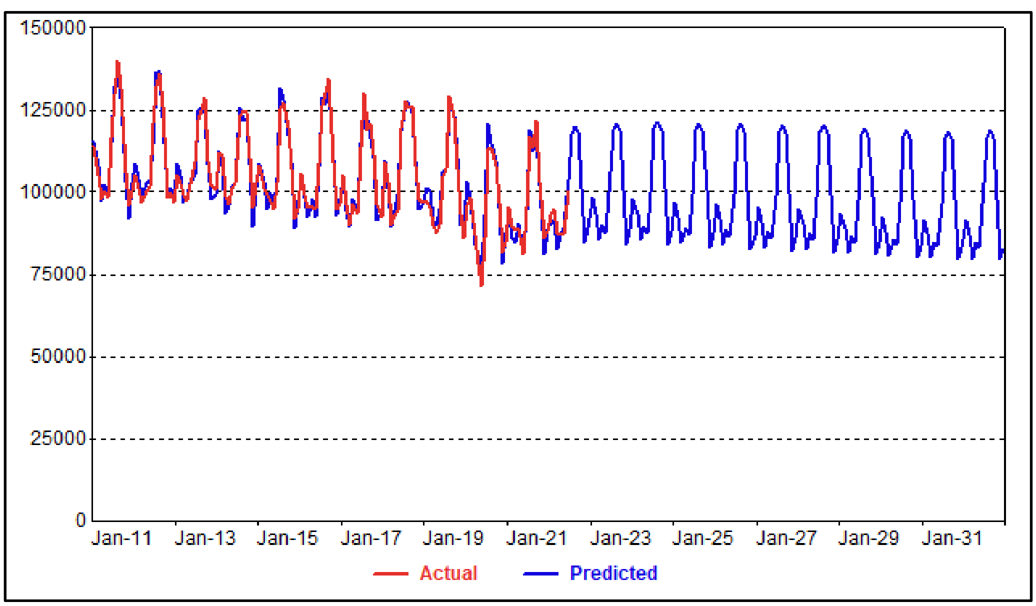


Figure 13 shows model results.

FIGURE 13: COMMERCIAL SALES BASELINE FORECAST



The commercial model specification explains historical sales variation and growth relatively well with an Adjusted R^2 of 0.95 and an in-sample MAPE of 2.3%. The model is estimated with monthly billed sales data from January 2011 to June 2022. Since 2020, commercial sales have been recovering but never get back to pre-COVID levels as work activity continues at elevated levels from home. Model statistics are included in Appendix A. The forecast reflects expected increase in efficiency due to standards, but does not include future DSM, solar self-generation, or electric vehicle charging.

TABLE 2-2: COMMERCIAL BASELINE FORECAST

Year	Sales (MWh)		Customers	
2022	1,174,529		19,085	
2023	1,186,006	1.0%	19,104	0.1%
2024	1,185,789	0.0%	19,159	0.3%
2025	1,179,712	-0.5%	19,211	0.3%
2026	1,173,134	-0.6%	19,257	0.2%
2027	1,166,780	-0.5%	19,299	0.2%
2028	1,162,204	-0.4%	19,343	0.2%
2029	1,151,379	-0.9%	19,389	0.2%
2030	1,141,452	-0.9%	19,435	0.2%
2031	1,135,443	-0.5%	19,479	0.2%
2032	1,134,151	-0.1%	19,523	0.2%
2033	1,128,122	-0.5%	19,570	0.2%
2034	1,126,279	-0.2%	19,622	0.3%
2035	1,124,869	-0.1%	19,669	0.2%
2036	1,126,986	0.2%	19,713	0.2%
2037	1,125,074	-0.2%	19,756	0.2%
2038	1,126,752	0.1%	19,809	0.3%
2039	1,128,542	0.2%	19,860	0.3%
2040	1,131,894	0.3%	19,906	0.2%
2041	1,129,874	-0.2%	19,948	0.2%
2042	1,131,305	0.1%	19,986	0.2%
CAGR 22-42		-0.2%		0.2%

2.3 INDUSTRIAL MODEL

The industrial sales forecast is developed with a two-step approach. The first three years of the forecast are derived from CEI South's expectation of specific customer activity. The forecast after the first three years is based on the industrial forecast model. CEI South determines a baseline volume based on historical consumption use. The baseline use is then adjusted to reflect expected closures and expansions. Near-term sales are also adjusted for the addition of new industrial customers. After the third year, the forecast is derived from the industrial sales model; forecasted growth is applied to the third-year industrial sales forecast.

The industrial sales model is a generalized linear regression model that relates monthly historical industrial billed to manufacturing employment, manufacturing output, CDD, and monthly binaries to capture seasonal load variation and shifts in sales data. The industrial economic driver is a weighted combination of manufacturing employment and manufacturing output. The industrial economic ($IndVar$) variable is defined as:

$$IndVar_{ym} = \left(ManufEmploy_{ym}^{0.67}\right) \times \left(ManufOutput_{ym}^{0.33}\right)$$

Where:

y = year
m = month

The imposed weights are determined by evaluating in-sample and out-of-sample statistics for alternative weighting schemes. The model Adjusted R^2 is 0.52 with a MAPE of 5.9%. The relatively low Adjusted R^2 and high MAPE, in comparison to the residential and commercial models, are a result of the large month-to-month variations in industrial billing data. The industrial model excludes sales to one of CEI South's largest customers, which is currently meeting most of its load through onsite cogeneration.

Excluding DSM, industrial sales average 1.1% annual growth, driven by the addition of a large new customer in 2023. After 2025, industrial sales average 0.3% annual growth. Table 2-3 summarizes the industrial sales forecast.

TABLE 2-3: INDUSTRIAL FORECAST (EXCLUDING FUTURE DSM, PV, EV)

Year	Sales (MWh)	
2022	1,854,221	
2023	1,793,424	-3.3%
2024	2,189,424	22.1%
2025	2,179,125	-0.5%
2026	2,178,524	0.0%
2027	2,187,341	0.4%
2028	2,194,083	0.3%
2029	2,198,120	0.2%
2030	2,200,486	0.1%
2031	2,206,341	0.3%
2032	2,212,215	0.3%
2033	2,219,392	0.3%
2034	2,223,532	0.2%
2035	2,229,140	0.3%
2036	2,239,930	0.5%
2037	2,252,123	0.5%
2038	2,264,307	0.5%
2039	2,274,252	0.4%
2040	2,282,621	0.4%
2041	2,288,406	0.3%
2042	2,294,127	0.2%
CAGR 22-42		1.1%

2.4 STREET LIGHTING MODEL

Streetlight sales are fitted with a regression model with a trend and monthly binaries. Streetlighting sales are decreasing 0.7% annually throughout the forecast period. Table 2-4 shows the streetlight forecast.

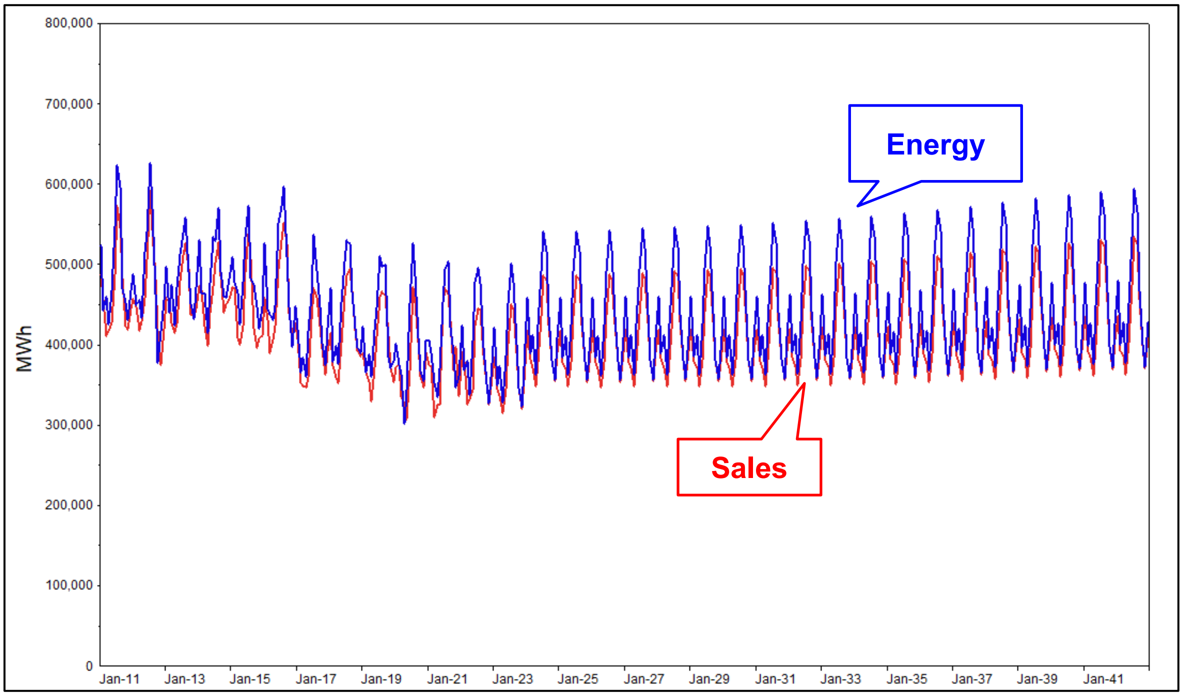
TABLE 2-4: STREET LIGHTING FORECAST

Year	Sales (MWh)	
2022	20,509	
2023	20,561	0.3%
2024	20,424	-0.7%
2025	20,287	-0.7%
2026	20,149	-0.7%
2027	20,012	-0.7%
2028	19,874	-0.7%
2029	19,737	-0.7%
2030	19,600	-0.7%
2031	19,462	-0.7%
2032	19,325	-0.7%
2033	19,188	-0.7%
2034	19,050	-0.7%
2035	18,913	-0.7%
2036	18,775	-0.7%
2037	18,638	-0.7%
2038	18,501	-0.7%
2039	18,363	-0.7%
2040	18,226	-0.7%
2041	18,088	-0.8%
2042	17,951	-0.8%
CAGR 22-42		-0.7%

2.5 ENERGY FORECAST MODEL

The baseline energy forecast is derived directly from the sales forecast by applying a monthly energy adjustment factor to the sales forecast. The energy adjustment factor includes line losses and any differences in timing between monthly sales estimates and delivered energy (*unaccounted for energy*). Monthly adjustment factors are calculated based on the historical relationship between energy and sales. Figure 14 shows the monthly sales and energy forecast, excluding the impact of future DSM, PV or electric vehicles.

FIGURE 14: ENERGY AND SALES FORECAST (EXCLUDING DSM, EV, PV)



2.6 PEAK FORECAST MODEL

The baseline system peak forecast is derived through a monthly peak regression model that relates peak demand to heating, cooling, and base load requirements:

$$Peak_{ym} = B_0 + B_1 HeatVar_{ym} + B_2 CoolVar_{ym} + B_3 BaseVar_{ym} + e_{ym}$$

Where:

y = year
m = month

End-use energy requirements are estimated from class sales forecast models.

Heating and Cooling Model Variables

The residential and commercial SAE model coefficients are used to isolate historical and projected weather-normal heating and cooling requirements. Heating requirements are interacted with peak-day HDD and cooling requirements with peak-day CDD; this interaction allows peak-day weather impacts to change over time with changes in heating and cooling requirements. The peak model heating and cooling variables are calculated as:

- $HeatVar_{ym} = HeatLoadIdx_{ym} \times PkHDD_{ym}$
- $CoolVar_{ym} = CoolLoadIdx_{ym} \times PkCDD_{ym}$

Where $HeatLoadIdx_{ym}$ is an index of total system heating requirements in year y and month m and $CoolLoadIdx_{ym}$ is an index of total system cooling requirements in year y and month m. $PkHDD_{ym}$ is the peak-day HDD in year y and month m and $PkCDD_{ym}$ is the peak-day CDD in year y and month m.

Figure 15 and Figure 16 show *HeatVar* and *CoolVar*. The variation in the historical period is a result of variation in peak-day HDD and CDD.

FIGURE 15: PEAK-DAY HEATING VARIABLE

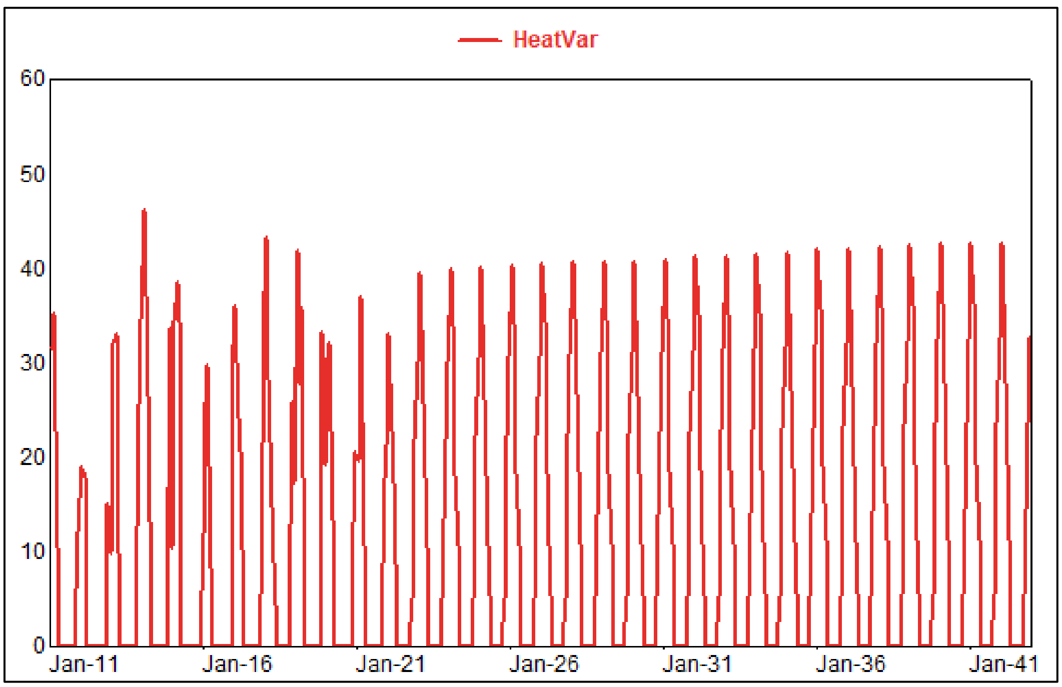
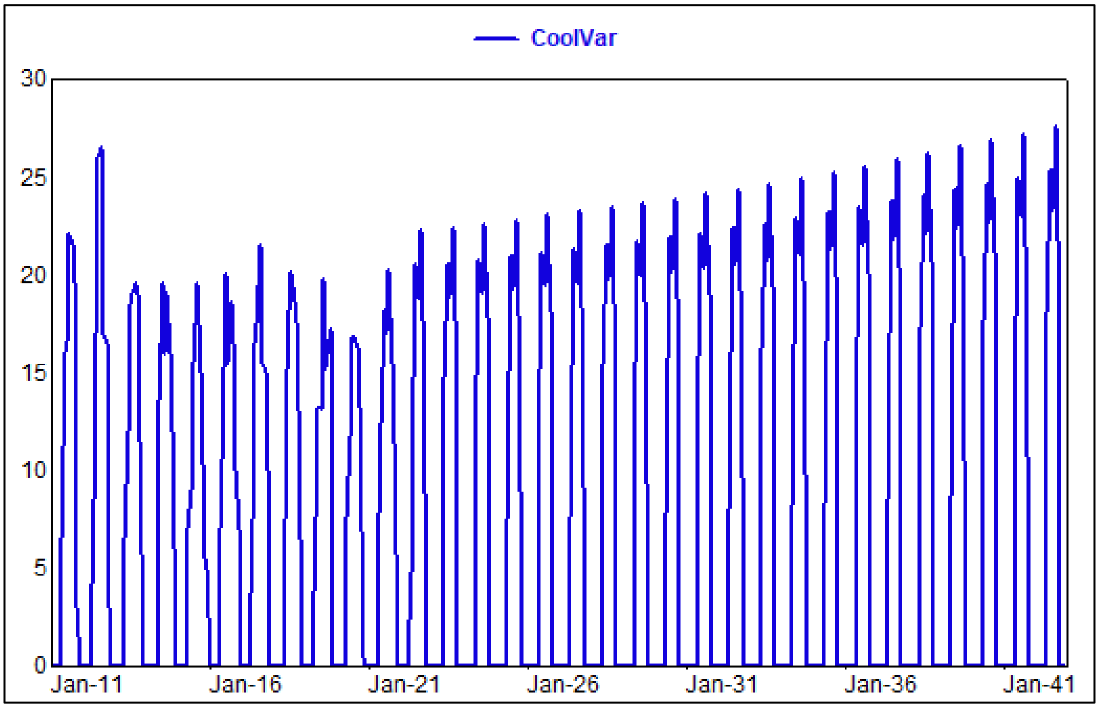


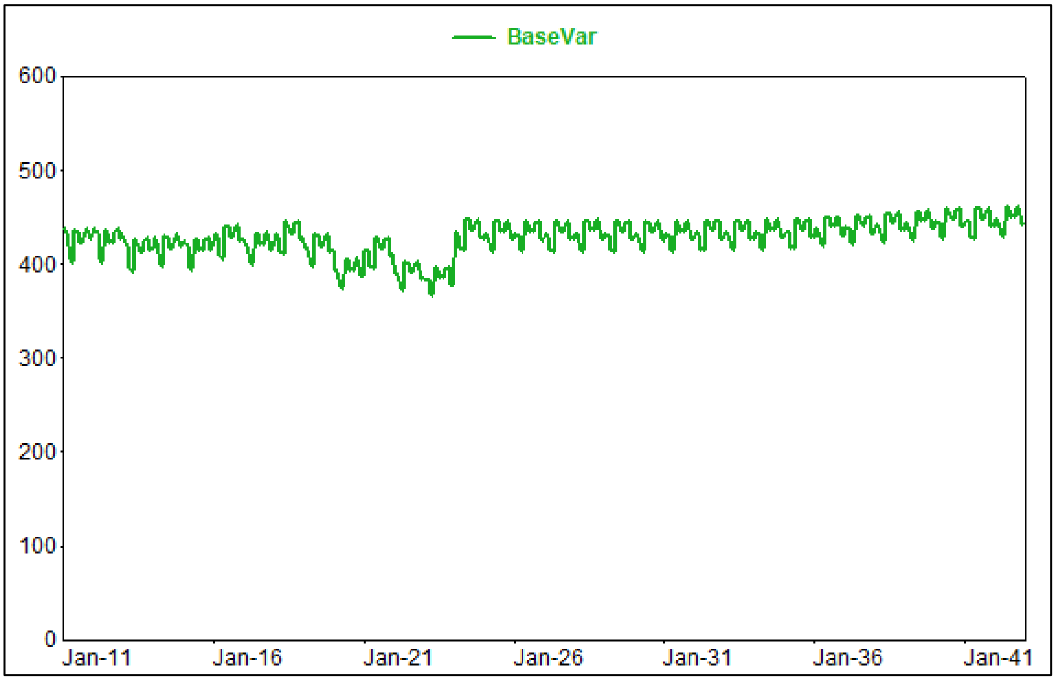
FIGURE 16: PEAK-DAY COOLING VARIABLE



Base Load Variable

The base-load variable (*$BaseVar_{ym}$*) captures non-weather sensitive load at the time of the monthly peak. Monthly base-load estimates are calculated by allocating non-weather sensitive energy requirements to end-use estimates at the time of peak. End-use allocation factors are based on a set of end-use profiles developed by Itron. Figure 17 shows the non-weather sensitive peak-model variable.

FIGURE 17: PEAK-DAY BASE-USE VARIABLE

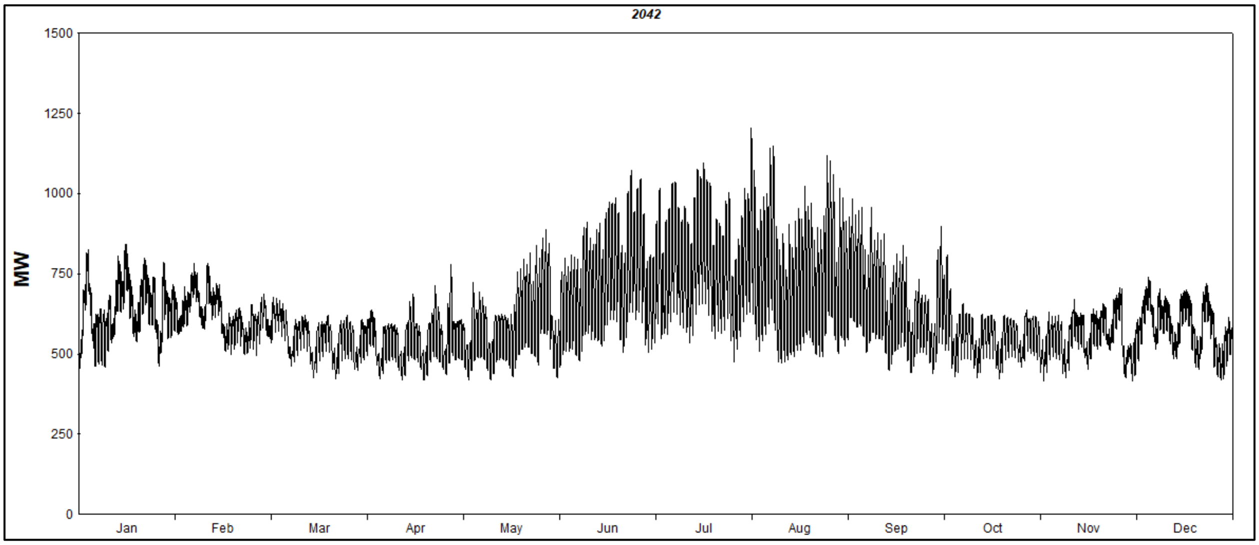


Model Results

The peak model is estimated over the period January 2011 to June 2022. The model explains monthly peak variation well with an adjusted R^2 of 0.93 and an in-sample MAPE of 3.57%. The end-use variables – *HeatVar*, *CoolVar*, and *BaseVar* are all highly statistically significant. Model statistics and parameters are included in Appendix A.

The baseline energy and peak forecast, excluding DSM, PV, and electric vehicles, are combined with a system hourly load profile to derive the baseline hourly load forecast. Figure 18 shows the hourly load forecast for 2042.

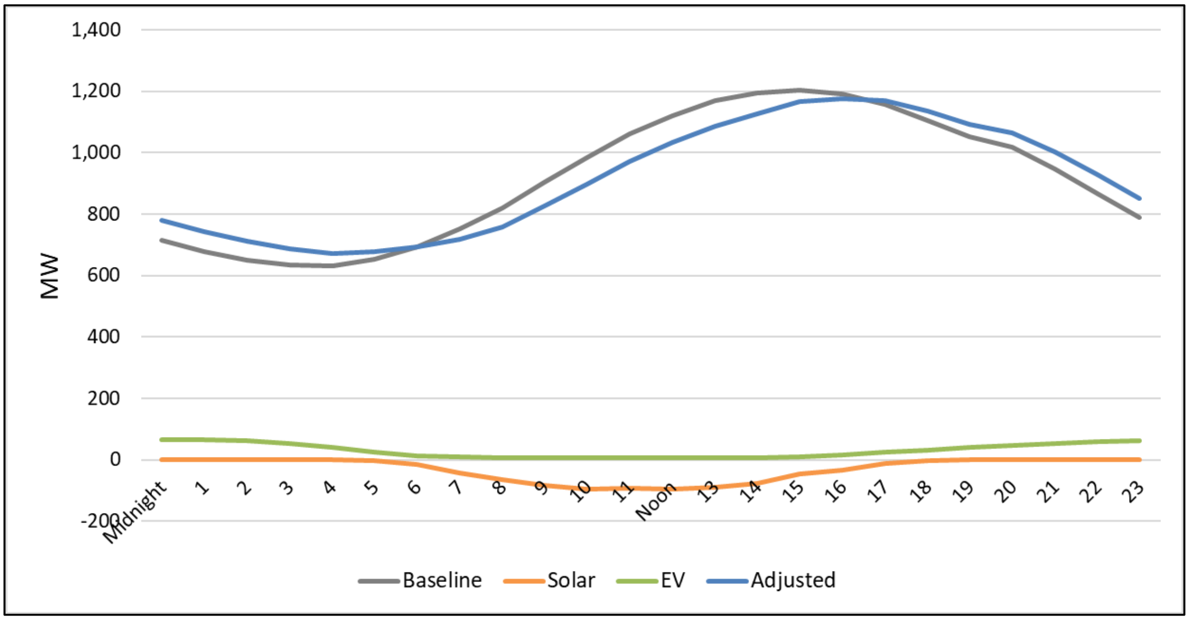
FIGURE 18: BASELINE SYSTEM HOURLY LOAD FORECAST



2.7 ADJUSTED ENERGY & PEAK FORECAST

The final adjusted energy and peak forecast is produced by adding additional solar and electric vehicle hourly load forecasts to the baseline forecast. This approach is a change from the prior IRP in which coincident peak load factors for PV and electric vehicles were used to estimate peak impacts. The advantage of the hourly approach is the ability to capture the changing impact of PV and electric vehicles with changes to the timing of the system peak. Due to the additional PV and electric vehicles, the summer system peak shifts forward one hour beginning in 2034, reducing the impact of solar. Figure 19 shows the baseline hourly load, PV and electric vehicles loads, and final adjusted system load for a summer peak day in 2042.

FIGURE 19: ADJUSTED SYSTEM HOURLY LOAD FORECAST



The final adjusted energy and peak forecast is derived from the adjusted hourly system forecast. Table 2-5 shows adjusted energy and peak demand forecast.

TABLE 2-5: ENERGY AND PEAK FORECAST (EXCLUDING DSM)

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2022	4,815,801		1,019		802	
2023	4,725,478	-1.9%	1,010	-0.9%	738	-8.0%
2024	5,163,907	9.3%	1,087	7.6%	812	10.0%
2025	5,152,172	-0.2%	1,087	0.0%	810	-0.2%
2026	5,153,363	0.0%	1,088	0.1%	811	0.1%
2027	5,164,632	0.2%	1,092	0.3%	813	0.3%
2028	5,178,436	0.3%	1,095	0.3%	816	0.4%
2029	5,175,063	-0.1%	1,095	0.0%	816	0.0%
2030	5,178,761	0.1%	1,096	0.1%	817	0.2%
2031	5,199,311	0.4%	1,100	0.3%	821	0.5%
2032	5,238,099	0.7%	1,105	0.5%	828	0.9%
2033	5,254,460	0.3%	1,110	0.4%	831	0.4%
2034	5,277,650	0.4%	1,114	0.4%	836	0.5%
2035	5,304,282	0.5%	1,120	0.6%	841	0.6%
2036	5,345,573	0.8%	1,128	0.7%	849	1.0%
2037	5,377,724	0.6%	1,136	0.7%	855	0.7%
2038	5,418,448	0.8%	1,145	0.8%	862	0.9%
2039	5,455,497	0.7%	1,154	0.8%	869	0.8%
2040	5,493,803	0.7%	1,162	0.7%	875	0.8%
2041	5,518,739	0.5%	1,169	0.6%	880	0.5%
2042	5,551,532	0.6%	1,177	0.6%	886	0.7%
CAGR 22-42		0.7%		0.7%		0.5%

3 CUSTOMER OWNED DISTRIBUTED GENERATION

The energy and peak forecasts incorporate the impact of customer-owned photovoltaic systems. System adoption is expected to increase as solar system costs decline, which is partially offset by changes in net metering laws that will credit excess generation at a rate lower than retail rates in the future. As of June 2022, CEI South had 950 residential solar customers and 136 commercial solar customers, with an approximate installed capacity of 22.6 MW.

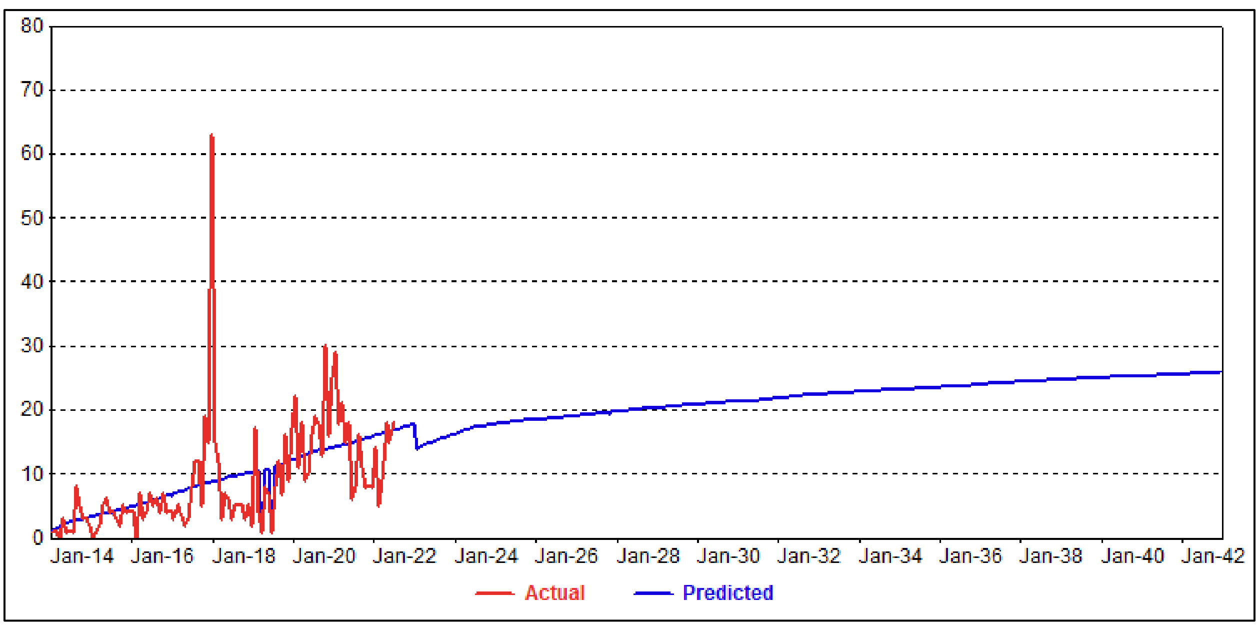
3.1 MONTHLY ADOPTION MODEL

The primary factor driving system adoption is a customer's return-on-investment. A simple payback model is used as proxy. Simple payback reflects the length of time needed to recover the cost of installing a solar system - the shorter the payback, the higher the system adoption rate. From the customer's perspective, this is the number of years until electricity is "free." Simple payback also works well to explain leased system adoption as return on investment drives the leasing company's decision to offer leasing programs. Solar investment payback is calculated as a function of system costs, federal and state tax credits and incentive payments, retail electric rates, and treatment of excess generation (solar generation returned to the grid). The payback calculation incorporates the impact of switching from net metering to Excess Distributed Generation (EDG). Federal investment tax credits were extended in accordance with the Inflation Reduction Act.

One of the most significant factors driving adoption is declining system costs; costs have continued declining over the last five years. In 2010, residential solar system cost was approximately $8.00 per watt. By 2020 costs had dropped to $3.80 per watt. For the forecast period, we assume system costs continue to decline 10% annually through 2024 and an additional 3% annually after 2024.

The solar adoption model relates monthly residential solar adoptions to simple payback. Figure 20 shows the resulting residential solar adoption forecast.

FIGURE 20: RESIDENTIAL SOLAR ADOPTION FORECAST



In the commercial sector, there have been too few adoptions to estimate a robust model; commercial system adoption has been low across the country. Limited commercial adoption reflects higher investment hurdle rates, building ownership issues (i.e., the entity that owns the building often does not pay the electric bill), and physical constraints as to the placement of the system. For this forecast, we assume there continues to be some commercial rooftop adoption by allowing commercial adoption to increase over time, based on the current relationship between commercial and residential adoptions rates. Table 3-1 shows projected solar adoption.

TABLE 3-1: SOLAR CUSTOMER FORECAST

Year	Residential Systems	Commercial Systems	Total Systems
2022	961	141	1,103
2023	1,150	177	1,327
2024	1,345	207	1,552
2025	1,559	240	1,799
2026	1,780	274	2,053
2027	2,008	309	2,317
2028	2,246	346	2,592
2029	2,489	383	2,872
2030	2,741	422	3,162
2031	2,994	461	3,454
2032	3,256	501	3,757
2033	3,524	542	4,066
2034	3,800	585	4,384
2035	4,076	627	4,703
2036	4,358	671	5,029
2037	4,646	715	5,361
2038	4,936	759	5,696
2039	5,236	806	6,041
2040	5,536	852	6,387
2041	5,836	898	6,734
2042	6,144	945	7,089
CAGR 22-42	9.7%	10.0%	9.8%

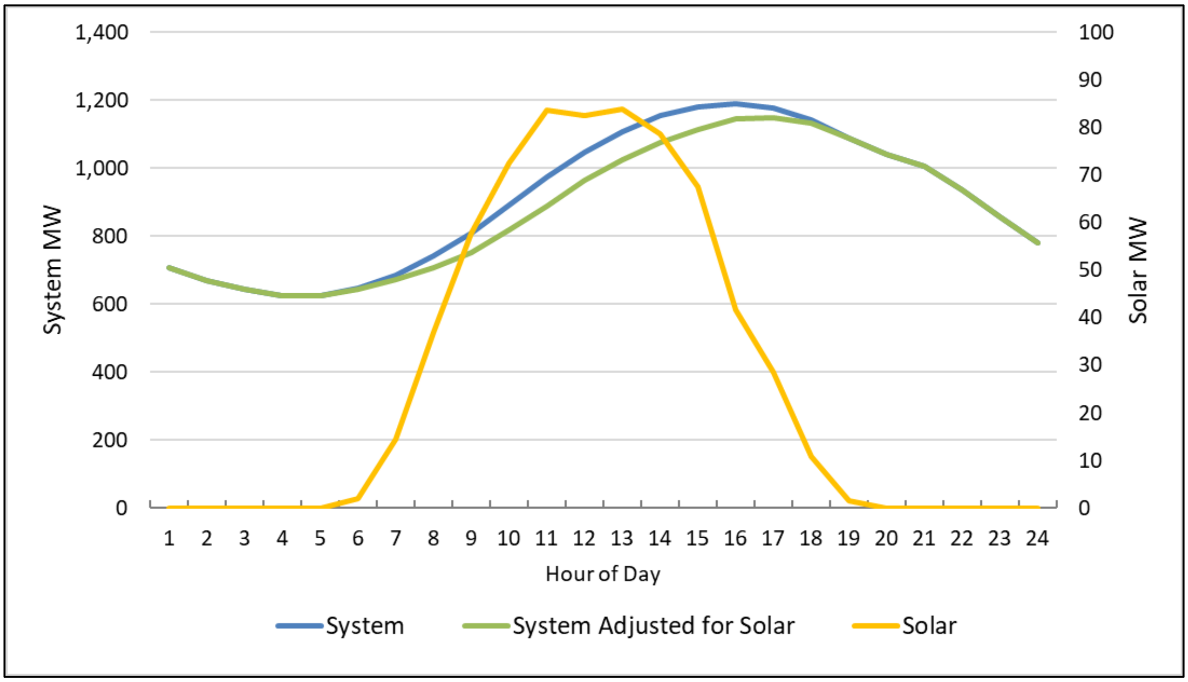
3.2 SOLAR CAPACITY AND GENERATION

Installed solar capacity forecast is the product of the solar customer forecast and average system size (measured in kW). Based on recent solar installation data, the residential average size is 10.4 KW, and commercial average system size is 93.6 KW.

The capacity forecast (MW) is translated into system generation (MWh) forecast by applying monthly solar load factors to the capacity forecast. Monthly load factors are derived from a typical PV load profile for Evansville, IN. The PV shape is from the National Renewable Energy Laboratory (NREL) and represents a typical meteorological year (TMY).

The impact of solar generation on system peak demand is a function of the timing between solar load generation and system hourly demand. Solar output peaks during the mid-day while system peaks later in the afternoon. Figure 21 shows the system profile, solar adjusted system profile, and solar profile for a peak producing summer day.

FIGURE 21: SOLAR HOURLY LOAD IMPACT



Based on system and solar load profiles, 1.0 MW of solar capacity reduces summer peak demand by approximately 0.36 MW through 2033. In 2034 the timing of the system peak shifts forward one hour, resulting in diminished solar impact per installed MW. In 2034 1.0 MW of solar capacity reduces summer peak demand by approximately 0.25 MW.

Table 3-2 shows the incremental new PV capacity forecast, expected annual generation, and demand at time of peak.

TABLE 3-2: NEW SOLAR CAPACITY AND GENERATION

Year	Total Generation MWh	Installed Capacity MW (Aug)	Demand Impact MW
2022	1,537	1.8	0.7
2023	8,211	6.5	2.3
2024	15,018	11.4	4.1
2025	22,399	16.8	6.0
2026	30,039	22.3	8.0
2027	37,960	27.9	10.0
2028	46,299	33.9	12.1
2029	54,615	40.0	14.4
2030	63,335	46.2	16.6
2031	72,103	52.5	18.9
2032	81,374	59.1	21.3
2033	90,470	65.7	23.4
2034	100,029	72.6	17.9
2035	109,595	79.4	19.6
2036	119,645	86.5	21.2
2037	129,363	93.6	23.1
2038	139,416	100.9	24.7
2039	149,790	108.3	26.3
2040	160,542	115.8	28.6
2041	170,589	123.2	30.2
2042	181,272	130.9	32.2

4 ELECTRIC VEHICLE FORECAST

The 2022 Long-Term forecast also includes the impact of electric vehicle adoption. Currently CEI South has relatively few electric vehicles, but this is expected to increase significantly over the next twenty years with improvements in EV technology and declines in battery and vehicle costs. Multiple private and public institutions produce electric vehicle forecasts that vary from conservative to aspirational. Major manufactures have continued to pledge increased EV availability and options. At the time of the forecast CEI South had 238 registered electric vehicles in the counties that CEI South serves: this included full electric (i.e., battery electric vehicles - BEV) as well as plug-in hybrid electric (PHEV) vehicles. The 238 vehicles were comprised of 105 BEVs and 133 PHEVs, with a total of 23 different make/model vehicles represented.

4.1 METHODOLOGY

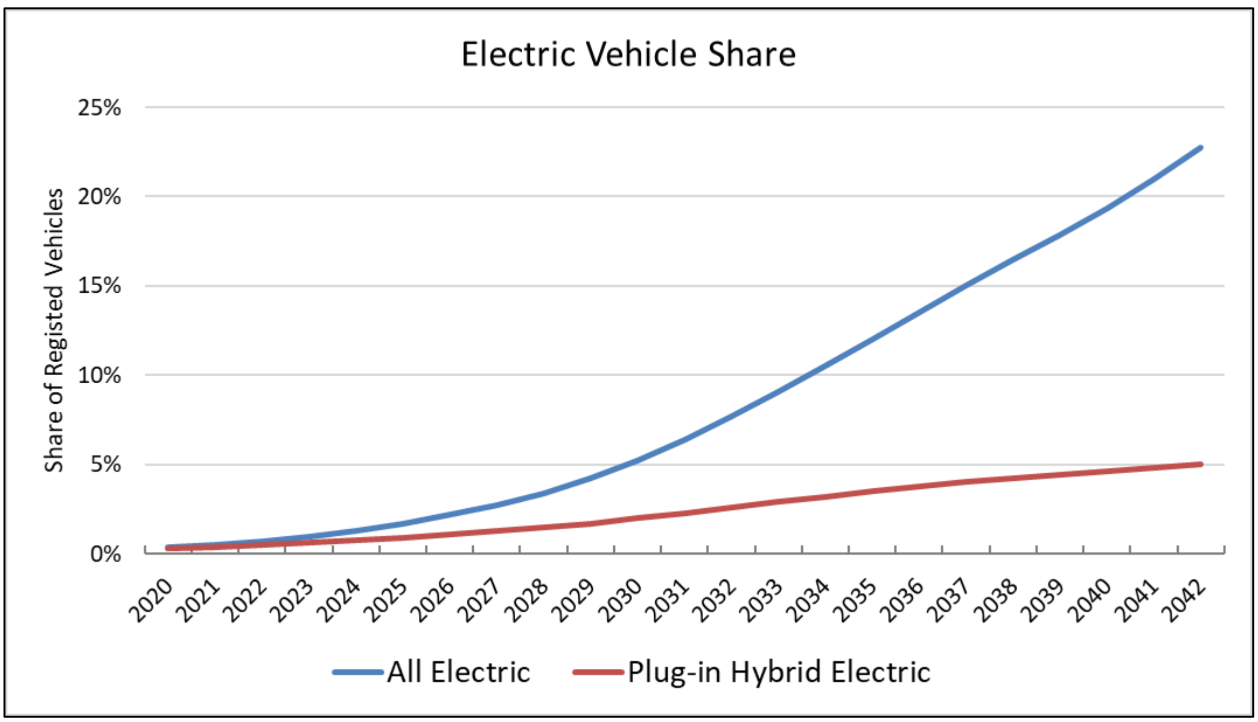
The Energy Information Administration (EIA) Annual Energy Outlook and BloombergNEF are two commonly referenced sources for electric vehicle forecasts. The 2022 Long-Term forecast uses a consensus forecast, averaging the EIA and Bloomberg forecasts to calculate the share of registered light-duty vehicles which are electric, BEV and PHEV. We rely on the EIA's assumption of total light-duty vehicles per household. Using these data, we calculate the average number of cars per household and projected electric vehicle share - BEV and PHEV.

Total service area vehicles are calculated as the product of forecasted customers times EIA projected vehicles per household:

$$Ttl\,Vehicles = \ Custs_{yr} \times EIA\,Vehicle\ Per\ HH_{yr}$$

The number of BEV and PHEV are calculated by applying consensus projected BEV and PHEV saturation to the service area total vehicle forecast. A calibration step is first taken to adjust to the known number of registered EV in CenterPoint's service territory as of 2022. The share of electric vehicles is projected to increase from less than 1% to 23% BEV and 5% PHEV by 2042. The BEV and PHEV saturation forecast is shown in Figure 22.

FIGURE 22: BEV & PHEV MARKET SHARE



The resulting electric vehicle forecast is summarized in Table 4-1:

TABLE 4-1: ELECTRIC VEHICLE FORECAST

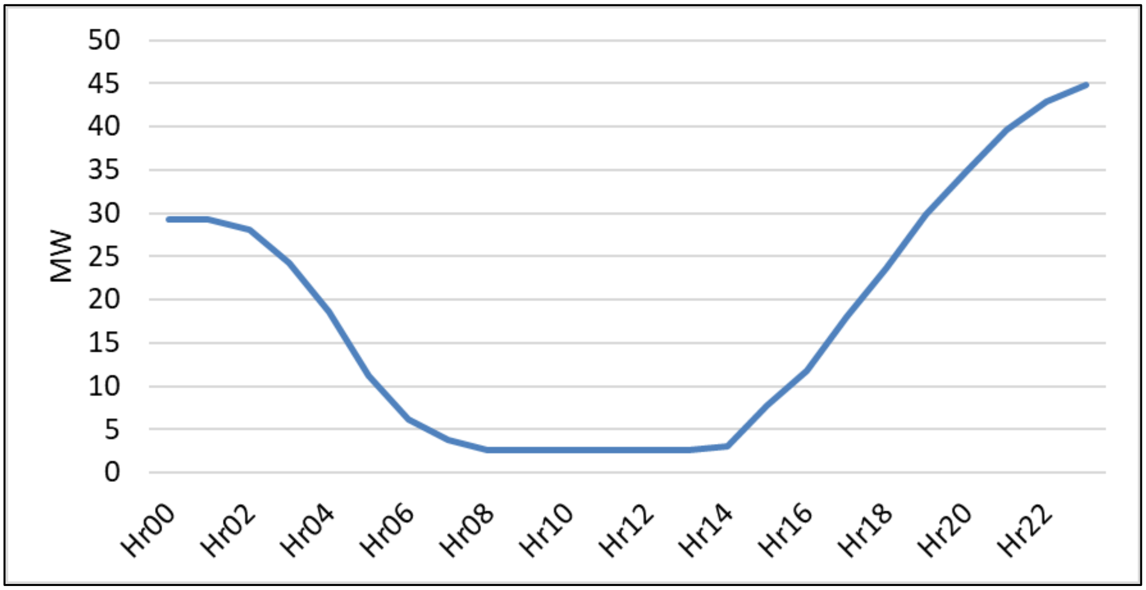
Year	BEV Count	PHEV Count
2022	378	309
2023	585	441
2024	905	629
2025	1,401	898
2026	2,167	1,284
2027	3,354	1,835
2028	4,460	2,266
2029	6,057	2,819
2030	8,412	3,546
2031	11,934	4,514
2032	17,250	5,819
2033	20,422	6,549
2034	23,835	7,287
2035	27,405	8,005
2036	30,950	8,665
2037	34,444	9,261
2038	37,895	9,796
2039	41,251	10,257
2040	44,872	10,728
2041	48,786	11,208
2042	53,012	11,698

4.2 ELECTRIC VEHICLE ENERGY & LOAD FORECAST

Electric vehicles' impact on CEI South's load forecast depends on the amount of energy a vehicle consumes annually and the timing of vehicle charging. BEVs consume more electricity than PHEVs and accounting for this distinction is important. An EV weighted annual kWh use is calculated based on the current mix of EV models. EV usage is derived from manufacturers' reported fuel efficiency to the federal government (www.fueleconomy.gov). The average annual kWh for the current mix of EVs registered in CEI South's service territory is 3,752kWh for BEV and 2,180 kWh for PHEV based on annual mileage of 12,000 miles.

Electric vehicles' impact on peak demand depends on when and where EVs are charged. Since CEI South does not have incentivized BEV/PHEV off-peak charging rates, it is assumed the majority of charging will occur at home in the evening hours. There is a distinction made for weekend and weekday charging. Figure 23 shows the weekday EV charging profile.

FIGURE 23: EV CHARGING PROFILE



The EV load forecast is derived by combining EV energy requirements with the hourly charging load profile, Table 4-2 shows the electric vehicle load forecast.

TABLE 4-2: ELECTRIC VEHICLE LOAD FORECAST

Year	Total Vehicle (MWh)	Summer Peak Impact (MW)	Winter Peak Impact (MW)
2024	691	0.0	0.0
2025	1,808	0.1	0.3
2026	3,500	0.2	0.5
2027	6,069	0.3	0.8
2028	9,972	0.5	1.4
2029	15,909	0.7	2.2
2030	21,251	1.0	3.7
2031	28,809	1.3	5.1
2032	39,752	1.8	7.0
2033	55,841	2.5	9.8
2034	79,773	3.6	13.9
2035	93,941	4.3	16.5
2036	109,076	7.6	19.1
2037	124,785	8.7	25.5
2038	140,262	9.7	28.5
2039	155,391	10.8	31.7
2040	170,208	11.8	34.7
2041	184,488	12.8	37.6
2042	199,831	13.9	40.7
2043	216,348	15.0	44.1
2044	234,119	16.3	47.7

5 FORECAST ASSUMPTIONS

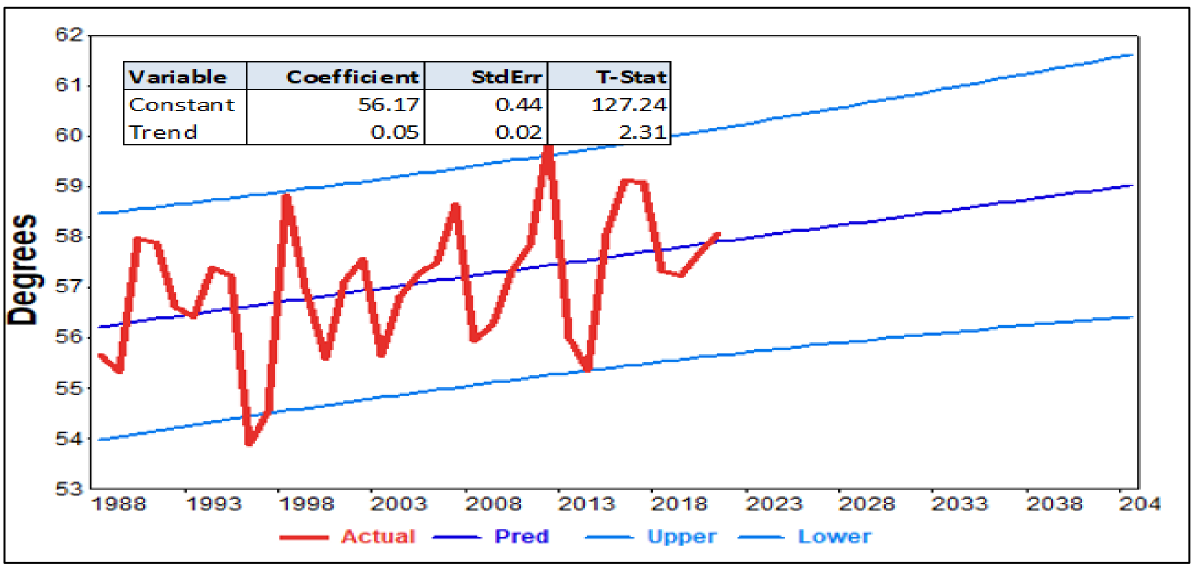
5.1 WEATHER DATA

Historical and normal HDD and CDD are derived from daily temperature data for the Evansville airport. HDD and CDD are often referred to as spline variables as they either take on a positive value or are 0. HDD are positive when temperatures are below a specified temperature reference point and are 0 when temperatures are at or above the temperature reference point. CDD are positive when temperatures are above a temperature reference point and are 0 when temperatures are at or below the temperature reference point. The best temperature breakpoints in terms of statistical model fit varies by customer class. Commercial heating and cooling generally start at lower temperature points than residential. Temperature breakpoints are evaluated as part of the model estimation process. For the residential rate classes, the best temperature breakpoints are 60 degrees for HDD and 65 degrees for CDD. In the non-residential classes, HDD with a 60 degree reference point and CDD with a 60 degree reference point improve the overall model fit.

Traditionally, utilities base their long-term forecast on what the industry calls normal weather. Normal weather is calculated by averaging historical weather usually over a 20-year or 30-year period. Given the large variation in month-to-month and year over year weather conditions, it seemed reasonable to assume that the best representation of current and forecast weather is an average of the past.

Recent studies that Itron and others have conducted have shown that this is probably not the best assumption; over the last fifty years, average temperatures have been increasing. In reviewing historical Evansville weather data, we found a statistically significant positive, but slow, increase in average temperature. Figure 24 shows long-term Evansville temperature trend, and 90% confidence interval.

FIGURE 24: EVANSVILLE TEMPERATURE TRENDS



Since 1988, average annual temperatures have been increasing 0.05 degrees per year, or 0.5 degrees per decade. The trend coefficient is highly statistically significant indicating a high probability of increasing temperatures. This results in HDDs decreasing 0.2% per year while CDDs are increasing 0.5% per year. These trends are incorporated into the forecast. Starting normal HDD are allowed to decrease 0.2% over the forecast period while CDD increase 0.5% per year through 2042. Figure 25 and Figure 26 show historical and forecasted monthly HDD and CDD.

FIGURE 25: HEATING DEGREE DAYS

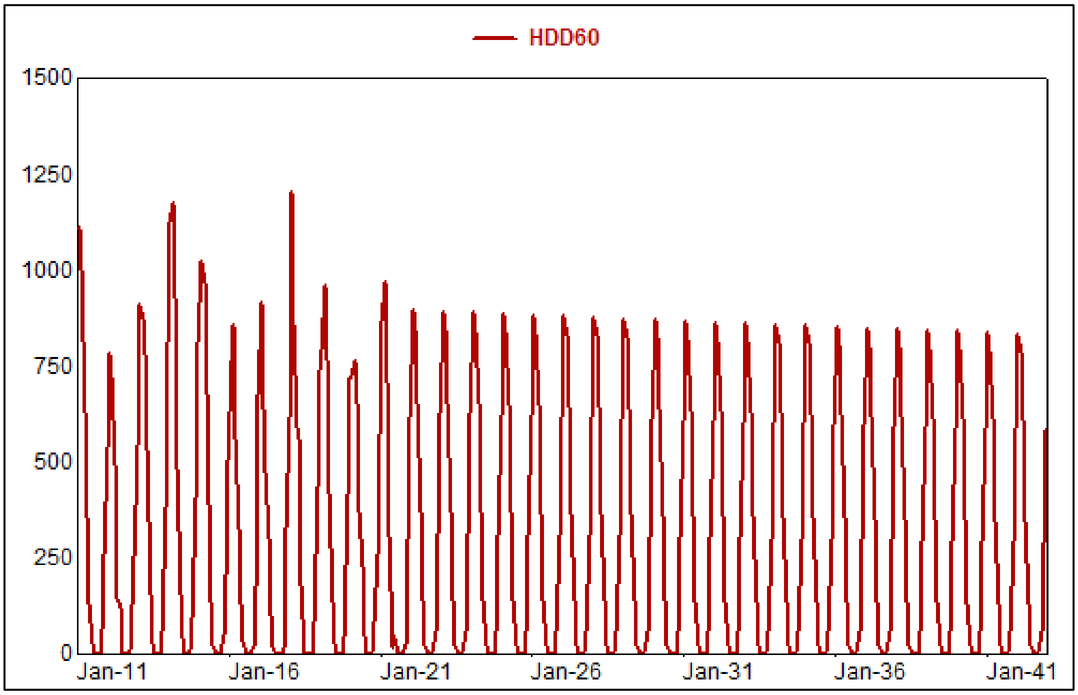
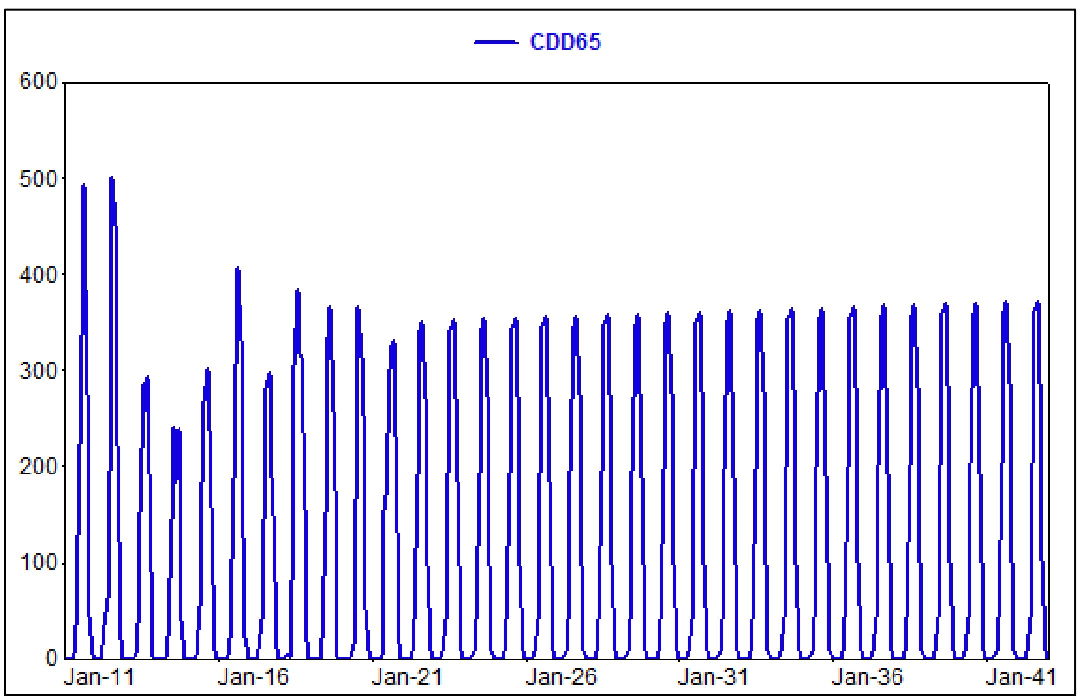


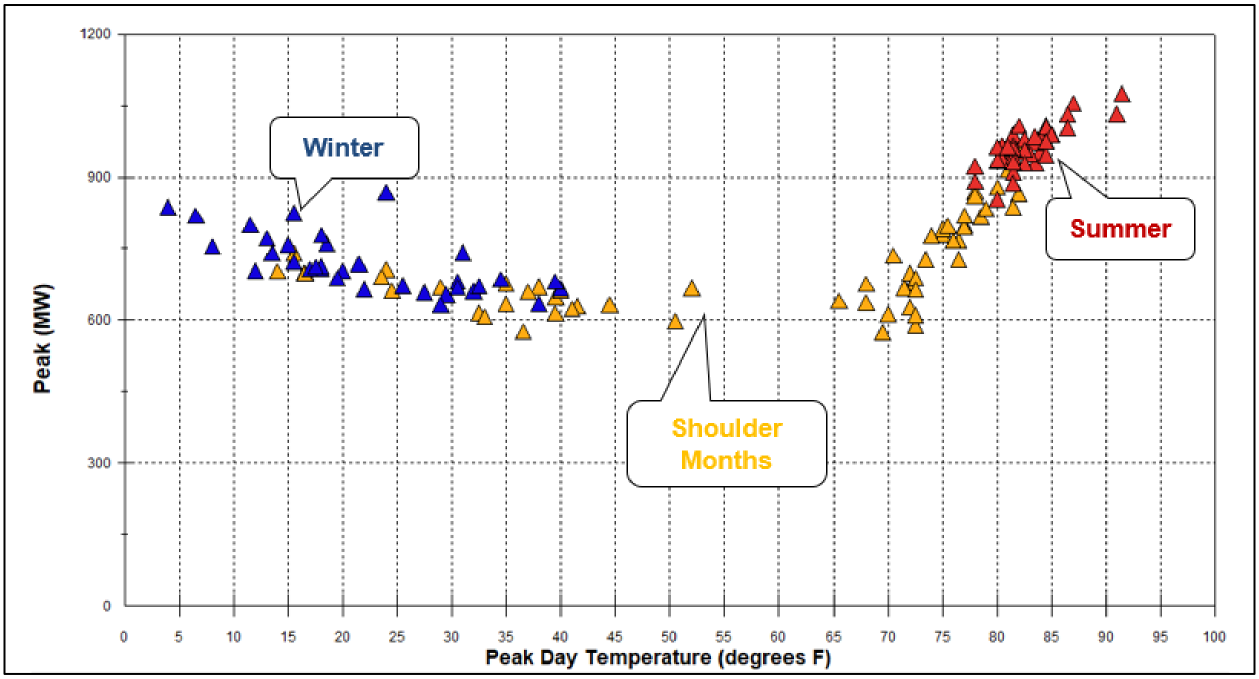
FIGURE 26: COOLING DEGREE DAYS



Peak-Day Weather Variables

Peak-day CDD and HDD are used in forecasting system peak demand. Peak-day HDD and CDD are derived by finding the daily HDD and CDD that occurred on the peak day in each month. The appropriate breakpoints for defining peak-day HDD and CDD are determined by evaluating the relationship between monthly peak and the peak-day average temperature, as shown in Figure 27.

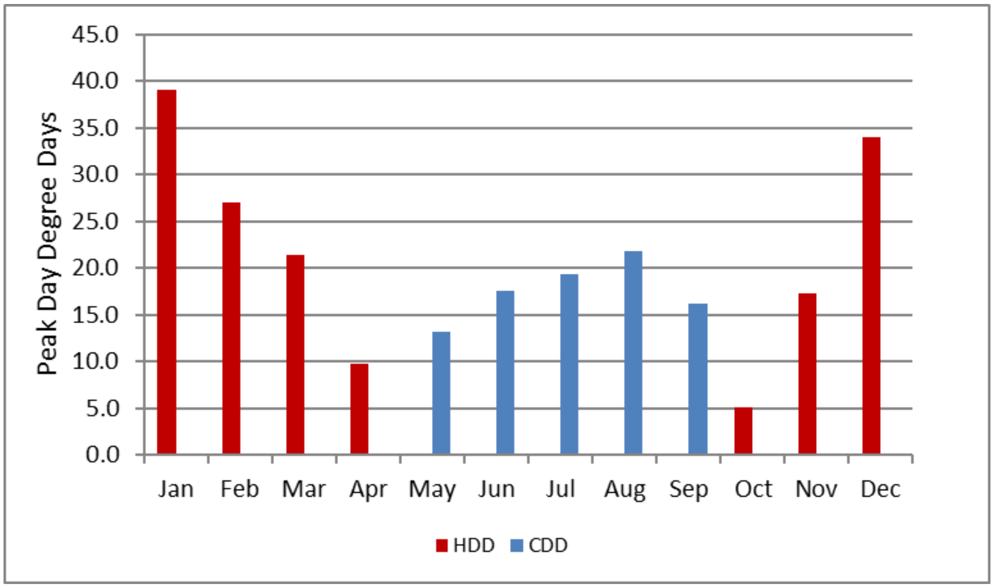
FIGURE 27: MONTHLY PEAK DEMAND /TEMPERATURE RELATIONSHIP



Peak-day cooling occurs when temperatures are above 65 degrees and peak-day heating occurs when temperatures are below 55 degrees.

Normal peak-day HDD and CDD are calculated using 20 years of historical weather data, based on a rank and average approach, these are not trended. The underlying rate class sales models incorporate trended normal weather; derived heating and cooling sales from these models are an input into the peak model. Using a trended peak weather would double count the impact of increasing temperatures. Normal peak-day HDD and CDD are based on the hottest and coldest days that occurred in each month over the historical time period. Figure 28 shows the normal peak-day HDD and CDD values used in the forecast.

FIGURE 28: NORMAL PEAK-DAY HDD & CDD



5.2 ECONOMIC DATA

The class sales forecasts are based on *IHS Markit* June 2022 economic forecast for the Evansville Metropolitan Statistical Area (MSA) and Indiana. The primary economic drivers in the residential sector are household income and the number of new households. Household formation is stable and increasing consistently though the forecast period with 0.4% average annual growth. Real household income growth is modest, averaging 1.6% over the forecast period.

Commercial sales are driven by nonmanufacturing output, nonmanufacturing employment, and population. Non-manufacturing output is forecasted to grow at 1.4% per year through the forecast period with non-manufacturing employment growing 0.4% per year and population a little over 0.04% per year.

The industrial model relates sales to manufacturing output and employment. Manufacturing output is projected to increase more rapidly than non-manufacturing output, with output increasing 2.2% per year. While output increases, associated manufacturing employment is projected to decline at a 0.5% annual rate.

Table 5-1 through Table 5-3 shows economic forecasts applicable to each customer class.

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TABLE 5-1: RESIDENTIAL ECONOMIC DRIVERS

Year	Population (Thou)		Households (Thou)		Household Income (Thou $)	
2022	313.8		131.0		125.7	
2023	313.9	0.0%	131.5	0.4%	127.5	1.4%
2024	314.0	0.0%	132.1	0.5%	129.9	1.9%
2025	314.3	0.1%	132.7	0.4%	132.0	1.6%
2026	314.5	0.1%	133.2	0.4%	134.5	2.0%
2027	314.6	0.0%	133.7	0.4%	137.4	2.1%
2028	314.7	0.0%	134.2	0.4%	140.2	2.0%
2029	314.9	0.1%	134.7	0.4%	142.4	1.6%
2030	315.3	0.1%	135.2	0.4%	144.5	1.5%
2031	315.7	0.1%	135.7	0.4%	146.8	1.6%
2032	315.9	0.1%	136.2	0.4%	149.0	1.5%
2033	316.1	0.0%	136.7	0.4%	151.1	1.4%
2034	316.2	0.0%	137.3	0.4%	153.1	1.3%
2035	316.2	0.0%	137.8	0.4%	155.2	1.4%
2036	316.1	0.0%	138.3	0.3%	157.4	1.4%
2037	316.0	0.0%	138.8	0.4%	159.6	1.5%
2038	316.2	0.0%	139.3	0.4%	161.8	1.4%
2039	316.3	0.1%	139.9	0.4%	164.0	1.4%
2040	316.4	0.0%	140.4	0.4%	166.4	1.5%
2041	316.4	0.0%	140.9	0.3%	168.8	1.4%
2042	316.3	0.0%	141.3	0.3%	171.3	1.5%
22-42		0.0%		0.4%		1.6%

TABLE 5-2: COMMERCIAL ECONOMIC DRIVERS

Year	Non-Manufacturing GDP (Mil $)		Non-Manufacturing Employment (Thou)		Population (Thou)	
2022	253,187		2,643.2		313.8	
2023	256,123	1.2%	2,664.3	0.8%	313.9	0.0%
2024	260,156	1.6%	2,664.7	0.0%	314.0	0.0%
2025	263,884	1.4%	2,667.2	0.1%	314.3	0.1%
2026	267,077	1.2%	2,676.6	0.4%	314.5	0.1%
2027	270,657	1.3%	2,688.4	0.4%	314.6	0.0%
2028	274,621	1.5%	2,699.7	0.4%	314.7	0.0%
2029	278,367	1.4%	2,710.8	0.4%	314.9	0.1%
2030	282,165	1.4%	2,722.5	0.4%	315.3	0.1%
2031	285,891	1.3%	2,731.5	0.3%	315.7	0.1%
2032	289,857	1.4%	2,739.5	0.3%	315.9	0.1%
2033	294,371	1.6%	2,750.1	0.4%	316.1	0.0%
2034	299,853	1.9%	2,763.5	0.5%	316.2	0.0%
2035	305,016	1.7%	2,774.8	0.4%	316.2	0.0%
2036	309,490	1.5%	2,784.5	0.4%	316.1	0.0%
2037	313,794	1.4%	2,794.2	0.3%	316.0	0.0%
2038	318,078	1.4%	2,803.1	0.3%	316.2	0.0%
2039	322,587	1.4%	2,812.0	0.3%	316.3	0.1%
2040	327,598	1.6%	2,822.6	0.4%	316.4	0.0%
2041	332,301	1.4%	2,829.6	0.2%	316.4	0.0%
2042	337,283	1.5%	2,836.0	0.2%	316.3	0.0%
22-42		1.4%		0.4%		0.04%

TABLE 5-3: INDUSTRIAL ECONOMIC DRIVERS

Year	Manufacturing GDP (Mil $)		Manufacturing Employment (Thou)	
2022	104,581		544.4	
2023	107,562	2.9%	550.6	1.1%
2024	109,532	1.8%	545.5	-0.9%
2025	110,981	1.3%	535.6	-1.8%
2026	113,113	1.9%	529.9	-1.1%
2027	115,724	2.3%	528.7	-0.2%
2028	118,245	2.2%	526.6	-0.4%
2029	120,744	2.1%	523.2	-0.7%
2030	123,055	1.9%	519.3	-0.7%
2031	125,631	2.1%	517.0	-0.5%
2032	128,328	2.1%	514.5	-0.5%
2033	131,222	2.3%	512.5	-0.4%
2034	134,229	2.3%	508.7	-0.7%
2035	137,326	2.3%	505.7	-0.6%
2036	140,855	2.6%	504.8	-0.2%
2037	144,496	2.6%	504.6	0.0%
2038	148,346	2.7%	504.2	-0.1%
2039	152,180	2.6%	502.7	-0.3%
2040	156,000	2.5%	500.6	-0.4%
2041	159,680	2.4%	497.5	-0.6%
2042	163,171	2.2%	494.8	-0.5%
22-42		2.2%		-0.5%

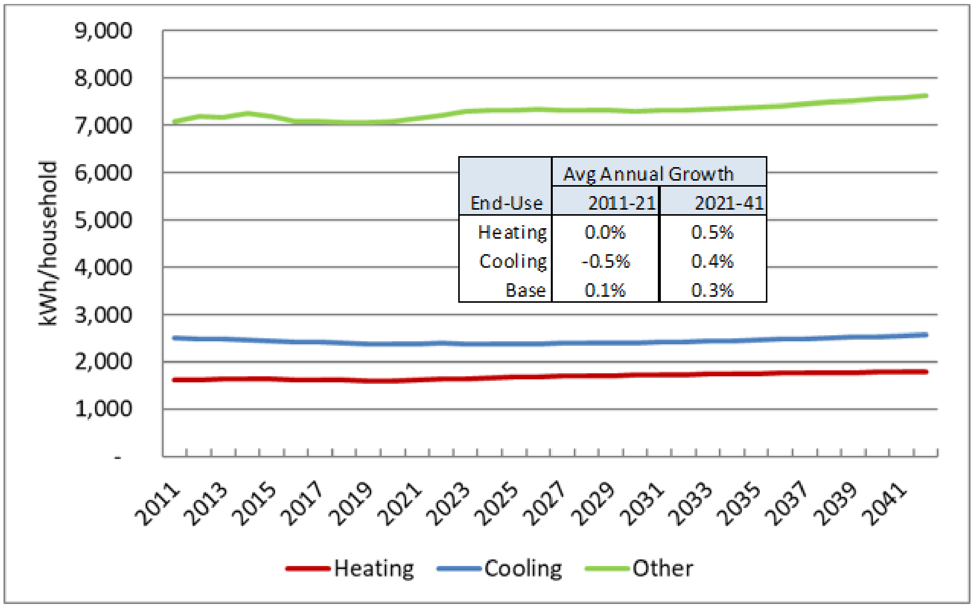
Historical electric prices (in real dollars) are derived from billed sales and revenue data. Historical prices are calculated as a 12-month moving average of the average rate (revenues divided by sales); prices are expressed in real dollars. Prices impact residential and commercial sales through imposed short-term price elasticities. Short-term price elasticities are small; residential and commercial price elasticities are set at -0.10. Price is not an input to the industrial sales model. Price projections are based on the Energy Information Administration's (EIA) Short-term Energy Outlook and Annual Energy Outlook. Over the forecast period, residential prices are flat in real dollars, commercial prices decline 0.2% annually.

5.3 APPLIANCE SATURATION & EFFICIENCY TRENDS

Over the long-term, changes in end-use saturation and stock efficiency impact class sales, system energy, and peak demand. End-use energy intensities, expressed in kWh per household for the residential sector and kWh per square foot for the commercial sectors, are incorporated into the constructed forecast model variables. Energy intensities reflect both change in ownership (saturation) and average stock efficiency. In general, efficiency is improving faster than end-use saturation resulting in declining end-use energy use. Energy intensities are derived from Energy Information Administration's (EIA) 2022 Annual Energy Outlook and CEI South's appliance saturation surveys. The residential sector incorporates saturation and efficiency trends for seventeen end-uses. The commercial sector captures end-use intensity projections for ten end-use classifications across ten building types.

Residential end-use intensities are used in constructing the model end-use variables. Figure 29 shows the resulting aggregated end-use intensity projections.

FIGURE 29: RESIDENTIAL END-USE ENERGY INTENSITIES

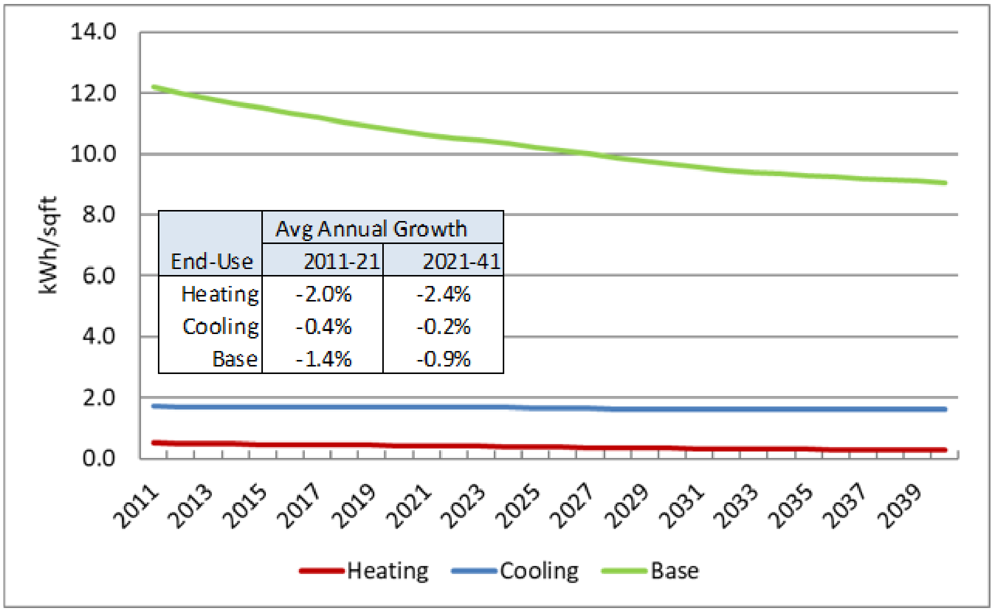


	Avg Annual Growth	
End-Use	2011-21	2021-41
Heating	0.0%	0.5%
Cooling	-0.5%	0.4%
Base	0.1%	0.3%

Heating intensity increases 0.5% annually through the forecast period, reflecting an increasing share in heat-pump saturation. Cooling intensity increases 0.5% annually through the forecast period as overall air conditioning efficiency improvements are offset by increased growth in heat-pump saturation. Total non-weather sensitive end-use intensity increases 0.3% annually.

Commercial end-use intensities (expressed in kWh per sqft) are based on the EIA's East South Central Census Division forecast; the starting intensity estimates are calibrated to CEI South commercial sales. As in the residential sector, end-use energy use has been declining as a result of new codes and standards and utility DSM programs. Figure 30 shows commercial end-use energy intensity forecasts for total heating, cooling, and non-weather sensitive loads.

FIGURE 30: COMMERCIAL END-USE ENERGY INTENSITY



End-Use	Avg Annual Growth 2011-21	2021-41
Heating	-2.0%	-2.4%
Cooling	-0.4%	-0.2%
Base	-1.4%	-0.9%

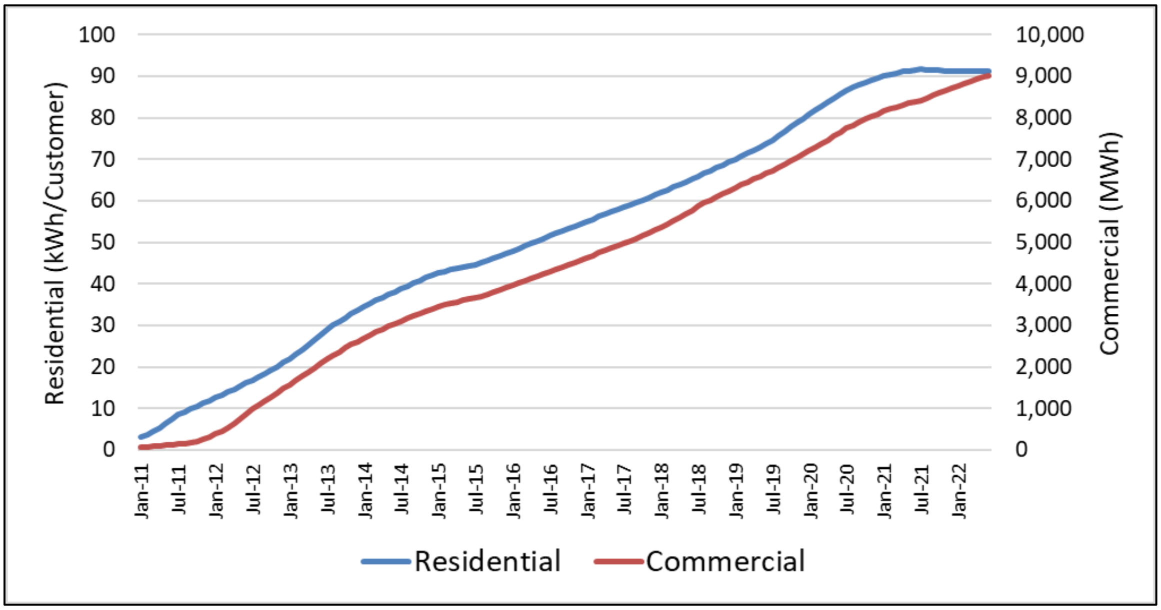
Commercial usage is dominated by non-weather sensitive (Base) end-uses, which over the forecast period are projected to decline 0.9% per year. Cooling intensity declines 0.2% annually through the forecast period. Heating intensity declines even stronger at 2.4% annual rate though commercial electric heating is relatively small.

5.4 HISTORICAL DSM SAVINGS

For more than ten years CEI South has promoted energy efficiency savings through utility sponsored programs. These programs have had a significant impact on electricity usage across nearly all customer classes. The DSM program savings are above and beyond naturally occurring savings, and impact of federal codes and standards.

The residential and commercial models incorporate historical DSM to account for historical program savings. The DSM variables help explain historical usage trends. In the forecast period DSM are held constant, as incremental program savings are modeled on a consistant and comparable basis as supply-side resources in the IRP modeling framework. The DSM variables are based on annual verified DSM savings that are converted to a monthly series. In the residential average use models, DSM is expressed as savings per customer. Figure 31 shows the cumulative DSM saving for the residential and commercial classes.

FIGURE 31: HISTORICAL DSM



5.5 COVID-19 IMPACT

By the spring of 2020, Indiana, like many others states across the country, issued a "Stay at Home" order in response to the COVID-19 virus. This had the impact of significantly reducing commercial and industrial usage as businesses shutdown and significantly increasing residential usage as work activity shifted from the office to the home. As these restrictions were lifted most businesses re-opened, although even today some portion of the workforce remains working from home. To capture the impact, the residential average use and non-residential rate class models include a COVID impact variable. This variable is constructed using Google Mobility Report data for the residential, workplace and retail place types for Vanderburgh County. Google Mobility Report data tracks daily cell phone locations by place type compared to a pre-COVID baseline. The residential place type active increased while the workplace and retail decreased, this data correlates well to the actual changes in electric sales.

APPENDIX A: MODEL STATISTICS

Residential Average Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRevRes.XHeat	1.42	0.026	53.902	0.00%
mStructRevRes.XCool	1.21	0.015	80.281	0.00%
mStructRevRes.XOther	0.95	0.013	71.961	0.00%
mBin.Jan	26.779	8.485	3.156	0.20%
mBin.Aug	49.469	9.532	5.19	0.00%
mBin.Sep	43.299	8.788	4.927	0.00%
mBin.Oct	3577.50%	8.177	4.375	0.00%
mBin.Jun14	-92.799	24.491	-3.789	0.02%
mBin.May16	63.925	24.594	2.599	1.04%
mDSMFcst.ResDSM_Const	-1.105	0.087	-12.658	0.00%
COVID.ResIdx	33.829	16.51	2.049	4.25%

Model Statistics	
Iterations	1
Adjusted Observations	138
Deg. of Freedom for Error	127
R-Squared	0.989
Adjusted R-Squared	0.988
AIC	6.443
BIC	6.676
Model Sum of Squares	6,668,954.77
Sum of Squared Errors	73,915.51
Mean Squared Error	582.01
Std. Error of Regression	24.12
Mean Abs. Dev. (MAD)	17.6
Mean Abs. % Err. (MAPE)	1.89%
Durbin-Watson Statistic	1.657

Residential Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Econ.HHs	980.543	0.366	2677.188	0.00%
mBin.Yr20Plus	2,878.09	100.746	28.568	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	138
Deg. of Freedom for Error	136
R-Squared	0.967
Adjusted R-Squared	0.967
AIC	12.388
BIC	12.43
Model Sum of Squares	942,570,437.63
Sum of Squared Errors	32,157,085.58
Mean Squared Error	236449.16
Std. Error of Regression	486.26
Mean Abs. Dev. (MAD)	369.89
Mean Abs. % Err. (MAPE)	0.29%
Durbin-Watson Statistic	0.3

Commercial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRevCom.XHeat	18.623	1.888	9.866	0.00%
mStructRevCom.XCool	14.93	0.441	33.855	0.00%
mStructRevCom.XOther	1.18	0.013	88.658	0.00%
mBin.Feb	4587.139	1091.1	4.204	0.01%
mBin.Jun	-6175.569	1017.093	-6.072	0.00%
mBin.Oct	3995.709	1027.751	3.888	0.02%
mBin.Jun14	-857584.60%	3204.273	-2.676	0.84%
mBin.Jul19	-12961.405	3133.007	-4.137	0.01%
mDSMFcst.ComDSM_Const	-0.367	0.123	-2.981	0.34%
COVID.ComIdx	-9401.596	1900.935	-4.946	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	138
Deg. of Freedom for Error	128
R-Squared	0.955
Adjusted R-Squared	0.952
AIC	16.124
BIC	16.336
Model Sum of Squares	25,518,480,761.69
Sum of Squared Errors	1,200,949,076.36
Mean Squared Error	9382414.66
Std. Error of Regression	3063.07
Mean Abs. Dev. (MAD)	2428.62
Mean Abs. % Err. (MAPE)	2.38%
Durbin-Watson Statistic	1.744

Industrial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	47659.506	24178.291	1.971	5.08%
mEcon.IndVar	102,632.85	24881.768	4.125	0.01%
mWthrRev.CDD65	66.28	7.912	8.377	0.00%
mBin.Feb	7311.369	4193.517	1.743	8.36%
mBin.Mar	-10732.371	4187.386	-2.563	1.15%
mBin.Nov	19035.26	4472.841	4.256	0.00%
mBin.Oct12	6537566.70%	13177.36	4.961	0.00%
mBin.Nov12	-55445.067	13733.821	-4.037	0.01%
COVID.ComIdx	-7356.898	6361.812	-1.156	24.96%

Model Statistics	
Iterations	1
Adjusted Observations	138
Deg. of Freedom for Error	129
R-Squared	0.552
Adjusted R-Squared	0.524
AIC	19.005
BIC	19.196
Model Sum of Squares	26,784,531,047.87
Sum of Squared Errors	21,728,430,928.25
Mean Squared Error	168437449.1
Std. Error of Regression	12978.35
Mean Abs. Dev. (MAD)	9272.65
Mean Abs. % Err. (MAPE)	5.89%
Durbin-Watson Statistic	2.089

Peak Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mCPkEndUses.HeatVar	3.899	0.36	10.822	0.00%
mCPkEndUses.CoolVar	19.00	0.591	32.179	0.00%
mCPkEndUses.BaseVar	1.44	0.022	66.004	0.00%
mBin.May	-46.444	11.304	-4.109	0.01%
mBin.Oct	-24.704	12.117	-2.039	4.35%
mBin.Jan16	143.733	36.148	3.976	0.01%
mBin.Apr20	-9773.60%	36.14	-2.704	0.78%
mBin.Apr21	-109.766	36.192	-3.033	0.29%

Model Statistics	
Iterations	1
Adjusted Observations	137
Deg. of Freedom for Error	129
R-Squared	0.935
Adjusted R-Squared	0.931
AIC	7.214
BIC	7.384
Model Sum of Squares	2,378,330.01
Sum of Squared Errors	165,515.34
Mean Squared Error	1283.06
Std. Error of Regression	35.82
Mean Abs. Dev. (MAD)	27.74
Mean Abs. % Err. (MAPE)	3.57%
Durbin-Watson Statistic	1.674

APPENDIX B: RESIDENTIAL SAE MODELING FRAMEWORK

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, econometric models are well suited to identify historical trends and to project these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that drive energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal shell integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes the SAE approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The source for the SAE spreadsheets is the 2021 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

RESIDENTIAL STATISTICALLY ADJUSTED END-USE MODELING FRAMEWORK

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \quad (2)$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \quad (3)$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} / Eff_y^{Type} \right)}{\left(Sat_{base\ yr}^{Type} / Eff_{base\ yr}^{Type} \right)} \quad (4)$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{base\ yr} \times SurfaceArea_{base\ yr}} \tag{5}$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \tag{6}$$

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 0-1.

TABLE 0-1: ELECTRIC SPACE HEATING EQUIPMENT WEIGHTS

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	767
Electric Space Heating Heat Pump	127

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps is given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{base\ yr}}\right) \times \left(\frac{HHSize_y}{HHSize_{base\ yr,m}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{base\ yr,m}}\right)^{0.15} \times \left(\frac{Elec\ Price_{y,m}}{Elec\ Price_{base\ yr,m}}\right)^{-0.1} \tag{7}$$

Where:

- *HDD* is the number of heating degree days in year (y) and month (m).
- *HHSize* is average household size in a year (y)
- *Income* is average real income per household in year (y)
- *ElecPrice* is the average real price of electricity in month (m) and year (y)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year. The first term, which involves heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \qquad (8)$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m)
- $CoolIndex_y$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{base\,yr}^{Type} \Big/ Eff_{base\,yr}^{Type} \right)} \quad (9)$$

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 0-2.

TABLE 0-2: SPACE COOLING EQUIPMENT WEIGHTS

Equipment Type	Weight (kWh)
Central Air Conditioning	1,219
Space Cooling Heat Pump	240
Room Air Conditioning	177

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. The estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{base\,yr}} \right) \times \left(\frac{HHSize_y}{HHSize_{base\,yr,m}} \right)^{0.25} \times \left(\frac{Income_y}{Income_{base\,yr,m}} \right)^{0.15} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{base\,yr,m}} \right)^{-0.1} \quad (10)$$

Where:

- *CDD* is the number of cooling degree days in year (y) and month (m).
- *HHSize* is average household size in a year (y)
- *Income* is average real income per household in year (y)
- *ElecPrice* is the average real price of electricity in month (m) and year (y)

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year. The first term, which involves cooling degree days, serves to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \tag{11}$$

The first term on the right-hand side of this expression ($OtherEqpIndex_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term (*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left(Sat_{base\,yr}^{Type} \Big/ \frac{1}{UEC_{base\,yr}^{Type}} \right)} \times MoMult_m^{Type} \times \tag{12}$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- $MoMult_m$ is a monthly multiplier for the appliance type in month (m)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{HHSize_{y}}{HHSize_{base\ yr,m}}\right)^{0.26} \times \left(\frac{Income_{y}}{Income_{base\ yr,m}}\right)^{0.15} \times \left(\frac{Elec\ Price_{y,m}}{Elec\ Price_{base\ yr,m}}\right)^{-0.1} \qquad (13)$$

The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_{k} ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \qquad (14)$$

APPENDIX C: COMMERCIAL SAE MODELING FRAMEWORK

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identifying historical trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency trends and saturation changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations and equipment efficiency levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

This document describes this approach, the associated supporting Commercial SAE spreadsheets, and *MetrixND* project files that are used in the implementation. The source for the commercial SAE spreadsheets is the 2021 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

COMMERCIAL STATISTICALLY ADJUSTED END-USE MODEL FRAMEWORK

The commercial statistically adjusted end-use model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \qquad (2)$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating equipment saturation levels,
- Heating equipment operating efficiencies,
- Commercial output, employment, population, and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m} \tag{3}$$

Where:

- *$XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m),*
- *$HeatIndex_y$ is the annual index of heating equipment, and*
- *$HeatUse_{y,m}$ is the monthly usage multiplier.*

The heating equipment index is composed of electric space heating equipment saturation levels normalized by operating efficiency levels. The index will change over time with changes in heating equipment saturations (*HeatShare*) and operating efficiencies (*Eff*). Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{base\ yr} \times \frac{\left({HeatShare_y}/{Eff_y} \right)}{\left({HeatShare_{base\ yr}}/{Eff_{base\ yr}} \right)} \tag{4}$$

The ratio on the right is equal to 1.0 in the base year. In other years, it will be greater than one if equipment saturation levels are above their base year level. This will be counteracted by higher efficiency levels, which will drive the index downward. Base year space heating sales are defined as follows.

$$HeatSales_{base\ yr} = \left(\frac{kWh}{Sqft} \right)_{Heating} \times \left(\frac{CommercialSales_{base\ yr}}{\sum_e {kWh}/{Sqft_e}} \right) \tag{5}$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting $HeatIndex_y$ value in the base year will be equal to the estimated annual heating sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, commercial level economic activity, prices and billing days. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{base\ yr}} \right) \times \left(\frac{EconVar_{y,m}}{EconVar_{base\ yr,m}} \right) \times \left(\frac{Price_{y,m}}{Price_{base\ yr,m}} \right)^{-0.10} \tag{6}$$

Where:

- *HDD* is the number of heating degree days in month (m) and year (y).

- *EconVar* is the weighted commercial economic variable that blends Output, Employment, and Population in month (m), and year (y).
- *Price* is the average real price of electricity in month (m) and year (y).

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to one in the base year. The first term, which involves heating degree days, serves to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will reflect changes in commercial output and prices, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.18 power).

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling equipment saturation levels,
- Cooling equipment operating efficiencies,
- Commercial output, employment, population, and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$\mathrm{XCool}_{y,m} = \mathrm{CoolIndex}_{y} \times \mathrm{CoolUse}_{y,m} \tag{7}$$

Where:

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m),
- $CoolIndex_y$ is an index of cooling equipment, and
- $CoolUse_{y,m}$ is the monthly usage multiplier.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Formally, the cooling equipment index is defined as:

$$CoolIndex_y = CoolSales_{base\ yr} \times \frac{\left(CoolShare_y / Eff_y \right)}{\left(CoolShare_{base\ yr} / Eff_{base\ yr} \right)} \tag{8}$$

Data values in 2004 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in the base year. In other years, it will be greater than one if equipment saturation levels are above their base year level. This will be counteracted by higher efficiency levels, which will drive the index downward. Estimates of base year cooling sales are defined as follows.

$$CoolSales_{base\ yr} = \left(\frac{kWh}{Sqft}\right)_{Cooling} \times \left(\frac{CommercialSales_{base\ yr}}{\sum_e {kWh}/{Sqft_e}}\right) \tag{9}$$

Here, base-year sales for space cooling is the product of the average space cooling intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space cooling sales value is defined on the *BaseYrInput* tab. The resulting *CoolIndex* value in the base year will be equal to the estimated annual cooling sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, economic activity levels and prices. Using the COMMEND default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{base\ yr}}\right) \times \left(\frac{EconVar_{y,m}}{EconVar_{base\ yr,m}}\right) \times \left(\frac{Price_{y,m}}{Price_{base\ yr,m}}\right)^{-0.15} \tag{10}$$

Where:

- *HDD* is the number of heating degree days in month (m) and year (y).
- *EconVar* is the weighted commercial economic variable that blends Output, Employment, and Population in month (m), and year (y).
- *Price* is the average real price of electricity in month (m) and year (y).

By construction, the *CoolUse* variable has an annual sum that is close to one in the base year. The first term, which involves cooling degree days, serves to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will change to reflect changes in commercial output and prices.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Equipment saturation levels,
- Equipment efficiency levels,
- Average number of days in the billing cycle for each month, and
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherIndex_{y,m} \times OtherUse_{y,m} \tag{11}$$

The second term on the right-hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{base\ yr}^{Type} \times \left(\frac{Share_y^{Type} / Eff_y^{Type}}{Share_{base\ yr}^{Type} / Eff_{base\ yr}^{Type}} \right) \tag{12}$$

Where:

- *Weight* is the weight for each equipment type,
- *Share* represents the fraction of floor stock with an equipment type, and
- *Eff* is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the main equipment categories. The weights are defined as follows.

$$Weight_{base\ yr}^{Type} = \left(\frac{kWh}{Sqft}\right)_{Type} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh / Sqft_e} \right) \tag{13}$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end-uses, constructed as follows:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{EconVar_{y,m}}{EconVar_{base\ yr,m}}\right) \times \left(\frac{Price_{y.m}}{Price_{base\ yr,m}}\right)^{-0.15} \tag{14}$$

Attachment 4.2 CEI South Hourly System Load Data

Dt	Hour1	Hour2	Hour3	Hour4	Hour5	Hour6	Hour7	Hour8	Hour9	Hour10	Hour11	Hour12	Hour13	Hour14	Hour15	Hour16	Hour17	Hour18	Hour19	Hour20	Hour21	Hour22	Hour23	Hour24
1/1/2021	484.5	468.4	460.2	460.5	463	462.7	470	487.6	486.9	484.9	491.8	496.3	487.1	473.4	473.1	452.9	469	484.4	503.3	501.9	486.7	480.6	474.4	448.5
1/2/2021	439.3	440.2	427.3	428.5	430.1	433.3	447.3	463.5	482.3	502.6	519.6	517.6	519.4	502.9	498.8	487.4	495.6	507.3	539	529.2	515.7	508.8	486.9	467.4
1/3/2021	458.3	441.9	435.4	425.2	438.2	437.3	448.6	461.2	477.8	486.7	486	501.6	497.2	501.1	498.9	478.6	493.5	508.4	547.8	552.3	553.1	546.9	530.2	513.3
1/4/2021	510.8	496.7	505.1	504.8	512.6	526.2	562.5	604.5	617.1	603.4	595.4	569.3	555.9	540.3	543.2	526.2	537.8	551.6	569.4	575	579.9	565.7	535.4	516.6
1/5/2021	496.6	486	488	489.4	496.3	510.6	537.9	574.9	600.8	598.3	595.3	579.7	558.9	542.2	541.4	526.7	536	559.6	597.1	588.6	603.7	592	569.6	551.9
1/6/2021	530.3	535.1	529.7	534.2	536.1	544	571.6	617	627.5	621.8	623.5	596.1	583.2	575	569.6	569.8	563.8	584.9	607.9	603.6	602.7	592.7	580.2	552.2
1/7/2021	531.9	535	522	530.4	539	538.8	570.9	614.7	623.8	627.6	624.9	621.2	618.4	610	612.7	611.1	620	620.2	624.9	622.4	611	603.1	578.3	546.3
1/8/2021	529.1	517.1	512.7	514.6	507.8	513.1	542.4	591.7	608.3	607.5	620.1	614	613.4	611.3	608.3	610.6	604.1	604.9	614.1	607.8	594.8	589.2	568.5	545
1/9/2021	521.4	493.8	501.2	507.6	506.9	505.4	519.8	534.4	557.3	564.4	580.8	573.3	578.3	578.9	562.8	569.1	568.9	582.3	593.3	591.5	583.5	580.3	563	539.4
1/10/2021	525.8	505.8	505.8	499	497.3	499	504.7	503.1	508.4	526.8	541.1	546	548	551.4	537.8	550.9	548.5	576.1	589.1	587.8	579.7	575.9	543.9	520.9
1/11/2021	502.1	505.2	491	496.4	506.1	520.2	558.9	613.4	624	646.2	643.8	647	634.6	644.3	638.3	636.9	634.3	653.9	661.6	658.4	644.2	629.2	606.2	576.3
1/12/2021	569.7	553.3	547	555	557.9	573.3	616.8	647.4	665.5	653.5	633.4	620.1	595.9	583.1	564.2	551.3	552	574.4	611.5	617.4	611.9	600.1	587.7	555.7
1/13/2021	545.2	535.8	533.2	528.7	534.7	550.2	580.4	617.2	623	623.4	588.2	583.8	550.3	549.4	537.9	536.7	536.3	559.4	595.7	590.9	581.4	564.3	554.5	521
1/14/2021	506.8	502.7	504.4	507.2	502.9	522.7	543.6	594	608.5	593	588.5	555.5	559.6	550.4	534.9	522.7	524.8	538.8	568.8	553.5	544.6	539.7	526.1	504.1
1/15/2021	486.3	472.2	481.3	472.9	485.9	497.3	535	577	588.7	583.7	563.5	557.5	564.5	561	548.2	565	561.1	572.7	604.4	586.3	587.2	568.6	563.2	532.8
1/16/2021	512.9	504.7	496.9	497.5	492.1	503.6	502.8	515.4	516.4	529.4	530.7	529.9	547.3	538.4	529.6	534.1	527.1	537.2	548.6	545.2	540.9	516.6	509.7	486.8
1/17/2021	469.5	464.4	458.6	452.5	455.6	448.6	458.1	481	490.8	503.7	517.3	529.6	524.7	528.1	526.2	513.1	520.5	523.1	573.8	553.5	542.3	539.7	520.4	509.5
1/18/2021	486	478.6	483	477.3	474.6	488.1	517.9	544.5	551.9	565.5	562.1	547.6	546.9	522.4	515.9	509.1	515	529.2	554.7	559.6	547.6	528	512.1	481.8
1/19/2021	475	462.6	449	458.9	455.9	486.4	515.1	575.6	597.9	597.6	578.4	560.7	539.1	535.4	521.3	514.9	521.7	531.2	555.2	574.5	572.7	566.4	549.2	519.8
1/20/2021	504.5	499.7	500	497.3	502.9	527.8	558.1	617.1	625	616.7	600.8	582.3	566.7	554.4	551.3	551	542.4	570.3	610.7	597.4	585.3	579.8	555.1	528.3
1/21/2021	502.6	501.2	487.9	489.3	484.6	496.1	518.3	570.3	579	582.7	570.3	563.9	548	537.6	523.6	522	520.7	537	572.2	570.6	569.3	563.7	541.1	518.7
1/22/2021	501	495.4	495.7	488.6	494.1	509.3	538.8	580.5	597.6	596.6	586.6	572.4	560.7	548.7	541	532.5	532.3	544.2	583.1	587.3	595	583.2	566.6	546.9
1/23/2021	530.8	524.6	526.2	523.6	528.8	531.2	552.4	563	565	559.4	554.2	532.1	508.6	508.8	492.5	477.2	482	505.5	536.3	532.2	526.9	524	505.4	480
1/24/2021	466.4	465.2	452.1	448.5	444.8	451.1	454.5	472.1	481.4	501.8	515.9	516.9	526.9	505.1	513.9	498	504.4	513.3	544.9	536	525.5	513.5	490.8	473
1/25/2021	453.9	444.3	446.8	444.4	456.9	471.2	510.7	565.7	587.5	608.2	615.9	614.8	625.4	632.3	620.5	606.1	608.1	602.4	611.3	605.5	585.9	562.4	549.8	510.8
1/26/2021	488.1	483.2	479.4	470.7	477	487.1	507	557.5	569	569.9	565.6	566.7	570.4	575.6	566.9	563.4	571.3	580.7	596.6	596.5	595.9	588.6	557.8	535.7
1/27/2021	510.9	505.9	498.2	503	503.9	520.1	554.1	593.3	608.6	615.9	610	616.4	620.6	615.2	616.2	615.1	626.5	634	645.8	650.2	642.6	634.2	609.9	579.7
1/28/2021	558.2	561.9	554.2	551.4	562.7	575.7	606.3	658	664.7	652.1	653.1	626.8	627.5	606.3	596.3	581.8	583.7	598.5	630.8	648.6	648.6	642.4	626.6	604.8
1/29/2021	586.2	585.5	576.5	572	583.2	596.9	623.2	654	671.2	649.4	630.4	603.4	585.2	574.2	567.5	544.4	536	550	587.5	594.7	586	590.1	576.8	544.3
1/30/2021	525.2	516.1	509.9	503.9	505.3	513.8	514.2	520.6	522.4	537.7	546	542.1	535.2	536.2	528.9	531.2	538.3	541.3	551.7	558.1	550.7	536.8	521.5	493.8
1/31/2021	467.9	456.6	452.4	434.2	424.8	426.4	416.9	433.1	441.7	480.2	494.8	498.5	516.5	516.3	522.7	521.2	528.8	545.2	571.7	567	557.4	554.4	538.8	509.8
2/1/2021	494	489.7	491.2	494.8	495.5	510.9	555.8	608.4	623.8	624.6	633	636.1	630.3	629.3	623.8	612	605.7	625	639.9	643.2	632	632.8	614.3	573
2/2/2021	556.7	546.9	549.2	549.3	551.2	559.2	596.5	634.9	641.7	628.1	617.8	608.8	599.7	602.4	597.5	587.9	588	606.8	625.4	619.8	613.3	601	582.3	560.1
2/3/2021	543.6	530.5	543	539.7	549.5	566.9	591.3	636.4	644.1	626.1	592.8	584	570.6	560.9	542.2	544.8	543.5	555.6	578.1	589.8	602.1	596.4	587.1	565.6
2/4/2021	539.3	539.5	535.5	528.8	534.6	537.9	559.8	601.6	606.3	618.1	614.8	605.8	619.9	627.2	622.4	613.3	608.4	600.4	610.3	611.7	586.5	589.7	578.1	554.8
2/5/2021	534.6	528	522.6	533.9	536.8	548.2	574.6	622.7	627.1	628.4	647.8	641.2	650.5	618.2	563.5	539.5	531.4	536.6	575.2	583.5	566.5	561.9	543.8	527.6
2/6/2021	508.2	498.7	490.3	493.2	499.6	504.1	518.5	536.4	542.2	556.5	554.2	554.4	540.2	507.4	502.3	495.7	501.1	511	543.8	556	549.6	551.9	535.5	522.3
2/7/2021	514.1	505.6	500.3	508.8	517.5	524.8	552.7	568.5	587	594	590.6	579.1	591.2	578.4	575.1	568.8	557.4	579.9	617.8	625.7	615.9	627.1	599.5	585.8
2/8/2021	563.9	553.2	546.4	541.2	543.8	558	587	626.8	653	644.5	637.6	611.5	599.3	583.6	588.3	601	597.7	607.8	625.9	628.2	625	616.1	587.7	574.4
2/9/2021	549.9	542.5	532.8	533.5	538.5	540.9	568.9	614.4	636.2	647.6	652.6	667.5	657.5	657.9	654.4	647.3	640.3	642.5	662	665.6	664.6	649.6	626.1	599.3
2/10/2021	574.5	564.9	551.7	554.6	562.8	562.9	588.7	636.1	648	655.2	663.9	669.6	678.2	656.5	669.9	663	646.7	651.7	666	652.1	653.8	644.8	613.9	597.8
2/11/2021	580	588.8	572.8	588.4	579.2	586.6	607.1	631.4	658.6	657.3	659.3	663.7	653.9	654.4	640.9	643	640.4	636.6	652.6	661	646.5	643.4	619.7	598.4
2/12/2021	578.5	573.1	567.1	573.9	557.8	568.7	589.2	622.9	636.2	652.4	652.6	653.7	637.4	655.1	637.5	644.9	635.8	646.4	653.6	654	652.2	645.8	636.5	615.6
2/13/2021	600.6	587.2	589.1	589.4	592.4	592.8	594.4	612.1	623.4	648.9	651.7	658.5	656	663.9	654.5	651.6	646.2	660.4	669.8	675.3	667.1	670.6	657.4	638.2
2/14/2021	613.1	610.4	613	619.5	608.8	615.3	641.4	646.2	667.7	679	677.7	675.6	669.8	648.9	632.9	625	629.6	639.4	666.9	688.2	674	671	660.5	644.5
2/15/2021	631.5	621.7	624.6	626.2	637.3	642.4	678.5	707.8	718.9	736.6	741.6	736.1	743.1	734.1	712.8	708.5	681.5	673.6	691	697.1	680.7	661	642.1	619.7
2/16/2021	600.8	596	602	600.3	610.8	629.3	644.6	669.9	668.9	670.3	655.7	655.9	647.8	629.8	628	617.1	607.6	628.3	667.3	690.4	679.5	687.3	676.5	650.6
2/17/2021	639.7	635.6	626.3	626.3	631.4	649.4	665.3	695.2	706.6	718.5	703.9	687.6	680	658.5	652	655.3	654.3	652.9	670.4	680.9	656.1	658	639.2	613
2/18/2021	590.9	585.6	581.9	576.5	587.7	597.7	612	636.3	655.7	657.1	657.6	651.4	641.2	636.4	616.5	617.6	612.1	617.4	652.3	664.7	659.1	650.2	638	622.2
2/19/2021	599.5	602.2	600.3	607.4	610	628	650.6	683.4	691.1	679.4	659.8	642.2	628	618.2	611.5	596.9	598.1	601	632.7	657	661.5	658.3	650.3	634
2/20/2021	622.8	620.8	622.4	630	626.5	633	646.8	653.3	650.4	638.1	620.4	601.1	563.5	546.4	535.1	519.1	517.8	525.8	559.7	597.6	579.1	577.5	554.7	550.3
2/21/2021	543.2	536	528.6	528.4	521.9	533.2	540.3	547.9	548	566.8	553.9	531.6	523.3	519	512.4	503.3	509.4	521.7	549.8	563.4	550.1	536.4	506.7	485.7
2/22/2021	465.6	461.6	459.7	456.5	461.9	479.2	524.1	559.1	580	589.8	580.2	585.8	560.7	550.4	543	533.2	517.4	532.4	555.2	584.9	578.6	568.4	553.6	527.4
2/23/2021	506.1	498	493.1	497.9	499.3	512.3	541.7	563.5	585.3	574.2	544.1	536	524.5	513.3	507.8	498.1	498.4	489.1	519.2	539.2	550.2	537.1	518.2	508
2/24/2021	475	472.2	459.6	460.9	468.7	471	503	537.1	541.8	545.2	541.2	529.6	516.5	519.8	519.7	510.4	509.8	491.6	513.9	540.3	537.5	520.1	509.3	487.4
2/25/2021	462.4	465.9	457.7	463.5	470.1	495	530.7	561.9	565.7	566.4	542.5	536.3	526.1	506.4	504.6	503.6	496.4	508.9	527.2	547.2	549.4	553.9	528.7	503.6
2/26/2021	488.8	476	476.3	483.9	492	494.5	522.7	558.9	567.9	576	578.8	574.5	555.1	558.8	552.3	547.4	549.3	543.9	556.9	560.1	548.1	541	523.2	498.2
2/27/2021	464	457.5	447.9	438.4	443.6	437	444.2	454.6	460.3	456.4	453	454.6	450	448.1	437.1	439.2	436.2	446.5	472	470.1	465.8	461.9	439.2	422.2
2/28/2021	405.7	384.8	389.3	384.5	377.6	383.2	394.4	396.8	412	428.6	431.8	442.1	443.1	440.9	432.6	433.8	443.1	457.1	478.2	481.9	474.4	453.8	436.9	409.3
3/1/2021	404.2	406.8	407.6	407.6	424	445.4	481.7	529.5	564.1	575.2	555	559.8	555.7	553.7	548.8	526.4	527.1	523.5	550	574.9	572.7	564.3	553.9	528.7
3/2/2021	515.7	508.1	513.6	510	518.3	531.1	561.6	604.3	615.7	588.5	577.9	556.9	539.4	536.4	519.6	513.4	515	514.8	534.4	566.4	567.3	575.6	552.8	543.3
3/3/2021	515.1	518.7	518.7	519.3	519.5	535.3	558.5	595.1	593	576.8	559.7	539.4	567.3	581.8	579.2	557.1	562.2	554.2	565.5	589.1	595.5	583.2	577.3	539.8
3/4/2021	530.1	519.2	511.6	525.2	526	545.1	572.2	607.2	604.2	602.1	585.2	577.6	571.2	568.7	560.3	564.8	550.1	562.3	572.6	590.8	596.2	549.6	504.6	479.3
3/5/2021	471.4	460.1	466.2	470	475.8	482	517.2	553	569	570.1	559.4	538	525.2	515.5	504.5	499.8	500.7	507	513.5	538.8	537.5	528.6	515.1	499.2
3/6/2021	478.8	470.3	474.1	470.4	474.3	475	482.1	486.1	490.3	480.6	475.2	462.2	444.7	443.8	430.4	426.3	425.2	424	449.8	469.6	466.5	474.7	455.8	448.3
3/7/2021	435.1	426.8	433.7	419.6	437.8	436.6	455.9	461.8	467.1	460	443.7	431.7	423.8	417	409.4	400.3	403.2	420.8	436.3	470.7	468.9	465.8	448.8	434.8
3/8/2021	420.3	420.5	422.4	424.8	429.3	451.2	496.8	533.7	541.1	530	524	516.7	507.7	502.1	497.2	495.6	484.4	490	489.5	522.5	515.1	508.4	483.2	464
3/9/2021	442.7	441.9	440.3	438.9	438.5	458	488.9	518.6	528.2	527.3	517.1	511.8	507.5	503	489.9	490	485.5	481.5	492	520.6	515.8	495.9	483.9	462.5
3/10/2021	437.7	427.3	424.2	420.1	423.1	435.8	456	488.5	498.6	511.9	511.4	506.3	504	513.4	509.1	495.5	498.9	496.9	498.9	513.7	518.9	501.5	483.8	453.3
3/11/2021	435.1	414.7	416.5	403	410.1	413.5	430.7	468	488.8	501.7	503.3	513.2	498.4	527.7	509.1	510	506.6	513.3	522.9	526.8	519	506.7	482.1	461.7
3/12/2021	437.7	417.7	419.6	414.7	417.8	432.6	449.3	477.6	497.2	515.5	515.4	511.4	500	540.9	497	495.1	492.9	485.3	492.4	502.6	502.7	497.2	476.3	459.5
3/13/2021	425.3	416.4	415.3	407.3	406.3	407.9	409.2	419.7	437.3	448.5	456.9	450.9	452.2	443.3	440.4	440	434.7	431.9	444.8	466.4	464.7	459.2	440	424.9
3/14/2021	377.2	410.1	381.1	384.9	387.8	390.5	404.1	403	422.5	441.2	444.1	450.4	452.2	456.7	448.6	442.2	460.2	462.7	472.2	482.7	475	456.9	434	430.7

Dt	Hour1	Hour2	Hour3	Hour4	Hour5	Hour6	Hour7	Hour8	Hour9	Hour10	Hour11	Hour12	Hour13	Hour14	Hour15	Hour16	Hour17	Hour18	Hour19	Hour20	Hour21	Hour22	Hour23	Hour24
3/15/2021	407.2	403.8	399.9	407.6	424.4	453.9	513.4	527.2	547.4	555.2	564.1	554.2	551.4	545.1	539.1	524	527.9	512.8	519.3	535.4	537.1	512.8	489.8	469.9
3/16/2021	450.9	449.2	443.7	442.5	446.7	475.7	511.7	532.1	525.2	542.8	527.4	529.1	528.5	521	518.5	504	505.6	506.8	510.3	530	530	513.5	486.1	455.4
3/17/2021	454.8	442.9	445.5	440.2	452.7	482.4	520.1	533.3	540.5	538.7	538.3	536.5	525.5	518.8	535.3	528.9	518.6	518.7	522.5	528.1	522.6	506.7	473.5	451
3/18/2021	447.8	433.9	424.7	427.4	430.3	457.5	492.2	513.7	509.9	513.2	518.3	517	513	507.8	515.8	505.8	506.5	505.2	517.8	535.7	531.2	522	499.9	476.8
3/19/2021	467.9	463.6	457.7	464.7	475.1	503.1	546.1	562.5	566.9	563.6	544.7	531.9	515.6	519.8	493.9	485.7	480.9	476.8	487.6	516.3	515.4	506.5	491.1	466.2
3/20/2021	458.7	461.2	453	455.5	457.5	464.1	479.5	487.2	481	470.3	459.5	440.6	432.6	419.2	421	414.1	412.8	417.3	427.2	441.9	438.1	433.6	416.5	412.4
3/21/2021	395	393.3	397.2	390.7	391.8	407.6	437.5	433.6	442.2	422.6	413.7	404.4	410.3	397.4	398.5	402.4	403.7	415.7	425.3	433	439.3	431.6	405.1	383.7
3/22/2021	381	376.9	378	386.9	401.3	432	478.4	490.8	497.7	497.8	491.2	489.5	484.2	479.2	487.2	478.5	478.9	474.7	472.6	492.6	498.4	476.5	452.2	425.7
3/23/2021	416.3	409.9	402.9	397.7	410.3	430.2	456.4	478.1	485.5	489.7	488.3	497.6	492.3	504	493.9	492.1	492.3	490.7	497.8	507	502.7	485.2	457.6	437.5
3/24/2021	433.1	418.6	411.6	415.1	420.5	430.3	466.1	488.5	489.6	501.4	501.4	500.8	501.8	506.2	505	496.3	498.9	495	493.5	515.1	516.5	492.7	466	433.7
3/25/2021	418.3	411.3	405	403.7	410.7	427.3	470.5	486.1	498.9	519.1	528.9	517	508.7	509.7	506.4	506.6	505	512.5	512.6	514.2	515.2	487.2	467.9	445.5
3/26/2021	427.4	423.4	414.4	407.5	416.2	431.1	458.3	482.4	497.1	503.4	507.7	504.9	497.6	490.1	482.3	477.6	466.7	452.6	455	471.1	473.2	468	445.5	428.1
3/27/2021	412.7	405.7	403.4	408.1	402.5	401.9	413.9	417.9	428	436.1	425.1	429.8	422.3	423.6	433.5	436.7	448.9	455.3	448.8	465.3	454.2	437.2	425.3	395.8
3/28/2021	381.6	363.8	353.6	354.7	349.7	357.2	359.3	371.7	388.6	406.8	405	412.8	414.7	406.6	410.9	415.2	413.5	429.8	432.1	451.5	467.1	454.7	421.8	409.7
3/29/2021	407.7	403	400.8	416.8	440	473.9	528.3	541.1	532	518.8	512.3	499.9	490.4	488	483.3	485.4	472.9	472.1	486.8	497.4	501.5	483.2	454.4	427.1
3/30/2021	420.7	420.8	418.7	416.3	426.5	451.1	496.7	505.3	504.3	497.8	493.9	491.2	492.3	490.8	494.9	491.8	498.8	504.3	504.2	505.7	506.6	484	453.1	428.3
3/31/2021	421.9	413.4	403.4	402.7	412.9	437	483	499.9	508.9	507.6	502.8	502	507.2	510.6	503.8	496	489.5	482.5	496.5	520.6	534.6	514.5	496	476
4/1/2021	465.8	464.3	464.8	472.2	483.4	534.1	560.7	566.4	574.9	552.9	547.2	547.6	534.5	522.2	521	504.9	503.1	501.2	506.2	542.5	551.9	534.1	513.5	487.8
4/2/2021	482.5	482.7	483.2	487.8	495.5	517.4	550.1	549.5	539.5	528.7	516.3	497.6	489.2	473.6	465.8	459.1	449.4	454.6	454.3	474.8	494.7	481.4	476.6	453.4
4/3/2021	445.3	440.2	436.7	441.5	443.8	448.7	458.4	451.6	450.1	440.3	439.8	415.3	408.4	406.9	402.7	403.5	406.8	413	412.6	431.3	428.6	426.2	396.1	384.4
4/4/2021	367.3	364.5	365.3	360.3	367	384.9	390.8	399.6	403	405.4	402.5	397.8	395.7	381.5	389.8	394.7	399.7	416.3	418.6	434.5	434.4	418.4	393.6	368.6
4/5/2021	362.7	353.2	357.1	361.9	369.4	407.1	451.1	477	485	487.4	500.6	505.9	511.6	520.3	522.3	525.7	521.2	522.1	512.5	543.7	530	501.5	468.7	442.2
4/6/2021	421.6	408.7	402.5	399.8	411.3	432.8	465.9	482.9	495.9	505.7	510	521	538	546.5	556.7	562.4	557.7	559.4	554.4	564.9	556	528.7	481.7	458.1
4/7/2021	428.2	425.1	411.8	408.7	424.7	443.3	482.4	497.7	511.2	534.6	540.6	561.6	581.3	575.9	565.5	590.5	589.5	579.7	579.9	579.9	574.8	553	513.1	479.3
4/8/2021	461.7	447	437.7	431.8	428.1	445.8	478	495.6	506.1	518.9	528.7	522.1	520.7	522	520.5	513.7	503.3	500.7	509.7	511.5	517.5	491.1	468.3	436.6
4/9/2021	420.7	411.6	411.4	405.5	412.9	427.1	470.1	481.3	492.4	496.7	507.4	512.1	522.5	542.4	546.6	552.7	556.9	539.4	534.4	548	535.4	507.5	469.5	431.3
4/10/2021	422.1	408.9	399.1	388.4	380.4	383.3	386.3	391.7	410.4	435.8	445.7	438.3	449.2	439.8	437.2	439.4	442.4	435.7	430.2	433.7	435	421	394.6	368.9
4/11/2021	358.1	345.5	346	346.8	335.7	351.4	354	371.3	387.6	407.5	414.7	415.2	404.1	409.2	405.7	403.6	402.9	415.6	427	429.2	432.7	417.7	394.6	376.5
4/12/2021	364.2	362.4	372	374.4	385.9	420.4	455	481.5	481.7	483.1	488.1	482.9	493.7	499.4	495.8	497.3	500.4	505.8	492.8	507.4	515.2	483.8	454.3	419.5
4/13/2021	411.9	401	391.8	398	398.2	424.5	450.3	468.7	479.7	494.3	494.6	491.1	495	495	488.6	502	483.5	486.3	487.2	501.1	496.8	476.2	446.6	429.3
4/14/2021	409	406.4	400.1	399.7	398.7	423.7	469.9	486	504.4	499.3	505.2	500.3	505.9	493.6	492.9	491.6	486.5	488.7	482.4	504.2	505.8	481	447.5	431.7
4/15/2021	419.2	421.7	408.3	418.1	416.4	448.3	495.3	506.7	508.5	507.7	501.4	495.9	502.7	493.6	489	491.5	481.1	475.3	473.7	492.3	498.1	486.6	462.2	433.9
4/16/2021	430.7	425	416.7	430.4	420.5	452.3	482	492.5	501.2	495.3	499.5	490.8	486.4	485.4	480.3	482.5	477	476.9	470.3	479	483.2	459.9	442.7	412
4/17/2021	411.4	398.8	383.6	388	386.1	392.1	394.4	412.7	420	431.5	439.4	432.5	435.4	434.1	426.1	421.8	425.1	423	431.7	442.4	436.4	423.6	408.7	392.8
4/18/2021	373.4	376.5	370.7	368.3	374.8	383.3	392.7	404.3	409.3	408.7	408.4	404.6	411.9	413.9	419.7	424.8	429.4	442.2	440	457.5	441.8	429.6	406.4	388.6
4/19/2021	390.5	377.2	388.6	391.1	410.3	452.2	489	497.3	503.3	506.6	507.6	507.1	490.5	492.3	485.8	501.2	507.1	500.2	507.7	512.3	514.7	493.1	458.7	434.1
4/20/2021	416.8	408.7	413.1	410.3	424.4	444.8	485.1	505	501.4	511.3	496	498.9	504.9	501.5	503.1	502.2	488	491.9	508	530	535	530.7	510.9	487.6
4/21/2021	474	471.5	473.2	473.9	488.8	476.3	532.6	558.4	558.8	548.1	540.3	537.8	526.3	521.9	506.5	508.6	500.1	503.7	519.8	516.2	530.2	517.2	498.5	470.6
4/22/2021	452.5	450.4	452.8	456.5	467.7	500.9	526.5	543	534.7	532.2	519.9	509.2	512.2	505.2	498.4	489.3	488	478.3	486.1	498.9	512.5	496.8	464.7	441.1
4/23/2021	434.5	429.3	425.8	421.9	430.3	450.6	484.4	498.6	507.9	501.4	503.4	498.1	496.3	494.7	489.1	473.8	471.4	457.4	462.5	475.5	482.4	467.1	452.1	423.1
4/24/2021	403.3	396.8	388.8	384.3	381.6	388.1	387.9	413.4	433.5	444.2	458.8	457.9	461	450.6	456.8	448.1	438.2	447.3	444.6	447.3	460.3	436.7	424	399
4/25/2021	388.8	385.5	379.5	378.4	377	389.5	383.8	406.7	409.5	418.9	417.7	423.2	415.6	419.2	419.2	426.9	438	451.9	448.7	451.5	465.4	439.3	414.6	389.1
4/26/2021	373.4	375.4	371.8	386	404.8	429.7	471.8	494.4	501.7	507.4	500	513.6	522.2	532.9	533.9	543.2	537.9	537.8	541.6	540.9	546.9	516.5	488.7	452.8
4/27/2021	438.9	430.8	423.5	410.5	393.9	423.4	470.4	498.9	534.8	535.5	540.9	550.6	561.6	575	579.8	596.7	591	589.2	586.3	596.5	611.2	575.2	539.9	507.9
4/28/2021	491.8	468.7	457	456.7	456.7	467.9	507.4	534.3	549.1	570	591.5	601.5	614.6	616.2	604.8	610.4	630.5	594.7	597.6	597.7	588.2	573.8	534.5	494.6
4/29/2021	485.4	466.9	467.6	470.5	477.8	474.8	511.7	539.2	541	565.5	576	568.7	579.7	578.6	570.2	559.8	548.5	532.2	526.6	523.3	532.3	506.7	473.1	438.3
4/30/2021	430.7	421.7	408.6	414.8	405.2	423.4	447.1	480.5	499.3	506.6	516.5	523.9	531.4	538.7	543	544.4	542.1	546.4	527.8	517.1	525.5	499.3	468.5	471.9
5/1/2021	495	485.2	471.4	471.7	466.7	473.5	472.7	478.9	496.3	496.5	508.9	503.3	513.7	517.1	524.3	544.3	554.6	565.6	560.4	557.5	558.5	536	518.2	488.9
5/2/2021	470.2	459	454.6	449.3	444.2	448.6	445	462.6	476.9	503.5	510.9	522	524.2	531.9	534.1	536.3	543.4	547.8	554.1	558	547.2	537.3	514.5	489.1
5/3/2021	479.8	466.4	472.4	475.7	486.8	520.5	555.3	589.8	604.7	618.6	621.8	627.8	631	641.7	657.9	673	678.5	692.8	683.4	687.1	689	662.3	623.1	580
5/4/2021	569.8	547.7	547.3	544.6	539	555.2	583.5	610.5	610.6	633.2	635.3	653.4	652.8	659.1	661.9	666.5	649.2	639.8	637.4	618.8	619.8	595.2	569.6	536.5
5/5/2021	521.1	509	500.4	495	505.4	521.4	553.7	568.8	590	591.5	598.5	598	599.8	600.1	591.8	601.9	594.4	593.8	581.2	589.5	608	572.9	549.1	517.1
5/6/2021	503.8	494.1	496.8	497.2	502.5	525.9	542.8	574.2	576.3	583.9	591.3	595.5	595.6	599	608.4	602	579.3	584.6	581.1	584.8	590.3	573.9	548	515.2
5/7/2021	503.4	499.9	496.5	492.5	500.7	520.4	548.7	564.6	567.6	570.6	572.4	573.2	574.2	579.2	571.2	580.2	571.8	570.7	562.2	573.6	586.2	567.1	539.1	508.4
5/8/2021	493.5	483.1	467.3	467	465.5	460.9	462.8	473.2	491.4	491.3	504	501.8	503.4	493.2	498.5	511.1	501.8	504.7	509.5	507.8	517	506.1	490.6	470.8
5/9/2021	447	441.5	439.7	440.1	433.6	439	454.5	474.5	489.1	507.3	505.1	523.9	519.4	518.4	502.6	508	499.9	508.2	516	529.2	523.7	521.8	496.9	475.6
5/10/2021	467.7	462.4	469	472.8	483.6	518.5	550.4	576.2	590.6	589.1	600.8	585.7	602.6	599.6	598.5	602.3	603	588.9	590.3	596.7	613.8	577.1	552.5	520.5
5/11/2021	510.4	501.6	500.1	495.9	514.9	537.9	571.5	586.8	600.3	605.5	608.1	603.2	604.4	611.7	605.3	605.4	601	598.7	592.3	597.8	605.7	587.1	549.8	527.6
5/12/2021	505.7	506	506.9	502.5	504.9	531	564.8	583	584.6	592.3	597.3	590	590.2	593	588.8	586.3	582.7	577.3	585	584.5	594.9	577.3	545.7	518.4
5/13/2021	498.1	494.5	490.1	494.6	509.5	522.5	558.8	576.6	581.4	586.6	587.8	586.5	590.7	594.6	599.7	589.4	599.2	585.5	590.8	587.3	595.8	575	551	519.9
5/14/2021	501.4	491.7	488.8	492.4	502.8	517.6	552.1	565.3	581.1	591	598.8	601.4	595	609.2	597.5	601.6	597	603.2	594.7	587.3	594.6	570.3	549	498.8
5/15/2021	500.8	490.7	483.4	478.6	482.9	489	487.3	496.4	506.8	523	524.7	522.5	533.2	541.1	530.7	537.1	527.3	542.7	536.7	534.6	536.7	521.1	498.6	482.3
5/16/2021	465.4	453.9	446.1	448.2	448.1	445.4	452.9	468.7	483	504.5	509.2	516.9	528.7	536.7	547.7	567.1	583.9	591.5	593.4	589.4	600.7	578.6	546.3	514.4
5/17/2021	497.7	490.5	481.5	485.1	490.7	517.7	560.7	584.5	611.8	613.7	633.1	651.3	665.9	680.4	679.4	680	661.6	642.8	643.8	652.1	643.8	623.7	583.5	549.8
5/18/2021	532	519.5	523.8	508.9	520	531	619.9	604.8	616	636	647.3	664.4	682.3	689.3	702.4	693.2	684.9	664.1	669.8	661.4	672.6	653.5	622.4	579.9
5/19/2021	559.7	543.6	539.7	537.7	535.7	557.6	601.5	618	636	638	664.2	666	688.8	684.8	720.1	723.2	736.1	722.2	717.8	709.5	716.4	700.1	649.4	607.8
5/20/2021	593.1	567.9	550.3	542.3	546.1	555.8	591.6	628	663.4	689.8	706.7	745.4	759.5	799	806.9	815.9	804.6	783.1	765	737.3	728.5	702.5	644.6	602.3
5/21/2021	563.6	545	523	523.3	520.4	533.4	553.5	597.6	628	662.4	686.3	707.8	720.1	749.2	753.7	749.5	780.6	740.7	709.8	691.4	676.7	641.9	607.5	560
5/22/2021	524.1	513.3	494.5	490.2	475	483.7	481.2	524.2	558.2	598.2	635.1	672.8	703.7	727.7	748.4	754.7	747.4	747.7	726.5	702.6	690.3	668.7	611.2	580.3
5/23/2021	543.3	518.5	498.6	486.8	471.7	458.1	462.4	500.8	535.9	573.8	617.7	663	689.3	725.7	731.8	750.3	766.5	769.6	754.8	735.2	707.8	675.1	620.3	574
5/24/2021	539.7	515.7	502.4	497.7	500.1	523.1	561.9	592.4	645.9	680.4	738.8	777.3	798.7	833.4	847.2	863.3	864.1	866.4	829.5	806.7	774.1	743.7	677.8	620.7
5/25/2021	586.6	563.2	544.8	535.4	534.7	548.1	575.2	623.6	668.9	718.6	774.4	802	837.8	859	871.7	883.7	884.1	875	846.1	815.3	799.1	771.7	701	662.5
5/26/2021	616.1	594	577.5	565.1	561	571.8	610.7	637.8	651.8	653.2	675.9	668.3	674.9	692.5	704.4	706.4	722.9	733.4	727	720.2	715.5	690.2	642.5	588.7

Dt	Hour1	Hour2	Hour3	Hour4	Hour5	Hour6	Hour7	Hour8	Hour9	Hour10	Hour11	Hour12	Hour13	Hour14	Hour15	Hour16	Hour17	Hour18	Hour19	Hour20	Hour21	Hour22	Hour23	Hour24
5/27/2021	563.5	545.6	532.6	523.9	526.5	537.4	574.5	601.8	633.6	657.3	700.3	730.5	762	787.6	808.1	826.8	817.2	806.3	775.1	758.5	721.7	684.1	640.4	599.9
5/28/2021	572	547.5	544.2	532.1	539	547.5	574.6	607.2	628.5	642.3	622.3	677.7	687	694.1	683.1	611.3	505.5	508.8	494.3	545.5	512.7	499.8	521.3	460.2
5/29/2021	404.9	395.5	388.3	387.3	375.5	378.3	366.4	377.5	387.3	401.5	430.2	412.6	419.4	412.9	408.6	406.8	415.1	411.1	415.8	412.2	425.3	418.1	394.3	379.1
5/30/2021	362.4	356.6	358.1	346.9	348.9	347	352.5	363.2	377.6	386.4	395.6	396.9	402.3	402.4	409	417.4	424.4	430.7	429.6	416.7	429.6	419.7	390.2	377.7
5/31/2021	358.9	349.6	347.8	338.9	341.7	340.5	351.4	360.5	382.4	399.5	411.5	425.3	441.3	445.8	461.3	481.4	491.7	507.1	492.6	496.4	485	469.4	437.9	409.1
6/1/2021	393.2	386.8	378	381.7	388.4	414.3	448.1	486	506.1	520.8	541.7	553.4	554.4	563.6	556.9	557.7	545.7	537.3	541.2	548.6	541.1	524.3	495.3	467.4
6/2/2021	448.7	436.9	433.8	424.7	429.8	451.2	475.7	507.9	527.8	542.6	559	560.9	568.9	579.1	581.7	596.3	589.1	591.8	589.5	588.1	588.8	573.6	532.7	503.7
6/3/2021	475.3	466.2	454.7	451.9	451.6	464.4	495.2	517.5	546.4	559	563.6	573	595.9	591	585.8	601.8	607.6	611.7	613.6	595	599.9	581.1	534.4	498
6/4/2021	473.4	456.8	440.1	440.1	438.5	447.7	469.7	518.1	552.8	583.3	625.6	646.2	676.9	706.8	722.2	741.4	742.9	729	717.2	685.3	666.4	632.1	584.1	539.4
6/5/2021	502.8	490.5	463.8	451.6	444.6	430.8	435.2	465.1	492.7	546.9	587.2	622.8	647.3	676.2	695.3	712.2	723.2	719.6	708	677.6	646.1	618.6	569.9	531.7
6/6/2021	493.6	465.6	446	447.7	444.2	436.7	442.2	458.9	496.7	539.3	591.6	633.9	664.6	678.9	653.5	640.2	640.2	634.2	619	609.5	605.9	593.5	560.2	517.4
6/7/2021	495.6	471.3	462.7	469.9	476.4	495.3	540.7	576.2	620	646.1	677.4	692.2	716.4	740	761.9	771	784.9	779.9	766	742.4	724.3	697.7	646.6	596.1
6/8/2021	568.4	540.1	524.5	519.9	520.4	531.4	567.1	606.7	617.9	634.5	660.1	666.1	684.7	686	706.4	716	716.3	708.8	701.3	688	695.5	669.1	635.3	586.2
6/9/2021	564.2	542.1	523.6	517.1	521.5	533.2	564.5	592.1	619.5	640.8	664.7	692.4	732.7	758.3	762.3	747.9	731.6	725.2	736	721.4	713.5	689.4	644.4	588.9
6/10/2021	556.6	536.2	519.4	511.8	521.4	530.7	559.6	612.8	632.1	678.9	715.1	743.3	758.3	752.6	726.7	714.3	702.4	690	687.3	683.4	661.6	650.2	611.9	562.6
6/11/2021	537.2	511.5	505.8	498.3	497.6	511.8	538	591.2	625.3	679.5	735.5	764.4	781	826.6	853.7	866	868.1	866.5	840	823.6	787.9	750.2	686.4	636.9
6/12/2021	581.4	559.1	530.5	514.1	508.7	495.6	512.1	562.6	631.4	689	742.6	793.2	823.8	856.3	869.9	882.9	885.6	871.1	863.8	831.4	814.8	760.2	705.7	658.8
6/13/2021	603.1	573.4	548.7	521	506.6	486.9	492	525.3	574.7	630.7	675.7	712.6	762.7	790.5	799.6	825.2	817.1	820.3	806.3	772.5	731.9	702.4	638.9	582.3
6/14/2021	537	497.2	485.2	463.6	466.3	479.8	519.8	575.5	626.5	677.8	718.2	767.2	807.9	854.7	883.8	902.9	912.5	899.6	870.5	828.6	777.5	739	669.2	603.6
6/15/2021	560.3	517.9	497	480.5	473.2	479.9	495.2	557.1	586	624.4	656.1	686.4	709.9	734.4	754.6	764.1	754.7	760.9	745.8	719.6	693.8	660.5	607.4	558.5
6/16/2021	516.6	497.5	483.7	478.2	475	478.5	501.9	543.9	577.8	620.1	640.5	680	704.9	748.2	773.1	798.5	798.5	801.7	783.6	746.6	718.7	672.1	617.2	551.6
6/17/2021	511.4	501.2	477.8	472.3	468.4	478.2	508	564.6	596.1	652.3	686.2	727.9	762.9	796.4	829.8	853.9	855	846.1	839	803.5	767.9	732.6	673.2	632.1
6/18/2021	587	571.2	550.2	540.9	546	550.8	579.6	635.4	692.9	754.8	805	854.1	884.1	918.9	935	953.8	940.4	929.5	899.5	860.4	844.4	796.1	737.7	685
6/19/2021	644	613.8	584.1	561.7	538.1	515.3	516.9	516.9	539.3	568.5	613.2	630.7	664.9	709.9	748.5	771.2	781.1	790.2	765.7	727	714.2	676.8	636.3	602.2
6/20/2021	557	536.6	515.1	499.2	488.7	485.2	486.9	535.5	586.3	639.7	690.7	722.1	761.2	785.7	812.1	818.7	822.6	824	801.7	777.5	761.3	739.9	685.9	645.3
6/21/2021	609.2	594.5	587	575.5	600.5	600.8	631.2	673.3	683.3	697.6	707.9	712.1	712	704.1	684.6	651	643.5	631.6	610.8	598.6	586.7	570.3	534.7	503.7
6/22/2021	474.3	462.1	449.6	437.5	433.8	456.4	474.8	511.1	541.5	568.8	577.5	591	601.5	615.3	633.2	652.1	656.8	653.2	655.8	667.8	693.8	664.8	624.8	586.1
6/23/2021	555.6	546.8	532.5	537.6	530.8	541.6	558	592.7	619.9	647.1	670	687.1	714.8	735.6	762.2	779.1	788	794.5	780.4	758.5	735.6	706.4	658.3	616.5
6/24/2021	588.7	566.2	552.8	550.6	545.4	553.9	586.7	619	674.8	701	750.9	786.8	829.1	863	885.8	882.1	841.7	819.2	840.2	790.9	816.2	796.7	748.7	702.8
6/25/2021	683.2	646.6	644.8	639.9	646.8	664.9	682	711.4	751.9	780.4	813.4	851	861.5	879.1	890.3	891.7	888.5	866.3	848.6	851.8	822.5	812.4	770.1	719.1
6/26/2021	677.5	658.5	642.3	628.1	615.2	610.8	613.6	659	698.7	747.1	788.9	812.6	828.3	844.9	868.9	876.1	896.3	894.8	879.9	850.2	782.2	744.2	696.6	643.4
6/27/2021	598.4	588.3	583.5	524.1	515.3	500.9	495.3	530.1	589	640.7	694.5	734.5	771.1	790.7	811.6	805.5	831.6	832.7	803.8	801.9	769.8	732.8	676.2	627.6
6/28/2021	587.3	558.7	542.7	525.2	539.6	545.8	591	659.1	724.3	774.6	825.6	861.9	878	912.6	929.1	940.8	949.1	941.8	923	896.4	858.8	821.2	760.2	709.1
6/29/2021	668.9	631.3	606.1	586.9	596.1	599.1	623.9	691.7	747.4	814.2	871.3	904.1	941.8	938.8	926.5	916.9	892.3	868.3	847.3	833.9	820.8	782.7	727	670.6
6/30/2021	635.6	605.2	589.9	567.9	571.3	580.6	600.7	657.2	681.1	744.8	781.6	833.7	860.9	895	909.8	900.3	854.5	806.4	780.5	745.9	729.8	705.4	661.9	618
7/1/2021	593.9	565.1	548.8	542.2	542.1	559.1	591.1	614.1	652	656.5	656.9	664.5	680.7	702.7	721.6	746.6	767.3	780.4	775	746.4	727.7	696.6	654.6	605.8
7/2/2021	563.7	517.7	495.7	474.7	463.2	472.1	486.4	520.4	540.9	556.3	576.7	605.4	640.7	675.6	688.2	701.8	702.9	694.6	655.8	630.1	603.9	585.9	536	500.3
7/3/2021	461.4	437.6	429.7	411.8	409.7	399.5	402.1	414.5	443.5	475.2	505.5	524.5	558.1	577.1	611.1	620	635.5	633.9	606.8	585.8	558.6	535.1	499.2	473.2
7/4/2021	426.9	414.6	398.1	390.6	386.1	379.5	385.7	408	451.4	480.6	528.8	572.8	614.4	644.6	670.6	697.5	711.3	704.8	690.8	650	613.3	580.5	547.4	525.4
7/5/2021	486.8	451.9	429.4	410.9	417.4	410.1	424.6	462	509.1	572.7	619.7	676	704.8	738.2	771.1	786.4	800.2	808.2	784.1	762.8	737.8	700	637	582
7/6/2021	567.5	538.5	512.5	507.4	504	530.5	561.6	624.6	676.9	736.1	788.5	832.6	853.6	888.3	906.4	911.9	915.9	904.4	880.6	848	811.5	772.8	716.5	660.4
7/7/2021	622.1	591.1	577	560	552.4	561.1	587.9	640	692.1	733.3	784.8	814.9	838.8	865.5	879.5	889.7	892	876.9	862.8	824.2	795.9	760.5	701.7	647.7
7/8/2021	615.7	582.1	562	548.4	546.4	569.3	585.1	635.3	667.8	705.6	757	811.7	851.2	887.5	900.8	821	780.7	765.5	748.8	731.3	722.2	694.4	649.4	603.6
7/9/2021	569.4	544.9	529.1	506.9	506	513.5	533.2	574.3	608.4	653.3	678.8	713	730	756.7	785	801.1	801	783.3	757.4	731.4	713	676.9	635.8	583.6
7/10/2021	548.4	526	509.9	499.3	487.6	480.3	474.7	478.4	502.9	532.3	582.5	628.7	663	686.8	701.3	726.6	684.5	644	609.8	599	572.3	552	517.6	487.3
7/11/2021	466.2	443.7	433.5	426	429.2	423.2	428.5	456.7	478.8	507.5	531.5	546	558.7	560.3	569.6	586.6	626.1	648.4	647.8	634.1	625.1	602.8	563.9	526.3
7/12/2021	499.6	493.9	478.7	477.8	491.3	533.9	577	620	656	700.9	743.9	780.9	798.1	810.6	789.2	818.1	813.2	797.7	795.9	761.7	749.4	726	687.1	630.9
7/13/2021	596.3	580.7	568	558.8	560.7	580.3	607.7	646.6	667.1	691.4	718.2	756.3	800.7	836.7	855	871.3	863.4	863.1	850.3	825.5	792.6	766.7	708.1	664
7/14/2021	600.9	579.1	555.3	557.2	566.3	581	605.1	634.3	651.1	664.7	733.4	773.3	826.3	848.7	870.1	885.5	880.1	872.4	847.4	813.1	791.8	742.7	692.3	644
7/15/2021	607.2	578.9	555.1	548.8	539.3	560	584	639.2	686	733.7	796.1	837.2	866	875.8	917.4	925.9	933.1	911.5	883.1	844.3	831.7	793	731.5	694.4
7/16/2021	651.5	613.1	578.1	568.1	558.5	571.5	595.4	624.9	655.4	704.2	762.7	789.8	827.2	843.9	870.9	868.9	841.5	800.6	762.4	715.7	691.1	665.3	623.9	588.9
7/17/2021	556.7	534.1	527.5	513.4	507.4	508.4	499.5	518.5	542.8	581.8	605.3	641.4	666.9	694.3	720.7	735.6	757.6	747	733.8	693.2	675.4	640.2	601	552.8
7/18/2021	533.2	498	484.3	474.8	470	469.4	483	516.7	551.4	587.8	613.5	637.2	673	683.6	684.8	671	629.5	608.8	605	591.4	590.4	580.6	546.2	524.6
7/19/2021	490.8	477.6	457.9	459.4	460.3	485.4	518.7	559.9	607.6	643.4	683.9	716.1	754.3	775.8	805.6	811.2	809.7	797.5	782.3	740.3	721.5	665.9	624.2	578.2
7/20/2021	542	507.6	493.1	490	481.8	504.7	528	568.1	597	648.1	686.5	733.4	766.6	789.2	810.2	824.9	825.5	809.9	788.4	753	731.7	701.9	646.2	599.2
7/21/2021	565.1	537.8	522.9	510.1	503	532.7	559.1	601.9	639.8	688.2	728.8	785.2	816	841.9	856.6	864.8	866.8	839.8	817.4	769.2	735.5	703.8	644.3	600.4
7/22/2021	558.1	526.7	503.1	496.1	490.2	502.9	534.3	573.3	598.6	643.1	696.6	741.6	774.3	784.2	807.4	817.1	803.7	802.6	777.6	750.7	726.6	692.9	635.1	592
7/23/2021	550.3	519.7	497.2	490.7	479.7	498	512.8	555.3	597.9	643.3	693.5	739	776.7	803.6	813.9	826.8	820.8	808.6	786.3	750.2	718.7	690.3	631.6	587.9
7/24/2021	546	520.7	500.9	487.6	485.6	481	495.8	522.1	567.3	618.8	674.3	727.6	766.9	810.2	823.8	846.5	860.8	868.5	836	797	771.1	734.6	695.1	641.9
7/25/2021	601.8	567.4	533.3	518.4	508.6	512.9	515.6	518.9	551	576.9	613.7	648.5	686.7	723	771.5	793.4	822.2	823.7	810.7	771.9	757.5	722.3	672.4	621.7
7/26/2021	591.2	565.7	541.9	532.8	534.9	554.1	585.2	632.3	708.6	751.5	804.6	839.7	867.9	901.5	918.4	921.7	925.6	902.9	890.6	848.3	809.7	775.5	704.8	649.2
7/27/2021	603.9	569.6	497.8	537.7	517.6	543.9	551	599.6	639.1	708.2	774.9	828.6	863	902.6	913.7	914.8	921.1	897	875.7	828.1	799.7	748	684	649.3
7/28/2021	602.7	566.4	542.9	528.8	526.4	533	562.7	603.8	647.4	695.7	759.3	808.6	853.8	875.6	916.8	927.9	926.2	912.9	880.3	851.8	816.3	770.1	710.6	656.2
7/29/2021	619.3	591.8	563.1	548.3	549.8	556.6	585.6	629.3	657.6	711.7	767.6	813.2	865.7	896.4	934.2	938.7	936.6	917.1	902.1	866.8	841.7	809.4	770.8	716.3
7/30/2021	682.1	648.7	609.1	589.4	577.1	587.4	597.4	626.3	666.8	714.9	760.2	791.7	819.5	838.5	849.9	847.3	825.6	786.8	752.8	720.2	692.6	667.5	617.8	571.4
7/31/2021	531	500.1	477.7	467.9	455.6	445.5	434.4	459	473.9	520.6	539.6	545.4	557.5	547.8	562.2	559.5	556.8	564.3	560	548.1	545.6	533.8	500.9	474.9
8/1/2021	455.7	432.8	425.1	418.1	419.2	412.1	407.8	425	464.1	488.6	531.7	568.8	595.6	628.6	657.9	677.4	695.2	687.4	672.4	645.2	623.8	585.6	555.4	507.8
8/2/2021	481.1	455	434.7	433.2	445	461	483.7	521.6	548.7	586.2	611.7	647.4	671.1	690.5	709.9	734.3	727.7	731.1	712.6	679.6	667.4	631.3	582.5	535.6
8/3/2021	517.2	481.2	475	463.9	467.9	481.4	507.6	534.5	564.2	597.9	636.4	670.2	695.3	685.1	711.8	717.1	717.7	722.1	701.8	687.7	663.7	627.6	580.1	536.8
8/4/2021	515.2	494.6	478.6	475.8	467.8	486	516	549	583.1	627.7	662.8	698.4	722.9	728.5	748.2	769.3	771.6	754.4	734.5	717.6	684.2	647.5	591.5	555.9
8/5/2021	512.4	498.9	480.3	470.3	469.8	494.7	510.5	549.1	594.4	636.6	672.2	709.6	731.6	776.9	786.7	810.1	804.7	797.2	769.7	742.2	720.5	672.4	629.9	574.4
8/6/2021	541.4	518.4	498.8	489.2	493.4	498	528.6	559.5	597.3	637.8	672.1	710.1	738.7	782.5	801.5	813.9	823.9	815.6	783.4	744.5	727.7	691.2	645.1	600.2
8/7/2021	552.1	532.2	511.2	505.3	485	489.4	477.6	494.6	538.8	593.3	643.1	685.6	732	760.6	782.2	797.8	807.1	796.2	778	737.9	714.8	668.6	622.3	579.7

Dt	Hour1	Hour2	Hour3	Hour4	Hour5	Hour6	Hour7	Hour8	Hour9	Hour10	Hour11	Hour12	Hour13	Hour14	Hour15	Hour16	Hour17	Hour18	Hour19	Hour20	Hour21	Hour22	Hour23	Hour24
8/8/2021	550.7	509.9	488.1	476.4	471.9	470.8	464.3	495	528.5	576.9	629.9	679.1	733	765.3	793.2	808.6	814	829.5	789.2	768.2	748.6	706.2	648.1	589.9
8/9/2021	553.5	532.2	523.7	512.2	517.3	543	581.4	604.4	625	627.4	666.9	701	711.4	720	754.7	789.8	813.9	827.5	819.2	802.1	789.1	748	701.5	662.7
8/10/2021	635.1	612.3	601.8	589.4	582.9	597.6	629.5	673.1	725.8	771.1	835.2	878.5	934.2	965.2	982	993.6	978.5	954.4	870.7	821.3	796.3	750.9	693	654.7
8/11/2021	618.1	597.4	596.8	583.4	594.7	612.1	656.1	703.4	727.7	776.8	830.5	885.2	921.1	958.2	976.3	985.9	977	970.7	944.8	911	884.6	828.2	772.3	723.4
8/12/2021	688.5	658.3	644.9	627.3	625.7	633.6	659.1	701.2	737.1	797.8	843.8	898.9	939.1	980.6	998.6	1001.2	994.1	975.4	948.5	902	844.6	778.5	724.6	671.7
8/13/2021	653.9	610.5	593.1	576.4	572.7	583.5	607.1	638.8	661.8	697.6	736.2	778.1	828.7	858.3	879.2	892.2	893.9	878.6	847.3	814.4	794.5	757.2	705.2	662.8
8/14/2021	622.1	591	574.4	551.6	543.1	551.8	535.8	544.3	568.2	589.4	610.9	629.3	633.4	644.1	675.1	706.4	695.9	705.7	685.4	648.7	633.1	610.1	571.2	543
8/15/2021	508.9	491.5	479	532.4	531.7	526.5	530	543.1	571.7	613.3	633.1	666.1	700.8	727.4	739.4	727.1	728.3	718.4	717.8	706.1	706.5	680.2	640.9	606.8
8/16/2021	582.8	567.1	554.5	556.6	568.3	597.1	638.1	672	684	723.5	760.1	783.3	827.2	852.5	884.2	911.1	915.7	906.5	892.8	863.4	836.3	786.6	740.5	696.4
8/17/2021	675.6	630	619.4	597.1	605.7	611.4	651.2	680	727.3	769.3	808.2	819.6	873.6	898	913.4	901.8	883.3	867.7	853.6	826.4	810.8	753.2	700.3	650.8
8/18/2021	616.4	575.1	562.3	550.1	551.6	565.2	603.2	637.5	665	713	761.7	791.3	811.7	820.1	826.2	832	833.1	810.9	790.7	775.3	769.2	711.6	669.7	621
8/19/2021	583.5	573.6	546.1	547.1	548.1	571.6	608.1	633.9	667.6	701.8	751.7	777.2	822.1	845.2	862	883.6	873.7	859.2	831.5	815.8	796	747.1	697.7	645.3
8/20/2021	601.5	586.4	561.4	555	550.9	568.3	593.1	633.3	674.7	723.8	772	808.4	846.3	875	887.7	909	904.2	892.7	857	831.8	796.4	750.3	707.7	642.3
8/21/2021	607.5	582.6	560	550	532	528.6	524.8	555	580.4	624.2	681.3	734.6	775.8	794.1	778.8	753.6	711.4	678	654.4	636.1	637.5	600.5	579.9	533.2
8/22/2021	505.4	479	473.6	460.5	471.5	465.1	478.8	496.1	547.4	597.9	657.5	714.5	756.7	786.9	802.1	823.8	827.6	821.8	809.5	777.2	754.7	712.4	666.6	609.6
8/23/2021	575.2	550	534.4	528.3	527.4	557.1	593.4	627.1	688.5	729.5	789.6	834.3	872.2	904.8	923.7	947.7	937.2	925.9	884.5	852.7	817.1	772.5	707.7	663.1
8/24/2021	629.6	607.6	589.1	574.4	582.3	593.5	624.9	659.1	708.8	764.1	817.7	874.7	915.5	944.1	967.4	985	972.6	964	930.9	901.7	878.8	819.2	763.4	709.2
8/25/2021	668.2	638.8	615.1	601.5	598	606.5	642.1	681.3	723	777.9	834.7	895.1	929.1	962.7	986.6	994.8	993.4	977	946.6	918.1	880.5	832.1	775.9	714
8/26/2021	681.4	656	620.6	616.5	604.5	626.8	653	685.3	715.2	765.2	824.2	881	927.2	963.6	979.6	1002.6	999.8	981.1	948.5	932.8	890.6	840.8	788.8	733.5
8/27/2021	698.5	667.4	638.8	628.5	621.2	631.8	654.6	687.4	720.1	777.3	846.8	889.6	942.5	965.2	907.1	829.7	785.6	763.9	747.9	733.8	719.9	700.1	654.6	625.3
8/28/2021	580.7	566.8	543.8	543.7	524	524.9	514	541.7	594.2	658.9	711.6	771.1	815.9	832.4	858.3	873.6	866.9	867.8	838.3	797	761.8	712.3	660.1	612.7
8/29/2021	580.6	554	522.5	506.4	500.7	494.4	495.4	522.8	575.8	635.3	700.3	756.6	796.6	835.2	848.3	876.9	890.4	885.3	852.4	823.5	797.1	747.8	687.1	653.8
8/30/2021	612.3	589.9	564.6	557.3	557.9	596.2	633.1	672.2	708.7	742.6	753	783.3	813.8	826	853.9	834.1	810.1	787.6	754.1	730.1	714.4	673.6	632.7	593.3
8/31/2021	572.8	550.5	536.4	531.4	535.4	551.2	582.4	605.2	621.2	649.6	668.8	699.6	720.4	740.6	763	760.6	772.5	760.4	735.3	732.2	712.7	666.8	625.6	576.2
9/1/2021	551.1	532	518.5	509.7	514	531	570.8	600.5	609.3	631.5	662.6	701	728.9	763.6	761.5	801.1	791.1	768.4	744.5	706.9	681.5	635.3	578	527
9/2/2021	502.2	484.1	473.5	463	460.5	484.4	507.1	535.5	565.2	591.4	620.6	642.1	663	692	718	741.7	741.2	728.3	698.1	688.1	662.1	617.8	569.3	525.3
9/3/2021	500.7	485.3	467.3	454.1	453.2	469.1	494	520.7	544.4	573.2	605.9	627.8	656.6	689.4	704.8	725.8	719.5	689.8	658.2	643.1	626	589.7	547.5	503.3
9/4/2021	482.8	463.7	450.4	444.3	431.3	423.3	420	441.1	464.7	503.6	539.6	552.3	568.7	573.3	573.1	580.5	577.6	571	578.1	576.4	572.1	553.6	534.2	501.8
9/5/2021	480.6	458.5	453.9	443.6	446.7	445.8	453.4	455.8	472.7	508.3	520	537.1	560.5	579.1	602.1	613.6	637.7	624.3	601.2	567.7	544.6	514.4	487.3	449.1
9/6/2021	426.2	404	392.3	391.1	384.9	384.6	381.1	394.6	416.9	465.4	508.5	548.4	586.4	626.3	651.3	684.3	706.8	701.3	675.8	645.4	616.7	579.8	527.3	487.4
9/7/2021	457.7	442.1	434.3	427.6	430.6	446.3	499.5	525	572.1	607.4	650.9	690.9	722.3	743	781.9	796.6	804	792.2	750	733.2	696.8	657.7	605.9	559.1
9/8/2021	538	516.8	512.4	497.4	497.2	511.9	552.6	572.9	585.8	618.1	649.3	680.1	700.8	718.9	742.2	750.8	757.9	738.9	704.3	676.7	649.8	603	557.4	510.2
9/9/2021	486.9	475.1	453.3	449.3	450.9	469.1	497.2	513	544.4	564.2	598.9	621.6	646.5	672.1	695.7	695.9	704.8	694.5	669.9	659.3	624.8	591.1	551.2	507.7
9/10/2021	492.4	475.7	463	454.2	460.1	465.6	504.1	520.8	546.9	580.2	594.6	633.1	660.3	689.3	704.9	721.5	729.4	711.4	686.7	656.9	632.1	595.2	555.6	517.8
9/11/2021	488.4	468.7	456	451.2	436.5	436.1	439.8	450.1	466.5	504.6	537.7	577.6	603.1	638.4	665.6	686.2	692.6	686.1	652.1	636.6	621.2	585.3	553.1	518.6
9/12/2021	484.5	470.2	451.3	437	432.7	434	437.3	449.2	476.3	532.8	576	620.2	658.1	688.5	722.2	735.2	738.1	740.7	704.9	692.2	668.8	627.6	585.5	546.9
9/13/2021	507.3	499.9	471.5	478.4	484.3	507.8	553	582.6	605.9	654.1	712.9	763.9	799.9	832.3	856.9	875.2	878.2	860	835.3	803.8	771.5	726.5	676.6	637.7
9/14/2021	603.4	576.6	563.4	550.1	550.5	565	594.7	619.3	660.1	697	754.8	779.5	819.1	848.2	867.8	881.8	880.7	861.7	829.6	816.3	777.4	726.5	680.6	632.3
9/15/2021	599.4	574.6	554.6	542.5	543.1	554.4	607.8	620.6	635.6	660.7	693.8	723.2	753.1	746.4	754.3	777.7	769.7	754	719.9	696.5	666.5	632.6	577.6	537.1
9/16/2021	515	506.1	482	491.6	479.1	502.2	539	555.6	581.8	597.1	630.1	664.3	713.9	743.9	775.4	793	793.3	785.7	758.6	740.7	712.4	671.4	613.3	575.7
9/17/2021	540	527.6	513.9	505.7	503.8	522.7	548.4	566.1	609.6	642.2	684.6	718.6	760.1	778.8	789.3	784.9	778.9	762.1	734.9	711.3	679	650.6	610.3	572
9/18/2021	540.4	525.8	499.3	496.3	488.2	499.5	510.8	517.2	548	595.3	644.2	695.6	722.3	768.2	784.7	800.8	780.7	748.8	739.1	706.8	680.5	651.4	608.7	575.6
9/19/2021	534.2	509.8	497.1	473.8	472.6	466.7	476.4	489.8	531.2	561.7	587.6	612.5	603.4	598.5	590.1	601	608.4	620.9	616.9	621.7	604.7	583.9	556	524.7
9/20/2021	502.4	496.7	484.6	490.3	511.6	535	577	611.4	629.6	641.7	663.9	680.3	719.6	749.9	770.9	786.4	787.6	764.7	736.8	721.6	708.9	654.6	598.4	566.9
9/21/2021	527.1	507.4	488.3	487.1	487.3	506	549.8	569.4	592.3	606	616.7	636.2	651.4	690	698.3	704.9	676.5	670.2	644.5	626.7	605.5	544.5	536.3	493.8
9/22/2021	470.1	459.6	447.8	443.9	446.4	464.2	498.4	514.2	520.6	531.3	529.3	524.1	521	525.8	525.6	517.8	509.7	509.1	519.3	519.3	523.1	498.3	474.6	452.3
9/23/2021	436.2	429.9	416.3	420	424.8	443	473.7	490	499.1	510.5	515.6	522.4	527.4	534.1	540.7	536.2	536.8	530.7	519.7	531	518.2	502.1	472.1	440.9
9/24/2021	429.7	422.4	413.4	412.5	417.8	432.5	464.2	471.9	484.7	495.9	510.2	511.4	529.2	529.4	543.2	548.9	552.3	551.2	532.4	529.7	511.3	495.8	459.8	432.9
9/25/2021	419.2	405	402	400.1	398.2	399.5	418.4	425.3	443.8	449.6	455.4	483.5	489.2	508.5	513.3	536.6	538	537.5	518	515.2	489.4	463.3	436.1	410.5
9/26/2021	398.1	383.9	372	373.1	378.7	364.7	382.8	385.5	407.2	424	445.7	462.1	477.3	494	514.9	540.7	551	550.7	542.5	543.2	522.7	497	462.6	438.2
9/27/2021	420.2	416.9	407.8	411.5	419.1	450.9	486.1	507.5	530.8	551.7	573.4	598.8	633.4	669.8	693.7	710.2	725.5	700.2	683.9	666.9	646.3	605.6	564.6	518
9/28/2021	495.1	474.7	463.1	456.8	454.3	475.3	499.3	524.6	544	572.9	617.8	659.6	691.2	727.6	766.7	786.1	805	785.2	737.7	708.6	680	632.8	583	540.6
9/29/2021	514.1	485.4	476.5	466.7	470.1	490.8	520.4	541	571.3	591.4	643.5	684.7	719.8	755.1	771.8	793.3	789.6	766.1	727.2	707.6	678.4	635.9	583.7	542.6
9/30/2021	510.6	495.6	484.5	491.1	486.9	505	541.8	555.9	579.8	610.8	652.2	694.3	728.7	752.4	780.8	790.7	778.8	753.2	731.2	723.2	693.7	658.1	606.1	563.4
10/1/2021	531.7	518.8	501	492.2	484	500.7	534.2	546.3	561	585.9	645.8	697.9	721.3	744.3	770.3	779.4	785.4	761	737.3	729.4	691.3	658.2	628.9	593.7
10/2/2021	557.7	542.6	530.6	515.4	504.3	515.3	523.7	539.7	555.3	576.2	595.3	604.9	612.9	615.5	616.7	628.2	620.7	620.8	618	621.3	596.4	591.3	558.1	538.9
10/3/2021	515.5	500.4	495.8	492.1	495.9	496.5	512.9	510	544.5	568.5	591.4	616	647.1	667.6	684.2	689.9	682.3	664.7	648.7	640.5	615	584.4	554.1	531.5
10/4/2021	508	493.2	486.2	490.9	501.4	530.1	575.4	603.2	619.5	636.5	664.7	696.2	717.2	738.3	750	768.7	756	735.2	718.5	712.2	684.1	656.6	601.3	571.6
10/5/2021	534.3	521.5	511.8	514.4	504.9	534	587.8	610.7	617.4	628.4	692.7	658.6	719.8	726.7	743.4	750.8	754.5	725.8	736.6	720.1	696.2	661.4	617.2	572.5
10/6/2021	562.7	556.5	542	539.1	529.4	559.8	590.9	619.5	634.3	644	688.1	643.3	684.6	698.7	710.4	716.1	712.9	704.9	701.4	695	677.2	640.7	624.6	576.9
10/7/2021	560.9	551.7	540.1	529.3	509.3	547.8	575.8	607.8	630.9	642.6	653.1	673.1	693	731.7	743	717.6	708.3	687.3	681.3	683.1	662.1	643.7	600.1	569.5
10/8/2021	553.7	544.9	529.5	531	531.7	539.8	583.1	594.4	621.1	641.5	670.1	690.1	715.7	731.7	751.3	758	745.5	729.2	696.8	673.3	654	608.7	588.8	577.3
10/9/2021	586.2	566.2	550.8	545.7	546.3	548	545.9	552.9	558.4	607	642.8	678.7	716.6	735	758.1	776.7	787.6	763.5	739.4	718.6	689.3	671.8	646.1	622.3
10/10/2021	559.1	574.1	576.6	554.2	553.6	556.3	562.1	564	591.8	634	664.1	709.7	743	770.3	800.1	814.8	826.5	822.2	786.4	767.2	736.6	706.7	668.7	632.8
10/11/2021	531.2	514.9	508.8	511.3	516.1	545.7	578.6	601.1	636.2	640.4	683.2	713.5	755.4	764.2	760.5	753.9	728.4	696.8	696.9	689.9	670.1	635.3	562.6	544.6
10/12/2021	525.7	515	503.7	496	493.4	501.7	537.8	556.2	571.8	582.7	589.9	609.3	633.8	650.8	680.4	691.3	692.7	673.1	655.9	641	619.4	584.9	553.2	517.3
10/13/2021	496.2	491.6	480.9	483.1	485.7	509	547.1	571.3	577.6	595	616.9	641.6	651.8	656.4	671	683.9	689.6	675.7	692.7	692.4	678.2	650.3	624.6	584.7
10/14/2021	577.8	552.6	542	537.9	537.5	560.4	598.2	614.4	640.3	659.2	698.2	722.2	750.8	768.2	783.4	779.3	768.8	749.6	747	734.8	716.5	687.6	644	609.8
10/15/2021	590.9	578.8	560.1	557.2	560.3	574.5	612.7	625.6	639.9	659.1	676.1	698.5	709.3	738.4	749.5	724.1	704.8	695.8	686.5	667.4	632.8	593.1	551.2	519.4
10/16/2021	498.3	475.1	476.9	459.3	459	454.1	459.6	458.4	474.2	482.4	493.7	497.3	495.8	498.2	496.4	500.7	505.5	504.3	506.5	511.6	492.6	483	474.6	451.3
10/17/2021	435.1	426.6	430.4	419.7	424.7	418.9	436.1	447.5	452.7	458.9	462.6	467.4	471.9	482.2	487.1	490.9	501.4	508.7	511.4	513	495.2	481.8	458.7	445.1
10/18/2021	433.5	437.3	439.1	449.9	459.3	494	524.8	548.3	562.8	578.1	571.3	585.8	577.5	578.7	592.7	608	612.9	604.4	597.1	598.1	581.4	564.7	530.6	516
10/19/2021	494.9	490	489.9	484.4	491.9	506.6	551.1	563.5	567.1	571.7	574.4	584	595.8	604.5	592.9	600.1	590.5	592.3	601.3	603.8	589.9	569	539.1	519.9

Dt	Hour1	Hour2	Hour3	Hour4	Hour5	Hour6	Hour7	Hour8	Hour9	Hour10	Hour11	Hour12	Hour13	Hour14	Hour15	Hour16	Hour17	Hour18	Hour19	Hour20	Hour21	Hour22	Hour23	Hour24
10/20/2021	504.1	497.1	488.1	493.1	496.1	508.8	548.9	565	576.6	583	587.8	594.8	600.4	611.2	613.9	623.7	619.8	613.7	618.7	615.2	602.3	579.7	547.3	523.3
10/21/2021	504.6	499.5	502.2	497	492.2	517	560.9	579	592.4	601.5	603.8	605.9	606.3	610.7	607.6	606.9	600	589	590.7	593.6	585.7	566.3	536.6	513.1
10/22/2021	496.5	493.3	487.3	491.7	485.9	511.3	549.1	568.4	567.1	577.1	584.8	577.5	586	582	577	583.6	573.1	568.5	579.5	583.9	574.6	559.8	528.3	510.6
10/23/2021	496.2	492.4	485.9	483.6	481.6	485.9	494.5	493.4	508.2	509.5	517	520.6	514.6	513.6	525.5	521	521	529.5	535.4	533.7	521	507.3	495.3	469.3
10/24/2021	462.9	454.5	446	444.8	446.6	448.4	454.9	471.7	482.7	497.3	514.8	530.1	539	545.7	550.6	560.7	564.5	580	593.8	587.6	573.4	552.8	519.3	495.1
10/25/2021	487.3	473.5	466.7	468.3	479	518.7	559.4	581.9	579	592.1	589.3	584.7	585.1	590.3	587.3	585.3	586.6	581.3	599.3	594.5	585.6	563.6	535.6	514.6
10/26/2021	507.2	498.8	486.8	497.4	499.6	523.8	565.1	578.7	584.7	584.9	588.4	590.9	584.8	584.9	587.9	583	580.7	581.8	598.5	598.2	595.3	567.1	543.3	522.5
10/27/2021	516.1	508.9	502.5	509.5	521.1	544.8	591.4	598.6	598.4	593.1	602.3	594.5	590.4	596	588.5	600.2	597	587.1	592.7	588	575.4	562.6	534.6	519.2
10/28/2021	505.4	497.6	494.7	497.4	500.3	524.8	565.2	597.1	600.9	607.7	607.8	609.9	608.7	609.7	603.9	601.1	596.3	586.1	579.7	558.2	550.5	535.5	513.5	484.3
10/29/2021	481	464.8	461.1	462	467.6	489.3	524.6	538.6	546.9	566.2	585.5	598.3	594.8	586.9	566.8	496.4	499.1	486.1	501	499.7	491	480.3	447.8	428.6
10/30/2021	406.9	403	395.9	391.8	398.3	392.8	406.3	412.7	427.9	435.3	441.6	446.4	439.6	436.1	433	432.7	435.1	440.1	450.1	441.3	434.4	424.2	414.1	391.6
10/31/2021	378.6	376.8	370	366.9	366.9	375.7	389	397.3	414.3	410.6	420.5	428.1	427.7	432.9	433.7	432.1	428.8	428.2	453	443.7	443.1	430.2	408.7	388.7
11/1/2021	383.7	377.6	376.7	384.9	397.6	442.9	488.6	506.8	508.8	519.9	508.5	511.6	505.3	509.1	500.2	509.9	509.7	524.2	526.3	529.3	515.3	499.2	475	453.5
11/2/2021	436.3	435.3	432.9	441.3	442.9	471.6	509.1	529.6	528.1	529.5	521	517.1	516.4	508.4	505.9	500.8	503.1	516.3	543.8	548.5	529.7	523.1	494.4	472.4
11/3/2021	473.3	465.2	469.8	476.7	481.7	511.8	547.6	582.7	575	567.5	550.7	530	526.8	515.4	507.6	514.1	506.1	528.3	545.9	550.6	540.2	529.1	506	493
11/4/2021	479	481.9	477.4	480.9	498.8	521.9	563.4	583.5	571.9	551.3	541.7	519.5	515.1	504.3	498.7	497.1	506	509.2	533.9	544.1	540.9	508.7	500.4	481.2
11/5/2021	477.6	468	479	480.7	488.6	514.6	553.4	574.5	569.7	545.5	527	503.4	501.6	491.8	491.3	476.7	479.4	492.3	499.6	508.6	500.8	497.5	481.5	456.6
11/6/2021	453.8	455.4	454.3	461.6	454.2	462.8	478.6	493.8	482.5	468.9	452.5	443	434.5	423.5	416.3	416.6	426.3	436.1	452.6	443.2	442.8	428.3	416.8	410.5
11/7/2021	403.4	395.8	393.3	393.9	400.8	416.8	445.5	472.7	460.2	435.4	423.8	420.8	422.4	419.3	395.4	382.9	405.3	438.7	475.9	468.2	462	441.3	431.3	421.4
11/8/2021	401.9	401.7	402	401.4	407.7	430.9	475.3	530.1	530.4	520.7	507.4	508.4	517.3	503.3	519	502.3	496.8	520.3	535.6	519.1	520.7	504.4	485.6	463.4
11/9/2021	439.3	425.7	424.5	428.3	422.3	440.1	470.4	515.4	523.6	516.2	518.6	529.7	517.3	515.9	511	512.5	517	529.2	535.8	527.2	528.2	506.5	487.1	464.7
11/10/2021	440.5	434	429.1	423.9	429.6	433.3	456.3	485.9	509.5	499.6	515.6	516.1	515.1	522.7	521.6	518.2	524.1	517.8	533.2	523.2	516	508	488.5	457.5
11/11/2021	435.7	426.7	422.5	418.6	415.9	424.8	449.3	474.4	501.3	507.7	523.3	522.6	524.9	516.5	518.5	505.4	499	510.5	520.3	513.8	513.1	504.2	490.8	471.7
11/12/2021	445.2	452.7	450.1	439.2	442.1	453	472.4	510.1	525.7	533.1	526.3	539.6	541.6	527.5	520	509.4	503.8	521.3	525.7	524	516.6	521.3	501.1	481.6
11/13/2021	466.6	454.8	447.4	444.7	450.5	447.5	449.3	454.5	461.1	474.9	483.6	485.6	483.3	483.8	479.9	480	480.1	501.6	505.8	504.9	499	493.5	478.4	476.4
11/14/2021	444.5	438	432.4	423.8	431.2	422.8	434.9	439.2	452.4	463.2	477.9	468.4	469.1	462.4	460.4	453.4	461.6	488.3	513	515	501.3	502.8	485.4	469.6
11/15/2021	457.3	458.8	460.3	456.8	473.3	491.5	513.1	566.7	578.9	578.8	569.3	552.7	558.8	544.1	526.6	525.3	526.4	532	568.2	557	560.9	546.8	534.1	504
11/16/2021	482.4	480.3	469.4	471.9	474	478	504.1	544.2	548.3	535.8	526.4	513.3	515.6	509.3	509	511.4	515.4	517	539.5	530.5	524.3	517.7	486.8	473.1
11/17/2021	446.8	432.8	435.9	423.9	426.2	432.7	451.1	483.7	498	512.2	521.7	529.4	527.3	528.8	529.2	530.3	525.2	532.2	544.3	539.3	526.6	514.9	484.3	460.2
11/18/2021	436	421.5	426.4	423.7	427.8	439	464.2	495.1	523.6	520.3	525.6	525.1	509.6	519.8	509.7	505.8	516.6	522.8	558.7	559	556.3	547.4	538.5	516.2
11/19/2021	498.2	481.4	491.8	493.8	497.5	514.6	536.8	576	581.7	570.4	559.8	537.4	522.6	514.7	508.7	502.5	499.4	520.9	542.1	539.2	551.9	540.8	521.4	505.1
11/20/2021	476.5	466.6	464.7	456.6	455.3	457.2	466.2	480	475	479.3	472.4	461.5	456.9	444.3	436.2	435.4	434.2	454.3	474.1	468.1	469.6	451.6	440	424.7
11/21/2021	406.4	397.4	385.1	384.4	379.7	385.6	394.4	412.8	429.2	441.4	454.3	455	461.8	463	457.6	457.1	452.4	475.9	487.6	481.1	485.2	469.4	467.1	449.9
11/22/2021	432.6	428.1	432.1	429.7	446.5	461.2	500	549.7	560.8	571.5	575.6	563.1	566.2	558.3	555.9	548.1	559.5	573.2	604.6	596.9	599.9	593.4	571.3	553
11/23/2021	531	524.8	528.6	526	537.7	543.8	577.6	607.2	617.7	600.2	580.5	559.8	540.8	534.1	524.4	512.2	523.5	540.3	565.3	562.6	568.6	559.6	540.5	522.6
11/24/2021	490.3	485.8	484.5	480.6	478.6	490.9	508.6	540.6	547.9	556.3	545.8	537.6	520.4	492	504	499.8	493.6	507.6	522.8	520.7	508.6	491.5	462.3	425
11/25/2021	392.1	383.3	363.7	352.6	344.2	335.7	347.5	355.7	367.6	388	411.3	427.3	422.7	400.4	388.6	390.7	391.9	407.6	411.7	417.4	426.2	417.3	418.8	405.9
11/26/2021	395.4	393.7	393.9	389.5	399.7	411.4	427.3	443.7	453	456.7	443.5	432.3	425.6	413.4	403.9	390.4	409	433.6	477.7	471.3	474.4	462	458.2	441.6
11/27/2021	428.5	422.2	416.4	413.9	410.8	424.3	429.5	448.4	446.9	455.8	443.8	440.7	430.4	415.4	415.9	409.2	412.3	435.5	454.4	456.4	453.5	446.3	437.2	417.2
11/28/2021	410.4	389.8	395.1	389.8	387.9	397.4	401.8	422.9	430	423.8	430.7	428.4	422	425	421.2	419.5	431.9	460.3	492.8	499.1	493.8	490.3	486.9	459.1
11/29/2021	457.9	452.4	453.9	459.2	472.6	501	533	575.9	583.5	574.9	556.5	546.2	526.6	529.4	523.4	516.6	534.8	553.1	565.1	563.7	557	550.4	521.7	502.8
11/30/2021	479.8	468	463.3	457.9	461.6	464.8	492.1	529.5	543.3	537.7	522.7	515.1	510.9	510.1	505.9	508	500	518.3	539	540.3	543.9	537	521.7	505.1
12/1/2021	476.8	467.7	460	454.9	461.1	466.2	494.1	531.1	543.1	549.5	547.8	544	540	525.6	509.9	509.7	513.4	524.2	544.1	544.7	543.7	535.4	511.8	486.7
12/2/2021	466.3	457.7	447.8	440.3	440.1	447.1	478.1	516.6	518.5	518.6	501.8	503.9	510.3	505.5	500.4	502.4	497.4	513.2	524.7	527.4	523.6	519.3	491.3	476.3
12/3/2021	445.4	437.3	437.9	438.8	440.6	445.3	472	510.7	519.1	522.4	508.9	508.8	496.6	507.5	508.1	501.9	502.5	510.2	522.9	514.7	502.1	494.2	483.1	455.6
12/4/2021	429.7	424.4	409.8	411.5	406	412.7	417.8	433.5	438.2	453.2	441.1	443.1	433.6	431.9	432.1	423	441.3	458.8	473.5	481.8	467.7	471.1	461.6	443.9
12/5/2021	427.2	423	410.6	410.2	404.1	410.6	416.1	427.1	438.3	450.4	457.5	455.8	454.5	455.1	460.2	455.1	468.7	482.7	504.1	498.4	496.4	490.8	466.2	446.6
12/6/2021	416.9	402.6	398.9	396.5	405.1	412.9	448.6	493.4	521.4	528.7	539.4	529.1	533.1	531.1	523.9	533.3	543.3	565	592.9	592.6	597.7	591.4	569	549.5
12/7/2021	528.3	514.3	505	511.2	506.9	519	550.7	590.7	604.5	606.7	602.3	599.8	594.1	603.2	599.1	610.7	613	625	636	628.9	620.9	614.9	584.8	563.4
12/8/2021	537.3	519.2	519	512.6	509.2	520.7	564.8	605.1	614.2	612.4	583.7	577.9	557.3	542.7	539.7	541.5	541.2	560.1	585.3	582.3	594.6	578.3	560.5	546.1
12/9/2021	518.5	507.6	509.6	502	510.9	515.8	542.4	582.5	592.5	575.3	562.3	547.8	552.4	555	552.8	548.5	546.1	562	568.4	558	555.7	546.7	525.9	500.3
12/10/2021	482.9	466	459	449.9	443.9	449.8	474.8	514.9	527.7	531.8	543.5	535.8	528.2	534.9	536.9	535.1	536.1	540.7	551	537.9	537.4	522.9	509.5	485.4
12/11/2021	462	447.7	429.1	425.2	420	412.6	422.1	423.9	418	438	460.1	463.8	471.2	481.5	479.7	475.7	472.9	491	520.3	520.5	515.4	513	508	492.6
12/12/2021	496.5	480.4	476.1	480.1	479.7	488.2	502.7	509.5	516.7	514.9	508.5	490.9	473.8	479.5	462	464.6	475.6	504.2	539	533.2	532.1	528.8	516.9	498.5
12/13/2021	465.1	465.8	463.2	466.9	468.9	489.8	525.8	557.9	588.4	567.8	550.6	537.4	529.3	520	523.9	509.4	519.1	527.1	563.2	561.8	555.5	554.1	532.6	504.7
12/14/2021	490.4	477.5	482.6	476.2	480.4	493.9	517.9	553.8	552	550.7	548	540.3	534.1	536.5	524	523.5	528.9	548.5	553.5	551.5	548.2	540.3	510.4	485
12/15/2021	459.2	441.8	441.4	438.6	431.9	437.4	469.7	503.8	518.6	520.3	524	526.1	518	517.5	510.1	512.9	512.1	527.5	538.1	534.3	536.5	524.6	502.8	476
12/16/2021	457.7	447.2	437.7	443.9	434.9	448.8	470	504.5	525.7	534.1	537.5	543	529	531	541	530.8	531.7	540.5	546.7	550.2	552.4	547.9	532.6	503.9
12/17/2021	477.9	468.5	468.6	463.8	465.2	477.6	500.5	538	553.3	558.2	562	556	562.5	566.9	561.2	556.2	552.3	566.2	568.1	560.4	550.3	544.6	527.8	498.3
12/18/2021	473	459.2	450	441.2	431.7	435.8	443.1	445.9	449	462.6	486.6	492.4	498.9	500	500.5	499.1	504.5	527.1	527.4	522.8	513.6	508.5	500.1	481.7
12/19/2021	458.7	448.6	445.7	446.7	446.7	450.5	475.2	486.8	497.6	494	482.4	477.5	479.4	471.8	467.9	465.5	479.5	505	549.7	551.4	550	545.8	534.9	520.2
12/20/2021	504.2	498	497.9	503.8	518.5	531.3	556.6	599.7	620	602.7	588.4	568.8	553.8	544.5	537	530	532	551.3	582.7	587	590.2	589.1	579	559.5
12/21/2021	541.1	529	515.5	517.4	527.7	532.6	564.5	592	614.2	607.1	589.8	565.8	557.8	547	538.1	537.5	530.3	554	575	581.7	577.9	569.5	555.1	534.6
12/22/2021	515.7	507.6	500.9	500.2	507.8	518.8	542.6	582.9	590.8	593.5	574.6	574.5	559.1	543.3	547.6	527.8	535.9	558.5	592.7	587.1	594.7	585.6	563.7	532
12/23/2021	506	495.9	481	484.1	486.9	486.2	510.6	535.8	549.5	537.3	529.2	530.3	514.5	492.7	490.8	490.5	473.9	492	512.4	505	504.9	490.4	470.2	443.9
12/24/2021	423	401.1	389.7	372.9	370.7	366.2	373.5	385.4	387.2	405.8	415.2	425.9	427.2	425.9	406.4	417.9	407.2	413.1	429.5	412	407.7	399.2	401.3	376.6
12/25/2021	360	346.3	333.1	324.4	321.7	327.6	331.1	335.2	350	367.1	368.7	390.1	382.1	385.6	376.1	370.8	370.7	382.6	384.3	386.4	381.6	373.1	367.7	351.4
12/26/2021	338.4	328.6	324.1	323.2	324	326.5	335.9	354.1	359.5	380.1	398.4	404.7	403.5	398.4	399.4	400.5	406.5	425.5	455	444.9	441.6	427.4	425.9	398.7
12/27/2021	385.5	372.4	364.6	361.1	365	365.3	388.5	408.4	420.5	437.2	451.1	465.4	470.5	469.1	467.8	462.9	476	483.8	485.9	486.7	475.8	451.9	447	415.4
12/28/2021	392.7	379.9	376.2	384.5	381.7	395.8	407.3	442.6	466.2	487.2	499	500.1	501.8	496.7	499.7	498.4	483.6	501.3	508.7	493.8	494.7	472	456.6	433.4
12/29/2021	407.4	403.2	390.4	392	393.5	397	420.1	449.9	464.7	470.1	480.7	486.8	482.6	482.5	485.1	479.7	487.2	499.8	509.7	501.1	489.3	476.7	454.6	437.4
12/30/2021	411.2	394.9	388.3	387.5	389.4	399	417.6	440.6	452.2	465.9	469.4	474.2	476.8	473	476.6	468.1	469.8	478.1	496.5	493	475.7	468.4	456.4	435.5
12/31/2021	417.7	397.4	384.9	381.1	387.6	388.2	395.8	419.6	422	426.2	445.9	443.8	442.9	444.2	440.9	439.6	447.9	458.4	476.3	469.2	459.5	441.4	436.5	418.4

Attachment 4.3 2023-2024 MISO LOLE Study Report

Planning Year 2023-2024 Loss of Load Expectation Study Report

MISO – Resource Adequacy

Highlights

- MISO's seasonal construct, accepted by FERC in September 2022, introduces seasonal requirements to the Planning Resource Auction (PRA) to account for the unique risk profile of each season.

- MISO made several modeling improvements to the LOLE study to support the new seasonal construct.

- MISO's annual Loss of Load Expectation (LOLE) study sets the system-wide Planning Reserve Margin and the zonal Local Reliability Requirements for each season of the upcoming Planning Year.

Update (5/1/2023): outyear Planning Reserve Margin (PRM) and Local Reliability Requirement (LRR) results added to study report

Contents

Executive Summary

Midcontinent Independent System Operator (MISO) conducts an annual Loss of Load Expectation (LOLE) study to determine a Planning Reserve Margin Unforced Capacity (PRM UCAP), zonal per-unit Local Reliability Requirements (LRR), Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL) and Capacity Export Limits (CEL) for each season (Summer, Fall, Winter, & Spring) of the upcoming Planning Year. The results of the study and its deliverables supply inputs to the MISO Planning Resource Auction (PRA).

The Planning Year 2023-2024 (PY 2023-2024) LOLE Study:

- Establishes PRM UCAP for each season to be applied to the Load Serving Entity (LSE) seasonal coincident peaks for the Planning Year starting June 2023 and ending May 2024:
    - Summer 2023 PRM UCAP of 7.4%
    - Fall 2023 PRM UCAP of 14.9%
    - Winter 2023-2024 PRM UCAP of 25.5%
    - Spring 2024 PRM UCAP of 24.5%
- Uses the Strategic Energy Risk Valuation Model (SERVM) software for Loss of Load analysis to provide results applicable across the MISO market footprint.
- Provides zonal ZIA, ZEA, CIL and CEL for each Local Resource Zone (LRZ) (Figure ES-1). These values may be adjusted in March 2023 based on changes to MISO units with firm capacity commitments to non-MISO load, and equipment rating changes since the LOLE analysis. The Simultaneous Feasibility Test (SFT) process can further adjust CIL and CEL to ensure the resources cleared in the auction are simultaneously reliable.
- Determines a minimum planning reserve margin for each season of the studied Planning Year that would result in the MISO system experiencing a less than one-day loss of load event every 10 years, as per the MISO Tariff.[1] The MISO analysis shows that the system would achieve this reliability level for the summer 2023 season when the amount of installed capacity available (considering external support) is 1.159 times that of the MISO system summer 2023 coincident peak.
- Sets forth initial zonal-based (Table 1-1) PRA deliverables in the LOLE charter.

The stakeholder review process played an integral role in this study. The MISO staff would like to thank the Loss of Load Expectation Working Group (LOLEWG) for its assistance and input. There were several process improvements made to the LOLE study this year including updated transfer limits due to improved redispatch and four major LOLE modeling enhancements: seasonal outage rates, wind and solar hourly profiles, probabilistic modeling of non-firm support, and correlated cold weather outages.

[1] A one-day loss of load in 10 years (0.1 day/year) is not necessarily equal to 24 hours loss of load in 10 years (2.4 hours/year).

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Summer 2023 PRM UCAP	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%
LRR UCAP per-unit of LRZ Peak Demand	1.139	1.120	1.299	1.212	1.333	1.172	1.171	1.473	1.157	1.538
Capacity Import Limit (CIL) (MW)	5,301	3,477	6,108	7,884	3,576	8,492	5,087	4,139	5,268	3,064
Capacity Export Limit (CEL) (MW)	3,959	2,550	4,310	No Limit Found[2]	No Limit Found	2,703	3,953	5,503	1,574	1,794
Zonal Import Ability (ZIA) (MW)	5,299	3,477	6,043	6,992	3,576	8,092	5,087	4,091	4,456	3,064
Zonal Export Ability (ZEA) (MW)	3,961	2,550	4,375	No Limit Found	No Limit Found	3,109	3,953	5,551	2,386	1,794

Table ES-1: Initial Planning Resource Auction Deliverables — Summer 2023

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Fall 2023 PRM UCAP	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%
LRR UCAP per-unit of LRZ Peak Demand	1.274	1.218	1.408	1.254	1.452	1.247	1.345	1.490	1.278	1.619
Capacity Import Limit (CIL) (MW)	6,528	4,411	14,375[2]	5,173	5,380	6,070	4,285	4,705	6,045	2,425
Capacity Export Limit (CEL) (MW)	3,804	3,577	4,354	4,878	1,992	1,701	3,990	5,080	1,526	2,878
Zonal Import Ability (ZIA) (MW)	6,526	4,411	14,310[2]	4,281	5,380	5,670	4,285	4,657	5,233	2,425
Zonal Export Ability (ZEA) (MW)	3,806	3,577	4,419	5,770	1,992	2,101	3,990	5,128	2,338	2,878

Table ES-2: Initial Planning Resource Auction Deliverables — Fall 2023

[2] "No Limit Found" reflects no valid constraint identified.

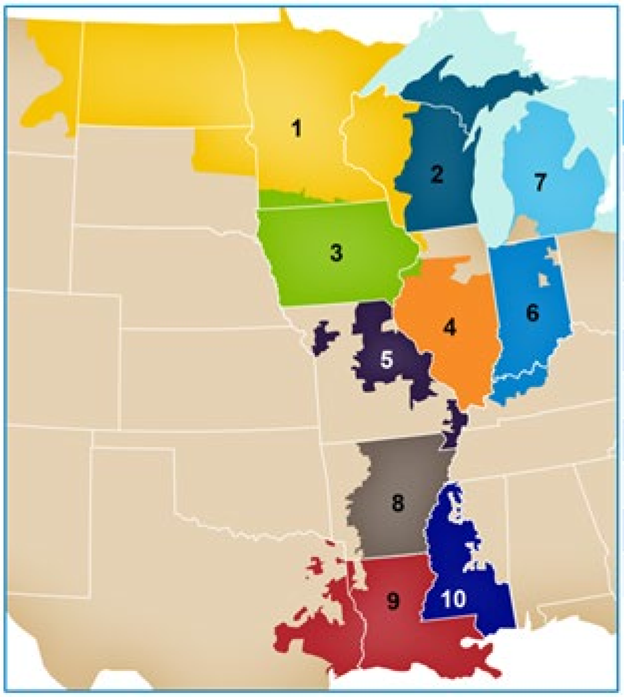
PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Winter 23-24 PRM UCAP	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%
LRR UCAP per-unit of LRZ Peak Demand	1.403	1.422	1.850	1.365	1.474	1.301	1.573	1.503	1.323	1.777
Capacity Import Limit (CIL) (MW)	4,937	4,905	11,039[2]	3,928	3,811	8,818	6,340	4,729	6,080	2,396
Capacity Export Limit (CEL) (MW)	3,501	4,198	7,002	3,445	6,348	1,242	4,350	5,351	877	1,980
Zonal Import Ability (ZIA) (MW)	4,935	4,905	10,974[2]	3,036	3,811	8,418	6,340	4,681	5,268	2,396
Zonal Export Ability (ZEA) (MW)	3,503	4,198	7,067	4,337	6,348	1,642	4,350	5,399	1,689	1,980

Table ES-3: Initial Planning Resource Auction Deliverables — Winter 2023-2024

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Spring 2024 PRM UCAP	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%
LRR UCAP per-unit of LRZ Peak Demand	1.375	1.267	1.623	1.454	1.610	1.320	1.329	1.627	1.315	1.747
Capacity Import Limit (CIL) (MW)	6,185	4,454	7,675	5,906	3,881	8,162	5,559	4,606	6,250	2,144
Capacity Export Limit (CEL) (MW)	4,321	3,679	6,173	3,745	3,724	2,344	4,413	5,472	2,240	2,720
Zonal Import Ability (ZIA) (MW)	6,183	4,454	7,610	5,014	3,881	7,762	5,559	4,558	5,438	2,144
Zonal Export Ability (ZEA) (MW)	4,323	3,679	6,238	4,637	3,724	2,744	4,413	5,520	3,052	2,720

Table ES-4: Initial Planning Resource Auction Deliverables — Spring 2024

LRZ3 Fall and Winter ZIA and CIL were updated after the final results were presented at the October LOLEWG. Both studies resulted in No Limit found and the equation was updated to include Tier 2, the October 3rd 2022 LOLEWG presentation has also been updated accordingly.



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, HMPL, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

Figure ES-1: Local Resource Zones (LRZ)

1 LOLE Study Process Overview

In compliance with Module E-1 of the MISO Tariff, MISO performed its annual LOLE study to determine, for each season of Planning Year 2023-2024, the system unforced capacity (UCAP) Planning Reserve Margin (PRM) and the per-unit Local Reliability Requirements (LRR) of Local Resource Zone (LRZ) Peak Demand.

In addition to the LOLE analysis, MISO performed seasonal transfer analyses to determine seasonal Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL) and Capacity Export Limits (CEL). CIL, CEL, and ZIA are used, in conjunction with the LOLE analysis results, in the Planning Resource Auction (PRA). ZEA is informational and not used in the PRA.

The PY 2023-2024 per-unit seasonal LRR UCAP multiplied by the updated LRZ seasonal Peak Demand forecasts submitted for the 2023-2024 PRA determines each LRZ's seasonal LRR. Once the seasonal LRR is determined, the ZIA values and non-pseudo tied exports are subtracted from the seasonal LRR to determine each LRZ's seasonal Local Clearing Requirement (LCR) consistent with Section 68A.6 of Module E-1[3]. An example calculation pursuant to Section 68A.6 of the current effective Module E-1 shows how these values are reached (Table 1-1).

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP (1d in 10yr)	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Zonal Import Ability (ZIA)	3,469	[G]
Zonal Export Ability (ZEA)	2,317	[H]
Proposed PRA (UCAP) EXAMPLE	**Example LRZ**	**Formula Key**
Forecasted LRZ Peak Demand	14,270	[I]
Forecasted LRZ Coincident Peak Demand	13,939	[J]
Non-Pseudo Tied Exports UCAP	150	[K]
Local Reliability Requirement (LRR) UCAP	16,376	[L]=[F]x[I]
Local Clearing Requirement (LCR)	12,757	[M]=[L]-[G]-[K]
Planning Reserve Margin (PRM)	7.4%	[N]
Zone's System Wide PRMR	14,970	[O]=[1.074]x[J]
PRMR	14,970	[P]=Higher of [M] or [O]

Table 1-1: Example LRZ Calculation

[3] https://www.misoenergy.org/legal/tariff
Effective Date: November 1, 2018

The actual effective PRM Requirement (PRMR) for each season of Planning Year 2023-2024 will be determined after the updated LRZ Seasonal Peak Demand forecasts are submitted by November 1, 2022, for the 2023-2024 PRA. The ZIA, ZEA, CIL and CEL values are subject to updates in March 2023 based on changes to exports of MISO resources to non-MISO load, changes to pseudo tied commitments, and updates to facility ratings following the completion of the LOLE study.

Finally, the simultaneous feasibility test (SFT) is performed as part of the PRA where cleared generation is tested to ensure transmission reliability and if constraints arise, they are mitigated by adjusting CIL and CEL values as needed.

1.1 Study Improvements

The Planning Year 2023-2024 LOLE study incorporated a number of study improvements as a result of the approved seasonal construct. These improvements include seasonal outage rates, correlated cold weather outages, probabilistic distribution of non-firm support, and hourly wind and solar profiles.

Historically, the LOLE model utilized a 5-year average EFORd, based on historic GADS data, which was constant throughout the simulated year for all resources. This year, seasonal EFORd was calculated using the same GADS data but outages were classified by season to produce four unique seasonal EFORd values for each resource. This change better captures the seasonal availability of resources observed in operations.

Additional outages are added to the model during times of extreme cold temperatures to better capture the magnitude of correlated outages observed. The magnitude of forced outages added increases as temperatures decrease based on the relationship between outages and temperature determined from historic GADS and weather data. Each LRZ has a unique outage/temperature curve based on actual performance. The incremental cold weather outages are not assigned to a particular resource but instead represent the aggregate impact on the system for coal and gas resources.

For the last several years MISO has accounted for non-firm support in the LOLE process by simply reducing the PRM by a fixed amount on a 1-for-1 MW basis. This year's study incorporated seasonal distributions of non-firm support directly in the model which are based on historic Net Scheduled Interchange (NSI) data. As the model steps through time chronologically, SERVM will randomly draw import values from this distribution to be used to serve load.

In previous LOLE studies, wind resources were modeled as perfect units with a constant output equal to their monthly ELCC values while solar resources were modeled as perfect units with constant output equal to their capacity credit. For Planning Year 2023-2024, wind and solar resources were modeled as variable energy resources with 30 unique hourly profiles corresponding to the 30 unique weather years within SERVM.

2 Transfer Analysis

2.1 Calculation Methodology and Process Description

Transfer analyses determined CIL and CEL values for LRZs in each season for Planning Year 2023-2024. Annual adjustments are made for Border External Resources (BERs) and Coordinating Owner Resources (COs) to determine the ZIA and ZEA in each season. Further adjustments are made for exports to non-MISO Loads to arrive at the CIL and CEL values. The objective of transfer analysis is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Multiple factors impacted the analysis when compared to previous studies, including:

- 3.7 GW of Retirements / Suspensions
- New Intermittent Resources
- Base Model Dispatch in MISO and Seams

2.1.1 Generation Pools

To determine an LRZ's import or export limit, a transfer is modeled by ramping generation up in a source subsystem and ramping generation down in a sink subsystem. The source and sink definitions depend on the limit being tested. The LRZ studied for import limits is the sink subsystem and the adjacent MISO LBA's are the source subsystem. The LRZ studied for export limits is the source subsystem and the rest of MISO is the sink subsystem. These are the same in all seasons for the upcoming Planning Year.

Transfers can cause potential issues, which are addressed through the study assumptions. First, an abundantly large source pool spreads the impact of the transfer widely which can cause differences in studied zones transfer capabilities and constraints identified. Second, ramping up generation from remote areas could cause electrically distant constraints for any given LRZ, which should not determine a zone's limit. For example, export constraints due to dispatch of LRZ 1 generation in the northwest portion of the footprint should not limit the import capability of LRZ 10, which covers the MISO portion of Mississippi.

To address these potential issues, the transfer studies limit the source pool for the import studies to the Tier 1 and Tier 2 adjacent LBA's to the study zone. Since the generation that is ramped up in export studies are contained in the study LRZ, these issues only apply to import studies. Generation within the zone studied for an export limit is ramped up and constraints are expected to be near or in the study zone.

2.1.2 Redispatch

Limited redispatch is applied after performing transfer analyses to mitigate constraints. Redispatch ensures constraints are not caused by the base dispatch and aligns with potential actions that can be implemented for the constraint in MISO operations. Redispatch scenarios can be designed to address multiple constraints as required and may be used for constraints that are electrically close to each other or to further optimize transfer limits for several constraints requiring only minor redispatch. The redispatch assumptions include:

- The use of no more than 10 conventional fuel plants or intermittent resources
- Redispatch limit at 2,000 MW total (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units
- No adjustments to the portions of pseudo-tied units committed to non-MISO load

2.1.3 Generation Limited Transfer for CIL/CEL and ZIA/ZEA

When conducting transfer analysis to determine import or export limits, the source subsystem might run out of generation to dispatch before identifying a valid constraint caused by a transmission limit. MISO developed a Generation Limited Transfer (GLT) process to identify transmission constraints in these situations, when possible, for both imports and exports.

After running the First Contingency Incremental Transfer Capability (FCITC) analysis to determine limits for each LRZ, MISO will determine whether a zone is experiencing a GLT (e.g. whether the first constraint would only occur after all the generation is dispatched at its maximum amount). If the LRZ experiences a GLT, MISO will adjust the base model depending on whether it is an import or export analysis and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after dispatching all generation within the exporting system (LRZ under study) MISO will decrease load and generation dispatch in the study zone. The adjustment creates additional capacity to export from the zone. After the adjustments are complete, MISO will rerun the transfer analysis. If a GLT reappears, MISO will make further adjustments to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after dispatching all generation within the source subsystem, MISO will decrease load and generation in the source subsystem. This increases the export capacity of the adjacent LBA's for the study zone. After the adjustments are complete, MISO will run the transfer analysis again. If a GLT reappears, MISO will make further adjustments to the model's load and generation in the source subsystem.

FCITC could indicate the transmission system can support larger thermal transfers than would be available based on installed generation for some zones. However, large variations in load and generation for any zone may lead to unreliable limits and constraints. Therefore, MISO limits load scaling for both import and export studies to 50 percent of the zone's load. In a GLT, redispatch, or GLT plus redispatch scenario, the FCITC of the most limiting constraint might exceed Zonal Export/Import Capability. If the GLT does not produce a limit for a zone(s), due to a valid constraint not being identified, or due to other considerations as listed in the prior paragraph, MISO shall report that LRZ as having no limit and ensure that the limit will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

2.1.4 Voltage Limited Transfer for CIL/CEL and ZIA/ZEA

Zonal imports may be limited by voltage constraints due to a decrease in the generation in the study zone. Voltage constraints might occur at lower transfer levels than thermal limits determined by linear FCITC. As such, LOLE studies may evaluate Power-Voltage curves for LRZs with known voltage-based transfer limitations identified through existing MISO or Transmission Owner studies. Such evaluation may also occur if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from resources outside of the zone. MISO will coordinate with stakeholders as it encounters these scenarios. For Planning Year 2023-2024, all seasons only Zones 1, 4 and 7 import analysis included voltage screening and study. Only LRZ4 Summer identified a voltage limit with lower transfer capability than the thermal limit.

2.2 Powerflow Models and Assumptions

2.2.1 Tools Used

MISO used the Siemens PTI Power System Simulator for Engineering (PSS/E) and Transmission Adequacy and Reliability Assessment (TARA) for analysis tools.

2.2.2 Inputs Required

Thermal transfer analysis requires powerflow models and related input files. MISO used contingency files from MTEP[4] reliability assessment studies. Single-element contingencies in MISO/seam areas were also evaluated.

MISO developed a subsystem file to monitor its footprint and seam areas which was used for all seasons. LRZ definitions were developed as sources and sinks in the study. See Appendix B for tables containing adjacent area definitions (Tiers 1 and 2) used for this study. The monitored file includes all facilities under MISO functional control and single elements in the seam areas of 100 kV and above.

2.2.3 Powerflow Modeling

The MTEP22 models were built using MISO's Model on Demand (MOD) model data repository, with the following base assumptions (Table 2-1).

Scenario	Effective Date	Projects Applied	External Modeling	Load and Generation Profile	Wind %	Solar %
Summer 2023	July 15th	MTEP Appendix A and Target A	2021 Series 2023 Summer ERAG MMWG	Summer Peak	Capacity Credit ~15.5%	50%
Fall 2023	October 15th	MTEP Appendix A and Target A	2021 Series 2023 Summer ERAG MMWG	Fall Peak	32%	28.5%
Winter 2023-2024	January 15th	MTEP Appendix A and Target A	2021 Series 2023 Summer ERAG MMWG	Winter Peak	67%	0%
Spring 2024	April 15th	MTEP Appendix A and Target A	2021 Series 2023 Summer ERAG MMWG	Spring Peak	28.5%	32%

Table 2-1: Model Assumptions

MISO excluded several types of units from the transfer analysis dispatch—these units' base dispatch remained fixed.

- Nuclear dispatch does not change for any transfer
- Wind and solar resources can be ramped down, but not up
- Pseudo-tied resources were modeled at their expected commitments to non-MISO load, although portions of these units committed to MISO could participate in transfer analyses

System conditions such as load, dispatch, topology, and interchange have an impact on transfer capability. The model was reviewed as part of the base model build for MTEP22 analyses, with study files made available on MISO

[4] Refer to the Transmission Planning BPM (BPM-20) for more information regarding MTEP input files. https://www.misoenergy.org/legal/business-practice-manuals/

ShareFile. MISO worked closely with transmission owners and stakeholders in order to model the transmission system accurately, as well as to validate constraints and redispatch. Like other planning studies, transmission outage schedules were not included in the analysis. This is driven partly by limited availability of outage information as well as current transmission planning standards. Although no outage schedules were evaluated, single element contingencies were evaluated. This includes BES lines, transformers, and generators.

Contingency coverage covers most of category P1 and some of category P2 outlined in Table 1 of TPL-001: (https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf).

2.2.4 General Assumptions

MISO uses TARA to process the powerflow model and associated input files to determine the import and export limits of each LRZ in each season by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions. The incremental amount of power that can be transferred is determined through FCITC analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of transferrable power before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (Equation 3-1). All published limits are based on the zone's FCTTC and may be adjusted for capacity exports.

$$First\ Contingency\ Total\ Transfer\ Capability\ (FCTTC) = FCITC + Base\ Power\ Transfer$$

Equation 2-1: Total Transfer Capability

FCITC constraints are identified under base case situations in each season or under P1 contingencies provided through the MTEP process. Linear FCITC analysis identifies the limiting constraints using a minimum transfer Distribution Factor (DF) cutoff of 3 percent, meaning the transfer must increase the loading on the overloaded element, under system intact or contingency conditions, by 3 percent or more.

A pro-rata dispatch is used, which ensures all available generators will reach their maximum dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit.

Table 2-2 and Equation 2-2 show an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Unit Dispatch Max – Unit Dispatch Min)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	**310**

Table 2-2: Example Subsystem

$$\boldsymbol{Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch} = \frac{\boldsymbol{Machine\ 1\ Reserve\ MW}}{\boldsymbol{Source\ Subsystem\ Reserve\ MW}} \times \boldsymbol{Transfer\ Level\ MW}$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = 25.8$$

Equation 2-2: Machine 1 Dispatch Calculation for 100 MW Transfer

2.3 Results for CIL/CEL and ZIA/ZEA

Study constraints and associated ZIA, ZEA, CIL, and CEL for each LRZ for each season were presented and reviewed through the LOLEWG with final results for Planning Year 2023-2024 presented at the October 3rd, 2022 meeting. Table 2-3 below shows the Planning Year 2023-2024 CIL and ZIA with corresponding constraint, GLT, and redispatch (RDS) information.

All zones had an identified ZIA this year. If there is no valid constraint identified the following equation will be used where the FCITC will be replaced by the Tier 1 & 2 capacity.

$$\boldsymbol{ZIA = FCITC + AI - Border\ External\ Resources\ and\ Coordinating\ Owners}$$

Equation 2-3: Zonal Import Ability (ZIA) Calculation

LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2023	North Appleton - Werner W 345kV	North Appleton - Morgan 345kV	15%	494MWx2	5299	5301
Fall 2023	North Appleton - Werner W 345kV	North Appleton - Morgan 345kV	None	636MWx2	6526	6528
Winter 2023/24	Council Bluffs - Sarpy County 345kV	Arbor Hill - Raccoon Trail 345kV	None	681MWx2	4935	4937
Spring 2024	North Appleton - Werner W 345kV	North Appleton - Morgan 345kV	None	328MWx2	6183	6185
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Elk Mound - Wheaton 161kV	King - Eau Claire 345kV	10%	1000MWx2	3477	3477
Fall 2023	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	1000MWx2	4411	4411
Winter 2023/24	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	1000MWx2	4905	4905
Spring 2024	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	603MWx2	4454	4454
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	S3458 3 - S3456 3 345kV	S3455 - S3740 345kV	10%	113MWx2	6043	6108
Fall 2023	No Limit Found		None	None	14,310	14,375
Winter 2023/24	No Limit Found		None	None	10,974	11,039
Spring 2024	Prairie Island - North Rochester 345kV	North Rochester - Hampton Corner 345kV	None	345MWx2	7610	7675
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Bus 636410 Sub P Iowa City 161kV	Hills 345/161kV Transformer	None	None	6992	7884
Fall 2023	Marblehead 161/138kV Transformer	Herlman - Maywood 345kV	None	1000MWx2	4281	5173
Winter 2023/24	Marblehead 161/138kV Transformer	Herlman - Maywood 345kV	None	1000MWx2	3036	3928
Spring 2024	Marblehead 161/138kV Transformer	Herlman - Maywood 345kV	None	935MWx2	5014	5906
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Pike - Cryene 161kV	Maywood - Spencer Creek 345kV	10%	81MWx2	3576	3576
Fall 2023	Mississippi Tap - Sioux 138kV	Loss of Sioux Generation	15%	708MWx2	5380	5380
Winter 2023/24	Overton 345/161kV Transformer	Mc Credie - Overton 345kV	None	1000MWx2	3811	3811
Spring 2024	Calif - Apache Tap 161kV	Mc Credie - Montgomery 345kV	None	244MWx2	3881	3881
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Cayuga Sub - Cayuga 345kV	Kansas - Sugar Creek 345kV	20%	619MWx2	8092	8492
Fall 2023	Jord - West Frankfort 138kV	Mount Vernon - West Frankfort 345kV	None	1000MWx2	5670	6070
Winter 2023/24	Cayuga Sub - Cayuga 345kV	Kansas - Sugar Creek 345kV	None	923MWx2	8418	8818
Spring 2024	Cayuga Sub - Cayuga 345kV	Kansas - Sugar Creek 345kV	None	620MWx2	7762	8162
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Argenta - Tompkins 345kV	Argenta - Battle Creek 345kV	15%	1000MWx2	5087	5087
Fall 2023	Benton Harbor - Segreto 345kV	Cook - Segreto 345kV	None	1000MWx2	4285	4285
Winter 2023/24	Stillwell 345kV/138kV Transformer	Dumont - Stillwell 345kV	None	1000MWx2	6340	6340
Spring 2024	Benton Harbor - Segreto 345kV	Cook - Segreto 345kV	None	1000MWx2	5559	5559
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Lyon - Jonestown 115kV	Crossroads - Moonlake 230kV	None	180MWx2	4091	4139
Fall 2023	Moon Lake - Ritchie 230kV	Clarksdale - Crossroads 230/115kV Transformer	None	372MWx2	4657	4705
Winter 2023/24	Mount Olive - Vienna 115kV	Mount Olive - El Dorado 500kV	None	1000MWx2	4681	4729
Spring 2024	Mount Olive - Vienna 115kV	Mount Olive - El Dorado 500kV	None	181MWx2	4558	4606

LRZ9	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2023	Bogalusa - Barkers Corner 230kV	McKnight - Franklin 500kV	None	1000MWx2	4456	5268
Fall 2023	Braswell - Franklin 500kV	Franklin - Grand Gulf 500kV	None	325MWx2	5233	6045
Winter 2023/24	Camden - Smackover 115kV	McNeil - Camden 115kV	None	963MWx2	5268	6080
Spring 2024	Boogalusa 500/230kV Transformer	McKnight - Franklin 500kV	None	1000MWx2	5438	6250
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Braswell - Northside 230kV	Braswell - Lakeover 500kV	None	38MWx2	3064	3064
Fall 2023	Braswell - Northside 230kV	Braswell - Lakeover 500kV	None	33MWx2	2425	2425
Winter 2023/24	Adams Creek - Angie 230kV	Slidel - Logtown 230kV	None	134MWx2	2396	2396
Spring 2024	Hernando - Coldwater 115kV	Moonlake - Ritchie 230kV	None	31MWx2	2144	2144

Table 2-3: Planning Year 2023–2024 Import Limits

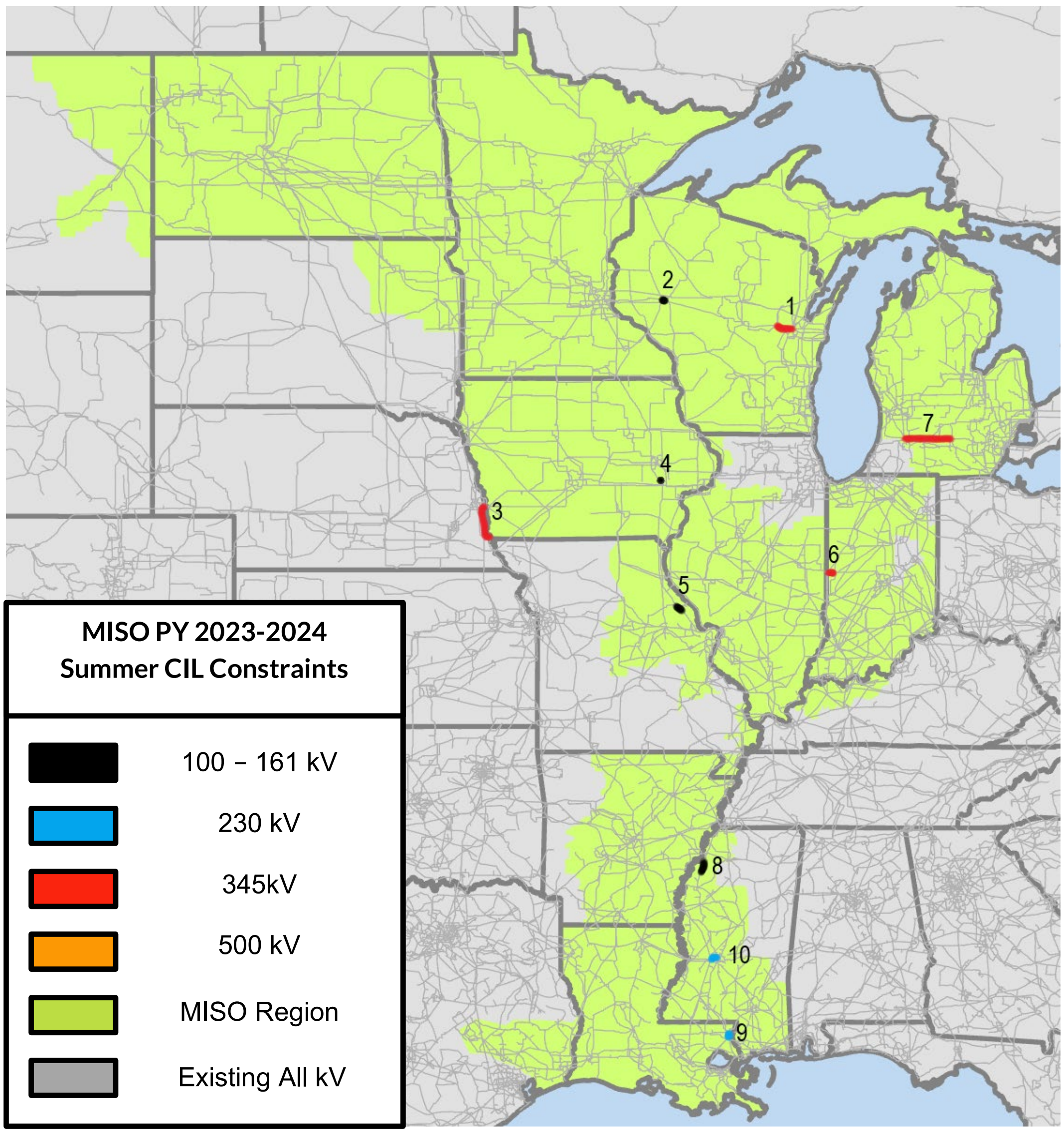


Figure 2-1: Planning Year 2023-2024 Summer Capacity Import Constraints Map

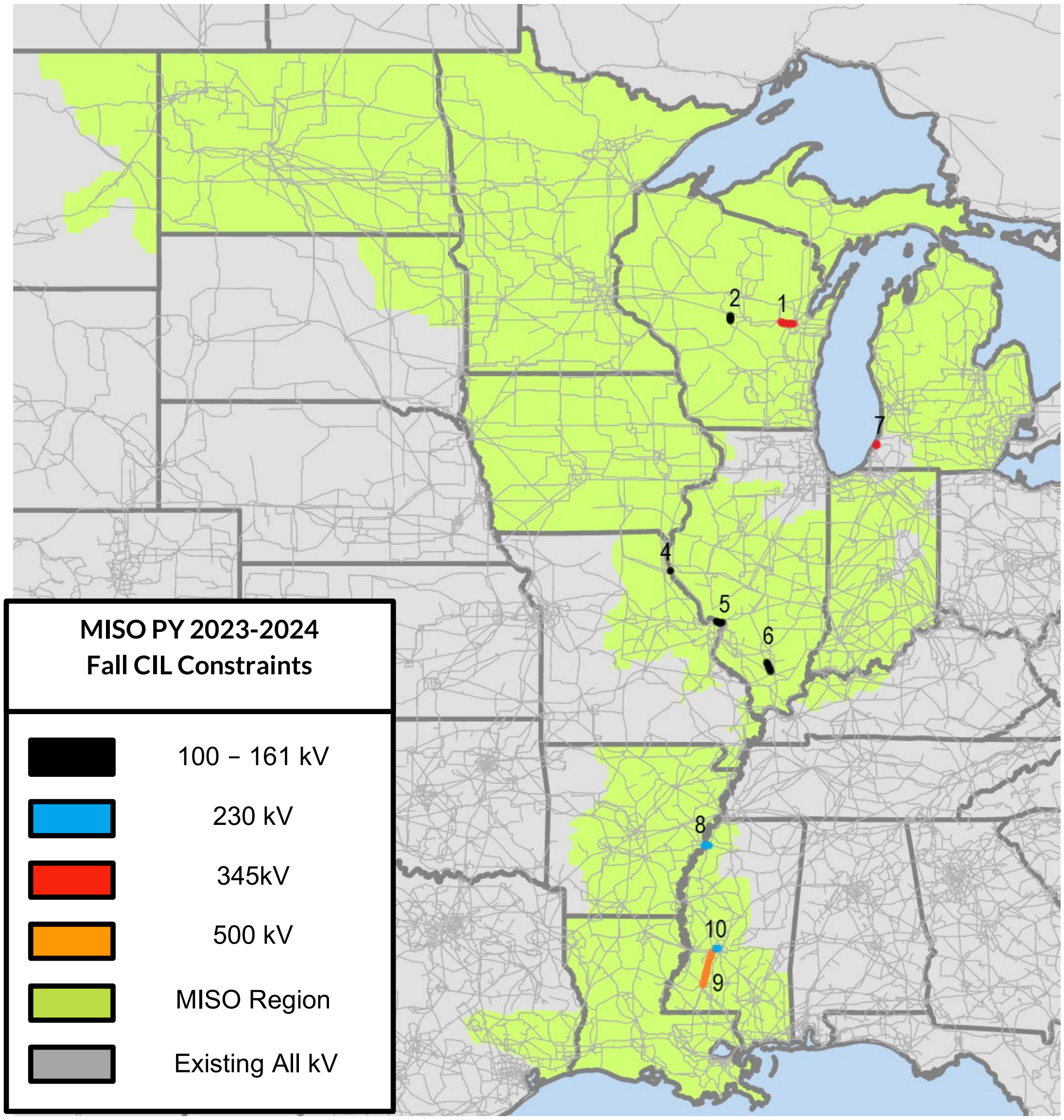


Figure 2-2: Planning Year 2023-2024 Fall Capacity Import Constraints Map

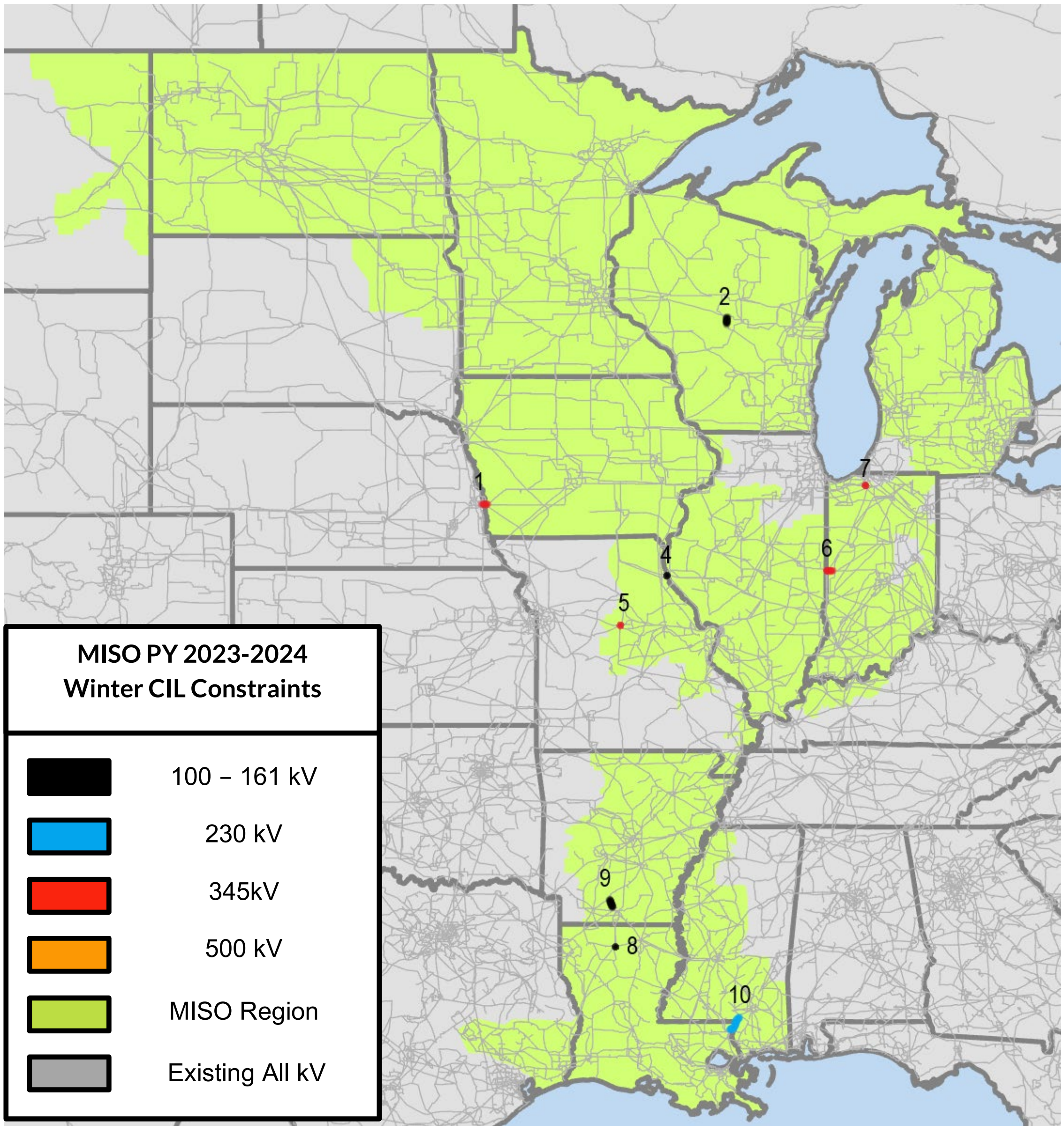


Figure 2-3: Planning Year 2023-2024 Winter Capacity Import Constraints Map

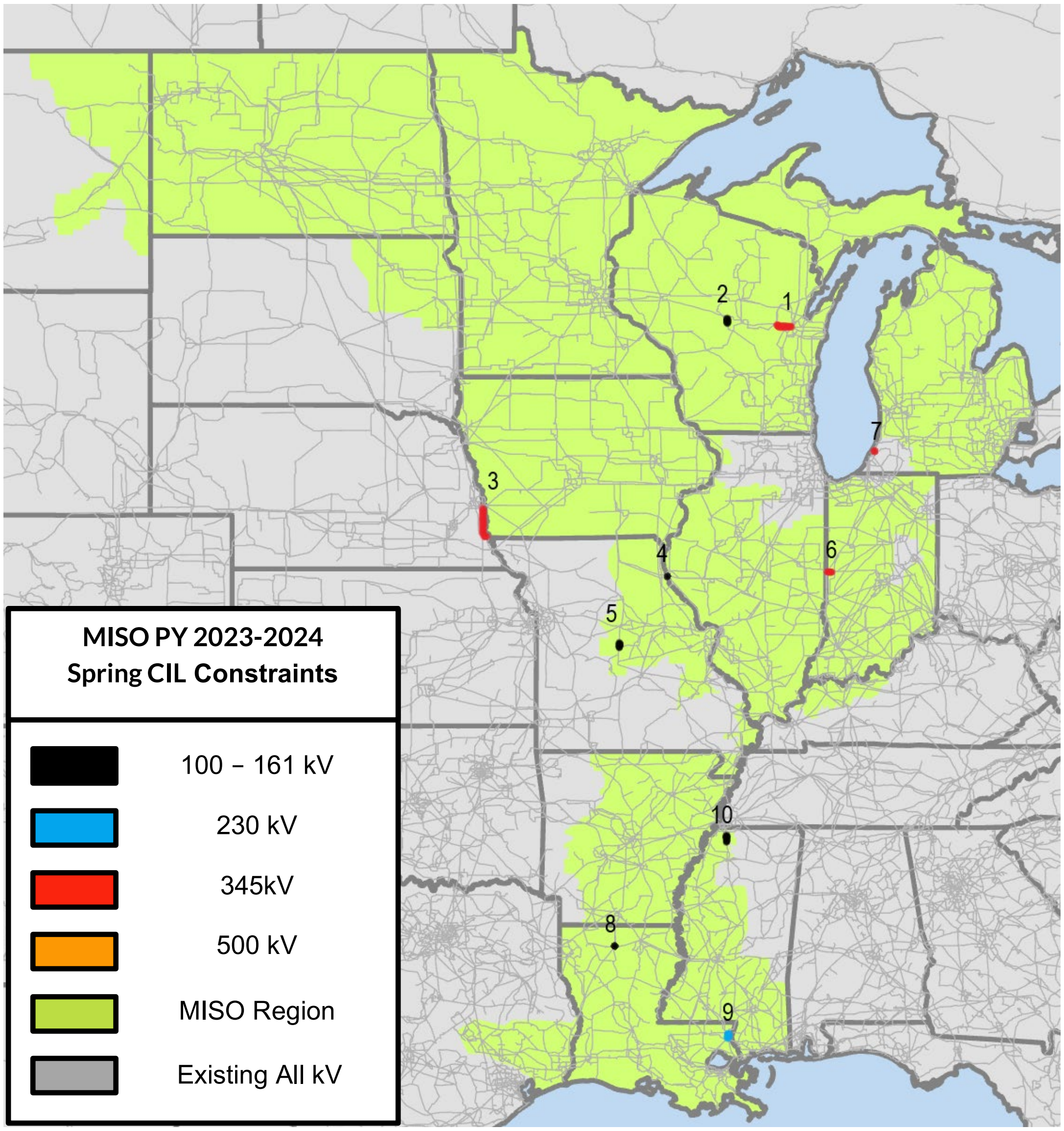


Figure 2-4: Planning Year 2023-2024 Spring Capacity Import Constraints Map

Capacity Exports Limits are found by increasing generation in the study zone and decreasing generation in the rest of the MISO footprint to create a transfer. Table 2-4 below shows the Planning Year 2023-2024 CEL and ZEA with corresponding constraint, GLT, and redispatch information.

LRZ1	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2023	Granville - Butler 138kV	Granville - Arcadian 345kV	15%	None	3961	3959
Fall 2023	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	18MWx2	3806	3804
Winter 2023/24	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	29MWx2	3503	3501
Spring 2024	Rocky Run - Werner 345kV	Highway 22 - Gardner Park 345kV	None	21MWx2	4323	4321
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Wempletown 345/138kV Transformer	Cherry Valley - Wempleton 345kV	20%	None	2550	2550
Fall 2023	Elm Road - Racine 345kV	Base Case	None	None	3577	3577
Winter 2023/24	Pleasant Prairie - Zion EC 345kV	Pleasant Prairie - Zion 345kV	15%	None	4198	4198
Spring 2024	Elm Road - Racine 345kV	Base Case	None	None	3679	3679
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Mercer - Sandburg 161kV	Sandburg - Oak Grove 345kV	45%	None	4375	4310
Fall 2023	Prar Creek - Marion 115	Prar Creek - Bertram 115kV	None	147MWx2	4419	4354
Winter 2023/24	Sandburg 161/138kV Transformer	Sandburg - Oak Grove 345kV	None	109MWx2	7067	7002
Spring 2024	Sandburg 161/138kV Transformer	Sandburg - Oak Grove 345kV	40%	None	6238	6173
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	No CEL Found	No CEL Found	50%	None	9999	9999
Fall 2023	No CEL Found	No CEL Found	50%	None	9999	9999
Winter 2023/24	No CEL Found	No CEL Found	50%	None	9999	9999
Spring 2024	No CEL Found	No CEL Found	50%	None	9999	9999
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	No CEL Found	No CEL Found	45%	None	9999	9999
Fall 2023	Jord - West Frankfort 138kV	Mount Vernon - West Frankfort 345kV	None	None	1992	1992
Winter 2023/24	Miles Avenue - Moro 138kV	Roxford - Moro 345kV	35%	121MWx2	6348	6348
Spring 2024	Mass 345/161 kV Transformer	Joppa - Mass 345kV	None	None	3724	3724
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Franscisco - Duff 345kV	AB Brown - Reid 345kV	15%	206MWx2	3109	2703
Fall 2023	Newtonville - Coleman 161kV	Duff - Coleman 345kV	None	493MWx2	2101	1701
Winter 2023/24	Newtonville- Grandview 138kV	Cutley - Dubois 138kV	None	42MWx2	1642	1242
Spring 2024	Newtonville - Coleman 161kV	AB Brown - Reid 345kV	None	65MWx2	2744	2344
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Monroe - Lulu 345kV	Monroe - Lallendorf 345kV	25%	None	3953	3953
Fall 2023	Monroe - Lulu 345kV	Monroe - Lallendorf 345kV	None	None	3990	3990
Winter 2023/24	Monroe - Lulu 345kV	Monroe - Lallendorf 345kV	None	None	4350	4350
Spring 2024	Monroe - Lulu 345kV	Monroe - Lallendorf 345kV	None	None	4413	4413
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Cash - Jonesboro 161kV	Ises - Powerlane Road 500kV	50%	218MWx2	5551	5503
Fall 2023	Arklahoma - HS EHV 115kV 2	Arklahoma - HS EHV 115kV 2	None	177MWx2	5128	5080
Winter 2023/24	Cash - Jonesboro 161kV	Ises - Powerlane Road 500kV	25%	134MWx2	5399	5351
Spring 2024	Cash - Jonesboro 161kV	Ises - Powerlane Road 500kV	None	177MWx2	5520	5472

LRZ9	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2023	Adams Creek - Angie 230kV	Slidel - Log Town 230kV	None	None	2386	1574
Fall 2023	Wrightsville - Keo 500kV	White Bluff - Keo 500kV	None	None	2338	1526
Winter 2023/24	Adams Creek - Angie 230kV	Slidel - Log Town 230kV	None	None	1689	877
Spring 2024	Adams Creek - Angie 230kV	Slidel - Log Town 230kV	None	None	3052	2240
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Andrus 230/115kV Transformer	Andrus - Indianola	None	510MWx2	1794	1794
Fall 2023	Clarksdale - Lyon 115kV	Crossroads - Moon Lake 230kV	None	284MWx2	2878	2878
Winter 2023/24	Batesville - Tallahachie 161kV	Choctaw - Clay 500kV	None	690MWx2	1980	1980
Spring 2024	Clarksdale - Lyon 115kV	Crossroads - Moon Lake 230kV	None	535MWx2	2720	2720

Table 2-4: Planning Year 2023–2024 Export Limits

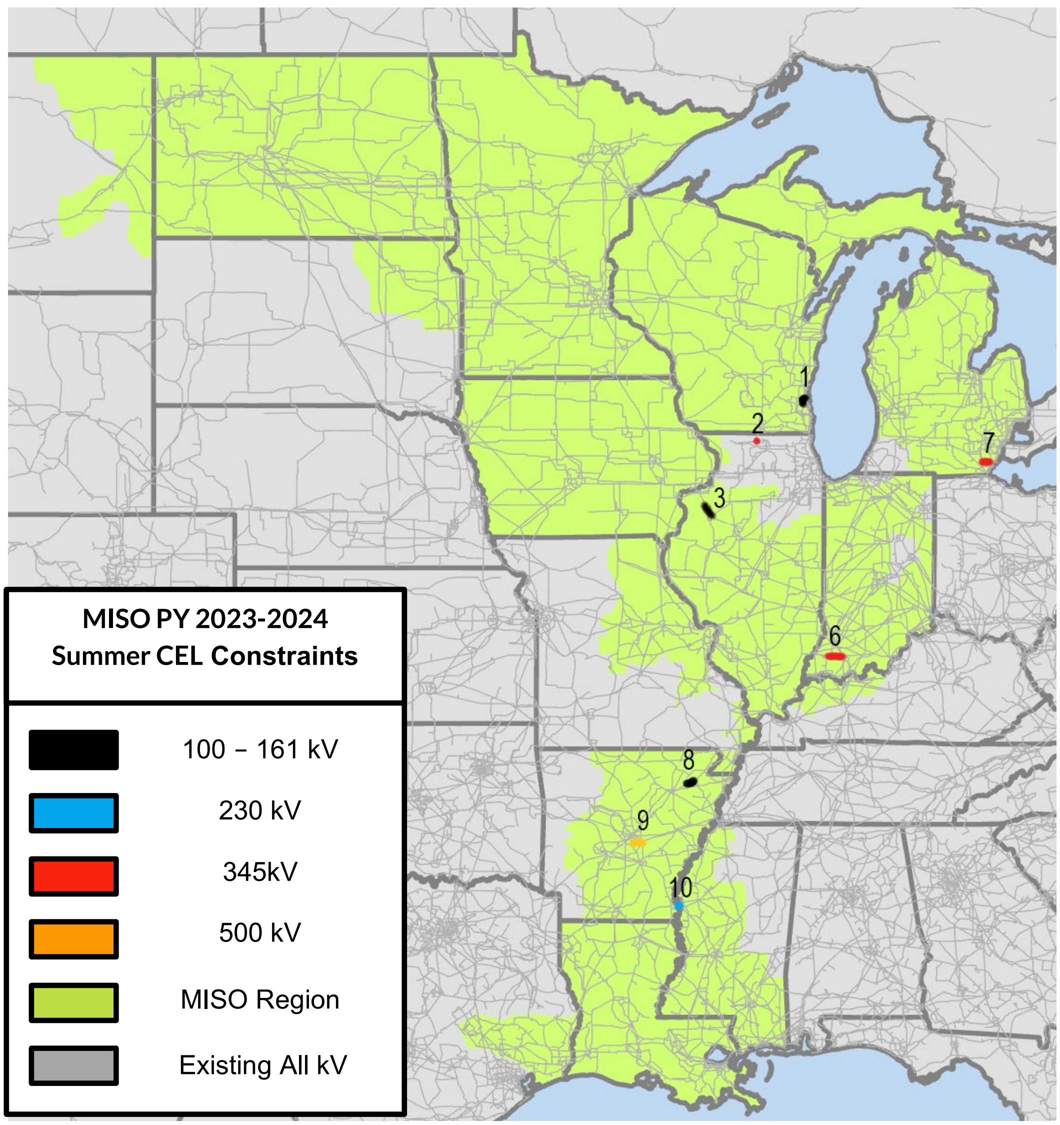


Figure 2-5: Planning Year 2023-2024 Summer Export Constraint Map

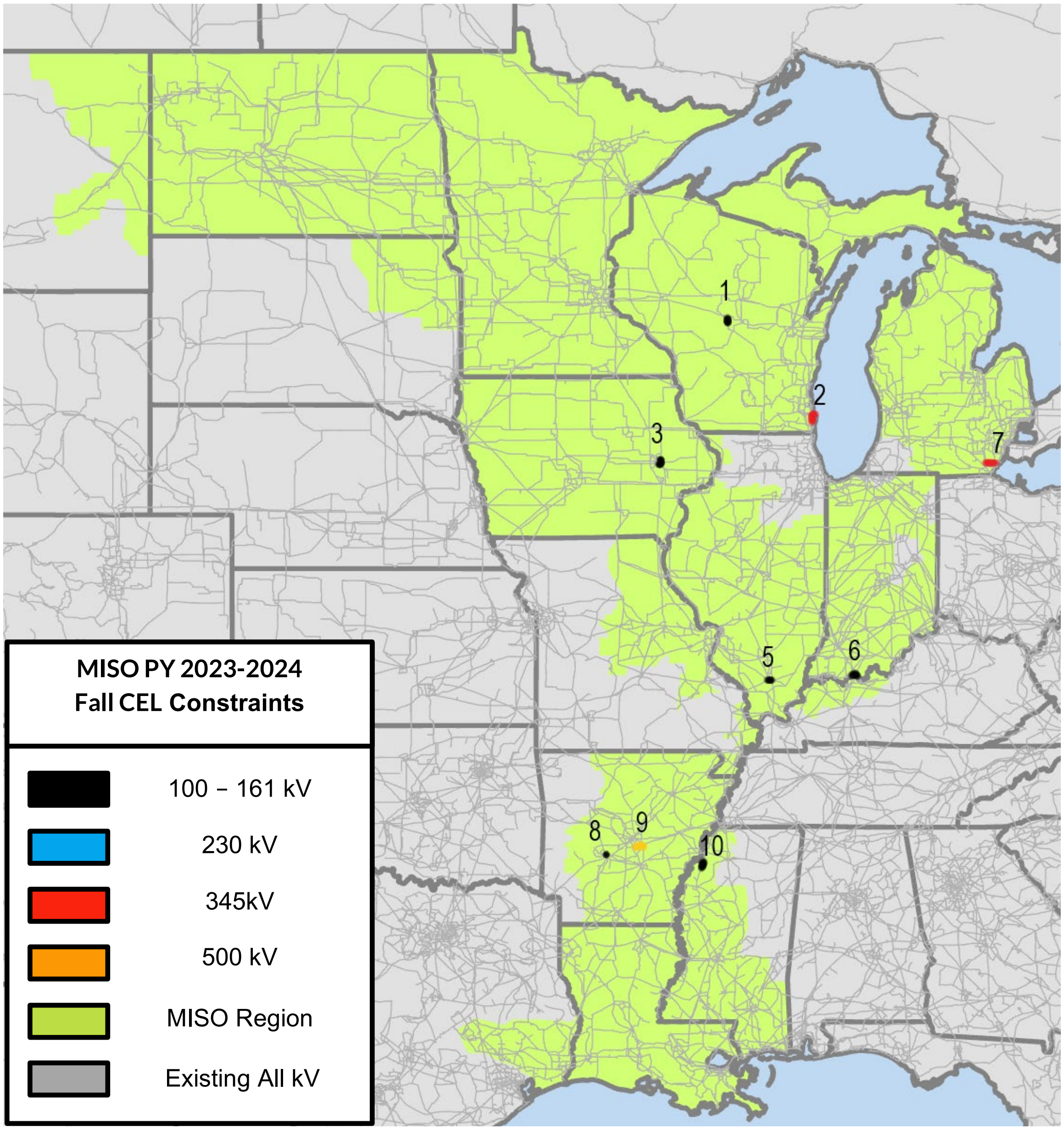


Figure 2-6: Planning Year 2023-2024 Fall Export Constraint Map

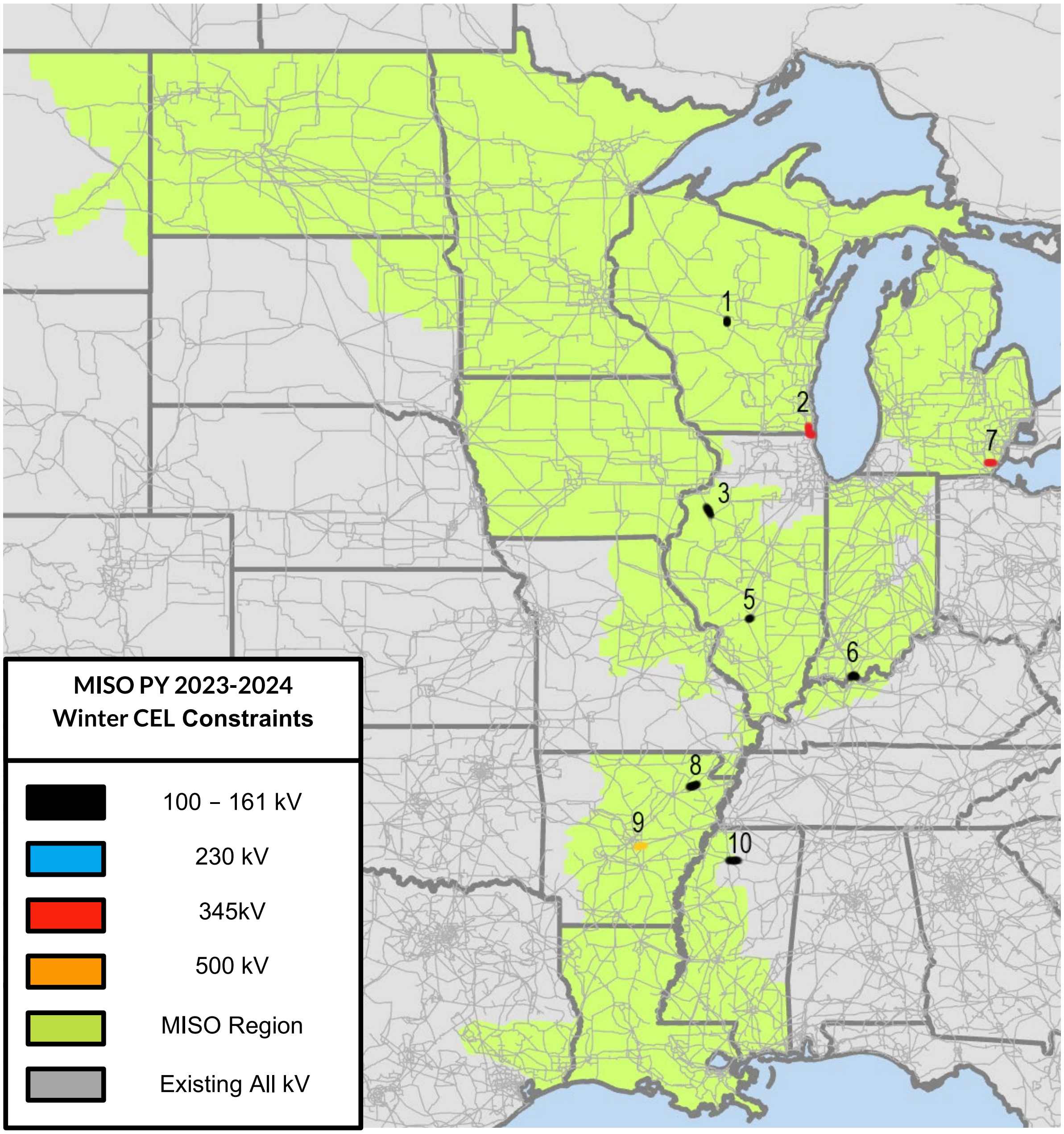


Figure 2-7: Planning Year 2023-2024 Winter Export Constraint Map

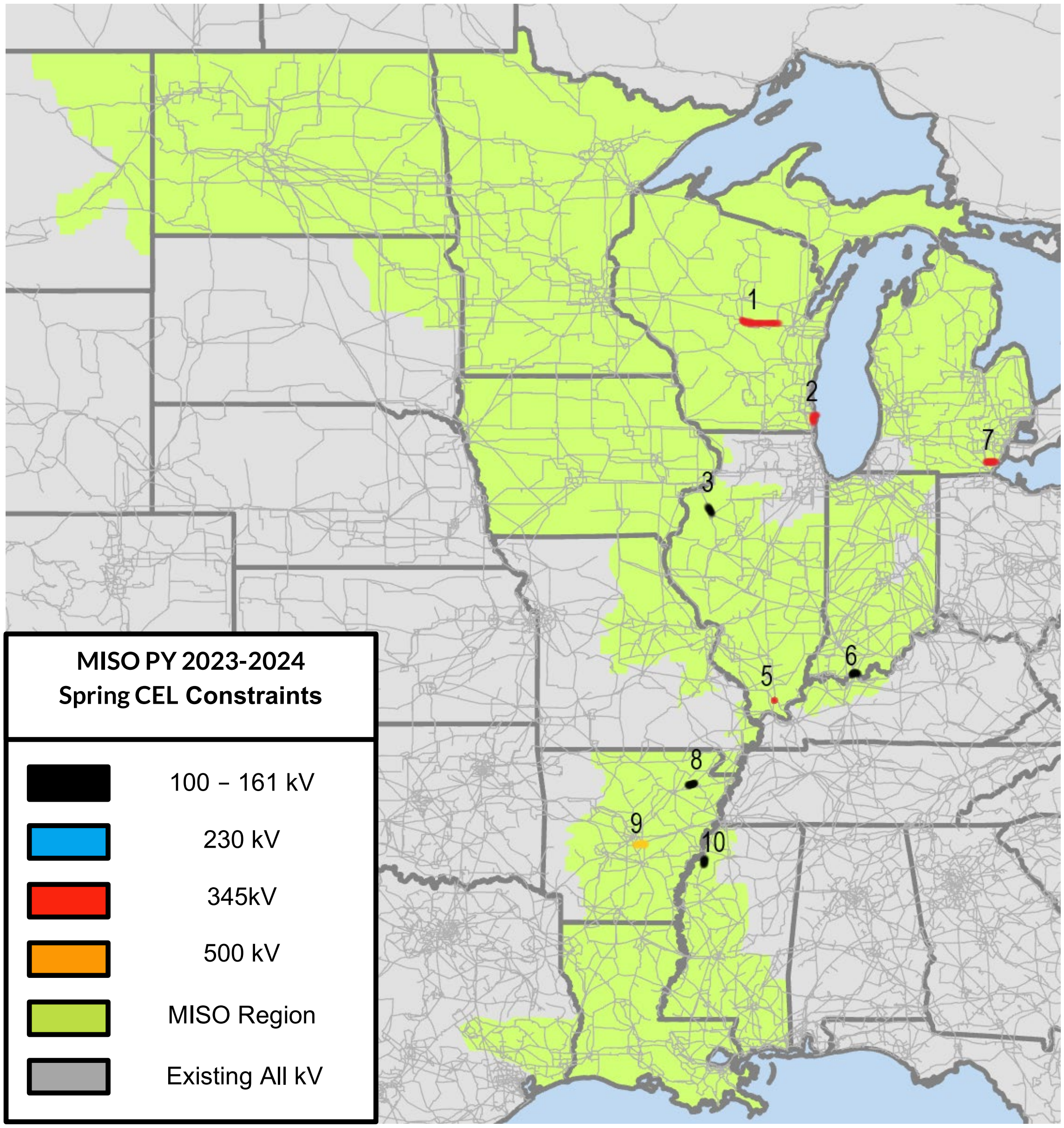


Figure 2-8: Planning Year 2023-2024 Spring Export Constraint Map

2.3.1 Outyear Analysis

In 2018, MISO and its stakeholders redesigned the outyear LOLE transfer analysis process through the LOLEWG and Resource Adequacy Subcommittee (RASC). The outyear analysis is now performed after the prompt Planning Year analyses are complete. The outyear results are informational only. The zones identified for outyear analysis are determined by BPM-011 criteria. The results will be documented outside of the LOLE report and recorded in RASC meeting materials in Q2 of 2023 and memorialized at a later date as an addendum to the LOLE report in 2023.

3 Loss of Load Expectation Analysis

3.1 LOLE Modeling Input Data and Assumptions

MISO uses a program managed by Astrapé Consulting called Strategic Energy & Risk Valuation Model (SERVM) to calculate the LOLE for the applicable Planning Year. SERVM uses a sequential Monte Carlo simulation to model a generation system and to assess the system's reliability based on any number of interconnected areas. SERVM calculates the LOLE for the MISO system and each LRZ by stepping through the year chronologically and taking into account generation, load, load modifying and energy efficiency resources, equipment forced outages, planned and maintenance outages, weather and economic uncertainty, and external support.

Building the SERVM model is the most time-consuming task of the LOLE study. Many scenarios are built in order to determine how certain variables impact the results. The base case models determine the seasonal MISO PRM Installed Capacity (ICAP), PRM UCAP, and the LRRs for each LRZ for future Planning Years one, four and six.

3.2 MISO Generation

3.2.1 Thermal Units

The Planning Year 2023-2024 LOLE study used the 2022-2023 PRA converted capacity as a starting point for which resources to include in the study. This ensured that only resources eligible as a Planning Resources were included in the LOLE study. An exception was made for resources with a signed GIA with an anticipated in-service date for PY 2023-2024—these resources were also included. All internal Planning Resources were modeled in the LRZ in which they are physically located. Additionally, Coordinating Owners and Border External Resources were modeled as being internal to the LRZ in which they are committed to serving load.

Forced outage rates and planned maintenance factors were calculated over a five-year period (January 2017 to December 2021) and modeled as four seasonal values for each unit. Some units did not have five years of historical data in MISO's Generator Availability Data System (PowerGADS)—however, if they had at least 3 consecutive months of seasonal data, unit-specific information was used to calculate their seasonal forced outage rates and maintenance factors. Units with fewer than 3 consecutive months of seasonal unit-specific data were assigned the corresponding MISO seasonal class average forced outage rate and seasonal planned maintenance factor based on their fuel type. The overall MISO ICAP-weighted seasonal class average forced outage rate and seasonal planned maintenance factor are applied in lieu of class averages for classes with fewer than 30 units. When the units are populated into the LOLE model, the weighted outage rate in SERVM may be different from the calculated MISO-wide weighted average because the MISO-wide weighted average excludes units with insufficient operating history. Therefore, the weighted outage rate is recalculated to include units that were assigned class average outage rates to gauge how SERVM views the MISO-wide weighted average. This value is for information only and is not assigned to any units.

Each nuclear unit has a fixed maintenance schedule, which was pulled from publicly available information and was modeled for each of the study years.

The historical class average outage rates as well as the MISO system-wide weighted average forced outage rate are provided in Table 3-1 to show the year-over-year trends, as well as in Table 3-2 on a seasonal basis.

Pooled EFORd GADS Years	2017-2021 (%)	2016-2020 (%)	2015-2019 (%)	2014-2018 (%)	2013-2017 (%)	2012-2016 (%)
LOLE Study Planning Year	**PY 2023-2024 LOLE Study – Summer 2023**	**PY 2022-2023 LOLE Study**	**PY 2021-2022 LOLE Study**	**PY 2020-2021 LOLE Study**	**PY 2019-2020 LOLE Study**	**PY 2018-2019 LOLE Study**
Combined Cycle	5.54	5.85	5.52	5.70	5.370	4.62
Combustion Turbine (0-20 MW)	23.40	35.20	36.38	40.39	23.18	29.02
Combustion Turbine (20-50 MW)	6.30	13.65	14.20	15.29	15.76	13.48
Combustion Turbine (50+ MW)	4.07	4.36	4.76	4.65	5.18	6.19
Diesel Engines	12.79	7.25	10.05	23.53	10.26	10.42
Fluidized Bed Combustion	*	*	*	*	*	*
Hydro (0-30 MW)	*	*	*	*	*	*
Hydro (30+ MW)	*	*	*	*	*	*
Nuclear	*	*	*	*	*	*
Pumped Storage	*	*	*	*	*	*
Steam - Coal (0-100 MW)	*	*	*	5.33	4.60	5.14
Steam - Coal (100-200 MW)	*	*	*	*	*	*
Steam - Coal (200-400 MW)	*	*	10.47	10.16	9.82	9.77
Steam - Coal (400-600 MW)	*	*	*	*	*	*
Steam - Coal (600-800 MW)	*	*	*	*	8.22	7.90
Steam - Coal (800-1000 MW)	*	*	*	*	*	*

Steam - Gas	11.26	11.84	12.91	12.54	11.56	11.94
Steam - Oil	*	*	*	*	*	*
Steam - Waste Heat	*	*	*	*	*	*
Steam - Wood	*	*	*	*	*	*
MISO Weighted System-wide	8.23	9.04	9.36	9.24	9.28	9.16
MISO Weighted as seen in SERVM	7.64	8.95	9.17	9.22	9.18	-

******MISO system-wide weighted forced outage rate used in place of class data for those with less than 30 units reporting 12 or more months of data*

Table 3-1: Historical Class Average Forced Outage Rates

Pooled EFORd GADS Years	2017-2021 (%)	2017-2021 (%)	2017-2021 (%)	2017-2021 (%)
LOLE Study Planning Year 2023-2024	Summer 2023	Fall 2023	Winter 2023-2024	Spring 2024
Combined Cycle	5.54	8.32	4.70	6.19
Combustion Turbine (0-20 MW)	23.40	53.44	42.92	58.75
Combustion Turbine (20-50 MW)	6.30	16.79	56.52	25.23
Combustion Turbine (50+ MW)	4.07	6.60	9.68	4.81
Diesel Engines	12.79	9.32	14.84	8.07
Fluidized Bed Combustion	*	*	*	*
Hydro (0-30 MW)	*	*	*	*
Hydro (30+ MW)	*	*	*	*

Nuclear	*	*	*	*
Pumped Storage	*	*	*	*
Steam - Coal (0-100 MW)	*	*	*	*
Steam - Coal (100-200 MW)	*	*	*	*
Steam - Coal (200-400 MW)	*	*	*	*
Steam - Coal (400-600 MW)	*	*	*	*
Steam - Coal (600-800 MW)	*	*	*	*
Steam - Coal (800-1000 MW)	*	*	*	*
Steam - Gas	12.48	13.66	8.28	11.26
Steam - Oil	*	*	*	*
Steam - Waste Heat	*	*	*	*
Steam - Wood	*	*	*	*
MISO Weighted System-wide	8.23	9.48	12.47	11.42

**MISO system-wide weighted forced outage rate used in place of class data for those with less than 30 units reporting 12 or more months of data*

Table 3-2: Planning Year 2023-2024 Seasonal Class Average Forced Outage Rates

3.2.2 Behind-the-Meter Generation

Behind-the-Meter Generation data came from the Module E Capacity Tracking (MECT) tool. Behind-the-Meter Generation backed by thermal resources were explicitly modeled just as any other thermal generator with a monthly capacity and forced outage rate. Performance data was pulled from PowerGADS. Behind-the-Meter Generation backed by wind or solar resources had their hourly generation tied to the hourly wind and solar profiles in the model.

3.2.3 Attachment Y

MISO obtained information on generating units with approved suspensions or retirements (as of June 1, 2022) through MISO's Attachment Y process. Any unit with approved retirement or suspension in Planning Year 2023-2024 was excluded from the year-one analysis during the months the unit has been approved to be out-of-service for. This same methodology is used for the four- and six-year analyses.

3.2.4 Future Generation

Future thermal generation and upgrades were added to the LOLE model based on unit information in the MISO Generator Interconnection Queue. The LOLE model included units with a signed generator interconnection agreement (as of June 1, 2022). These new units were assigned seasonal class average forced outage rates and planned maintenance factors based on their particular unit class. Units upgraded during the study period reflect the megawatt increase for each month, beginning the month the upgrade was finished. The LOLE analysis also included future wind and solar generation, tied to the same hourly wind and solar profiles used for existing wind and solar resources in the model.

3.2.5 Intermittent Resources

Intermittent resources such as run-of-river hydro, biomass, wind and solar were explicitly modeled as demand-side resources. Run-of-river hydro and biomass provide MISO with a minimum of 3 years and up to 15 years of historical output data during seasonal peak hours, defined as hours ending 15, 16, & 17 EST for summer, fall, and spring, and hours ending 8, 9, 19, & 20 for winter. This data is averaged at the seasonal level and modeled in the LOLE analysis as UCAP for all months within a given season. Each individual unit is modeled and put in the corresponding LRZ.

As a process improvement to the LOLE model for this year's study, in collaboration with the SERVM vendor Astrapé, hourly wind and solar profiles were developed and introduced into the model to better simulate the variance in renewable generation on an hourly basis.

Using historical hourly wind data from 246 front-of-meter wind resources from 2013 to 2021, normalized hourly capacity profiles were developed and aggregated at the LRZ level to represent wind in the model. As a result of the LOLE analysis being based on 30 weather years (1992 – 2021), synthetic shapes were created for the 1992 – 2013 period based on historical wind performance and temperatures. Once the weather and wind performance matching has been performed, the data is analyzed as a function of load to ensure the variability around the load profiles is reasonable.

Solar profiles were developed using historical solar irradiance data from the NREL National Solar Radiation Database (NSRDB) from 1998 – 2021.

For more details, refer to the supporting documentation Astrapé provided for stakeholders at the LOLEWG detailing the development of the wind and solar profiles: MISO Seasonal Inputs for the 2022 LOLE Study

3.2.6 Demand Response

Demand response data came from the MECT tool. These resources were explicitly modeled as dispatch-limited resources. Each demand response program was modeled individually with a monthly capacity, limited to the number of times each program can be called upon, and limited by duration.

3.3 MISO Load Data

The Planning Year 2023-2024 LOLE analysis used a load training process with neural net software to create a neural-net relationship between historical weather and load data. This relationship was then applied to 30 years of hourly historical weather data to create 30 different load shapes for each LRZ in order to capture both load diversity and seasonal variations. The average monthly loads of the predicted load shapes were adjusted to match each LRZ's

Module E 50/50 monthly zonal peak load forecasts for each study year. The results of this process are shown as the MISO System Peak Demand (Table 4-1) and LRZ Peak Demands (Table 5-1, Table 5-2, Table 5-3, & Table5-4).

Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE.

3.3.1 Weather Uncertainty

MISO has adopted a six-step load training process in order to capture the weather uncertainty associated with the 50/50 load forecasts. The first step of this process requires the collection of five years of historical real-time load modifying resource (LMR) performance and load data, as well as the collection of 30 years of historical weather data. Both the LMR and load data are taken from the MISO market for each LBA, while the historical weather data is collected from the National Oceanic and Atmospheric Administration (NOAA) for each LRZ. After collecting the data, the hourly gross load for each LRZ is calculated using the five years of historical data.

The second step of the process is to normalize the five years of load data to consistent economics. With the load growth due to economics removed from 5 years of historical LRZ load, the third step of the process utilizes neural network software to establish functional relationships between the five years of historical weather and load data. In the fourth step of the process the neural network relationships are applied to the 30 years of historical weather data in order to predict/create 30 years' worth of load shapes for each LRZ.

In the fifth step of the load training process, MISO undertakes extreme temperature verification on the 30 years of load shapes to ensure that the hourly load data is accurate at extremely hot or cold temperatures. This is required since there are fewer data points available at the temperature extremes when determining the neural network functional relationships. This lack of data at the extremes can result in inaccurate predictions when creating load shapes, which will need to be corrected before moving forward.

The sixth and final step of the load training process is to average the monthly peak loads of the predicted load shapes and adjust them to match each LR's Module E 50/50 monthly zonal peak load forecasts for each study year. In order to calculate this adjustment, the ratio of the first year's non-coincident peak forecast to the zonal coincident peak forecast is applied to future year's non-coincident peak forecast.

By adopting this new methodology for capturing weather uncertainty MISO is able to model multiple load shapes based off a functional relationship with weather. This modeling approach provides a variance in load shapes, as well as the peak loads observed in each load shape. This approach also provides the ability to capture the frequency and duration of severe weather patterns.

3.3.2 Economic Load Uncertainty

To account for economic load uncertainty in the Planning Year 2023-2024 LOLE model, MISO utilized a normal distribution of electric utility forecast error accounting for projected and actual Gross Domestic Product (GDP), as well as electricity usage. The historic projections for GDP growth were taken from the Congressional Budget Office (CBO), the actual GDP growth was taken from the Bureau of Economic Analysis (BEA), and the electric use was taken from the U.S. Energy Information Administration (EIA). Due to lack of statewide projected GDP data MISO relied on United States aggregate level data when calculating the economic uncertainty.

In order to calculate the electric utility forecast error, MISO first calculated the forecast error of GDP between the projected and actual values. The resulting GDP forecast error was then translated into electric utility forecast error by multiplying by the rate at which electric load grows in comparison to the GDP. Finally, a standard deviation is calculated from the electric utility forecast error and used to create a normal distribution representing the probabilities of the load forecast errors (LFE) as shown in Table 3-3.

	LFE Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability assigned to each LFE				
0.90%	4.8%	24.1%	42.1%	24.1%	4.8%

Table 3-3: Economic Uncertainty

As a result of stakeholder feedback MISO is exploring possible alternative methods for determining economic uncertainty to be used in the LOLE process.

3.4 External System

Firm imports from external areas to MISO are modeled at the individual unit level. The specific external units were modeled with their specific installed capacity amount and their corresponding Equivalent Forced Outage Rate demand (EFORd). This better captures the probabilistic reliability impact of firm external imports. These units are only modeled within the MISO PRM analysis and are not modeled when calculating the LRZ LRRs. Due to the locational Tariff filing, Border and Coordinating Owners External Resources are no longer considered firm imports. Instead, these resources are modeled as internal MISO units and are included in the PRM and LRR analysis. The external resources to include for firm imports were based on the amount offered into the Planning Year 2022-2023 Planning Resource Auction (PRA).

The LOLE analysis incorporates firm exports to neighboring regions where information was available. For units with capacity sold off-system, their monthly capacities were reduced by the megawatt amount exported. These values came from PJM's Reliability Pricing Model (RPM) as well as information on exports to other external areas taken from the Independent Market Monitor (IMM) exclusion list.

Firm exports from MISO to external areas were modeled the same as previous years. Capacity ineligible as MISO capacity due to transactions with external areas is removed from the model. Table 3-4 shows the amount of firm imports and exports in this year's study.

Contracts	Summer ICAP (MW)	Summer UCAP (MW)	Fall ICAP (MW)	Fall UCAP (MW)	Winter ICAP (MW)	Winter UCAP (MW)	Spring ICAP (MW)	Spring UCAP (MW)
Imports (MW)	1,731	1,673	1,734	1,672	1,874	1,819	1,803	1,755
Exports (MW)	2,543	2,287	2,543	2,287	2,543	2,287	2,543	2,287
Net	**-812**	**-614**	**-809**	**-615**	**-669**	**-468**	**-740**	**-532**

Table 3-4: Planning Year 2023-2024 Firm Imports and Exports

Non-firm imports in the Planning Year 2023-2024 LOLE study were modeled as a probabilistic distribution of capacity value. These distributions were developed using historic seasonal NSI data which accounted for imports into MISO during emergency pricing hours. Firm imports cleared in the PRA for each planning year were subtracted from the NSI data to isolate the non-firm values. An additional region was included in SERVM which contained 12,000 MW of perfect generation connected to the MISO system. A distribution of the regions export capability was modeled up to the upper and lower bounds. As SERVM steps through the hourly simulation, random draws on the export limits of the external region were used to represent the amount of capacity MISO could import to meet peak demand. The probability distribution of non-firm external imports used in the LOLE model has been provided in Table 3-5.

	Summer	Fall	Winter	Spring
p5	1,456	649	-	1,777
p10	2,663	1,259	205	2,144
p25	3,674	2,199	1,142	2,768
p50	4,708	3,393	3,143	4,031
p75	5,608	4,537	4,941	5,265
p90	6,465	5,453	7,249	6,271
p95	6,807	6,217	8,452	7,055

Table 3-5: Non-Firm External Import Distribution During Emergency Pricing Hours

3.5 Loss of Load Expectation Analysis and Metric Calculations

Upon completion of the annual LOLE study model refresh, MISO performed probabilistic analyses to determine the seasonal PRM ICAP and PRM UCAP for the Planning Year 2023-2024 as well as the seasonal Local Reliability Requirement for each of the 10 LRZs. These metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the seasonal LOLE targets.

3.5.1 Seasonal LOLE Distribution

To determine the seasonal LOLE distribution that will be used to calculate the PRM and LRRs, MISO followed the process described in Section 68A.2.1 of Module E-1 of the MISO Tariff. This process involves first solving the LOLE model to an annual value of 0.1 and then checking the seasonal distribution of the annual LOLE of 0.1. If a season had an LOLE value of at least 0.01, then it met the minimum seasonal criteria and would be set to that LOLE. If a season had less than 0.01 LOLE, additional analysis was performed until the minimum seasonal criteria of 0.01 LOLE was met.

Example: Assume the model is solved to an annual LOLE of 0.1 with 0.05 occurring in both summer and winter while spring and fall had LOLE values of 0 from this simulation. In this case the summer and winter seasons would not need additional analysis since both had at least 0.01 LOLE naturally when the model was solved to an annual value of 0.1. Since spring and fall had 0 LOLE they would be assigned the LOLE minimum seasonal criteria of 0.01 and additional LOLE simulations would be performed until the minimum seasonal criteria was met.

The seasonal LOLE distribution determined in the Planning Year 2023-2024 LOLE study are shown in Table 3-6.

Region	Summer	Fall	Winter	Spring
MISO-wide	0.1	0.01	0.01	0.01
1	0.08	0.01	0.02	0.01
2	0.1	0.01	0.01	0.01
3	0.07	0.01	0.03	0.01
4	0.04	0.01	0.04	0.01
5	0.04	0.01	0.05	0.01
6	0.05	0.01	0.04	0.01
7	0.07	0.03	0.01	0.01
8	0.01	0.01	0.08	0.01
9	0.06	0.01	0.02	0.01
10	0.05	0.04	0.01	0.01

Table 3-6: Planning Year 2023-2024 Seasonal LOLE Distribution

3.7.1 MISO-Wide LOLE Analysis and PRM Calculation

MISO will determine the appropriate PRM for each season of the applicable Planning Year based upon probabilistic analysis of reliably serving expected demand. The probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations.

To determine the PRM, the LOLE model will initially be run with no adjustments to the capacity. If the LOLE is less than 0.1 day per year, a negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. This is comparable to adding load to the model. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

MISO's annual LOLE study will calculate the seasonal PRMs based on the LOLE targets identified in the previous section. The minimum seasonal PRM requirement will be determined using the LOLE analysis by either adding a zero EFORd, negative output unit or adding proxy units until a minimum LOLE of 0.01 day per season is reached.

The formulas for the PRM values for the MISO system are:

PRM ICAP % = (Installed Capacity + Firm External Support ICAP + ICAP Adjustment to meet LOLE target – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

PRM UCAP % = (Unforced Capacity + Firm External Support UCAP + UCAP Adjustment to meet LOLE target – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

Where Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – XEFORd)

3.7.2 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the LRZ analysis, each LRZ included only the generating units within the LRZ (including Coordinating Owners and Border External Resources) and was modeled without consideration of the benefit of the LRZ's import capability. Much like the MISO analysis, unforced capacity is either added or removed in each LRZ such that an LOLE of 0.1 day per year is achieved when solving for the annual target and a minimum LOLE at least 0.01 day per season when solving for a seasonal target. The minimum amount of unforced capacity above each LRZ's Peak Demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

The Planning Year 2023-2024 seasonal LRRs were determined using the LOLE analysis by first either adding or removing capacity until the annual LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

After solving each LRZ for to the annual LOLE target of 0.1 day per year, MISO will calculate each seasonal LRR such that the summation of seasonal LOLE across the year in each zone is 1 day in 10 years, or 0.1 day per year. An LOLE target of 0.01 will be used to calculate the LRR in seasons with less than 0.01 LOLE risk. The seasonal Local Reliability Requirement will be determined using the LOLE analysis by either adding a zero EFORd, negative output unit or adding proxy units until a minimum LOLE of 0.01 day per season is reached.

For Planning Year 2023-2024, only LRZ-1 had sufficient capacity internal to the LRZ to achieve any of the seasonal LOLE targets as an island. In the nine zones without sufficient capacity as an island, proxy units of typical size (160 MW) and class average seasonal EFORd were added to the LRZ. When needed, a fraction of the final proxy unit was added to achieve the exact seasonal LOLE target for the LRZ.

LRR UCAP % = (Unforced Capacity + UCAP Adjustment to meet LOLE target – Zonal Coincident Peak Demand)/Zonal Coincident Peak Demand

4 MISO System Planning Reserve Margin Results

4.1 Planning Year 2023-2024 MISO Planning Reserve Margin Results

For Planning Year 2023-2024, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 15.9 percent and a planning UCAP reserve margin of 7.4 percent for the summer season. Numerous values and calculations went into determining the MISO system PRM ICAP and PRM UCAP (Table 4-1).

MISO Planning Reserve Margin (PRM)	**2023/2024 PY** Summer	**2023/2024 PY** Fall	**2023/2024 PY** Winter	**2023/2024 PY** Spring	**Formula Key**
MISO System Peak Demand (MW)	123,711	111,012	103,455	99,113	[A]
Installed Capacity (ICAP) (MW)	144,268	144,992	150,673	145,366	[B]
Unforced Capacity (UCAP) (MW)	133,764	132,911	134,503	130,753	[C]
Firm External Support (ICAP) (MW)	1,731	1,734	1,874	1,803	[D]
Firm External Support (UCAP) (MW)	1,707	1,714	1,857	1,778	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-2,650	-7,100	-6,500	-9,150	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-2,650	-7,100	-6,500	-9,150	[G]
ICAP PRM Requirement (PRMR) (MW)	143,349	139,626	146,047	138,019	[H]=[B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	132,821	127,525	129,860	123,381	[I]=[C]+[E]+[G]
MISO PRM ICAP	**15.9%**	**25.8%**	**41.2%**	**39.3%**	[J]=([H]-[A])/[A]
MISO PRM UCAP	**7.4%**	**14.9%**	**25.5%**	**24.5%**	[K]=([I]-[A])/[A]

Table 4-1: Planning Year 2023-2024 MISO System Planning Reserve Margins

4.2 Comparison of PRM Targets Across 10 Years

Figure 4-1 compares the PRM UCAP values over the last 10 Planning Years. The last endpoint of the green line shows the Planning Year 2023-2024 Summer PRM value.

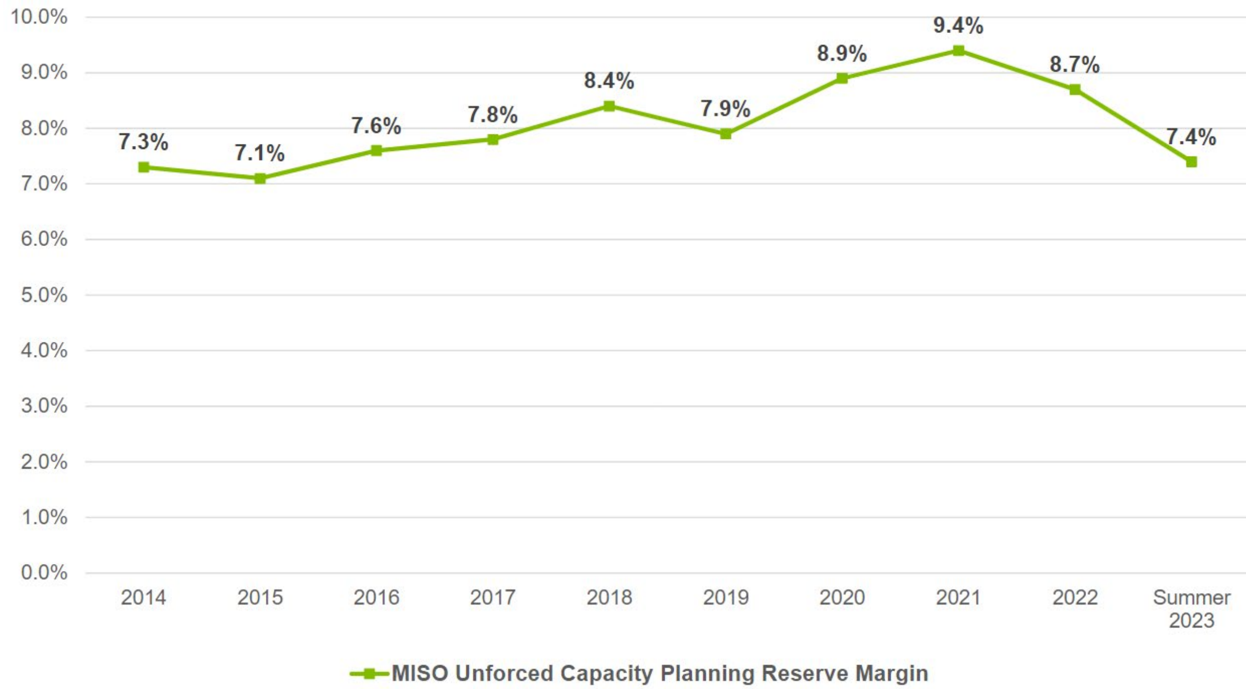


Figure 4-1: Comparison of PRM Targets Across 10 Years

4.3 Future Years 2023 through 2032 Planning Reserve Margins

Beyond the Planning Year 2023-2024 LOLE study analysis, an LOLE analysis will be performed for the four-year-out Planning Year of 2026-2027, as well as for the six-year-out Planning Year of 2028-2029. All other future Planning Years in scope will be derived from interpolation and extrapolation of the three modeled Planning Years.

5 Local Resource Zone Analysis – LRR Results

5.1 Planning Year 2023-2024 Local Resource Zone Analysis

MISO calculated the per-unit LRR of LRZ Seasonal Peak Demand for Planning Year 2023-2024 on a seasonal basis (Table 5-1, Table 5-2, Table 5-3, and Table 5-4). The UCAP values in the seasonal LRR tables reflect the assumed seasonal UCAP within each LRZ, including Border External Resources and Coordinating Owners. The adjustments to UCAP values are the megawatt adjustments needed in each LRZ so that the reliability criterion of 0.1 days per year LOLE is met. The LRR is the summation of the UCAP and adjustment to UCAP megawatts. The LRR is then divided by each LRZ's Seasonal Peak Demand to determine the per-unit LRR UCAP. The Planning Year 2023-2024 per-unit LRR UCAP values will be multiplied by the updated seasonal peak demand forecasts submitted for the 2023-2024 PRA to determine each LRZ's LRR. The zonal LRR LOLE targets have been provided for peak demand timestamps for all 30 weather years modeled in SERVM is shown in Table 5-5. These peak demand timestamps are the result of the SERVM load training process and are not necessarily the actual peaks for each year.

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2023-2024 Local Reliability Requirements – Summer 2023											
Installed Capacity (ICAP) (MW)	21,839	13,026	11,651	8,734	7,917	17,585	21,512	11,290	24,264	6,449	[A]
Unforced Capacity (UCAP) (MW)	20,843	12,145	11,225	7,986	7,410	15,973	20,476	10,866	21,097	5,743	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-255	2,062	1,583	3,242	2,859	4,844	3,952	403	2,897	1,209	[C]
LRR (UCAP) (MW)	20,588	14,207	12,808	11,228	10,269	20,817	24,428	11,269	23,994	6,952	[D]=[B]+[C]
Peak Demand (MW)	18,077	12,686	9,859	9,263	7,704	17,760	20,855	7,652	20,739	4,521	[E]
LRR UCAP per-unit of LRZ Peak Demand	**113.9%**	**112.0%**	**129.9%**	**121.2%**	**133.3%**	**117.2%**	**117.1%**	**147.3%**	**115.7%**	**153.8%**	[F]=[D]/[E]

Table 5-1: Planning Year 2023-2024 LRZ Local Reliability Requirements for Summer 2023

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2023-2024 Local Reliability Requirements – Fall 2023											
Installed Capacity (ICAP) (MW)	21,895	13,096	12,134	8,748	8,068	17,659	21,574	11,149	24,245	6,424	[A]
Unforced Capacity (UCAP) (MW)	20,460	12,097	11,545	7,787	7,201	16,014	20,269	10,190	21,787	5,561	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,230	1,289	1,046	3,138	2,625	4,170	3,848	28	2,821	1,177	[C]
LRR (UCAP) (MW)	19,230	13,386	12,591	10,925	9,825	20,184	24,117	10,218	24,607	6,738	[D]=[B]+[C]
Peak Demand (MW)	15,093	10,991	8,942	8,713	6,767	16,180	17,933	6,858	19,258	4,162	[E]
LRR UCAP per-unit of LRZ Peak Demand	**127.4%**	**121.8%**	**140.8%**	**125.4%**	**145.2%**	**124.7%**	**134.5%**	**149.0%**	**127.8%**	**161.9%**	[F]=[D]/[E]

Table 5-2: Planning Year 2023-2024 LRZ Local Reliability Requirements for Fall 2023

Local Resource Zone (LRZ)	**LRZ-1 MN/ND**	**LRZ-2 WI**	**LRZ-3 IA**	**LRZ-4 IL**	**LRZ-5 MO**	**LRZ-6 IN**	**LRZ-7 MI**	**LRZ-8 AR**	**LRZ-9 LA/TX**	**LRZ-10 MS**	**Formula Key**
PY 2023-2024 Local Reliability Requirements – Winter 2023-2024											
Installed Capacity (ICAP) (MW)	22,449	13,578	14,291	9,028	8,528	18,244	21,710	11,298	24,921	6,626	[A]
Unforced Capacity (UCAP) (MW)	20,931	12,041	13,353	7,125	7,032	16,480	20,151	9,901	21,775	5,714	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-255	1,536	1,491	3,054	2,692	4,562	1,789	379	2,728	1,138	[C]
LRR (UCAP) (MW)	20,676	13,577	14,844	10,179	9,724	21,042	21,940	10,280	24,503	6,852	[D]=[B]+[C]
Peak Demand (MW)	14,738	9,549	8,025	7,456	6,599	16,173	13,945	6,839	18,523	3,856	[E]
LRR UCAP per-unit of LRZ Peak Demand	**140.3%**	**142.2%**	**185.0%**	**136.5%**	**147.4%**	**130.1%**	**157.3%**	**150.3%**	**132.3%**	**177.7%**	[F]=[D]/[E]

Table 5-3: Planning Year 2023-2024 LRZ Local Reliability Requirements for Winter 2023-2024

Local Resource Zone (LRZ)	**LRZ-1 MN/ND**	**LRZ-2 WI**	**LRZ-3 IA**	**LRZ-4 IL**	**LRZ-5 MO**	**LRZ-6 IN**	**LRZ-7 MI**	**LRZ-8 AR**	**LRZ-9 LA/TX**	**LRZ-10 MS**	**Formula Key**
PY 2023-2024 Local Reliability Requirements – Spring 2024											
Installed Capacity (ICAP) (MW)	21,224	13,196	12,339	8,776	8,281	18,041	21,224	11,228	24,631	6,427	[A]
Unforced Capacity (UCAP) (MW)	19,769	11,963	11,601	7,265	7,342	16,150	19,638	9,700	21,470	5,856	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,330	626	1,147	2,907	2,371	3,615	1,836	152	2,601	726	[C]
LRR (UCAP) (MW)	18,439	12,590	12,748	10,172	9,713	19,765	21,475	9,852	24,071	6,582	[D]=[B]+[C]
Peak Demand (MW)	13,407	9,938	7,856	6,998	6,034	14,977	16,157	6,055	18,310	3,768	[E]
LRR UCAP per-unit of LRZ Peak Demand	**137.5%**	**126.7%**	**162.3%**	**145.4%**	**161.0%**	**132.0%**	**132.9%**	**162.7%**	**131.5%**	**174.7%**	[F]=[D]/[E]

Table 5-4: Planning Year 2023-2024 LRZ Local Reliability Requirements for Spring 2024

Weather Year Time of Peak Demand (ESTHE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
1992	7/9/92 16:00	8/9/92 17:00	8/10/92 18:00	7/8/92 17:00	7/2/92 15:00	7/2/92 17:00	1/16/92 8:00	7/2/92 16:00	7/16/92 17:00	7/11/92 18:00	7/12/92 17:00
1993	7/27/93 17:00	8/11/93 17:00	8/27/93 14:00	8/22/93 19:00	7/17/93 17:00	7/27/93 16:00	7/25/93 16:00	7/9/93 15:00	7/31/93 17:00	8/14/93 16:00	7/31/93 18:00
1994	7/6/94 15:00	6/14/94 17:00	6/15/94 17:00	7/19/94 17:00	7/5/94 17:00	7/19/94 18:00	1/19/94 6:00	6/18/94 17:00	6/29/94 18:00	8/14/94 17:00	7/5/94 17:00
1995	7/13/95 17:00	7/13/95 18:00	7/13/95 16:00	7/14/95 17:00	7/14/95 17:00	7/13/95 16:00	7/13/95 17:00	7/13/95 17:00	8/17/95 14:00	7/27/95 17:00	7/12/95 15:00
1996	6/29/96 17:00	8/6/96 17:00	6/29/96 17:00	7/18/96 17:00	7/18/96 18:00	7/18/96 17:00	7/19/96 17:00	8/7/96 15:00	7/20/96 15:00	2/5/96 7:00	7/3/96 18:00
1997	7/26/97 16:00	7/16/97 16:00	7/16/97 17:00	7/25/97 18:00	7/18/97 16:00	7/26/97 17:00	7/26/97 16:00	7/16/97 16:00	7/25/97 18:00	8/16/97 16:00	7/25/97 18:00
1998	7/20/98 16:00	7/13/98 16:00	6/25/98 18:00	7/20/98 18:00	7/20/98 18:00	7/19/98 16:00	7/19/98 17:00	6/25/98 18:00	7/6/98 17:00	8/28/98 18:00	8/27/98 15:00
1999	7/30/99 14:00	7/25/99 15:00	7/13/95 16:00	7/30/99 18:00	7/18/99 22:00	7/30/99 17:00	7/26/97 16:00	7/30/99 14:00	7/25/99 17:00	8/14/99 18:00	8/20/99 18:00
2000	8/31/00 16:00	6/8/00 19:00	9/1/00 17:00	8/31/00 16:00	9/1/00 15:00	8/17/00 16:00	9/1/00 15:00	9/1/00 14:00	7/19/00 17:00	8/30/00 16:00	8/30/00 17:00
2001	8/8/01 16:00	8/7/01 16:00	8/9/01 16:00	7/31/01 16:00	7/23/01 17:00	7/23/01 17:00	8/7/01 17:00	8/8/01 16:00	7/11/01 16:00	7/10/01 16:00	7/20/01 17:00
2002	7/3/02 16:00	7/6/02 18:00	8/1/02 15:00	7/20/02 18:00	7/5/02 17:00	8/1/02 16:00	8/3/02 16:00	7/3/02 16:00	7/9/02 17:00	8/2/02 19:00	10/4/02 15:00
2003	8/21/03 16:00	8/24/03 17:00	8/21/03 16:00	7/26/03 18:00	8/21/03 16:00	8/21/03 18:00	8/27/03 17:00	8/21/03 17:00	7/18/03 14:00	8/10/03 16:00	7/17/03 17:00
2004	7/22/04 16:00	6/7/04 17:00	7/22/04 16:00	7/20/04 17:00	7/13/04 17:00	7/13/04 16:00	1/31/04 9:00	7/22/04 16:00	7/14/04 17:00	7/24/04 17:00	7/25/04 15:00
2005	7/24/05 17:00	7/17/05 17:00	7/24/05 16:00	7/25/05 17:00	7/24/05 16:00	7/24/05 18:00	7/25/05 17:00	7/24/05 18:00	8/21/05 18:00	7/25/05 16:00	8/21/05 15:00
2006	7/31/06 17:00	7/31/06 17:00	8/1/06 17:00	7/19/06 18:00	7/31/06 18:00	7/31/06 16:00	7/31/06 16:00	7/31/06 16:00	7/31/93 17:00	8/15/06 18:00	7/16/06 15:00
2007	8/1/07 17:00	7/26/07 15:00	8/2/07 15:00	7/17/07 17:00	8/15/07 18:00	8/15/07 18:00	8/29/07 17:00	7/31/07 18:00	8/17/95 14:00	8/14/07 15:00	8/14/07 15:00

2008	7/16/08 17:00	7/11/08 18:00	7/17/08 17:00	8/3/08 17:00	7/20/08 17:00	7/20/08 16:00	8/23/08 16:00	8/24/08 12:00	8/17/95 14:00	7/20/08 17:00	7/27/08 16:00
2009	6/25/09 16:00	6/22/09 19:00	7/28/09 16:00	7/24/09 18:00	8/9/09 16:00	8/9/09 16:00	1/16/09 8:00	6/25/09 16:00	6/22/09 16:00	7/2/09 16:00	7/2/09 18:00
2010	8/10/10 17:00	8/8/10 18:00	8/20/10 14:00	7/17/10 19:00	7/15/10 15:00	8/3/10 16:00	8/2/91 18:00	9/1/10 17:00	8/17/95 14:00	8/1/10 17:00	8/2/10 17:00
2011	7/20/11 18:00	6/7/11 19:00	7/13/95 16:00	7/20/11 16:00	9/1/11 16:00	8/31/11 16:00	7/26/97 16:00	7/20/11 19:00	7/31/93 17:00	7/2/11 17:00	7/10/11 18:00
2012	7/6/12 17:00	7/6/12 18:00	7/13/95 16:00	7/7/12 16:00	7/7/12 17:00	7/25/12 18:00	7/26/97 16:00	7/6/12 17:00	7/30/12 17:00	6/26/12 16:00	7/3/12 15:00
2013	7/19/13 16:00	7/18/13 19:00	8/27/13 16:00	8/30/13 16:00	9/11/13 16:00	8/31/13 17:00	8/31/13 15:00	7/19/13 14:00	6/27/13 18:00	8/7/13 16:00	8/8/13 17:00
2014	7/22/14 16:00	7/22/14 17:00	7/22/14 16:00	7/22/14 16:00	9/5/14 16:00	7/26/14 15:00	2/7/14 9:00	7/22/14 17:00	7/27/14 17:00	8/23/14 16:00	7/26/14 17:00
2015	7/29/15 16:00	8/14/15 15:00	8/14/15 17:00	7/13/15 15:00	9/3/15 16:00	7/13/15 16:00	7/18/15 17:00	8/2/15 16:00	8/7/15 18:00	8/10/15 16:00	7/30/15 16:00
2016	7/20/16 15:00	7/21/16 17:00	8/10/16 17:00	7/22/16 16:00	9/22/16 16:00	7/23/16 17:00	6/11/16 14:00	8/10/16 14:00	7/20/16 13:00	9/1/16 16:00	7/20/16 15:00
2017	7/20/17 16:00	7/6/17 17:00	6/12/17 14:00	7/21/17 17:00	9/26/17 15:00	7/12/17 15:00	9/26/17 16:00	6/12/17 14:00	7/21/17 15:00	8/19/17 15:00	7/20/17 15:00
2018	6/29/18 15:00	6/29/18 15:00	6/29/18 15:00	5/28/18 14:00	9/5/18 15:00	8/6/18 16:00	9/5/18 16:00	9/5/18 15:00	1/17/18 6:00	1/17/18 6:00	9/19/18 16:00
2019	7/19/19 14:00	7/19/19 18:00	7/19/19 16:00	7/19/19 14:00	9/12/19 16:00	10/1/19 15:00	9/13/19 16:00	7/19/19 13:00	8/13/19 14:00	10/4/19 15:00	10/2/19 16:00
2020	7/9/20 15:00	7/2/20 17:00	8/27/20 14:00	7/8/20 14:00	7/8/20 15:00	7/11/20 15:00	8/25/20 15:00	7/9/20 15:00	7/12/20 15:00	7/11/20 15:00	9/4/20 16:00
2021	8/24/21 15:00	7/27/21 16:00	8/10/21 15:00	7/28/21 16:00	8/27/21 15:00	8/25/21 16:00	8/24/21 16:00	8/24/21 15:00	8/10/21 14:00	8/23/21 16:00	7/29/21 14:00

Table 5-5: Historical Peak Days/Hours by Local Resource Zone

6 Appendix A: Comparison of Planning Year 2022 to 2023

Multiple study sensitivity analyses were performed to compute changes in the PRM target on an UCAP basis, from Planning Year 2022-2023 to Planning Year 2023-2024. These sensitivities included one-off incremental changes of input parameters to quantify how each change affected the PRM result independently. Note the impact of the incremental PRM changes from Planning Year 2022-2023 to Planning Year 2023-2024 in the waterfall chart of Figure A-1. Summer was determined to be the season most comparable to the annual PRM from last year's study. The following subsections provide more details around each of the sensitivities.

Figure A-1: Waterfall Chart of PY 2022-2023 Annual PRM UCAP to PY 2023-2024 Summer PRM UCAP

6.1 A.1 Waterfall Chart Details

6.1.1 A.1.1 Load

The MISO Coincident Peak Demand increased from the 2021-2022 planning year, which was driven by the updated actual load forecasts submitted by the LSEs. Overall, the magnitude of changes in the load profiles and economic uncertainty resulted in a slight decrease in the PRM.

6.1.2 A.1.2 Units

Changes from 2022-2023 planning year values are due to changes in Generation Verification Test Capacity (GVTC), seasonal EFORd or equivalent forced outage rate demand, new units, retirements, suspensions, and changes in the resource mix. The MISO fleet weighted average forced outage rate decreased from an annual 9.04 percent to a summer value of 8.23 percent from the previous study to this study. A general decrease in unit outage rates lead to a decrease in summer reserve margin. Non-firm support was included in the model which resulted in a slight decrease to the summer PRM.

7 Appendix B: Capacity Import Limit Tier 1 & 2 Source Subsystem Definitions

MISO Local Resource Zone 1

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
XEL / 600	ITCM / 627	WEC / 295
MP / 608	ALTE / 694	MIUP / 296
SMMPA / 613	WPS / 696	AMMO / 356
GRE / 615	MGE / 697	AMIL / 357
OTP / 620		MPW / 633
MDU / 661		MEC / 635
BEPC-MISO / 663		
DPC / 680		

MISO Local Resource Zone 2

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
WEC / 295	METC / 218	NIPS / 217
MIUP / 296	XEL / 600	ITCT / 219
ALTE / 694	MP / 608	SMMPA / 613
WPS / 696	DPC / 680	GRE / 615
MGE / 697		OTP / 620
UPPC / 698		ITCM / 627

MISO Local Resource Zone 3

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
ITCM / 627	AMMO / 356	DEI / 208	GRE / 615
MPW / 633	AMIL / 357	NIPS / 217	OTP / 620
MEC / 635	XEL / 600	CWLP / 360	ALTE / 694
	SMMPA / 613	SIPC/ 361	WPS / 696
	DPC / 680	GLHB / 362	MGE / 697
		MP / 608	

MISO Local Resource Zone 4

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
ITCM / 627	AMMO / 356	DEI / 208	GRE / 615
MPW / 633	AMIL / 357	NIPS / 217	OTP / 620
MEC / 635	XEL / 600	CWLP / 360	ALTE / 694
	SMMPA / 613	SIPC/ 361	WPS / 696
	DPC / 680	GLHB / 362	MGE / 697
		MP / 608	

MISO Local Resource Zone 5

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
CWLD / 333	AMIL / 357	DEI / 208	XEL / 600
AMMO / 356	GLHB / 362	NIPS / 217	SMMPA / 613
	ITCM / 627	CWLP / 360	MPW / 633
	MEC / 635	SIPC / 361	DPC / 680

MISO Local Resource Zone 6

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ITCM / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 7

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ITCM / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 8

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ITCM / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 9

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
LAGN / 332	EES-EMI / 326	Cooperative Energy / 349
EES / 351	EES-EAI / 327	
CLEC / 502		
LAFA / 503		
LEPA / 504		

MISO Local Resource Zone 10

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EMI / 326	EES-EAI / 327	LAGN / 332
Cooperative Energy / 349	EES / 351	CLEC / 502
		LAFA / 503

8 Appendix C: Compliance Conformance Table

Requirements under: Standard BAL-502-RF-03	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2023-2024 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2023 through May 2024 and beyond. Analysis of Planning Year 2023-2024 is in Sections 4.1 and 5.1. Analysis of Future Years 2024-2033 is in Section 10.
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).	Section 3.5 of this report outlines the utilization of LOLE in the reserve margin determination. "These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year."
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 3.3 of this report. "Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 4.1 of this report. "…the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin…"
R1.2 Be performed or verified separately for each of the following planning years.	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In Sections 4.1 and 5.1, a full analysis was performed for Planning Year 2023-2024.
R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.	Sections 4.3 and 5.1 show a full analysis was performed for future planning years 2025 and 2027.
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.	Analysis was performed.
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.

R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts). • Load diversity. • Seasonal Load variations. • Daily demand modeling assumptions (firm, interruptible). • Contractual arrangements concerning curtailable/Interruptible Demand.	Median forecasted load – In Section 3.3 of this report: "The average monthly loads of the predicted load shapes were adjusted to match each LRZ's Module E 50/50 monthly zonal peak load forecasts for each study year." Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties are given in Sections 3.3 and 3.3.2. Load Diversity/Seasonal Load Variations — In Section 3.3 of this report: "The Planning Year 2023-2024 LOLE analysis used a load training process with neural net software to create a neural-net relationship between historical weather and load data. This relationship was then applied to 30 years of hourly historical weather data to create 30 different load shapes for each LRZ in order to capture both load diversity and seasonal variations." Demand Modeling Assumptions/Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E. As stated in Section 3.2.6: "Each demand response program was modeled individually with a monthly capacity and was limited to the number of times each program can be called upon as well as limited by duration."
R1.3.2 Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area. • Resource planned outage schedules, deratings, and retirements. • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration. • Criteria for including planned resource additions in the analysis.	Section 3.2 details how historic performance data and seasonal ratings are gathered, and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in Section 3.4.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves	Annual MTEP deliverability analysis identifies transmission limitations preventing delivery of generation reserves. Additionally, Section 2 of this report details the transfer analysis to capture transmission constraints limiting capacity transfers.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Inclusion of the planned transmission addition assumptions is detailed in Section 2.2.3.

R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 3.4 provides the analysis on the treatment of external support assistance and limitations.
R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel. • Common mode outages that affect resource availability. • Environmental or regulatory restrictions of resource availability. • Any other demand (Load) response programs not included in R1.3.1. • Sensitivity to resource outage rates. • Impacts of extreme weather/drought conditions that affect unit availability. • Modeling assumptions for emergency operation procedures used to make reserves available. • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.	Fuel availability, environmental restrictions, common mode outage and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 3.2.1. The use of demand response programs is mentioned in Section 3.2.6. The effects of resource outage characteristics on the reserve margin are outlined in Section 3.7.1 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 2 treats worst-case theoretical outages by Perform First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category P0 (system intact) and Category P1 (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis	MISO internal resources are among the quantities documented in the tables provided in Sections 4 and 5.
R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis	MISO load is among the quantities documented in the tables provided in Sections 4 and 5.
R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.	In Sections 4 and 5, the peak load and estimated amount of resources for Planning Years 2023-2024, 2026-2027, and 2028-2029 are shown. This includes the detail for each transmission constrained sub-area.

R2.1 This documentation shall cover each of the years in year one through ten.	Section 10.3 and Tables 10-3, 10-4, 10-5, and 10-6 show the three calculated study years, in-between years estimated by interpolation, and future outyears estimated by extrapolation. Estimated transmission limitations may be determined through a review of the PY 2023-2024 LOLE study transfer analysis shown in Section 2 of this report, along with the results from previous LOLE studies.
R2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	Covered in Sections 10.1 and 10.2.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.	The 2023-2024 LOLE Study Report documentation is posted on November 1 prior to the planning year.
R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2.	In Sections 4 and 5, the difference between the needed amount and the projected planning reserves for Planning Years 2023-2024, 2026-2027, and 2028-2029 are shown in the adjustments to ICAP and UCAP in Table 4-1, Table 10-1, and Table 10-2.

9 Appendix D: Acronyms List Table

CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
DF	Distribution Factor
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
ERZ	External Resource Zone
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GADS	Generator Availability Data System
GLT	Generation Limited Transfer
GVTC	Generation Verification Test Capacity
ICAP	Installed Capacity
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFE	Load Forecast Error
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt hours
NERC	North American Electric Reliability Corp.

PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRM ICAP	PRM Installed Capacity
PRM UCAP	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
RCF	Reciprocal Coordinating Flowgate
RDS	Redispatch
RPM	Reliability Pricing Model
SERVM	Strategic Energy & Risk Valuation Model
SPS	Special Protection Scheme
TARA	Transmission Adequacy and Reliability Assessment
UCAP	Unforced Capacity
XEFORd	Equivalent forced outage rate demand with adjustment to exclude events outside management control
ZIA	Zonal Import Ability
ZEA	Zonal Export Ability

10 Appendix E: Outyear PRM and LRR Results

Beyond the prompt Planning Year 2023-2024, LOLE analyses were performed for the four-year-out Planning Year of 2026-2027, and the six-year-out Planning Year of 2028-2029. Tables 10-1 and 10-2 show the capacity and demand values that went into the MISO system seasonal Planning Reserve Margin for outyears four and six, respectively. Tables 10-3, 10-4, 10-5, and 10-6 show the seasonal outyear PRM projections ten years out based on future capacity and demand assumptions. Tables 10-7, 10-8, 10-9, and 10-10 show the MISO zonal seasonal Local Reliability Requirements for outyear four while Tables 10-11, 10-12, 10-13, and 10-14 show the Local Reliability Requirements for outyear six.

10.1 Planning Year 2026-2027 MISO Planning Reserve Margin Results

For Planning Year 2026-2027, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 17.9 percent and a planning UCAP reserve margin of 8.8 percent for the summer season. Numerous values and calculations went into determining the four-year-out MISO system seasonal PRM ICAP and PRM UCAP (Table 10-1).

MISO Planning Reserve Margin (PRM)	**2026/2027 PY** Summer	**2026/2027 PY** Fall	**2026/2027 PY** Winter	**2026/2027 PY** Spring	**Formula Key**
MISO System Peak Demand (MW)	125,138	111,950	104,946	99,950	[A]
Installed Capacity (ICAP) (MW)	155,038	152,619	155,210	149,975	[B]
Unforced Capacity (UCAP) (MW)	144,623	139,494	138,423	133,904	[C]
Firm External Support (ICAP) (MW)	1,731	1,734	1,874	1,803	[D]
Firm External Support (UCAP) (MW)	1,707	1,714	1,857	1,778	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-9,200	-11,000	-9,200	-11,850	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-9,200	-11,000	-9,200	-11,850	[G]
ICAP PRM Requirement (PRMR) (MW)	147,569	143,353	147,884	139,928	[H]=[B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	136,130	130,208	131,080	123,832	[I]=[C]+[E]+[G]
MISO PRM ICAP	**17.9%**	**28.1%**	**40.9%**	**40.0%**	[J]=([H]-[A])/[A]
MISO PRM UCAP	**8.8%**	**16.3%**	**24.9%**	**23.9%**	[K]=([I]-[A])/[A]

Table 10-1: Planning Year 2026-2027 MISO System Planning Reserve Margins

10.2 Planning Year 2028-2029 MISO Planning Reserve Margin Results

For Planning Year 2028-2029, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 18.4 percent and a planning UCAP reserve margin of 9.2 percent for the summer season. Numerous values and calculations went into determining the six-year-out MISO system seasonal PRM ICAP and PRM UCAP (Table 10-2).

MISO Planning Reserve Margin (PRM)	**2028/2029 PY** Summer	**2028/2029 PY** Fall	**2028/2029 PY** Winter	**2028/2028 PY** Spring	**Formula Key**
MISO System Peak Demand (MW)	125,794	112,548	105,525	100,486	[A]
Installed Capacity (ICAP) (MW)	157,656	155,189	157,826	152,532	[B]
Unforced Capacity (UCAP) (MW)	146,097	141,837	140,816	136,237	[C]
Firm External Support (ICAP) (MW)	1,731	1,734	1,874	1,803	[D]
Firm External Support (UCAP) (MW)	1,707	1,714	1,857	1,778	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-10,400	-14,360	-10,400	-13,165	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-10,400	-14,360	-10,400	-13,165	[G]
ICAP PRM Requirement (PRMR) (MW)	148,987	142,563	149,300	141,170	[H]=[B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	137,404	129,191	132,272	124,850	[I]=[C]+[E]+[G]
MISO PRM ICAP	**18.4%**	**26.7%**	**41.5%**	**40.5%**	[J]=([H]-[A])/[A]
MISO PRM UCAP	**9.2%**	**14.8%**	**25.3%**	**24.2%**	[K]=([I]-[A])/[A]

Table 10-2: Planning Year 2028-2029 MISO System Planning Reserve Margins

10.3 MISO Planning Reserve Margin Outyear Projections

Tables 10-3, 10-4, 10-5, and 10-6 show the outyear seasonal PRM projections. Years one, four, and six were probabilistically modeled. PRM projections in years two, three, and five are the result of interpolation of the years studied and years seven through ten are the resulting extrapolations of the outyear analyses.

Metric	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
PRM ICAP	15.9%	16.6%	17.2%	17.9%	18.2%	18.4%	19.6%	20.1%	20.7%	21.2%
PRM UCAP	7.4%	7.9%	8.3%	8.8%	9.0%	9.2%	10.1%	10.4%	10.8%	11.2%
Demand (GW)	123.7	124.3	124.9	125.5	125.7	125.8	126.9	127.3	127.8	128.2
ICAP (GW)	144.3	150.5	153.0	155.0	155.0	157.7	157.7	157.7	157.7	157.7

Table 10-3: MISO Summer Planning Reserve Margin Outyear Projections

Metric	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
PRM ICAP	25.8%	26.6%	27.3%	28.1%	27.4%	26.7%	27.8%	28.1%	28.3%	28.5%
PRM UCAP	14.9%	15.4%	15.8%	16.3%	15.6%	14.8%	15.4%	15.4%	15.5%	15.5%
Demand (GW)	111.0	111.3	111.7	112.0	112.3	112.5	113.1	113.4	113.8	114.1
ICAP (GW)	144.3	148.8	150.3	152.6	152.6	155.2	155.2	155.2	155.2	155.2

Table 10-4: MISO Fall Planning Reserve Margin Outyear Projections

Metric	23-24	24-25	25-26	26-27	27-28	28-29	29-30	30-31	31-32	32-33
PRM ICAP	41.2%	41.1%	41.0%	40.9%	41.2%	41.5%	41.4%	41.5%	41.5%	41.5%
PRM UCAP	25.5%	25.3%	25.1%	24.9%	25.1%	25.3%	25.0%	25.0%	24.9%	24.8%
Demand (GW)	103.5	104.0	104.4	104.9	105.2	105.5	106.4	106.8	107.2	107.6
ICAP (GW)	150.7	154.0	154.7	155.2	155.2	157.8	157.8	157.8	157.8	157.8

Table 10-5: MISO Winter Planning Reserve Margin Outyear Projections

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM ICAP	39.3%	39.5%	39.8%	40.0%	40.3%	40.5%	41.0%	41.2%	41.4%	41.7%
PRM UCAP	24.5%	24.3%	24.1%	23.9%	24.1%	24.2%	23.9%	23.8%	23.8%	23.7%
Demand (GW)	99.1	99.4	99.7	100.0	100.3	100.5	101.1	101.4	101.7	101.9
ICAP (GW)	145.4	148.9	149.9	150.0	150.0	152.5	152.5	152.5	152.5	152.5

Table 10-6: MISO Spring Planning Reserve Margin Outyear Projections

10.4 Planning Year 2026-2027 MISO Local Reliability Requirement Results

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2026-2027 Local Reliability Requirements – Summer 2026											
Installed Capacity (ICAP) (MW)	22,350	15,251	12,350	9,629	9,494	19,595	21,761	12,368	25,425	6,814	[A]
Unforced Capacity (UCAP) (MW)	21,349	14,232	11,903	8,881	8,690	17,946	20,388	11,944	22,182	6,108	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-317	48	2,369	3,060	2,235	3,935	4,012	278	2,230	1,113	[C]
LRR (UCAP) (MW)	21,032	14,280	14,272	11,942	10,925	21,881	24,400	12,222	24,412	7,221	[D]=[B]+[C]
Peak Demand (MW)	18,622	13,121	9,976	9,384	8,121	18,517	21,003	7,880	22,036	4,802	[E]
LRR UCAP per-unit of LRZ Peak Demand	**112.9%**	**108.8%**	**143.1%**	**127.3%**	**134.5%**	**118.2%**	**116.2%**	**155.1%**	**110.8%**	**150.4%**	[F]=[D]/[E]

Table 10-7: Planning Year 2026-2027 LRZ Local Reliability Requirements for Summer 2026

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2026-2027 Local Reliability Requirements – Fall 2026											
Installed Capacity (ICAP) (MW)	22,303	14,924	12,708	9,267	9,296	19,057	21,756	11,773	24,952	6,584	[A]
Unforced Capacity (UCAP) (MW)	20,862	13,680	12,104	8,306	8,124	17,356	20,120	10,815	22,406	5,721	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,150	-608	1,303	2,861	2,032	3,138	3,906	-296	2,172	1,083	[C]
LRR (UCAP) (MW)	19,712	13,072	13,407	11,167	10,156	20,495	24,026	10,519	24,577	6,805	[D]=[B]+[C]
Peak Demand (MW)	18,622	13,121	9,976	9,384	8,121	18,517	21,003	7,880	22,036	4,802	[E]
LRR UCAP per-unit of LRZ Peak Demand	**105.9%**	**99.6%**	**134.4%**	**119.0%**	**125.1%**	**110.7%**	**114.4%**	**133.5%**	**111.5%**	**141.7%**	[F]=[D]/[E]

Table 10-8: Planning Year 2026-2027 LRZ Local Reliability Requirements for Fall 2026

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2026-2027 Local Reliability Requirements – Winter 2026-2027											
Installed Capacity (ICAP) (MW)	22,576	15,148	14,708	9,272	9,380	19,027	21,721	11,471	25,252	6,654	[A]
Unforced Capacity (UCAP) (MW)	21,048	13,357	13,748	7,369	7,698	17,193	20,149	10,074	22,044	5,742	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-317	45	2,231	2,882	2,105	3,706	1,915	262	2,100	1,048	[C]
LRR (UCAP) (MW)	20,731	13,402	15,980	10,251	9,803	20,899	22,064	10,336	24,145	6,790	[D]=[B]+[C]
Peak Demand (MW)	18,622	13,121	9,976	9,384	8,121	18,517	21,003	7,880	22,036	4,802	[E]
LRR UCAP per-unit of LRZ Peak Demand	**111.3%**	**102.1%**	**160.2%**	**109.2%**	**120.7%**	**112.9%**	**105.0%**	**131.2%**	**109.6%**	**141.4%**	[F]=[D]/[E]

Table 10-9: Planning Year 2026-2027 LRZ Local Reliability Requirements for Winter 2026-2027

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2026-2027 Local Reliability Requirements – Spring 2027											
Installed Capacity (ICAP) (MW)	21,384	14,796	12,729	9,040	9,196	18,876	21,235	11,457	24,783	6,480	[A]
Unforced Capacity (UCAP) (MW)	19,924	13,355	11,985	7,528	7,922	16,950	18,781	9,929	21,622	5,908	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,085	-700	1,023	2,827	1,980	2,719	2,722	53	1,994	647	[C]
LRR (UCAP) (MW)	18,839	12,655	13,008	10,356	9,902	19,669	21,503	9,982	23,616	6,556	[D]=[B]+[C]
Peak Demand (MW)	18,622	13,121	9,976	9,384	8,121	18,517	21,003	7,880	22,036	4,802	[E]
LRR UCAP per-unit of LRZ Peak Demand	**101.2%**	**96.5%**	**130.4%**	**110.4%**	**121.9%**	**106.2%**	**102.4%**	**126.7%**	**107.2%**	**136.5%**	[F]=[D]/[E]

Table 10-10: Planning Year 2026-2027 LRZ Local Reliability Requirements for Spring 2027

10.5 Planning Year 2028-2029 MISO Local Reliability Requirement Results

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2028-2029 Local Reliability Requirements – Summer 2028											
Installed Capacity (ICAP) (MW)	22,350	16,418	12,350	9,629	9,494	19,595	23,212	12,368	25,425	6,814	[A]
Unforced Capacity (UCAP) (MW)	21,349	15,324	11,903	8,881	8,690	17,946	21,769	11,944	22,182	6,108	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-232	-463	1,981	3,089	2,294	4,020	2,628	39	2,283	1,132	[C]
LRR (UCAP) (MW)	21,117	14,861	13,884	11,970	10,983	21,967	24,398	11,983	24,465	7,240	[D]=[B]+[C]
Peak Demand (MW)	18,177	13,132	10,172	9,485	8,001	18,099	20,705	7,725	21,417	4,716	[E]
LRR UCAP per-unit of LRZ Peak Demand	**116.2%**	**113.2%**	**136.5%**	**126.2%**	**137.3%**	**121.4%**	**117.8%**	**155.1%**	**114.2%**	**153.5%**	[F]=[D]/[E]

Table 10-11: Planning Year 2028-2029 LRZ Local Reliability Requirements for Summer 2028

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2028-2029 Local Reliability Requirements – Fall 2028											
Installed Capacity (ICAP) (MW)	22,303	16,090	12,708	9,267	9,296	19,057	23,160	11,773	24,952	6,584	[A]
Unforced Capacity (UCAP) (MW)	20,862	14,727	12,104	8,306	8,124	17,356	21,415	10,815	22,406	5,721	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,035	-1,100	1,275	2,903	2,078	3,260	2,559	-281	2,223	1,102	[C]
LRR (UCAP) (MW)	19,827	13,627	13,379	11,209	10,202	20,616	23,975	10,534	24,629	6,823	[D]=[B]+[C]
Peak Demand (MW)	18,177	13,132	10,172	9,485	8,001	18,099	20,705	7,725	21,417	4,716	[E]
LRR UCAP per-unit of LRZ Peak Demand	**109.1%**	**103.8%**	**131.5%**	**118.2%**	**127.5%**	**113.9%**	**115.8%**	**136.4%**	**115.0%**	**144.7%**	[F]=[D]/[E]

Table 10-12: Planning Year 2028-2029 LRZ Local Reliability Requirements for Fall 2028

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2028-2029 Local Reliability Requirements – Winter 2028-2029											
Installed Capacity (ICAP) (MW)	22,576	16,326	14,708	9,272	9,380	19,027	23,159	11,471	25,252	6,654	[A]
Unforced Capacity (UCAP) (MW)	21,048	14,468	13,748	7,369	7,698	17,193	21,430	10,074	22,044	5,742	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-232	-463	1,866	2,909	2,160	3,786	1,301	289	2,150	1,066	[C]
LRR (UCAP) (MW)	20,816	14,005	15,614	10,278	9,858	20,980	22,731	10,363	24,194	6,808	[D]=[B]+[C]
Peak Demand (MW)	18,177	13,132	10,172	9,485	8,001	18,099	20,705	7,725	21,417	4,716	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.5%**	**106.6%**	**153.5%**	**108.4%**	**123.2%**	**115.9%**	**109.8%**	**134.2%**	**113.0%**	**144.4%**	[F]=[D]/[E]

Table 10-13: Planning Year 2028-2029 LRZ Local Reliability Requirements for Winter 2028-2029

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2028-2029 Local Reliability Requirements – Spring 2029											
Installed Capacity (ICAP) (MW)	21,384	15,965	12,729	9,040	9,196	18,876	22,622	11,457	24,783	6,480	[A]
Unforced Capacity (UCAP) (MW)	19,924	14,365	11,985	7,528	7,922	16,950	20,104	9,929	21,622	5,908	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,030	-1,072	1,471	2,932	1,995	2,970	1,774	50	2,266	652	[C]
LRR (UCAP) (MW)	18,894	13,293	13,456	10,460	9,917	19,920	21,878	9,979	23,887	6,560	[D]=[B]+[C]
Peak Demand (MW)	18,177	13,132	10,172	9,485	8,001	18,099	20,705	7,725	21,417	4,716	[E]
LRR UCAP per-unit of LRZ Peak Demand	**103.9%**	**101.2%**	**132.3%**	**110.3%**	**123.9%**	**110.1%**	**105.7%**	**129.2%**	**111.5%**	**139.1%**	[F]=[D]/[E]

Table 10-14: Planning Year 2028-2029 LRZ Local Reliability Requirements for Spring 2029

11 Appendix F: Outyear CIL/CEL Results

MISO will not be conducting the outyear CIL/CEL study as part of the PY 2023-2024 LOLE study report. This has been communicated to stakeholders at the February 2023 RASC: https://cdn.misoenergy.org/20230228-0301%20RASC%20Item%2004d%20Out-Year%202027-28%20CIL-CEL%20Study%20Update627986.pdf

The usefulness and value created by the outyear CIL/CEL study is being evaluated by MISO. Any updates or changes to the outyear CIL/CEL study going forward will be communicated through the RASC and/or LOLEWG.

Attachment 4.4 Confidential Long-Term Electric Energy and Demand Input-Output Files

SEE ATTACHMENT: Confidential Model Outputs.zip

Attachment 6.1 CEI South Electric 2018-2020 DSM Plan

Vectren South 2021-2023
Electric Energy Efficiency Plan

Prepared by:
Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana Inc. (Vectren South)

5/8/2020

Table of Contents

List of Acronyms & Abbreviations

Acronym	Description
ARCA	Appliance Recycling Centers of America Inc.
BTU	Building Tune-Up
BYOT	Bring Your Own Thermostat
C&I	Commercial and Industrial
CAC	Central Air Conditioning
CVR	Conservation Voltage Reduction
DLC	Direct Load Control
DR	Demand Response
DSM	Demand Side Management
EAP	Energy Assistance Program
ECM	Electronically Commutated Motors
EDA	Energy Design Assistance
EE	Energy Efficiency
EISA	Energy Independence and Security Act
EM&V	Evaluation, Measurement and Verification
ES	ENERGY STAR
FPL	Federal Poverty Level
H&S	Health & Safety
HEA	Home Energy Assessment
HEMS	Home Energy Management Systems
HERS	Home Efficiency Rating System
HVAC	Heating, Ventilation and Air Conditioning
IQW	Income Qualified & Weatherization
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
kW/kWh	Kilowatt, Kilowatt hour
LED	Light Emitting Diode
MPS	Market Potential Study
MW,MWh	Megawatt, Megawatt hour
NEF	National Energy Foundation
NPV	Net Present Value
O&M	Operations and Maintenance
PCT	Participant Cost Test
PPC	Program Partner Center

Acronym	Description
RIM	Ratepayer Impact Measure
RNC	Residential New Construction
SEM	Strategic Energy Management
TRM	Technical Reference Manual
UCT	Utility Cost Test

1. Introduction

Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. (Vectren South), a CenterPoint Energy Company. Vectren South provides energy delivery services to approximately 147,000 electric customers and 112,000 natural gas customers located in Southwestern Indiana. Vectren South is a direct, wholly owned subsidiary of Vectren Utility Holdings, Inc. ("Vectren"), which is a wholly-owned indirect subsidiary of CenterPoint Energy Company, headquartered in Houston, TX. This Vectren South 2021-2023 Electric Demand Side Management (DSM) Plan ("2021-2023 Plan" or "Plan") describes the details of the electric Energy Efficiency (EE) and Demand Response (DR) programs Vectren South plans to offer in its service territory in 2021-2023.

Vectren South is proposing a 2021-2023 Plan designed to cost effectively reduce energy use by approximately 1.3% of eligible retail sales each year over the three-year plan. The EE savings goals are consistent with Vectren South's 2019 Integrated Resource Plan ("2019 IRP"), reasonably achievable and cost effective. The Plan includes program budgets, including the direct and indirect costs of energy efficiency programs. The 2021-2023 Plan recommends electric EE and DR programs for the residential and commercial & industrial (C&I) sectors in Vectren South's service territory. Where appropriate, it also describes opportunities for coordination with some of Vectren South's gas EE programs to leverage the best total EE and DR opportunities for customers and to share costs of delivery. Vectren South utilizes a portfolio of DSM programs to achieve demand reductions and energy savings, thereby providing reliable electric service to its customers. Vectren's DSM programs have been approved by the Indiana Utility Regulatory Commission ("Commission" or "IURC") and implemented pursuant to various IURC orders over the years.

2. Vectren South DSM Strategy

Energy efficiency remains at the core of Vectren's culture as one of the company's objectives is to partner with customers to help them use energy wisely. Vectren proactively works with its oversight boards in each state it serves to assemble progressive, cost-effective programs that work toward achieving that objective.

Vectren South's 2019 Integrated Resource Plan ("2019 IRP") includes EE programs for all customer classes and sets an annual savings target of 1.25% of retail sales for 2021-2023. The framework for the 2021-2023 Plan was modeled at a savings level of 1.3% of retail sales adjusted for an opt-out rate of 77% eligible load, as provided for in Indiana Code § 8-1-8.5-10 ("Section

10”). The IRP load forecast also includes an ongoing level of EE related to codes and standards embedded in the load forecast projections. Ongoing EE and DR programs are also important given the integration of Vectren South’s natural gas and electric EE and DR programs.

A. Integration with Vectren South Gas

Opportunities exist to gain both natural gas and electric savings from some EE programs and measures. In these instances, energy savings will be captured by the respective utility. For the programs where integration opportunities exist, Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric. Below is a list of programs that Vectren South has identified as integrated:

- Residential Prescriptive
- Residential New Construction
- Home Energy Assessment
- Income Qualified Weatherization
- Energy Efficient Schools
- Residential Behavioral Savings
- Residential Midstream
- Home Energy Management Systems (HEMS)
- Commercial and Industrial (C&I) Prescriptive
- Commercial Midstream
- Commercial and Industrial (C&I) Custom
- Small Business Energy Solutions

B. Vectren Oversight Board

The Vectren Oversight Board (VOB) provides input into the planning and evaluation of Vectren South's EE programs. The VOB was formed in 2010 pursuant to the Final Order issued in Cause No. 43427 and included the Indiana Office of the Utility Consumer Counselor (OUCC) and Vectren South as voting members. The Citizens Action Coalition was added as a voting member of the VOB in 2013 pursuant to the Final Order issued in Cause No. 44318. In 2014, the Vectren South Electric Oversight Board merged with the Vectren South Gas Oversight Board and Vectren North Gas Oversight Board to form one governing body, the VOB. Vectren and the VOB have worked collaboratively over the last several years and Vectren requests to continue the current voting structure.

3. Vectren South Planning Process

Vectren South has offered a variety of EE programs since April 2010 and has engaged in a similar planning process each time a new portfolio is presented to the Commission for approval.

The 2021-2023 Plan was developed in conjunction with the 2019 IRP planning process and therefore the 2019 IRP served as a key input into the 2021-2023 Plan. As such, this process aligns with Indiana Code § 8-1-8.5-10 ("Section 10"), which requires that EE goals be consistent with an electricity supplier's IRP.

Consistent with the 2019 IRP, the framework for the 2021-2023 Plan was modeled at a savings level of 1.3% of retail sales with opt-out assumptions incorporated. Once the level of EE programs to be offered from 2021 through 2023 was established, Vectren South engaged in a process to develop the 2021-2023 Plan. The objective of the planning process was to develop a plan based upon market-specific information for Vectren South's territory, which could be successfully implemented utilizing realistic assessments of achievable market potential.

The program design used the Electric Market Potential Study (MPS) for guidance to validate that the plan estimates were reasonable. While building from the bottom up with estimates from program implementers to help determine participation, this comparison to the MPS allowed the planning team to determine if the results were reasonable.

In 2018, Vectren South engaged GDS Associates, Inc., to conduct an MPS and Action Plan. For this effort, GDS evaluated electric energy-efficiency resources in the residential, commercial, and industrial sectors for the years 2020-2025. The study included a detailed, bottom-up assessment of the Vectren South market in the Evansville metropolitan area to deliver a projection of baseline electric energy use, forecasts of the energy savings achievable through efficiency measures, and program designs and strategies to optimally deliver those savings. The study assessed various tiers of technical, economic and achievable potential by sector, customer type and measure.

In addition, vendors and other implementation partners who operate the current programs were involved in the planning process by providing suggestions for program changes and enhancements. The vendors and partners also provided technical information about measures to include recommended incentives, estimated participation and estimated implementation costs. This data provided a foundation for the 2021-2023 Plan based on actual experience within Vectren South's territory. These companies also bring their experience operating programs for other utilities. Once the draft version of the 2021-2023 Plan was developed, Vectren South solicited feedback from the VOB for consideration in the final design.

Other sources of program information were also considered. Current evaluations and the Indiana Technical Resource Manual (TRM) were used for adjustments to inputs. In addition, best practices were researched and reviewed to gain insights into the program design of successful EE and DR programs implemented by other utility companies.

VOB feedback was incorporated into the planning process, as applicable.

4. Cost Effectiveness Analysis

Vectren South's last step of the planning process was the cost benefit analysis. Vectren South retained Mr. Richard Morgan, President of Morgan Marketing Partners, to complete the cost benefit modeling. Utilizing DSMore, the measures and programs were analyzed for cost effectiveness. The DSMore tool is nationally recognized and used in many states across the country to determine cost-effectiveness. Developed and licensed by Integral Analytics based in Newport, KY, the DSMore cost-effectiveness modeling tool takes hourly prices and hourly energy savings from the specific measures/technologies being considered for the EE program, and then correlates both to weather. This tool looks at more than 30 years of historic weather variability to get the full weather variances appropriately modeled. In turn, this allows the model to capture the low probability, but high consequence weather events and apply appropriate value to them. Thus, a more accurate view of the value of the efficiency measure can be captured in comparison to other alternative supply options.

The outputs of DSMore include all the California Standard Practice Manual results including Total Resource Cost (TRC), Utility Cost Test (UCT), Participant Cost Test (PCT) and Ratepayer Impact Measure (RIM) tests. Inputs into the model include the following: participation rates, incentives paid, energy savings of the measure, life of the measure, implementation costs, and administrative costs, incremental costs to the participant of the high efficiency measure, and escalation rates and discount rates. Vectren South considers the results of each test and ensures that the portfolio passes the TRC test as it includes the total costs and benefits to both the utility and the consumer. The model includes a full range of economic perspectives typically used in EE and DSM analytics. The perspectives include:

- Total Resource Cost Test - shows the combined perspective of the utility and the participating customers. This test compares the level of benefits associated with the reduced energy supply costs to utility programs and participant costs.
- Utility Cost Test - shows the value of the program considering only avoided utility supply cost (based on the next unit of generation) in comparison to program costs.
- Participant Cost Test - shows the value of the program from the perspective of the utility's customer participating in the program. The test compares the participant's bill savings over the life of the EE/DR program to the participant's cost of participation.
- Ratepayer Impact Measure Test - shows the impact of a program on all utility customers through impacts in average rates. This perspective also includes the estimates of revenue losses, which may be experienced by the utility as a result of the program.

The cost effectiveness analysis produces two types of resulting metrics:

- Net Benefits (dollars) = NPV ∑ benefits – NPV ∑ costs
- Benefit Cost Ratio = NPV ∑ benefits ÷ NPV ∑ costs

Cost effectiveness analysis is performed using each of the four primary tests. The results of each test reflect a distinct perspective and have a separate set of inputs demonstrating the treatment of costs and benefits. A summary of benefits and costs included in each cost effectiveness test can be found in Appendix A.

5. 2021 - 2023 Plan Objectives and Impact

The framework for the 2021-2023 Plan aligns with Vectren South's 2019 IRP and was designed to reach a reduction in sales of approximately 1.3% of eligible retail sales with opt-out assumptions incorporated. Table 1 below provides an overview of energy savings and demand impacts, participation and budget by the residential and C&I sectors and for the total portfolio. Table 2 provides an overview of budget and energy savings by program and by year.

Table 1: 2021-2023 Portfolio Summary of Participation, Impacts & Budget

Program Year	Participants/ Measures	Annual Energy Savings kWh	Annual Demand Savings kW	Res & C&I Direct Program Budget	Cost/Kwh *	Levelized Costs /Kwh**	Indirect Portfolio Level Budget	Other Costs Budget	Portfolio Total Budget Including Indirect & Other
2021	235,332	44,325,438	10,061	$10,061,209	$0.23	$0.03	$1,046,819	$400,000	$11,508,027
2022	225,146	43,961,753	9,571	$10,092,043	$0.23	$0.03	$1,051,408	$200,000	$11,343,451
2023	218,863	43,533,925	10,303	$10,073,357	$0.23	$0.03	$1,061,922	$200,000	$11,335,280

* Cost per Kwh is calculated by dividing program cost by total savings and does not include carry forward costs related to smart thermostat, BYOT and CVR programs. The cost per kWh excludes indirect and other costs for budget. Including indirect and other costs, the cost per kwh is $0.26/Kwh.

** Levelized Costs per kWh are consistent with the 2019 IRP.

Table 2: Vectren South 2021 - 2023 Plan Overview by Program

	Total Budget ($)			Total Savings (kWh)			Total Demand (kW)		
Residential Programs	**2021**	**2022**	**2023**	**2021**	**2022**	**2023**	**2021**	**2022**	**2023**
Residential Specialty Lighting	$ 606,656	$ 546,634	$ 521,634	5,046,833	4,801,366	4,385,296	698	664	607
Residential Prescriptive	$ 1,135,825	$ 960,500	$ 953,909	1,657,282	1,317,201	1,319,270	866	482	419
Residential New Construction	$ 88,852	$ 88,049	$ 85,065	163,986	188,637	188,637	56	66	66
Home Energy Assessment	$ 239,713	$ 256,589	$ 296,868	550,810	576,574	684,783	52	54	63
Income Qualified Weatherization	$ 687,423	$ 707,709	$ 714,673	485,948	460,780	444,441	102	111	103
Community Based - LED Specialty Bulb Distribution	$ 168,110	$ 171,693	$ 177,923	1,159,285	1,159,285	1,159,285	160	160	160
Energy Efficient Schools	$ 118,451	$ 122,451	$ 102,451	733,118	696,462	661,639	78	74	71
Residential Behavioral Savings	$ 254,105	$ 261,391	$ 268,896	7,020,000	7,100,000	6,790,000	1,350	1,270	1,210
Appliance Recycling	$ 244,152	$ 246,902	$ 249,152	1,322,563	1,250,423	1,082,097	175	165	143
CVR Residential	$ 354,969	$ 348,828	$ 418,537			1,067,954			430
Smart Cycle (DLC Change Out)	$ 984,328	$ 1,063,328	$ 1,142,328	362,577	362,577	362,577	1,140	1,140	1,140
BYOT (Bring Your Own Thermostat)	$ 126,646	$ 156,496	$ 189,246				456	513	570
Residential Midstream	$ 439,289	$ 417,849	$ 498,073	922,215	1,061,351	1,271,737	695	745	938
Home Energy Management Systems	$ 203,513	$ 210,513	$ 220,513	515,000	515,000	515,000	80	80	80
Residential Subtotal	**$ 5,652,032**	**$ 5,558,932**	**$ 5,839,268**	**19,939,618**	**19,489,656**	**19,932,715**	**5,908**	**5,523**	**6,000**
C&I Programs	**2021**	**2022**	**2023**	**2021**	**2022**	**2023**	**2021**	**2022**	**2023**
Commercial Prescriptive	$ 2,513,494	$ 2,431,243	$ 2,234,780	15,650,556	13,813,073	12,520,261	2,961	2,593	2,695
Commercial Midstream	$ 15,577	$ 15,577	$ 15,577	31,570	31,570	31,570	5	5	5
Commercial Custom	$ 847,795	$ 982,471	$ 933,500	5,509,079	6,677,683	6,221,324	702	892	831
Small Business Energy Solutions	$ 807,181	$ 884,304	$ 878,048	3,194,615	3,949,771	3,952,715	485	558	558
CVR Commercial	$ 225,130	$ 219,516	$ 172,184	0	0	875,340	0	0	214
Commercial Subtotal	**$ 4,409,177**	**$ 4,533,111**	**$ 4,234,089**	**24,385,820**	**24,472,097**	**23,601,210**	**4,153**	**4,048**	**4,303**
Residential & Commercial Subtotal	**$10,061,209**	**$10,092,043**	**$10,073,357**	**44,325,438**	**43,961,753**	**43,533,925**	**10,061**	**9,571**	**10,303**
Portfolio Level Costs Subtotal*	$ 1,046,819	$ 1,051,408	$ 1,061,922						
Other Costs Subtotal**	$ 400,000	$ 200,000	$ 200,000						
DSM Portfolio Total including Other Costs	**$11,508,027**	**$11,343,451**	**$11,335,280**	**44,325,438**	**43,961,753**	**43,533,925**	**10,061**	**9,571**	**10,303**

*Portfolio level costs include: Contact Center, Online Audit, Outreach & Education, and Evaluation.

**Other Costs include Market Potential Study and Emerging Markets.

A. Plan Savings

The planned savings goal for 2021-2023 was calculated based on a percentage of forecasted weather normalized electric sales for 2021 to 2023 with a target of 1.3% of eligible retail sales. The forecast is consistent with Vectren South's 2019 IRP sales forecast. Goals are based on gross energy savings with opt-out assumptions incorporated. Table 3 demonstrates the portfolio, residential and C&I energy savings targets at the 1.3% eligible retail sales level. Table 4 demonstrates the portfolio energy and demand savings by program and by year.

Table 3: Vectren South 2021 - 2023 Plan Portfolio Summary Planned Energy Savings

Portfolio Summary	Total Savings (kWh)			Total Demand (kW)		
	2021	2022	2023	2021	2022	2023
Residential Total	19,939,618	19,489,656	19,932,715	5,908	5,523	6,000
Commercial & Industrial Total	24,385,820	24,472,097	23,601,210	4,153	4,048	4,303
Portfolio Total	44,325,438	43,961,753	43,533,925	10,061	9,571	10,303

Table 4: Vectren South 2021 - 2023 Plan Portfolio Planned Energy Savings

Residential	2021 kWh	2021 kW	2022 kWh	2022 kW	2023 kWh	2023 kW
Residential Specialty Lighting	5,046,833	698	4,801,366	664	4,385,296	607
Residential Prescriptive	1,657,282	866	1,317,201	482	1,319,270	419
Residential New Construction	163,986	56	188,637	66	188,637	66
Home Energy Assessment	550,810	52	576,574	54	684,783	63
Income Qualified Weatherization	485,948	102	460,780	111	444,441	103
Community Based - LED Specialty Bulb Distribution	1,159,285	160	1,159,285	160	1,159,285	160
Energy Efficient Schools	733,118	78	696,462	74	661,639	71
Residential Behavioral Savings	7,020,000	1,350	7,100,000	1,270	6,790,000	1,210
Appliance Recycling	1,322,563	175	1,250,423	165	1,082,097	143
CVR Residential	0	0	0	0	1,067,954	430
Smart Cycle (DLC Change Out)	362,577	1,140	362,577	1,140	362,577	1,140
BYOT (Bring Your Own Thermostat)	0	456	0	513	0	570
Residential Midstream	922,215	695	1,061,351	745	1,271,737	938
Home Energy Management Systems	515,000	80	515,000	80	515,000	80
Residential Total	**19,939,618**	**5,908**	**19,489,656**	**5,523**	**19,932,715**	**6,000**
Commercial & Industrial	**2021 kWh**	**2021 kW**	**2022 kWh**	**2022 kW**	**2023 kWh**	**2023 kW**
Commercial Prescriptive	15,650,556	2,961	13,813,073	2,593	12,520,261	2,695
Commercial Midstream	31,570	5	31,570	5	31,570	5
Commercial Custom	5,509,079	702	6,677,683	892	6,221,324	831
Small Business Energy Solutions	3,194,615	485	3,949,771	558	3,952,715	558
CVR Commercial	0	0	0	0	875,340	214
Commercial & Industrial Total	**24,385,820**	**4,153**	**24,472,097**	**4,048**	**23,601,210**	**4,303**
Portfolio Total	**44,325,438**	**10,061**	**43,961,753**	**9,571**	**43,533,925**	**10,303**

B. Plan Budget

The total planned program budget includes the direct and indirect costs of implementing Vectren South's electric energy efficiency programs. In addition, a budget for other costs are being requested as described below.

Direct program costs include three main categories: vendor implementation, program incentives and administration costs. The program budgets were built based upon multiple resources. Program budgets were discussed with program implementers as a basis for the development of this plan. Vendor implementation budgets were estimated using historical data and estimates provided by the current vendors with consideration for MPS costs. This helps to assure that the estimates are realistic for successful delivery. Program incentives were calculated by assigning measures with appropriate incentive values based upon existing program incentives, evaluation results and vendor recommendations. Lastly, administrative costs are comprised of internal costs for Vectren South's management and oversight of the programs. Administrative costs were allocated back to programs based on the percent of savings these programs represent as well as estimated staff time spent on programs.

Indirect costs are costs that are not directly tied to a single program, but rather support multiple programs or the entire portfolio. These include: Contact Center, Online Audit, Outreach & Education, and Evaluation, Measurement and Verification (EM&V). These costs are budgeted at the portfolio level.

Other costs are also being requested in the 2021-2023 filed plan. Vectren South requests approval to continue funding for Emerging Markets, which is discussed later in the Plan. Emerging Markets funding allows Vectren's EE portfolio to offer leading-edge program designs for next-generation technologies, services, and engagement strategies to growing markets in the Vectren South territory. This funding will not be used to support existing measures or programs, but rather support new program development or new measures within an existing program. Tables 5 through 8 below list the summary budgets by year, program and category.

Table 5: Vectren South 2021 – 2023 Summary Budgets by Year

Residential	**2021**	**2022**	**2023**	**Total Budget**
Residential Specialty Lighting	$606,656	$546,634	$521,634	$1,674,924
Residential Prescriptive	$1,135,825	$960,500	$953,909	$3,050,235
Residential New Construction	$88,852	$88,049	$85,065	$261,965
Home Energy Assessment	$239,713	$256,589	$296,868	$793,169
Income Qualified Weatherization	$687,423	$707,709	$714,673	$2,109,806
Community Based - LED Specialty Bulb Distribution	$168,110	$171,693	$177,923	$517,727
Energy Efficient Schools	$118,451	$122,451	$102,451	$343,352
Residential Behavioral Savings	$254,105	$261,391	$268,896	$784,392
Appliance Recycling	$244,152	$246,902	$249,152	$740,205
CVR Residential	$354,969	$348,828	$418,537	$1,122,334
Smart Cycle (DLC Change Out)	$984,328	$1,063,328	$1,142,328	$3,189,985
BYOT (Bring Your Own Thermostat)	$126,646	$156,496	$189,246	$472,388
Residential Midstream	$439,289	$417,849	$498,073	$1,355,211
Home Energy Management Systems	$203,513	$210,513	$220,513	$634,538
Residential Total	**$5,652,032**	**$5,558,932**	**$5,839,268**	**$17,050,232**
Commercial & Industrial	**2021**	**2022**	**2023**	**Total Budget**
Commercial Prescriptive	$2,513,494	$2,431,243	$2,234,780	$7,179,517
Commercial Midstream	$15,577	$15,577	$15,577	$46,732
Commercial Custom	$847,795	$982,471	$933,500	$2,763,766
Small Business Energy Solutions	$807,181	$884,304	$878,048	$2,569,533
CVR Commercial	$225,130	$219,516	$172,184	$616,829
Commercial & Industrial Total	**$4,409,177**	**$4,533,111**	**$4,234,089**	**$13,176,377**
Total Direct Program Costs	**$10,061,209**	**$10,092,043**	**$10,073,357**	**$30,226,609**
Indirect Portfolio Level Costs	**2021**	**2022**	**2023**	**Total Budget**
Contact Center	$64,008	$65,032	$67,130	$196,170
Online Audit	$43,598	$44,295	$45,724	$133,617
Outreach & Education	$416,560	$423,225	$436,877	$1,276,661
Evaluation	$522,653	$518,856	$512,192	$1,553,701
Indirect Portfolio Level Costs Subtotal	**$1,046,819**	**$1,051,408**	**$1,061,922**	**$3,160,149**
Total Portfolio	**$11,108,027**	**$11,143,451**	**$11,135,280**	**$33,386,758**
Other Costs	**2021**	**2022**	**2023**	**Total Budget**
Emerging Markets	$200,000	$200,000	$200,000	$600,000
Market Potential Study	$200,000	$0	$0	$200,000
Other Costs Subtotal	**$400,000**	**$200,000**	**$200,000**	**$800,000**
DSM Portfolio Total including Other Costs	**$11,508,027**	**$11,343,451**	**$11,335,280**	**$34,186,758**

Table 6: Vectren South 2021 Summary Budgets by Category

Residential	Administrative	Implementation	Incentives	Total Budget
Residential Specialty Lighting	$ 112,254	$ 189,402	$ 305,000	$ 606,656
Residential Prescriptive	$ 40,411	$ 610,334	$ 485,080	$ 1,135,825
Residential New Construction	$ 5,613	$ 58,614	$ 24,625	$ 88,852
Home Energy Assessment	$ 5,613	$ 223,720	$ 10,380	$ 239,713
Income Qualified Weatherization	$ 11,225	$ 676,198		$ 687,423
Community Based - LED Specialty Bulb Distribution	$ 33,676	$ 134,434		$ 168,110
Energy Efficient Schools	$ 22,451	$ 96,000		$ 118,451
Residential Behavioral Savings	$ 11,225	$ 242,879		$ 254,105
Appliance Recycling	$ 44,902	$ 130,500	$ 68,750	$ 244,152
CVR Residential	$ 41,225	$ 313,744		$ 354,969
Smart Cycle (DLC Change Out)	$ 55,004	$ 815,764	$ 113,560	$ 984,328
BYOT (Bring Your Own Thermostat)	$ 16,838	$ 52,288	$ 57,520	$ 126,646
Residential Midstream	$ 5,613	$ 140,976	$ 292,700	$ 439,289
Home Energy Management Systems	$ 5,613	$ 197,900		$ 203,513
Residential Subtotal	**$ 411,663**	**$ 3,882,754**	**$1,357,615**	**$ 5,652,032**
Commercial & Industrial				**Total Budget**
Commercial Prescriptive	$ 56,127	$ 752,660	$ 1,704,707	$ 2,513,494
Commercial Midstream	$ 5,613	$ 4,826	$ 5,139	$ 15,577
Commercial Custom	$ 67,352	$ 354,804	$ 425,638	$ 847,795
Small Business Energy Solutions	$ 5,613	$ 239,848	$ 561,720	$ 807,181
CVR Commercial	$ 14,902	$ 210,228		$ 225,130
Commercial Subtotal	**$ 149,606**	**$ 1,562,366**	**$2,697,204**	**$ 4,409,177**
Residential & Commercial Subtotal	**$ 561,270**	**$ 5,445,120**	**$4,054,819**	**$ 10,061,209**
Indirect Costs				**Total Budget**
Contact Center				$ 64,008
Online Audit				$ 43,598
Outreach & Education				$ 416,560
Portfolio Costs Subtotal				$ 524,166
Subtotal - Before evaluation				$ 10,585,374
Evaluation				$ 522,653
DSM Portfolio Total				**$ 11,108,027**
Other Costs				**Total Budget**
Emerging Markets				$ 200,000
Market Potential Study				$ 200,000
Other Costs Subtotal				**$ 400,000**
DSM Portfolio Total including Other Costs				**$ 11,508,027**

Table 7: Vectren South 2022 Summary Budgets by Category

Residential	Administrative	Implementation	Incentives	Total Budget
Residential Specialty Lighting	$ 112,254	$ 144,380	$ 290,000	$ 546,634
Residential Prescriptive	$ 40,411	$ 535,729	$ 384,360	$ 960,500
Residential New Construction	$ 5,613	$ 53,186	$ 29,250	$ 88,049
Home Energy Assessment	$ 5,613	$ 240,596	$ 10,380	$ 256,589
Income Qualified Weatherization	$ 11,225	$ 696,484		$ 707,709
Community Based - LED Specialty Bulb Distribution	$ 33,676	$ 138,017		$ 171,693
Energy Efficient Schools	$ 22,451	$ 100,000		$ 122,451
Residential Behavioral Savings	$ 11,225	$ 250,166		$ 261,391
Appliance Recycling	$ 44,902	$ 137,000	$ 65,000	$ 246,902
CVR Residential	$ 41,225	$ 307,603		$ 348,828
Smart Cycle (DLC Change Out)	$ 55,004	$ 874,764	$ 133,560	$ 1,063,328
BYOT (Bring Your Own Thermostat)	$ 16,838	$ 69,388	$ 70,270	$ 156,496
Residential Midstream	$ 5,613	$ 90,486	$ 321,750	$ 417,849
Home Energy Management Systems	$ 5,613	$ 204,900		$ 210,513
Residential Subtotal	**$ 411,663**	**$ 3,842,698**	**$1,304,570**	**$ 5,558,932**
Commercial & Industrial				**Total Budget**
Commercial Prescriptive	$ 56,127	$ 820,040	$ 1,555,076	$ 2,431,243
Commercial Midstream	$ 5,613	$ 4,826	$ 5,139	$ 15,577
Commercial Custom	$ 67,352	$ 383,785	$ 531,334	$ 982,471
Small Business Energy Solutions	$ 5,613	$ 265,897	$ 612,794	$ 884,304
CVR Commercial	$ 14,902	$ 204,614		$ 219,516
Commercial Subtotal	**$ 149,606**	**$ 1,679,163**	**$2,704,342**	**$ 4,533,111**
Residential & Commercial Subtotal	**$ 561,270**	**$ 5,521,861**	**$4,008,912**	**$ 10,092,043**
Indirect Costs				**Total Budget**
Contact Center				$ 65,032
Online Audit				$ 44,295
Outreach & Education				$ 423,225
Portfolio Costs Subtotal				$ 532,552
Subtotal - Before evaluation				$ 10,624,595
Evaluation				$ 518,856
DSM Portfolio Total				**$ 11,143,451**
Other Costs				**Total Budget**
Emerging Markets				$ 200,000
Market Potential Study				$ -
Other Costs Subtotal				**$ 200,000**
DSM Portfolio Total including Other Costs				**$ 11,343,451**

Table 8: Vectren South 2023 Summary Budgets by Category

Residential	Administrative	Implementation	Incentives	Total Budget
Residential Specialty Lighting	$ 112,254	$ 144,380	$ 265,000	$ 521,634
Residential Prescriptive	$ 40,411	$ 542,843	$ 370,655	$ 953,909
Residential New Construction	$ 5,613	$ 50,202	$ 29,250	$ 85,065
Home Energy Assessment	$ 5,613	$ 280,875	$ 10,380	$ 296,868
Income Qualified Weatherization	$ 11,225	$ 703,448		$ 714,673
Community Based - LED Specialty Bulb Distribution	$ 33,676	$ 144,247		$ 177,923
Energy Efficient Schools	$ 22,451	$ 80,000		$ 102,451
Residential Behavioral Savings	$ 11,225	$ 257,671		$ 268,896
Appliance Recycling	$ 44,902	$ 148,000	$ 56,250	$ 249,152
CVR Residential	$ 41,225	$ 377,311		$ 418,537
Smart Cycle (DLC Change Out)	$ 55,004	$ 933,764	$ 153,560	$ 1,142,328
BYOT (Bring Your Own Thermostat)	$ 16,838	$ 88,388	$ 84,020	$ 189,246
Residential Midstream	$ 5,613	$ 93,311	$ 399,150	$ 498,073
Home Energy Management Systems	$ 5,613	$ 214,900		$ 220,513
Residential Subtotal	**$ 411,663**	**$ 4,059,340**	**$1,368,265**	**$ 5,839,268**
Commercial & Industrial				**Total Budget**
Commercial Prescriptive	$ 56,127	$ 757,586	$ 1,421,067	$ 2,234,780
Commercial Midstream	$ 5,613	$ 4,826	$ 5,139	$ 15,577
Commercial Custom	$ 67,352	$ 366,652	$ 499,496	$ 933,500
Small Business Energy Solutions	$ 5,613	$ 269,179	$ 603,256	$ 878,048
CVR Commercial	$ 14,902	$ 157,282		$ 172,184
Commercial Subtotal	**$ 149,606**	**$ 1,555,525**	**$2,528,957**	**$ 4,234,089**
Residential & Commercial Subtotal	**$ 561,270**	**$ 5,614,865**	**$3,897,222**	**$ 10,073,357**
Indirect Costs				**Total Budget**
Contact Center				$ 67,130
Online Audit				$ 45,724
Outreach & Education				$ 436,877
Portfolio Costs Subtotal				$ 549,730
Subtotal - Before evaluation				$ 10,623,088
Evaluation				$ 512,192
DSM Portfolio Total				**$ 11,135,280**
Other Costs				**Total Budget**
Emerging Markets				$ 200,000
Market Potential Study				$ -
Other Costs Subtotal				**$ 200,000**
DSM Portfolio Total including Other Costs				**$ 11,335,280**

C. Cost Effectiveness Results

The total portfolio for the Vectren South programs passes the TRC and UCT test for both the Residential and Commercial & Industrial sectors. Table 9 below confirms that all programs pass the TRC at greater than one. In completing the cost effectiveness testing, Vectren South used 6.19% as the weighted average cost of capital (WACC) as approved by the Commission on May 29, 2019 in Cause No. 44910. For the 2021 - 2023 Plan, Vectren South utilized the avoided costs aligned with its 2019 IRP[1] adjusted down for fixed capacity.

Table 9: Vectren South 2021-2023 Plan Cost Effectiveness Results without Performance Incentive

Residential	TRC	UCT	RIM	Participant	TRC NPV $	UCT NPV $	Levelized Cost/kWh	Cost/kWh
Residential Specialty Lighting	3.19	3.65	0.62	8.51	$ 3,967,261	$ 4,193,963	$0.02	$0.12
Residential Prescriptive	1.08	1.40	0.65	1.71	$ 300,270	$ 1,164,193	$0.09	$0.69
Residential New Construction	1.16	2.14	0.74	1.08	$ 72,542	$ 281,636	$0.08	$0.54
Home Energy Assessment	1.05	1.05	0.35	n/a	$ 37,257	$ 37,257	$0.04	$0.44
Income Qualified Weatherization	0.46	0.46	0.28	n/a	$ (1,078,445)	$ (1,078,445)	$0.14	$1.41
Community Based - LED Specialty Bulb Distribution	5.79	5.79	0.66	n/a	$ 2,336,936	$ 2,336,936	$0.01	$0.15
Energy Efficient Schools	3.67	3.67	0.60	n/a	$ 865,233	$ 865,233	$0.02	$0.16
Residential Behavioral Savings	1.62	1.62	0.44	n/a	$ 459,597	$ 459,597	$0.03	$0.04
Appliance Recycling	1.58	1.31	0.39	n/a	$ 335,377	$ 214,881	$0.03	$0.18
CVR Residential	1.05	1.05	0.51	n/a	$ 55,675	$ 55,675	$0.08	$0.00
Smart Cycle (DLC Change Out)	2.30	2.01	1.44	n/a	$ 3,407,118	$ 3,031,604	$0.19	$2.71
BYOT (Bring Your Own Thermostat)	4.76	4.76	4.45	n/a	$ 1,643,293	$ 1,643,293	$1.12	$0.00
Residential Midstream	1.78	3.38	1.11	1.26	$ 1,888,023	$ 3,034,364	$0.08	$0.48
Home Energy Management Systems	1.01	1.01	0.43	n/a	$ 5,611	$ 5,611	$0.07	$0.40
Residential Portfolio	**1.79**	**2.01**	**0.72**	**4.53**	**$14,295,750**	**$16,245,800**	**$0.05**	**$0.28**
Commercial & Industrial	**TRC**	**UCT**	**RIM**	**Participant**	**TRC NPV $**	**UCT NPV $**	**Levelized Cost/kWh**	**Cost/kWh**
Commercial Prescriptive	2.70	3.71	0.53	4.84	$ 15,853,125	$ 18,417,119	$0.02	$0.16
Commercial Midstream	2.64	1.77	0.46	0.00	$ 48,350	$ 33,814	$0.02	$0.49
Commercial Custom	2.23	4.06	0.53	3.85	$ 5,822,944	$ 7,947,156	$0.03	$0.15
Small Business Energy Solutions	1.96	3.93	0.62	2.45	$ 4,661,100	$ 7,084,994	$0.03	$0.25
CVR Commercial	1.04	1.04	0.39	n/a	$ 21,853	$ 21,853	$0.05	$0.00
Commercial & Industrial Total	**2.35**	**3.69**	**0.54**	**4.00**	**$26,407,372**	**$33,504,937**	**$0.02**	**$0.18**
Indirect Portfolio Level Costs					$ (3,744,371)	$ (3,744,371)		
Total Portfolio	**1.90**	**2.43**	**0.58**	**4.16**	**$36,958,750**	**$46,006,366**	**$0.04**	**$0.26**

* Cost per Kwh is calculated by dividing program cost by total savings and do not include carry forward costs related to smart thermostat, BYOT and CVR programs. The cost per kWh excludes indirect and other costs for budget. Levelized cost per kWh is .03 per kWh, excluding IQW and CVR.

Table 10: Vectren South 2021-2023 Plan Cost Effectiveness Results including Performance Incentive

Including Performance Incentive	TRC	UCT	RIM	Participant	TRC NPV $	UCT NPV $	Levelized Cost/kWh	First Year Cost/kWh
Total Portfolio	**1.71**	**2.13**	**0.57**	**4.16**	**$32,525,115**	**$41,572,731**	**$0.04**	**$0.29**

* Cost per kWh includes indirect and other costs for budget. Utility Performance Incentive does not include IQW or CVR.

[1] Avoided costs aligned with Vectren South's 2019 IRP, with an adjustment down to fixed capacity cost assumptions.

6. New or Modified Program Initiatives

Vectren South's 2021-2023 filing largely extends the existing momentum of the portfolio of programs from 2019 and 2020 while applying the lessons learned from Vectren's program experience and evaluations as well as making refinements to key data and assumptions as described in this document. Below is a summary which outlines notable changes for the 2021-2023 Plan from previous filings. More in depth details on the following topics can be found within the Program Descriptions portion of this document.

A. Residential Specialty Lighting & Community Based LED

These programs have been modified to remove LED A-line standard bulbs. Both LED specialty and reflector bulbs will continue to be offered.

B. Residential Prescriptive

The Residential Prescriptive program will continue to run mostly unchanged from previous years. One program enhancement will include new delivery mechanisms to complement the existing program design. This expansion will include many of the same measures from Residential Prescriptive to be offered through Residential Midstream, instant rebates and an online marketplace. These additional channels of program delivery will be provided to reach additional customers and markets.

C. Residential Behavioral Savings Program

This program will be expanded to target more customers as identified in the MPS, including a low-income segment, which will motivate customers to act on energy savings tips. The main delivery channel will be targeted mail and email with the addition of specific tips provided to the low-income customer segment.

D. Smart Cycle DLC Change Out & BYOT

Vectren will be partnering with a demand response provider beginning in 2020 that will manage customer enrollments, energy savings, and provide a platform for management of Demand Response (DR) events. Our previous DR provider, Nest, will no longer offer these services and does not have the capability to manage other thermostats in the market such as Ecobee.

E. Residential and Commercial Midstream

Following the successful launch of a Residential Midstream pilot in Q2 2020, Vectren will continue to offer the Residential Midstream program for this 2021-2023 Plan. Midstream measures and savings will continue to shift from prescriptive to midstream based on program performance. The 2020 pilot will include high-efficiency measures such as the Air Source Heat Pump (18 SEER) and Ductless Heat Pump (21 & 23 SEER). Additional measures will be transitioned over the Residential Midstream program during the 2021-2023 Plan period, specifically a Heat Pump Water Heater.

Through midstream incentives, the program aims to influence the equipment that distributors stock, fine-tune incentives to fit desired program outcomes. Because distributors have a large influence on the HVAC equipment that customers eventually install, the pilot will be able to encourage distributors to supply more energy-efficient options. Midstream incentives can be more easily adjusted, as customers receive the discount at the time of equipment purchase, not after a lengthy application process. Because customers receive a discount at the time of purchase, the pilot may influence quicker purchasing decisions.

F. Home Energy Management Systems (HEMS)

The Home Energy Management Systems (HEMS) program is a behavioral program that provides real time energy usage data to encourage customers to take action to reduce energy consumption. The objectives of this program include:

- Motivate customers to save energy by increasing customer awareness and engagement around energy consumption and their utility bill
- Increase customer knowledge of and participation in Company programs including, but not limited to, energy efficiency programs and advanced data analytics
- Deliver energy and demand savings

G. Commercial & Industrial Prescriptive

C&I Prescriptive - Program includes a Compressed Air Leak Repair component as suggested in the MPS. The program would offer a compressed air leak study for no cost to the customer if they agree to a predefined customer commitment (e.g. fixing a certain % of the leaks). High usage compressed air industries include food manufacturers, plastics, metals and chemical plants. The

Strategic Energy Management (SEM) program will continue to be offered to select large energy users for program years 2021-2023. Upon enrollment, customers are assigned an energy manager and must undergo a training process that introduces customers to SEM and ISO 50001 concepts and gives them instructions on how to implement energy efficient change within their organization.

A targeted marketing effort will be launched related to food service equipment, offering a bonus incentive to Trade Allies to push the adoption of the equipment to customers. Additionally, the 2019 midstream pilot within Prescriptive will expand beyond just furnaces to cover large HVAC equipment, water heaters and food service equipment. The electric Commercial Prescriptive Program will be offering the addition of Advanced Rooftop Controls.

The program will also take the simple functionality of the Mobile Assessment Tool used in the Small Business Program and expand it into the prescriptive program. This will allow Trade Allies the option of generating a report detailing all the savings opportunities and their associated rebates for any of their Vectren customers.

Commercial & Industrial Program Reporting

Several of the Commercial & Industrial programs have been consolidated to better reflect overall program progress. Multi-Family Retrofit has been combined to the Small Business Energy Solutions program and Commercial New Construction and Building Tune up have been added to the C&I Custom program. Additionally, for scorecard reporting, C&I Programs are reported in total.

7. Program Descriptions

A. Residential Specialty Lighting

The Residential Specialty Lighting Program is a market-based residential EE program designed to reach residential customers through retail outlets. This program has been modified to remove standard A-line LED bulbs and replace with specialty and reflector bulbs. The program consists of a buy-down strategy that provides incentives to consumers to facilitate the purchase of EE specialty lighting products. The overall program goal is to increase the penetration of ENERGY STAR qualified specialty lighting products based on the most up-to-date standards.

Table 11: Residential Lighting Program Budget & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Residential	**Residential Specialty Lighting**				
	Number of Measures	115,000	110,000	100,000	325,000
	Energy Savings kWh	5,046,833	4,801,366	4,385,296	14,233,495
	Peak Demand kW	698.0	664.0	606.5	1,968.5
	Total Program Budget $	606,656	546,634	521,634	1,674,924
	Per Participant Avg Energy Savings (kWh)*	43.9	43.6	43.9	43.8
	Per Participant Avg Demand Savings (kW)*				0.006
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				50%

Eligible Customers

Any customer of a participating retailer in Vectren South's electric territory.

Marketing Plan

The program is designed to reach residential customers through retail outlets. Proposed marketing efforts include point of purchase promotional activities, the use of utility bill inserts and customer emails, utility web site and social media promotions and coordinated advertising with selected manufacturers and retail outlets.

Barriers/Theory

The program addresses the market barriers by empowering customers to take advantage of new lighting technologies through education and availability in the marketplace; accelerating the adoption of proven energy efficient technologies through incentives to lower price; and working with retailers to allow them to sell more high-efficient products.

Initial Measures, Products and Services

The measures will include a variety of ENERGY STAR qualified specialty lighting products currently available at retailers in Indiana, including specialty LED bulbs, reflectors and decorative.

Program Delivery

Vectren South will oversee the program and partner with CLEAResult to deliver the program.

Evaluation, Measurement and Verification

The implementation contractor will verify the paperwork of the participating retail stores. They will also spot check stores to assure that the program guidelines are being followed. A third-party evaluator will evaluate the program using standard EM&V protocols.

B. Residential Prescriptive

Program Description

The program is designed to incent customers to purchase energy efficient equipment by covering part of the incremental cost. The program also offers home weatherization rebates to residential customers for attic insulation, wall insulation and duct sealing. If a product vendor or contractor chooses to do so, the rebates can be presented as an "instant discount" to Vectren South residential customers on their invoice.

One program enhancement will include new delivery mechanisms to complement the existing program design. This expansion will include many of the same measures from Residential Prescriptive to be offered through residential midstream, instant rebates and an online marketplace. The online marketplace allows customers to purchase smart thermostats, LED specialty and reflector bulbs, smart power strips and other products with an instant rebate applied. The Instant Rebates will provide Vectren customers the flexibility to receive targeted coupons either in store or via email that can be used at point-of-purchase for smart thermostats, heat pump water heaters and air purifiers.

Table 12: Residential Prescriptive Budget & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Residential	Residential Prescriptive				
	Number of Measures	3,771	3,679	3,792	11,242
	Energy Savings kWh	1,657,282	1,317,201	1,319,270	4,293,754
	Peak Demand kW	865.8	481.6	419.3	1,766.8
	Total Program Budget $	1,135,825	960,500	953,909	3,050,235
	Per Participant Avg Energy Savings (kWh)*				381.9
	Per Participant Avg Demand Savings (kW)*				0.157
	Weighted Avg Measure Life*				16
	Net To Gross Ratio				68%

Eligible Customers

Any residential customer located in the Vectren South electric service territory. For the equipment rebates, the applicant must reside in a single-family home or multi-family complex with up to 12 units. Only single-family homes are eligible for insulation and duct sealing remediation measures.

Marketing Plan

The marketing plan includes program specific materials that will target contractors, trade allies, distributors, manufacturers, industry organizations and appropriate retail outlets in the Heating, Ventilation and Air Conditioning (HVAC) industry. Marketing outreach medium include targeted direct marketing, direct contact by vendor personnel, trade shows and trade associations. Vectren will also use web banners, bill inserts, customer emails, social media outreach, press releases and mass market advertising. Program marketing will direct customers and contractors to the Vectren South website or call center for additional information.

Barriers/Theory

The initial cost is one of the key barriers. Customers do not always understand the long-term benefits of the energy savings from efficient alternatives. Trade allies are also often reluctant to sell the higher cost items as they do not want to be the high cost bidder. Incentives help address the initial cost issue and provide a good reason for Trade Allies to promote these higher efficient options.

Initial Measures, Products and Services

Details of the measures, savings, and incentives can be found in Appendix B. Measures included in the program will change over time as baselines change, new technologies become available and customer needs are identified.

Program Delivery

Vectren South will oversee the program and will partner with CLEAResult for prescriptive. A Third Party, which has not been identified, will oversee Marketplace and Instant Rebates. Vendors will work with local contractors to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

As part of the Quality Assurance/Quality Control process, the vendor will provide 100% paper verification that the equipment/products purchased meet the program efficiency standards and a field verification of 5% of the measures installed. A third-party evaluator will review the program using appropriate EM&V protocols.

C. Residential New Construction

Program Description

The Residential New Construction (RNC) program produces long-term energy savings by encouraging the construction of single-family homes, duplexes, or end-unit townhomes with only one shared wall that are inspected and evaluated through the Home Efficiency Rating System (HERS). Builders can select from two rebate tiers, based on HERS ratings plus an additional rebate if the builder reaches the Platinum eligible HERS rating and installs a tankless water heater. Gold Star homes must achieve a HERS rating of 61 to 63. Platinum Star homes must meet a HERS rating of 60 or less. Additionally, we will continue to deliver energy efficiency kits for new homes being constructed by Habitat for Humanity.

The RNC Program provides incentives and encourages home builders to construct homes that are more efficient than current building codes and address the lost opportunities in this customer segment by promoting EE at the time the initial decisions are being made. The Residential New Construction program will work closely with builders, educating them on the benefits of energy efficient new homes. Homes may feature additional insulation, better windows, and higher efficiency appliances. The homes should also be more efficient and comfortable than standard homes constructed to current building codes.

Table 15: Residential New Construction Program Budget & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Residential	**Residential New Construction**				
	Number of Homes	148	171	171	490
	Energy Savings kWh	163,986	188,637	188,637	541,260
	Peak Demand kW	56.1	66.0	66.0	188.0
	Total Program Budget $	88,852	88,049	85,065	261,965
	Per Participant Avg Energy Savings (kWh)*				1104.6
	Per Participant Avg Demand Savings (kW)*				0.384
	Weighted Avg Measure Life*				23
	Net To Gross Ratio				54%

Eligible Customers

Any customer or home builder constructing an eligible home in the Vectren South service territory.

Marketing Plan

In order to move the market toward an improved home building standard, education will be required for home builders, architects and designers as well as customers buying new homes. A combination of in-person meetings with these market participants as well as other educational methods will be necessary.

Barriers/Theory

The Residential New Construction program addresses the primary barriers of first cost as well as builder and customer knowledge. First cost is addressed by program incentives to help reduce the cost of the EE upgrades. The program provides opportunities for builders and developers to gain knowledge and skills concerning EE building practices and coaches them on application of these skills. The HERS rating system allows customers to understand building design and construction improvements through a rating system completed by professionals.

Incentive Strategy

Program incentives are designed to be paid to both all-electric and combination homes that have natural gas heating. It is important to note that the program is structured such that an incentive will not be paid for an all-electric home that has natural gas available to the home site. Incentives can be paid to either the home builder or the customer/account holder. Incentives will be based on the rating tier qualification. For all-electric homes, where Vectren South natural gas service is not available, the initial incentives will be:

Tier	HERS Rating	Total Incentive
Platinum Plus	60 or less & install and installs a tankless water heater (.9 energy factor)	$1,200
Platinum	60 or less	$1,000
Gold	61 to 63	$700

For homes with central air conditioning and Vectren South natural gas space heating, the electric portion of the incentive will be:

Tier	HERS Rating	Total Incentive	Gas Portion	Electric Portion
Platinum Plus	60 or less & install and installs a tankless water heater (.9 energy factor)	$1,200	$900	$300
Platinum	60 or less	$1,000	$750	$250
Gold	61 to 63	$700	$525	$175

Program Delivery

Vectren South will oversee the program and will partner with CLEAResult to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory.

Evaluation, Measurement and Verification

Field inspections will occur at least once during construction and upon completion by a certified HERS Rater. As part of the Quality Assurance/Quality Control process, the vendor will provide 100% paper verification that the equipment/products purchased meet the program efficiency standards. A third-party evaluator will evaluate the program using standard EM&V protocols.

D. Home Energy Assessments

Program Description

The Home Energy Assessment (HEA) program is designed to produce long term energy and demand savings in the residential market. The program provides direct installation of energy-saving measures such as LED light bulbs, aerators, pipe wrap, water heater set-back and a smart thermostat (if qualified). It also provides a detailed report which educates consumers on ways to reduce energy consumption further.

The contractor will educate the customer while performing installation of appropriate direct install measures during the assessment. A comprehensive leave behind report outlining the results and recommendations is also provided. Duct sealing may be available if needed. In order to receive the duct sealing rebate, customers provide a minimum co-pay of $100 and the contractor will specify the leak reduction. If the home is eligible for air sealing and/or insulation, the customer will be referred to a program approved insulation contractor..

Table 16: Home Energy Assessments & Weatherization Budget & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Residential	**Home Energy Assessment**				
	Number of Homes	400	420	504	1,324
	Energy Savings kWh	550,810	576,574	684,783	1,812,167
	Peak Demand kW	52.0	54.0	63.0	169.0
	Total Program Budget $	239,713	256,589	296,868	793,169
	Per Participant Avg Energy Savings (kWh)*				1368.7
	Per Participant Avg Demand Savings (kW)*				0.128
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				75%

Eligible Customers

Any residential customer located in the Vectren South electric service territory. Any customer that qualifies for the residential low-income weatherization program will be referred to that program and not included in the HEA program. Additional requirements include:

- Home was not built within the last five years;
- How has not had an audit within the last three years; and
- Is owner occupied or authorized non-owner occupied where the occupants have the electric service in their name.
- Building type is single-family, or condo/apartment with four units or less

Marketing Plan

Proposed marketing efforts include utilizing direct mailers, email blasts, Vectren South online audit tools, bill inserts, social media outreach, as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained. The preferred program contractor will also market the program to their current customer base as an additional incentive opportunity for use of their services.

Barriers/Theory

The audit requires the customer to select an appointment for the audit to occur. The requirement to be at the appointment can create difficulty for the customer. This program provides customers with some basic improvements to help them save energy and provides the customer with feedback that the customer can use to further improve its energy efficiency such as insulation referral or duct sealing. It is the customer's choice whether they will make the suggested upgrades to save energy.

Initial Measures, Products and Services

Measures available for installation will vary based on the home and include:

- GSL and Specialty LED bulbs/lamps (interior/exterior/candelabra/retrofit – up to 30 bulbs)
- High Efficiency Kitchen and bathroom aerators
- High Efficiency Showerheads (Standard or Handheld)
- Pipe Wrap
- Filter Whistles
- Smart Thermostat
- Water Heater Temperature Setback
- Smart Power Strip
- Duct Sealing/Insulation (requires co-pay)

For customers who elect to move forward with duct sealing, air sealing or attic insulation recommended in the audit report, an instant rebate is available and savings are applied to the HEA.

Program Delivery

Vectren South will oversee the program and partner with a local contractor to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

To assure compliance with program guidelines, field visits with auditors will occur as well as spot check verifications of measure installations. A third-party evaluator will evaluate the program using standard EM&V protocols.

E. Income Qualified Weatherization

Program Description

The Income Qualified Weatherization (IQW) program is designed to produce long-term energy and demand savings in the residential market. The program is designed to provide weatherization upgrades to low-income homes that otherwise would not have been able to afford the energy saving measures. The program provides direct installation of energy-saving measures and educates consumers on ways to reduce energy consumption. Customers eligible through the Income Qualified Weatherization Program will have opportunity to receive deeper retrofit measures including refrigerators, attic insulation, duct sealing, air infiltration reduction and installation of new central air conditioner or air source heat pump.

Collaboration and coordination between gas and electric low-income programs along with state and federal funding is recommended to provide the greatest efficiencies among all programs. The challenge of meeting the goals set for this program have centered on health and safety as well as customer cancellations and scheduling. Vectren South is committed to finding innovative solutions to these areas. A health and safety (H&S) budget has been established, and we continue to work on improving methods of customer engagement with various confirmations via phone and email reminders prior to the appointment. Vectren continues to look for ways to do more of a qualitative approach within this program to ensure the maximum savings is reached and H&S issues are addressed appropriately.

Table 17: Income Qualified Weatherization Budget & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Residential	**Income Qualified Weatherization**				
	Number of Homes	788	735	710	2,233
	Energy Savings kWh	485,948	460,780	444,441	1,391,169
	Peak Demand kW	101.8	111.0	103.5	316.3
	Total Program Budget $	687,423	707,709	714,673	2,109,806
	Per Participant Avg Energy Savings (kWh)*				623.0
	Per Participant Avg Demand Savings (kW)*				0.142
	Weighted Avg Measure Life*				12
	Net To Gross Ratio				100%

Eligible Customers

This program is available to residential customer who receive either electric only or gas and electric service from Vectren where Vectren is the homes primary heat source. Homes must be at 5 years or older and have not received an audit within the last three years; and is owner occupied or authorized non-owner occupied where occupants have the service in their name. Eligible homes must be less than 4 total units, and units should not be stacked. The traditional IQW will continue in its current state offering a home audit, direct install measures and air sealing for customers up to 300% of the Federal Poverty Level (FPL). Additionally, deeper measures including weatherization, air conditioner or air source heat pump replacement will be performed under a "Whole Home IQW" which is offered to customers who qualify with income of up to 200% FPL.

Marketing Plan

Vectren South will provide a list to the implementation contractor of high consumption customers who have received Energy Assistance Program (EAP) funds within the past 12 months to help prioritize those customers who will benefit most from the program. This will also help in any direct marketing activities to specifically target those customers. In addition to utilizing the EAP List, the program will utilize census data to target low-income areas within Vectren territory. Vectren uses door-to-door canvassing for obtaining most of the appointments. The program is marketed to the public as "Neighborhood Weatherization" at various community events also working closely with the Vectren Foundation.

Barriers/Theory

Lower-income homeowners do not have the money to make even simple improvements to lower their bill and often live in homes with the most need for EE improvements. They may also lack the knowledge, experience, or capability to do the work. Health and safety can also be at risk for low-income homeowners, as their homes typically are not as "tight", and indoor air quality can be compromised. In order to increase participation and eligibility, Vectren South has incorporated a H&S budget into the program. An average of $250 per fuel type or $500 per home has been budgeted, but H&S dollars can be spent up to $5,000 per home, upon approval by Vectren. This program provides customers with basic improvements to help them start saving energy without needing to make the investment themselves.

Initial Measures, Products and Services

As specified above under program changes, the measures available for installation will vary based on the home and include:

Traditional IQW - Income requirement of up to 300% FPL

- GSL and Specialty LED Bulbs/Lamps (Interior/Exterior/Candelabras)
- High Efficiency Kitchen and Bathroom Aerators
- High Efficiency Showerhead (Standard or Handheld)
- Pipe Wrap
- Filter Whistles
- Infiltration Reduction
- Attic Insulation
- Duct Repair, Seal and Insulation
- Air Sealing - Gas Furnace with CAC, Heat Pump, Electric Furnace with CAC

- Refrigerator replacement
- Smart thermostat
- Water Heater Temperature Setback
- Smart power strips
- CAC or Furnace Tune-Up

Whole Home IQW - Income requirement of up to 200% FPL. Includes all the "Traditional" measures plus:

- Water heater replacement
- Attic Insulation
- Wall Insulation
- Exterior caulking
- CAC or Furnace Replacement

Program Delivery

Vectren South will oversee the program and will partner with CLEAResult to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

To assure quality installations, 5% of the installations will be field inspected. A third-party evaluator will evaluate the program using standard EM&V protocols.

F. Community Based – LED Specialty Bulb Distribution (formerly Food Bank LED)

Program Description

The Community Based Specialty LED Distribution program is designed to provide energy efficient specialty lighting products to low-income community members who receive assistance from local food banks and township trustees. The program is intended to educate low-income community members on the benefits of energy efficient lighting and provide them with products which would otherwise be unaffordable.

Eligible Customers

The Community Based Specialty LED Distribution program targets local food banks and township trustees who serve low-income homeowners and tenants within Vectren electric service territory.

Marketing Plan

Marketing materials will be created to educate product recipients on the benefits of energy efficiency lighting.

Barriers/Theory

Lower income customers often do not have the money to make even simple improvements to lower their bill and often live in homes with the most need for EE improvements. This program provides those customers with products to help them start saving energy without needing to make the investment themselves.

Initial Measures, Products and Services

LED specialty bulbs will be offered.

Table 18. Community Based LED Distribution Program Budget & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Residential	**Community Based - LED Specialty Bulb Distribution**				
	Number of Measures	33,976	33,976	33,976	101,928
	Energy Savings kWh	1,159,285	1,159,285	1,159,285	3,477,855
	Peak Demand kW	159.7	159.7	159.7	479.1
	Total Program Budget $	168,110	171,693	177,923	517,727
	Per Participant Avg Energy Savings (kWh)*				34.1
	Per Participant Avg Demand Savings (kW)*				0.005
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				100%

Program Delivery

Vectren South will oversee the program and will partner with CLEAResult to deliver the program.

Evaluation, Measurement and Verification

A third-party evaluator will evaluate the program using standard EM&V protocols.

G. Energy Efficient Schools

Program Description

The Energy Efficient Schools Program is designed to impact students by teaching them how to conserve energy and to produce cost effective electric savings by influencing students and their families to focus on the efficient use of electricity.

The program consists of a school education program for 5th grade students attending schools served by Vectren South. To help in this effort, each child that participates will receive a take-home energy kit with various energy saving measures for their parents to install in the home. The kits, along with the in-school teaching materials, are designed to make a lasting impression on the students and help them learn ways to conserve energy.

Table 19: Energy Efficient Schools Budget & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Residential	**Energy Efficient Schools**				
	Number of Kits	2,600	2,600	2,600	7,800
	Energy Savings kWh	733,118	696,462	661,639	2,091,220
	Peak Demand kW	78.3	74.4	70.7	223.4
	Total Program Budget $	118,451	122,451	102,451	343,352
	Per Participant Avg Energy Savings (kWh)*				268.1
	Per Participant Avg Demand Savings (kW)*				0.029
	Weighted Avg Measure Life*				10
	Net To Gross Ratio				100%

Eligible Customers

The program will be available to selected 5th grade students/schools in the Vectren South electric service territory.

Marketing Plan

The program will be marketed directly to elementary schools in Vectren South electric service territory as well as other channels identified by the implementation contractor. A list of the eligible schools will be provided by Vectren South to the implementation contractor for direct marketing to the schools via email, phone, and mail (if necessary) to obtain desired participation levels in the program.

Barriers/Theory

This program addresses the barrier of education and awareness of EE opportunities. Working through schools, both students and families are educated about opportunities to save. As well, the families receive energy savings devices they can install to begin their savings.

Initial Measures, Products and Services

The kits for students will include:

- High Efficiency Kitchen Aerator
- High Efficiency Bathroom Aerators (2)
- High Efficiency Showerhead
- GSL LED bulbs 11 Watt (2)
- GSL LED Bulb 15 Watt (1)
- LED Nightlight
- Filter Whistle

Please note that bulb type may be updated to include the BR30.

Program Delivery

Vectren South will oversee the program and will partner with National Energy Foundation (NEF) to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

Classroom participation will be tracked. A third-party evaluator will evaluate the program using standard EM&V protocols.

H. Residential Behavior Savings

Program Description

The Residential Behavioral Savings Program motivates behavior change and provides relevant, targeted information to the consumer through regularly scheduled direct contact via mailed and emailed home energy reports. The report and web portal include a comparison against a group of similarly sized and equipped homes in the area, usage history comparisons, goal setting tools, and progress trackers. The Home Energy Report program anonymously compares customers' energy use with that of other customers with similar home size and demographics. Customers can view the past 12 months of their energy usage and compare and contrast their energy consumption and costs with others in the same neighborhood. Once a consumer understands better how they use energy, they can then start conserving energy. This program will be expanded to target more customers as identified in the MPS, including a low-income segment, which will motivate customers to act on energy savings tips. The main delivery channel will be targeted mail and email with the addition of specific tips provided to the low-income customer segment. Customers in this low-income wave will also be offered a direct-ship kit with energy saving measures.

Program data and design was provided by Opower, the implementation vendor for the program. Opower provides energy usage insight that drives customers to take action by selecting the most relevant information for each particular household, which ensures maximum relevancy and high response rate to recommendations.

Table 20: Residential Behavior Savings Program Budget & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Residential	**Residential Behavioral Savings**				
	Number of Participants	41,543	42,016	40,182	123,741
	Energy Savings kWh	7,020,000	7,100,000	6,790,000	20,910,000
	Peak Demand kW	1,350	1,270	1,210	3,830
	Total Program Budget $	254,105	261,391	268,896	784,392
	Per Participant Avg Energy Savings (kWh)*				169.0
	Per Participant Avg Demand Savings (kW)*				0.031
	Weighted Avg Measure Life*				1
	Net To Gross Ratio				100%

Eligible Customers

Residential customers who receive electric service from Vectren South are eligible to participate in this integrated natural gas and electric EE program.

Barriers/Theory

The Residential Behavioral Savings program provides residential customers with better energy information through personalized reports delivered by mail, email and an integrated web portal to help them put their energy usage in context and make better energy usage decisions. Behavioral science research has demonstrated that peer-based comparisons are highly motivating ways to present information. The program will leverage a dynamically created comparison group for each residence and compare it to other similarly sized and located households.

Implementation & Delivery Strategy

The program will be delivered by Opower and include energy reports and a web portal. Customers typically receive between 4 to 6 reports annually and monthly emailed reports. These reports provide updates on energy consumption patterns compared to similar homes and provide energy savings strategies to reduce energy use. They also promote other Vectren South programs to interested customers. The web portal is an interactive system for customers to perform a self-audit, monitor energy usage over time, access energy savings tips and be connected to other Vectren South gas and electric programs. In efforts to enhance program savings to low income customers, Opower will provide specific tips to the low-income customer segment.

Program Delivery

Vectren South will oversee the program and partner with Opower to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

A third-party evaluator will complete the evaluation of this program and work with Vectren South to select the participant and non-participant groups.

I. Appliance Recycling

Program Description

The Residential Appliance Recycling program encourages customers to recycle their old inefficient air conditioners, refrigerators, and freezers in an environmentally safe manner. The program recycles operable refrigerators and freezers, so the appliance no longer uses electricity, and keeps 95% of the appliance out of landfills. An older refrigerator can use up to three times the amount of energy as new efficient refrigerators. An incentive of $50 will be provided to the customer for each operational unit picked up. Additionally, air conditioners were added to the mix offering a $25 rebate. To qualify for the air conditioner pick up, customers must have a refrigerator or freezer to be picked up.

Table 21: Appliance Recycling Budget & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Residential	**Appliance Recycling**				
	Number of Measures	1,375	1,300	1,125	3,800
	Energy Savings kWh	1,322,563	1,250,423	1,082,097	3,655,083
	Peak Demand kW	174.6	165.1	142.9	482.6
	Total Program Budget $	244,152	246,902	249,152	740,205
	Per Participant Avg Energy Savings (kWh)*				961.9
	Per Participant Avg Demand Savings (kW)*				0.127
	Weighted Avg Measure Life*				8
	Net To Gross Ratio				67%

Eligible Customers

Any residential customer with an operable secondary air conditioner, refrigerator, or freezer receiving electric service from Vectren South.

Marketing Plan

The program will be marketed through a variety of mediums, including the use of utility bill inserts and customer emails, press releases, retail campaigns coordinated with appliance sales outlets as well as the potential for direct mail, web and social and mass media promotional campaigns.

Barriers/Theory

Many homes have second air conditioners, refrigerators, and freezers that are very inefficient. Customers are not aware of the high energy consumption of these units. Customers also often have no way to move and dispose of the units, so they are kept in homes past their usefulness. This program educates customers about the waste of these units and provides a simple way for customers to dispose of the units.

Program Delivery

Vectren South will work directly with Appliance Recycling Centers of America Inc. (ARCA), to implement this program.

Evaluation, Measurement and Verification

Recycled units will be logged and tracked to assure proper handling and disposal. The utility will monitor the activity for disposal. Customer satisfaction surveys will also be used to understand the customer experience with the program. A third-party evaluator will evaluate the program using standard EM&V protocols.

J. Smart Cycle (DLC Change Out) Program

Program Description

Vectren South has had a Direct Load Control (DLC) program since the early 1990's and currently has approximately 22,994 switches that remain in the program. However, with the advent of smart thermostats and the myriad of benefits they offer for both EE and DR, Vectren South began replacing DLC switches with smart thermostats in 2018. Smart thermostats provide an alternative to traditional residential load control switches as well as enhance the way customers manage and understand their home energy use.

Throughout the 2018-2020 plan period, Vectren South replaced approximately 1,000 DLC switches with smart thermostats each year. As an alternative to DLC switches, smart thermostats can optimize heating and cooling of a home to reduce energy usage and control load while utilities can learn from occupant behavior/preference, adjusting heating, ventilation, and air conditioning (HVAC) settings. Evaluation results show significantly more load reduction can be delivered by smart thermostats. The current DLC switch program is a well-established means for Vectren South to shed load during peak demand; however, over time, to optimize results while minimizing cost to the customer, designing a program incorporating a change out from switches to smart thermostats is a strategic option for cost effective load control solutions. Vectren South's 2021-2023plan continues to replace 1,000 DLC switches with smart thermostats each year.

Vectren will be partnering with Energy Hub beginning in 2020 that will manage customer enrollments, energy savings, and provide a platform for management of Demand Response (DR) events. Our previous DR provider, Nest, will no longer offer these services and does not have the capability to manage other thermostats in the market such as Ecobee.

During the months of June through September, customers in this program will receive a monthly bill credit of $5 for participating in the program. Customers are notified of all events and have the capability of opting out of events at any time during the actual event.

Table 22: Smart Cycle (DLC Change Out) Program & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Residential	**Smart Cycle (DLC Change Out)**				
	Number of Measures	1,000	1,000	1,000	3,000
	Energy Savings kWh	362,577	362,577	362,577	1,087,731
	Peak Demand kW	1,140	1,140	1,140	3,420
	Total Program Budget $	984,328	1,063,328	1,142,328	3,189,985
	Per Participant Avg Energy Savings (kWh)*				362.6
	Per Participant Avg Demand Savings (kW)*				1.710
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				100%

Eligible Customers

Customers in the Vectren South territory who currently participate in the DLC Summer Cycler program and have access to Wi-Fi.

Marketing Plan

Proposed marketing efforts include utilizing direct mailers, email blasts, Vectren South online audit tools, bill inserts as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained.

Incentive Strategy

Customers will receive a professionally installed Wi-Fi thermostat at no additional cost and a monthly bill credit of $5 during the months of June to September. Additionally, the Smart Cycle program includes incentives for existing customers from the 2016 Pilot Program to participate in the Demand Response events for 2021-2023.

Program Delivery

Vectren South will oversee the program.

Evaluation, Measurement and Verification

A third-party evaluator will evaluate the program using standard EM&V protocols.

K. Bring Your Own Thermostat (BYOT)

Program Description

The Bring Your Own Thermostat (BYOT) program is a further expansion of the residential smart thermostat initiative. BYOT allows customers to purchase their own device from multiple vendors and participate in DR with Vectren South and other load curtailing programs managed through the utility. Taking advantage of two-way communicating smart thermostats, the BYOT program can help reduce acquisition costs for load curtailment programs and improve customer satisfaction.

Table 23: BYOT Program Budget & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Residential	**BYOT (Bring Your Own Thermostat)**				
	Number of Participants	400	450	500	1,350
	Energy Savings kWh				
	Peak Demand kW	456.0	513.0	570.0	1,539.0
	Total Program Budget $	126,646	156,496	189,246	472,388
	Per Participant Avg Energy Savings (kWh)*				0.0
	Per Participant Avg Demand Savings (kW)*				1.140
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				100%

Eligible Customers

Residential single or multi-family customers in the Vectren South territory with access to Wi-Fi and who own a qualifying compatible Wi-Fi thermostat that operates the central air-conditioning cooling system.

Marketing Plan

Proposed marketing efforts include utilizing direct mailers, email blasts, Vectren South online audit tools, bill inserts as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained.

Incentive Strategy

Customers will receive a one-time enrollment incentive of $75 and a bill credit of $5 during the months of June to September. The enrollment incentive will be provided in the first year to new enrollees only.

Program Delivery

Vectren South will oversee the program.

Evaluation, Measurement and Verification

A third-party evaluator will evaluate the program using standard EM&V protocols.

M. Residential Midstream

Program Description

Following the successful launch of a residential midstream pilot in Q2 2020, Vectren will continue to offer the Residential Midstream program. Midstream measures and savings will continue to shift from prescriptive to midstream based on program performance. The program targets a small number of distributors that serve the broader market, rather than individual customers. As the HVAC market in Vectren territory matures, midstream offerings can increase market penetration and enlist participants that have historically not taken part in incentive programs.

This approach moves a limited selection of current downstream HVAC measures to a midstream model to test the success of the delivery channel in Vectren territory. The measure selection will target measures that are currently experiencing limited uptake in the market so as not to disrupt the current downstream program. With success, the midstream offering will evaluate additional measures while incorporating feedback from Vectren and distributors.

Table 25: Residential Midstream Program Budget & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Residential	**Residential Midstream**				
	Number of Participants	1,310	1,411	1,771	4,492
	Energy Savings kWh	922,215	1,061,351	1,271,737	3,255,303
	Peak Demand kW	695.3	744.6	938.4	2,378.4
	Total Program Budget $	439,289	417,849	498,073	1,355,211
	Per Participant Avg Energy Savings (kWh)*				724.7
	Per Participant Avg Demand Savings (kW)*				0.529
	Weighted Avg Measure Life*				18
	Net To Gross Ratio				100%

Eligible Customers

Any residential customer located in the Vectren South electric service territory.

Marketing Plan

The marketing plan will target distributors through direct outreach to contractor trade networks. Co-branded materials will be available to participating distributors to draw attention to, and provide education on, the HVAC measures within the program. Fact Sheets will also be created to keep the program top of mind. CleaResult will provide program approved verbiage for email blast content for Distributors to promote the program to their Contractors.

Barriers/Theory

The main barrier for this program is the administrative burden and costs of implementation for the distributor. To address this burden, incentives are paid directly to the distributor, with savings passed along to the customer. With program activity focused on engaging distributors, customers find energy efficiency programs simple and appealing, as their participation varies little from their typical purchasing practices.

Initial Measures, Products and Services

Details of the measures, savings, and incentives can be found in Appendix B. Measures included in the program will change over time as baselines change, new technologies become available and customer needs are identified.

Program Delivery

Vectren South will oversee the program and will partner with CLEAResult to deliver the program. CLEAResult with partner with Distributors (or Participating Partners) to implement the Midstream Program. Participating Partners will be given access and trained on the program-specific platform, Program Partner Center (PPC). Within PPC, distributors will be able to validate that customers are eligible, verify that products meet the requirements of the program, and upload their sales data. Once data is uploaded, PPC will validate that information provided is accurate and meets eligibility requirements set forth by the program. Once all data has been verified, the incentive reimbursement will be processed for the participating partner.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

As part of the Quality Assurance/Quality Control process, the vendor will provide 100% paper verification that the equipment/products purchased meet the program efficiency standards and a field verification of the measures installed. A third-party evaluator will review the program using appropriate EM&V protocols.

P. Conservation Voltage Reduction - Residential and Commercial and Industrial

Program Description

Conservation Voltage Reduction (CVR) achieves energy conservation through automated monitoring and control of voltage levels provided on distribution circuits. End use customers realize lower energy and demand consumption when CVR is applied to the distribution circuit from which they are served. The first CVR was put into service on July 2017, for the Buckwood substation and the second CVR is being put into service in 2021 at the Eastside substation. This filing has the third CVR being planned in 2023.

Energy and demand savings occur when CVR is applied to distribution circuits. Once applied, a step change in energy and demand consumption by customers is realized, dependent upon where customer loads are located within the voltage zones, the load characteristics of the circuit, and how end-use loads respond to the voltage reduction. The resultant energy and demand consumption reduction persists at the new levels if tighter voltage bandwidth operation is applied. As a result, ongoing energy and demand savings persists for the duration of the life of the CVR equipment and if the equipment is maintained and operated in the voltage bandwidth mode.

As approved in Cause 44927, Vectren South capitalized the costs to implement the CVR program and will recover the program budget, consisting of ongoing maintenance, carrying cost, and depreciation expense associated with the implementation along with annual ongoing O&M expense through the annual DSMA rider. The 2021-2023 Plan will contain these expenses for the Buckwood and Eastside substation as well as the substation for the 2023 year.

Table 24: Conservation Voltage Reduction Energy Savings Targets[2]

Market	Program	2021	2022	2023	Total Program
Residential	**CVR Residential**				
	Number of Participants			4,965	4,965
	Energy Savings kWh			1,067,954	1,067,954
	Peak Demand kW			430	430
	Total Program Budget $	354,969	348,828	418,537	1,122,334
	Per Participant Avg Energy Savings (kWh)*				215.1
	Per Participant Avg Demand Savings (kW)*				0.087
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				100%

Market	Program	2021	2022	2023	Total Program
Commercial & Industrial	**CVR Commercial**				
	Number of Participants			662	662
	Energy Savings kWh			875,340	875,340
	Peak Demand kW			213.9	213.9
	Total Program Budget $	225,130	219,516	172,184	616,829
	Per Participant Avg Energy Savings (kWh)*				1322.3
	Per Participant Avg Demand Savings (kW)*				0.323
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				100%

Program Delivery

Vectren South will oversee the program and will partner with an implementer to deliver the program.

Eligible Customers

Vectren South has identified substations that will benefit from the CVR program. For this program, one substation will be installed in 2023.

Barriers/Theory

CVR is both a DR and an EE program. First, it seeks to cost effectively deploy new technology to targeted distribution circuits, in part to reduce the peak demand experienced on Vectren South's electrical power supply system. The voltage reduction stemming from the CVR program operates to effectively reduce consumption during the times in which system peaks are set and as a result directly reduces peak demand. CVR also cost effectively reduces the level of ongoing energy consumption by end-use devices located on the customer side of the utility meter as many end-use devices consume less energy with lower voltages consistently applied. Like an equipment maintenance service program, the voltage optimization

[2] For purposes of this filing, the CVR savings include only the 2023 CVR substation because savings are recognized fully the first year of implementation, therefore Buckwood substation and Eastside substation savings were recognized fully in 2017 and 2021.

allows the customer's equipment to operate at optimum levels which saves energy without requiring direct customer intervention or change.

Initial Measures, Products and Services

Vectren South will install the required communication and control equipment on the appropriate circuits from the substation. No action is required of the customers.

Q. Home Energy Management Systems (HEMS)

Program Description

A HEMS program is a behavioral program that provides real time energy usage data to encourage customers to take action to reduce energy consumption. The HEMS program will be piloted using advanced metering infrastructure (AMI) data to communicate energy usage to customers. The platform will utilize a smart phone application to communicate with customers about their home energy usage and provide suggestions for ways customers can save energy. To enhance customer engagement, participants in the program will receive a smart thermostat at no cost, if they do not currently have one installed in their home. The objectives of this program include:

- Motivate customers to save energy by increasing customer awareness and engagement around energy consumption and their utility bill
- Increase customer knowledge of and participation in Company programs including, but not limited to, energy efficiency programs and advanced data analytics
- Deliver energy and demand savings

Table 26: HEMS Program Budget & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Residential	**Home Energy Management Systems**				
	Number of Participants	1,000	1,000	1,000	3,000
	Energy Savings kWh	515,000	515,000	515,000	1,545,000
	Peak Demand kW	80.0	80.0	80.0	240.0
	Total Program Budget $	203,513	210,513	220,513	634,538
	Per Participant Avg Energy Savings (kWh)*				515.0
	Per Participant Avg Demand Savings (kW)*				0.080
	Weighted Avg Measure Life*				6
	Net To Gross Ratio				100%

Eligible Customers

Any residential customer located in the Vectren South electric service territory, having an AMI meter.

Program Delivery

Vectren South will oversee the program and will partner with a third-party to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

A third-party evaluator will review the program using appropriate EM&V protocols.

R. Commercial and Industrial Prescriptive

Program Description

The Commercial & Industrial (C&I) Prescriptive Program is designed to provide financial incentives on qualifying products to produce greater energy savings in the C&I market. The rebates are designed to promote lower electric energy consumption, assist customers in managing their energy costs, and build a sustainable market around EE.

Program participation is achieved by offering incentives structured to cover a portion of the customer's incremental cost of installing prescriptive efficiency measures.

Table 27: Commercial & Industrial Prescriptive Budget & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Commercial & Industrial	**Commercial Prescriptive**				
	Number of Measures	31,875	26,229	25,750	83,854
	Energy Savings kWh	15,650,556	13,813,073	12,520,261	41,983,890
	Peak Demand kW	2,960.7	2,592.7	2,694.7	8,248.0
	Total Program Budget $	2,513,494	2,431,243	2,234,780	7,179,517
	Per Participant Avg Energy Savings (kWh)*				500.7
	Per Participant Avg Demand Savings (kW)*				0.098
	Weighted Avg Measure Life*				14
	Net To Gross Ratio				84%

Eligible Customers

Any eligible participating commercial or industrial customer receiving Vectren South electric service.

Marketing Plan

Proposed marketing efforts include trade ally outreach, trade ally meetings, direct mail, face-to-face meetings with customers, marketing campaigns and bonuses, web-based marketing, and coordination with key account executives.

Barriers/Theory

Customers often have the barrier of higher first cost for EE measures, which precludes them from purchasing the more expensive EE alternative. They also lack information on high-efficiency alternatives. Trade allies often run into the barrier of not being able to promote more EE alternatives because of first cost or lack of knowledge. Trade allies also gain credibility with customers for their EE claims when a measure is included in a utility prescriptive program. Through the program the trade allies can promote EE measures directly to their customers encouraging them to purchase more efficient equipment while helping customers get over the initial cost barrier.

Initial Measures, Products and Services

Measures will include high-efficient lighting and lighting controls, HVAC equipment including variable frequency drives, commercial kitchen equipment including electronically commutated motors (ECMs), and miscellaneous items including compressed air equipment.

Note that measures included in the program will change over time as baselines change, new technologies become available and customer needs are identified. Detailed measure listings, participation and incentives are in Appendix B.

Implementation & Delivery Strategy

The program will be delivered primarily through the trade allies working with their customers. Vectren South and its implementation partners will work with the trade allies to make them aware of the offerings and help them promote the program to their customers. The implementation partner will provide training and technical support to the trade allies to become familiar with the EE technologies offered through the program. The program will be managed by the same implementation provider as the Commercial & Industrial Custom program so that customers can seamlessly receive assistance and all incentives can be efficiently processed through a single procedure.

Incentive Strategy

Incentives are provided to customers to reduce the difference in first cost between the lower efficient technology and the high-efficient option. There is no fixed incentive percentage amount based on the difference in price because some technologies are newer and need higher amounts. Others have been available in the marketplace longer and do not need as much to motivate customers. Incentives will be adjusted to respond to market activity and bonuses may be available for limited time, if required, to meet goals.

Program Delivery

Vectren South will oversee the program partner Nexant to deliver the program.

Evaluation, Measurement and Verification

Site visits will be made on 5% of the installations, as well as all projects receiving incentive greater than $20,000, to verify the correct equipment was installed. Standard EM&V protocols will be used for the third-party evaluation of the program.

S. Commercial Midstream

Program Description

The Commercial Midstream program will provide incentives to actors at the distributor level (firms positioned between the manufacturer and the end user). An example will be to provide incentives for HVAC equipment such as Ductless Heat Pumps, Air Source Heat Pumps and Heat Pump Water Heaters.

Through midstream incentives, the program aims to influence the equipment that distributors stock and fine-tune incentives to fit desired program outcomes. Because distributors have a large influence on the essential equipment that customers install, the program will be able to encourage distributors to stock and promote more energy-efficient equipment to their clientele. Midstream incentives can be more easily adjusted, as customers receive the discount at the time of equipment purchase, not after a lengthy application process.

Table 28: Commercial & Industrial Midstream Budget & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Commercial & Industrial	**Commercial Midstream**				
	Number of Projects	12	12	12	36
	Energy Savings kWh	31,570	31,570	31,570	94,710
	Peak Demand kW	5.5	5.5	5.5	16.4
	Total Program Budget $	15,577	15,577	15,577	46,732
	Per Participant Avg Energy Savings (kWh)*				2630.8
	Per Participant Avg Demand Savings (kW)*				0.454
	Weighted Avg Measure Life*				18
	Net To Gross Ratio				100%

Eligible Customers

In order to receive midstream incentives, equipment must be installed at an active electric or natural gas General Service customer of Vectren Energy Delivery of Indiana on Rate 120, 125 Vectren South or 220, 225 Vectren North at the location of installation.

Marketing Plan

The marketing plan will target distributors and regional account representatives through direct outreach to contractor trade networks. Co-branded materials will be available to participating distributors to draw attention to, and provide education on, the measures within the program. Fact Sheets will also be created to keep the program top of mind. CleaResult will provide program approved verbiage for email blast content for Distributors to promote the program to their Contractors.

Barriers/Theory

The main barrier for this program is the administrative burden and costs of implementation for the distributor. To address this burden, incentives are paid directly to the distributor, with savings passed along to the customer. With program activity focused on engaging distributors, customers find energy efficiency programs simple and appealing, as their participation varies little from their typical purchasing practices.

Initial Measures, Products and Services

Details of the measures, savings, and incentives can be found in Appendix B. Measures included in the program will change over time as baselines change, new technologies become available and customer needs are identified.

Program Delivery

Vectren South will oversee the program and will partner with a third-party implementer to deliver the program. Participating Partners will be given access and trained on the program-specific platform, Program Partner Center (PPC). Within PPC, distributors will be able to validate that customers are eligible, verify that products meet the requirements of the program, and upload their sales data. Once data is uploaded, PPC will validate that information provided is accurate and meets eligibility requirements set forth by the program. Once all data has been verified, the incentive reimbursement will be processed for the participating partner.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

As part of the Quality Assurance/Quality Control process, the vendor will provide 100% paper verification that the equipment/products purchased meet the program efficiency standards and a field verification of the measures installed. A third-party evaluator will review the program using appropriate EM&V protocols.

T. Commercial and Industrial Custom

Program Description

To maximize cost-effectiveness and streamline program delivery, the Commercial Custom Program encompasses several different options for commercial & industrial customers to participate. These include: Custom Program, Commercial New Construction, Building Tune Up, and Strategic Energy Management (SEM).

The **Custom Program** promotes the implementation of customized energy-saving projects at qualifying customer facilities. Incentives promoted through this program serve to reduce the cost of implementing energy-reducing projects and upgrading to high-efficiency equipment. Due to the nature of a custom EE program, a wide variety of projects are eligible. Under the Custom program, Vectren will offer a Compressed Air Leak Repair component as suggested in the MPS. The program would offer a compressed air leak study for no cost to the customer if they agree to a predefined customer commitment (e.g. fixing a certain % of the leaks). High usage compressed air industries include food manufacturers, plastics, metals and chemical plants.

Specific to **Commercial New Construction-Energy Design Assistance (EDA)**, this program provides value by promoting EE designs with the goal of developing projects that are more energy efficient than current Indiana building code. This program applies to new construction and major renovation projects. Major renovation is defined as the replacement of at least two systems within an existing space (e.g. lighting, HVAC, controls, building envelope). The program provides incentives as part of the facility design process to explore opportunities in modeling EE options to craft an optimal package of investments. The program also offers customers the opportunity to receive prescriptive or custom rebates toward eligible equipment in order to reduce the higher capital cost for the EE solutions.

The **Building Tune-Up** program provides a targeted, turnkey, and cost-effective retro-commissioning solution for small- to mid-sized customer facilities. It is designed as a comprehensive customer solution that will identify, validate, quantify, and encourage the installation of both operational and capital measures. Most of these measures will be no- or low-cost with low payback periods and will capture energy savings from building automation systems.

Vectren will offer a **Strategic Energy Management** (SEM) offering to select large energy users throughout 18-month training process. Upon enrollment, the customer is assigned an energy manager to provide personalized service, as well as technical support, and a facility audit. Because of the 18-month training process, anticipated savings from this will be realized across program years. Savings will capture both prescriptive/custom capital investments and behavioral changes through on-site consultation.

Table 29: Commercial & Industrial Custom Budget & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Commercial & Industrial	**Commercial Custom**				
	Number of Measures	56	69	65	190
	Energy Savings kWh	5,509,079	6,677,683	6,221,324	18,408,086
	Peak Demand kW	702.0	892.0	831.0	2,425.0
	Total Program Budget $	847,795	982,471	933,500	2,763,766
	Per Participant Avg Energy Savings (kWh)*				96884.7
	Per Participant Avg Demand Savings (kW)*				12.763
	Weighted Avg Measure Life*				16
	Net To Gross Ratio				85%

Eligible Customers

Applicants must be an active electric or natural gas General Service customer of Vectren Energy Delivery of Indiana on Rate 120, 125 Vectren South or 220, 225 Vectren North at the location of installation.

Building Tune Up also requires applicants to be both an active Vectren South electric customer on a qualifying commercial rate and an active natural gas General Service customer on Rate 120 or 125.

Marketing Plan

Proposed marketing efforts include individualized outreach to large C&I customers through a variety of channels and coordination with key account representatives to leverage the contacts and relationships they have with the customers. Direct mail, media outreach, trade shows, marketing campaigns and bonuses, trade ally meetings, and educational seminars could also be used to promote the program. The Building Tune-Up and Commercial New Construction programs will now be marketed through the Commercial Custom Program through outreach and direct personal communication from Vectren South staff and third-party contractors. The program implementer will provide service provider specific-marketing collateral to support these companies as they connect with customers. SEM marketing includes individualized outreach to large C&I customers through a variety of channels to solicit program participants. We anticipate these outreach efforts will include several on-site meetings at customer facilities.

Barriers/Theory

Applications of some specific EE technologies are unique to that customer's application or process. The energy savings estimates for these measures are highly variable and cannot be assessed without an engineering estimation of that application; however, they offer a large opportunity for energy savings. To promote the installation of these high efficient technologies or measures, the Commercial & Industrial

Custom program will provide incentives based on the kWh saved as calculated by the engineering analysis. To assure savings, these projects will require program engineering reviews and pre approvals. The custom energy assessments offered will help remove customer barriers regarding opportunity identification and determining energy savings potential.

The Building Tune-Up program will typically target customers with buildings between 50,000 square feet and 150,000 square feet. Customers in this size range face unique barriers to energy efficiency. For example, although they are large enough to have a Building Automation System (BAS), they are usually too small to have a dedicated facility manager or staff with experience achieving operational efficiency. Also, most retro-commissioning service companies prefer larger projects and are too expensive for small-to-midsized customers. We have specifically tailored the incentive structure and program design to eliminate these barriers. The Building Tune-Up program is designed as a comprehensive customer solution that will identify, validate, quantify, and encourage the installation of both operational and capital measures eligible for incentive offerings.

Initial Measures, Products and Services

All technologies or measures that save kWh qualify for the program. There are different services offered in the Building Tune-Up, New Construction and SEM sub-programs. The BTU program will specifically target measures that provide no- and low-cost operational savings. Most measures involve optimizing the building automation system (BAS) settings but the program will also investigate related capital measures, like controls, operations, processes, and HVAC.

The New Construction service provides energy design assistance at the design phase to encourage new buildings to go beyond what Indiana code requires. Each recommendation is provided to the customer through a report that estimates the savings and cost impacts. Customers are then provided additional rebates for each recommendation they select and install from the report.

The service within the SEM program provides in-depth consulting and support to large energy users who are interested in becoming ISO 50001 Ready. The program assigns a certified trainer to help set up their Energy Management System and trains them on best practices of energy management over an 18-month period. The participating customer will also receive an energy audit that will identify areas of opportunity to optimize the energy use in their facility.

Implementation & Delivery Strategy

The implementation partner will work collaboratively with Vectren South staff to recruit and screen customers for receiving facility energy assessments, technical assistance and energy management education. The implementation partner will also provide engineering field support to customers and trade allies to calculate the energy savings. Customers or trade allies with a proposed project will complete an application form with the energy savings calculations for the project. The implementation team will review all calculations and where appropriate complete site visits to assess and document pre installation conditions. Customers will be informed, and funds reserved for the project. Implementation engineering staff will review the final project information as installed and verify the energy savings. Incentives are then paid on the verified savings.

C&I New Construction - The new construction program is designed as a proactive, cost-effective way to achieve energy efficiency savings and foster economic growth. Typically, program participants face time and cost constraints throughout the project that make it difficult to invest in sustainable building practices. Participants need streamlined and informed solutions that are specific to their projects and locations. This scenario is particularly true for small- to medium-sized new construction projects, where design fees and schedules provide for a very limited window of opportunity.

To help overcome the financial challenge, a Standard Energy Design Assistance (EDA) is offered. This provides additional engineering expertise during the design phase to identify energy-saving opportunities. Commercial and industrial projects for buildings greater than 100,000 square feet still in the conceptual design phase qualify for Vectren South's Enhanced EDA incentives which include energy modeling. The Vectren South implementation partner staff expert will work with the design team through the conceptual design, schematic design and design development processes providing advice and counsel on measures that should be considered and EE modeling issues. Incentives will be paid after the design team submits completed construction documents for review to verify that the facility design reflects the minimum energy savings requirements. For those projects that are past the phase where EDA can be of benefit, the C&I New Construction program offers the opportunity to receive prescriptive or custom rebates towards eligible equipment.

The **Building Tune-Up** program is designed to encourage high levels of implementation by customers seeking to optimize the operation of their existing HVAC system.

SEM is a new, comprehensive approach to energy management, customers are provided with expert support during their participation in the program. As soon as a customer enrolls in the program, an energy manager is assigned to provide personalized service throughout the 18-month training process. That process starts with a series of trainings that will introduce SEM and ISO 50001 concepts to the customer and gives them specific instructions on how they can implement lasting change within their organization. Key strategies include:

- **Energy Managers.** Program-provided energy managers guide customers through the process, helping them complete program requirements, and supporting their implementation of SEM.

- **High-Quality Training.** Energy Managers prepare each customer's energy champion for the cohort training, which is conducted in which customers learn the basic elements of ISO 50001 and how to apply them to their facilities.

- **Free Facility Audit.** SEM is focused on long-term change, and the program provides each customer with a free facility audit to identify both operational and capital energy efficiency projects. The energy audit also serves as a teaching moment for the companies' energy team on how to systematically identify opportunities for improvement. The low- and no-cost operational projects can be completed almost immediately, while the capital projects help customers continue to take advantage of savings.

Incentive Strategy

Incentives will be calculated on a per kWh basis. The initial kWh rate will be $0.10/kWh and is paid based on the first-year annual savings reduction. Rates may change over time and vary with some of the special initiatives. Incentives will not pay more than 50% of the project cost nor provide incentives for projects with paybacks less than 12 months. Vectren South will offer a cost share on facility energy assessments that will cover up to 100% of the assessment cost.

The Commercial New Construction program will provide incentives to help offset some of the expenses for the design team's participation in the EDA process with the design team incentive. The design team incentive is a fixed amount based on the new/renovated conditioned square footage and is paid when the proposed EE projects associated with the construction documents exceed a minimum energy savings threshold. The program also offers customers the opportunity to receive prescriptive or custom rebates toward eligible equipment in order to reduce the higher capital cost for the EE solutions. Program specific savings and incentive include:

Facility Size – Square Feet	Design Team Incentives	Minimum Savings
Small <25,000	$750	25,000 kWh
Medium 25,000 - 100,000	$2,250	75,000 kWh
Large >100,000	$3,750	150,000 kWh
Enhance Large >100,000	$5,000	10% beyond code

Program Delivery

Vectren South will oversee the program partner Nexant to deliver the program. Additionally, Nexant will oversee the SEM Program's implementation, training and modeling.

Integration

Vectren South will offer this integrated natural gas and electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

Given the variability and uniqueness of each project, all projects will be pre-approved. Pre and post visits to the site to verify installation and savings will be performed as defined by the program implementation partner. Monitoring and verification may occur on the largest projects. A third-party evaluator will be used for this project and use standard EM&V protocols.

U. Small Business Energy Solutions (SBES)

Program Description

The SBES Program provides value by directly installing EE products such as high efficiency lighting, pre-rinse sprayers, refrigeration controls, electrically commutated motors, smart thermostats and vending machine controls. The program helps small businesses, multi-family and not-for-profit customers identify and install cost effective energy saving measures by providing an on-site energy assessment customized for their business. The Multi-Family Retrofit program that began in 2017 will continue to be offered under the SBES program. This program is an integrated gas and electric and is targeting dual fuel customers. Vectren also permits the program to include eligible non-profit establishment of any size to participate within this program.

Table 30: Small Business Energy Solutions Budget & Energy Savings Targets

Market	Program	2021	2022	2023	Total Program
Commercial & Industrial	**Small Business Energy Solutions**				
	Number of Projects	78	78	78	234
	Energy Savings kWh	3,194,615	3,949,771	3,952,715	11,097,100
	Peak Demand kW	484.9	557.9	557.9	1,600.6
	Total Program Budget $	807,181	884,304	878,048	2,569,533
	Per Participant Avg Energy Savings (kWh)*				47423.5
	Per Participant Avg Demand Savings (kW)*				6.840
	Weighted Avg Measure Life*				15
	Net To Gross Ratio				100%

Eligible Customers

Any participating Vectren South business customer with a maximum peak energy demand of less than 400 kW. Additionally, multifamily building owners with Vectren general electric service may qualify for the program, including apartment buildings, condominiums, cooperatives, duplexes, quadraplexes, townhomes, nursing homes and retirement communities.

Marketing Plan

The SBES Program will be marketed primarily through in-network trade ally outreach. The program implementer will provide trade ally-specific marketing collateral to support trade allies as they connect with customers.

The program will provide targeted marketing efforts as needed to individual customer segments (e.g., hospitality, grocery stores, and retail) to increase participation in under-performing segments, including direct customer outreach and enhanced incentive campaigns. Additional program marketing may occur through direct mail, trade associations, local business organizations, marketing campaigns and bonuses, educational seminars, and direct personal communication from Vectren South staff and third-party contractors.

Barriers/Theory

Small business customers generally do not have the knowledge, time or money to invest in EE upgrades. This program assists these small businesses with direct installation and turn-key services to get measures installed at no or low out-of-pocket cost.

There is an implementation contractor in place providing suggested additions and changes to the program based on results and local economics.

Implementation & Delivery Strategy

Trade Ally Network: Trained trade ally energy advisors will provide energy assessments to business customers with less than 400 kW of annual peak demand. The program implementer will issue an annual Request for Qualification to select the trade allies with the best ability to provide high-quality and cost-effective service to small businesses and provide training to Small Business Energy Solutions trade allies on the program process, with an emphasis on improving energy efficiency sales.

Energy Assessment: Trade allies will walk through small businesses and record site characteristics and energy efficiency opportunities at no cost to the customer. They will provide an energy assessment report that will detail customer-specific opportunities, costs, energy savings, incentives, and simple payback periods. The trade ally will then review the report with the customer, presenting the program benefits and process, while addressing any questions.

Initial Measures, Products and Services

The program will have two types of measures provided. The first are measures that will be installed at no cost to the customer. They will include but are not limited to the following:

- Smart thermostats
- Programmable thermostats
- Program the programmable thermostats
- Pre-rinse sprayers
- Faucet aerators

The second types of measures require the customer to pay a portion of the labor and materials. These measures include:

- Interior LED Lighting (replacing incandescent, high bays and linear fluorescents)
- Linear Fluorescent Delamping
- Exterior LED Lighting
- Interior Lighting Controls EC motors
- Anti-Sweat Heater Controls
- Refrigerated LED
- Refrigerated Case Cover
- Furnace Tune-Up
- Steam Trap Replacement
- Vending Machine Control

Incentive Strategy

In addition to the no-cost measures identified during the audit, the program will also pay a cash incentive on every recommended improvement identified through the assessment. Incentive rates may change over time and vary with special initiatives.

Program Delivery

Vectren South will oversee the program partner Nexant to deliver the program.

Integration with Vectren South Gas

Vectren South will offer this integrated natural gas and electric EE program in its combined natural gas and electric service territory.

Evaluation, Measurement and Verification

On-site verification will be provided for the first three projects completed by each trade ally, in addition to the program standard 5% of all completed projects and all projects receiving incentives greater than $20,000. These verifications allow the program to validate energy savings, in addition to providing an opportunity to ensure the trade allies are providing high-quality customer services and the incentivized equipment satisfies program requirements. A third-party evaluator will evaluate the program using standard EM&V protocols.

8. Program Administration

As in previous years, Vectren South will continue to serve as the program administrator for the 2021-2023 Plan. Vectren South will utilize third-party program implementers to deliver specific programs or program components where specialty expertise is required. Contracting directly with specialty vendors avoids an unnecessary layer of management, oversight and expense that occurs when utilizing a third-party administration approach.

Program administration costs are allocated at the program level and include costs associated with program support and internal labor. Program support includes costs associated with outside consulting and annual license and maintenance fees for DSMore, Data Management, and Esource. Based upon the EE and DR programs proposed in the 2021 - 2023 Plan, Vectren South is proposing to maintain the staffing levels that were previously approved to support the portfolio. The major responsibilities associated with these FTEs are as follows:

- **Portfolio Management and Implementation** - Oversees the overall portfolio and staff necessary to support program administration. Serves as primary contact for regulatory and oversight of programs.
- **Reporting and Analysis** - Responsible for all aspects of program reporting including, budget analysis/reporting, scorecards and filings.
- **Outreach and Education** - Serves as contact to trade allies regarding program awareness. Also serves as point of contact for residential and commercial/industrial customers to assist with responding to program inquiries.
- **Research and Evaluation** - Works with the selected EM&V Administrator and facilitates measurement and verification efforts, assists with program reporting/tracking.

9. Support Services

Support services are considered indirect costs which support the entire portfolio and include: Contact Center, Online Audit, Outreach & Education, and Evaluation, Measurement and Verification (EM&V). These costs are budgeted at the portfolio level.

Table 31: Portfolio Level Costs by Year

Indirect Portfolio Level Costs	2021	2022	2023
Contact Center	$64,008	$65,032	$67,130
Online Audit	$43,598	$44,295	$45,724
Outreach & Education	$416,560	$423,225	$436,877
Evaluation	$522,653	$518,856	$512,192
Total Indirect Portfolio Level Costs	**$1,046,819**	**$1,051,408**	**$1,061,922**

A. Contact Center

The Vectren Contact Center, called the Energy Efficiency Advisory Team, fields referrals from the company's general call center and serves as a resource for interested customers. A toll-free number is provided on all outreach and education materials. Direct calls are initial contacts from customers or market providers coming through the dedicated toll-free number printed on all Vectren South's energy efficiency materials. Transferred calls are customers that have spoken with a Vectren Contact Center representative and have either asked or been offered a transfer to an Energy Efficiency Advisor who is trained to respond to energy efficiency questions or conduct the on-line energy audit.

These customer communication channels provide support mechanisms for Vectren South customers to receive the following services:

- Provide general guidance on energy saving behaviors and investments using customer specific billing data via the on-line tool (bill analyzer and energy audit).
- Respond to questions about the residential and general service programs.
- Facilitate the completion of and provide a hard copy report from the online audit tool for customers without internet access or who have difficulty understanding how to use the tool.
- Respond to inquiries about rebate fulfillment status.

B. Online Audit

The Online Energy Audit tool is a customer engagement and messaging tool that uses actual billing data from a customer's energy bills to pinpoint ways to save energy in their home. Data collected drives account messaging through providing tips and rebates relevant to that customer's situation. Additionally, data collected from the online energy audit is used to validate neighbor comparison data, which illustrates how the customer's monthly energy use compares to their neighbors and is designed to inspire customers to try and save more energy than their efficient neighbors. This tool provides the online ability and means to communicate, cross promote, and educate customers about energy efficiency and Vectren's energy efficiency programs. The Online Energy Audit tool provides tools and messaging to educate customers and provide suggestions, tips, and advice on energy usage. The budget for the Online Audit tool is shared across Vectren's Indiana Gas DSM, Electric DSM and Vectren Energy Delivery of Ohio, Inc. (VEDO) DSM portfolios.

C. Outreach & Education

Vectren South's Customer Outreach and Education program serves to raise awareness and drive customer participation as well as educate customers on how to manage their energy bills. The program includes the following goals as objectives:

- Build awareness;
- Educate consumers on how to conserve energy and reduce demand;
- Educate customers on how to manage their energy costs and reduce their bill;
- Communicate support of customer EE needs; and
- Drive participation in the EE and DR programs.

The marketing approach includes paid media as well as web-based tools to help analyze bills, energy audit tools, EE and DSM program education and information. Informational guides and sales promotion materials for specific programs are included in this budget.

This effort is the key to achieving greater energy savings by convincing the families and businesses making housing/facility, appliance and equipment investments to opt for greater EE. The first step in convincing the public and businesses to invest in EE is to raise their awareness.

It is essential that a broad public education and outreach campaign not only raise awareness of what consumers can do to save energy and control their energy bills, but also prime them for participation in the various EE and DR programs.

Vectren South will oversee outreach and education for the programs and work closely with implementation partners to provide consistent messaging across different program outreach and education efforts. Vectren South will utilize the services of communication and EE experts to deliver the EE and DR message.

The Outreach budget also includes funds for program development and staff training. Examples of these costs include memberships to EE related organizations, outreach for home/trade shows and travel and training related to EE associated staff development.

Another outreach opportunity that Vectren South has employed is a jointly facilitated Industrial Energy Efficiency Workshop. Vectren South first offered this workshop in June 2019 to share resources available for commercial and industrial customers. There were 25 total attendees, with 10 customers represented (6 opt-out and 4 opt-in). The workshop featured speakers from the Midwest Energy Efficiency Alliance (MEEA), Department of Energy (DOE) ENERGY STAR® division, Nexant and Vectren, and included a bonus incentive for companies who attended in an effort to increase program participation. The workshop was well received and Vectren South plans to continue offering this resource during the 2021-2023 Plan period. Evaluation

Vectren South will work with an independent third-party evaluator, selected by the VOB, to conduct an evaluation of DSM programs approved as part of its 2021-2023 Plan. The evaluation will include standard EM&V analyses, such as a process, impact, and/or market effects evaluation of Vectren South's portfolio of DSM programs. Gas impacts will be calculated for all of Vectren South's integrated gas programs. EM&V costs are based on 5% of the budget and allocated at the portfolio level.

10. Other Costs

Other costs being requested in the 2021-2023 filed plan include a Market Potential Study and funding for Emerging Markets.

Table 32: Other Costs by Year

Other Costs	2021	2022	2023
Emerging Markets	$200,000	$200,000	$200,000
Market Potential Study	$200,000	$0	$0
Total	**$400,000**	**$200,000**	**$200,000**

A. Emerging Markets

The Emerging Markets funding allows Vectren's DSM portfolio to offer leading-edge program designs for next-generation technologies, services, and engagement strategies to growing markets in the Vectren territory. The budget will be $200,000 each year for 2021-2023 and will not be used to support existing programs, but rather support new program development or new measures within an existing program.

Incentives promoted through this program may range from innovative rebate offerings to engineering and trade ally assistance to demand-control services that encourage early adoption of new, efficient technologies in high-impact market sectors. Depending on the development of certain technologies and growth areas in the service territory, a wide variety of projects and services are eligible.

To offset the risks of oversaturation of common prescriptive measures and redefined prescriptive baselines, this program will bring to market next generation technologies and energy-saving strategies that have significant savings and cost-effectiveness potential. As new technologies develop towards lower costs and higher efficiency, their market penetration and energy-savings potential will increase. This program will allow Vectren to be on the forefront of emerging technologies to understand the market disruption a new product may cause, test strategies for capturing their energy-saving opportunities, and plan for future program savings growth. This offering will supplement the other DSM programs that do not easily fit into other program offerings. Additionally, growing segments of Vectren South electric customers may require tailored offerings to accommodate their needs in order to participate.

Because this program will focus on innovative new approaches and leading the DSM market, the exact list of measures cannot be set at this time. However, potential measures and services include: new technologies, such as Advanced Lighting Controls; new strategies for achieving significant energy savings, such as midstream incentives, contractor bids to provide energy efficiency projects, and targeting high-impact market sectors; and integrated DSM (iDSM) approaches, such as demand response, combined energy efficiency and demand response measures, and load shifting.

Emerging technologies and measures will be reviewed and may be offered using this funding as long as they do not fall into a current program offering. Innovative engagement and incentivizing approaches may also be used as a tool to provide reduced costs to new systems, equipment and/or services to help reduce peak demand and electric usage. This program also allows Vectren to take steps toward an integrated Demand Side Management approach to address both energy efficiency and demand response together.

B. Market Potential Study

Vectren South is requesting $200,000 to complete a refresh and Market Potential Study (MPS) in 2021 to include 2026. The current MPS is for program years 2021-2025, including 2026 is necessary to support future EE filings which will be based on 2022 IRP. Vectren will issue a Request for Quote to select a consultant to perform this work.

11. Conclusion

Vectren South has developed a 2021-2023 Electric Energy Efficiency Plan that is aligned with the 2019 Integrated Resource Plan and is reasonably achievable and cost effective. The cost effectiveness analysis was performed for 2021-2023 using the DSMore model – a nationally recognized economic analysis tool that is specifically designed to evaluate the cost effectiveness of implementing energy efficiency and demand response programs.

Program costs were determined by referencing current program delivery costs, based on prior contracts and performance in the field and consultation with the program vendors that will deliver the DSM Plan. Energy and demand savings were primarily determined by using recent EM&V results and the IN TRM version 2.2. For measures that were not addressed in the IN TRM or EM&V, Vectren South used Technical Resource Manual resources from nearby states or vendor input. Vectren South utilized the avoided costs from 2019 IRP[1] adjusted down for fixed capacity.

Based on this information, Vectren South requests IURC approval of this 2021-2023 DSM Plan as well as the costs associated with Emerging Markets and the Market Potential study for 2021 and beyond.

[1] Avoided costs aligned with Vectren South's 2019 IRP, with an adjustment down to fixed capacity cost assumptions.

12. Appendix A: Cost Effectiveness Tests Benefits & Costs Summary

Test	Benefits	Costs
Participant Cost Test	• Incentive payments • Annual bill savings • Applicable tax credits	• Incremental technology/equipment costs • Incremental installation costs
Utility Cost Test (Program Administrator Cost Test)	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs
Rate Impact Measure Test	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs • Lost revenue due to reduced energy bills
Total Resource Cost Test	• Avoided energy costs • Avoided capacity costs • Applicable participant tax credits	• All program costs (not including incentive costs) • Incremental technology/equipment costs (whether paid by the participant or the utility)

Appendix B: Program Measure Detail

Program Name	Measure	Measure Life	NTG	Average kWh/ Unit	Average KW/ Unit	2021 Participation	2022 Participation	2023 Participation	Avg Incentive/Unit	IMC/unit	2021 kWh	2022 kWh	2023 kWh	2021 kW	2022 kW	2023 kW
Lighting	LED Specialty	15	50%	34.1	0.005	40,000	40,000	35,000	$ 2.00	$ 3.50	1,364,829	1,364,828	1,194,224	188	188	165
Lighting	LED Reflector	15	50%	49.1	0.007	75,000	70,000	65,000	$ 3.00	$ 3.50	3,682,005	3,436,538	3,191,071	510	476	442
Lighting Total			50%			115,000	110,000	100,000			5,046,834	4,801,366	4,385,295	698	664	607
EE Products - Electric	AC Tune Up	2	63%	111.1	0.123	250	325	350	$ 25.00	$ 82.00	27,787	36,122	38,901	31	40	43
EE Products - Electric	Air Purifier	9	69%	681.1	0.078	5	5	5	$ 50.00	$ 70.00	3,405	3,405	3,405	0	0	0
EE Products - Electric	Air Source Heat Pump 16 SEER	18	65%	880.8	0.464	150	50	40	$ 300.00	$ 870.00	132,122	44,041	35,233	70	23	19
EE Products - Electric	Air Source Heat Pump 18 SEER	18	65%	1,590.0	0.530	40	20	15	$ 500.00	$ 870.00	63,598	31,799	23,849	21	11	8
EE Products - Electric	ASHP Tune Up	2	63%	285.0	-	15	20	25	$ 50.00	$ 64.00	4,275	5,700	7,125	-	-	-
EE Products - Electric	Attic Insulation - South (Dual - Gas & Electric)	25	68%	303.6	0.464	100	100	100	$ 360.00	$ 750.00	30,359	30,359	30,359	46	46	46
EE Products - Electric	Attic Insulation - South (Electric Only)	25	68%	3,018.7	0.103	20	10	10	$ 450.00	$ 1,500.00	60,373	30,187	30,187	2	1	1
EE Products - Electric	Central Air Conditioner 16 SEER	18	65%	434.9	0.540	600	500	400	$ 200.00	$ 400.00	260,950	217,458	173,967	324	270	216
EE Products - Electric	Central Air Conditioner 18 SEER	18	65%	666.0	0.577	40	35	30	$ 400.00	$ 800.00	26,640	23,310	19,980	23	20	17
EE Products - Electric	Dual Fuel Air Source Heat Pump 16 SEER	18	65%	695.3	0.330	10	10	10	$ 300.00	$ 1,000.00	6,953	6,953	6,953	3	3	3
EE Products - Electric	Dual Fuel Air Source Heat Pump 18 SEER	18	65%	991.7	0.325	5	5	5	$ 500.00	$ 1,666.67	4,958	4,958	4,958	2	2	2
EE Products - Electric	Duct Sealing - South (Dual - Gas & Electric)	20	68%	217.5	0.382	21	21	21	$ 240.00	$ 175.00	4,568	4,568	4,568	8	8	8
EE Products - Electric	Ductless Heat Pump 19 SEER 9.5 HSPF	18	65%	3,066.5	0.380	10	5	5	$ 300.00	$ 2,333.33	30,665	15,332	15,332	4	2	2
EE Products - Electric	Ductless Heat Pump 21 SEER 10.0 HSPF	18	65%	2,932.2	0.368	15	10	10	$ 500.00	$ 2,833.33	43,984	29,322	29,322	6	4	4
EE Products - Electric	Ductless Heat Pump 23 SEER 10.0 HSPF	18	65%	4,306.1	0.711	20	15	10	$ 500.00	$ 3,333.33	86,123	64,592	43,061	14	11	7
EE Products - Electric	Heat Pump Water Heater	10	69%	2,556.8	0.349	7	10	12	$ 500.00	$ 1,000.00	17,897	25,568	30,681	2	3	4
EE Products - Electric	Pool Heater	10	69%	1,266.5	-	2	4	5	$ 1,000.00	$ 3,333.33	2,533	5,066	6,332	-	-	-
EE Products - Electric	Smart Programmable Thermostat - South (Dual -	15	78%	299.4	-	700	650	500	$ 60.00	$ 63.81	209,606	194,634	149,718	-	-	-
EE Products - Electric	Smart Programmable Thermostat - South (Electr	15	78%	740.3	-	120	100	80	$ 75.00	$ 127.61	88,830	74,025	59,220	-	-	-
EE Products - Electric	Variable Speed Pool Pump	15	69%	1,172.6	1.716	160	-	-	$ 300.00	$ 750.00	187,612	-	-	275	-	-
EE Products - Electric	Wall Insulation - South (Dual - Gas & Electric)	25	68%	29.3	0.259	94	94	94	$ 360.00	$ 750.00	2,758	2,758	2,758	24	24	24
EE Products - Electric	Wall Insulation - South (Electric Only)	25	68%	801.0	0.019	12	12	12	$ 450.00	$ 1,500.00	9,612	9,612	9,612	0	0	0
EE Products - Electric	Wifi Thermostat - South (Dual - Gas & Electric)	15	78%	294.6	-	80	75	60	$ 40.00	$ 51.60	23,570	22,097	17,678	-	-	-
EE Products - Electric	Wifi Thermostat - South (Electric Only)	15	78%	294.6	-	30	25	20	$ 50.00	$ 103.20	8,839	7,366	5,893	-	-	-
EE Products - Electric Total						2,506	2,101	1,819			1,338,016	889,232	749,092	856	469	405
Marketplace - Electric	Air Purifier	9	69%	681.1	0.078	10	10	15	$ 50.00	$ 70.00	6,811	6,811	10,216	1	1	1
Marketplace - Electric	Smart Power Strips	4	100%	25.8	0.002	50	50	50	$ 10.00	$ 35.00	1,292	1,292	1,292	0	0	0
Marketplace - Electric	Smart Programmable Thermostat - South (Dual -	15	78%	299.4	-	200	230	250	$ 60.00	$ 63.81	59,887	68,870	74,859	-	-	-
Marketplace - Electric	Smart Programmable Thermostat - South (Electr	15	78%	740.3	-	35	42	50	$ 75.00	$ 127.61	25,909	31,091	37,013	-	-	-
Marketplace - Electric	LED Specialty	15	23%	34.1	0.005	250	250	250	$ 2.00	$ 3.50	8,530	8,530	8,530	1	1	1
Marketplace - Electric	LED Reflector	15	39%	49.1	0.007	250	250	250	$ 3.00	$ 3.50	12,273	12,273	12,273	2	2	2
Marketplace - Electric Total						795	832	865			114,702	128,867	144,183	4	4	4
Instant Rebates - Electric	Smart Programmable Thermostat - South (Dual -	15	78%	299.4	-	385	663	995	$ 60.00	$ 63.81	115,283	198,527	297,940	-	-	-
Instant Rebates - Electric	Smart Programmable Thermostat - South (Electr	15	78%	740.3	-	55	47	71	$ 75.00	$ 127.61	40,714	34,792	52,558	-	-	-
Instant Rebates - Electric	Heat Pump Water Heater	10	69%	2,556.8	0.349	15	22	25	$ 500.00	$ 1,000.00	38,352	56,249	63,919	5	8	9
Instant Rebates - Electric	Air Purifier	9	69%	681.1	0.078	15	14	17	$ 50.00	$ 70.00	10,216	9,535	11,578	1	1	1
Instant Rebates - Electric Total						470	746	1,108			204,565	299,102	425,995	6	9	10
RNC-Electric	Gold Star: HERS Index Score ≤ 63 - Electric Heate	25	54%	0.5	-	-	-	700	$ 2,059.00	$ -	-	-	-	-	-	36
RNC-Electric	Gold Star: HERS Index Score ≤ 63 - Gas Heated So	25	54%	0.4	75.000	90	90	175	$ 846.80	$ 77,490.58	92,989	92,989	30	36	36	0
RNC-Electric	Habitat Kit Electric Only	14	100%	0.1	8.000	8	8	-	$ 48.75	$ 19,140.39	19,140	19,140	0	0	0	1
RNC-Electric	Habitat Kit Gas and Electric	14	100%	0.0	20.000	20	20	-	$ 48.75	$ 14,368.44	14,368	14,368	1	1	1	6
RNC-Electric	Platinum Star Plus: HERS Index Score ≤ 60 - Elect	25	54%	2.1	-	-	-	1,200	$ 3,793.19	$ -	-	-	-	-	-	
RNC-Electric	Platinum Star Plus: HERS Index Score ≤ 60 - Gas H	25	54%	1.2	5.000	5	5	300	$ 2,492.27	$ 7,224.29	7,224	7,224	6	6	6	
RNC-Electric	Platinum Star: HERS Index Score ≤ 60 - Electric He	25	54%	0.6	-	-	-	1,000	$ 3,079.19	$ -	-	-	-	-	-	
RNC-Electric	Platinum Star: HERS Index Score ≤ 60 - Gas Heate	25	54%	0.5		48	48	250	$ 1,778.27	$ 45,762.41	54,915	54,915	19	23	23	23
RNC-Electric Total						171	171	3,625			188,637	188,637	56	66	66	66

Program Name	Measure	Measure Life	NTG	Average kWh/ Unit	Average KW/ Unit	2021 Participation	2022 Participation	2023 Participation	Avg Incentive/Unit	IMC/unit	2021 kWh	2022 kWh	2023 kWh	2021 kW	2022 kW	2023 kW
Home Energy Assessments	Bathroom Aerator 1.0 gpm - Elec DHW	10		23.7	0.003	60	63	76			1,423	1,494	1,793	0	0	0
Home Energy Assessments	Customer Education (Audit & Report)	1		63.1	0.007	332	349	418			20,959	22,007	26,408	2	3	3
Home Energy Assessments	Duct Sealing Electric Heat Pump	20		298.0	0.293	8	8	8			2,384	2,384	2,384	2	2	2
Home Energy Assessments	Duct Sealing Gas Heating w/ CAC	20		169.0	0.293	6	6	6			1,014	1,014	1,014	2	2	2
Home Energy Assessments	Attic Insulation - South (Electric Only)	25		3,018.7	0.103	8	8	8			24,149	24,149	24,149	1	1	1
Home Energy Assessments	Attic Insulation - South (Dual - Gas & Electric)	25		303.6	0.464	5	5	5			1,518	1,518	1,518	2	2	2
Home Energy Assessments	Wall Insulation - South (Electric Only)	25		801.0	0.019	8	8	8			6,408	6,408	6,408	0	0	0
Home Energy Assessments	Wall Insulation - South (Dual - Gas & Electric)	25		29.3	0.259	2	2	2			59	59	59	1	1	1
Home Energy Assessments	Exterior 9W LED (A19-9W Exterior)	15		84.2	0.008	113	118	142			9,492	9,967	11,960	1	1	1
Home Energy Assessments	Interior 9W LED (A19-9W Interior)	15		31.7	0.004	4,725	4,961	5,953			149,833	157,325	188,790	20	21	25
Home Energy Assessments	Exterior 6W LED	15		21.3	0.003	655	688	826			13,948	14,646	17,575	2	2	2
Home Energy Assessments	LED Lamp Candelabra	15		32.8	0.004	1,435	1,507	1,808			47,127	49,483	59,379	6	7	8
Home Energy Assessments	LED Lamp Downlight Retro	15		41.8	0.005	233	244	293			9,723	10,209	12,251	1	1	2
Home Energy Assessments	LED Night Light -.5W	8		13.1	-	838	880	1,056			11,017	11,567	13,881	-	-	-
Home Energy Assessments	LED 8W Dimmable R30 (BR30-8W)	15		52.6	0.007	1,172	1,231	1,477			61,642	64,724	77,669	8	9	10
Home Energy Assessments	Furnace Whistle (Elec)	15		238.7	0.050	12	13	15			2,864	3,008	3,609	1	1	1
Home Energy Assessments	Furnace Whistle (Gas)	15		62.9	0.002	64	67	81			4,023	4,224	5,069	0	0	0
Home Energy Assessments	Kitchen Flip Aerator 1.5 gpm - Elec DHW	5		162.9	0.007	40	42	50			6,515	6,840	8,208	0	0	0
Home Energy Assessments	Low Flow Showerhead 1.5 gpm - Elec DHW	10		259.4	0.015	40	42	50			10,374	10,893	13,071	1	1	1
Home Energy Assessments	Pipe Wrap - Elec DHW (per home)	15		74.8	0.009	8	8	10			599	628	754	0	0	0
Home Energy Assessments	PowerStrip (Tier 1 Advanced -7 outlet plug)	4		25.6	0.002	120	126	151			3,071	3,225	3,870	0	0	0
Home Energy Assessments	Smart Thermostat - Elec Heated	15		1,224.2	-	60	63	76			73,452	77,125	92,550	-	-	-
Home Energy Assessments	Smart Thermostat - Gas Heated	15		277.2	-	320	336	403			88,689	93,123	111,748	-	-	-
Home Energy Assessments	Water Heater Setback - Elec DHW	15		66.0	0.008	8	8	10			528	554	665	0	0	0
Home Energy Assessments Total						400	420	504			550,810	576,574	684,783	50	53	61
IQW - Electric	5W Candelabra	15	100%	10.4	0.001	1,138	900	719		$ 2.08	11,795	9,332	7,453	2	1	1
IQW - Electric	9W LED	15	100%	33.4	0.004	1,950	1,800	1,725		$ 3.21	65,119	60,110	57,605	8	7	7
IQW - Electric	Air Sealing Gas Furnace w/ CAC	15	100%	124.9	0.162	25	35	30		$ 50.00	3,122	4,370	3,746	4	6	5
IQW - Electric	Air Source Heat Pump 16 SEER	18	100%	694.0	0.407	1	1	1		$ 5,400.00	694	694	694	0	0	0
IQW - Electric	Attic Insulation - Gas Heated (Electric)	25	100%	383.3	0.378	50	55	50		$ 706.30	19,163	21,080	19,163	19	21	19
IQW - Electric	Audit Recommendations - dual (Electric)	1	100%	82.9	0.004	650	600	575		$ 26.00	53,876	49,732	47,659	2	2	2
IQW - Electric	Audit Recommendations - Electric Only	1	100%	102.2	0.004	38	35	30		$ 106.00	3,882	3,576	3,065	0	0	0
IQW - Electric	Bathroom Aerator 1.0 gpm - Elec DHW	10	100%	34.6	0.003	98	90	86		$ 0.52	3,376	3,116	2,987	0	0	0
IQW - Electric	Central Air Conditioner 16 SEER	18	100%	587.2	1.047	20	20	20		$ 3,500.00	11,744	11,744	11,744	21	21	21
IQW - Electric	Duct Sealing Gas Heating with A/C	20	100%	155.1	0.269	25	40	35		$ 110.00	3,877	6,204	5,428	7	11	9
IQW - Electric	Exterior LED Lamps	15	100%	99.0	-	195	180	173		$ 7.20	19,305	17,820	17,078	-	-	-
IQW - Electric	Filter Whistle	15	100%	46.0	0.076	7	6	6		$ 1.64	299	276	264	0	0	0
IQW - Electric	HVAC/Furnace Tune Up (With filter replacemen	2	100%	155.1	0.197	145	165	150		$ 75.00	22,496	25,599	23,272	29	33	30
IQW - Electric	IQW - Whole Home (Dual - Gas & Electric)	15	100%	1,316.4	-	-	-	5		$ -	-	-	6,582	-	-	-
IQW - Electric	IQW - Whole Home (Electric Only)	10	100%	1,490.4	-	-	-	1		$ -	-	-	1,490	-	-	-
IQW - Electric	IQW MFDI 9W LED	15	100%	33.3	0.004	400	200	200		$ 3.21	13,324	6,662	6,662	2	1	1
IQW - Electric	IQW MFDI Bathroom Aerator 1.0 gpm - Elec DHW	10	100%	29.4	0.003	80	80	70		$ -	2,350	2,350	2,056	0	0	0
IQW - Electric	IQW MFDI Kitchen Flip Aerator 1.5 gpm - Elec DH	16	100%	96.7	0.007	70	70	80		$ -	6,772	6,772	7,739	0	0	1
IQW - Electric	IQW MFDI LED Nightlight	8	100%	13.6	-	-	100	100		$ 2.75	-	1,364	1,364	-	-	-
IQW - Electric	IQW MFDI Low Flow Showerhead 1.5 gpm - Elec	1	100%	266.7	0.015	75	75	75		$ -	20,005	20,005	20,005	1	1	1
IQW - Electric	IQW MFDI Site Visit and DI - Electric Only		100%	46.1	0.002	100	100	100		$ 22.50	4,609	4,609	4,609	0	0	0

Program Name	Measure	Measure Life	NTG	Average kWh/ Unit	Average KW/ Unit	2021 Participation	2022 Participation	2023 Participation	Avg Incentive/Unit	IMC/unit	2021 kWh	2022 kWh	2023 kWh	2021 kW	2022 kW	2023 kW
IQW - Electric	IQW MFDI Smart Thermostat (Electric Only)		100%	740.5	-	100	100	100		$ 39.00	74,048	74,048	74,048	-	-	-
IQW - Electric	Kitchen Flip Aerator 1.5 gpm - Elec DHW	10	100%	145.7	0.007	65	60	58		$ 1.34	9,469	8,740	8,376	0	0	0
IQW - Electric	LED 5W Globe	15	100%	19.6	0.002	650	600	575		$ 8.75	12,729	11,750	11,260	2	1	1
IQW - Electric	LED Nightlight	8	100%	13.6	-	1,300	1,200	1,150		$ 2.75	17,727	16,364	15,682	-	-	-
IQW - Electric	LED R30 Dimmable	15	100%	32.6	0.004	163	150	144		$ 11.54	5,297	4,889	4,686	1	1	1
IQW - Electric	Low Flow Showerhead 1.5 gpm - Elec DHW	5	100%	342.6	0.015	52	48	46		$ 3.32	17,815	16,445	15,759	1	1	1
IQW - Electric	Pipe Wrap - Elec DHW (per home)	15	100%	99.3	0.011	13	12	12		$ 1.72	1,291	1,191	1,142	0	0	0
IQW - Electric	Refrigerator Replacement	8	100%	359.8	0.053	20	20	20		$ 580.00	7,197	7,197	7,197	1	1	1
IQW - Electric	Smart Power Strips	4	100%	25.8	0.002	195	180	173		$ 35.00	5,037	4,650	4,456	0	0	0
IQW - Electric	Smart Thermostat (Dual)	15	100%	429.0	-	130	108	86		$ 39.00	55,770	46,332	37,001	-	-	-
IQW - Electric	Smart Thermostat (Electric)	15	100%	1,580.2	-	8	8	8		$ 39.00	12,642	12,642	12,642	-	-	-
IQW - Electric	Wall Insulation - Dual (gas heated)	25	100%	58.3	0.042	15	15	22		$ 877.00	874	874	1,282	1	1	1
IQW - Electric	Water Heater Temperature Setback - Elec DHW	4	100%	81.5	0.009	3	3	3		$ 6.50	245	245	245	0	0	0
IQW - Electric Total						788	735	710			485,948	460,780	444,441	102	111	103
Foodbank	9W LED	15	100%	34.1	0.005	33,976	33,976	33,976			1,159,285	1,159,285	1,159,285	160	160	160
Foodbank Total						33,976	33,976	33,976			1,159,285	1,159,285	1,159,285	160	160	160
Energy Efficiency Schools	15W LED	15	100%	38.2	0.004	2,600	2,600	2,600			104,581	99,352	94,385	11	11	10
Energy Efficiency Schools	11W LED	15	100%	28.2	0.003	2,600	2,600	2,600			77,060	73,207	69,547	8	8	8
Energy Efficiency Schools	11W LED	15	100%	28.2	0.003	2,600	2,600	2,600			77,060	73,207	69,547	8	8	8
Energy Efficiency Schools	Low Flow Showerhead	5	100%	99.3	0.003	2,600	2,600	2,600			271,411	257,841	244,949	7	7	6
Energy Efficiency Schools	Kitchen Aerator	10	100%	41.0	0.001	2,600	2,600	2,600			112,018	106,417	101,096	3	3	3
Energy Efficiency Schools	Bathroom Aerator	10	100%	8.1	0.000	2,600	2,600	2,600			22,086	20,982	19,933	1	1	1
Energy Efficiency Schools	Bathroom Aerator	10	100%	8.1	0.000	2,600	2,600	2,600			22,086	20,982	19,933	1	1	1
Energy Efficiency Schools	LED Night Light	8	100%	6.0	-	2,600	2,600	2,600			16,345	15,527	14,751	-	-	-
Energy Efficiency Schools	Furnace Filter Whistle	5	100%	11.1	0.014	2,600	2,600	2,600			30,471	28,947	27,500	38	36	34
Energy Efficiency Schools Total						2,600	2,600	2,600			733,118	696,462	661,639	78	74	70
Residential Behavioral	Residential Behavioral	1	100%	169.0	0.031	41,543	42,016	40,182			7,020,000	7,100,000	6,790,000	1,350	1,270	1,210
Residential Behavioral Total						41,543	42,016	40,182			7,020,000	7,100,000	6,790,000	1,350	1,270	1,210
Appliance Recycling	Refridgerator	8	100%	1,065.0	0.137	1,040	1,000	880	$ 50.00		1,120,313	1,064,203	925,206	142	137	121
Appliance Recycling	Freezer	8	100%	692.0	0.075	260	250	220	$ 50.00		182,000	172,885	150,304	19	19	17
Appliance Recycling	AC Pickup/unit	8	100%	267.8	0.216	75	50	25	$ 25.00		20,250	13,337	6,588	15	10	7
Appliance Recycling Total						1,375	1,300	1,125			1,322,563	1,250,424	1,082,098	176	166	145
CVR Residential	CVR Residential	15	100%	189.8	0.076			5,627					1,067,954			430
CVR Residential Total						-	-	5,627			-	-	1,067,954	-	-	430
Smart DLC Changeout	Smart DLC Changeout	15	100%	362.6	1.140	1,000	1,000	1,000			362,577	362,577	362,577	1,140	1,140	1,140
Smart DLC Changeout Total						1,000	1,000	1,000			362,577	362,577	362,577	1,140	1,140	1,140
Bring Your Own Thermostat (BYOT)	BYOT	15	100%	-	1.140	400	450	500						456	513	570
Bring Your Own Thermostat (BYOT) Total						400	450	500			-	-	-	456	513	570
Midstream HVAC - Electric	Ductless Heat Pump 19 SEER 9.5 HSPF	18	65%	3,066.5	0.380	38	51	55	$ 250.00		116,527	156,391	168,657	14	19	21
Midstream HVAC - Electric	Ductless Heat Pump 21 SEER 10 HSPF	18	65%	2,932.2	0.368	14	19	26	$ 400.00		41,051	55,713	76,238	5	7	10
Midstream HVAC - Electric	Ductless Heat Pump 23 SEER 10 HSPF	18	65%	4,306.1	0.711	27	30	35	$ 400.00		116,266	129,184	150,715	19	21	25
Midstream HVAC - Electric	Air Source Heat Pump 16 SEER	18	65%	880.8	0.464	142	189	190	$ 200.00		125,076	166,474	167,355	66	88	88
Midstream HVAC - Electric	Air Source Heat Pump 18 SEER	18	65%	1,590.0	0.530	28	37	40	$ 400.00		44,519	58,828	63,598	15	20	21
Midstream HVAC - Electric	Central Air Conditioner 16 SEER	18	65%	434.9	0.540	986	986	1,315	$ 200.00		428,827	428,827	571,915	533	533	710
Midstream HVAC - Electric	Central Air Conditioner 18 SEER	18	65%	666.0	0.577	75	99	110	$ 400.00		49,949	65,933	73,259	43	57	63
Midstream HVAC - Electric Total						1,310	1,411	1,771			922,215	1,061,351	1,271,737	695	745	938

Program Name	Measure	Measure Life	NTG	Average kWh/ Unit	Average KW/ Unit	2021 Participation	2022 Participation	2023 Participation	Avg Incentive/Unit	IMC/unit	2021 kWh	2022 kWh	2023 kWh
Home Energy Management Systems	HEMS	6	100%	515.0	0.080	1,000	1,000	1,000			515,000	515,000	515,000
Home Energy Management Systems Total						1,000	1,000	1,000			515,000	515,000	515,000
C&I Custom	Building Tune-Up (Electric)	7	83%	50,000.0	0.050	5	6	6	$ 2,500.00	$ 3,000.00	250,000	300,000	300,000
C&I Custom	Custom Electric	17	83%	114,089.8	15.121	32	41	37	$ 7,959.36	$ 38,513.34	3,650,875	4,677,683	4,221,324
C&I Custom	EDA Lighting Power Density Reduction	15	83%	41,571.7	7.170	10	10	10	$ 3,345.02	$ 4,000.00	410,894	418,128	418,128
C&I Custom	EDA Non-Lighting (Electric)	13	83%	28,187.2	18.000	7	10	10	$ 2,254.98	$ 4,000.00	197,310	281,872	281,872
C&I Custom	SEM Electric	13	83%	500,000.0	10.000	2	2	2	$ 60,000.00	$ 35,000.00	1,000,000	1,000,000	1,000,000
C&I Custom Total						56	69	65			5,509,079	6,677,683	6,221,324
C&I Prescriptive	Advanced Rooftop Controls	9	83%	3,034.0	2.620	150	150	188	$ 827.15	$ 1,000.00	455,100	455,100	570,392
C&I Prescriptive	Agriculture - Automatic Milker Take Off	15	83%	10,062.0	2.100	1	1	1	$ 1.67	$ -	10,062	10,062	10,062
C&I Prescriptive	Agriculture - Dairy Plate Cooler	15	83%	76.2	0.016	1	1	1	$ 1.00	$ -	76	76	76
C&I Prescriptive	Agriculture - HE Diary Scroll Compressor	12	83%	279.5	0.069	1	1	1	$ 16.67	$ -	279	279	279
C&I Prescriptive	Agriculture - Heat Mat	5	83%	657.0	-	1	1	1	$ 21.67	$ 225.00	657	657	657
C&I Prescriptive	Agriculture - Heat Reclaimer	14	83%	152.7	-	1	1	1	$ 1.67	$ -	153	153	153
C&I Prescriptive	Agriculture - High Speed Fans	7	83%	625.0	0.198	1	1	1	$ 25.00	$ 150.00	625	625	625
C&I Prescriptive	Agriculture - High Volume Low Speed Fans	10	83%	8,543.0	3.100	1	1	1	$ 250.00	$ 4,180.00	8,543	8,543	8,543
C&I Prescriptive	Agriculture - Livestock Waterer	10	83%	1,592.0	0.525	1	1	1	$ 66.67	$ 787.50	1,592	1,592	1,592
C&I Prescriptive	Agriculture - Poultry Farm LED Lighting	7	83%	292.0	0.050	1	1	1	$ 0.03	$ 30.00	292	292	292
C&I Prescriptive	Agriculture - VSD Milk Pump	15	83%	32.0	0.007	1	1	1	$ 1.67	$ 4,000.00	32	32	32
C&I Prescriptive	Air Compressor	15	83%	36,724.0	6.552	2	2	2	$ 1,875.00	$ -	73,448	73,448	73,448
C&I Prescriptive	Air Conditioners	15	83%	1,520.0	4.731	75	75	100	$ 309.00	$ 100.00	114,000	114,000	152,000
C&I Prescriptive	Barrel Wrap Insulation	5	83%	360.1	0.068	1	1	1	$ 30.00	$ -	360	360	360
C&I Prescriptive	Chilled Water Reset Control	10	83%	16,536.0	3.059	3	3	3	$ 238.50	$ 681.34	49,608	49,608	49,608
C&I Prescriptive	Chiller	20	83%	191,462.0	8.245	3	3	4	$ 5,830.43	$ 79.46	574,386	574,386	765,848
C&I Prescriptive	Chiller Tune-Up	5	83%	34,339.9	7.204	6	6	6	$ 1,100.63	$ -	206,039	206,039	206,039
C&I Prescriptive	Clothes Washer	10	83%	541.5	-	3	3	3	$ 60.00	$ 475.33	1,625	1,625	1,625
C&I Prescriptive	Compressed Air Leak Study	2	83%	172,000.0	10.000	9	9	1	$ 5,676.00	$ 6,364.00	1,548,000	1,548,000	172,000
C&I Prescriptive	Compressed Air Nozzles	15	83%	888.2	0.337	2	2	2	$ 6.50	$ 14.00	1,776	1,776	1,776
C&I Prescriptive	EC Motors	15	83%	410.1	0.042	125	125	125	$ 37.75	$ 50.00	51,266	51,266	51,266
C&I Prescriptive	Exterior LED	15	83%	1,315.0	0.020	1,342	1,042	956	$ 105.00	$ 270.24	1,764,730	1,370,230	1,257,140
C&I Prescriptive	Food Service - Anti-Sweat Heater Control	12	83%	1,278.0	-	75	75	75	$ 100.00	$ 200.00	95,850	95,850	95,850
C&I Prescriptive	Food Service - Combination Oven	12	83%	18,431.7	3.535	1	1	1	$ 1,000.00	$ 2,125.00	18,432	18,432	18,432
C&I Prescriptive	Food Service - Commercial Dishwasher	16	83%	3,090.0	1.911	8	8	8	$ 442.00	$ 616.25	24,720	24,720	24,720
C&I Prescriptive	Food Service - Convection Oven	12	83%	3,234.8	0.620	1	1	1	$ 350.00	$ 1,113.00	3,235	3,235	3,235
C&I Prescriptive	Food Service - Freezer	12	83%	2,931.2	0.313	8	8	8	$ 200.00	$ 220.25	23,450	23,450	23,450
C&I Prescriptive	Food Service - Fryer	12	83%	1,526.2	0.220	1	1	1	$ 80.00	$ 500.00	1,526	1,526	1,526
C&I Prescriptive	Food Service - Griddle	12	83%	10,032.7	1.924	3	3	3	$ 550.00	$ 2,090.00	30,098	30,098	30,098
C&I Prescriptive	Food Service - Hot Food Holding Cabinet	12	83%	5,256.0	0.506	8	8	8	$ 420.00	$ 1,110.00	42,048	42,048	42,048
C&I Prescriptive	Food Service - Ice Machine	9	83%	924.3	0.143	3	3	3	$ 170.00	$ 1,333.60	2,773	2,773	2,773
C&I Prescriptive	Food Service - Low Flow Pre-Rinse Sprayer	5	83%	713.0	-	1	1	1	$ 10.00	$ -	713	713	713
C&I Prescriptive	Food Service - Refrigerated Case Cover	6	83%	157.5	-	1	1	1	$ 10.00	$ 42.00	158	158	158
C&I Prescriptive	Food Service - Refrigerator	12	83%	1,482.6	0.066	7	7	7	$ 58.43	$ 180.00	10,378	10,378	10,378
C&I Prescriptive	Food Service - Steam Cooker	12	83%	2,225.9	0.433	1	1	1	$ 200.00	$ 3,500.00	2,226	2,226	2,226
C&I Prescriptive	Heat Pump	15	83%	660.1	0.677	11	11	11	$ 78.00	$ 143.64	7,293	7,246	7,246
C&I Prescriptive	Heat Pump Water Heater	10	83%	1,534.0	0.032	1	1	1	$ 500.00	$ -	1,534	1,534	1,534
C&I Prescriptive	High Efficiency Hand Dryer	15	83%	769.0	-			10	$ 180.00	$ 200.00			7,690

Program Name	Measure	Measure Life	NTG	Average kWh/ Unit	Average KW/ Unit	2021 Participation	2022 Participation	2023 Participation	Avg Incentive/Unit	IMC/unit	2021 kWh	2022 kWh	2023 kWh	2021 kW	2022 kW	2023 kW
C&I Prescriptive	Interior LED - High-Bay	15	83%	1,005.9	0.371	1,183	1,062	1,002	$ 81.00	$ 113.54	1,189,977	1,068,264	1,007,910	439	394	372
C&I Prescriptive	Interior LED - Low-Bay	15	83%	241.2	0.052	28,314	23,367	22,967	$ 21.74	$ 78.04	6,840,582	5,631,299	5,535,124	1,474	1,217	1,196
C&I Prescriptive	Lighting Control	8	83%	401.9	0.216	582	305	306	$ 35.00	$ 98.75	233,900	122,610	123,012	126	66	66
C&I Prescriptive	Lighting Power Density Reduction	15	83%	156,097.2	7.166	11	11	11	$ 14,778.31	$ -	1,717,082	1,717,082	1,717,043	79	79	79
C&I Prescriptive	Pellet Dryer Duct Insulation	5	83%	198.5	0.030	1	1	1	$ 30.00	$ -	198	198	198	0	0	0
C&I Prescriptive	Plug Load Occupancy Sensor	8	83%	169.0	-	1	1	1	$ 20.00	$ 70.00	169	169	169	-	-	-
C&I Prescriptive	Programmable Thermostat	15	83%	648.9	-	215	214	214	$ 50.00	$ 35.00	139,518	138,870	138,870	-	-	-
C&I Prescriptive	Refrigerated LED	8	83%	237.0	0.048	820	820	820	$ 16.00	$ 35.89	194,340	194,340	194,340	39	39	39
C&I Prescriptive	Showerheads	5	83%	7,130.5	-	1	1	1	$ 10.00	$ -	7,130	7,130	7,130	-	-	-
C&I Prescriptive	Smart Strip Plug Outlet	8	83%	23.4	-	1	1	1	$ 8.00	$ 15.00	23	23	23	-	-	-
C&I Prescriptive	Vending Machine Control	5	83%	1,054.4	-	3	3	3	$ 41.67	$ 179.67	3,163	3,163	3,163	-	-	-
C&I Prescriptive	VFD-Fan	15	83%	107,827.9	2.975	5	5	5	$ 7,500.00	$ 3,638.33	539,140	539,140	539,140	15	15	15
C&I Prescriptive	VFD-Pump	15	83%	122,828.9	8.175	5	5	5	$ 7,500.00	$ -	614,145	614,145	614,145	41	41	41
C&I Prescriptive	Wifi-Enabled Thermostat	15	83%	649.0	-	115	115	115	$ 100.00	$ 250.00	74,635	74,635	74,635	-	-	-
C&I Prescriptive	Window Air Conditioner & PTAC	14	83%	207.3	0.143	5	5	5	$ 46.85	$ 196.00	1,036	1,036	1,036	1	1	1
C&I Prescriptive	Window Film	10	83%	3.1	0.001	1	1	1	$ 1.00	$ 2.67	3	3	3	0	0	0
C&I Prescriptive Total						33,122	27,476	26,997			16,650,556	14,813,073	13,520,261	3,215	2,847	2,948
Commercial Midstream	Ductless Heat Pump 19 SEER 9.5 HSPF	18	100%	3,066.5	0.380	3	3	3	$ 300.00	$ 2,333.33	9,199	9,199	9,199	1	1	1
Commercial Midstream	Ductless Heat Pump 21 SEER 10 HSPF	18	100%	2,932.2	0.368	2	2	2	$ 500.00	$ 2,833.33	5,864	5,864	5,864	1	1	1
Commercial Midstream	Ductless Heat Pump 23 SEER 10 HSPF	18	100%	4,306.1	0.711	2	2	2	$ 500.00	$ 3,333.33	8,612	8,612	8,612	1	1	1
Commercial Midstream	Air Source Heat Pump 18 SEER	18	100%	1,590.0	0.530	4	4	4	$ 500.00	$ 870.00	6,360	6,360	6,360	2	2	2
Commercial Midstream	Heat Pump Water Heater	10	100%	1,534.0	0.032	1	1	1	$ 238.50	$ 1,362.68	1,534	1,534	1,534	0	0	0
Commercial Midstream Total						12	12	12			31,570	31,570	31,570	5	5	5
SBES	Anti-Sweat Heater Control	12	83%	909.3	-	1	1	1	$ 170.00	$ 200.00	909	909	909	-	-	-
SBES	EC Motors	15	83%	403.2	0.042	8	9	9	$ 77.25	$ 50.00	3,210	3,637	3,637	0	0	0
SBES	Exterior LED	15	83%	1,583.6	0.015	597	853	853	$ 295.37	$ 181.64	945,410	1,350,813	1,350,813	9	13	13
SBES	Faucet Aerator	10	83%	507.8	-	1	1	1	$ 4.72	$ 2.00	508	508	508	-	-	-
SBES	Interior LED	15	83%	183.8	0.036	5,935	7,836	7,836	$ 35.20	$ 131.43	1,090,612	1,439,939	1,439,939	214	283	283
SBES	Lighting Control	8	83%	136.2	0.026	188	188	188	$ 26.00	$ 107.33	25,568	25,568	25,691	5	5	5
SBES	Low Flow Pre-Rinse Sprayer	5	83%	7,130.5	-	1	1	1	$ 60.00	$ -	7,130	7,130	7,130	-	-	-
SBES	Program the Programmable Thermostat	5	83%	736.5	-	12	12	12	$ 25.00	$ 25.00	8,838	8,838	8,838	-	-	-
SBES	Programmable Thermostat	15	83%	1,737.0	-	9	9	9	$ 100.00	$ 35.00	15,633	15,633	15,633	-	-	-
SBES	Refrigerated Case Cover	6	83%	415.0	0.195	15	15	15	$ 83.40	$ 14.50	6,225	6,225	6,225	3	3	3
SBES	Refrigerated LED	8	83%	409.5	0.070	3	3	3	$ 47.50	$ 190.00	1,228	1,228	1,228	0	0	0
SBES	Vending Machine Control	5	83%	1,410.4	-	3	3	5	$ 265.00	$ 215.50	4,231	4,231	7,052	-	-	-
SBES	Wifi-Enabled Thermostat	15	83%	1,737.0	-	49	49	49	$ 100.00	$ 250.00	85,111	85,111	85,111	-	-	-
SBES Total						78	78	78			2,194,615	2,949,771	2,952,715	231	304	304
CVR Commercial	CVR Commercial	15	100%	155.6	0.038			5,627					875,340			214
CVR Commercial Total						-	-	5,627			-	-	875,340	-	-	214
Portfolio Total						236,579	226,393	225,737			44,325,438	43,961,753	43,533,925	10,061	9,571	10,303

Attachment 6.2 2019 DSM Market Potential Study

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

prepared for

CENTERPOINT ENERGY

2022 Demand Side Management Market Potential Study

May 22,
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FINAL REPORT

prepared by

GDS ASSOCIATES INC

VOLUME I *2022 Demand Side Management Market Potential Study Report*

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VOLUME I

2022 CenterPoint Energy Market Potential Study

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1 Introduction

1.1 BACKGROUND & STUDY SCOPE

This Market Potential Study was conducted to support the Integrated Resource Plan ("IRP") and DSM planning for CenterPoint Energy in Indiana ("CenterPoint"). The study included a comprehensive review of current programs, historical savings, and projected energy savings opportunities to develop estimates of technical, economic, and achievable potential. Separate estimates of electric energy efficiency ("EE") and demand response potential were developed. The GDS Team worked collaboratively alongside CenterPoint and the CenterPoint Oversight Board to produce estimates of future saving potential, using the best available information and best practices for developing market potential saving estimates.

1.2 TYPES OF POTENTIAL ESTIMATED

The scope of this study distinguishes three types of energy efficiency potential: (1) technical, (2) economic, and (3) achievable.

- ***Technical Potential*** is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is constrained only by factors such as technical feasibility and applicability of measures.
- ***Economic Potential*** refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources. Economic potential follows the same adoption rates as technical potential. Like technical potential, the economic scenario ignores market barriers to ensuring actual implementation of efficiency. Finally, economic potential only considers the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration) that would be necessary to capture them. This study uses the Utility Cost Test ("UCT") to assess cost-effectiveness.
- ***Achievable Potential*** is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and Evaluation, Measurement & Verification ("EM&V"); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate ("WTP") in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:
- ***Maximum Achievable Potential ("MAP")*** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- ***Realistic Achievable Potential (`"RAP")*** estimates achievable potential with CenterPoint paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

1.3 STUDY LIMITATIONS

As with any assessment of energy efficiency potential, this study necessarily builds on various assumptions and data sources, including the following:

- Energy efficiency and demand response measure lives, savings, and costs
- Projected penetration rates for energy efficiency measures
- Projections of electric avoided costs
- Future known changes to codes and standards
- CenterPoint load forecasts and assumptions on their disaggregation by sector, segment, and end use
- End-use saturations and fuel shares

While the GDS team has sought to use the best and most current available data, there are often reasonable alternative assumptions which would yield slightly different results.

2 Baseline Forecast

The load forecast is a critical input into CenterPoint's 2022 DSM Market Potential Study, having various uses in estimation of residential and business sector potential. Therefore, the GDS Team took considerable time and effort to review CenterPoint's most recently completed load forecast models and documentation to produce the various forecast components necessary as inputs into this analysis. The chapter describes the various ways in which the forecast is used for this study, presents the baseline and disaggregated forecasts, and describes the methodology and data sources used by GDS for the purposes of generating the load forecasts that were used in the potential analysis.

2.1 CENTERPOINT LOAD FORECASTING SYSTEM

CenterPoint employs a sophisticated load forecasting system that uses econometric and Statistically Adjusted End-Use ("SAE") models to project number of consumers, average consumption per consumer, and total energy sales by class. Residential, Commercial, and Industrial consumers are projected using traditional econometric techniques. Residential average usage and commercial energy sales are projected using SAE model specifications. Industrial energy sales are projected using econometric techniques.

A residential SAE model specification takes end-use data drawn from utility, regional, and even national sources and develops monthly end-use indices designed to predict average household consumption. The end-use data includes market shares of key electric consuming appliances, average device efficiency trends, average building shell efficiency trends, price elasticity of demand, income elasticity of demand, and elasticity associated with the average number of people per household. A cooling index is developed to represent space cooling load and is further modified by Cooling Degree Days to incorporate summer weather into the model. Likewise, a heating index representing space heating is modified by Heating Degree Days. Finally, a base index is developed to represent consumption of all other end-uses in the home.

A commercial SAE model specification is very similar to a residential specification, except end-use energy intensity indices are developed for each commercial building type based on area employment in various industry codes. National and regional commercial data is used to estimate end-use consumption for various industries (for example, restaurants will have higher cooking usage shares than offices).

CenterPoint also projects the impacts of DSM programs it has run in the past. The DSM impacts included in the load forecast based on the evaluated results of CenterPoint DSM programs.

2.2 ADJUSTMENTS TO THE CENTERPOINT LOAD FORECAST

Before assessing the future potential for energy efficiency and demand response in the CenterPoint service area, a few modifications to CenterPoint's 2021-vintage forecast were necessary to create an adjusted baseline forecast. These modifications are addressed in more detail below.

2.2.1 Adjustment for Large C&I Opt-Out Customers

The 2021 CenterPoint business sector customer database containing usage and demographic data for all C&I customers, with indication for large customer opt-out of DSM/EE programs status was utilized to determine how to adjust for opt-out customers. The number of customers and total energy use was calculated both including and excluding opt-out customers. The load forecast for the C&I sectors was adjusted down by the percent of load attributed to opt-out customers from the customer database, in effect excluding from the potential analysis any load of opt-out customers. The opt-out adjustment was held constant for all years of the load forecast. In total, GDS removed approximately 11% of commercial energy sales and 72% of industrial energy sales due to large customer opt-out.

2.2.2 Reclassification of Load

The 2021 CenterPoint C&I sector customer database designated commercial and industrial ("C&I") rate code based on current tariff definition. When only using the account type/tariff definition to classify customers as either commercial or industrial, there were several manufacturing type premises classified as commercial, as well as several customers that GDS typically classifies as commercial classified as industrial, (i.e. a retail service building coded as an industrial account).

Additionally, the dataset also identified each business by North American Industry Classification System ("NAICS") code. To reclassify CenterPoint C&I sector data, GDS mapped industry codes to a specified building type and classified the building type as either commercial or industrial. Customers with a building type classified as "Industrial Manufacturing" were coded as Industrial customers, while all other building types were coded as Commercial. While the goal for this analysis is to determine the actual amount of energy sales attributable to the commercial and industrial customer classes as a whole, it is only achievable by analyzing individual customer data. The result of this reclassification was a shift of approximately 23% of industrial sector sales, or 135,742 MWh, to the commercial sector. This 23% shift was then applied to the CenterPoint case forecasted sales for the commercial and industrial classes. It is important to have accurate energy sales by customer class so that specific DSM/EE programs have the correct amount of energy sales eligible for savings.

2.3 LOAD FORECAST DISAGGREGATION

The baseline forecasts represent projected total energy sales by class. For the potential studies, it is useful to have the class forecasts disaggregated in several different ways. This section presents the forecast disaggregation scenarios used by GDS to determine intensity by end-use.

2.3.1 Residential Sector

The residential electric calibration effort led to an end-use intensity breakdown as shown below in Figure 2-1. Overall, we estimated per home consumption to be 9,835 kWh per year for 2025 (which grows to 10,475 per home by 2042). The Cooling end use is the leading stand-alone end-use, followed by Lighting, Appliances, Heating, Water Heating, TV, and Cooking. The Miscellaneous end-use includes small appliances and plug loads, and accounts for about 25% of the per home consumption. This reflects the increasing prominence of electronics and other plug-in load devices within the typical residential home.

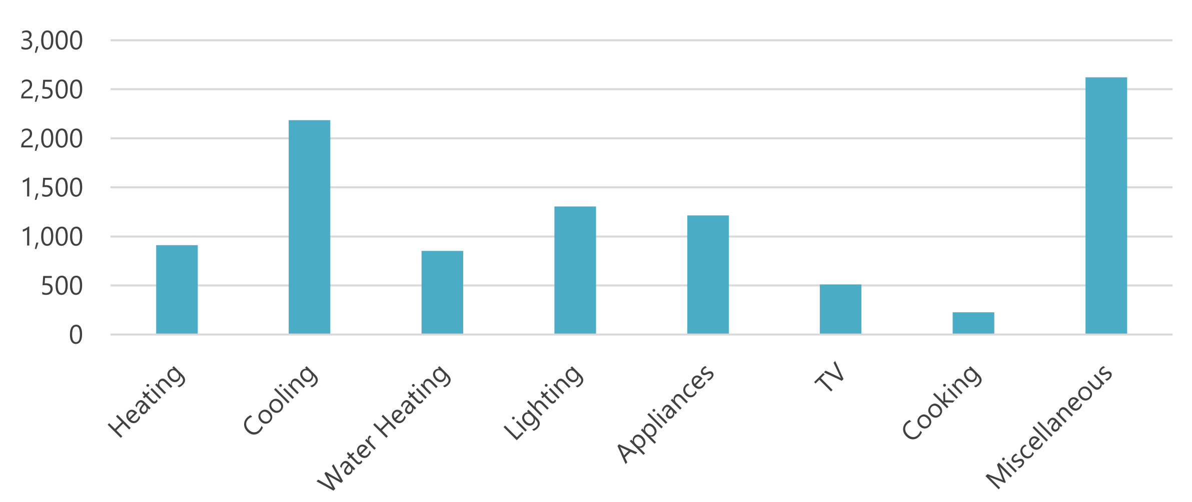

FIGURE 2-1 RESIDENTIAL ELECTRIC END-USE BREAKDOWN

2.3.2 C&I Sector

In the C&I sector, disaggregated forecast data provides the foundation for the development of energy efficiency potential estimates. GDS received a base case sales forecast from CenterPoint for the residential, commercial and industrial sectors. As noted above, the C&I forecast was adjusted from the base case by using NAICS information from CenterPoint to reclassify usage as commercial or industrial. NAICS information from CenterPoint, along with Commercial Buildings Energy Consumption Survey ("CBECS") building type consumption tables, was then used to segment the forecast into building types. The forecast was further segmented into end-uses by building type using regional specifical projections of end-use consumption contained within Energy Information Administration's ("EIA") Annual Energy Outlook supporting workpapers. Figure 2-2 provides a breakdown of commercial electric sales by building type.[1]

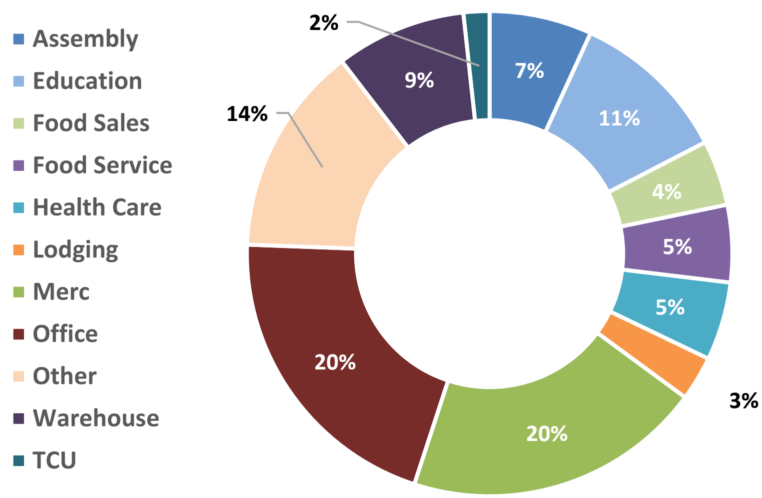

FIGURE 2-2: COMMERCIAL ELECTRIC SALES BREAKDOWN BY BUILDING TYPE

Figure 2-3 provides an illustration of the leading end-uses across all building types in the commercial sector. Lighting, space cooling, and ventilation are the primary end-uses with a significant share of load across most building types. Shares of refrigeration and office/computing are often dependent on the type of building, with refrigeration loads greatest in food sales and food service while office/computing loads are greatest in offices and education. Miscellaneous plug load is also a significant share of load in some building types, indicating that various small electric devices are becoming more common in commercial buildings.

1 "Other" commercial building types include buildings that engage in several different activities, a majority of which are commercial (e.g. retail space), though the single largest activity may be industrial or agricultural; "other" also includes miscellaneous buildings that do not fit into any other category.

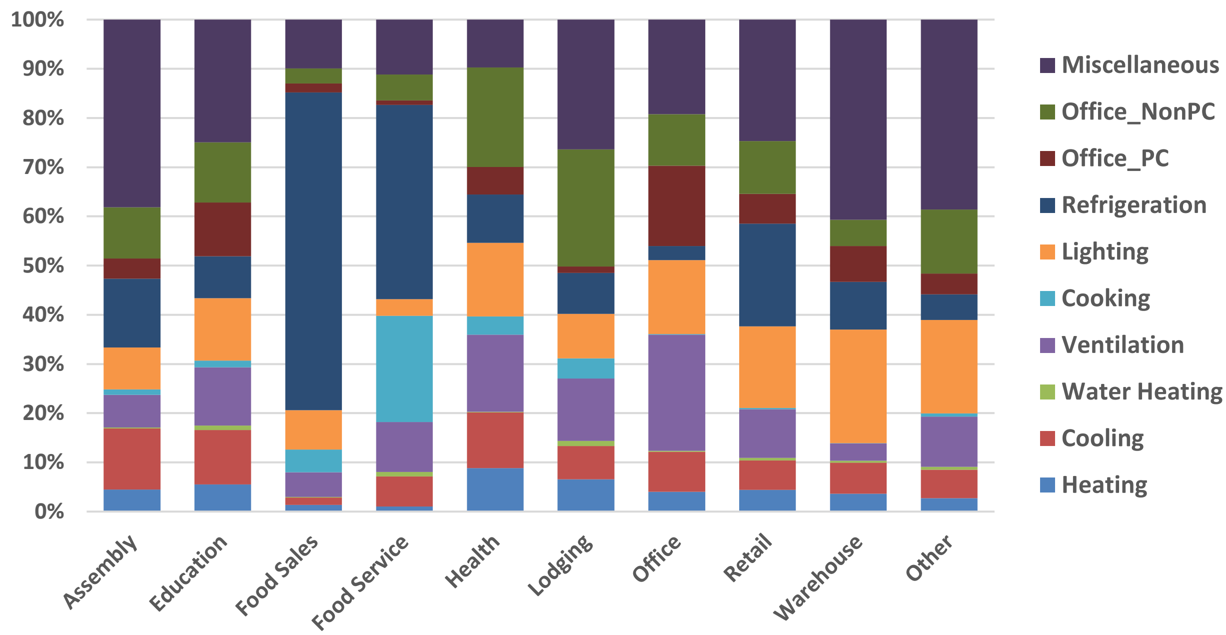

FIGURE 2-3: COMMERCIAL ELECTRIC END-USE BREAKDOWN BY BUILDING TYPE

Industrial sales were also segmented by end-use based on the overall distribution of sales by industry type and EIA Manufacturing Energy Consumption Survey ("MECS") data on end-use consumption by industrial segment. Figure 2-4 provides a breakdown of the sales by end-use. Overall, the weighted average industrial sales by end-use in the CenterPoint service area was roughly 50% Machine Drive, 13% Process Heat, 7% Process Refrigeration, 8% HVAC, and 6% Lighting. The remaining 15% was split between other process and other facility loads.

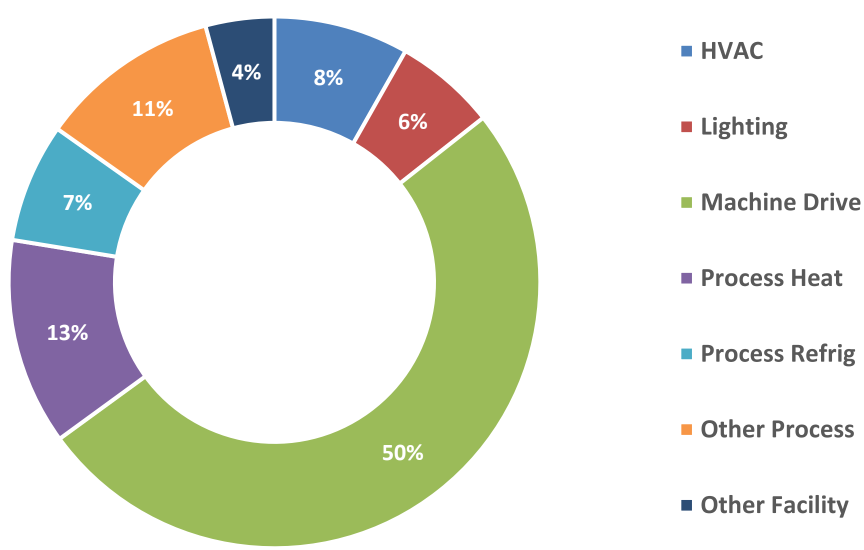

FIGURE 2-4: INDUSTRIAL ELECTRIC END-USE BREAKDOWN

3 Energy Efficiency Potential Analysis

This chapter describes the overall methodology utilized to assess the electric energy efficiency potential in the CenterPoint service area. The main objectives of this demand-side management ("DSM") market potential study ("MPS", or "study") were to estimate the technical, economic, maximum, and realistic potential savings from energy efficiency ("EE") in the CenterPoint service territory; and to quantify these estimates of potential in terms of MWh and MW savings, for each level of energy efficiency and demand response ("DR") potential (see Chapter 4 for details on the DR analysis).

3.1 OVERVIEW OF APPROACH

For the residential sector, GDS utilized a bottom-up approach to the modeling of energy efficiency potential, whereby measure-level estimates of costs, savings, and useful lives were used as the basis for developing the technical, economic, and achievable potential estimates. The measure data was used to build-up the technical potential, by applying the data to each relevant market segment. The measure data allowed for benefit-cost screening to assess economic potential, which was in turn used as the basis for achievable potential, taking into consideration incentives and estimates of annual adoption rates. For the C&I sector, GDS employed a bottom-up modeling approach to first estimate measure-level savings, costs, and cost-effectiveness, and then applied measure savings to all applicable shares of energy load.

3.2 MARKET CHARACTERIZATION

The initial step in the analysis was to gather a clear understanding of the current market segments in the CenterPoint service area. The GDS team coordinated with CenterPoint to gather utility sales and customer data and existing market research to define appropriate market sectors, market segments, vintages, saturation data and end uses. This information served as the basis for completing a forecast disaggregation and market characterization of both the residential and non-residential sectors.

3.2.1 Forecast Disaggregation

Through the development of the baseline forecasts, the GDS Team produced disaggregated forecasts by sector and end-use. The resulting aggregate baseline forecasts were disaggregated by sector and then further segmented as follows:

- ***Residential.*** The residential forecast was broken out by housing type as well as existing vs. new construction.
- ***Commercial.*** Typically based on major EIA CBECS business types: retail, warehouse, food sales, office, lodging, health, food service, education, and miscellaneous.
- ***Industrial.*** As determined by actual load consumption shares and major industry types as defined by EIA's MECS data.

The segmentation analysis was performed by applying CenterPoint-specific segment and end-use consumption shares, derived from CenterPoint's customer database and NAICS code analysis (building segmentation), and by EIA CBECS and MECS data (end-use segmentation) to forecast year sales. Within the residential, commercial, and industrial market segments, the sector level disaggregated forecasts were further segmented by the major end uses shown in Table 3-1.

TABLE 3-1: ELECTRIC END-USE LOADS

Residential	C&I	
	Commercial	Industrial
Heating	Interior Lighting	Lighting
Cooling	Exterior Lighting	HVAC
Water Heating	Refrigeration	Machine Drive
Cooking	Space Cooling	Process Heat

Refrigerator	**Space Heating**	**Process Cool / Refrigeration**
Freezer	**Ventilation**	**Other Process**
Dishwasher	**Water Heating**	**Process – Machine Drive**
Clothes Washer	**Plug Loads / Office Equipment**	**Other Facility**
Dryer	**Cooking**	**Compressed Air**
TV	**Other**	
Light	**Whole Building / Behavioral**	
Miscellaneous		

3.2.2 Eligible Opt-Out Customers

In Indiana, individual commercial or industrial customer sites with a peak load greater than 1MW are eligible to opt out of utility-funded electric energy efficiency programs. In the CenterPoint service area, approximately 11% of total reclassified retail commercial sales have opted out of utility-funded electric energy efficiency programs, while roughly 72% of total reclassified retail industrial sales have opted out.

Figure 3-1 shows the total sales for the C&I sectors, as well as the sales, by sector, that have currently opted out of paying the charge levied to support utility-administered energy efficiency programs. The portion of sales that have not opted out include both ineligible load (i.e., does not meet the 1 MW peak demand requirement) as well as eligible load that has not yet opted out.

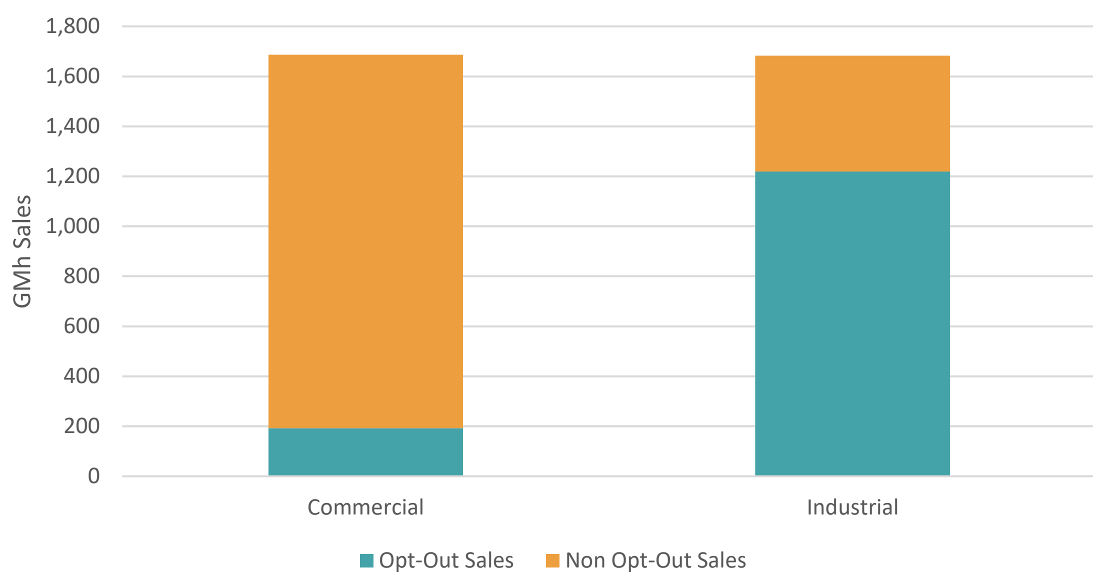

FIGURE 3-1 OPT-OUT SALES BY C&I SECTOR

GDS removed the sales from opt-out GDS also examined the full potential in the C&I sector if these customers were no longer able to opt-out of utility-funded electric energy efficiency programs. These results are included in the appendices of this report.

3.2.3 Building Stock/Equipment Saturation

To assess the potential electric energy efficiency savings available, estimates of the current saturation of baseline equipment and energy efficiency measures are necessary.

3.2.3.1 Residential Sector

For the residential sector, GDS relied on a 2021 Energy Efficiency Baseline Survey conducted by CenterPoint and other historical research efforts. Other data sources included ENERGY STAR unit shipment data, CenterPoint evaluation reports, and EIA Residential Energy Consumption Survey data. The ENERGY STAR unit shipment data filled data gaps related to the increased saturation of energy efficient equipment across the U.S. in the last decade.

3.2.3.2 Business Sector

For the commercial sector, building stock and equipment saturation data was informed from a combination of historical primary market research as well as other available regional or national data. The data helped inform the disaggregation of the end-use sales forecast further into measure groups consistent with the measures included in the potential analysis as well as saturation of energy efficient equipment.

For the industrial sector, the analysis employed a top-down analysis at the end-use level. Accordingly, it was not critical to disaggregate the industrial sales at a measure-level. Instead, measures were developed to estimate savings at a total end-use level.

3.2.4 Remaining Factor

The remaining factor is the proportion of a given market segment that is not yet efficient and can still be converted to an efficient alternative. It is the inverse of the saturation of an energy efficient measure, prior to any adjustments. In this study, two key adjustments were made in order to recognize that the energy efficient saturation does not necessarily always fully represent the state of market transformation. First, while a percentage of installed measures may already be efficient, some customers may backslide (i.e. revert to standard technologies, or otherwise less efficient alternatives in the future, based on considerations like measure cost and availability and customer preferences). For example, customers who purchased efficient HVAC equipment in the past may not want to pay the full cost for an efficient piece of equipment again due to price increases in recent years.

Second, for measures categorized as market opportunity (i.e. replace-on-burnout), we assumed that 50% of the instances in which an efficient measure is already installed, the burnout or failure of those measures would be eligible for inclusion in the estimate of future savings potential. This adjustment assumes that 50% of the market is transformed, and no future savings potential exists, whereas the remaining 50% of the market is not transformed and could backslide without the intervention of a CenterPoint program and an incentive. Similarly, for retrofit measures, we assumed that only 10% of the instances in which an efficient measure is already installed, the burnout or failure of those measures would be eligible for inclusion in the estimate of future savings potential. This recognizes the more proactive nature of retrofit measures, as the implementation of these measures are more likely to be elective in nature, compared to market opportunity measures, which are more likely to be needs-based. The uncertainty in these assumptions is appropriate, as they factor in a key component of natural customer decision making.

3.3 MEASURE CHARACTERIZATION

3.3.1 Measure Lists

The study's sector-level energy efficiency measure lists were informed by a range of sources including the Illinois Technical Reference Manual ("TRM"), current CenterPoint program offerings, measures included in other recent Indiana utility market potential studies, and commercially viable emerging technologies, among others. Measure list development was a collaborative effort in which GDS developed draft lists that were shared with CenterPoint and stakeholders. The final measure lists ultimately included in the study reflected the informed comments and considerations from the parties that participated in the measure list review process.

In total, GDS analyzed 356 measure types for this study. Several measures were included with multiple permutations to account for different specific market segments, such as different building types, efficiency levels, and replacement options. In total, GDS developed 2,440 measure permutations for this study. Each permutation was screened for cost-effectiveness under the UCT cost test. The parameters for cost-effectiveness under the UCT are discussed in detail later in Section 3.4.3.

TABLE 3-2: NUMBER OF MEASURES EVALUATED

	# of Measures	Total # of Measure Permutations
Residential	172	770
Commercial	184	1,670
Total	***356***	***2,440***

3.3.2 Emerging Technologies

GDS considered several specific emerging technologies as part of analyzing future potential. In the residential sector, these technologies include several smart technologies, including smart appliances, smart water heater ("WH") tank controls, smart window coverings, smart TVs, heat pump dryers and smart vents/sensors. In the non-residential sector, specific emerging technologies that were considered as part of the analysis include several commercial behavioral options, triple pane windows, energy recovery ventilators, variable refrigerant flow heat pumps, switch reluctance motels, Q-Sync Motors for Refrigeration, ozone commercial laundry, advanced lighting controls, power distribution equipment upgrades, and server virtualization. While this is likely not an exhaustive list of possible emerging technologies over the next twenty years it does consider many of the known technologies that are available today but may not yet have widespread market acceptance and/or product availability.

In addition to these specific technologies, GDS acknowledges that there could be future opportunities for new technologies as equipment standards improve and market trends occur. While this analysis does not make any explicit assumption about unknown future technologies, the methodology assumes that subsequent equipment replacement that occurs over the course of the study timeframe, and at the end of the initial equipment's useful life, will continue to achieve similar levels of energy savings, relative to improved baselines, at similar incremental costs.

3.3.3 Assumptions & Sources

A significant amount of data is needed to estimate the electric savings potential for individual energy efficiency measures or programs across the residential and nonresidential customer sectors. GDS utilized data specific to CenterPoint when it was available and current. GDS used the most recent CenterPoint evaluation report findings (as well as CenterPoint program planning documents), the Illinois TRM, and the Michigan Energy Measures Database ("MEMD"), and EIA data for a large amount of the data requirements. Additional source documents included American Council for an Energy-Efficient Economy ("ACEEE") research reports covering topics like emerging technologies.

Measure Savings: GDS relied on existing CenterPoint evaluation report findings and the Illinois TRM to inform calculations supporting estimates of annual measure savings as a percentage of base equipment usage. For custom measures and measures not included in the Illinois TRM, GDS estimated savings from a variety of sources, including:

- MEMD, IN TRM, and other regional/state TRMs
- Secondary sources such as the ACEEE, Department of Energy ("DOE"), EIA, ENERGY STAR©, and other technical potential studies

Measure Costs: Measure costs represent either incremental or full costs. These costs typically include the incremental cost of measure installation, when appropriate based on the measure definition. For purposes of this study, nominal measure costs held constant over time.

GDS obtained measure cost estimates primarily from CenterPoint evaluation report findings and the Illinois TRM. GDS also used the following supplementary data sources:

- MEMD, IN, and other regional/state TRMs

- Secondary sources such as the ACEEE, ENERGY STAR, and NREL

Costs and savings for new construction and replace on burnout measures were calculated as the incremental difference between the code minimum equipment and the energy efficiency measure. This approach was utilized because the consumer must select an efficiency level that is at least the code minimum equipment when purchasing new equipment. The incremental cost is calculated as the difference between the cost of high efficiency and standard efficiency (code compliant) equipment. However, for retrofit or direct install measures, the measure cost was the "full" cost of the measure, as the baseline scenario assumes the consumer would not make energy efficiency improvements in the absence of a program. In general, the savings for retrofit measures are calculated as the difference between the energy use of the removed equipment and the energy use of the new high efficiency equipment (until the removed equipment would have reached the end of its useful life).

Measure Life: Measure life represents the number of years that energy using equipment is expected to operate. GDS obtained measure life estimates from the CenterPoint evaluation report findings and the Illinois TRM:

- MEMD, IN TRM, and other regional/state TRMs
- Manufacturer data
- Savings calculators and life-cycle cost analyses

All measure savings, costs, and useful life assumption sources are documented in the Appendices volume of this report.

3.3.4 Treatment of Codes & Standards

Although this analysis does not attempt to predict how energy codes and standards will change over time, the analysis does attempt to reflect the latest legislated improvements to federal codes and standards. Where possible, improvements to baseline equipment standards can typically be met with incremental improvements to efficient equipment standards. However, in select cases, such as screw-in lighting improvements to the baseline standard effectively were expected to eliminate the efficient technology from future consideration.

3.3.5 Net to Gross (NTG)

All estimates of technical, economic, and achievable potential, as well as measure level cost-effectiveness screening were conducted in terms of gross savings to reflect the absence of program design considerations in these phases of the analysis. The impacts of free-riders (participants who would have installed the high efficiency option in the absence of the program) and spillover customers (participants who install efficiency measures due to program activities, but never receive a program incentive) were considered in the development of DSM Inputs into CenterPoint's upcoming IRP.

3.4 ENERGY EFFICIENCY POTENTIAL

3.4.1 Types of Potential

This section reviews the types of potential analyzed in this report, as well as some key methodological considerations in the development of technical, economic, and achievable potential.

The first two types of potential, technical and economic, provide a theoretical upper bound for energy savings from energy efficiency measures. Still, even the best-designed portfolio of programs is unlikely to capture 100% of the technical or economic potential. Therefore, achievable potential attempts to estimate what savings may realistically be achieved through market interventions, when it can be captured, and how much it would cost to do so. Figure 3-2 illustrates the types of energy efficiency potential considered in this analysis.

FIGURE 3-2: TYPES OF ENERGY EFFICIENCY POTENTIAL

Not Technically Feasible	TECHNICAL POTENTIAL			
Not Technically Feasible	*Not Cost Effective*	ECONOMIC POTENTIAL		
Not Technically Feasible	*Not Cost Effective*	*Market Barriers*	MAXIMUM ACHIEVABLE POTENTIAL	
Not Technically Feasible	*Not Cost Effective*	*Market Barriers*	*Partial Incentives*	REALISTIC ACHIEVABLE POTENTIAL

3.4.2 Technical Potential

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures. Under technical potential, GDS assumed that 100% of new construction and market opportunity measures are adopted as those opportunities become available (e.g., as new buildings are constructed, they immediately adopt efficiency measures, or as existing measures reach the end of their useful life). For retrofit measures, implementation was assumed to be resource constrained and that it was not possible to install all retrofit measures all at once. Rather, retrofit opportunities were assumed to be replaced incrementally until 100% of stock was converted to the efficient measure over a period of no more than 15 years.

The core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Equation 3-1 below. The C&I sector employs a similar analytical approach.

EQUATION 3-1 CORE EQUATION FOR RESIDENTIAL SECTOR TECHNICAL POTENTIAL

$$\text{TECHNICAL POTENTIAL OF EFFICIENT MEASURES} = \text{Total Number of Households} \times \text{Base Case End Use Intensity (kWh/unit)} \times \text{Saturation Share} \times \text{Remaining Factor} \times \text{Feasibility Factor} \times \text{Savings Factor}$$

Where…

Base Case Equipment End-Use Intensity = the electricity used per customer per year by each base-case technology in each market segment. In other words, the base case equipment end-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.

Saturation Share = the fraction of the end-use electrical energy that is applicable for the efficient technology in a given market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household.

Remaining Factor = the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of electric water heaters that is not already energy efficient.

Feasibility Factor = (also functions as the applicability factor) the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective (e.g., it may not be possible to install heat pump water heaters in all homes because of space limitations).

Savings Factor = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

3.4.2.1 Competing Measures & Interactive Effects Adjustments

GDS prevents double-counting of savings, and accounts for competing measures and interactive savings effects, through three primary adjustment factors:

Baseline Saturation Adjustment. Competing measure shares are factored into the baseline saturation estimates. For example, nearly all homes can receive insulation. To account for this, GDS' analysis used multiple measure permutations that account for varying impacts of different heating/cooling combinations and baseline saturations were applied to reflect the proportions of households with each heating/cooling combination.

Applicability Factor Adjustment. Combined measures into measure groups, where total applicability factor across measures is set to 100%. For example, homes cannot receive a programmable thermostat and a smart thermostat for the same zone. In general, the models assign the measure with the most savings the greatest applicability factor in the measure group, with competing measures picking up any remaining share.

Interactive Savings Adjustment. As savings are introduced from select measures, the per-unit savings from other measures need to be adjusted (downward) to avoid over-counting. The analysis typically prioritizes market opportunity equipment measures (versus retrofit measures that can be installed at any time). For example, the savings from building shell upgrades are adjusted down to reflect the efficiency gains of installing an efficient HVAC equipment.

3.4.3 Economic Potential

Economic potential refers to the subset of the technical potential that is economically cost-effective (based on screening with the UCT) as compared to conventional supply-side energy resources.

3.4.3.1 Utility Cost Test & Incentive Levels

The economic potential assessment included a screen for cost-effectiveness using the UCT at the measure level. In the CenterPoint territory, the UCT considers electric energy, capacity, and transmission & distribution ("T&D") savings as benefits, and utility incentives and direct install equipment expenses as the cost. Consistent with application of economic potential according to the National Action Plan for Energy Efficiency ("NAPEE"), the measure level economic screening does not consider non-incentive/measure delivery costs (e.g. admin, marketing, evaluation etc.) in determining cost-effectiveness.[2]

Apart from the low-income segment of the residential sector, all measures were required to have a UCT benefit-cost ratio greater than 1.0 to be included in economic potential and all subsequent estimates of energy efficiency potential. Low-income measures were not required to be cost-effective.

For both the calculation of the measure-level UCT, as well as the determination of RAP, historical incentive levels (as a % of incremental measure cost) were calculated for current measure offerings. GDS relied on the prior CenterPoint DSM plan estimates and historical CenterPoint evaluation reports files to map current measure offerings to their historical incentive levels.

- In the residential sector, incentives by program ranged from 34% to 100% and averaged 62%.

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[2] National Action Plan for Energy Efficiency: Understanding Cost-Effectiveness of Energy Efficiency Programs. *Note: Non-incentive delivery costs are included in the assessment of achievable potential.*

- In the non-residential sector, prescriptive incentives averaged 61% of the measure cost for interior lighting, 16% for exterior lighting and 33% for non-lighting measures.
- Custom measures received incentives equal to $0.10 per first-year kWh saved (up to 50% of the measure cost).
- In the MAP scenario, incentives were increased up to 100% of the incremental measure cost.[3]

3.4.3.2 Avoided Costs

Avoided energy supply costs are used to assess the value of energy savings. Avoided cost values for electric energy, electric capacity, and avoided T&D were provided by CenterPoint as part of an initial data request. Electric energy is based on an annual system marginal cost. For years outside of the avoided cost forecast timeframe, future year avoided costs are escalated by the rate of inflation.

CenterPoint provided the GDS team with annual on and off-peak avoided energy costs. GDS used this data to create 8,760 avoided cost values for each forecast year. GDS then applied these avoided costs to the 8,760 savings from each measure based on assigned end-use load shapes[4] to determine the value of measures that save more energy during peak periods than those that might saving during off-peak periods. In addition, the avoided capacity and T&D avoided costs were applied to the estimated coincident peak demand savings for each measure.

3.4.4 Achievable Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and WTP in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:

- ***MAP*** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- ***RAP*** estimates achievable potential with CenterPoint paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

3.4.4.1 Market Adoption Rates

GDS assessed achievable potential on a measure-by-measure basis. In addition to accounting for the natural replacement cycle of equipment in the achievable potential scenario, GDS estimated measure specific maximum adoption rates that reflect the presence of possible market barriers and associated difficulties in achieving the 100% market adoption assumed in the technical and economic scenarios.

The initial step was to assess the long-term market adoption potential for energy efficiency technologies. Due to the wide variety of measures across multiple end-uses, GDS employed varied measure and end-use-specific ultimate adoption rates versus a singular universal market adoption curve. These long-term market adoption estimates were based on a combination of CenterPoint-specific WTP research (conducted for the prior CenterPoint MPS) and more recent WTP surveys conducted in neighboring Indiana utility service areas.

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[3] The GDS team lowered MAP incentives to less than 100% of measure incremental cost in some cases if 100% incentives would preclude the measure from being cost-effective. MAP incentives were lowered to either 75% or 50% of the incremental measure cost if either of those incentive levels would allow for a measure to remain cost-effective.

[4] End-use load shapes were derived from building energy simulation models created by housing type and building type, specific to the CenterPoint service area.

The CenterPoint-specific research included questions to residential homeowners and nonresidential facility managers regarding their perceived willingness to purchase and install energy efficient technologies across various end uses and incentive/payback performance levels. One caveat to this approach is that the WTP adoption score is generally a simple function of incentive levels and/or payback performance. There are other factors (both as barriers and motivations) that may influence a customer's willingness to purchase an energy efficiency measure. For example, increased marketing and education programs can have a critical impact on the success of energy efficiency programs. The secondary WTP research conducted in neighboring jurisdictions included additional questions related to these barriers and motivations factors, and the general impact of these additional elements were layered onto the initial CenterPoint-specific research to be able to update and refine the original long-term adoption rates. The WTP approach and results were provided to the CenterPoint Oversight Board during a discussion of draft methodology and results.

GDS utilized likelihood and WTP data to estimate the long-term market adoption potential for both the maximum and realistic achievable scenarios. Table 3-3 presents the long-term market adoption rates at varied incentive levels used for the residential sector. Most end-uses are based on the WTP primary market research. Behavior was set to 100% to reflect that the program design is typically opt-out and participation levels are dictated by the utility.

TABLE 3-3 RESIDENTIAL LONG-TERM MARKET ADOPTION RATES AT DISCRETE INCENTIVE LEVELS

End Use/Housing Type/Income	0% Incentive	25% Incentive	50% Incentive	75% Incentive	100% Incentive
Water Heating	20%	37%	49%	65%	93%
HVAC Equipment	22%	36%	43%	60%	89%
Appliances	21%	37%	53%	68%	95%
Building Shell	20%	35%	48%	64%	91%
Behavior	100%	100%	100%	100%	100%

Table 3-4 presents the long-term market adoption rates used in the nonresidential sector. . Again, the adoption scores were informed by a combination of CenterPoint-specific WTP research (conducted for the prior CenterPoint MPS) and more recent WTP surveys conducted in neighboring Indiana utility service areas. GDS also included a custom project opportunity adjustment of 80% to reflect the difficulty in raising awareness levels for all potential custom project opportunities compared to the discrete energy efficient opportunities included in the WTP survey research. This adjustment was applied to all measures mapped to the Custom Program.

TABLE 3-4 NONRESIDENTIAL LONG-TERM MARKET ADOPTION RATES AT DISCRETE PAYBACK INTERVALS

End-Use	20 Year Payback Period	10 Year Payback Period	5 Year Payback Period	3 Year Payback Period	1 Year Payback Period	0 Year Payback Period
Lighting/Office	19%	28%	47%	71%	88%	95%
HVAC	27%	41%	55%	70%	83%	93%
Refrigeration	24%	36%	59%	77%	84%	88%
Water Heat	20%	31%	51%	68%	80%	84%
Motors/Process	23%	34%	48%	62%	73%	83%

GDS then estimated initial year adoption rates by reviewing the current saturation levels of efficient technologies and (if necessary) calibrating the estimates of 2025 annual potential to recent historical levels achieved by CenterPoint's current DSM portfolio. Although this calibration ensured that near-term savings indicated in the MPS demonstrated achievable incremental increases relative to recent historical levels, the near-term adjustment had little impact on the long-term potential. GDS then assumed a non-linear ramp rate from the initial year market adoption rate to the various long-term market adoption rates for each specific end-use.

3.4.4.2 Non-Incentive Costs

Consistent with (NAPEE) guidelines[5], utility non-incentive costs were included in the overall assessment of cost-effectiveness at the RAP scenario. Program non-incentive costs were calibrated to recent projected levels (using the 2022 Operating Plan) and set at:

- $0.037 per Behavioral program participant
- $0.307 per first year kWh saved for measures in the Residential Prescriptive program;
- $0.164 per first year kWh saved for residential Appliance Recycling program measures;
- $0.410 per first year kWh saved for Income-Qualified program measures;
- $0.134 per first year kWh saved for the remaining residential measures,
- $0.061 per first year kWh saved for prescriptive C&I measures;
- $0.082 per first year kWh saved for Small Business Direct Install measures;
- $0.115 per first year kWh saved for custom C&I measures.

Non-incentive costs were then escalated annually at the rate of inflation.[6]

3.5 RESIDENTIAL ENERGY EFFICIENCY POTENTIAL

This section provides the potential results for technical, economic, MAP and RAP for the residential sector. The cost-effectiveness results and budgets for the RAP scenario are also provided.

3.5.1 Scope of Measures & End Uses Analyzed

There were 172 total unique residential electric measures included in the analysis. Table 3-5 provides the number of unique measures by end-use. The measure list was developed based on a review of current CenterPoint programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 3-5: RESIDENTIAL ENERGY EFFICIENCY MEASURES – BY END USE

End-Use	Number of Unique Measures
Appliances	23
Behavior	5
HVAC	55
Lighting	14
New Construction	6
Plug Loads	4
Pool/Pump	5
Shell	45
Water Heating	15
Total	**172**

[5] National Action Plan for Energy Efficiency (2007). Guide for Conducting Energy Efficiency Potential Studies. Prepared by Optimal Energy. This study notes that economic potential only considers the cost of efficiency measures themselves, ignoring programmatic costs. Conversely, achievable potential should consider the non-measures costs of delivering programs. Pg. 2-4.
[6] Measure costs and utility incentives were not escalated over analysis timeframe to keep those costs constant in nominal dollars.

3.5.2 Summary of Residential Electric Potential

Figure 3-3 provides the technical, economic, MAP and RAP results for the 3-year, 6-year, and 18-year timeframes. The respective 18-yr technical and economic potential is 34% and 30% of residential sector sales. The MAP reaches 3.5% in three years and grows to 6.8% over six years, while the RAP reaches 2.5% in three years and grows to 4.9% over six years. The MAP and RAP reach 20% and 14% of residential sector sales, respectively, over the 18-yr timeframe of the study.

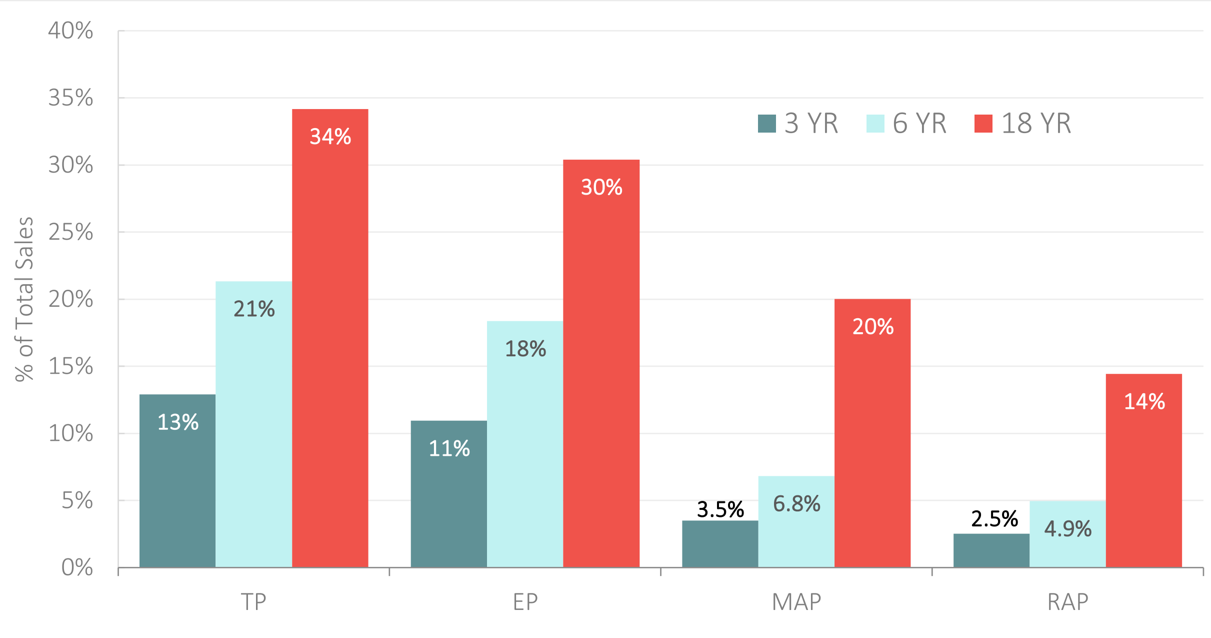


FIGURE 3-3: RESIDENTIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF SECTOR SALES)

Table 3-6 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The MW demand savings for each level of potential are also provided. In 2025, the RAP is 1.0% of sector sales with nearly 14,000 MWh in estimated energy savings and 5 MW in demand savings. By 2030, the estimated cumulative annual savings in the RAP scenario reaches 4.9% of sector sales at nearly 67,000 MWh and 28 MW in demand savings.

TABLE 3-6: RESIDENTIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2025	2026	2027	2030	2042
MWh					
Technical	74,412	126,483	170,550	287,834	501,010
Economic	62,782	105,733	144,625	247,761	445,761
MAP	18,914	32,248	46,162	91,987	293,458
RAP	13,744	23,531	33,467	66,783	211,623
Forecasted Sales	1,310,095	1,316,263	1,322,505	1,349,158	1,466,187
Savings as a % of Sales					
Technical	5.7%	9.6%	12.9%	21.3%	34.2%
Economic	4.8%	8.0%	10.9%	18.4%	30.4%
MAP	1.4%	2.4%	3.5%	6.8%	20.0%
RAP	1.0%	1.8%	2.5%	4.9%	14.4%
MW					
Technical	33	58	81	141	253
Economic	26	47	65	114	214
MAP	6	11	17	39	147
RAP	5	8	12	28	105

Table 3-7 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The MW demand savings for each level of potential are also provided. The incremental MAP ranges from 1.4% to 2.0% of sector sales over the next six years. The incremental RAP ranges from 1.0% to 1.4% per year over the next six years.

TABLE 3-7: RESIDENTIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2025	2026	2027	2030	2042
MWh					
Technical	74,412	71,635	70,211	67,063	63,281
Economic	62,782	61,518	60,346	57,963	55,469
MAP	18,914	21,033	22,596	27,528	40,816
RAP	13,744	17,118	18,557	22,847	32,103
Forecasted Sales	1,310,095	1,316,263	1,322,505	1,349,158	1,466,187
Savings as a % of Sales					
Technical	5.7%	5.4%	5.3%	5.0%	4.3%
Economic	4.8%	4.7%	4.6%	4.3%	3.8%
MAP	1.4%	1.6%	1.7%	2.0%	2.8%
RAP	1.0%	1.3%	1.4%	1.7%	2.2%
MW					
Technical	33	31	30	30	29
Economic	26	26	25	25	25
MAP	6	8	8	12	16
RAP	5	6	7	9	11

3.5.3 Residential Technical, Economic and Achievable Potential Summary and Detail by End-Use

Figure 3-4 provides the technical and economic potential across the 18-yr timeframe of the study. The green and red bars provide the respective incremental annual technical and economic in MWh per year energy savings. The green and orange lines provide the corresponding cumulative annual technical and economic as a percent of forecasted annual sales. The technical potential ("TP") rises to 34% by 2042, and the economic potential ("EP") rises to 30%.

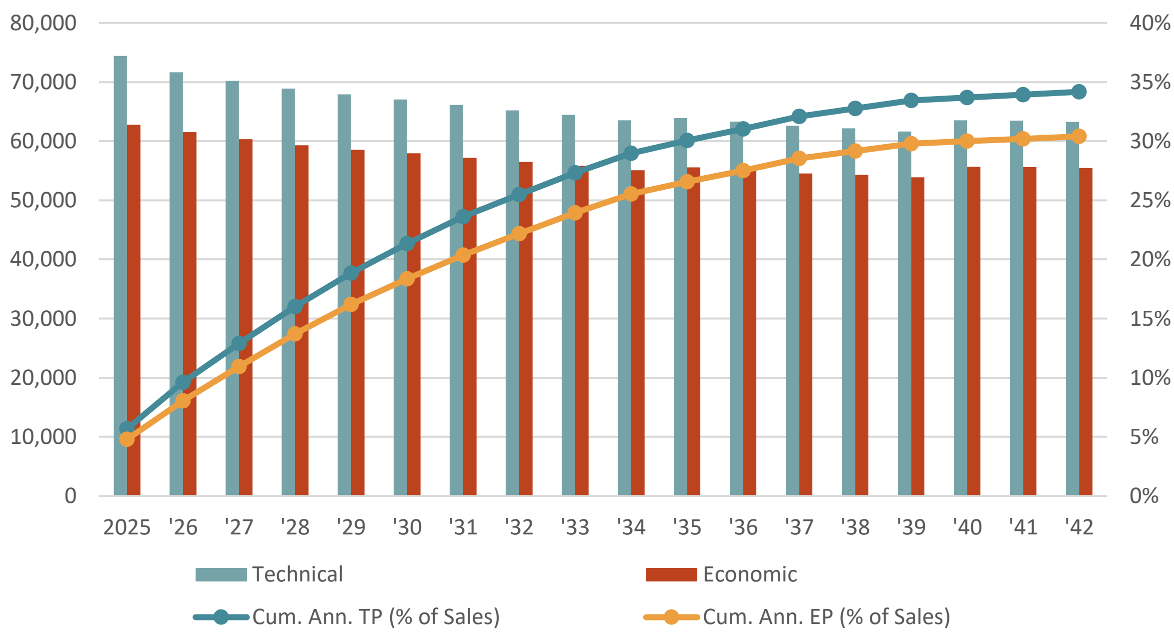


FIGURE 3-4: RESIDENTIAL ANNUAL TP AND EP

Table 3-8 provides cumulative annual technical, economic, and achievable potential results, by end-use, across the 18-yr study timeframe. The HVAC end use has the most potential in each scenario, with the Water Heating, Shell, and Appliances end uses also contributing a significant amount potential in each scenario.

TABLE 3-8: RESIDENTIAL ELECTRIC POTENTIAL – DETAIL BY END-USE

	Technical	Economic	MAP	RAP
End Use				
Appliances	65,043	63,946	42,049	35,256
Behavior	13,639	13,876	11,903	12,690
HVAC	159,628	141,759	82,867	57,112
Lighting	42,519	42,519	35,605	14,525
Pool/Pump	4,381	4,125	2,423	1,518
New Construction	11,525	12,044	4,336	3,469
Plug Loads	19,876	19,684	6,206	4,173
Shell	89,311	56,601	39,254	35,845
Water Heating	95,089	91,206	68,814	47,035
Total	**501,010**	**445,761**	**293,458**	**211,623**
Savings as % of Forecast	**34.2%**	**30.4%**	**20.0%**	**14.4%**

Figure 3-5 provides the MAP and RAP across the 18-yr timeframe of the study. The green and red bars provide the respective incremental annual MAP and RAP in MWh per year energy savings. The green and orange lines provide the corresponding cumulative annual MAP and RAP as a percent of forecasted annual sales. The MAP rises to 20% by 2042, and the RAP rises to 14%.

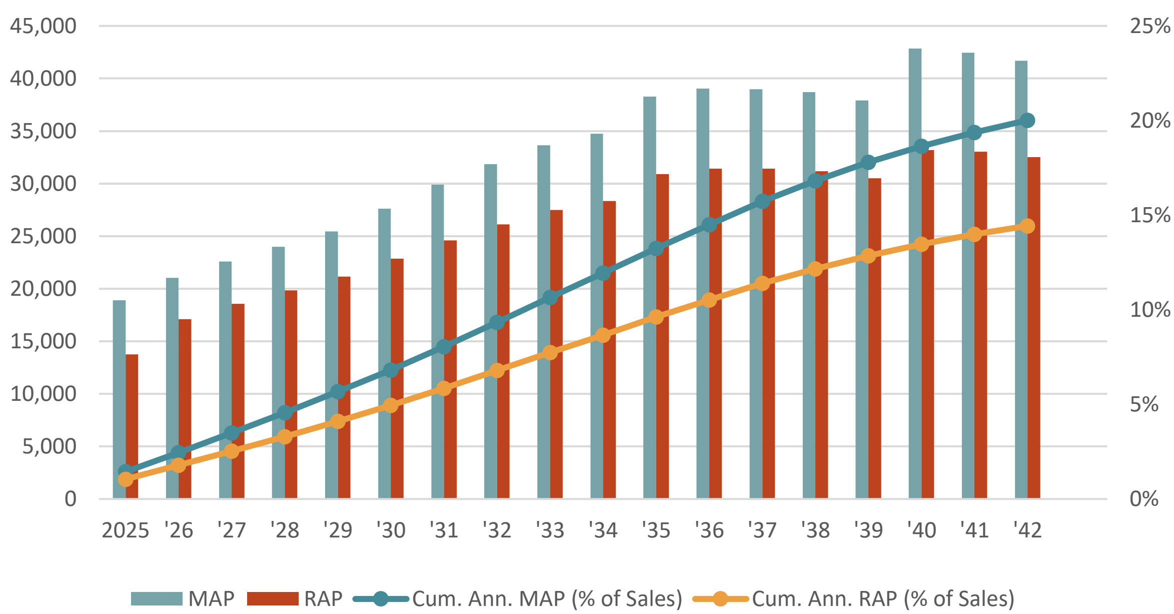
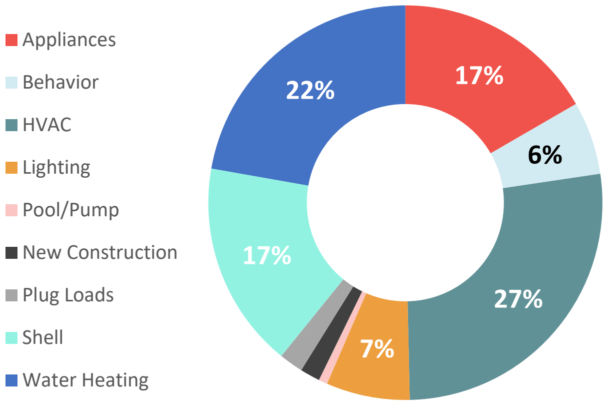


FIGURE 3-5: RESIDENTIAL ANNUAL MAP AND RAP

Figure 3-6 provides a breakdown of the RAP potential in 2042 across end-uses and building type market segments. As in technical and economic potential, HVAC is the leading end-use accounting for 27% of the total. The Shell, Water Heating and Appliances end-uses combine to account for an additional 56% of the RAP. The single-family housing segment represents 72% of the potential and the multifamily segment represents 5% of the potential. The new construction segment accounts for 6% of potential, and measures dedicated to low-income customers account for 17% of potential.



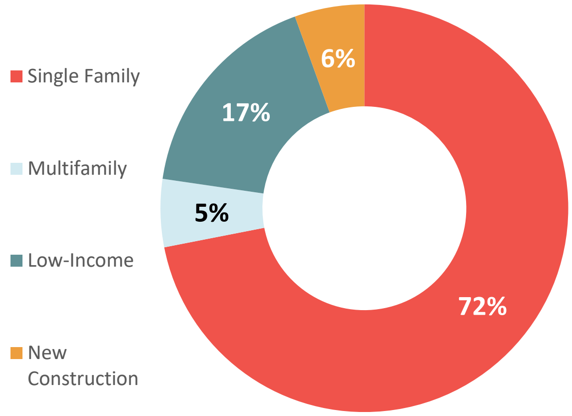


FIGURE 3-6: RESIDENTIAL POTENTIAL BY END-USE AND BUILDING TYPE – RAP 2042

Table 3-9 provides additional end-use level detail for the incremental annual residential MAP and RAP. On an incremental annual basis, the Behavior end-use is the leading end-use, with the HVAC, Shell, Water Heating and Appliances end-uses provide significant levels of achievable potential each year as well.

TABLE 3-9: RESIDENTIAL INCREMENTAL ANNUAL MAP AND RAP – END-USE DETAIL

	2025	2026	2027	2028	2029	2030
MAP Incremental Annual MWh						
Appliances	1,379	1,537	1,716	1,923	2,163	2,430
Behavior	7,671	8,486	9,188	9,777	10,262	10,667
HVAC	5,572	5,434	5,346	5,200	5,002	5,060
Lighting	738	1,102	1,226	1,317	1,454	1,821
New Construction	29	39	53	71	95	125
Plug Loads	55	67	79	96	121	160
Pool/Pump	129	193	214	230	364	482
Shell	1,271	1,632	1,797	2,022	2,288	2,736
Water Heating	2,071	2,543	2,975	3,364	3,716	4,047
Total	**18,914**	**21,033**	**22,596**	**24,000**	**25,465**	**27,528**
% of Forecasted Sales	**1.4%**	**1.6%**	**1.7%**	**1.8%**	**1.9%**	**2.0%**
RAP Incremental Annual MWh						
Appliances	1,211	1,399	1,546	1,713	1,908	2,124
Behavior	7,319	8,540	9,275	9,900	10,424	10,870
HVAC	2,495	3,031	3,044	3,036	3,006	3,179
Lighting	296	441	491	528	583	731
New Construction	16	22	30	41	55	72
Plug Loads	44	54	64	77	97	128
Pool/Pump	86	128	143	153	243	322
Shell	960	1,407	1,558	1,750	1,982	2,387
Water Heating	1,317	2,094	2,406	2,656	2,856	3,036
Total	**13,744**	**17,118**	**18,557**	**19,854**	**21,155**	**22,847**
% of Forecasted Sales	**1.0%**	**1.3%**	**1.4%**	**1.5%**	**1.6%**	**1.7%**

3.5.4 Residential Achievable Potential Benefits & Costs

Table 3-10 provides the net present value ("NPV") benefits and costs, as calculated using the UCT, across the 2025-2042 timeframe for the MAP and RAP scenarios. The overall UCT ratio in the RAP scenario is 1.79. The overall UCT ratio in the MAP scenario is 1.41 due to higher assumed incentive costs.

TABLE 3-10: RESIDENTIAL MAP AND RAP NPV BENEFITS & COSTS

End Use	NPV Benefits	NPV Costs	Net Benefits	UCT Ratio
MAP	$318,964,649	$226,308,700	$92,655,949	1.41
RAP	$237,975,390	$133,134,210	$104,841,181	1.79

Figure 3-7 provides the budget for the MAP and RAP scenarios. For the RAP scenarios, the budget is broken into incentive and non-incentive budgets for each year of the study timeframe. The RAP budgets range from $4.4 million to $18 million, with incentives accounting for approximately 52% of the total RAP budget. The MAP budgets range from $9 million to $32 million.

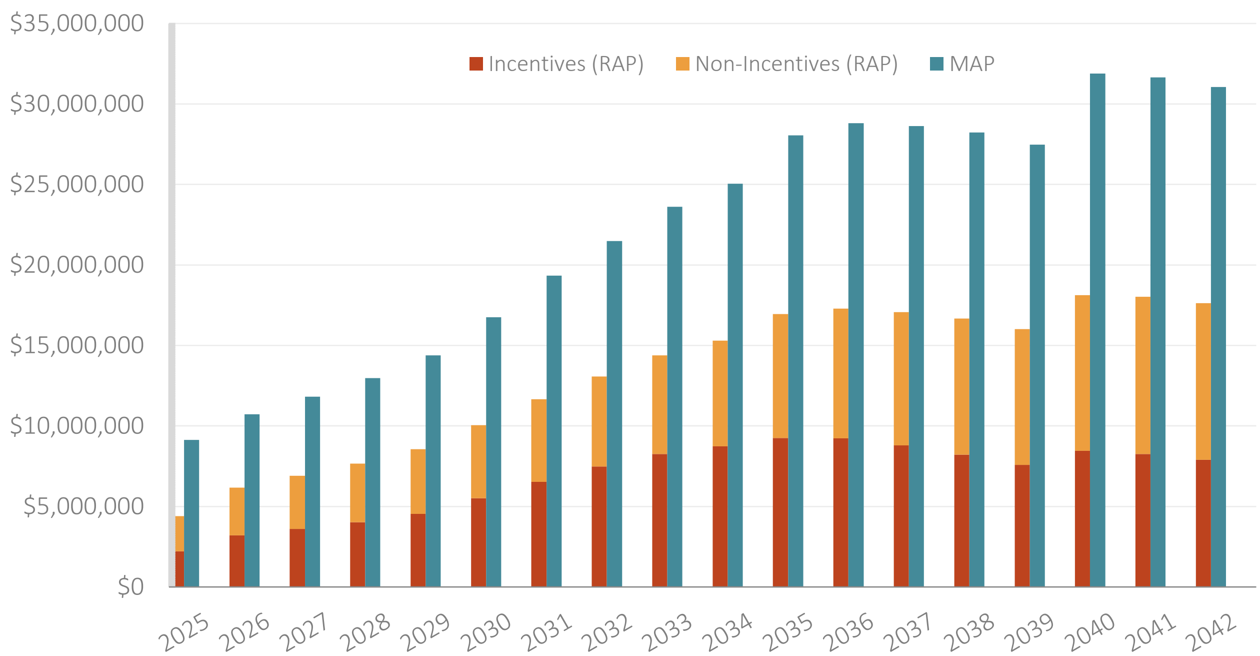


FIGURE 3-7: RESIDENTIAL ANNUAL BUDGETS – MAP AND RAP

3.6 COMMERCIAL AND INDUSTRIAL ENERGY EFFICIENCY POTENTIAL

This section provides the potential results for technical, economic, MAP and RAP for the commercial and industrial sector. The cost-effectiveness results and budgets for the RAP scenario are also provided.

3.6.1 Scope of Measures & End Uses Analyzed

There were 170 total unique commercial and industrial (C&I) electric measures included in the analysis. Table 3-11 provides the number of unique measures by end-use. The measure list was developed based on a review of current CenterPoint programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 3-11: COMMERCIAL AND INDUSTRIAL ENERGY EFFICIENCY MEASURES – BY END USE

End-Use	Number of Unique Measures
HVAC	57
Lighting	33
Refrigeration	27
Office Equipment	11
Whole Building	10
Cooking	9
Process	8
Compressed Air	7
Behavioral	6
Miscellaneous	6
Hot Water	5
Motors	5
Total	**184**

3.6.2 Summary of Commercial and Industrial Electric Potential

Figure 3-8 provides the technical, economic, MAP and RAP results for the 3-year, 6-year, and 18-year timeframes. The respective 18-yr technical and economic potential is 31% and 30% of C&I sector sales. The MAP reaches 4.9% in three years and grows to 10.1% over six years, while the RAP reaches 3.1% in three years and grows to 6.4% over six years. The MAP and RAP reach 24% and 16% of C&I sector sales, respectively, over the 18-yr timeframe of the study.

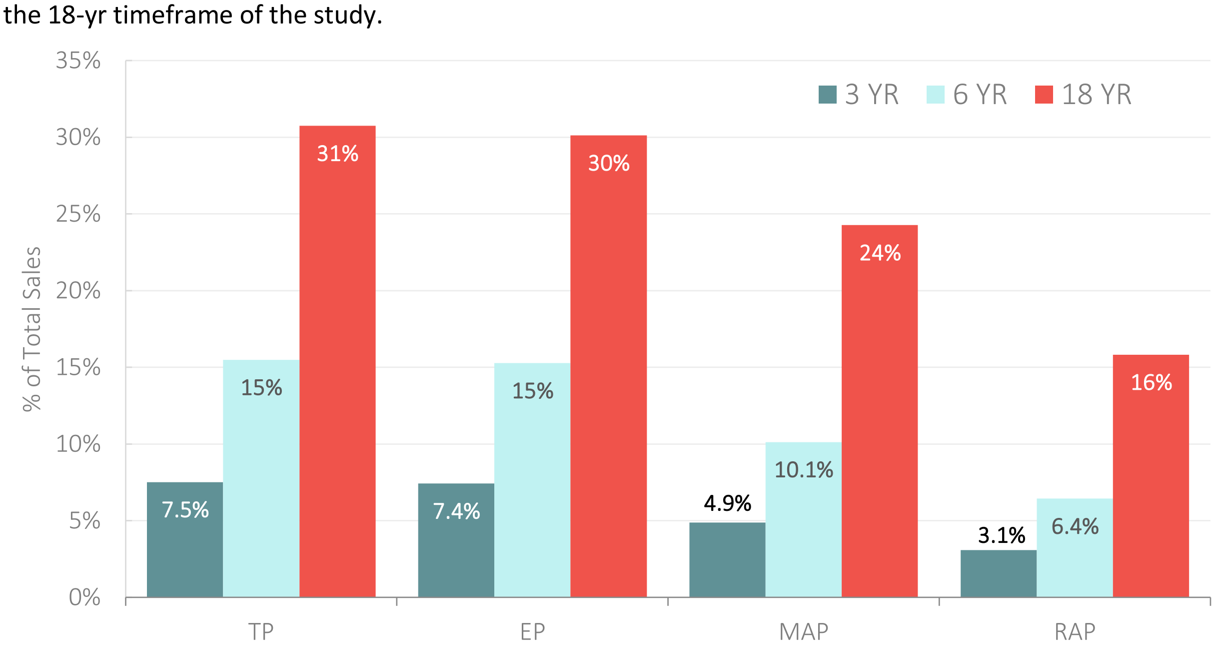


FIGURE 3-8: C&I ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF COMMERICAL AND INDUSTRIAL SALES)

Table 3-12 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The MW demand savings for each level of potential are also provided. In 2025, the RAP is 0.9% of sector sales with more than 21,000 MWh in estimated energy savings and 5 MW in demand savings. By 2030, the estimated cumulative annual savings in the RAP scenario reaches 6.4% of sector sales at nearly 148,000 MWh and 33 MW in demand savings.

TABLE 3-12: C&I CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2025	2026	2027	2030	2042
MWh					
Technical	52,423	109,850	170,504	355,588	738,789
Economic	51,828	108,456	168,281	350,674	723,732
MAP	34,328	71,839	110,811	232,609	583,159
RAP	21,377	45,043	69,832	147,777	380,213
Forecasted Sales	2,254,314	2,260,433	2,268,314	2,296,773	2,403,292
Technical	2.3%	4.9%	7.5%	15.5%	30.7%
Economic	2.3%	4.8%	7.4%	15.3%	30.1%
MAP	1.5%	3.2%	4.9%	10.1%	24.3%
RAP	0.9%	2.0%	3.1%	6.4%	15.8%
MW					
Technical	12	24	37	78	167
Economic	12	24	37	78	167
MAP	8	16	25	54	138
RAP	5	10	15	33	84

Table 3-13 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The MW demand savings for each level of potential are also provided. The incremental MAP ranges from 1.5% to 1.9% of sector sales over the next six years. The incremental RAP ranges from 0.9% to 1.2% per year over the next six years.

TABLE 3-13: C&I INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2025	2026	2027	2030	2042
MWh					
Technical	52,423	57,427	61,147	58,432	77,954
Economic	51,828	56,628	59,842	66,062	70,675
MAP	34,328	37,511	38,980	43,596	39,160
RAP	21,377	23,666	24,796	28,197	26,666
Forecasted Sales	2,254,314	2,260,433	2,268,314	2,296,773	2,403,292
Technical	2.3%	2.5%	2.7%	2.5%	3.2%
Economic	2.3%	2.5%	2.6%	2.9%	2.9%
MAP	1.5%	1.7%	1.7%	1.9%	1.6%
RAP	0.9%	1.0%	1.1%	1.2%	1.1%
MW					
Technical	12	13	13	15	14
Economic	12	13	13	15	14
MAP	8	9	9	10	8
RAP	5	5	5	6	5

3.6.3 Commercial and Industrial Technical & Economic Potential

Figure 3-9 provides the technical and economic potential across the 18-yr timeframe of the study. The green and red bars provide the respective incremental annual technical and economic in MWh per year energy savings. The green and orange lines provide the corresponding cumulative annual technical and economic as a percent of forecasted annual sales. The technical potential rises to 31% by 2042, and the economic potential rises to 30%.

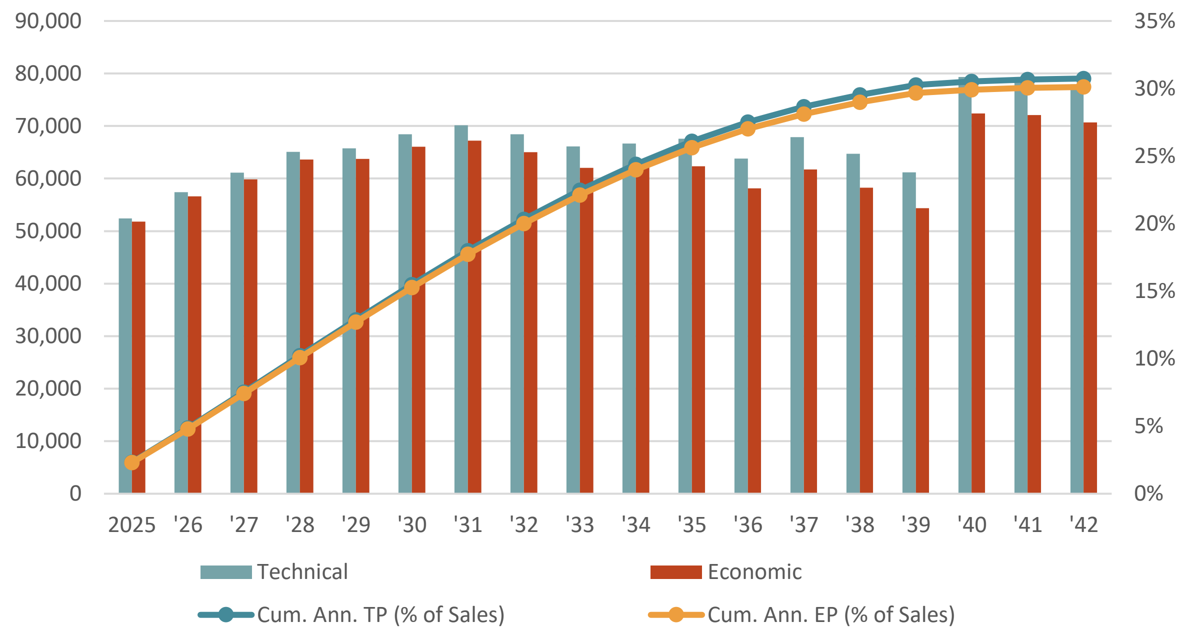


FIGURE 3-9: C&I ANNUAL TP AND EP

Table 3-14 provides cumulative annual technical, economic, and achievable potential results, by end-use, across the 18-yr study timeframe. The Lighting end use has the most potential in each scenario, which, along with the HVAC, Whole Building and Refrigeration end uses, contributes approximately 75% of the RAP.

TABLE 3-14: C&I ELECTRIC POTENTIAL – DETAIL BY END-USE

End Use	Technical	Economic	MAP	RAP
Lighting	168,415	168,286	149,753	104,645
HVAC	158,636	157,496	134,226	76,091
Whole Building	96,233	96,317	90,402	54,323
Refrigeration	72,893	72,457	46,365	34,874
Process	59,118	59,118	35,878	21,919
Motors	39,838	39,838	32,542	22,672
Office Equipment	45,951	45,951	38,417	22,798
Compressed Air	20,983	20,983	18,231	13,047
Miscellaneous	34,965	34,965	19,778	13,847
Behavioral	28,898	15,464	8,348	8,370
Cooking	8,086	8,086	6,133	5,025
Hot Water	4,772	4,772	3,086	2,601
Total	**738,789**	**723,732**	**583,159**	**380,213**
Savings as % of Forecast	**30.7%**	**30.1%**	**24.3%**	**15.8%**

3.6.4 Commercial and Industrial Achievable Potential

Figure 3-10 provides the MAP and RAP across the 18-yr timeframe of the study. The green and red bars provide the respective incremental annual MAP and RAP in MWh per year energy savings. The green and orange lines provide the corresponding cumulative annual MAP and RAP as a percent of forecasted annual sales. The MAP rises to 24% by 2042, and the RAP rises to 16%.

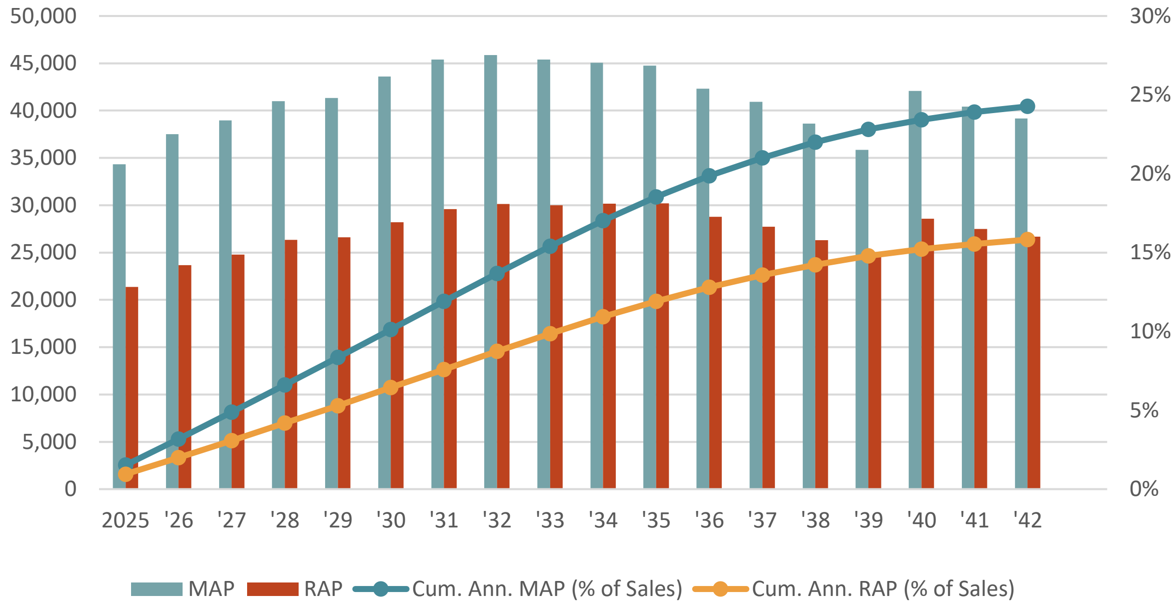


FIGURE 3-10: COMMERCIAL AND INDUSTIRAL ANNUAL MAP AND RAP

Figure 3-11 provides a breakdown of the RAP potential in 2042 across end-uses and building type market segments. As in technical and economic potential, HVAC and Lighting are the leading end-uses, accounting for 48% of the total. The Whole Building, Refrigeration, Process, Motors, and Office Equipment end-uses each contribute at least six percent of the total and combine to account for an additional 41% of the RAP. The commercial sector represents 76% of the potential and the industrial sector represents 24% of the potential.

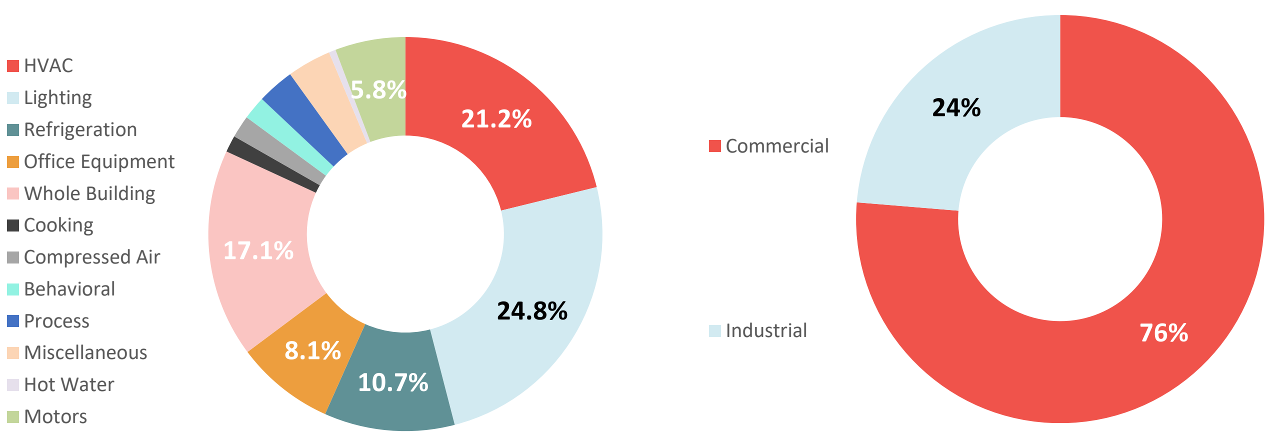


FIGURE 3-11: COMMERCIAL AND INDUSTRIAL POTENTIAL BY END-USE AND BUILDING TYPE – RAP 2042

Table 3-15 provides additional end-use level detail for the incremental annual commercial and industrial MAP and RAP. The incremental annual savings have a similar representation as the cumulative annual savings across end-uses, with Lighting and HVAC leading the way, followed by the Whole Building, Refrigeration, Process, Motors, Office Equipment and Compressed Air end-uses each providing more than 1,000 MWh in annual savings by 2030.

TABLE 3-15: COMMERCIAL AND INDUSTRIAL ANNUAL MAP AND RAP – END-USE DETAIL

	2025	2026	2027	2028	2029	2030
MAP Incremental Annual MWh						

	2025	2026	2027	2028	2029	2030
Lighting	17,268	17,329	16,868	16,000	14,785	13,461
HVAC	8,496	9,315	9,836	10,518	10,665	10,727
Whole Building	2,916	3,780	4,329	5,228	5,333	6,411
Refrigeration	938	1,418	1,591	1,721	1,961	2,702
Process	481	607	764	1,107	1,369	1,660
Motors	726	1,067	1,186	1,281	1,419	1,767
Office Equipment	1,140	1,287	1,462	1,759	2,137	2,511
Compressed Air	951	1,074	1,180	1,361	1,437	1,531
Miscellaneous	717	781	828	879	943	1,331
Behavioral	238	350	390	558	666	854
Cooking	309	342	371	398	420	439
Hot Water	149	162	175	188	203	202
Total	34,328	37,511	38,980	40,998	41,338	43,596
% of Forecasted Sales	1.5%	1.7%	1.7%	1.8%	1.8%	1.9%
RAP Incremental Annual MWh						
Lighting	10,862	11,232	11,197	10,808	10,110	9,325
HVAC	4,917	5,345	5,617	6,070	6,117	6,096
Whole Building	1,563	2,031	2,350	2,946	2,983	3,685
Refrigeration	684	1,037	1,166	1,265	1,441	1,974
Process	305	381	475	704	866	1,047
Motors	498	739	822	884	976	1,219
Office Equipment	687	771	869	1,039	1,268	1,495
Compressed Air	769	856	924	1,041	1,077	1,117
Miscellaneous	491	533	563	597	641	912
Behavioral	215	319	357	512	616	799
Cooking	254	280	304	324	342	356
Hot Water	132	142	153	164	176	172
Total	21,377	23,666	24,796	26,355	26,612	28,197
% of Forecasted Sales	0.9%	1.0%	1.1%	1.2%	1.2%	1.2%

3.6.5 Commercial and Industrial Achievable Potential Benefits & Costs

Table 3-16 provides the net present value (NPV) benefits and costs, as calculated using the UCT, across the 2025-2042 timeframe for the MAP and RAP scenarios. The overall UCT ratio in the RAP scenario is 4.84. The overall UCT ratio in the MAP scenario is 2.11 due to higher assumed incentive costs.

TABLE 3-16: C&I MAP AND RAP NPV BENEFITS & COSTS

End Use	NPV Benefits	NPV Costs	Net Benefits	UCT Ratio
MAP	$411,885,368	$195,172,667	$216,712,701	2.11
RAP	$250,846,614	$51,877,902	$198,968,711	4.84

Figure 3-12 provides the budget for the MAP and RAP scenarios. For the RAP scenarios, the budget is broken into incentive and non-incentive budgets for each year of the study timeframe. The RAP budgets range from $3.9 million to $7.2 million, with incentives accounting for approximately 43% of the total RAP budget. The MAP budgets range from $16 million to $24 million.

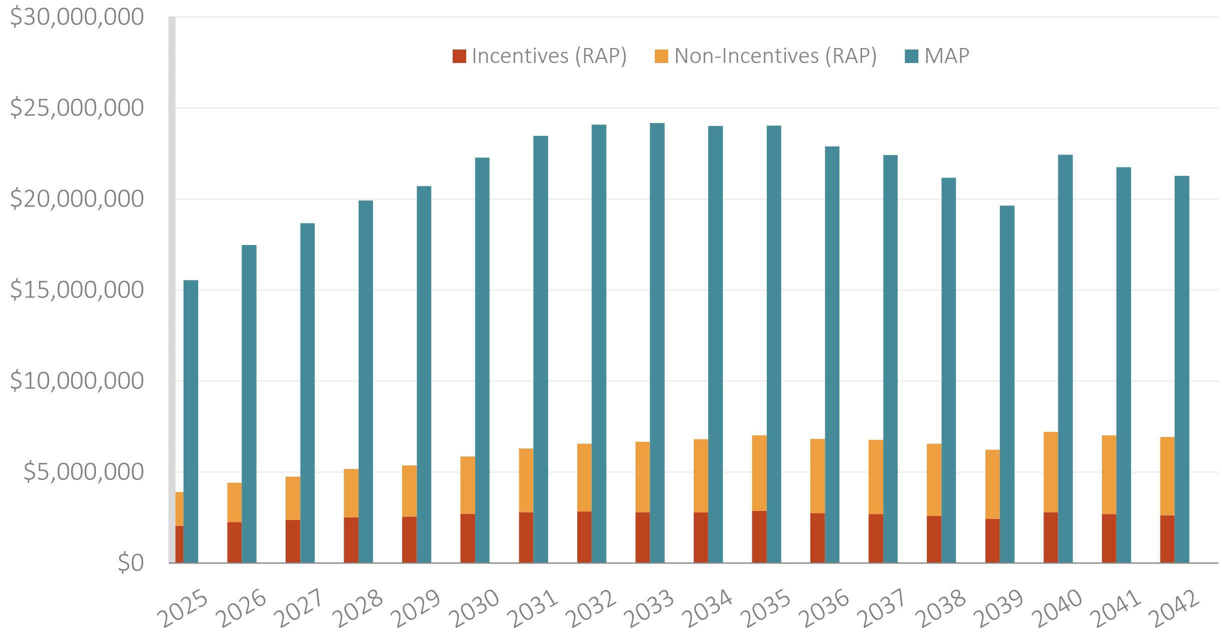


FIGURE 3-12: COMMERCIAL AND INDUSTRIAL ANNUAL BUDGETS – MAP AND RAP

4 Demand Response Potential

This chapter provides the results of the MAP and RAP potential for the demand response analysis. Results are broken down by sector and program. The cost-effectiveness results and budgets for the MAP and RAP scenarios are also provided. Section 4.1 provides a description of the demand response methodology.

4.1 DEMAND RESPONSE PROGRAM OPTIONS

Table 4-1 provides a brief description of the demand response program options considered and identifies the eligible customer segment for each demand response program that was considered in this study. This includes direct load control (DLC) and rate design options.

TABLE 4-1 DEMAND RESPONSE PROGRAM OPTIONS AND ELIGIBLE MARKETS

Demand Response Program Option	Program Description	Eligible Markets
DLC AC (Switch)	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle). GDS looked at both the one-way communicating Cannon switches and two-way communicating L+G switches. Both switch options were assumed to be phased out as customers switch to thermostats over time.	Residential and C&I Customers
DLC AC (Thermostat)	The system operator can remotely raise the AC's thermostat set point during peak load conditions, lowering AC load. GDS looked at the three options CenterPoint currently has: a customer is given a free thermostat to participate along with an annual incentive, a customer is given a rebate through the marketplace or a storefront along with an annual incentive, or the customer brings an existing thermostat and is only given an annual incentive.	Residential and C&I Customers
DLC Pool Pumps	The swimming pool pump is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours.	Residential Customers
DLC Water Heaters	The water heater is remotely shut off by the system operator for periods normally ranging from 2 to 8 hours.	Residential and C&I Customers
Critical Peak Pricing with Enabling Technology	A retail rate in which an extra-high price for electricity is provided during critical periods (e.g. 100 hours) of the year. Prices can be fixed or fluctuate with the market. Market-based prices. are typically provided on a day-ahead basis, or an hour-ahead basis. Enabling technology, such as smart thermostat, is provided to the customer.	Residential and C&I Customers
Critical Peak Pricing without Enabling Technology	A retail rate in which an extra-high price for electricity is provided during critical periods (e.g. 100 hours) of the year. Prices can be fixed or fluctuate with the market. Market-based prices. are typically provided on a day-ahead basis, or an hour-ahead basis. Customer is not required to have enabling technology.	Residential and C&I Customers
Peak Time Rebates	Customers are given a rebate for less consumption during times selected as critical periods.	Residential and C&I Customers
Time of Use	A retail rate with different prices for usage during different blocks of time. Daily pricing blocks could include on-peak, mid-peak, and off-peak periods.	Residential and C&I Customers

Demand Response Program Option	Program Description	Eligible Markets
Real Time Pricing	A retail rate in which the price for electricity fluctuates hourly during all hours of the year. Prices are typically provided on a day-ahead basis, or an hour-ahead basis	C&I Customers

Double-counting savings from demand response programs that affect the same end uses is a common issue that must be addressed when calculating the demand response savings potential. For example, a direct load control (DLC) program of air conditioning and a rate program both assume load reduction of the customers' air conditioners. For this reason, it is typically assumed that customers cannot participate in programs that affect the same end uses. One cannot save a kW of load in a specific hour more than once. In general, the hierarchy of demand response programs is accounted for by subtracting the number participants in a higher priority program from the eligible market for a lower priority program. Table 4-2 shows the hierarchy for each sector, with 1 being the top priority. Note that only cost-effective programs are included in the hierarchy.

TABLE 4-2 DR HIERARCHY FOR EACH SECTOR

Order	Residential Hierarchy	C&I Hierarchy
1	Direct Load Control	Direct Load Control
2	Critical Peak Pricing with Enabling Technology	Critical Peak Pricing with Enabling Technology
3	Critical Peak Pricing without Enabling Technology	Critical Peak Pricing without Enabling Technology
4	Peak Time Rebate	N/A
5	Time of Use	N/A

4.1.1 Demand Response Potential Assessment Approach Overview

The analysis of demand response, where possible, closely followed the approach outlined for energy efficiency. The framework for assessing the cost-effectiveness of demand response programs is based *on A Framework for Evaluating the Cost-Effectiveness of Demand Response, prepared for the National Forum on the National Action Plan (NAPA) on Demand Response*.[7] Additionally, GDS reviewed the May 2017 National Standard Practice Manual published by the National Efficiency Screening Project.[8] GDS utilized this guide to define avoided ancillary services and energy and/or capacity price suppression benefits.

Direct load control and rate programs demand response analysis was conducted using the GDS Demand Response Model. GDS determined the estimated savings for each demand response program by performing a review of all benefits and cost associated with each program. A modeling approach that considers numerous required inputs for each program was used, including expected life, coincident peak (CP) kW load reductions, proposed incentive levels, program related expenses such as vendor service fees, marketing and evaluation cost and on-going O&M expenses.

The UCT was used to determine the cost-effectiveness of each demand response program. Benefits are based on avoided demand, energy (including load shifting), wholesale cost reductions and T&D costs. Costs include incremental program equipment costs (such as control switches or smart thermostats), fixed program capital costs (such as the cost of a central controller), program administrative, marketing, and evaluation costs. Incremental equipment program costs are included for both new and replacement units (such as control switches) to account for units that are replaced at the end of their useful life.

[7] Study was prepared by Synapse Energy Economics and the Regulatory Assistance Project, February 2013.
[8] National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, May 18, 2017, Prepared by The National Efficiency Screening Project

The demand response analysis includes estimates of technical, economic, and achievable potential. Achievable potential is broken into maximum achievable potential (MAP) and realistic achievable potential (RAP) in this study:

MAP represents an estimate of the maximum cost-effective demand response potential that can be achieved over the 18-year study period. For this study, this is defined as customer participation in demand response program options that reflect a "best practices" estimate of what could eventually be achieved. MAP assumes no barriers to effective delivery of programs.

RAP represents an estimate of the amount of demand response potential that can be realistically achieved over the 18-year study period. For this study, this is defined as achieving customer participation in demand response program options that reflect a realistic estimate of what could eventually be achieved assuming typical or "average" industry experience. RAP is a discounted MAP, by considering program barriers that limit participation, therefore reducing savings that could be achieved.

4.1.2 Avoided Costs

Demand response avoided costs were consistent with those utilized in the energy efficiency potential analysis and were provided by CenterPoint. The primary benefit of demand response is avoided generation capacity, resulting from a reduction in the need for new peaking generation capacity. Demand response can also produce energy related benefits. If the demand response option is considered "load shifting", such as direct load control of electric water heating, the consumption of energy is shifted from the control period to the period immediately following the period of control. For this study, GDS assumed that the energy is shifted with no loss of energy. If the program is not considered to be "load shifting" the measure is turned off during peak control hours, and the energy is saved altogether. Demand response programs can also potentially delay the construction of new transmission and distribution lines and facilities, which is reflected in avoided T&D costs.

4.1.3 Demand Response Program Assumptions

This section briefly discusses the general assumptions and sources used to complete the demand response potential analysis.

4.1.3.1 Direct Load Control Program Assumptions

Load Reduction: Demand reductions were based on load reductions found in CenterPoint's existing demand response programs, and various secondary data sources including the FERC and other industry reports, including demand response potential studies that conducted primary research. DLC and thermostat-based demand response options were typically calculated based on a per-unit kW demand reduction.

Useful Life: The useful life of a smart thermostat is assumed to be 15 years . Load control switches have a useful life of 15 years. This life was used for all direct load control measures in this study.

Program Costs: One-time program development costs included in the first year of the analysis for new programs. No program development costs are assumed for programs that already exist. Each new program includes an evaluation cost. It was assumed that there would be a cost of $50[9] per new participant for marketing for the DLC programs for RAP. Marketing costs are assumed to be 33.3% higher for MAP. All program costs were escalated each year by the general rate of inflation assumed for this study.

Saturation: The number of control units per participant was assumed to be 1 for all direct load control programs using switches (such as water heaters and air conditioning switches), because load control switches can control up to two units. However, for controllable thermostats, some participants have more than one

[9] TVA Potential Study Volume III: Demand Response Potential, Global Energy Partners, December 2011

thermostat. The average number of residential thermostats per single family home was assumed to be 1.72 thermostats.[10]

Program Adoption Levels: Long-term program adoption levels (or "steady state" participation) represent the enrollment rate once the fully achievable participation has been reached. GDS reviewed industry data and program adoption levels from several utility demand response programs. The main sources of participant rates are several studies completed by the Brattle Group. As noted earlier in this section, for direct load control programs, MAP participation rates rely on industry best adoption rates and RAP participation rates are based on industry average adoption levels. For the rate programs, the MAP steady-state participation rates assumed programs were opt-out based and RAP participation assumed opt-in status.

Customer participation in new demand response programs is assumed to reach the steady state take rate over a five-year period. The path to steady state customer participation follows an "S-shaped" curve, in which participation growth accelerates over the first half of the five-year period, and then slows over the second half of the period (see Figure 4-1). Existing programs have already gone through this ramp-up period, so they were escalated linearly to the final participation rate.

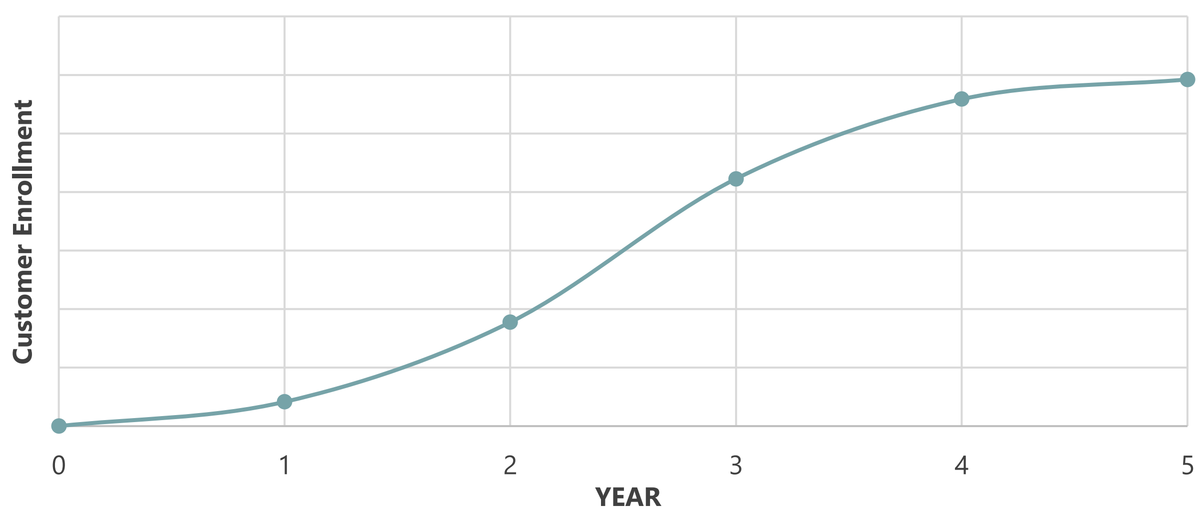


FIGURE 4-1: ILLUSTRATION OF S-SHAPED MARKET ADOPTION CURVE

4.1.3.2 Rate Program Assumptions

Load Reduction: Demand reductions were based on various secondary data sources including the FERC and other industry reports, including demand response potential studies that conducted primary research. Rate-based demand response options were typically assumed to reduce a percentage of the total facility coincident peak load.

Useful Life: The useful life of a smart thermostat is assumed to be 15 years. Smart thermostats were assumed to be the enabling technology required for the CPP with Enabling Technology program. For other rate programs that did not require any additional technology, the only equipment needed is a smart meter. The life of a smart meter was assumed to be 20 years.

Program Costs: One-time program development costs included in the first year of the analysis for new programs. No program development costs are assumed for programs that already exist. Each new program includes an evaluation cost, with evaluation cost for existing programs already being included in the

[10] Vectren Electric Baseline Study 2016

administration costs. It was assumed that there would be a cost of $50[11] per new participant for marketing for the DLC programs. Marketing costs are assumed to be 33.3% higher for MAP. All program costs were escalated each year by the general rate of inflation assumed for this study.

4.2 TOTAL DEMAND RESPONSE POTENTIAL

Figure 4-2 provides the technical and economic demand response potential across the 3-year, 6-year, and 18-year timeframes. The technical potential ranges from 437 MW to 531 MW, whereas the economic potential ranges from 383 MW to 454 MW, which indicates that most technical potential is cost-effective.

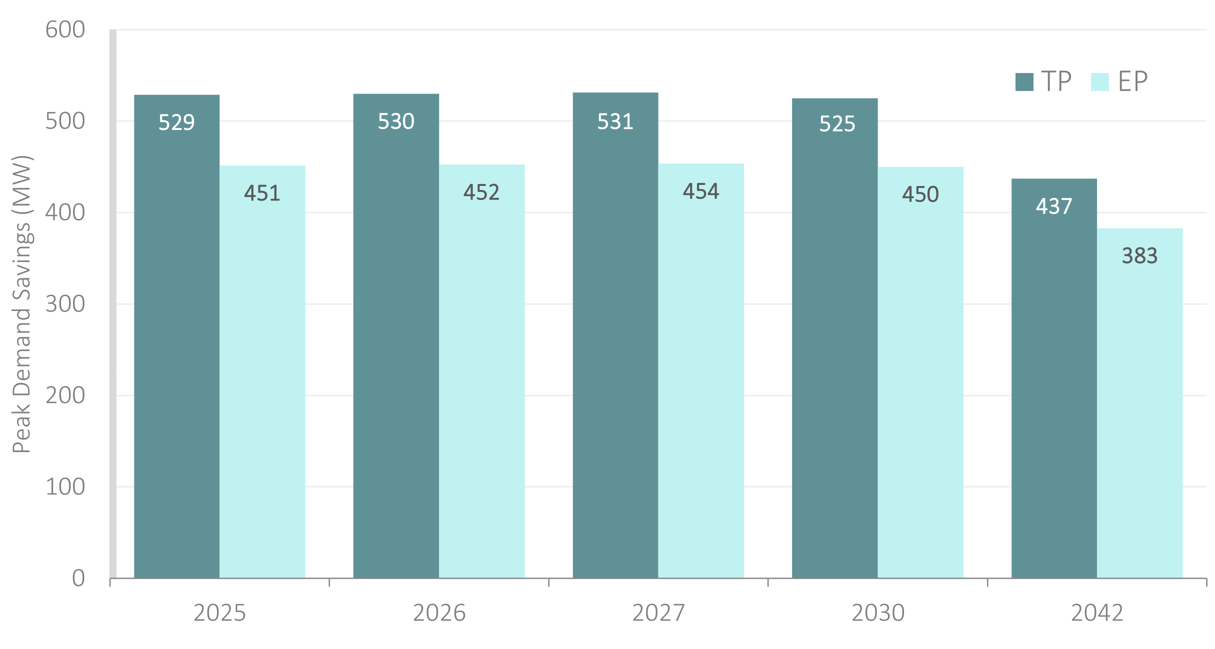


FIGURE 4-2: RESIDENTIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF SECTOR SALES)

Table 4-3 and Table 4-4 show the cumulative annual MAP and RAP savings for across the first six years of the study timeframe (2025-2030). These values are at the customer meter. The MAP assumes the maximum participation that would happen in the real-world, while the RAP considers additional barriers to program implementation that could limit the amount of savings achieved. The DLC Thermostat program options provide the most potential in the residential sector, and the Critical Peak Pricing and DLC Thermostat program options provide the most potential in the commercial sector. Overall, the MAP ranges from 23 MW to 41 MW over the next six years, and the RAP ranges from 16 MW to 27 MW over the next six years.

TABLE 4-3: MAP SAVINGS BY PROGRAM AND SECTOR

Sector	Program	2025	2026	2027	2028	2029	2030
Residential	DLC AC Thermostat (Utility Incentivized)	2.6	2.9	3.2	3.5	3.8	4.1
	DLC AC Thermostat (BYOT)	7.6	9.0	10.5	12.0	13.5	14.9
	DLC AC Switch	2.8	2.6	2.5	2.3	2.2	2.0
	DLC Water Heaters	5.0	4.9	4.7	4.5	4.4	4.2
	DLC Pool Pumps	0.1	0.1	0.1	0.1	0.1	0.1
	Critical Peak Pricing (with Enabling Technologies)	0.0	0.5	0.8	1.4	2.2	3.3

[11] TVA Potential Study6 Volume III: Demand Response Potential, Global Energy Partners, December 2011

Sector	Program	2025	2026	2027	2028	2029	2030
	Critical Peak Pricing (without Enabling Technologies)	0.0	0.3	0.5	0.8	1.3	2.0
	Peak Time Rebates	0.0	0.4	0.6	1.0	1.5	2.3
	Time of Use Rates	0.0	0.1	0.2	0.4	0.6	0.8
	Residential Total	**18.1**	**20.8**	**23.1**	**25.9**	**29.3**	**33.7**
Commercial	DLC AC Thermostat (Utility Incentivized)	0.4	0.4	0.5	0.5	0.6	0.6
	DLC AC Thermostat (BYOT)	1.1	1.3	1.5	1.8	2.0	2.2
	DLC AC Switch	2.8	2.6	2.5	2.3	2.2	2.0
	DLC Water Heaters	0.0	0.0	0.0	0.0	0.0	0.0
	Critical Peak Pricing (with Enabling Technologies)	0.0	0.3	0.4	0.7	1.1	1.7
	Critical Peak Pricing (without Enabling Technologies)	0.0	0.1	0.1	0.1	0.2	0.4
	Real Time Pricing	0.0	0.0	0.0	0.0	0.0	0.0
	Peak Time Rebates	0.0	0.0	0.0	0.0	0.0	0.0
	Time of Use Rates	0.0	0.0	0.0	0.0	0.0	0.0
	Commercial Total	**4.3**	**4.7**	**5.0**	**5.4**	**6.0**	**6.8**
All Sectors Combined		**22.3**	**25.5**	**28.1**	**31.3**	**35.3**	**40.5**

TABLE 4-4 RAP SAVINGS BY PROGRAM AND SECTOR

Sector	Program	2025	2026	2027	2028	2029	2030
Residential	DLC AC Thermostat (Utility Incentivized)	2.6	2.9	3.2	3.5	3.8	4.1
	DLC AC Thermostat (BYOT)	7.6	9.0	10.5	12.0	13.5	14.9
	DLC AC Switch	2.8	2.6	2.5	2.3	2.2	2.0
	DLC Water Heaters	0.5	0.5	0.5	0.5	0.4	0.4
	DLC Pool Pumps	0.1	0.1	0.1	0.1	0.1	0.1
	Critical Peak Pricing (with Enabling Technologies)	0.0	0.1	0.2	0.3	0.5	0.8
	Critical Peak Pricing (without Enabling Technologies)	0.0	0.1	0.1	0.2	0.3	0.4
	Peak Time Rebates	0.0	0.1	0.1	0.2	0.4	0.6
	Time of Use Rates	0.0	0.0	0.1	0.1	0.2	0.3
	Residential Total	**13.5**	**15.4**	**17.2**	**19.1**	**21.2**	**23.6**
Commercial	DLC AC Thermostat (Utility Incentivized)	0.4	0.4	0.5	0.5	0.6	0.6
	DLC AC Thermostat (BYOT)	1.1	1.3	1.5	1.8	2.0	2.2
	DLC AC Switch	0.4	0.4	0.4	0.3	0.3	0.3
	DLC Water Heaters	0.0	0.0	0.0	0.0	0.0	0.0
	Critical Peak Pricing (with Enabling Technologies)	0.0	0.1	0.1	0.2	0.3	0.5

Sector	Program	2025	2026	2027	2028	2029	2030
	Critical Peak Pricing (without Enabling Technologies)	0.0	0.0	0.0	0.0	0.1	0.1
	Real Time Pricing	0.0	0.0	0.0	0.0	0.0	0.0
	Peak Time Rebates	0.0	0.0	0.0	0.0	0.0	0.0
	Time of Use Rates	0.0	0.0	0.0	0.0	0.0	0.0
	Commercial Total	**1.9**	**2.2**	**2.5**	**2.8**	**3.2**	**3.7**
All Sectors Combined		**15.5**	**17.7**	**19.7**	**22.0**	**24.4**	**27.3**

Figure 4-3 shows the cumulative annual RAP (MW) by program in the residential sector. The two DLC AC Thermostat options provide the greatest amount of potential, with the Critical Peak Pricing options and Peak Time Rebates program options growing over time as well. The DLC AC Switch and DLC Water Heaters program options contribute some RAP early in the study timeframe before fading out over time. Overall the residential RAP grows from 14 MW in 2025 to 60 MW in 2042.

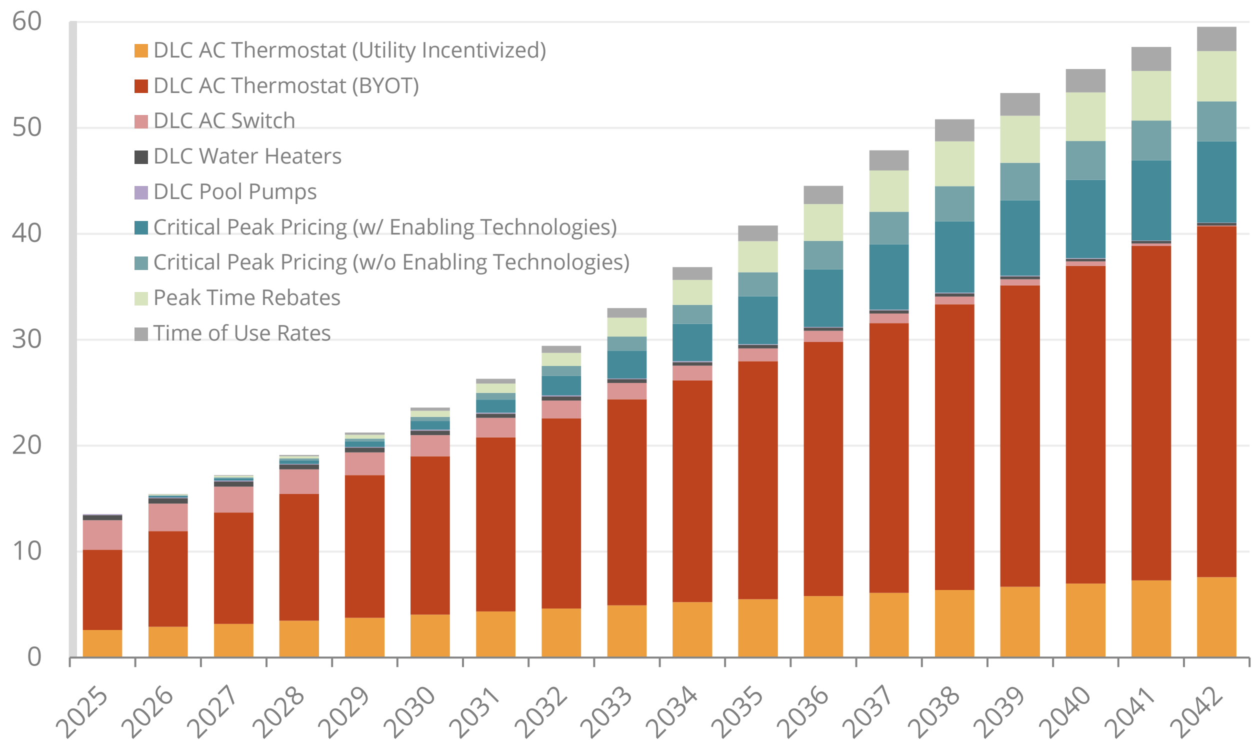


FIGURE 4-3 RESIDENTIAL SECTOR DEMAND RESPONSE RAP – BY PROGRAM

Figure 4-4 shows the cumulative annual RAP (MW) by program in the commercial sector. The two DLC AC Thermostat options provide the greatest amount of potential in the early years of the study timeframe, with the Critical Peak Pricing options growing significantly over time as well. Overall the commercial RAP grows from 2 MW in 2025 to 12 MW in 2042.

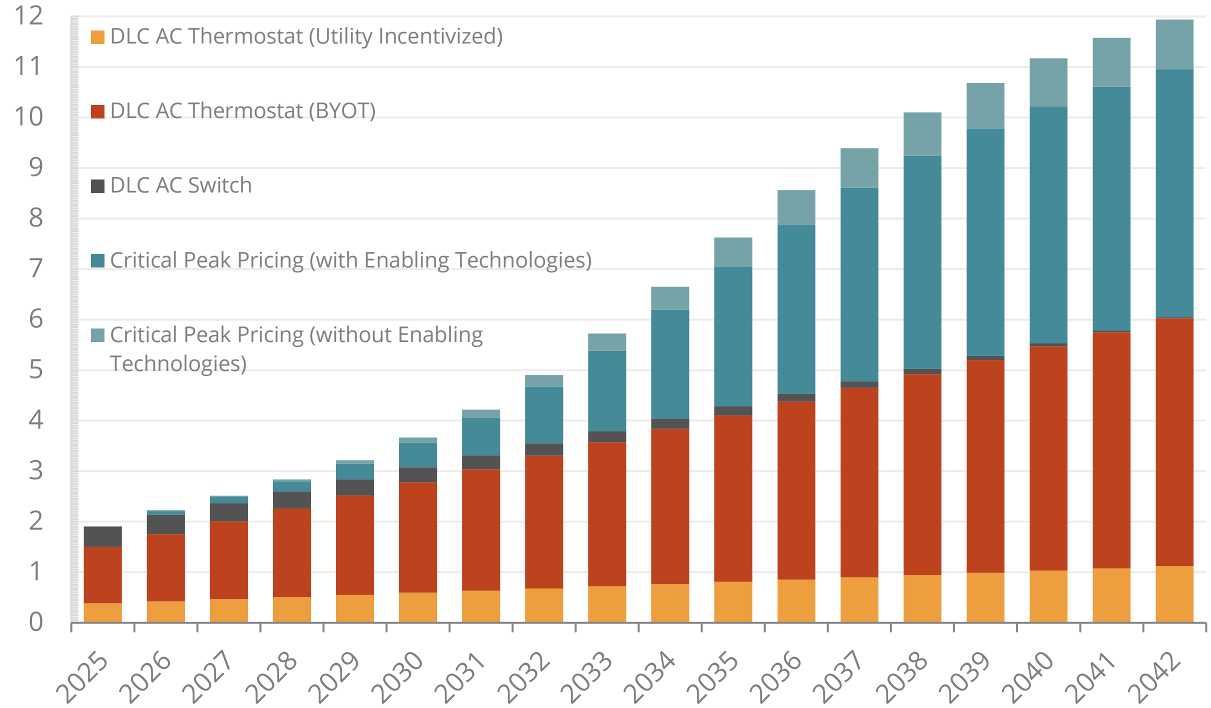


FIGURE 4-4 COMMERCIAL SECTOR DEMAND RESPONSE RAP – BY PROGRAM

4.3 BENEFITS & COSTS

Figure 4-5 provides the budget for the MAP and RAP scenarios, with a breakout shown for the residential and commercial sectors. For the MAP scenario, the budget ranges from $2.3 million to $4.2 million. For the RAP scenario, the budget ranges from $2.0 million to $3.3 million. The residential sector accounts for 81% of the total RAP budget and 83% of the total MAP budget.

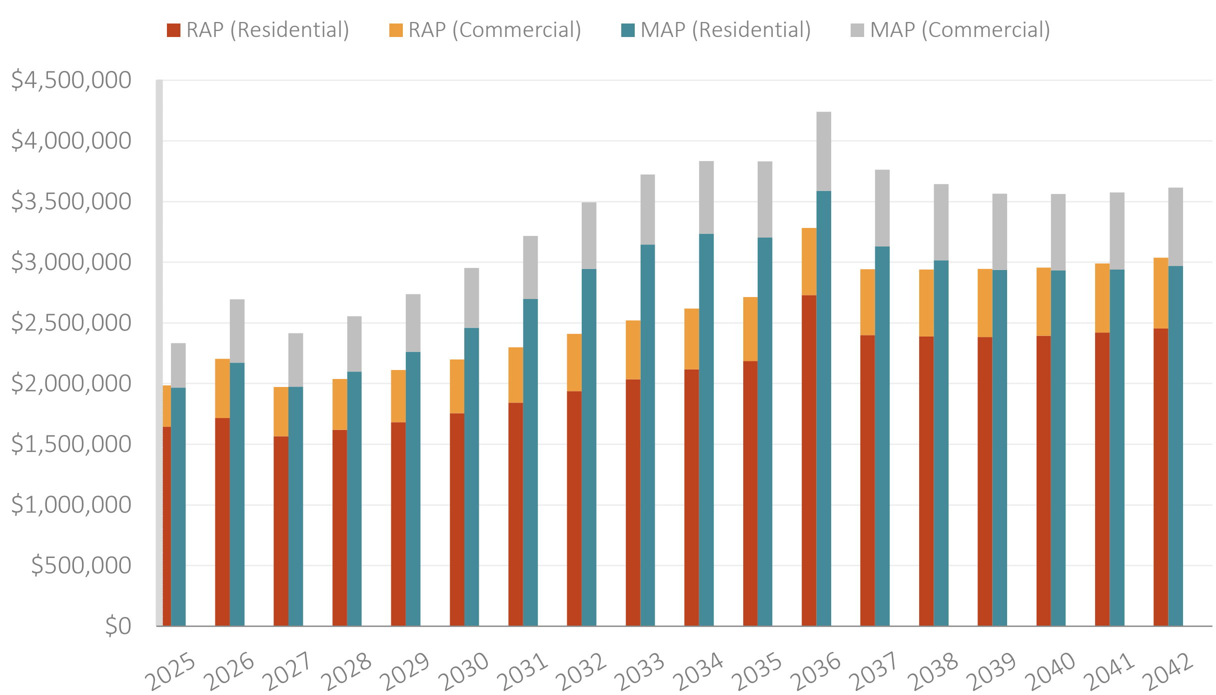


FIGURE 4-5: DEMAND RESPONSE ANNUAL BUDGETS – MAP AND RAP

Table 4-5 and Table 4-6 show the MAP and RAP residential NPVs of the total benefits, costs, and savings, along with the TRC ratio for each program for the length of the study.

TABLE 4-5 MAP NPV BENEFITS, COSTS, AND TRC RATIOS FOR EACH DEMAND RESPONSE PROGRAM

Sector	Program	NPV Benefits	NPV Costs	TRC Ratio
Residential	DLC AC Thermostat (Utility Incentivized)	8,787,424	2,454,193	3.58
	DLC AC Thermostat (BYOT)	34,120,895	11,869,557	2.87
	DLC AC Switch	3,125,746	3,356,379	0.93
	DLC Water Heaters	722,311	1,739,204	0.42
	DLC Pool Pumps	137,709	1,038,307	0.13
	Critical Peak Pricing (w/ Enabling Technologies)	18,300,247	1,537,084	11.91
	Critical Peak Pricing (w/o Enabling Technologies)	9,647,179	1,918,625	5.03
	Peak Time Rebates	8,709,602	1,684,783	5.17
	Time of Use Rates	2,266,606	1,294,072	1.75
	Residential Total	**$85,817,719**	**$26,892,204**	**3.19**
Commercial	DLC AC Thermostat (Utility Incentivized)	1,292,270	853,892	1.51
	DLC AC Thermostat (BYOT)	5,018,993	1,609,334	3.12
	DLC AC Switch	458,809	946,154	0.48
	DLC Water Heaters	17,189	695,563	0.02
	DLC Pool Pumps	9,764,337	690,926	14.13
	Critical Peak Pricing (w/ Enabling Technologies)	1,776,247	670,535	2.65
	Critical Peak Pricing (w/o Enabling Technologies)	134,411	923,789	0.15
	Peak Time Rebates	257,338	792,370	0.32
	Time of Use Rates	776,244	801,377	0.97
	Commercial Total	**$19,495,838**	**$7,983,939**	**2.44**
Residential & Commercial Total		**$105,313,558**	**$34,876,144**	**3.02**

TABLE 4-6 RAP NPV BENEFITS, COSTS, AND TRC RATIOS FOR EACH DEMAND RESPONSE PROGRAM

Sector	Program	NPV Benefits	NPV Costs	TRC Ratio
Residential	DLC AC Thermostat (Utility Incentivized)	8,787,424	1,883,531	4.67
	DLC AC Thermostat (BYOT)	34,120,895	9,574,949	3.56
	DLC AC Switch	3,125,746	2,680,835	1.17
	DLC Water Heaters	722,311	1,408,519	0.51
	DLC Pool Pumps	137,709	1,026,180	0.13
	Critical Peak Pricing (w/ Enabling Technologies)	4,858,797	720,738	6.74
	Critical Peak Pricing (w/o Enabling Technologies)	2,423,264	788,727	3.07
	Peak Time Rebates	3,103,847	966,077	3.21

Sector	Program	NPV Benefits	NPV Costs	TRC Ratio
	Time of Use Rates	1,546,670	1,034,266	1.50
	Residential Total	**$58,826,662**	**$20,083,823**	**2.93**
Commercial	DLC AC Thermostat (Utility Incentivized)	1,292,270	796,945	1.62
	DLC AC Thermostat (BYOT)	5,018,993	1,384,722	3.62
	DLC AC Switch	458,809	877,693	0.52
	DLC Water Heaters	17,189	689,725	0.02
	DLC Pool Pumps	3,018,612	550,641	5.48
	Critical Peak Pricing (w/ Enabling Technologies)	622,728	552,735	1.13
	Critical Peak Pricing (w/o Enabling Technologies)	450,715	930,878	0.48
	Peak Time Rebates	273,035	741,627	0.37
	Time of Use Rates	457,273	702,040	0.65
	Commercial Total	**$11,609,625**	**$7,227,008**	**1.61**
Residential & Commercial Total		**$70,436,288**	**$27,310,831**	**2.58**

5 Action Plan Summary

5.1 DEVELOPMENT OF DSM ACTION PLAN

The Market Potential Study serves as the basis for developing CenterPoint Indiana's DSM Action Plan. The DSM Action Plan is designed to extract the insights and data from the Market Potential Study and translate them into opportunities to deliver to customers. The DSM Action Plan provides guidance to mobilize the results of the Market Potential Study findings to provide a pathway to advance efforts that are reasonable and relevant in developing CenterPoint Indiana's portfolio in future years. The following section lays out the process, principles, and elements of CenterPoint Indiana's portfolio of programs. A summary of the results for the proposed portfolio is also provided.

5.2 DSM ACTION PLAN – GUIDING PRINCIPLES AND FRAMEWORK

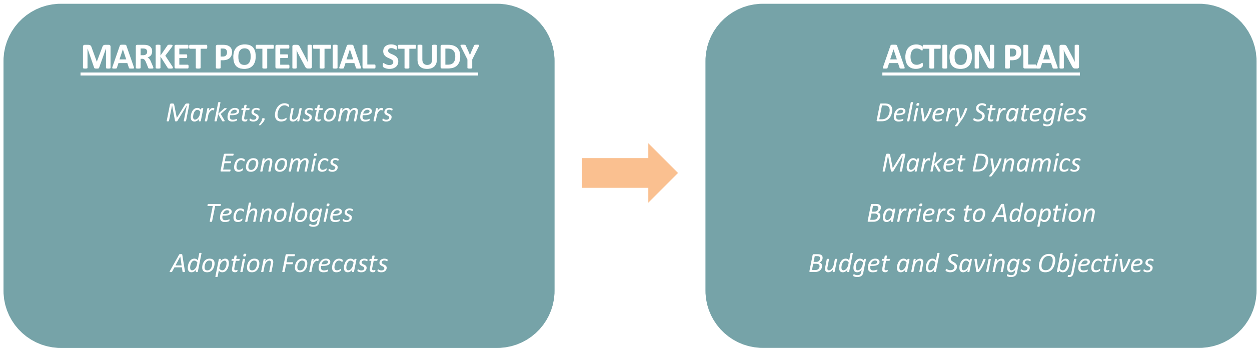
CenterPoint Indiana's DSM Action Plan was developed in accordance with a number of guiding principles and considerations. The process was built on using the most recent Market Potential Study as the foundation, and was then designed to incorporate industry best standards, implementer experiences, and projected changes in the market (such as codes and standards) in order to translate the insights and knowledge from the Market Potential Study into actionable energy efficiency programs for CenterPoint Indiana's planning purposes and customers.[12] Key planning guidelines and considerations used to frame the Action Plan are listed in Table 5-1 below.

TABLE 5-1: KEY PLANNING GUIDELINES IN DEVELOPING THE ACTION PLAN

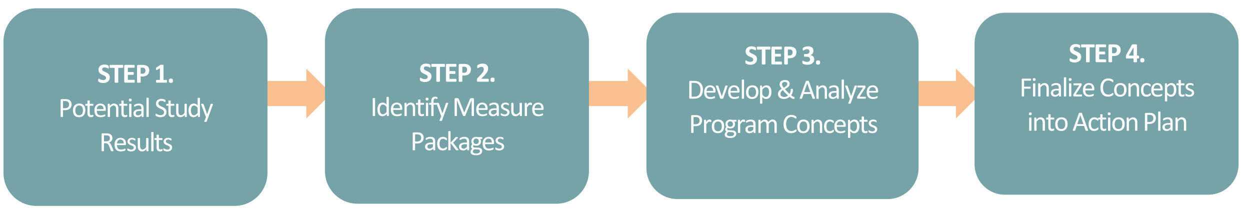
Plan Consideration	Description
Market Coverage	Consideration was given to crafting a portfolio of programs that offers opportunities for savings across all CenterPoint Indiana's customer groups.
Market Potential Study	The Action Plan is linked to the Market Potential Study.
Current Program Efforts	The Action Plan leverages current CenterPoint Indiana offerings to take advantage of market and trade ally understanding, to utilize existing market relationships, retain the relevant elements of programs already working well, and to continue promotional efforts.
Cost Effectiveness Analysis	All programs were screened for cost-effectiveness using the TRC test (except for the Income Qualified program)
Income-Qualified Programs	Program funding is linked to the Market Potential Study.
Program Costs and Budgets	A budget that characterizes the estimated costs for delivering programs to customers is presented for each program. The costs include all participant incentive, implementation, admin, and evaluation costs for each year of program operation.

The development of the Action Plan is designed to translate the insights and information from the broader Market Potential Study analysis into discrete and specific offerings for CenterPoint Indiana's customers. The Market Potential Study and the Action Plan are related and share common values, but the Action Plan provides more detail, specificity, and mobilization strategies. The Action Plan outlines recommended gas programs for 2025-2030, a shorter timeframe than the potential research. The Action Plan lays out how to achieve the savings uncovered in the potential study research, shifting the broad and high-level forecast of savings opportunities in the Market Potential Study results into specific and actionable savings opportunities. An illustrative view between the Market Potential Study and the Action Plan elements follows:

[12] The DSM Action Plan represents modified versions of the RAP from the MPS. The residential sector includes minor modifications to better align program measure mapping with current CenterPoint Indiana offerings. The C&I sector is a slightly enhanced version of RAP and yields approximately 8% higher savings and 24% higher costs over the DSM Action Plan timeframe.



The effort to develop CenterPoint Indiana's energy efficiency programs follows a grounded and sequential process. The process was built on applying the recent market potential analytics as a starting point and, from there, developing program offerings that cost-effectively meet CenterPoint Indiana's planning and program objectives. An illustrative review of the process follows.



5.3 DSM ACTION PLAN – PORTFOLIO SUMMARY

Figure 5-1 below provides an overview of the savings and budgets. The annual savings range from approximately 36,000 MWh to nearly 44,000 MWh with annual budgets ranging from $13.9 million to $17.9 million.

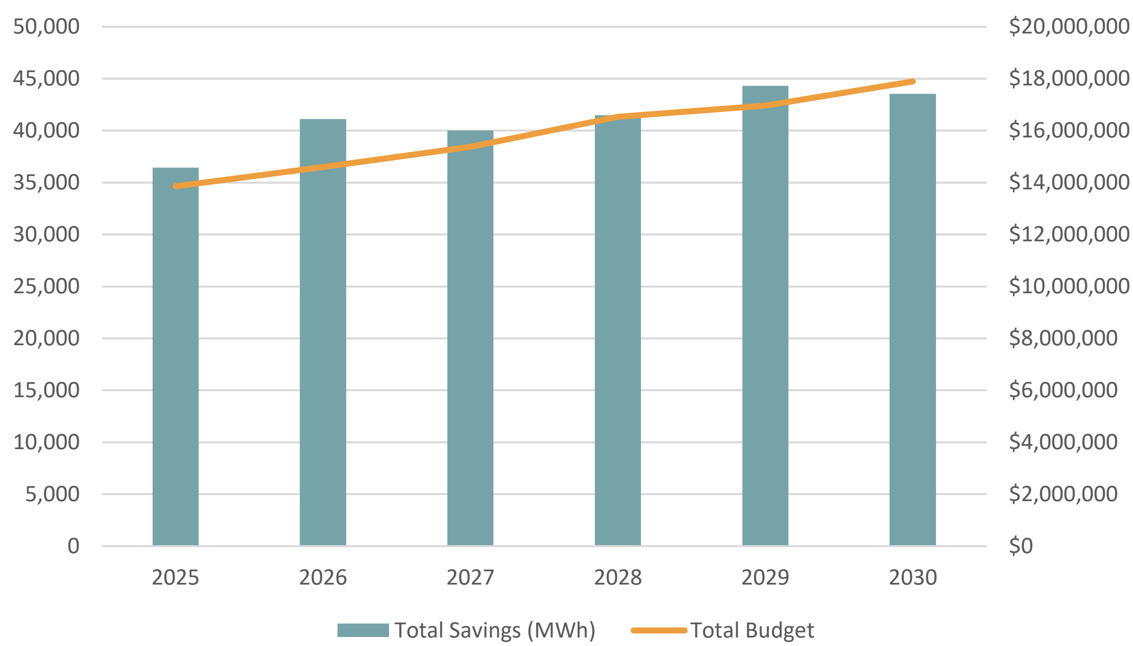


FIGURE 5-1: ANNUAL SAVINGS (MWH) AND BUDGET (2025-2030)

Table 5-2 below provides additional savings and budget detail by sector, as well as detailed indirect costs.13 The residential sector accounts for approximately 40% of total savings and 50% of total spending.

TABLE 5-2: ANNUAL SAVINGS AND BUDGET DETAIL BY SECTOR (2025-2030)

	2025	2026	2027	2028	2029	2030
Residential Savings (MWh)	16,131	17,446	16,895	17,052	18,331	17,624
C&I Savings (MWh)	20,305	23,659	23,121	24,420	25,985	25,915
Total Savings (MWh)	***36,436***	***41,105***	***40,016***	***41,472***	***44,316***	***43,538***
Residential Budget	$6,743,571	$7,259,632	$7,715,562	$8,160,427	$8,731,718	$9,194,431
C&I Budget	$5,489,577	$5,955,173	$6,221,726	$6,582,211	$6,693,151	$7,097,700
Outreach & Education	$561,116	$572,338	$583,785	$595,461	$607,370	$619,517
Contact Center	$69,842	$71,239	$72,664	$74,117	$75,599	$77,111
Online Audit	$47,571	$48,523	$49,493	$50,483	$51,493	$52,523
Evaluation	$645,584	$695,345	$732,161	$773,135	$807,967	$852,064
Market Potential Study	$300,000	$0	$0	$300,000	$0	$0
Total Budget	***$13,857,261***	***$14,602,251***	***$15,375,391***	***$16,535,833***	***$16,967,297***	***$17,893,346***

Table 5-3 below provides additional savings and budget detail by sector. Annual budgets range from $13.9 million to $17.9 million from 2025-2030. Incentives are the greatest expenditure by category, followed by delivery and implementation, indirect costs, and administrative costs. Refer to Chapter 6 for additional detail.

TABLE 5-3: ANNUAL BUDGET DETAIL BY SECTOR AND SPENDING CATEGORY (2025-2030)

	2025	2026	2027	2028	2029	2030
Residential						
Incentives	$3,675,161	$3,975,275	$4,164,544	$4,349,463	$4,506,756	$4,714,800
Delivery & Implementation	$2,637,032	$2,829,665	$3,073,741	$3,311,780	$3,691,705	$3,924,052
Admin	$431,378	$454,692	$477,276	$499,184	$533,257	$555,579
Residential Budget	**$6,743,571**	**$7,259,632**	**$7,715,562**	**$8,160,427**	**$8,731,718**	**$9,194,431**
Commercial						
Incentives	$3,172,801	$3,341,490	$3,408,169	$3,492,443	$3,452,667	$3,532,609
Delivery & Implementation	$1,865,199	$2,102,724	$2,262,624	$2,483,593	$2,604,165	$2,863,851
Admin	$451,577	$510,959	$550,934	$606,176	$636,319	$701,240
Commercial Budget	**$5,489,577**	**$5,955,173**	**$6,221,726**	**$6,582,211**	**$6,693,151**	**$7,097,700**
All Sectors						
Incentives	$6,847,962	$7,316,766	$7,572,713	$7,841,906	$7,959,423	$8,247,408
Delivery & Implementation	$4,502,231	$4,932,389	$5,336,365	$5,795,373	$6,295,870	$6,787,903
Admin	$882,955	$965,651	$1,028,210	$1,105,359	$1,169,576	$1,256,820
Indirect	$1,624,113	$1,387,445	$1,438,103	$1,793,195	$1,542,428	$1,601,215
Total Budget	**$13,857,261**	**$14,602,251**	**$15,375,391**	**$16,535,833**	**$16,967,297**	**$17,893,346**

[13] Indirect costs include outreach and education, contact center, online audit, and evaluation.

5.4 PORTFOLIO TARGETS BY YEAR

The following tables present the portfolio participation, savings, and costs targets by each program year.

TABLE 5-4: 2025 PORTFOLIO TARGETS

	Participants	Energy Savings (kWh)	Demand Savings (kW)	Incentives	Implementation	Admin	Total Budget
Residential							
Residential Prescriptive	2,952	620,886	297	$357,897	$114,419	$18,533	$490,848
Residential Midstream	1,963	1,271,863	581	$581,774	$518,820	$21,054	$1,121,647
Residential Marketplace	14,856	2,625,568	1,330	$1,082,814	$2,883	$37,474	$1,123,170
Residential Instant Rebate	2,319	810,272	48	$32,214	$68,091	$29,848	$130,153
Residential New Construction	209	76,496	43	$75,549	$14,912	$2,415	$92,876
Community Connections	1,767	311,197	203	$126,464	$118,236	$6,223	$250,923
Income Qualified Weatherization	2,413	443,552	303	$588,184	$191,509	$10,079	$789,772
Residential Behavioral	40,002	7,678,859	2,098	$908	$294,627	$116,300	$411,835
Appliance Recycling	1,071	671,801	86	$49,162	$157,115	$7,585	$213,861
Residential Emerging Markets Pilot	17,539	1,620,646	618	$401,918	$249,265	$40,374	$691,556
CVR – Residential	0	0	0	$0	$256,228	$12,843	$269,071
Smart Cycle	2,841	0	3	$56,811	$265,231	$74,359	$396,400
Bring Your Own Thermostat	8,242	0	8	$321,468	$401,120	$55,000	$777,588
Residential Subtotal	***96,174***	***16,131,139***	***5,618***	***$3,675,161***	***$2,652,455***	***$432,086***	***$6,759,702***
Commercial & Industrial							
Commercial Prescriptive	21,079	9,943,108	2,741	$1,280,711	$651,371	$162,843	$2,094,925
Commercial Custom	78	6,394,169	1,150	$685,440	$641,012	$160,253	$1,486,705
Small Business Energy Solutions	15,628	3,967,243	864	$1,206,650	$320,354	$80,089	$1,607,092
CVR – Commercial	0	0	0	$0	$230,723	$51,371	$282,094
Commercial & Industrial Subtotal	***36,786***	***20,304,520***	***4,755***	***$3,172,801***	***$1,843,460***	***$454,556***	***$5,470,817***
Indirect Costs							
Contact Center							$69,842
Online Audit							$47,571
Outreach							$561,116
Indirect Costs Subtotal							***$678,529***
Other Costs							
Evaluation							$645,452
Market Potential Study							$300,000
Other Costs Subtotal							***$945,452***
DSM Portfolio Totals	**132,960**	**36,435,659**	**10,372**	**$6,847,962**	**$4,495,915**	**$886,642**	**$13,854,500**

TABLE 5-5: 2026 PORTFOLIO TARGETS

	Participants	Energy Savings (kWh)	Demand Savings (kW)	Incentives	Implementation	Admin	Total Budget
Residential							
Residential Prescriptive	4,165	867,546	426	$507,931	$164,793	$26,692	$699,416
Residential Midstream	2,183	1,413,437	641	$643,888	$589,298	$23,914	$1,257,099
Residential Marketplace	15,029	2,505,155	1,339	$1,064,098	$2,843	$36,956	$1,103,896
Residential Instant Rebate	2,791	958,708	60	$38,486	$82,541	$36,182	$157,209
Residential New Construction	214	78,830	45	$80,517	$15,912	$2,577	$99,006
Community Connections	1,917	352,995	243	$154,431	$138,056	$7,266	$299,752
Income Qualified Weatherization	3,565	441,355	294	$601,877	$195,757	$10,303	$807,937
Residential Behavioral	47,304	7,596,136	2,062	$1,045	$301,284	$118,928	$421,257
Appliance Recycling	1,071	671,801	86	$49,162	$160,728	$7,759	$217,649
Residential Emerging Markets Pilot	18,402	1,754,890	694	$453,040	$269,711	$43,686	$766,437
CVR – Residential	5,097	1,328,231	1,011	$0	$344,113	$13,228	$357,341
Smart Cycle	3,151	0	3	$63,024	$233,406	$72,085	$368,515
Bring Your Own Thermostat	9,824	0	9	$317,778	$434,529	$56,210	$808,517
Residential Subtotal	***114,713***	***17,969,082***	***6,912***	***$3,975,275***	***$2,932,971***	***$455,786***	***$7,364,032***
Commercial & Industrial							
Commercial Prescriptive	21,977	10,326,534	2,962	$1,341,984	$696,126	$174,031	$2,212,141
Commercial Custom	97	7,977,395	1,455	$862,774	$828,242	$207,061	$1,898,077
Small Business Energy Solutions	15,458	3,931,082	866	$1,136,732	$325,895	$81,474	$1,544,101
CVR – Commercial	674	524,327	284	$0	$250,466	$52,913	$303,378
Commercial & Industrial Subtotal	***38,206***	***22,759,338***	***5,567***	***$3,341,490***	***$2,100,729***	***$515,478***	***$5,957,698***
Indirect Costs							
Contact Center							$71,239
Online Audit							$48,523
Outreach							$572,338
Indirect Costs Subtotal							***$692,100***
Other Costs							
Evaluation							$700,691
Market Potential Study							$0
Other Costs Subtotal							***$700,691***
DSM Portfolio Totals	**152,919**	**40,728,420**	**12,479**	**$7,316,766**	**$5,033,700**	**$971,264**	**$14,714,521**

TABLE 5-6: 2027 PORTFOLIO TARGETS

	Participants	Energy Savings (kWh)	Demand Savings (kW)	Incentives	Implementation	Admin	Total Budget
Residential							
Residential Prescriptive	4,530	952,995	464	$563,775	$187,049	$30,297	$781,121
Residential Midstream	2,378	1,537,465	693	$698,268	$655,200	$26,588	$1,380,055
Residential Marketplace	14,752	2,331,078	1,279	$1,002,954	$2,728	$35,467	$1,041,149
Residential Instant Rebate	3,258	1,109,820	73	$46,810	$97,957	$42,940	$187,708
Residential New Construction	213	79,310	44	$84,389	$16,620	$2,692	$103,701
Community Connections	2,130	412,859	317	$204,697	$166,521	$8,764	$379,982
Income Qualified Weatherization	4,421	470,929	315	$600,050	$215,146	$11,323	$826,520
Residential Behavioral	52,064	7,511,612	2,024	$1,200	$308,079	$121,610	$430,889
Appliance Recycling	1,071	671,801	86	$49,162	$164,425	$7,938	$221,525
Residential Emerging Markets Pilot	18,620	1,817,360	741	$491,068	$286,238	$46,362	$823,668
CVR – Residential	0	0	0	$0	$384,236	$13,625	$397,861
Smart Cycle	3,463	0	3	$69,253	$238,955	$73,713	$381,922
Bring Your Own Thermostat	11,415	0	11	$352,919	$494,016	$57,447	$904,382
Residential Subtotal	***118,313***	***16,895,229***	***6,050***	***$4,164,544***	***$3,217,171***	***$478,766***	***$7,860,482***
Commercial & Industrial							
Commercial Prescriptive	21,719	10,288,046	3,066	$1,364,528	$713,802	$178,451	$2,256,781
Commercial Custom	110	9,072,627	1,664	$1,000,185	$976,000	$244,000	$2,220,185
Small Business Energy Solutions	14,774	3,760,299	836	$1,043,455	$320,361	$80,090	$1,443,906
CVR – Commercial	0	0	0	$0	$283,279	$54,500	$337,779
Commercial & Industrial Subtotal	***36,603***	***23,120,971***	***5,566***	***$3,408,169***	***$2,293,443***	***$557,041***	***$6,258,652***
Indirect Costs							
Contact Center							$72,664
Online Audit							$49,493
Outreach							$583,785
Indirect Costs Subtotal							***$705,942***
Other Costs							
Evaluation							$741,254
Market Potential Study							$0
Other Costs Subtotal							***$741,254***
DSM Portfolio Totals	**154,916**	**40,016,201**	**11,616**	**$7,572,713**	**$5,510,614**	**$1,035,807**	**$15,566,329**

TABLE 5-7: 2028 PORTFOLIO TARGETS

	Participants	Energy Savings (kWh)	Demand Savings (kW)	Incentives	Implementation	Admin	Total Budget
Residential							
Residential Prescriptive	4,935	1,078,993	518	$661,776	$219,726	$35,589	$917,092
Residential Midstream	2,543	1,642,378	737	$744,124	$715,480	$29,034	$1,488,638
Residential Marketplace	13,962	2,105,012	1,162	$905,489	$2,536	$32,964	$940,988
Residential Instant Rebate	3,664	1,248,210	86	$57,485	$113,045	$49,554	$220,084
Residential New Construction	214	81,828	44	$89,620	$17,794	$2,882	$110,296
Community Connections	2,327	464,194	389	$255,186	$193,291	$10,173	$458,650
Income Qualified Weatherization	4,988	489,101	319	$603,539	$229,891	$12,100	$845,530
Residential Behavioral	56,315	7,427,133	1,985	$1,368	$315,021	$124,350	$440,739
Appliance Recycling	1,071	671,801	86	$49,162	$168,207	$8,120	$225,489
Residential Emerging Markets Pilot	18,273	1,843,573	771	$517,969	$297,512	$48,189	$863,671
CVR – Residential	0	0	0	$0	$376,075	$14,034	$390,109
Smart Cycle	3,775	0	3	$75,501	$244,672	$75,383	$395,556
Bring Your Own Thermostat	13,013	0	12	$388,244	$553,799	$58,710	$1,000,753
Residential Subtotal	***125,081***	***17,052,221***	***6,111***	***$4,349,463***	***$3,447,049***	***$501,082***	***$8,297,594***
Commercial & Industrial							
Commercial Prescriptive	20,727	10,153,038	3,247	$1,375,613	$726,184	$181,546	$2,283,343
Commercial Custom	131	10,798,876	1,996	$1,180,522	$1,200,377	$300,094	$2,680,993
Small Business Energy Solutions	13,610	3,467,768	774	$936,308	$304,571	$76,143	$1,317,021
CVR – Commercial	0	0	0	$0	$275,063	$56,135	$331,198
Commercial & Industrial Subtotal	***34,468***	***24,419,682***	***6,016***	***$3,492,443***	***$2,506,194***	***$613,918***	***$6,612,555***
Indirect Costs							
Contact Center							$74,117
Online Audit							$50,483
Outreach							$595,461
Indirect Costs Subtotal							***$720,061***
Other Costs							
Evaluation							$781,510
Market Potential Study							$300,000
Other Costs Subtotal							**$1,081,510**
DSM Portfolio Totals	**159,550**	**41,471,903**	**12,127**	**$7,841,906**	**$5,953,243**	**$1,115,000**	**$16,711,720**

TABLE 5-8: 2029 PORTFOLIO TARGETS

	Participants	Energy Savings (kWh)	Demand Savings (kW)	Incentives	Implementation	Admin	Total Budget
Residential							
Residential Prescriptive	5,290	1,217,625	568	$774,602	$256,963	$41,621	$1,073,186
Residential Midstream	2,679	1,728,605	772	$781,583	$769,891	$31,242	$1,582,716
Residential Marketplace	11,775	1,592,209	1,007	$738,591	$2,006	$26,073	$766,669
Residential Instant Rebate	3,955	1,358,296	99	$70,726	$126,389	$55,404	$252,519
Residential New Construction	226	89,105	46	$101,276	$20,150	$3,264	$124,689
Community Connections	3,666	647,368	477	$311,507	$276,051	$14,529	$602,087
Income Qualified Weatherization	6,011	516,760	338	$602,056	$249,775	$13,146	$864,977
Residential Behavioral	60,043	7,342,957	1,945	$1,540	$322,122	$127,153	$450,815
Appliance Recycling	1,071	671,801	86	$49,162	$172,076	$8,307	$229,544
Residential Emerging Markets Pilot	21,302	2,360,975	875	$569,952	$390,532	$63,255	$1,023,739
CVR – Residential	3,182	554,744	422	$0	$410,842	$14,455	$425,297
Smart Cycle	4,089	0	4	$81,780	$250,874	$77,126	$409,780
Bring Your Own Thermostat	14,621	0	13	$423,983	$614,070	$60,002	$1,098,055
Residential Subtotal	***137,910***	***18,080,443***	***6,654***	***$4,506,756***	***$3,861,741***	***$535,577***	***$8,904,074***
Commercial & Industrial							
Commercial Prescriptive	19,243	9,639,114	3,198	$1,337,248	$710,428	$177,607	$2,225,284
Commercial Custom	143	11,834,726	2,159	$1,296,488	$1,360,806	$340,201	$2,997,495
Small Business Energy Solutions	12,093	3,087,629	697	$818,931	$280,470	$70,117	$1,169,518
CVR – Commercial	713	988,633	606	$0	$348,106	$57,819	$405,925
Commercial & Industrial Subtotal	***32,192***	***25,550,102***	***6,659***	***$3,452,667***	***$2,699,810***	***$645,745***	***$6,798,222***
Indirect Costs							
Contact Center							$75,599
Online Audit							$51,493
Outreach							$607,370
Indirect Costs Subtotal							***$734,462***
Other Costs							
Evaluation							$821,838
Market Potential Study							$0
Other Costs Subtotal							***$821,838***
DSM Portfolio Totals	**170,103**	**43,630,545**	**13,313**	**$7,959,423**	**$6,561,550**	**$1,181,322**	**$17,258,595**

TABLE 5-9: 2030 PORTFOLIO TARGETS

	Participants	Energy Savings (kWh)	Demand Savings (kW)	Incentives	Implementation	Admin	Total Budget
Residential							
Residential Prescriptive	6,668	1,441,958	747	$924,015	$313,462	$50,772	$1,288,249
Residential Midstream	2,787	1,798,099	800	$811,400	$818,866	$33,229	$1,663,495
Residential Marketplace	10,469	1,383,030	839	$621,958	$1,782	$23,170	$646,910
Residential Instant Rebate	4,095	1,430,293	111	$86,634	$136,968	$60,041	$283,642
Residential New Construction	250	102,512	51	$121,111	$24,121	$3,907	$149,139
Community Connections	3,744	662,572	518	$342,823	$291,315	$15,332	$649,470
Income Qualified Weatherization	7,770	524,654	345	$610,567	$260,589	$13,715	$884,871
Residential Behavioral	63,262	7,262,069	1,908	$1,707	$329,396	$130,025	$461,127
Appliance Recycling	1,071	671,801	86	$49,162	$176,033	$8,498	$233,693
Residential Emerging Markets Pilot	23,692	2,346,687	1,058	$597,049	$398,097	$64,480	$1,059,626
CVR – Residential	0	0	0	$0	$448,682	$14,888	$463,571
Smart Cycle	4,405	0	4	$88,105	$257,641	$78,953	$424,698
Bring Your Own Thermostat	16,241	0	15	$460,270	$674,977	$61,322	$1,196,570
Residential Subtotal	***144,454***	***17,623,675***	***6,481***	***$4,714,800***	***$4,131,928***	***$558,333***	***$9,405,060***
Commercial & Industrial							
Commercial Prescriptive	18,138	9,291,629	3,129	$1,289,422	$704,462	$176,115	$2,169,999
Commercial Custom	167	13,937,265	2,500	$1,519,017	$1,651,219	$412,805	$3,583,041
Small Business Energy Solutions	10,412	2,685,738	608	$724,170	$255,709	$63,927	$1,043,806
CVR – Commercial	0	0	0	$0	$382,901	$59,554	$442,455
Commercial & Industrial Subtotal	***28,718***	***25,914,632***	***6,238***	***$3,532,609***	***$2,994,291***	***$712,401***	***$7,239,301***
Indirect Costs							
Contact Center							$77,111
Online Audit							$52,523
Outreach							$619,517
Indirect Costs Subtotal							***$749,151***
Other Costs							
Evaluation							$869,676
Market Potential Study							$0
Other Costs Subtotal							***$869,676***
DSM Portfolio Totals	**173,172**	**43,538,308**	**12,718**	**$8,247,408**	**$7,126,220**	**$1,270,734**	**$18,263,188**

6 Action Plan Program Detail

The 2025-2030 Action Plan is built from currently offered existing programs by CenterPoint Indiana to its electric customers. The programs in the 2025-2030 Action Plan include:

Residential Programs:

- Residential Prescriptive Program (Prescriptive, Midstream, Marketplace, Instant Rebates)
- Residential New Construction Program
- Income Qualified Weatherization
- Community Connections
- Residential Behavior Savings Program
- Appliance Recycling
- Bring Your Own Thermostat (BYOT)
- Smart Cycle
- Residential Emerging Markets Program
- Conservation Voltage Reduction

Business Programs

- Commercial Prescriptive (Rx) Rebates Program
- Commercial Small Business Energy Solutions (SBES) Program
- Commercial Custom Program

6.1 RESIDENTIAL PRESCRIPTIVE PROGRAM

Program Description: The program includes the Residential Prescriptive, Residential Midstream, Online Marketplace, and Instant Rebates pathways (each is a separate program under the Residential Prescriptive Program umbrella). The program is designed to incent customers to purchase energy efficient equipment by covering part of the incremental cost. The program also offers home weatherization rebates to residential customers for attic insulation.

The following tables indicate the measures in each of the programs, along with average incentives, and savings per unit.

TABLE 6-1: RESIDENITAL PRESCRIPTIVE PROGRAM MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Wifi Thermostat	$41.15	207.1	0.00
Smart Thermostat	$61.84	216.7	0.00
Attic Insulation	$445.51	636.3	0.24
ENERGY STAR Dehumidifier	$35.00	134.4	0.03
AC Tune Up	$25.00	74.2	0.12
ASHP Tune Up	$50.00	239.8	0.12
ENERGY STAR Clothes Washer	$50.00	157.6	0.02
Duct Sealing	$240.00	105.1	0.15
Wall Insulation	$450.00	610.2	0.05
Heat Pump Water Heater	$500.00	1,543.7	0.21

TABLE 6-2: RESIDENITAL MIDSTREAM PROGRAM MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Air Source Heat Pump 16 SEER	$200.00	4,037.8	0.14
Air Source Heat Pump 17 SEER	$300.00	3,939.7	0.20

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Air Source Heat Pump 18 SEER	$400.00	3,864.7	0.25
Air Source Heat Pump 21 SEER	$400.00	3,804.2	0.38
Central Air Conditioner 15 SEER	$200.00	110.5	0.12
Central Air Conditioner 16 SEER	$200.00	214.6	0.23
Central Air Conditioner 17 SEER	$300.00	292.4	0.32
Central Air Conditioner 18 SEER	$400.00	368.2	0.40
Ductless Heat Pump 17 SEER 9.5 HSPF	$373.02	3,621.3	0.29
Ductless Heat Pump 19 SEER 9.5 HSPF	$357.08	3,316.5	0.44
Ductless Heat Pump 21 SEER 10.0 HSPF	$536.63	3,791.6	0.58
Ductless Heat Pump 23 SEER 10.0 HSPF	$566.55	3,615.7	0.67

TABLE 6-3: RESIDENITAL MARKETPLACE PROGRAM MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
ENERGY STAR Air Purifier	$50.00	303.0	0.03
ENERGY STAR Dehumidifier	$35.00	206.2	0.05
Smart Thermostat	$61.84	274.3	0.00
Wifi Thermostat	$41.15	262.2	0.00
Air Sealing	$200.00	273.1	0.28
Kitchen Faucet Aerator 1.5 gpm	$1.25	141.3	0.01
Bathroom Aerator 1.0 gpm	$1.25	35.5	0.00

TABLE 6-4: RESIDENITAL INSTANT REBATE PROGRAM MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
ENERGY STAR Dehumidifier	$35.00	170.8	0.04
Smart Thermostat	$75.00	825.7	0.00
Heat Pump Water Heater	$500.00	2,389.2	0.33
Low Flow Showerhead 1.5 gpm	$1.25	321.1	0.01

Eligible Customers: The program is available to all residential customers located in the CenterPoint Indiana electric service territory. For the equipment rebates, the applicant must reside in a single-family home or multi-family complex with up to 12 units. Only single-family homes are eligible for insulation measures.

Marketing: The marketing plan includes program specific marketing materials that will target contractors and trade allies in the Heating, Ventilation and Air Conditioning (HVAC) industry. The HVAC industry will be marketed by using targeted direct marketing, direct contact by the program vendor personnel, trade shows and trade association outreach. The program will be promoted through trade allies, distributors, manufacturers, industry organizations and appropriate retail outlets. CenterPoint Indiana will also use web banners, bill inserts, and mass market advertising. Program marketing directs customers and contractors to the CenterPoint Indiana website or call center for information.

The Midstream marketing plan will target distributors through direct outreach to contractor trade networks. Co-branded materials will be available to participating distributors to draw attention to, and provide education on, the HVAC measures within the program. Fact Sheets will also be created to keep the program top of mind.

The program implementation contractor will provide program approved verbiage for email blast content for distributors to promote the program to their contractors.

Program Delivery Channels: CenterPoint Indiana will oversee the program and will partner with a program implementation contractor for the Prescriptive and Midstream pathways. CenterPoint Indiana will also oversee Marketplace and Instant Rebates and will partner with a program implementation contractor. Vendors will work with local contractors to deliver the program.

Evaluation: CenterPoint Indiana will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint Indiana is not expected to evaluate the program every year but will evaluate the program at least once every three years.

Estimated Participation, Savings, and Budgets: The following four tables provide the measure-level annual participation, incentive budget, and savings for each program under the Residential Prescriptive program umbrella. The fifth table provides program-level budget summaries and a total for the Residential Prescriptive program, with all four pathways aggregated.

TABLE 6-5: RESIDENTIAL PRESCRIPTIVE PROGRAM SUMMARY

Measure	2025	2026	2027	2028	2029	2030
Wifi Thermostat						
Participation	509	671	671	636	572	492
Incentive Budget	$20,926	$27,609	$27,609	$26,158	$23,544	$20,234
Projected kWh Savings	105,326	138,965	138,965	131,658	118,504	101,844
Projected kW Savings	0	0	0	0	0	0
Smart Thermostat						
Participation	319	420	420	398	358	308
Incentive Budget	$19,700	$25,992	$25,992	$24,625	$22,165	$19,049
Projected kWh Savings	69,026	91,071	91,071	86,283	77,662	66,744
Projected kW Savings	0	0	0	0	0	0
Attic Insulation						
Participation	374	503	561	694	838	973
Incentive Budget	$167,557	$226,755	$251,636	$305,942	$371,187	$433,217
Projected kWh Savings	246,891	330,498	361,820	436,536	525,109	607,654
Projected kW Savings	94	126	137	169	202	233
ENERGY STAR Dehumidifier						
Participation	53	90	122	163	217	284
Incentive Budget	1,861	3,162	4,267	5,717	7,591	9,952
Projected kWh Savings	7,167	12,160	16,390	21,941	29,120	38,179
Projected kW Savings	2	3	4	5	7	9
AC Tune Up						
Participation	1,037	1,440	1,520	1,520	1,440	2,283
Incentive Budget	25,915	35,990	37,988	37,988	35,990	57,063
Projected kWh Savings	76,956	106,872	112,804	112,804	106,872	169,447
Projected kW Savings	125	174	184	184	174	276
ASHP Tune Up						
Participation	37	57	69	80	89	129
Incentive Budget	1,825	2,856	3,458	4,024	4,471	6,456
Projected kWh Savings	8,753	13,694	16,583	19,295	21,437	30,959
Projected kW Savings	4	7	8	9	10	15

Measure	2025	2026	2027	2028	2029	2030
ENERGY STAR Clothes Washer						
Participation	186	314	420	556	728	937
Incentive Budget	9,299	15,689	20,984	27,794	36,376	46,866
Projected kWh Savings	29,304	49,441	66,124	87,585	114,629	147,685
Projected kW Savings	4	7	9	12	16	20
Duct Sealing						
Participation	417	634	700	824	964	1,152
Incentive Budget	100,176	152,080	168,085	197,821	231,348	276,426
Projected kWh Savings	44,005	69,267	75,896	86,562	98,982	118,312
Projected kW Savings	62	102	112	125	142	171
Wall Insulation						
Participation	2	2	2	3	3	4
Incentive Budget	682	913	1,005	1,258	1,523	1,773
Projected kWh Savings	952	1,262	1,376	1,706	2,046	2,358
Projected kW Savings	0	0	0	0	0	0
Heat Pump Water Heater						
Participation	20	34	46	61	81	106
Incentive Budget	$9,956	$16,886	$22,751	$30,449	$40,408	$52,979
Projected kWh Savings	32,507	54,315	71,967	94,624	123,264	158,776
Projected kW Savings	4	7	10	13	17	22

TABLE 6-6: RESIDENTIAL MIDSTREAM PROGRAM SUMMARY

Measure	2025	2026	2027	2028	2029	2030
Air Source Heat Pump 16 SEER						
Participation	19	21	23	24	26	26
Incentive Budget	$3,828	$4,235	$4,584	$4,872	$5,103	$5,282
Projected kWh Savings	77,288	85,493	92,544	98,367	103,019	106,640
Projected kW Savings	3	3	3	4	4	4
Air Source Heat Pump 17 SEER						
Participation	15	16	18	19	20	20
Incentive Budget	$4,392	$4,859	$5,259	$5,590	$5,855	$6,060
Projected kWh Savings	57,680	63,803	69,066	73,411	76,884	79,585
Projected kW Savings	3	3	3	4	4	4
Air Source Heat Pump 18 SEER						
Participation	13	15	16	17	18	18
Incentive Budget	$5,289	$5,851	$6,333	$6,732	$7,050	$7,298
Projected kWh Savings	51,102	56,527	61,189	65,040	68,116	70,509
Projected kW Savings	3	4	4	4	4	5
Air Source Heat Pump 21 SEER						
Participation	17	19	20	21	23	23
Incentive Budget	$6,753	$7,470	$8,086	$8,595	$9,001	$9,318
Projected kWh Savings	64,226	71,044	76,903	81,742	85,608	88,616
Projected kW Savings	6	7	8	8	9	9

Measure	2025	2026	2027	2028	2029	2030
Central Air Conditioner 15 SEER						
Participation	351	409	464	513	555	590
Incentive Budget	$70,274	$81,822	$92,762	$102,609	$111,072	$118,061
Projected kWh Savings	38,811	45,189	51,231	56,669	61,343	65,203
Projected kW Savings	43	49	56	62	67	71
Central Air Conditioner 16 SEER						
Participation	423	480	531	575	611	640
Incentive Budget	$84,671	$95,993	$106,183	$114,940	$122,173	$127,951
Projected kWh Savings	90,863	103,012	113,948	123,346	131,107	137,308
Projected kW Savings	98	111	123	133	141	148
Central Air Conditioner 17 SEER						
Participation	495	536	570	597	618	634
Incentive Budget	$148,538	$160,789	$170,906	$178,989	$185,279	$190,073
Projected kWh Savings	144,768	156,708	166,568	174,446	180,576	185,249
Projected kW Savings	159	172	182	191	198	203
Central Air Conditioner 18 SEER						
Participation	468	506	538	563	583	598
Incentive Budget	$187,048	$202,475	$215,215	$225,394	$233,314	$239,351
Projected kWh Savings	172,172	186,373	198,099	207,469	214,759	220,316
Projected kW Savings	189	204	217	227	235	241
Ductless Heat Pump 17 SEER 9.5 HSPF						
Participation	38	43	47	51	54	57
Incentive Budget	$13,879	$15,791	$17,537	$19,070	$20,375	$21,461
Projected kWh Savings	139,076	156,049	171,151	184,157	195,065	204,081
Projected kW Savings	11	12	14	15	16	16
Ductless Heat Pump 19 SEER 9.5 HSPF						
Participation	49	55	61	66	70	73
Incentive Budget	$17,186	$19,550	$21,707	$23,600	$25,212	$26,557
Projected kWh Savings	164,514	184,677	202,627	218,095	231,077	241,819
Projected kW Savings	21	24	27	29	30	32
Ductless Heat Pump 21 SEER 10.0 HSPF						
Participation	36	41	44	48	50	53
Incentive Budget	$19,016	$21,473	$23,693	$25,626	$27,266	$28,632
Projected kWh Savings	135,679	152,580	167,702	180,787	191,806	200,940
Projected kW Savings	21	23	26	27	29	30
Ductless Heat Pump 23 SEER 10.0 HSPF						
Participation	38	42	46	49	52	54
Incentive Budget	$20,898	$23,582	$26,003	$28,106	$29,884	$31,356
Projected kWh Savings	135,682	151,982	166,436	178,850	189,245	197,832
Projected kW Savings	25	28	31	33	35	37

TABLE 6-7: RESIDENTIAL MARKETPLACE PROGRAM SUMMARY

Measure	2025	2026	2027	2028	2029	2030
ENERGY STAR Air Purifier						
Participation	210	238	264	286	304	320
Incentive Budget	$10,507	$11,918	$13,190	$14,291	$15,216	$15,979
Projected kWh Savings	63,674	72,225	79,934	86,606	92,210	96,832
Projected kW Savings	7	8	9	10	11	11
ENERGY STAR Dehumidifier						
Participation	5	6	7	9	11	14
Incentive Budget	$178	$215	$253	$302	$376	$486
Projected kWh Savings	1,048	1,266	1,489	1,778	2,214	2,865
Projected kW Savings	0	0	0	0	1	1
Smart Thermostat						
Participation	1,159	884	663	491	0	0
Incentive Budget	$71,690	$54,641	$40,994	$30,393	$0	$0
Projected kWh Savings	317,965	242,349	181,821	134,801	0	0
Projected kW Savings	0	0	0	0	0	0
Wifi Thermostat						
Participation	1,850	1,410	1,058	785	0	0
Incentive Budget	$76,152	$58,042	$43,546	$32,285	$0	$0
Projected kWh Savings	485,179	369,797	277,439	205,691	0	0
Projected kW Savings	0	0	0	0	0	0
Low Flow Showerhead 1.5 gpm						
Participation	4,577	4,647	4,473	4,089	3,566	2,983
Incentive Budget	$915,468	$929,477	$894,612	$817,840	$713,130	$596,552
Projected kWh Savings	1,275,899	1,283,838	1,224,406	1,109,050	958,519	794,668
Projected kW Savings	1,294	1,300	1,237	1,118	965	799
Kitchen Faucet Aerator 1.5 gpm						
Participation	2,188	2,432	2,570	2,575	2,449	2,220
Incentive Budget	$2,735	$3,041	$3,213	$3,219	$3,061	$2,774
Projected kWh Savings	309,069	343,627	363,074	363,787	345,966	313,552
Projected kW Savings	15	17	18	18	17	16
Bathroom Aerator 1.0 gpm						
Participation	4,866	5,411	5,717	5,727	5,446	4,933
Incentive Budget	$6,083	$6,763	$7,146	$7,159	$6,807	$6,167
Projected kWh Savings	172,734	192,053	202,915	203,300	193,300	175,113
Projected kW Savings	13	14	15	15	14	13

TABLE 6-8: RESIDENTIAL INSTANT REBATE PROGRAM SUMMARY

Measure	2025	2026	2027	2028	2029	2030
ENERGY STAR Dehumidifier						
Participation	274	352	443	545	652	759
Incentive Budget	$9,574	$12,322	$15,521	$19,074	$22,825	$26,575
Projected kWh Savings	46,721	60,135	75,743	93,084	111,387	129,690
Projected kW Savings	11	14	17	21	25	29

Measure	2025	2026	2027	2028	2029	2030
Smart Thermostat						
Participation	101	80	63	48	36	26
Incentive Budget	$7,541	$6,025	$4,688	$3,573	$2,681	$1,987
Projected kWh Savings	83,023	66,334	51,615	39,340	29,515	21,882
Projected kW Savings	0	0	0	0	0	0
Heat Pump Water Heater						
Participation	25	34	46	62	82	108
Incentive Budget	$12,700	$17,233	$23,219	$31,076	$41,239	$54,069
Projected kWh Savings	64,128	85,721	113,579	149,337	194,538	250,584
Projected kW Savings	9	12	16	20	27	34
Low Flow Showerhead 1.5 gpm						
Participation	1,919	2,325	2,706	3,009	3,185	3,201
Incentive Budget	$2,399	$2,906	$3,382	$3,762	$3,981	$4,002
Projected kWh Savings	616,399	746,518	868,883	966,449	1,022,856	1,028,137
Projected kW Savings	28	34	40	45	47	47

TABLE 6-9: RESIDENTIAL PRESCRIPTIVE PROGRAM BUDGET SUMMARY

	2025	2026	2027	2028	2029	2030
Prescriptive						
Incentives	$357,897	$507,931	$563,775	$661,776	$774,602	$924,015
Delivery & Implementation	$114,419	$164,793	$187,049	$219,726	$256,963	$313,462
Admin	$18,533	$26,692	$30,297	$35,589	$41,621	$50,772
Total Budget	**$490,848**	**$699,416**	**$781,121**	**$917,092**	**$1,073,186**	**$1,288,249**
Participation	2,952	4,165	4,530	4,935	5,290	6,668
Savings (kWh)	620,886	867,546	952,995	1,078,993	1,217,625	1,441,958
Demand Savings (kW)	297	426	464	518	568	747
Weighted Program EUL	17.4	17.2	17.0	17.3	17.6	17.1
NTG	78%	78%	78%	77%	77%	77%
Midstream						
Incentives	$581,774	$643,888	$698,268	$744,124	$781,583	$811,400
Delivery & Implementation	$518,820	$589,298	$655,200	$715,480	$769,891	$818,866
Admin	$21,054	$23,914	$26,588	$29,034	$31,242	$33,229
Total Budget	**$1,121,647**	**$1,257,099**	**$1,380,055**	**$1,488,638**	**$1,582,716**	**$1,663,495**
Participation	1,963	2,183	2,378	2,543	2,679	2,787
Savings (kWh)	1,271,863	1,413,437	1,537,465	1,642,378	1,728,605	1,798,099
Demand Savings (kW)	581	641	693	737	772	800
Weighted Program EUL	18.0	18.0	18.0	18.0	18.0	18.0
NTG	85%	85%	85%	85%	85%	85%
Marketplace						
Incentives	$1,082,814	$1,064,098	$1,002,954	$905,489	$738,591	$621,958
Delivery & Implementation	$2,883	$2,843	$2,728	$2,536	$2,006	$1,782
Admin	$37,474	$36,956	$35,467	$32,964	$26,073	$23,170
Total Budget	**$1,123,170**	**$1,103,896**	**$1,041,149**	**$940,988**	**$766,669**	**$646,910**

	2025	2026	2027	2028	2029	2030
Participation	14,856	15,029	14,752	13,962	11,775	10,469
Savings (kWh)	2,625,568	2,505,155	2,331,078	2,105,012	1,592,209	1,383,030
Demand Savings (kW)	1,330	1,339	1,279	1,162	1,007	839
Weighted Program EUL	13.9	13.8	13.6	13.4	13.0	12.8
NTG	92%	92%	92%	92%	90%	91%
Instant Rebate						
Incentives	$32,214	$38,486	$46,810	$57,485	$70,726	$86,634
Delivery & Implementation	$68,091	$82,541	$97,957	$113,045	$126,389	$136,968
Admin	$29,848	$36,182	$42,940	$49,554	$55,404	$60,041
Total Budget	**$130,153**	**$157,209**	**$187,708**	**$220,084**	**$252,519**	**$283,642**
Participation	2,319	2,791	3,258	3,664	3,955	4,095
Savings (kWh)	810,272	958,708	1,109,820	1,248,210	1,358,296	1,430,293
Demand Savings (kW)	48	60	73	86	99	111
Weighted Program EUL	11.0	10.9	10.9	10.9	10.9	11.1
NTG	100%	100%	100%	100%	100%	100%
Total						
Incentives	$2,054,698	$2,254,403	$2,311,807	$2,368,874	$2,365,502	$2,444,006
Delivery & Implementation	$704,212	$839,474	$942,934	$1,050,787	$1,155,249	$1,271,078
Admin	$106,908	$123,743	$135,291	$147,141	$154,339	$167,212
Total Budget	**$2,865,818**	**$3,217,621**	**$3,390,032**	**$3,566,802**	**$3,675,090**	**$3,882,296**
Participation	22,090	24,168	24,917	25,104	23,700	24,019
Savings (kWh)	5,328,589	5,744,845	5,931,358	6,074,592	5,896,734	6,053,380
Demand Savings (kW)	2,256	2,466	2,509	2,502	2,447	2,496

6.2 RESIDENTIAL NEW CONSTRUCTION PROGRAM

Program Description: The Residential New Construction program produces long-term savings by encouraging the construction of single-family homes, duplexes, or end-unit townhomes with only one shared wall to be built more energy efficient. The program incentivizes builders and helps improve cost effectiveness. The Residential New Construction program allows builders to individually select high-efficiency measures at a tiered approach, which improves flexibility enhancing the ability to meet participant demand. This approach also helps encourage a more energy efficiency focus at the measure level. Structuring this program around specific measures allows CenterPoint Indiana to analyze specific measures, add or remove measures and ensure the program is cost-effective. The Residential New Construction Program will work closely with builders, educating them on the benefits of energy efficient new homes. Homes may feature additional insulation, better windows, and higher efficiency appliances. The homes should also be more efficient and comfortable than standard homes constructed to current building codes.

TABLE 6-10: RESIDENTIAL NEW CONSTRUCTION MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Air Source Heat Pump 16 SEER	$200.00	4,457.1	0.16
Air Source Heat Pump 17 SEER	$300.00	4,539.9	0.22
Air Source Heat Pump 18 SEER	$400.00	4,733.0	0.28
Air Source Heat Pump 21 SEER	$400.00	4,899.6	0.42
Central Air Conditioner 15 SEER	$200.00	99.2	0.11
Central Air Conditioner 16 SEER	$200.00	185.8	0.21
Central Air Conditioner 17 SEER	$300.00	261.8	0.30

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Central Air Conditioner 18 SEER	$400.00	332.5	0.38
Smart Thermostat	$62.72	289.1	0.00
Wifi Thermostat	$41.51	247.5	0.00
ENERGY STAR New Home	$2,242.72	1,325.6	0.24

Eligible Customers: Any customer or home builder constructing a home to the program specifications in the CenterPoint Indiana electric service territory.

Marketing: To move the market toward an improved home building standard, education will be required for home builders, architects and designers as well as customers buying new homes. A combination of in-person meetings with these market participants as well as other educational methods will be necessary.

Program Delivery Channels: CenterPoint Indiana will oversee the program with the help of an implementation contractor.

Evaluation: CenterPoint Indiana will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint Indiana is not expected to evaluate the program every year but will evaluate the program at least once every three years.

Estimated Participation, Savings, and Budgets:

TABLE 6-11: RESIDENTIAL NEW CONSTRUCTION PROGRAM SUMMARY

Measure	2025	2026	2027	2028	2029	2030
Air Source Heat Pump 16 SEER						
Participation	1.1	1.0	0.9	0.8	0.7	0.7
Incentive Budget	$220	$196	$172	$154	$147	$147
Projected kWh Savings	4,766	4,337	3,830	3,488	3,329	3,343
Projected kW Savings	0	0	0	0	0	0
Air Source Heat Pump 17 SEER						
Participation	0.8	0.7	0.6	0.6	0.5	0.5
Incentive Budget	$239	$213	$186	$167	$159	$160
Projected kWh Savings	3,510	3,192	2,818	2,565	2,448	2,458
Projected kW Savings	0	0	0	0	0	0
Air Source Heat Pump 18 SEER						
Participation	0.7	0.6	0.5	0.5	0.4	0.4
Incentive Budget	$260	$232	$202	$182	$173	$174
Projected kWh Savings	2,989	2,717	2,398	2,182	2,082	2,091
Projected kW Savings	0	0	0	0	0	0
Air Source Heat Pump 21 SEER						
Participation	0.7	0.7	0.6	0.5	0.5	0.5
Incentive Budget	$300	$266	$232	$208	$198	$199
Projected kWh Savings	3,555	3,228	2,847	2,590	2,470	2,481
Projected kW Savings	0	0	0	0	0	0
Central Air Conditioner 15 SEER						
Participation	28	30	32	33	36	40

Measure	2025	2026	2027	2028	2029	2030
Incentive Budget	$5,538	$6,056	$6,330	$6,615	$7,127	$7,925
Projected kWh Savings	2,671	2,971	3,131	3,309	3,576	3,974
Projected kW Savings	3	3	4	4	4	5
Central Air Conditioner 16 SEER						
Participation	52	56	57	58	61	66
Incentive Budget	$10,448	$11,125	$11,315	$11,514	$12,102	$13,170
Projected kWh Savings	9,448	10,233	10,494	10,798	11,387	12,381
Projected kW Savings	11	12	12	12	13	14
Central Air Conditioner 17 SEER						
Participation	38	36	33	30	30	30
Incentive Budget	$11,336	$10,721	$9,808	$9,113	$8,883	$9,100
Projected kWh Savings	9,648	9,282	8,561	8,044	7,867	8,051
Projected kW Savings	11	11	10	9	9	9
Central Air Conditioner 18 SEER						
Participation	36	37	36	35	35	37
Incentive Budget	$14,564	$14,709	$14,222	$13,828	$13,971	$14,708
Projected kWh Savings	11,805	12,122	11,813	11,611	11,767	12,379
Projected kW Savings	14	14	14	13	13	14
Smart Thermostat						
Participation	31	29	26	23	22	22
Incentive Budget	$1,970	$1,810	$1,607	$1,471	$1,405	$1,411
Projected kWh Savings	8,992	8,315	7,418	6,818	6,512	6,538
Projected kW Savings	0	0	0	0	0	0
Wifi Thermostat						
Participation	7	9	10	13	16	20
Incentive Budget	$292	$362	$431	$523	$655	$847
Projected kWh Savings	1,738	2,158	2,570	3,124	3,910	5,053
Projected kW Savings	0	0	0	0	0	0
ENERGY STAR New Home						
Participation	14	16	18	20	25	33
Incentive Budget	$30,381	$34,828	$39,882	$45,844	$56,457	$73,271
Projected kWh Savings	17,373	20,274	23,431	27,299	33,757	43,763
Projected kW Savings	3	4	4	5	6	8

TABLE 6-12: RESIDENTIAL NEW CONSTRUCTION PROGRAM BUDGET SUMMARY

	2025	2026	2027	2028	2029	2030
Incentives	$75,549	$80,517	$84,389	$89,620	$101,276	$121,111
Delivery & Implementation	$14,912	$15,912	$16,620	$17,794	$20,150	$24,121
Admin	$2,415	$2,577	$2,692	$2,882	$3,264	$3,907
Total Budget	**$92,876**	**$99,006**	**$103,701**	**$110,296**	**$124,689**	**$149,139**
Participation	209	214	213	214	226	250
Energy Savings (kWh)	76,496	78,830	79,310	81,828	89,105	102,512
Demand Savings (kW)	43	45	44	44	46	51
Weighted Program EUL	18.6	18.9	19.2	19.6	20.0	20.3
NTG	80%	79%	78%	77%	76%	74%

6.3 INCOME QUALIFIED WEATHERIZATION PROGRAM

Program Description: The Income Qualified Weatherization program is designed to produce long term energy and demand savings in the residential market. The program is designed to provide weatherization upgrades to low-income homes that otherwise would not have been able to afford the energy saving measures. The program provides direct installation of energy-saving measures and educates consumers on ways to reduce energy consumption. Customers eligible through the Income Qualified Weatherization Program will have opportunity to receive deeper retrofit measures including refrigerators, attic insulation, duct sealing, air infiltration reduction and installation of new central air conditioner or air source heat pump.

TABLE 6-13: INCOME QUALIFIED WEATHERIZATION MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
ENERGY STAR Refrigerator	$288.53	503.4	0.07
Audit Recommendations	$47.27	38.2	0.01
Air Source Heat Pump 16 SEER	$613.38	2,482.6	0.09
Air Source Heat Pump 17 SEER	$817.84	2,461.9	0.13
Air Source Heat Pump 18 SEER	$1,022.30	2,485.4	0.16
Air Source Heat Pump 21 SEER	$1,022.30	2,485.0	0.24
AC Tune Up	$12.27	76.2	0.10
Central Air Conditioner 16 SEER	$109.94	114.3	0.13
Smart Thermostat	$132.96	146.4	0.00
Filter whistle	$1.55	20.6	0.03
Attic Insulation	$745.15	147.3	0.15
Duct Sealing	$230.82	67.5	0.08
Wall Insulation	$604.88	130.5	0.05
Air Sealing	$200.00	275.2	0.30
Low Flow Showerhead 1.5 gpm	$0.66	155.9	0.01
Kitchen Faucet Aerator 1.5 gpm	$0.66	62.0	0.00
Bathroom Aerator 1.0 gpm	$0.66	14.2	0.00
Pipe Wrap	$4.78	47.6	0.01
Water Heater Temperature Setback	$4.87	39.7	0.00

Eligible Customers: This program is available to residential customers who receive either electric only or gas and electric service from CenterPoint Indiana where CenterPoint Indiana is the homes primary heat source. Homes must be at least 5 years or older and have not received an audit within the last three years; and is owner occupied or authorized non-owner occupied where occupants have the service in their name up. Non-owner participation will be limited to a maximum of ten participants. Eligible homes must be less than 4 total units, and units should not be stacked. Eligible income qualified customer must receive a total household income not exceeding 200% of the federal-established poverty level.

Marketing: CenterPoint Indiana will provide a list to the implementation contractor of high consumption customers who have received Energy Assistance Program (EAP) funds within the past 12 months to help prioritize those customers who will benefit most from the program. In addition to utilizing the EAP List, the program will utilize census data to target low-income areas within CenterPoint Indiana territory. CenterPoint Indiana uses door-to-door canvassing for obtaining most of the appointments. The program is marketed to the public as “Neighborhood Weatherization” at various community events and works closely with the CenterPoint Energy Foundation.

Program Delivery Channels: CenterPoint Indiana will oversee the program with the help of an implementation contractor.

Evaluation: CenterPoint Indiana will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint Indiana is not expected to evaluate the program every year but will evaluate the program at least once every three years.

Estimated Participation, Savings, and Budgets:

TABLE 6-14: INCOME QUALIFIED WEATHERIZATION PROGRAM SUMMARY

Measure	2025	2026	2027	2028	2029	2030
ENERGY STAR Refrigerator						
Participation	59	84	114	154	205	269
Incentive Budget	$33,961	$31,740	$37,172	$45,206	$52,254	$55,003
Projected kWh Savings	59,256	55,381	64,859	78,877	91,174	95,971
Projected kW Savings	9	8	10	12	14	14
Audit Recommendations						
Participation	80	209	349	498	663	869
Incentive Budget	$7,951	$13,587	$19,527	$25,205	$29,135	$30,667
Projected kWh Savings	6,651	11,247	15,991	20,418	23,345	24,312
Projected kW Savings	2	3	4	5	6	6
Air Source Heat Pump 16 SEER						
Participation	1	1	1	2	2	3
Incentive Budget	$721	$673	$789	$959	$1,109	$1,167
Projected kWh Savings	2,917	2,726	3,192	3,882	4,488	4,724
Projected kW Savings	0	0	0	0	0	0
Air Source Heat Pump 17 SEER						
Participation	0	1	1	1	2	2
Incentive Budget	$807	$754	$883	$1,074	$1,242	$1,307
Projected kWh Savings	2,430	2,271	2,659	3,234	3,739	3,935
Projected kW Savings	0	0	0	0	0	0
Air Source Heat Pump 18 SEER						
Participation	0	1	1	1	2	2
Incentive Budget	$922	$862	$1,009	$1,227	$1,419	$1,493
Projected kWh Savings	2,241	2,095	2,453	2,984	3,449	3,630
Projected kW Savings	0	0	0	0	0	0
Air Source Heat Pump 21 SEER						
Participation	1	1	1	1	2	3
Incentive Budget	$1,122	$1,049	$1,228	$1,494	$1,726	$1,817
Projected kWh Savings	2,727	2,549	2,985	3,631	4,197	4,417
Projected kW Savings	0	0	0	0	0	0
AC Tune Up						
Participation	200	226	459	537	836	975
Incentive Budget	$5,003	$3,663	$6,427	$6,788	$9,185	$8,604
Projected kWh Savings	31,045	22,735	39,885	42,126	56,998	53,394
Projected kW Savings	39	29	51	54	72	68

Measure	2025	2026	2027	2028	2029	2030
Central Air Conditioner 16 SEER						
Participation	17	25	33	45	60	79
Incentive Budget	$3,783	$3,536	$4,141	$5,036	$5,821	$6,128
Projected kWh Savings	3,933	3,676	4,305	5,235	6,052	6,370
Projected kW Savings	4	4	5	6	7	7
Smart Thermostat						
Participation	112	177	197	211	232	291
Incentive Budget	$28,062	$28,771	$27,567	$26,687	$25,533	$25,662
Projected kWh Savings	30,897	31,677	30,351	29,382	28,111	28,254
Projected kW Savings	0	0	0	0	0	0
Filter whistle						
Participation	350	553	614	658	725	1,276
Incentive Budget	$1,051	$1,077	$1,032	$999	$956	$1,351
Projected kWh Savings	13,964	14,316	13,717	13,279	12,705	17,958
Projected kW Savings	23	23	22	22	21	29
Attic Insulation						
Participation	183	289	321	344	378	473
Incentive Budget	$256,043	$262,508	$251,519	$243,492	$232,960	$234,142
Projected kWh Savings	51,819	52,613	49,913	47,842	45,338	45,135
Projected kW Savings	51	52	49	47	45	45
Duct Sealing						
Participation	270	426	473	507	558	699
Incentive Budget	$117,057	$120,012	$114,989	$111,319	$106,504	$107,044
Projected kWh Savings	35,067	35,605	33,777	32,375	30,681	30,544
Projected kW Savings	41	41	39	37	35	35
Wall Insulation						
Participation	42	67	74	79	87	109
Incentive Budget	$47,927	$49,137	$47,080	$45,577	$43,606	$43,827
Projected kWh Savings	10,590	10,752	10,201	9,777	9,266	9,224
Projected kW Savings	4	4	4	3	3	3
Air Sealing						
Participation	399	402	410	418	427	435
Incentive Budget	$79,840	$80,474	$82,014	$83,638	$85,335	$87,082
Projected kWh Savings	114,561	116,353	115,930	115,372	114,773	114,138
Projected kW Savings	123	122	124	125	127	129
Low Flow Showerhead 1.5 gpm						
Participation	104	164	182	195	215	269
Incentive Budget	$130	$133	$127	$123	$118	$119
Projected kWh Savings	30,424	31,192	29,886	28,932	27,681	27,821
Projected kW Savings	2	2	2	1	1	1
Kitchen Faucet Aerator 1.5 gpm						
Participation	73	115	127	136	150	188
Incentive Budget	$91	$93	$89	$86	$83	$83
Projected kWh Savings	8,464	8,677	8,314	8,049	7,701	7,740
Projected kW Savings	1	1	0	0	0	0
Bathroom Aerator 1.0 gpm						

Measure	2025	2026	2027	2028	2029	2030
Participation	146	230	255	274	301	377
Incentive Budget	$182	$187	$179	$173	$166	$166
Projected kWh Savings	3,876	3,974	3,808	3,686	3,527	3,545
Projected kW Savings	0	0	0	0	0	0
Pipe Wrap						
Participation	241	380	422	452	498	623
Incentive Budget	$2,160	$2,214	$2,122	$2,054	$1,965	$1,975
Projected kWh Savings	21,512	22,056	21,132	20,458	19,573	19,672
Projected kW Savings	2	3	2	2	2	2
Water Heater Temperature Setback						
Participation	137	217	385	474	669	830
Incentive Budget	$1,371	$1,406	$2,156	$2,400	$2,940	$2,929
Projected kWh Savings	11,178	11,461	17,569	19,560	23,964	23,870
Projected kW Savings	1	1	2	2	3	3

TABLE 6-15: INCOME QUALIFIED WEATHERIZATION BUDGET SUMMARY

	2025	2026	2027	2028	2029	2030
Incentives	$588,184	$601,877	$600,050	$603,539	$602,056	$610,567
Delivery & Implementation	$191,509	$195,757	$215,146	$229,891	$249,775	$260,589
Admin	$10,079	$10,303	$11,323	$12,100	$13,146	$13,715
Total Budget	**$789,772**	**$807,937**	**$826,520**	**$845,530**	**$864,977**	**$884,871**
Participation	2,413	3,565	4,421	4,988	6,011	7,770
Energy Savings (kWh)	443,552	441,355	470,929	489,101	516,760	524,654
Demand Savings (kW)	303	294	315	319	338	345
Weighted Program EUL	12.6	12.8	11.9	11.5	10.9	10.8
NTG	100%	100%	100%	100%	100%	100%

6.4 COMMUNITY CONNECTIONS PROGRAM

Program Description: The Community Connections program is designed to provide energy efficient products to low-income community members who receive assistance from local food banks and township trustees. The program is intended to educate low-income community members on the benefits of energy efficient measures and provide them with products which would otherwise be unaffordable.

TABLE 6-16: COMMUNITY CONNECTIONS MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Smart Power Strips	$10.00	117.5	0.02
Air Sealing	$200.00	275.2	0.30

Eligible Customers: Community Connections program targets local food banks and township trustees who serve low-income homeowners and tenants within CenterPoint electric service territory.

Marketing: Marketing materials will be created to educate product recipients on the benefits of energy efficiency products.

Program Delivery Channels: CenterPoint Indiana will oversee the program with the help of an implementation contractor.

Evaluation: CenterPoint Indiana will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint Indiana is not expected to evaluate the program every year but will evaluate the program at least once every three years.

Estimated Participation, Savings, and Budgets:

TABLE 6-17: COMMUNITY CONNECTIONS PROGRAM SUMMARY

Measure	2025	2026	2027	2028	2029	2030
Smart Power Strips						
Participation	1,195	1,205	1,165	1,107	2,219	2,136
Incentive Budget	$11,946	$12,047	$11,646	$11,069	$22,192	$21,362
Projected kWh Savings	146,877	147,129	139,975	127,455	258,248	241,237
Projected kW Savings	26	26	25	23	46	43
Air Sealing						
Participation	573	712	965	1,221	1,447	1,607
Incentive Budget	$114,519	$142,384	$193,051	$244,117	$289,315	$321,460
Projected kWh Savings	164,321	205,866	272,884	336,739	389,119	421,336
Projected kW Savings	177	217	291	366	431	475

TABLE 6-18: COMMUNITY CONNECTIONS PROGRAM BUDGET SUMMARY

	2025	2026	2027	2028	2029	2030
Incentives	$126,464	$154,431	$204,697	$255,186	$311,507	$342,823
Delivery & Implementation	$118,236	$138,056	$166,521	$193,291	$276,051	$291,315
Admin	$6,223	$7,266	$8,764	$10,173	$14,529	$15,332
Total Budget	**$250,923**	**$299,752**	**$379,982**	**$458,650**	**$602,087**	**$649,470**
Participation	1,767	1,917	2,130	2,327	3,666	3,744
Energy Savings (kWh)	311,197	352,995	412,859	464,194	647,368	662,572
Demand Savings (kW)	203	243	317	389	477	518
Weighted Program EUL	13.9	13.8	13.7	13.5	13.8	13.7
NTG						

6.5 RESIDENTIAL BEHAVIORAL SAVINGS PROGRAM

Program Description: Residential Behavioral Savings Program motivates behavior change and provides relevant, targeted information to the consumer through regularly scheduled direct contact via mailed and emailed home energy reports. The report and web portal include a comparison against a group of similarly sized and equipped homes in the area, usage history comparisons, goal setting tools, and progress trackers. The Home Energy Report program anonymously compares customers' energy use with that of other customers with similar home size and demographics. Customers can view the past 12 months of their energy usage and compare and contrast their energy consumption and costs with others in the same neighborhood. Once a consumer understands better how they use energy, they can then start conserving energy.

TABLE 6-19: RESIDENTIAL BEHAVIORAL SAVINGS MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Home Energy Reports	$0.00	140.8	0.04
AMI Data Portal	$0.24	137.7	0.02

Eligible Customers: Residential customers who receive electric service from CEI South are eligible to participate in this integrated natural gas and electric program.

Marketing: CenterPoint Indiana will work with an implementation contractor and evaluation contractor to determine which customers are in the treatment/participant group and which are in the non-participant group.

Program Delivery Channels: CenterPoint Indiana will oversee the program with the help of an implementation contractor. The main delivery channel will be targeted mail and email with the addition of specific tips provided to the low-income customer segment.

Evaluation: CenterPoint Indiana will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint Indiana is not expected to evaluate the program every year but will evaluate the program at least once every three years.

Estimated Participation, Savings, and Budgets:

TABLE 6-20: RESIDENTIAL BEHAVIORAL SAVINGS PROGRAM SUMMARY

Measure	2025	2026	2027	2028	2029	2030
Home Energy Reports						
Participation	37,252	43,559	47,326	50,470	53,022	55,057
Incentive Budget	$0	$0	$0	$0	$0	$0
Projected kWh Savings	7,143,072	6,985,928	6,818,155	6,645,215	6,472,287	6,307,171
Projected kW Savings	2,037	1,992	1,945	1,895	1,846	1,799
AMI Data Portal						
Participation	2,750	3,745	4,738	5,846	7,021	8,205
Incentive Budget	$908	$1,045	$1,200	$1,368	$1,540	$1,707
Projected kWh Savings	535,787	610,208	693,458	781,917	870,670	954,898
Projected kW Savings	61	70	79	89	99	109

TABLE 6-21: RESIDENTIAL BEHAVIORAL SAVINGS PROGRAM BUDGET SUMMARY

	2025	2026	2027	2028	2029	2030
Incentives	$908	$1,045	$1,200	$1,368	$1,540	$1,707
Delivery & Implementation	$294,627	$301,284	$308,079	$315,021	$322,122	$329,396
Admin	$116,300	$118,928	$121,610	$124,350	$127,153	$130,025
Total Budget	**$411,835**	**$421,257**	**$430,889**	**$440,739**	**$450,815**	**$461,127**
Participation	40,002	47,304	52,064	56,315	60,043	63,262
Energy Savings (kWh)	7,678,859	7,596,136	7,511,612	7,427,133	7,342,957	7,262,069
Demand Savings (kW)	2,098	2,062	2,024	1,985	1,945	1,908
Weighted Program EUL	1.0	1.0	1.0	1.0	1.0	1.0
NTG	100%	100%	100%	100%	100%	100%

6.6 APPLIANCE RECYCLING PROGRAM

Program Description: The Residential Appliance Recycling program encourages customers to recycle their old inefficient refrigerators and freezers in an environmentally safe manner. The program recycles operable refrigerators and freezers, so the appliance no longer uses electricity, and keeps 95% of the appliance out of landfills. An older refrigerator can use up to three times the amount of energy as new efficient refrigerators. An incentive of $50 will be provided to the customer for each operational unit picked up. Additionally, the $25 air conditioners rebate will continue to be offered. Customers can choose a no-contact pickup if they so desire.

TABLE 6-22: APPLIANCE RECYCLING MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
Refrigerator Recycling	$50.00	628.7	0.09
Dehumidifier Recycling	$20.00	620.0	0.00

Eligible Customers: Any residential customer with an operable secondary refrigerator, window A/C or freezer receiving electric service from CenterPoint Indiana.

Marketing: The program will be marketed through a variety of mediums, including the use of utility bill inserts, retail campaigns coordinated with appliance sales outlets as well as the potential for direct mail, web and media promotional campaigns.

Program Delivery Channels: CenterPoint Indiana will oversee the program with the help of an implementation contractor.

Evaluation: CenterPoint Indiana will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint Indiana is not expected to evaluate the program every year but will evaluate the program at least once every three years.

Estimated Participation, Savings, and Budgets:

TABLE 6-23: APPLIANCE RECYCLNG PROGRAM SUMMARY

Measure	2025	2026	2027	2028	2029	2030
Refrigerator Recycling						
Participation	925	925	925	925	925	925
Incentive Budget	$46,250	$46,250	$46,250	$46,250	$46,250	$46,250
Projected kWh Savings	581,523	581,523	581,523	581,523	581,523	581,523
Projected kW Savings	86	86	86	86	86	86
Dehumidifier Recycling						
Participation	146	146	146	146	146	146
Incentive Budget	$2,912	$2,912	$2,912	$2,912	$2,912	$2,912
Projected kWh Savings	90,277	90,277	90,277	90,277	90,277	90,277
Projected kW Savings	0	0	0	0	0	0

TABLE 6-24: APPLIANCE RECYCLING PROGRAM BUDGET SUMMARY

	2025	2026	2027	2028	2029	2030
Incentives	$49,162	$49,162	$49,162	$49,162	$49,162	$49,162
Delivery & Implementation	$157,115	$160,728	$164,425	$168,207	$172,076	$176,033
Admin	$7,585	$7,759	$7,938	$8,120	$8,307	$8,498
Total Budget	**$213,861**	**$217,649**	**$221,525**	**$225,489**	**$229,544**	**$233,693**
Participation	1,071	1,071	1,071	1,071	1,071	1,071
Energy Savings (kWh)	671,801	671,801	671,801	671,801	671,801	671,801
Demand Savings (kW)	86	86	86	86	86	86
Weighted Program EUL	8.0	8.0	8.0	8.0	8.0	8.0
NTG	62%	62%	62%	62%	62%	62%

6.7 BRING YOUR OWN THERMOSTAT PROGRAM

Program Description: The BYOT program allows customers with a compatible thermostat to participate in demand response (DR) events – utility managed load curtailing programs during periods when electricity demand is high. The BYOT program allows the utility to avoid the costs of hardware, installation, and maintenance associated with traditional load control methods.

By taking advantage of two-way communicating smart thermostats, BYOT programs can help utilities curtail load, reduce acquisition costs associated with typical load curtailment programs and improve customer satisfaction. With smart enabled thermostats, the utility can remotely verify how many customers are participating in DR events. Customers are notified of all events and have the capability of opting out of events at any time during the actual event.

Eligible Customers: Any eligible residential customer who receives electric service from CenterPoint Indiana at a single-family residence.

Marketing: Customers will receive a one-time enrollment incentive of $75 and a bill credit of $5 during the months of June to September. The enrollment incentive, the amount for which was determined based on research of other utility BYOT programs, will be provided in the first year to new enrollees only.

Program Delivery Channels: CenterPoint Indiana oversees the program and has partnered with Energy Hub to provide delivery of the BYOT program.

Evaluation: CenterPoint Indiana will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint Indiana is not expected to evaluate the program every year but will evaluate the program at least once every three years.

Estimated Participation, Savings, and Budgets:

TABLE 6-25: BRING YOUR OWN THERMOSTAT PROGRAM BUDGET SUMMARY

	2025	2026	2027	2028	2029	2030
Incentives	$321,468	$317,778	$352,919	$388,244	$423,983	$460,270
Delivery & Implementation	$401,120	$434,529	$494,016	$553,799	$614,070	$674,977
Admin	$55,000	$56,210	$57,447	$58,710	$60,002	$61,322
Total Budget	**$777,588**	**$808,517**	**$904,382**	**$1,000,753**	**$1,098,055**	**$1,196,570**
Participation	8,242	9,824	11,415	13,013	14,621	16,241
Energy Savings (kWh)	0	0	0	0	0	0
Demand Savings (MW)	8	9	11	12	13	15
Weighted Program EUL	15.0	15.0	15.0	15.0	15.0	15.0
NTG	100%	100%	100%	100%	100%	100%

6.8 SMART CYCLE PROGRAM

Program Description: CenterPoint Indiana continues to replace DLC switches with smart thermostats each year. As an alternative to DLC switches, smart thermostats can optimize heating and cooling of a home to reduce energy usage and control load while utilities can learn from occupant behavior/preference, adjusting heating, ventilation, and air conditioning (HVAC) settings.

Eligible Customers: The Smart Cycle (DLC Change Out) Program will focus on residential single-family homes and apartment dwellers that have access to a Wi-Fi network and are participants of the DLC program.

Marketing: Customers who participate in the Demand Response events will be enrolled to receive a bill credit for the months of June through September.

Program Delivery Channels: CenterPoint Indiana will oversee the program.

Evaluation: CenterPoint Indiana will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint Indiana is not expected to evaluate the program every year but will evaluate the program at least once every three years.

Estimated Participation, Savings, and Budgets:

TABLE 6-26: SMART CYCLE PROGRAM BUDGET SUMMARY

	2025	2026	2027	2028	2029	2030
Incentives	$56,811	$63,024	$69,253	$75,501	$81,780	$88,105
Delivery & Implementation	$265,231	$233,406	$238,955	$244,672	$250,874	$257,641
Admin	$74,359	$72,085	$73,713	$75,383	$77,126	$78,953
Total Budget	**$396,400**	**$368,515**	**$381,922**	**$395,556**	**$409,780**	**$424,698**
Participation	2,841	3,151	3,463	3,775	4,089	4,405
Energy Savings (kWh)	0	0	0	0	0	0
Demand Savings (MW)	3	3	3	3	4	4
Weighted Program EUL	15.0	15.0	15.0	15.0	15.0	15.0
NTG	100%	100%	100%	100%	100%	100%

6.9 RESIDENTIAL EMERGING MARKETS PROGRAM

Program Description: The Residential Emerging Markets Program offers a variety of measures which are not currently offered by existing programs. This program is envisioned to operate similarly to the Residential Prescriptive Program. The program is designed to incent customers to purchase energy efficient equipment by covering part of the incremental cost.

TABLE 6-27: RESIDENTIAL EMERGING MARKETS MEASURES

Measure	Avg. Incentive per Unit	Savings per Unit (kWh)	Savings per Unit (kW)
ENERGY STAR Clothes Washer	$50.00	187.0	0.02
ENERGY STAR Clothes Dryer	$50.00	373.3	0.13
Packaged Terminal Heat Pump	$1,147.53	1,951.5	0.96
Packaged Terminal Air Conditioner	$1,147.53	3,257.3	0.96
Filter whistle	$3.00	44.4	0.07
Attic Fan	$100.00	170.5	0.18
ENERGY STAR Bath Vent Fan	$20.00	29.6	0.02
Smart Power Strips	$10.00	136.1	0.02
Duct Sealing	$296.07	1,053.7	0.24
Radiant Barrier	$575.86	946.9	0.13
Smart Water Heater	$96.00	414.0	0.02
Thermostatic Restrictor Shower Valve	$24.00	67.0	0.00
Pipe Wrap	$8.98	82.3	0.01

Eligible Customers: The program is available to all residential customers located in the CenterPoint Indiana electric service territory.

Marketing: The program may leverage a variety of marketing techniques similar to those currently used for the Residential Prescriptive Program.

Program Delivery Channels: CenterPoint Indiana will oversee the program with the help of an implementation contractor.

Evaluation: CenterPoint Indiana will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint Indiana is not expected to evaluate the program every year but will evaluate the program at least once every three years.

Estimated Participation, Savings, and Budgets:

TABLE 6-28: RESIDENTIAL EMERGING MARKETS PROGRAM SUMMARY

Measure	2025	2026	2027	2028	2029	2030
ENERGY STAR Clothes Washer						
Participation	908	1,116	1,336	1,556	1,765	1,955
Incentive Budget	$45,423	$55,819	$66,791	$77,785	$88,254	$97,764
Projected kWh Savings	169,921	208,809	249,852	290,979	330,143	365,716
Projected kW Savings	22	27	32	37	43	47
ENERGY STAR Clothes Dryer						
Participation	110	121	131	140	146	152
Incentive Budget	$5,477	$6,061	$6,563	$6,980	$7,317	$7,586
Projected kWh Savings	41,351	45,612	49,201	52,086	54,303	55,949
Projected kW Savings	15	16	18	19	19	20
Packaged Terminal Heat Pump						
Participation	0	121	131	140	146	1,723
Incentive Budget	$63	$6,061	$6,563	$6,980	$7,317	$34,459
Projected kWh Savings	108	45,612	49,201	52,086	54,303	51,033
Projected kW Savings	0	16	18	19	19	41
Packaged Terminal Air Conditioner						
Participation	2	2	3	3	4	4
Incentive Budget	$2,145	$2,637	$3,156	$3,678	$4,177	$4,636
Projected kWh Savings	6,090	7,486	8,959	10,440	11,858	13,159
Projected kW Savings	2	2	3	3	3	4
Filter whistle						
Participation	2,564	2,851	3,013	3,021	2,877	5,267
Incentive Budget	$7,691	$8,553	$9,040	$9,064	$8,632	$15,802
Projected kWh Savings	113,912	126,683	133,889	134,218	127,745	233,252
Projected kW Savings	186	207	218	219	208	380
Attic Fan						
Participation	912	1,141	1,382	1,608	1,788	1,891
Incentive Budget	$91,183	$114,125	$138,191	$160,848	$178,850	$189,080
Projected kWh Savings	155,454	194,568	235,597	274,224	304,915	322,356
Projected kW Savings	165	207	250	291	324	342
ENERGY STAR Bath Vent Fan						

Measure	2025	2026	2027	2028	2029	2030
Participation	3,494	3,314	2,988	2,575	2,137	1,723
Incentive Budget	$69,880	$66,279	$59,753	$51,492	$42,734	$34,459
Projected kWh Savings	103,492	98,160	88,495	76,259	63,289	51,033
Projected kW Savings	84	79	71	62	51	41
Smart Power Strips						
Participation	3,884	3,341	2,763	2,213	5,633	4,693
Incentive Budget	$38,835	$33,407	$27,627	$22,125	$56,329	$46,926
Projected kWh Savings	528,544	454,666	375,999	301,124	766,643	638,669
Projected kW Savings	97	83	69	55	140	117
Duct Sealing						
Participation	77	93	108	120	127	127
Incentive Budget	$22,742	$27,538	$32,043	$35,600	$37,576	$37,576
Projected kWh Savings	83,158	99,723	114,891	126,380	132,128	130,872
Projected kW Savings	19	23	26	29	30	30
Radiant Barrier						
Participation	12	13	13	12	11	10
Incentive Budget	$7,156	$7,553	$7,553	$7,156	$6,441	$5,536
Projected kWh Savings	12,040	12,585	12,461	11,689	10,421	8,871
Projected kW Savings	2	2	2	2	1	1
Smart Water Heater						
Participation	23	31	41	55	73	96
Incentive Budget	$2,161	$2,932	$3,950	$5,286	$7,015	$9,198
Projected kWh Savings	9,849	13,163	17,438	22,926	29,864	38,468
Projected kW Savings	0	1	1	1	1	2
Thermostatic Restrictor Shower Valve						
Participation	3,947	4,386	4,632	4,636	4,400	3,974
Incentive Budget	$94,724	$105,276	$111,173	$111,275	$105,609	$95,364
Projected kWh Savings	264,429	293,883	310,349	310,641	294,843	266,278
Projected kW Savings	13	14	15	15	14	13
Pipe Wrap						
Participation	1,608	1,871	2,078	2,194	2,194	2,078
Incentive Budget	$14,438	$16,800	$18,664	$19,700	$19,700	$18,664
Projected kWh Savings	132,299	153,941	171,029	180,521	180,521	171,029
Projected kW Savings	15	18	20	21	21	20

TABLE 6-29: RESIDENTIAL EMERGING MARKETS PROGRAM BUDGET SUMMARY

	2025	2026	2027	2028	2029	2030
Incentives	$401,918	$453,040	$491,068	$517,969	$569,952	$597,049
Delivery & Implementation	$249,265	$269,711	$286,238	$297,512	$390,532	$398,097
Admin	$40,374	$43,686	$46,362	$48,189	$63,255	$64,480
Total Budget	**$691,556**	**$766,437**	**$823,668**	**$863,671**	**$1,023,739**	**$1,059,626**
Participation	17,539	18,402	18,620	18,273	21,302	23,692
Energy Savings (kWh)	1,620,646	1,754,890	1,817,360	1,843,573	2,360,975	2,346,687
Demand Savings (kW)	618	694	741	771	875	1,058
Weighted Program EUL	9.8	10.3	10.8	11.2	9.8	9.8

	2025	2026	2027	2028	2029	2030
NTG	99%	99%	98%	98%	99%	99%

6.10 CONSERVATION VOLTAGE REDUCTION PROGRAM

Program Description: The Conservation Voltage Reduction Program achieves energy conservation through automated monitoring and control of voltage levels provided on distribution circuits. End use customers realize lower energy and demand consumption when CVR is applied to the distribution circuit from which they are served.

Eligible Customers: Customers receiving service from the Tekoppel substation.

Program Delivery Channels: Delivery of the CVR Program will be achieved through the installation of control logic, telecommunication equipment, and voltage control equipment in order to control the voltage bandwidth on CVR circuits within voltage compliance levels required by the Indiana Utility Regulatory Commission

Evaluation: A third-party evaluator will evaluate the program using standard EM&V protocols.

Estimated Participation, Savings, and Budgets: Annual budgets for the CVR program are approximately $250,000 for residential customers and $300,000 for C&I customers.

6.11 COMMERCIAL PRESCRIPTIVE (RX) REBATES PROGRAM

Program Description: The Commercial Prescriptive Rebate Program is designed to influence commercial customers to install energy efficient alternatives on equipment types typically found in most business facilities. Financial incentives (mail-in rebates) are intended to encourage customers to purchase high efficiency products that would have otherwise purchased standard efficiency products in the absence of the program.

The program will increase demand by educating customers about the energy and money saving benefits associated with efficient products via outreach and education, website, and equipping trade allies to communicate such benefits to customers. The program will foster sustainable improvements in the local CenterPoint Indiana market for these products. Product availability is addressed as market providers adjust to meet increased demand generated by incentive offers and consumer education activities.

The table below describes the end-uses included in this program, and an estimate of average savings per project within each end-use. Total program savings and costs for this program align with the “enhanced” program potential identified in the MPS. However, because the MPS’ definition of “unit” varied by measure, GDS used historical program savings and project counts to identify an “average” savings per project, by end-use.

TABLE 6-30: COMMERCIAL REBATE PRESCRIPTIVE MEASURES

End-Use	Avg. Incentive per Project/Unit	Savings per Project/Unit (kWh)	Demand per Project/Unit (kWh)
Compressed Air	$217 - $309	1,815	0.42
Cooking	$55 - $57	534	0.07
Cooling	$1852 - $2000	8,089	6.04
Heating	$253 - $268	1,574	0.91
Hot Water	$377 - $721	6,400	0.19
Lighting - Exterior	$154 - $178	1,160	0.00
Lighting - Interior	$15 - $16	268	0.06
Miscellaneous	$21 - $31	603	0.03
Refrigeration	$98 - $132	1,623	0.31
Ventilation	$2704 - $2704	17,963	3.79

Eligible Customers: Commercial Prescriptive rebates target non-residential electric customers. CenterPoint Indiana customers who have elected to opt out of participating in CenterPoint Indiana's energy efficiency programs are not eligible.

Marketing: The Commercial Prescriptive Rebate Program relies on networking with trade allies, mass media messages to consumers and businesses, and website tools and promotions.

Program Delivery Channels: The program is delivered primarily through trade allies. CenterPoint Indiana and its implementation partners work with the trade allies to make them aware of the offerings and help them promote the program to their customers. The implementation partner will provide training and technical support to the trade allies to become familiar with the EE technologies offered through the program. The program will be managed by the same implementation provider as the C&I Custom Program so that customers can seamlessly receive assistance and all incentives can be efficiently processed through a single procedure. To verify the correct equipment was installed, site visits will be made on 5% of the installations, as well as all projects receiving incentives greater than $20,000.

Evaluation: CenterPoint Indiana will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint Indiana is not expected to evaluate the program every year but will evaluate the program at least once every three years.

Estimated Participation, Savings, and Budgets:

TABLE 6-31: COMMERCIAL PRESCRIPTIVE REBATE PROGRAM SUMMARY

End-Use	2025	2026	2027	2028	2029	2030
Compressed Air						
Participation	318	347	363	366	356	337
Incentive Budget	$68,920	$79,194	$88,179	$95,402	$100,743	$104,389
Projected kWh Savings	485,255	529,727	554,167	557,288	542,065	514,300
Projected kW Savings	112	126	137	145	149	149
Cooking						
Participation	482	532	577	617	650	678
Incentive Budget	$27,299	$29,898	$32,220	$34,233	$35,929	$37,322
Projected kWh Savings	216,284	238,663	258,889	276,615	291,711	304,228
Projected kW Savings	27	30	32	34	36	37
Cooling						
Participation	110	123	135	171	177	180
Incentive Budget	$207,505	$240,448	$270,619	$316,655	$333,964	$343,220
Projected kWh Savings	746,870	838,389	919,591	1,162,025	1,203,245	1,221,333
Projected kW Savings	558	625	684	871	903	918
Heating						
Participation	120	141	162	183	202	218
Incentive Budget	$30,318	$36,144	$42,097	$47,941	$53,466	$58,510
Projected kWh Savings	158,443	186,653	214,813	241,799	266,683	288,824
Projected kW Savings	92	109	126	144	160	174
Hot Water						
Participation	17	19	21	23	26	26
Incentive Budget	$6,374	$8,334	$10,497	$12,897	$15,546	$18,438
Projected kWh Savings	90,881	101,958	113,443	124,958	137,195	137,568
Projected kW Savings	3	4	5	6	8	9
Lighting - Exterior						

End-Use	2025	2026	2027	2028	2029	2030
Participation	1,134	911	712	545	381	247
Incentive Budget	$174,736	$140,660	$110,141	$84,379	$62,426	$44,069
Projected kWh Savings	1,105,036	887,489	693,873	531,040	371,393	241,126
Projected kW Savings	0	0	0	0	0	0
Lighting - Interior						
Participation	17,932	18,811	18,590	17,605	16,154	14,694
Incentive Budget	$279,285	$296,493	$295,398	$279,484	$253,099	$224,071
Projected kWh Savings	4,036,741	4,234,738	4,185,002	3,963,346	3,636,540	3,307,920
Projected kW Savings	912	954	941	889	816	744
Miscellaneous						
Participation	614	637	663	699	747	1,112
Incentive Budget	$12,724	$14,769	$17,220	$20,130	$23,461	$30,568
Projected kWh Savings	310,935	322,766	335,946	353,864	378,164	563,277
Projected kW Savings	14	19	24	30	37	45
Refrigeration						
Participation	184	283	323	356	401	512
Incentive Budget	$18,102	$30,018	$37,332	$44,262	$52,646	$67,635
Projected kWh Savings	251,166	385,632	440,818	485,524	546,737	697,481
Projected kW Savings	48	74	83	90	101	127
Ventilation						
Participation	168	172	170	163	150	134
Incentive Budget	$455,448	$466,024	$460,825	$440,230	$405,966	$361,200
Projected kWh Savings	2,541,498	2,600,518	2,571,505	2,456,579	2,265,381	2,015,573
Projected kW Savings	536	548	542	518	478	425

TABLE 6-32: COMMERCIAL PRESCRIPTIVE REBATE PROGRAM BUDGET SUMMARY

	2025	2026	2027	2028	2029	2030
Incentives	$1,280,711	$1,341,984	$1,364,528	$1,375,613	$1,337,248	$1,289,422
Delivery & Implementation	$651,371	$696,126	$713,802	$726,184	$710,428	$704,462
Admin	$162,843	$174,031	$178,451	$181,546	$177,607	$176,115
Total Budget	**$2,094,925**	**$2,212,141**	**$2,256,781**	**$2,283,343**	**$2,225,284**	**$2,169,999**
Participation	21,079	21,977	21,719	20,727	19,243	18,138
Energy Savings (kWh)	9,943,108	10,326,534	10,288,046	10,153,038	9,639,114	9,291,629
Demand Savings (kW)	2,741	2,962	3,066	3,247	3,198	3,129
Weighted Program EUL	10.1	10.1	10.2	10.1	10.3	10.3
NTG	0.84	0.84	0.84	0.84	0.84	0.84

6.12 SMALL BUSINESS ENERGY SOLUTIONS (SBES) PROGRAM

Program Description: The Small Business Energy Solutions Program (SBES) helps small businesses and multi-family customers identify and install cost-effective energy-saving measures by providing an onsite energy assessment customized for their business and access to the highest rebates available for CenterPoint Indiana business customers.

The table below describes the end-uses included in this program. Lighting measures include most linear fluorescent lighting bulbs and fixtures, downlight fixtures, exterior wall packs and garage fixtures, LED exit signs, occupancy sensor, and daylighting controls. Non-lighting measures include smart thermostats, rooftop controls, pre-rinse spray valves, vending machine controllers, and select refrigeration equipment.

TABLE 6-33: SMALL BUSINESS ENERGY SOLUTIONS ELIGIBLE END-USES

End-Use	Avg. Incentive per Project/Unit	Savings per Project/Unit (kWh)	Demand per Project/Unit (kWh)
Lighting	$66 - $75	299	0.07
Non-Lighting	$576 - $881	1,797	0.16

Eligible Customers: Any participating CenterPoint Indiana electric business customer with a monthly electric demand of 400 kilowatts (kW) or less is eligible to participate in the program. Additionally, there is no kW restriction for nonprofit entities and multi-family building owners with CenterPoint Indiana's general electric service may qualify for the program, including apartment buildings, condominiums, cooperatives, duplexes, quadraplexes, townhomes, nursing homes, and retirement communities.

Marketing: The Small Business Energy Solutions program relies on networking with trade allies, mass media messages to consumers and businesses, and website tools and promotions.

Program Delivery Channels: Trained trade ally energy advisors provide energy assessments to business customers with less than 400 kW peak demand and to multi-family buildings. The program implementer issues an annual Request for Qualification (RFQ) to select the trade allies with the best ability to provide high-quality and cost-effective service to small businesses and provide training to SBES trade allies on the program process, with an emphasis on improving energy efficiency sales.

Trade allies walk through small businesses and record site characteristics and energy efficiency opportunities at no cost to the customer. They provide an energy assessment report that details customer-specific opportunities, costs, energy savings, incentives, and simple payback periods. The trade ally then reviews the report with the customer, presenting the program benefits and process, while addressing any questions.

Onsite verification is provided for the first three projects completed by each trade ally, in addition to the program standard of 5% of all completed projects and all projects receiving incentives greater than $20,000. These verifications allow the program to validate energy savings, in addition to providing an opportunity to ensure trade allies provide high-quality customer services and the incentivized equipment satisfies program requirements.

Evaluation: CenterPoint Indiana will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint Indiana is not expected to evaluate the program every year but will evaluate the program at least once every three years.

Estimated Participation, Savings, and Budgets:

TABLE 6-34: SMALL BUSINESS ENERGY SOLUTIONS PROGRAM SUMMARY

End-Use	2025	2026	2027	2028	2029	2030
Lighting						
Participation	15,595	15,419	14,735	13,571	12,053	10,356
Incentive Budget	$1,177,262	$1,107,890	$1,016,464	$911,428	$795,874	$683,291
Projected kWh Savings	3,916,866	3,872,586	3,700,821	3,408,500	3,027,240	2,600,965
Projected kW Savings	860	859	829	766	688	598
Non-Lighting						
Participation	33	39	39	39	40	56
Incentive Budget	$29,387	$28,843	$26,991	$24,880	$23,056	$40,879
Projected kWh Savings	50,377	58,495	59,477	59,269	60,389	84,773
Projected kW Savings	4	7	7	8	9	11

TABLE 6-35: COMMERCIAL SMALL BUSINESS ENERGY SOLUTIONS PROGRAM BUDGET SUMMARY

	2025	2026	2027	2028	2029	2030
Incentives	$1,206,650	$1,136,732	$1,043,455	$936,308	$818,931	$724,170
Delivery & Implementation	$320,354	$325,895	$320,361	$304,571	$280,470	$255,709
Admin	$60,066	$61,105	$60,068	$57,107	$52,588	$47,945
Total Budget	**$1,607,092**	**$1,544,101**	**$1,443,906**	**$1,317,021**	**$1,169,518**	**$1,043,806**
Participation	15,628	15,458	14,774	13,610	12,093	10,412
Energy Savings (kWh)	3,967,243	3,931,082	3,760,299	3,467,768	3,087,629	2,685,738
Demand Savings (kW)	864	866	836	774	697	608
Weighted Program EUL	10.2	10.2	10.2	10.1	10.1	10.0
NTG	84%	84%	84%	84%	84%	84%

6.13 COMMERCIAL CUSTOM PROGRAM

Program Description: The Commercial Custom Program offers business customers incentives for qualifying energy efficiency upgrades not covered under the Commercial Prescriptive Rebate Program. This program encourages the purchase and installation of efficient technologies or implementation of process improvements. CenterPoint Indiana envisions utilizing the same implementor for both the prescriptive rebate and custom programs.

CenterPoint Indiana staff and the third-party implementor will work with key customers and market providers to identify potential energy savings projects and answer questions on program requirements. Once prospective energy saving projects are identified, CenterPoint Indiana and the program implementor will work with the customer and/or market provider to complete custom engineering calculations.

Included in this program are conventional custom projects, commercial new construction, building retro-commissioning (RCx) opportunities and strategic energy management (SEM). The table below provides the average incentive and savings on a per project basis. Per project estimates are based on recent historical data, with total custom program savings informed by the current MPS' enhanced program potential scenario.

TABLE 6-36: COMMERCIAL CUSTOM PROJECTS

Program	Sub-Category	Avg. Incentive per kWh Saved	Savings per Project/Unit (kWh)	Demand per Project/Unit (kWh)
Custom	Lighting	$10,160 - $11,947	69,703	10.7
Custom	Non-Lighting & New Construction	$8,815 - $9,037	102,472	20.2
Custom	RCx	$7,630 - $7,841	80,996	13.5
Custom	SEM	$2,649 - $3,310	75,000	10.0

Eligible Customers: Commercial Prescriptive rebates target non-residential electric customers. CenterPoint Indiana customers who have elected to opt out of participating in CenterPoint Indiana's energy efficiency programs are not eligible.

Marketing: CenterPoint Indiana will provide outreach and education to contractors to inform them of the program offerings through direct contacts with key customers and market providers (e.g., mechanical contractors). This approach is highly dependent upon referrals and networking with trade allies to identify projects. Outreach will include in-person visits to customers and market providers, attending and presenting at public seminars and trade association meetings, (e.g., ASHRAE, school administrators, hospitality), direct mail, newsletters and other targeted media and networking.

Program Delivery Channels: CenterPoint Indiana staff will oversee the program and will utilize the services of a third-party implementation firm to perform project tracking, the engineering review, and rebate fulfillment services.

Conventional Custom Projects

Similar to previous program years, customers may propose new custom retrofit projects. CenterPoint Indiana staff and the third-party implementor will work with key customers and market providers to identify potential energy savings projects and answer questions on program requirements. Once prospective energy saving projects are identified, CenterPoint Indiana and the program implementor will work with the customer and/or market provider to complete custom engineering calculations.

If the project is deemed eligible, the third-party implementor and CenterPoint Indiana staff will assist the customer or market provider in completing the grant application and will manage the allocation of funds. Prior to starting a project, customers must complete an application and attach documentation verifying the energy savings potential, payback horizon, project eligibility and incentive amount. When the project is approved, CenterPoint Energy will send a Letter of Intent (LOI) to the applicant confirming the amount of the incentive that will be paid once the project is completed.

Once projects are implemented, the customer will submit incentive claims along with all necessary documentation to CenterPoint Indiana. The third-party implementor will review the applications and a qualified engineer will verify savings calculations are correct prior to payment. The CenterPoint Indiana representative will monitor the status of the rebate application and project until the point of payment.

Conventional New Construction

The Commercial New Construction (CNC) component promotes energy-efficient designs with the goal of developing projects that are more energy efficient than the current Indiana building code. This program applies to new construction and major renovation projects. Major renovation is defined as the replacement of at least two systems within an existing space (e.g., lighting, HVAC, controls, building envelope). The program provides incentives as part of the facility design process to explore opportunities in modeling EE options to craft an optimal package of investments. The program also offers customers the opportunity to receive prescriptive or custom rebates toward eligible equipment to reduce the higher capital cost for an energy efficient solution.

Commercial Retro-Commissioning (RCx)

A targeted, turnkey, and cost-effective retro-commissioning solution for small- to mid-sized customer facilities. It is designed as a comprehensive customer solution that will identify, validate, quantify, and encourage the installation of both operational and capital measures. Most of these measures will be no- or low-cost with low payback periods and will capture energy savings from a previously untapped source: building automation systems.

Facility energy assessments are offered to customers who are eligible and motivated to implement multiple energy efficiency measures. The RCx component specifically targets measures that provide no- and low-cost operational savings. Most measures involve optimizing the building automation system (BAS) settings, but the program also investigates related capital measures, like controls, operations, processes, and HVAC. The implementation partner works collaboratively with CenterPoint Indiana staff to recruit and screen customers for receiving facility energy assessments.

Strategic Energy Management

An extension of the SEM pilot, this custom component is a guided operations and maintenance program with benchmarking and regular follow-up meetings to chart customer performance. The implementer will recruit customers to participate in the program and achieve energy savings for their facilities. The implementer will then measure their performance over time (usually a period of 6 months or a year) using energy billing data to determine the amount of energy savings the customer achieved and provide incentives to the customer accordingly.

Evaluation: CenterPoint Indiana will hire a third-party evaluator contractor to evaluate the program savings. The evaluation budget is an estimated 5% of the total budget for the program. CenterPoint Indiana is not expected to evaluate the program every year but will evaluate the program at least once every three years.

Estimated Participation, Savings, and Budgets:

TABLE 6-37: COMMERCIAL CUSTOM PROGRAM SUMMARY

End-Use	2025	2026	2027	2028	2029	2030
Custom Lighting						
Participation	25	28	32	35	37	38
Incentive Budget	$249,811	$299,563	$351,065	$397,672	$434,117	$459,429
Projected kWh Savings	1,593,797	1,838,286	2,079,277	2,281,531	2,418,357	2,492,936
Projected kW Savings	245	288	329	364	388	400
Custom Non-Lighting						
Participation	39	51	58	68	75	90
Incentive Budget	$347,653	$449,210	$519,386	$617,468	$674,679	$812,282
Projected kWh Savings	3,758,595	4,848,220	5,542,448	6,514,568	7,141,031	8,565,536
Projected kW Savings	741	967	1,110	1,314	1,409	1,653
Custom RCx						
Participation	10	13	14	18	21	27
Incentive Budget	$75,941	$98,028	$112,018	$141,617	$160,792	$207,801
Projected kWh Savings	749,687	951,308	1,077,575	1,386,171	1,567,117	1,996,328
Projected kW Savings	125	158	179	232	262	332
Custom SEM						
Participation	4	5	5	9	10	13
Incentive Budget	$12,035	$15,973	$17,716	$23,766	$26,899	$39,505
Projected kWh Savings	292,091	339,582	373,327	616,606	708,220	882,465
Projected kW Savings	39	42	46	87	101	116

TABLE 6-38: COMMERCIAL CUSTOM PROGRAM BUDGET SUMMARY

	2025	2026	2027	2028	2029	2030
Incentives	$685,440	$862,774	$1,000,185	$1,180,522	$1,296,488	$1,519,017
Delivery & Implementation	$641,012	$828,242	$976,000	$1,200,377	$1,360,806	$1,651,219
Admin	$120,190	$155,295	$183,000	$225,071	$255,151	$309,604
Total Budget	$1,486,705	$1,898,077	$2,220,185	$2,680,993	$2,997,495	$3,583,041
Participation	78	97	110	131	143	167
Energy Savings (kWh)	6,394,169	7,977,395	9,072,627	10,798,876	11,834,726	13,937,265
Demand Savings (kW)	1,150	1,455	1,664	1,996	2,159	2,500
Weighted Program EUL	9.2	9.1	9.1	8.6	8.4	8.3
NTG	93%	93%	93%	93%	93%	93%

6.14 COST-EFFECTIVENESS

As part of the development of the DSM Action Plan, GDS evaluated the cost-effectiveness results of each program. Table 6-39 provides program-level, sector-level and overall portfolio-level cost-effectiveness results. The TRC and UCT ratios are provided, along with TRC and UCT net benefits.[14] The overall portfolio has a TRC ratio of 1.6 and a UCT ratio of 2.1.

TABLE 6-39: DSM ACTION PLAN BENEFIT-COST RATIOS – BY PROGRAM AND SECTOR

Program/Sector	TRC Ratio	UCT Ratio	TRC Net Benefits (S)	UCT Net Benefits (S)
Residential				
Residential Prescriptive	2.3	2.2	$30,850,282	$28,998,433
Residential New Construction	1.5	1.5	$301,459	$299,674
Community Connections	1.8	2.0	$1,955,223	$2,273,593
Income Qualified Weatherization	0.6	0.5	($1,904,830)	($1,972,814)
Residential Behavioral	1.6	1.6	$1,339,915	$1,339,915
Appliance Recycling	1.6	1.5	$680,369	$583,399
Residential Emerging Markets Pilot	1.8	2.3	$5,565,511	$5,659,599
Smart Cycle	1.5	1.5	$791,867	$791,867
Bring Your Own Thermostat	1.5	1.9	$3,218,513	$4,410,366
Residential Sub-total	***1.9***	***1.9***	***$42,798,308***	***$42,384,033***
Commercial				
Prescriptive Rebate	2.0	3.8	$21,732,120	$32,132,056
Small Business Energy Solutions	1.9	2.0	$6,511,460	$6,934,175
Custom	1.3	3.1	$8,870,404	$25,942,934
Commercial	***1.6***	***3.1***	***$37,113,984***	***$65,009,165***
All Sectors				
Total	***1.6***	***2.1***	***$79,912,292***	***$107,393,199***

Table 6-40 provides the annual program-level TRC ratios in the DSM Action Plan. All programs are cost-effective each year of the analysis. The overall portfolio is cost-effective when factoring in indirect costs.

TABLE 6-40: ANNUAL TRC RATIOS – BY PROGRAM

Annual TRC Ratios	2025	2026	2027	2028	2029	2030
Residential Programs						
Residential Prescriptive	2.32	2.35	2.39	2.37	2.35	2.23
Residential New Construction	1.44	1.49	1.52	1.55	1.57	1.57
Community Connections	1.50	1.30	1.29	1.32	1.25	1.08

[14] The Income Qualified Weatherization program does not need to be cost-effective.

Annual TRC Ratios	2025	2026	2027	2028	2029	2030
Income Qualified Weatherization	0.47	0.41	0.41	0.42	0.39	0.34
Residential Behavioral	1.59	1.59	1.61	1.66	1.67	1.67
Appliance Recycling	1.58	1.61	1.64	1.66	1.68	1.70
Residential Emerging Markets Pilot	1.56	1.69	1.82	1.92	1.72	1.88
Smart Cycle	1.04	1.26	1.37	1.47	1.58	1.67
Bring Your Own Thermostat	1.03	1.45	1.57	1.67	1.77	1.86
Residential Sub-total	***1.70***	***1.76***	***1.81***	***1.79***	***1.72***	***1.67***
C&I Programs						
Prescriptive Rebate	1.78	1.90	2.00	2.08	2.15	2.13
Small Business Energy Solutions	1.67	1.78	1.89	1.97	2.03	2.03
Custom	1.22	1.25	1.29	1.31	1.33	1.36
C&I Sub-total	***1.54***	***1.59***	***1.64***	***1.66***	***1.68***	***1.65***
Total	**1.49**	**1.56**	**1.69**	**1.59**	**1.59**	**1.55**

Table 6-42 provides the annual program-level UCT ratios in the DSM Action Plan. All programs are cost-effective each year of the analysis. The overall portfolio is cost-effective when factoring in indirect costs.

TABLE 6-41: ANNUAL UCT RATIOS – BY PROGRAM

Annual UCT Ratios	2025	2026	2027	2028	2029	2030
Residential Programs						
Residential Prescriptive	2.49	2.49	2.47	2.48	2.44	2.42
Residential New Construction	1.57	1.57	1.55	1.52	1.48	1.44
Community Connections	1.65	1.40	1.41	1.45	1.41	1.22
Income Qualified Weatherization	0.44	0.37	0.37	0.38	0.37	0.32
Residential Behavioral	1.59	1.59	1.61	1.66	1.67	1.67
Appliance Recycling	1.44	1.47	1.50	1.52	1.54	1.57
Residential Emerging Markets Pilot	2.10	2.20	2.29	2.38	2.29	2.48
Smart Cycle	1.04	1.26	1.37	1.47	1.58	1.67
Bring Your Own Thermostat	1.53	1.80	1.91	2.01	2.10	2.19
Residential Sub-total	***1.85***	***1.83***	***1.84***	***1.84***	***1.80***	***1.76***
C&I Programs						
Prescriptive Rebate	3.53	3.67	3.79	3.88	3.99	4.09

Annual UCT Ratios	2025	2026	2027	2028	2029	2030
Small Business Energy Solutions	1.77	1.89	2.00	2.08	2.15	2.14
Custom	3.02	3.08	3.13	3.07	3.08	3.08
C&I Sub-total	***2.84***	***2.98***	***3.11***	***3.16***	***3.22***	***3.26***
Total	**2.01**	**2.11**	**2.01**	**2.16**	**2.20**	**2.20**

VOLUME II

Appendices

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Appendix A. C&I Opt-Out Results

This section provides the potential results for technical, economic, MAP and RAP for the C&I sector, with opt-out customers included. A comparison of the RAP scenario (with without opt-out customers included) savings potential and RAP budgets is also provided.

Table A-1 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The forecasted sales, including opt-out customers are nearly double the forecast used in the base analysis, with nearly 90% of the forecasted sales growth coming from the industrial sector.

TABLE A-1: C&I CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – INCLUDING OPT-OUT

	2025	2026	2027	2030	2042
MWh					
Technical	84,651	176,410	272,966	567,724	1,205,797
Economic	83,977	174,830	270,437	562,069	1,187,492
MAP	46,905	98,486	152,758	329,062	916,832
RAP	30,222	63,733	99,147	214,159	599,723
Forecasted Sales	4,311,831	4,327,633	4,347,983	4,421,467	4,696,513
Technical	2.0%	4.1%	6.3%	12.8%	25.7%
Economic	1.9%	4.0%	6.2%	12.7%	25.3%
MAP	1.1%	2.3%	3.5%	7.4%	19.5%
RAP	0.7%	1.5%	2.3%	4.8%	12.8%

Figure A-1 provides the RAP results for the 3-year, 6-year, and 18-year timeframes for both the RAP scenario and the RAP scenario including opt-out customers. The savings as a percentage of forecasted sales are higher in the base RAP scenario, through total MWh savings are higher in the scenario in which opt-out customers are included in the analysis. Savings (as a percentage of forecasted sales) are lower when opt-out sales are included because of the large increase in the industrial sector, where overall future potential is estimates to be lower than in the commercial sector.

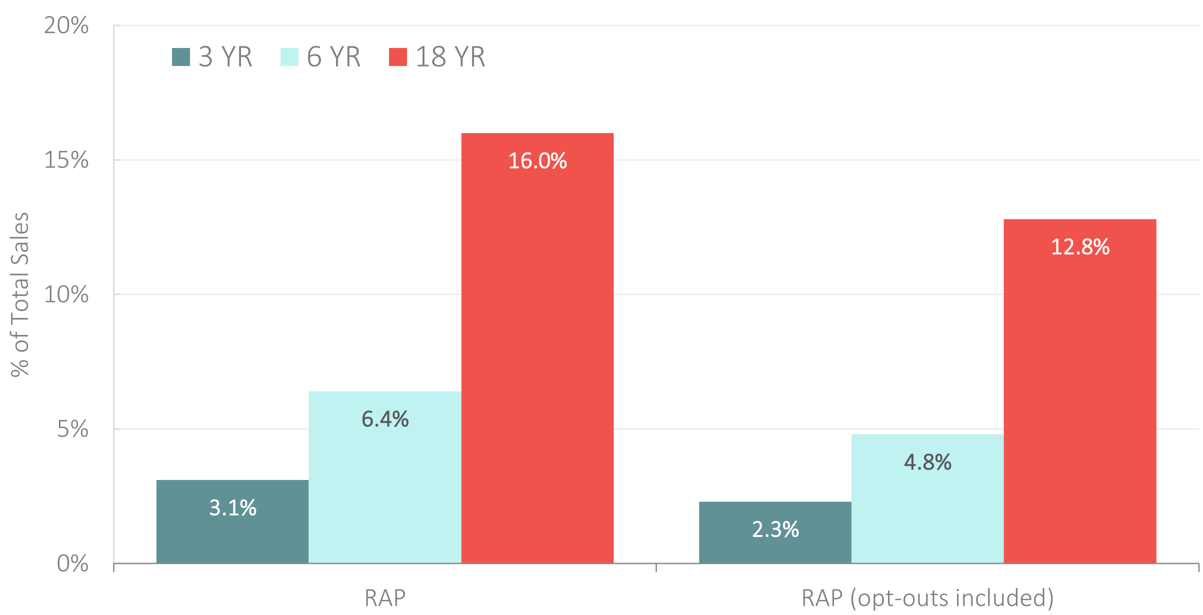

FIGURE A-1: C&I ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF C&I SALES)

Figure A-2 provides the annual budgets for commercial RAP, with and without opt-out customers. The budgets in the RAP scenario range from roughly $4 million to $7 million, while the budgets in the RAP scenario with opt-out customers included range from $5.4 million to $12 million.

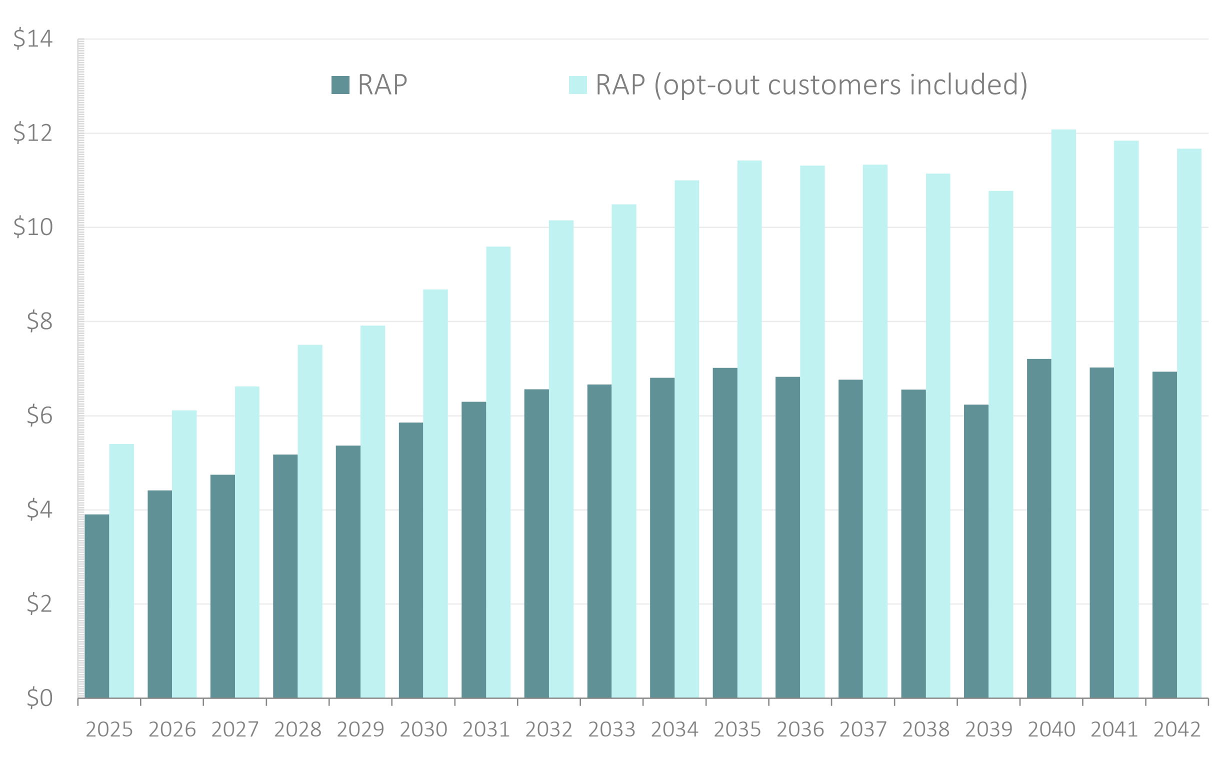

FIGURE A-2: C&I RAP BUDGETS – WITHOUT AND WITH OPT-OUT CUSTOMERS

Appendix B. Residential Sector Measure Detail

Appendix B: Residential Measure Assumptions

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
Measure #: Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. **End Use Measure Group:** Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **UCT Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
1001	Appliances	ENERGY STAR Air Purifier	Residential Instant Rebate	SF	N/A	MO	533	57%	303	0.03	9	$92	100%	54%	PUR-1	12%	29%	98%	55%	3.0
1002	Appliances	ENERGY STAR Air Purifier	Residential Marketplace	SF	N/A	MO	533	57%	303	0.03	9	$92	100%	54%	PUR-1	12%	29%	98%	55%	3.0
1003	Appliances	ENERGY STAR Air Purifier	Residential Instant Rebate	SF	N/A	NC	533	57%	303	0.03	9	$92	100%	54%	PUR-2	12%	0%	99%	55%	3.0
1004	Appliances	ENERGY STAR Air Purifier	Residential Marketplace	SF	N/A	NC	533	57%	303	0.03	9	$92	100%	54%	PUR-2	12%	0%	99%	55%	3.0
1005	Appliances	ENERGY STAR Air Purifier	Residential Instant Rebate	MF	N/A	MO	533	57%	303	0.03	9	$92	100%	54%	PUR-3	12%	29%	98%	55%	3.0
1006	Appliances	ENERGY STAR Air Purifier	Residential Marketplace	MF	N/A	MO	533	57%	303	0.03	9	$92	100%	54%	PUR-3	12%	29%	98%	55%	3.0
1007	Appliances	ENERGY STAR Air Purifier	Residential Instant Rebate	MF	N/A	NC	533	57%	303	0.03	9	$92	100%	54%	PUR-4	12%	0%	99%	55%	3.0
1008	Appliances	ENERGY STAR Air Purifier	Residential Marketplace	MF	N/A	NC	533	57%	303	0.03	9	$92	100%	54%	PUR-4	12%	0%	99%	55%	3.0
1009	Appliances	ENERGY STAR Refrigerator - early replacement	IQW	SF	LI	ER1	1,012	100%	1,012	0.15	6	$580	100%	100%	REF-2	100%	38%	96%	95%	0.7
1010	Appliances	ENERGY STAR Refrigerator - early replacement	IQW	MF	LI	ER1	1,012	100%	1,012	0.15	6	$580	100%	100%	REF-5	100%	38%	96%	95%	0.7
1011	Appliances	ENERGY STAR Refrigerator	No program	SF	NLI	MO	369	10%	37	0.01	16	$40	80%	80%	REF-1	100%	38%	48%	55%	1.0
1012	Appliances	ENERGY STAR Refrigerator	No program	SF	N/A	NC	369	10%	37	0.01	16	$40	80%	80%	REF-3	115%	0%	35%	55%	1.0
1013	Appliances	ENERGY STAR Refrigerator	No program	MF	NLI	MO	369	10%	37	0.01	16	$40	80%	80%	REF-4	100%	38%	48%	55%	1.0
1014	Appliances	ENERGY STAR Refrigerator	No program	MF	N/A	NC	369	10%	37	0.01	16	$40	80%	80%	REF-6	107%	0%	35%	55%	1.0
1015	Appliances	CEE Tier 2 Refrigerator	No program	SF	NLI	MO	369	15%	55	0.01	16	$140	80%	80%	REF-1	100%	38%	48%	55%	0.4
1016	Appliances	CEE Tier 2 Refrigerator	No program	SF	N/A	NC	369	15%	55	0.01	16	$140	80%	80%	REF-3	115%	0%	35%	55%	0.4
1017	Appliances	CEE Tier 2 Refrigerator	No program	MF	NLI	MO	369	15%	55	0.01	16	$140	80%	80%	REF-4	100%	38%	48%	55%	0.4
1018	Appliances	CEE Tier 2 Refrigerator	No program	MF	N/A	NC	369	15%	55	0.01	16	$140	80%	80%	REF-6	107%	0%	35%	55%	0.4
1019	Appliances	Smart Refrigerator	No program	SF	NLI	MO	369	20%	74	0.01	16	$1,078	80%	80%	REF-1	100%	38%	48%	55%	0.1
1020	Appliances	Smart Refrigerator	No program	SF	N/A	NC	369	20%	74	0.01	16	$1,078	80%	80%	REF-3	115%	0%	35%	55%	0.1
1021	Appliances	Smart Refrigerator	No program	MF	NLI	MO	369	20%	74	0.01	16	$1,078	80%	80%	REF-4	100%	38%	48%	55%	0.1
1022	Appliances	Smart Refrigerator	No program	MF	N/A	NC	369	20%	74	0.01	16	$1,078	80%	80%	REF-6	107%	0%	35%	55%	0.1
1023	Appliances	Refrigerator Recycling	Appliance Recycling	SF	N/A	Recycle	1,014	100%	1,014	0.15	8	$50	100%	100%	REF REC-1	15%	0%	99%	95%	9.9
1024	Appliances	Refrigerator Recycling	Appliance Recycling	MF	N/A	Recycle	1,014	100%	1,014	0.15	8	$50	100%	100%	REF REC-2	15%	0%	99%	95%	9.9
1025	Appliances	Freezer Recycling	Appliance Recycling	SF	N/A	Recycle	722	100%	722	0.11	8	$50	100%	100%	FRZ REC-1	2%	0%	99%	95%	7.0
1026	Appliances	Freezer Recycling	Appliance Recycling	MF	N/A	Recycle	722	100%	722	0.11	8	$50	100%	100%	FRZ REC-2	2%	0%	99%	95%	7.0
1027	Appliances	Dehumidifier Recycling	Appliance Recycling	SF	N/A	Recycle	1,000	100%	1,000	0.00	7	$20	100%	100%	DEH-1	30%	0%	47%	73%	14.1
1028	Appliances	Dehumidifier Recycling	Appliance Recycling	MF	N/A	Recycle	1,000	100%	1,000	0.00	7	$20	100%	100%	DEH-3	30%	0%	47%	73%	14.1
1029	Appliances	ENERGY STAR Freezer - Chest	No program	SF	N/A	MO	311	10%	31	0.01	22	$35	75%	71%	FRZ-1	27%	16%	37%	49%	1.5
1030	Appliances	ENERGY STAR Freezer - Chest	No program	SF	N/A	NC	311	10%	31	0.01	22	$35	75%	71%	FRZ-2	29%	0%	33%	49%	1.5
1031	Appliances	ENERGY STAR Freezer - Chest	No program	MF	N/A	MO	311	10%	31	0.01	22	$35	75%	71%	FRZ-3	27%	16%	37%	49%	1.5
1032	Appliances	ENERGY STAR Freezer - Chest	No program	MF	N/A	NC	311	10%	31	0.01	22	$35	75%	71%	FRZ-4	29%	0%	33%	49%	1.5
1033	Appliances	ENERGY STAR Freezer - Compact Upright	No program	SF	N/A	MO	467	10%	47	0.01	22	$35	100%	71%	FRZ-1	27%	16%	42%	49%	2.2
1034	Appliances	ENERGY STAR Freezer - Compact Upright	No program	SF	N/A	NC	467	10%	47	0.01	22	$35	100%	71%	FRZ-2	29%	0%	47%	49%	2.2
1035	Appliances	ENERGY STAR Freezer - Compact Upright	No program	MF	N/A	MO	467	10%	47	0.01	22	$35	100%	71%	FRZ-3	27%	16%	42%	49%	2.2
1036	Appliances	ENERGY STAR Freezer - Compact Upright	No program	MF	N/A	NC	467	10%	47	0.01	22	$35	100%	71%	FRZ-4	29%	0%	47%	49%	2.2
1037	Appliances	ENERGY STAR Dehumidifier	Residential Prescriptive	SF	N/A	MO	1,095	12%	134	0.03	10	$10	100%	100%	DEH-1	30%	88%	95%	95%	2.7
1038	Appliances	ENERGY STAR Dehumidifier	Residential Instant Rebate	SF	N/A	MO	1,095	12%	134	0.03	10	$10	100%	100%	DEH-1	30%	88%	95%	95%	2.7
1039	Appliances	ENERGY STAR Dehumidifier	Residential Prescriptive	SF	N/A	NC	1,095	12%	134	0.03	10	$10	100%	100%	DEH-2	30%	0%	99%	95%	2.7
1040	Appliances	ENERGY STAR Dehumidifier	Residential Marketplace	SF	N/A	NC	1,095	12%	134	0.03	10	$10	100%	100%	DEH-2	30%	0%	99%	95%	2.7
1041	Appliances	ENERGY STAR Dehumidifier	Residential Prescriptive	MF	N/A	MO	1,095	12%	134	0.03	10	$10	100%	100%	DEH-3	30%	88%	95%	95%	2.7
1042	Appliances	ENERGY STAR Dehumidifier	Residential Instant Rebate	MF	N/A	MO	1,095	12%	134	0.03	10	$10	100%	100%	DEH-3	30%	88%	95%	95%	2.7
1043	Appliances	ENERGY STAR Dehumidifier	Residential Prescriptive	MF	N/A	NC	1,095	12%	134	0.03	10	$10	100%	100%	DEH-4	30%	0%	99%	95%	2.7
1044	Appliances	ENERGY STAR Dehumidifier	Residential Marketplace	MF	N/A	NC	1,095	12%	134	0.03	10	$10	100%	100%	DEH-4	30%	0%	99%	95%	2.7
1045	Appliances	ENERGY STAR Most Efficient Dehumidifier	Residential Prescriptive	SF	N/A	MO	1,095	25%	273	0.06	10	$75	100%	47%	DEH-1	30%	88%	95%	51%	5.5
1046	Appliances	ENERGY STAR Most Efficient Dehumidifier	Residential Instant Rebate	SF	N/A	MO	1,095	25%	273	0.06	10	$75	100%	47%	DEH-1	30%	88%	95%	51%	5.5
1047	Appliances	ENERGY STAR Most Efficient Dehumidifier	Residential Prescriptive	SF	N/A	NC	1,095	25%	273	0.06	10	$75	100%	47%	DEH-2	30%	0%	99%	51%	5.5
1048	Appliances	ENERGY STAR Most Efficient Dehumidifier	Residential Marketplace	SF	N/A	NC	1,095	25%	273	0.06	10	$75	100%	47%	DEH-2	30%	0%	99%	51%	5.5

Appendix B: Residential Measure Assumptions

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
Measure #: Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. **End Use Measure Group:** Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **UCT Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
1049	Appliances	ENERGY STAR Most Efficient Dehumidifier	Residential Prescriptive	MF	N/A	MO	1,095	25%	273	0.06	10	$75	100%	47%	DEH-3	30%	88%	95%	51%	5.5
1050	Appliances	ENERGY STAR Most Efficient Dehumidifier	Residential Instant Rebate	MF	N/A	MO	1,095	25%	273	0.06	10	$75	100%	47%	DEH-3	30%	88%	95%	51%	5.5
1051	Appliances	ENERGY STAR Most Efficient Dehumidifier	Residential Prescriptive	MF	N/A	NC	1,095	25%	273	0.06	10	$75	100%	47%	DEH-4	30%	0%	99%	51%	5.5
1052	Appliances	ENERGY STAR Most Efficient Dehumidifier	Residential Marketplace	MF	N/A	NC	1,095	25%	273	0.06	10	$75	100%	47%	DEH-4	30%	0%	99%	51%	5.5
1053	Appliances	ENERGY STAR Dishwasher (E WH)	No program	SF	N/A	MO	307	12%	37	0.00	11	$76	66%	66%	DISH-1	26%	92%	93%	46%	0.4
1054	Appliances	ENERGY STAR Dishwasher (E WH)	No program	SF	N/A	NC	307	12%	37	0.00	11	$76	66%	66%	DISH-3	26%	0%	31%	46%	0.4
1055	Appliances	ENERGY STAR Dishwasher (E WH)	No program	MF	N/A	MO	307	12%	37	0.00	11	$76	66%	66%	DISH-5	26%	92%	93%	46%	0.4
1056	Appliances	ENERGY STAR Dishwasher (E WH)	No program	MF	N/A	NC	307	12%	37	0.00	11	$76	66%	66%	DISH-6	26%	0%	31%	46%	0.4
1057	Appliances	ENERGY STAR Dishwasher (NG WH)	No program	SF	N/A	MO	135	12%	16	0.00	11	$76	66%	66%	DISH-2	41%	92%	93%	46%	0.2
1058	Appliances	ENERGY STAR Dishwasher (NG WH)	No program	SF	N/A	NC	135	12%	16	0.00	11	$76	66%	66%	DISH-4	41%	0%	31%	46%	0.2
1059	Appliances	ENERGY STAR Dishwasher (NG WH)	No program	MF	N/A	MO	135	12%	16	0.00	11	$76	66%	66%	DISH-7	41%	92%	93%	46%	0.2
1060	Appliances	ENERGY STAR Dishwasher (NG WH)	No program	MF	N/A	NC	135	12%	16	0.00	11	$76	66%	66%	DISH-8	41%	0%	31%	46%	0.2
1061	Appliances	Smart Dishwasher (E WH)	No program	SF	N/A	MO	307	8%	24	0.00	11	$76	66%	66%	DISH-1	26%	92%	93%	46%	0.3
1062	Appliances	Smart Dishwasher (E WH)	No program	SF	N/A	NC	307	8%	24	0.00	11	$76	66%	66%	DISH-3	26%	0%	31%	46%	0.3
1063	Appliances	Smart Dishwasher (E WH)	No program	MF	N/A	MO	307	8%	24	0.00	11	$76	66%	66%	DISH-5	26%	92%	93%	46%	0.3
1064	Appliances	Smart Dishwasher (E WH)	No program	MF	N/A	NC	307	8%	24	0.00	11	$76	66%	66%	DISH-6	26%	0%	31%	46%	0.3
1065	Appliances	Smart Dishwasher (NG WH)	No program	SF	N/A	MO	135	8%	11	0.00	11	$76	66%	66%	DISH-2	41%	92%	93%	46%	0.1
1066	Appliances	Smart Dishwasher (NG WH)	No program	SF	N/A	NC	135	8%	11	0.00	11	$76	66%	66%	DISH-4	41%	0%	31%	46%	0.1
1067	Appliances	Smart Dishwasher (NG WH)	No program	MF	N/A	MO	135	8%	11	0.00	11	$76	66%	66%	DISH-7	41%	92%	93%	46%	0.1
1068	Appliances	Smart Dishwasher (NG WH)	No program	MF	N/A	NC	135	8%	11	0.00	11	$76	66%	66%	DISH-8	41%	0%	31%	46%	0.1
1069	Appliances	ENERGY STAR Clothes Washer (Electrc WH/Dryer)	Residential Prescriptive	SF	N/A	MO	590	34%	202	0.03	10	$84	100%	60%	CW-1	56%	63%	96%	58%	2.3
1070	Appliances	ENERGY STAR Clothes Washer (Electrc WH/Dryer)	Residential Prescriptive	SF	N/A	NC	590	34%	202	0.03	10	$84	100%	60%	CW-2	56%	0%	99%	58%	2.3
1071	Appliances	ENERGY STAR Clothes Washer (Electrc WH/Dryer)	Residential Prescriptive	MF	N/A	MO	590	34%	202	0.03	10	$84	100%	60%	CW-3	56%	63%	96%	58%	2.3
1072	Appliances	ENERGY STAR Clothes Washer (Electrc WH/Dryer)	Residential Prescriptive	MF	N/A	NC	590	34%	202	0.03	10	$84	100%	60%	CW-4	56%	0%	99%	58%	2.3
1073	Appliances	ENERGY STAR Clothes Washer (NG WH/E Dryer)	Residential Prescriptive	SF	N/A	MO	434	47%	202	0.03	10	$84	100%	60%	CW-5	56%	63%	96%	58%	2.3
1074	Appliances	ENERGY STAR Clothes Washer (NG WH/E Dryer)	Residential Prescriptive	SF	N/A	NC	434	47%	202	0.03	10	$84	100%	60%	CW-6	56%	0%	99%	58%	2.3
1075	Appliances	ENERGY STAR Clothes Washer (NG WH/E Dryer)	Residential Prescriptive	MF	N/A	MO	434	47%	202	0.03	10	$84	100%	60%	CW-7	56%	63%	96%	58%	2.3
1076	Appliances	ENERGY STAR Clothes Washer (NG WH/E Dryer)	Residential Prescriptive	MF	N/A	NC	434	47%	202	0.03	10	$84	100%	60%	CW-8	56%	0%	99%	58%	2.3
1077	Appliances	Smart/CEE Tier 2 Clothes Washer (Electrc WH/Dryer)	Residential Emerging Markets Pilot	SF	N/A	MO	590	40%	236	0.03	10	$141	75%	35%	CW-1	56%	63%	64%	32%	2.7
1078	Appliances	Smart/CEE Tier 2 Clothes Washer (Electrc WH/Dryer)	Residential Emerging Markets Pilot	SF	N/A	NC	590	40%	236	0.03	10	$141	75%	35%	CW-2	56%	0%	33%	32%	2.7
1079	Appliances	Smart/CEE Tier 2 Clothes Washer (Electrc WH/Dryer)	Residential Emerging Markets Pilot	MF	N/A	MO	590	40%	236	0.03	10	$141	75%	35%	CW-3	56%	63%	64%	32%	2.7
1080	Appliances	Smart/CEE Tier 2 Clothes Washer (Electrc WH/Dryer)	Residential Emerging Markets Pilot	MF	N/A	NC	590	40%	236	0.03	10	$141	75%	35%	CW-4	56%	0%	33%	32%	2.7
1081	Appliances	Smart/CEE Tier 2 Clothes Washer (NG WH/E Dryer)	Residential Emerging Markets Pilot	SF	N/A	MO	434	26%	114	0.01	10	$141	35%	35%	CW-5	56%	63%	64%	32%	1.3
1082	Appliances	Smart/CEE Tier 2 Clothes Washer (NG WH/E Dryer)	Residential Emerging Markets Pilot	SF	N/A	NC	434	26%	114	0.01	10	$141	35%	35%	CW-6	56%	0%	31%	32%	1.3
1083	Appliances	Smart/CEE Tier 2 Clothes Washer (NG WH/E Dryer)	Residential Emerging Markets Pilot	MF	N/A	MO	434	26%	114	0.01	10	$141	35%	35%	CW-7	56%	63%	64%	32%	1.3
1084	Appliances	Smart/CEE Tier 2 Clothes Washer (NG WH/E Dryer)	Residential Emerging Markets Pilot	MF	N/A	NC	434	26%	114	0.01	10	$141	35%	35%	CW-8	56%	0%	31%	32%	1.3
1085	Appliances	ENERGY STAR Clothes Dryer (Electric)	Residential Prescriptive	SF	N/A	MO	769	21%	160	0.02	11	$152	50%	33%	CD-1	56%	17%	50%	41%	2.0

Appendix B: Residential Measure Assumptions

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
Measure #: Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. **End Use Measure Group:** Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **UCT Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
1086	Appliances	ENERGY STAR Clothes Dryer (Electric)	Residential Prescriptive	SF	N/A	NC	769	21%	160	0.02	11	$152	50%	33%	CD-2	56%	0%	55%	41%	2.0
1087	Appliances	ENERGY STAR Clothes Dryer (Electric)	Residential Prescriptive	MF	N/A	MO	769	21%	160	0.02	11	$152	50%	33%	CD-3	56%	17%	50%	41%	2.0
1088	Appliances	ENERGY STAR Clothes Dryer (Electric)	Residential Prescriptive	MF	N/A	NC	769	21%	160	0.02	11	$152	50%	33%	CD-4	56%	0%	55%	41%	2.0
1089	Appliances	Smart Clothes Dryer (Electric)	Residential Emerging Markets Pilot	SF	N/A	MO	769	7%	54	0.01	11	$636	8%	8%	CD-1	56%	17%	38%	19%	0.7
1090	Appliances	Smart Clothes Dryer (Electric)	Residential Emerging Markets Pilot	SF	N/A	NC	769	7%	54	0.01	11	$636	8%	8%	CD-2	56%	0%	31%	19%	0.7
1091	Appliances	Smart Clothes Dryer (Electric)	Residential Emerging Markets Pilot	MF	N/A	MO	769	7%	54	0.01	11	$636	8%	8%	CD-3	56%	17%	38%	19%	0.7
1092	Appliances	Smart Clothes Dryer (Electric)	Residential Emerging Markets Pilot	MF	N/A	NC	769	7%	54	0.01	11	$636	8%	8%	CD-4	56%	0%	31%	19%	0.7
1093	Appliances	Heat Pump Dryer	Residential Emerging Markets Pilot	SF	N/A	MO	769	49%	378	0.14	11	$900	6%	6%	CD-1	56%	17%	38%	18%	7.2
1094	Appliances	Heat Pump Dryer	Residential Emerging Markets Pilot	SF	N/A	NC	769	49%	378	0.14	11	$900	6%	6%	CD-2	56%	0%	31%	18%	7.2
1095	Appliances	Heat Pump Dryer	Residential Emerging Markets Pilot	MF	N/A	MO	769	49%	378	0.14	11	$900	6%	6%	CD-3	56%	17%	38%	18%	7.2
1096	Appliances	Heat Pump Dryer	Residential Emerging Markets Pilot	MF	N/A	NC	769	49%	378	0.14	11	$900	6%	6%	CD-4	56%	0%	31%	18%	7.2
2001	Behavior	Home Energy Reports	Residential Behavioral	SF	N/A	MO	9,835	2%	194	0.06	1	$0	100%	35%	HER-1	100%	28%	104%	100%	1.0
2002	Behavior	Home Energy Reports	Residential Behavioral	SF	N/A	NC	9,835	2%	194	0.06	1	$0	100%	35%	HER-2	100%	28%	104%	100%	1.0
2003	Behavior	Home Energy Reports	Residential Behavioral	MF	N/A	MO	9,835	2%	194	0.06	1	$0	100%	35%	HER-3	100%	28%	104%	100%	1.0
2004	Behavior	Home Energy Reports	Residential Behavioral	MF	N/A	NC	9,835	2%	194	0.06	1	$0	100%	35%	HER-4	100%	28%	104%	100%	1.0
2005	Behavior	Audit Recommendations - dual (Electric)	Residential Emerging Markets Pilot	SF	NLI	Retrofit	9,835	1%	81	0.02	1	$100	100%	100%	AUDIT-1	87%	0%	47%	73%	0.1
2006	Behavior	Audit Recommendations - Electric Only	Residential Emerging Markets Pilot	SF	NLI	Retrofit	9,835	1%	114	0.02	1	$100	100%	100%	AUDIT-2	11%	0%	47%	73%	0.1
2007	Behavior	Audit Recommendations - dual (Electric)	Residential Emerging Markets Pilot	MF	NLI	Retrofit	9,835	1%	81	0.02	1	$100	100%	100%	AUDIT-5	87%	0%	47%	73%	0.1
2008	Behavior	Audit Recommendations - Electric Only	Residential Emerging Markets Pilot	MF	NLI	Retrofit	9,835	1%	114	0.02	1	$100	100%	100%	AUDIT-6	11%	0%	47%	73%	0.1
2009	Behavior	Audit Recommendations - dual (Electric)	IQW	SF	LI	Retrofit	9,835	1%	81	0.02	1	$100	100%	100%	AUDIT-3	87%	0%	104%	100%	0.1
2010	Behavior	Audit Recommendations - Electric Only	IQW	SF	LI	Retrofit	9,835	1%	114	0.02	1	$100	100%	100%	AUDIT-4	11%	0%	104%	100%	0.1
2011	Behavior	Audit Recommendations - dual (Electric)	IQW	MF	LI	Retrofit	9,835	1%	81	0.02	1	$100	100%	100%	AUDIT-7	87%	0%	104%	100%	0.1
2012	Behavior	Audit Recommendations - Electric Only	IQW	MF	LI	Retrofit	9,835	1%	114	0.02	1	$100	100%	100%	AUDIT-8	11%	0%	104%	100%	0.1
2013	Behavior	Customer Education	Residential Emerging Markets Pilot	SF	N/A	MO	9,835	0%	27	0.00	1	$0	100%	35%	JSTOMER ED	100%	0%	47%	32%	1.0
2014	Behavior	Customer Education	Residential Emerging Markets Pilot	SF	N/A	NC	9,835	0%	27	0.00	1	$0	100%	35%	JSTOMER ED	100%	0%	47%	32%	1.0
2015	Behavior	Customer Education	Residential Emerging Markets Pilot	MF	N/A	MO	9,835	0%	27	0.00	1	$0	100%	35%	JSTOMER ED	100%	0%	47%	32%	1.0
2016	Behavior	Customer Education	Residential Emerging Markets Pilot	MF	N/A	NC	9,835	0%	27	0.00	1	$0	100%	35%	JSTOMER ED	100%	0%	47%	32%	1.0
2017	Behavior	AMI Data Portal	Residential Behavioral	SF	N/A	MO	9,835	2%	197	0.02	1	$0	100%	100%	AMI-1	100%	0%	104%	100%	35.6
2018	Behavior	AMI Data Portal	Residential Behavioral	SF	N/A	NC	9,835	2%	197	0.02	1	$0	100%	100%	AMI-2	100%	0%	104%	100%	35.6
2019	Behavior	AMI Data Portal	Residential Behavioral	MF	N/A	MO	9,835	2%	197	0.02	1	$0	100%	100%	AMI-3	100%	0%	104%	100%	35.6
2020	Behavior	AMI Data Portal	Residential Behavioral	MF	N/A	NC	9,835	2%	197	0.02	1	$0	100%	100%	AMI-4	100%	0%	104%	100%	35.6
3001	HVAC	ASHP Tune Up	Residential Prescriptive	SF	N/A	Retrofit	6,485	4%	289	0.14	5	$64	100%	78%	HP TUNE-1	4%	49%	83%	63%	3.3
3002	HVAC	ASHP Tune Up	Residential Prescriptive	MF	N/A	Retrofit	2,125	14%	289	0.14	5	$64	100%	78%	HP TUNE-2	4%	49%	83%	63%	3.3
3003	HVAC	Air Source Heat Pump 16 SEER - Heat pump baseline	Residential Midstream	SF	NLI	MO	6,485	7%	454	0.13	15	$1,233	16%	16%	HP-4	4%	56%	59%	30%	2.5
3004	HVAC	Air Source Heat Pump 16 SEER - Heat pump baseline	IQW	SF	LI	MO	6,485	7%	454	0.13	15	$1,233	100%	100%	HP-5	4%	56%	88%	89%	0.4
3005	HVAC	Air Source Heat Pump 16 SEER - Heat pump baseline	Residential New Construction	SF	N/A	NC	6,485	7%	454	0.13	15	$1,233	16%	16%	HP-9	5%	20%	31%	30%	2.5

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Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
3006	HVAC	Air Source Heat Pump 16 SEER - Heat pump baseline	Residential Midstream	MF	NLI	MO	2,125	7%	146	0.09	15	$1,233	16%	16%	HP-13	4%	56%	59%	30%	1.2
3007	HVAC	Air Source Heat Pump 16 SEER - Heat pump baseline	IQW	MF	LI	MO	2,125	7%	146	0.09	15	$1,233	100%	100%	HP-14	4%	56%	88%	89%	0.2
3008	HVAC	Air Source Heat Pump 16 SEER - Heat pump baseline	Residential New Construction	MF	N/A	NC	2,125	7%	146	0.09	15	$1,233	16%	16%	HP-15	5%	20%	31%	30%	1.2
3009	HVAC	Air Source Heat Pump 17 SEER - Heat pump baseline	Residential Midstream	SF	NLI	MO	6,485	10%	675	0.17	15	$1,644	18%	18%	HP-4	4%	56%	59%	32%	2.3
3010	HVAC	Air Source Heat Pump 17 SEER - Heat pump baseline	IQW	SF	LI	MO	6,485	10%	675	0.17	15	$1,644	100%	100%	HP-5	4%	56%	88%	89%	0.4
3011	HVAC	Air Source Heat Pump 17 SEER - Heat pump baseline	Residential New Construction	SF	N/A	NC	6,485	10%	675	0.17	15	$1,644	18%	18%	HP-9	5%	20%	31%	32%	2.3
3012	HVAC	Air Source Heat Pump 17 SEER - Heat pump baseline	Residential Midstream	MF	NLI	MO	2,125	11%	226	0.17	15	$1,644	18%	18%	HP-13	4%	56%	59%	32%	1.5
3013	HVAC	Air Source Heat Pump 17 SEER - Heat pump baseline	IQW	MF	LI	MO	2,125	11%	226	0.17	15	$1,644	100%	100%	HP-14	4%	56%	88%	89%	0.3
3014	HVAC	Air Source Heat Pump 17 SEER - Heat pump baseline	Residential New Construction	MF	N/A	NC	2,125	11%	226	0.17	15	$1,644	18%	18%	HP-15	5%	20%	31%	32%	1.5
3015	HVAC	Air Source Heat Pump 18 SEER - Heat pump baseline	Residential Midstream	SF	NLI	MO	6,485	16%	1,060	0.23	15	$2,055	19%	19%	HP-4	4%	56%	59%	32%	2.6
3016	HVAC	Air Source Heat Pump 18 SEER - Heat pump baseline	IQW	SF	LI	MO	6,485	16%	1,060	0.23	15	$2,055	100%	100%	HP-5	4%	56%	88%	89%	0.5
3017	HVAC	Air Source Heat Pump 18 SEER - Heat pump baseline	Residential New Construction	SF	N/A	NC	6,485	16%	1,060	0.23	15	$2,055	19%	19%	HP-9	5%	20%	31%	32%	2.6
3018	HVAC	Air Source Heat Pump 18 SEER - Heat pump baseline	Residential Midstream	MF	NLI	MO	2,125	16%	349	0.23	15	$2,055	19%	19%	HP-13	4%	56%	59%	32%	1.6
3019	HVAC	Air Source Heat Pump 18 SEER - Heat pump baseline	IQW	MF	LI	MO	2,125	16%	349	0.23	15	$2,055	100%	100%	HP-14	4%	56%	88%	89%	0.3
3020	HVAC	Air Source Heat Pump 18 SEER - Heat pump baseline	Residential New Construction	MF	N/A	NC	2,125	16%	349	0.23	15	$2,055	19%	19%	HP-15	5%	20%	31%	32%	1.6
3021	HVAC	Air Source Heat Pump 21 SEER - Heat pump baseline	Residential Midstream	SF	NLI	MO	6,485	23%	1,479	0.40	15	$2,055	50%	19%	HP-4	4%	56%	59%	32%	4.0
3022	HVAC	Air Source Heat Pump 21 SEER - Heat pump baseline	IQW	SF	LI	MO	6,485	23%	1,479	0.40	15	$2,055	100%	100%	HP-5	4%	56%	88%	89%	0.8
3023	HVAC	Air Source Heat Pump 21 SEER - Heat pump baseline	Residential New Construction	SF	N/A	NC	6,485	23%	1,479	0.40	15	$2,055	50%	19%	HP-9	5%	20%	31%	32%	4.0
3024	HVAC	Air Source Heat Pump 21 SEER - Heat pump baseline	Residential Midstream	MF	NLI	MO	2,125	24%	505	0.40	15	$2,055	19%	19%	HP-13	4%	56%	59%	32%	2.6
3025	HVAC	Air Source Heat Pump 21 SEER - Heat pump baseline	IQW	MF	LI	MO	2,125	24%	505	0.40	15	$2,055	100%	100%	HP-14	4%	56%	88%	89%	0.5
3026	HVAC	Air Source Heat Pump 21 SEER - Heat pump baseline	Residential New Construction	MF	N/A	NC	2,125	24%	505	0.40	15	$2,055	19%	19%	HP-15	5%	20%	31%	32%	2.6
3027	HVAC	Ground Source Heat Pump 20 SEER - Heat pump baseline	Residential Emerging Markets Pilot	SF	N/A	MO	6,485	16%	1,054	0.53	25	$11,871	80%	80%	HP-4	4%	56%	59%	55%	0.2
3028	HVAC	Ground Source Heat Pump 20 SEER - Heat pump baseline	Residential Emerging Markets Pilot	SF	N/A	NC	6,485	16%	1,054	0.53	25	$11,871	80%	80%	HP-9	4%	0%	35%	55%	0.2
3029	HVAC	Ground Source Heat Pump 21.5 SEER - Heat pump baseline	Residential Emerging Markets Pilot	SF	N/A	MO	6,485	23%	1,514	0.64	25	$11,871	80%	80%	HP-4	4%	56%	59%	55%	0.3
3030	HVAC	Ground Source Heat Pump 21.5 SEER - Heat pump baseline	Residential Emerging Markets Pilot	SF	N/A	NC	6,485	23%	1,514	0.64	25	$11,871	80%	80%	HP-9	4%	0%	35%	55%	0.3
3031	HVAC	Ground Source Heat Pump 23.5 SEER - Heat pump baseline	Residential Emerging Markets Pilot	SF	N/A	MO	6,485	30%	1,931	0.76	25	$11,871	80%	80%	HP-4	4%	56%	59%	55%	0.4
3032	HVAC	Ground Source Heat Pump 23.5 SEER - Heat pump baseline	Residential Emerging Markets Pilot	SF	N/A	NC	6,485	30%	1,931	0.76	25	$11,871	80%	80%	HP-9	4%	0%	35%	55%	0.4
3033	HVAC	Ground Source Heat Pump 29 SEER - Heat pump baseline	Residential Emerging Markets Pilot	SF	N/A	MO	6,485	38%	2,434	1.02	25	$11,871	80%	80%	HP-4	4%	56%	59%	55%	0.5
3034	HVAC	Ground Source Heat Pump 29 SEER - Heat pump baseline	Residential Emerging Markets Pilot	SF	N/A	NC	6,485	38%	2,434	1.02	25	$11,871	80%	80%	HP-9	4%	0%	35%	55%	0.5
3035	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline	Residential Midstream	SF	NLI	MO	6,485	9%	571	0.25	15	$267	100%	94%	HP-4	4%	56%	88%	80%	3.1
3036	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline	Residential Midstream	SF	LI	MO	6,485	9%	571	0.25	15	$267	100%	94%	HP-5	4%	56%	88%	80%	3.1
3037	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline	Residential Midstream	SF	N/A	NC	6,485	9%	571	0.25	15	$267	100%	94%	HP-9	4%	0%	92%	80%	3.1

Appendix B: Residential Measure Assumptions

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Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
3038	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline	Residential Midstream	MF	NLI	MO	2,125	9%	197	0.17	15	$267	100%	94%	HP-13	4%	56%	88%	80%	1.7
3039	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline	Residential Midstream	MF	LI	MO	2,125	9%	197	0.17	15	$267	100%	94%	HP-14	4%	56%	88%	80%	1.7
3040	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline	Residential Midstream	MF	N/A	NC	2,125	9%	197	0.17	15	$267	100%	94%	HP-15	4%	0%	92%	80%	1.7
3041	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline	Residential Midstream	SF	NLI	MO	6,485	12%	769	0.44	15	$267	100%	94%	HP-4	4%	56%	88%	80%	5.1
3042	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline	Residential Midstream	SF	LI	MO	6,485	12%	769	0.44	15	$267	100%	94%	HP-5	4%	56%	88%	80%	5.1
3043	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline	Residential Midstream	SF	N/A	NC	6,485	12%	769	0.44	15	$267	100%	94%	HP-9	4%	0%	92%	80%	5.1
3044	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline	Residential Midstream	MF	NLI	MO	2,125	13%	284	0.30	15	$267	100%	94%	HP-13	4%	56%	88%	80%	2.9
3045	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline	Residential Midstream	MF	LI	MO	2,125	13%	284	0.30	15	$267	100%	94%	HP-14	4%	56%	88%	80%	2.9
3046	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline	Residential Midstream	MF	N/A	NC	2,125	13%	284	0.30	15	$267	100%	94%	HP-15	4%	0%	92%	80%	2.9
3047	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline	Residential Midstream	SF	NLI	MO	6,485	17%	1,130	0.60	15	$533	100%	75%	HP-4	4%	56%	88%	60%	4.4
3048	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline	Residential Midstream	SF	LI	MO	6,485	17%	1,130	0.60	15	$533	100%	75%	HP-5	4%	56%	88%	60%	4.4
3049	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline	Residential Midstream	SF	N/A	NC	6,485	17%	1,130	0.60	15	$533	100%	75%	HP-9	4%	0%	92%	60%	4.4
3050	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline	Residential Midstream	MF	NLI	MO	2,125	19%	409	0.40	15	$533	100%	75%	HP-13	4%	56%	88%	60%	2.5
3051	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline	Residential Midstream	MF	LI	MO	2,125	19%	409	0.40	15	$533	100%	75%	HP-14	4%	56%	88%	60%	2.5
3052	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline	Residential Midstream	MF	N/A	NC	2,125	19%	409	0.40	15	$533	100%	75%	HP-15	4%	0%	92%	60%	2.5
3053	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline	Residential Midstream	SF	NLI	MO	6,485	19%	1,262	0.73	15	$820	100%	49%	HP-4	4%	56%	88%	43%	5.2
3054	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline	Residential Midstream	SF	LI	MO	6,485	19%	1,262	0.73	15	$820	100%	49%	HP-5	4%	56%	88%	43%	5.2
3055	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline	Residential Midstream	SF	N/A	NC	6,485	19%	1,262	0.73	15	$820	100%	49%	HP-9	4%	0%	92%	43%	5.2
3056	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline	Residential Midstream	MF	NLI	MO	2,125	22%	467	0.49	15	$820	100%	49%	HP-13	4%	56%	88%	43%	3.0
3057	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline	Residential Midstream	MF	LI	MO	2,125	22%	467	0.49	15	$820	100%	49%	HP-14	4%	56%	88%	43%	3.0
3058	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline	Residential Midstream	MF	N/A	NC	2,125	22%	467	0.49	15	$820	100%	49%	HP-15	4%	0%	92%	43%	3.0
3059	HVAC	Air Source Heat Pump 16 SEER - Furnace baseline	Residential Midstream	SF	NLI	MO	11,910	55%	6,533	0.19	15	$1,233	100%	16%	HP-1	6%	56%	88%	30%	20.0
3060	HVAC	Air Source Heat Pump 16 SEER - Furnace baseline	IQW	SF	LI	MO	11,910	55%	6,533	0.19	15	$1,233	100%	100%	HP-2	6%	56%	88%	89%	3.2
3061	HVAC	Air Source Heat Pump 16 SEER - Furnace baseline	Residential New Construction	SF	N/A	NC	11,910	55%	6,533	0.19	15	$1,233	100%	16%	HP-3	6%	20%	89%	30%	20.0
3062	HVAC	Air Source Heat Pump 16 SEER - Furnace baseline	Residential Midstream	MF	NLI	MO	3,156	51%	1,612	0.19	15	$1,233	75%	16%	HP-10	6%	56%	59%	30%	6.3
3063	HVAC	Air Source Heat Pump 16 SEER - Furnace baseline	IQW	MF	LI	MO	3,156	51%	1,612	0.19	15	$1,233	100%	100%	HP-11	6%	56%	88%	89%	1.0
3064	HVAC	Air Source Heat Pump 16 SEER - Furnace baseline	Residential New Construction	MF	N/A	NC	3,156	51%	1,612	0.19	15	$1,233	75%	16%	HP-12	6%	20%	52%	30%	6.3
3065	HVAC	Air Source Heat Pump 17 SEER - Furnace baseline	Residential Midstream	SF	NLI	MO	11,910	57%	6,733	0.27	15	$1,644	100%	18%	HP-1	6%	56%	88%	32%	14.2
3066	HVAC	Air Source Heat Pump 17 SEER - Furnace baseline	IQW	SF	LI	MO	11,910	57%	6,733	0.27	15	$1,644	100%	100%	HP-2	6%	56%	88%	89%	2.6
3067	HVAC	Air Source Heat Pump 17 SEER - Furnace baseline	Residential New Construction	SF	N/A	NC	11,910	57%	6,733	0.27	15	$1,644	100%	18%	HP-3	6%	20%	89%	32%	14.2
3068	HVAC	Air Source Heat Pump 17 SEER - Furnace baseline	Residential Midstream	MF	NLI	MO	3,156	53%	1,674	0.27	15	$1,644	75%	18%	HP-10	6%	56%	59%	32%	4.8
3069	HVAC	Air Source Heat Pump 17 SEER - Furnace baseline	IQW	MF	LI	MO	3,156	53%	1,674	0.27	15	$1,644	100%	100%	HP-11	6%	56%	88%	89%	0.9

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Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
3070	HVAC	Air Source Heat Pump 17 SEER - Furnace baseline	Residential New Construction	MF	N/A	NC	3,156	53%	1,674	0.27	15	$1,644	75%	18%	HP-12	6%	20%	52%	32%	4.8
3071	HVAC	Air Source Heat Pump 18 SEER - Furnace baseline	Residential Midstream	SF	NLI	MO	11,910	59%	7,075	0.34	15	$2,055	100%	19%	HP-1	6%	56%	88%	32%	11.4
3072	HVAC	Air Source Heat Pump 18 SEER - Furnace baseline	IQW	SF	LI	MO	11,910	59%	7,075	0.34	15	$2,055	100%	100%	HP-2	6%	56%	88%	89%	2.2
3073	HVAC	Air Source Heat Pump 18 SEER - Furnace baseline	Residential New Construction	SF	N/A	NC	11,910	59%	7,075	0.34	15	$2,055	100%	19%	HP-3	6%	20%	89%	32%	11.4
3074	HVAC	Air Source Heat Pump 18 SEER - Furnace baseline	Residential Midstream	MF	NLI	MO	3,156	56%	1,770	0.34	15	$2,055	50%	19%	HP-10	6%	56%	59%	32%	4.0
3075	HVAC	Air Source Heat Pump 18 SEER - Furnace baseline	IQW	MF	LI	MO	3,156	56%	1,770	0.34	15	$2,055	100%	100%	HP-11	6%	56%	88%	89%	0.8
3076	HVAC	Air Source Heat Pump 18 SEER - Furnace baseline	Residential New Construction	MF	N/A	NC	3,156	56%	1,770	0.34	15	$2,055	50%	19%	HP-12	6%	20%	31%	32%	4.0
3077	HVAC	Air Source Heat Pump 21 SEER - Furnace baseline	Residential Midstream	SF	NLI	MO	11,910	63%	7,456	0.50	15	$2,055	100%	19%	HP-1	6%	56%	88%	32%	12.8
3078	HVAC	Air Source Heat Pump 21 SEER - Furnace baseline	IQW	SF	LI	MO	11,910	63%	7,456	0.50	15	$2,055	100%	100%	HP-2	6%	56%	88%	89%	2.5
3079	HVAC	Air Source Heat Pump 21 SEER - Furnace baseline	Residential New Construction	SF	N/A	NC	11,910	63%	7,456	0.50	15	$2,055	100%	19%	HP-3	6%	20%	89%	32%	12.8
3080	HVAC	Air Source Heat Pump 21 SEER - Furnace baseline	Residential Midstream	MF	NLI	MO	3,156	60%	1,893	0.50	15	$2,055	75%	19%	HP-10	6%	56%	59%	32%	5.0
3081	HVAC	Air Source Heat Pump 21 SEER - Furnace baseline	IQW	MF	LI	MO	3,156	60%	1,893	0.50	15	$2,055	100%	100%	HP-11	6%	56%	88%	89%	1.0
3082	HVAC	Air Source Heat Pump 21 SEER - Furnace baseline	Residential New Construction	MF	N/A	NC	3,156	60%	1,893	0.50	15	$2,055	75%	19%	HP-12	6%	20%	52%	32%	5.0
3083	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Electric furnace baseline	Residential Midstream	SF	NLI	MO	11,910	56%	6,643	0.40	15	$1,004	100%	25%	HP-1	6%	56%	88%	36%	17.8
3084	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Electric furnace baseline	Residential Midstream	SF	LI	MO	11,910	56%	6,643	0.40	15	$1,004	100%	100%	HP-2	6%	56%	59%	73%	4.4
3085	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Electric furnace baseline	Residential Midstream	SF	N/A	NC	11,910	56%	6,643	0.40	15	$1,004	100%	25%	HP-3	6%	0%	92%	36%	17.8
3086	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Electric furnace baseline	Residential Midstream	MF	NLI	MO	3,156	52%	1,653	0.27	15	$1,004	100%	25%	HP-10	6%	56%	88%	36%	5.7
3087	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Electric furnace baseline	Residential Midstream	MF	LI	MO	3,156	52%	1,653	0.27	15	$1,004	100%	100%	HP-11	6%	56%	59%	73%	1.4
3088	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Electric furnace baseline	Residential Midstream	MF	N/A	NC	3,156	52%	1,653	0.27	15	$1,004	100%	25%	HP-12	6%	0%	92%	36%	5.7
3089	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Electric furnace baseline	Residential Midstream	SF	NLI	MO	11,910	57%	6,827	0.60	15	$1,004	100%	25%	HP-1	6%	56%	88%	36%	19.7
3090	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Electric furnace baseline	Residential Midstream	SF	LI	MO	11,910	57%	6,827	0.60	15	$1,004	100%	100%	HP-2	6%	56%	59%	73%	4.9
3091	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Electric furnace baseline	Residential Midstream	SF	N/A	NC	11,910	57%	6,827	0.60	15	$1,004	100%	25%	HP-3	6%	0%	92%	36%	19.7
3092	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Electric furnace baseline	Residential Midstream	MF	NLI	MO	3,156	55%	1,722	0.40	15	$1,004	100%	25%	HP-10	6%	56%	88%	36%	6.8
3093	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Electric furnace baseline	Residential Midstream	MF	LI	MO	3,156	55%	1,722	0.40	15	$1,004	100%	100%	HP-11	6%	56%	59%	73%	1.7
3094	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Electric furnace baseline	Residential Midstream	MF	N/A	NC	3,156	55%	1,722	0.40	15	$1,004	100%	25%	HP-12	6%	0%	92%	36%	6.8
3095	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Electric furnace baseline	Residential Midstream	SF	NLI	MO	11,910	60%	7,153	0.75	15	$1,070	100%	37%	HP-1	6%	56%	88%	40%	13.5
3096	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Electric furnace baseline	Residential Midstream	SF	LI	MO	11,910	60%	7,153	0.75	15	$1,070	100%	100%	HP-2	6%	56%	59%	73%	5.1
3097	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Electric furnace baseline	Residential Midstream	SF	N/A	NC	11,910	60%	7,153	0.75	15	$1,070	100%	37%	HP-3	6%	0%	92%	40%	13.5
3098	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Electric furnace baseline	Residential Midstream	MF	NLI	MO	3,156	58%	1,820	0.50	15	$1,070	100%	37%	HP-10	6%	56%	88%	40%	4.9
3099	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Electric furnace baseline	Residential Midstream	MF	LI	MO	3,156	58%	1,820	0.50	15	$1,070	100%	100%	HP-11	6%	56%	59%	73%	1.8
3100	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Electric furnace baseline	Residential Midstream	MF	N/A	NC	3,156	58%	1,820	0.50	15	$1,070	100%	37%	HP-12	6%	0%	92%	40%	4.9
3101	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Electric furnace baseline	Residential Midstream	SF	NLI	MO	11,910	61%	7,276	0.89	15	$1,557	100%	26%	HP-1	6%	56%	88%	36%	14.3

Appendix B: Residential Measure Assumptions

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
Measure #: Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. **End Use Measure Group:** Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **UCT Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
3102	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Electric furnace baseline	Residential Midstream	SF	LI	MO	11,910	61%	7,276	0.89	15	$1,557	100%	100%	HP-2	6%	56%	59%	73%	3.7
3103	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Electric furnace baseline	Residential Midstream	SF	N/A	NC	11,910	61%	7,276	0.89	15	$1,557	100%	26%	HP-3	6%	0%	92%	36%	14.3
3104	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Electric furnace baseline	Residential Midstream	MF	NLI	MO	3,156	59%	1,866	0.59	15	$1,557	100%	26%	HP-10	6%	56%	88%	36%	5.4
3105	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Electric furnace baseline	Residential Midstream	MF	LI	MO	3,156	59%	1,866	0.59	15	$1,557	100%	100%	HP-11	6%	56%	59%	73%	1.4
3106	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Electric furnace baseline	Residential Midstream	MF	N/A	NC	3,156	59%	1,866	0.59	15	$1,557	100%	26%	HP-12	6%	0%	92%	36%	5.4
3107	HVAC	AC Tune Up	Residential Prescriptive	SF	NLI	Retrofit	2,131	4%	89	0.15	5	$64	100%	39%	AC TUNE-1	90%	44%	85%	40%	5.1
3108	HVAC	AC Tune Up	Residential Prescriptive	MF	NLI	Retrofit	796	11%	89	0.15	5	$64	100%	39%	AC TUNE-2	90%	44%	85%	40%	5.1
3109	HVAC	AC Tune Up	IQW	SF	LI	Retrofit	2,131	7%	155	0.20	2	$64	100%	39%	AC TUNE-3	90%	44%	85%	40%	3.0
3110	HVAC	AC Tune Up	IQW	MF	LI	Retrofit	796	19%	155	0.20	2	$64	100%	39%	AC TUNE-4	90%	44%	85%	40%	3.0
3111	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Electric baseboard baseline	Residential Midstream	SF	NLI	MO	11,911	56%	6,652	0.40	15	$2,324	100%	11%	HP-6	1%	56%	88%	27%	17.8
3112	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Electric baseboard baseline	Residential Midstream	SF	LI	MO	11,911	56%	6,652	0.40	15	$2,324	100%	11%	HP-7	1%	56%	88%	27%	17.8
3113	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Electric baseboard baseline	Residential Midstream	SF	N/A	NC	11,911	56%	6,652	0.40	15	$2,324	100%	11%	HP-8	1%	0%	92%	27%	17.8
3114	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Electric baseboard baseline	Residential Midstream	MF	NLI	MO	3,114	53%	1,640	0.27	15	$2,324	50%	11%	HP-16	1%	56%	59%	27%	5.7
3115	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Electric baseboard baseline	Residential Midstream	MF	LI	MO	3,114	53%	1,640	0.27	15	$2,324	100%	11%	HP-17	1%	56%	88%	27%	5.7
3116	HVAC	Ductless Heat Pump 17 SEER 9.5 HSPF - Electric baseboard baseline	Residential Midstream	MF	N/A	NC	3,114	53%	1,640	0.27	15	$2,324	50%	11%	HP-18	1%	0%	45%	27%	5.7
3117	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Electric baseboard baseline	Residential Midstream	SF	NLI	MO	11,911	57%	6,835	0.60	15	$2,324	100%	11%	HP-6	1%	56%	88%	27%	19.7
3118	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Electric baseboard baseline	Residential Midstream	SF	LI	MO	11,911	57%	6,835	0.60	15	$2,324	100%	11%	HP-7	1%	56%	88%	27%	19.7
3119	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Electric baseboard baseline	Residential Midstream	SF	N/A	NC	11,911	57%	6,835	0.60	15	$2,324	100%	11%	HP-8	1%	0%	92%	27%	19.7
3120	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Electric baseboard baseline	Residential Midstream	MF	NLI	MO	3,114	55%	1,707	0.40	15	$2,324	50%	11%	HP-16	1%	56%	59%	27%	6.8
3121	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Electric baseboard baseline	Residential Midstream	MF	LI	MO	3,114	55%	1,707	0.40	15	$2,324	100%	11%	HP-17	1%	56%	88%	27%	6.8
3122	HVAC	Ductless Heat Pump 19 SEER 9.5 HSPF - Electric baseboard baseline	Residential Midstream	MF	N/A	NC	3,114	55%	1,707	0.40	15	$2,324	50%	11%	HP-18	1%	0%	45%	27%	6.8
3123	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Electric baseboard baseline	Residential Midstream	SF	NLI	MO	11,911	60%	7,159	0.75	15	$2,590	100%	15%	HP-6	1%	56%	88%	30%	13.5
3124	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Electric baseboard baseline	Residential Midstream	SF	LI	MO	11,911	60%	7,159	0.75	15	$2,590	100%	15%	HP-7	1%	56%	88%	30%	13.5
3125	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Electric baseboard baseline	Residential Midstream	SF	N/A	NC	11,911	60%	7,159	0.75	15	$2,590	100%	15%	HP-8	1%	0%	92%	30%	13.5
3126	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Electric baseboard baseline	Residential Midstream	MF	NLI	MO	3,114	58%	1,803	0.50	15	$2,590	50%	15%	HP-16	1%	56%	59%	30%	4.9
3127	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Electric baseboard baseline	Residential Midstream	MF	LI	MO	3,114	58%	1,803	0.50	15	$2,590	100%	15%	HP-17	1%	56%	88%	30%	4.9

Appendix B: Residential Measure Assumptions

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
Measure #: Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. **End Use Measure Group:** Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **UCT Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
3128	HVAC	Ductless Heat Pump 21 SEER 10.0 HSPF - Electric baseboard baseline	Residential Midstream	MF	N/A	NC	3,114	58%	1,803	0.50	15	$2,590	50%	15%	HP-18	1%	0%	45%	30%	4.9
3129	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Electric baseboard baseline	Residential Midstream	SF	NLI	MO	11,911	61%	7,282	0.89	15	$2,877	100%	14%	HP-6	1%	56%	88%	29%	14.3
3130	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Electric baseboard baseline	Residential Midstream	SF	LI	MO	11,911	61%	7,282	0.89	15	$2,877	100%	14%	HP-7	1%	56%	88%	29%	14.3
3131	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Electric baseboard baseline	Residential Midstream	SF	N/A	NC	11,911	61%	7,282	0.89	15	$2,877	100%	14%	HP-8	1%	0%	92%	29%	14.3
3132	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Electric baseboard baseline	Residential Midstream	MF	NLI	MO	3,114	59%	1,847	0.59	15	$2,877	50%	14%	HP-16	1%	56%	59%	29%	5.4
3133	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Electric baseboard baseline	Residential Midstream	MF	LI	MO	3,114	59%	1,847	0.59	15	$2,877	100%	14%	HP-17	1%	56%	88%	29%	5.4
3134	HVAC	Ductless Heat Pump 23 SEER 10.0 HSPF - Electric baseboard baseline	Residential Midstream	MF	N/A	NC	3,114	59%	1,847	0.59	15	$2,877	50%	14%	HP-18	1%	0%	45%	29%	5.4
3135	HVAC	Central Air Conditioner 15 SEER	Residential Midstream	SF	NLI	MO	2,131	7%	142	0.15	18	$104	100%	100%	CAC-1	90%	50%	88%	89%	2.1
3136	HVAC	Central Air Conditioner 15 SEER	Residential Midstream	SF	LI	MO	2,131	7%	142	0.15	18	$104	100%	100%	CAC-2	90%	50%	88%	89%	2.1
3137	HVAC	Central Air Conditioner 15 SEER	Residential New Construction	SF	N/A	NC	2,131	7%	142	0.15	18	$104	100%	100%	CAC-3	95%	20%	89%	89%	2.1
3138	HVAC	Central Air Conditioner 15 SEER	Residential Midstream	MF	NLI	MO	796	7%	53	0.10	18	$104	100%	100%	CAC-4	90%	50%	88%	89%	1.3
3139	HVAC	Central Air Conditioner 15 SEER	Residential Midstream	MF	LI	MO	796	7%	53	0.10	18	$104	100%	100%	CAC-5	90%	50%	88%	89%	1.3
3140	HVAC	Central Air Conditioner 15 SEER	Residential New Construction	MF	N/A	NC	796	7%	53	0.10	18	$104	100%	100%	CAC-6	95%	20%	89%	89%	1.3
3141	HVAC	Central Air Conditioner 16 SEER	Residential Midstream	SF	NLI	MO	2,131	13%	266	0.28	18	$221	100%	90%	CAC-1	90%	50%	88%	76%	3.9
3142	HVAC	Central Air Conditioner 16 SEER	IQW	SF	LI	MO	2,131	13%	266	0.28	18	$221	100%	100%	CAC-2	90%	50%	88%	89%	3.5
3143	HVAC	Central Air Conditioner 16 SEER	Residential New Construction	SF	N/A	NC	2,131	13%	266	0.28	18	$221	100%	90%	CAC-3	95%	20%	89%	76%	3.9
3144	HVAC	Central Air Conditioner 16 SEER	Residential Midstream	MF	NLI	MO	796	13%	100	0.19	18	$221	100%	90%	CAC-4	90%	50%	88%	76%	2.4
3145	HVAC	Central Air Conditioner 16 SEER	IQW	MF	LI	MO	796	13%	100	0.19	18	$221	100%	100%	CAC-5	90%	50%	88%	89%	2.1
3146	HVAC	Central Air Conditioner 16 SEER	Residential New Construction	MF	N/A	NC	796	13%	100	0.19	18	$221	100%	90%	CAC-6	95%	20%	89%	76%	2.4
3147	HVAC	Central Air Conditioner 17 SEER	Residential Midstream	SF	NLI	MO	2,131	18%	376	0.40	18	$620	100%	48%	CAC-1	90%	50%	88%	43%	3.7
3148	HVAC	Central Air Conditioner 17 SEER	Residential Midstream	SF	LI	MO	2,131	18%	376	0.40	18	$620	100%	48%	CAC-2	90%	50%	88%	43%	3.7
3149	HVAC	Central Air Conditioner 17 SEER	Residential New Construction	SF	N/A	NC	2,131	18%	376	0.40	18	$620	100%	48%	CAC-3	95%	20%	89%	43%	3.7
3150	HVAC	Central Air Conditioner 17 SEER	Residential Midstream	MF	NLI	MO	796	18%	141	0.27	18	$620	75%	48%	CAC-4	90%	50%	55%	43%	2.2
3151	HVAC	Central Air Conditioner 17 SEER	Residential Midstream	MF	LI	MO	796	18%	141	0.27	18	$620	100%	48%	CAC-5	90%	50%	88%	43%	2.2
3152	HVAC	Central Air Conditioner 17 SEER	Residential New Construction	MF	N/A	NC	796	18%	141	0.27	18	$620	75%	48%	CAC-6	95%	20%	52%	43%	2.2
3153	HVAC	Central Air Conditioner 18 SEER	Residential Midstream	SF	NLI	MO	2,131	22%	474	0.50	18	$620	100%	65%	CAC-1	90%	50%	88%	52%	3.5
3154	HVAC	Central Air Conditioner 18 SEER	Residential Midstream	SF	LI	MO	2,131	22%	474	0.50	18	$620	100%	65%	CAC-2	90%	50%	88%	52%	3.5
3155	HVAC	Central Air Conditioner 18 SEER	Residential New Construction	SF	N/A	NC	2,131	22%	474	0.50	18	$620	100%	65%	CAC-3	95%	20%	89%	52%	3.5
3156	HVAC	Central Air Conditioner 18 SEER	Residential Midstream	MF	NLI	MO	796	22%	177	0.34	18	$620	100%	65%	CAC-4	90%	50%	88%	52%	2.1
3157	HVAC	Central Air Conditioner 18 SEER	Residential Midstream	MF	LI	MO	796	22%	177	0.34	18	$620	100%	65%	CAC-5	90%	50%	88%	52%	2.1
3158	HVAC	Central Air Conditioner 18 SEER	Residential New Construction	MF	N/A	NC	796	22%	177	0.34	18	$620	100%	65%	CAC-6	90%	20%	89%	52%	2.1
3159	HVAC	Smart Programmable Thermostat - South (Dual - Gas & Electric)	Residential Prescriptive	SF	NLI	Retrofit	2,442	8%	205	0.00	15	$250	24%	24%	T-STAT-1	87%	35%	35%	36%	1.9
3160	HVAC	Smart Programmable Thermostat - South (Dual - Gas & Electric)	Residential Prescriptive	SF	LI	Retrofit	2,442	8%	205	0.00	15	$250	75%	24%	T-STAT-3	87%	35%	43%	36%	1.9
3161	HVAC	Smart Thermostat (Dual)	IQW	SF	LI	Retrofit	9,740	3%	337	0.00	15	$250	100%	100%	T-STAT-3	87%	35%	87%	89%	0.8
3162	HVAC	Smart Programmable Thermostat - South (Dual - Gas & Electric)	Residential New Construction	SF	N/A	NC	2,442	8%	205	0.00	15	$250	24%	24%	T-STAT-5	90%	20%	31%	36%	1.9
3163	HVAC	Smart Programmable Thermostat - South (Dual - Gas & Electric)	Residential Prescriptive	MF	NLI	Retrofit	878	8%	74	0.00	15	$250	24%	24%	T-STAT-7	87%	35%	35%	36%	0.7

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Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
3164	HVAC	Smart Programmable Thermostat - South (Dual - Gas & Electric)	Residential Prescriptive	MF	LI	Retrofit	878	8%	74	0.00	15	$250	24%	24%	T-STAT-9	87%	35%	35%	36%	0.7
3165	HVAC	IQW MFDI Smart Thermostat - dual (Electric)	IQW	MF	LI	Retrofit	2,744	8%	225	0.00	15	$250	100%	100%	T-STAT-9	87%	35%	87%	89%	0.5
3166	HVAC	Smart Programmable Thermostat - South (Dual - Gas & Electric)	Residential New Construction	MF	N/A	NC	878	8%	74	0.00	15	$250	24%	24%	T-STAT-11	90%	20%	31%	36%	0.7
3167	HVAC	Wifi Thermostat - South (Dual - Gas & Electric)	Residential Prescriptive	SF	NLI	Retrofit	2,442	8%	205	0.00	15	$140	50%	29%	T-STAT-1	87%	35%	35%	37%	2.9
3168	HVAC	Wifi Thermostat - South (Dual - Gas & Electric)	Residential Prescriptive	SF	LI	Retrofit	2,442	8%	205	0.00	15	$140	100%	29%	T-STAT-3	87%	35%	87%	37%	2.9
3169	HVAC	Wifi Thermostat - South (Dual - Gas & Electric)	Residential New Construction	SF	N/A	NC	2,442	8%	205	0.00	15	$140	50%	29%	T-STAT-5	87%	0%	45%	37%	2.9
3170	HVAC	Wifi Thermostat - South (Dual - Gas & Electric)	Residential Prescriptive	MF	NLI	Retrofit	878	8%	74	0.00	15	$140	29%	29%	T-STAT-7	87%	35%	35%	37%	1.0
3171	HVAC	Wifi Thermostat - South (Dual - Gas & Electric)	Residential Prescriptive	MF	LI	Retrofit	878	8%	74	0.00	15	$140	50%	29%	T-STAT-9	87%	35%	35%	37%	1.0
3172	HVAC	Wifi Thermostat - South (Dual - Gas & Electric)	Residential New Construction	MF	N/A	NC	878	8%	74	0.00	15	$140	29%	29%	T-STAT-11	87%	0%	39%	37%	1.0
3173	HVAC	Smart Thermostat - South (Dual - Gas & Electric)	Residential Marketplace	SF	NLI	Retrofit	2,442	8%	205	0.00	15	$250	24%	24%	T-STAT-1	87%	35%	35%	36%	1.9
3174	HVAC	Smart Thermostat - South (Dual - Gas & Electric)	Residential Marketplace	SF	LI	Retrofit	2,442	8%	205	0.00	15	$250	75%	24%	T-STAT-3	87%	35%	43%	36%	1.9
3175	HVAC	Smart Thermostat - South (Dual - Gas & Electric)	Residential New Construction	SF	N/A	NC	2,442	8%	205	0.00	15	$250	24%	24%	T-STAT-5	90%	20%	31%	36%	1.9
3176	HVAC	Smart Thermostat - South (Dual - Gas & Electric)	Residential Marketplace	MF	NLI	Retrofit	878	8%	74	0.00	15	$250	24%	24%	T-STAT-7	87%	35%	35%	36%	0.7
3177	HVAC	Smart Thermostat - South (Dual - Gas & Electric)	Residential Marketplace	MF	LI	Retrofit	878	8%	74	0.00	15	$250	24%	24%	T-STAT-9	87%	35%	35%	36%	0.7
3178	HVAC	Smart Thermostat - South (Dual - Gas & Electric)	Residential New Construction	MF	N/A	NC	878	8%	74	0.00	15	$250	24%	24%	T-STAT-11	90%	20%	31%	36%	0.7
3179	HVAC	WiFi Tstat - South (Dual - Gas & Electric)	Residential Marketplace	SF	NLI	Retrofit	2,442	8%	205	0.00	15	$140	50%	29%	T-STAT-1	87%	35%	35%	37%	2.9
3180	HVAC	WiFi Tstat - South (Dual - Gas & Electric)	Residential Marketplace	SF	LI	Retrofit	2,442	8%	205	0.00	15	$140	100%	29%	T-STAT-3	87%	35%	87%	37%	2.9
3181	HVAC	WiFi Tstat - South (Dual - Gas & Electric)	Residential New Construction	SF	N/A	NC	2,442	8%	205	0.00	15	$140	50%	29%	T-STAT-5	87%	0%	45%	37%	2.9
3182	HVAC	WiFi Tstat - South (Dual - Gas & Electric)	Residential Marketplace	MF	NLI	Retrofit	878	8%	74	0.00	15	$140	29%	29%	T-STAT-7	87%	35%	35%	37%	1.0
3183	HVAC	WiFi Tstat - South (Dual - Gas & Electric)	Residential Marketplace	MF	LI	Retrofit	878	8%	74	0.00	15	$140	50%	29%	T-STAT-9	87%	35%	35%	37%	1.0
3184	HVAC	WiFi Tstat - South (Dual - Gas & Electric)	Residential New Construction	MF	N/A	NC	878	8%	74	0.00	15	$140	29%	29%	T-STAT-11	87%	0%	39%	37%	1.0
3185	HVAC	Smart Thermostat - South (Dual - Gas & Electric)	Residential Instant Rebate	SF	NLI	Retrofit	2,442	8%	205	0.00	15	$250	24%	24%	T-STAT-1	87%	35%	35%	36%	1.9
3186	HVAC	Smart Thermostat - South (Dual - Gas & Electric)	Residential Instant Rebate	SF	LI	Retrofit	2,442	8%	205	0.00	15	$250	75%	24%	T-STAT-3	87%	35%	43%	36%	1.9
3187	HVAC	Smart Thermostat - South (Dual - Gas & Electric)	Residential New Construction	SF	N/A	NC	2,442	8%	205	0.00	15	$250	24%	24%	T-STAT-5	90%	20%	31%	36%	1.9
3188	HVAC	Smart Thermostat - South (Dual - Gas & Electric)	Residential Instant Rebate	MF	NLI	Retrofit	878	8%	74	0.00	15	$250	24%	24%	T-STAT-7	87%	35%	35%	36%	0.7
3189	HVAC	Smart Thermostat - South (Dual - Gas & Electric)	Residential Instant Rebate	MF	LI	Retrofit	878	8%	74	0.00	15	$250	24%	24%	T-STAT-9	87%	35%	35%	36%	0.7
3190	HVAC	Smart Thermostat - South (Dual - Gas & Electric)	Residential New Construction	MF	N/A	NC	878	8%	74	0.00	15	$250	24%	24%	T-STAT-11	90%	20%	31%	36%	0.7
3191	HVAC	Smart Programmable Thermostat - South (Electric Only)	Residential Prescriptive	SF	NLI	Retrofit	9,740	8%	826	0.00	15	$250	100%	30%	T-STAT-2	11%	35%	87%	38%	6.1
3192	HVAC	Smart Programmable Thermostat - South (Electric Only)	Residential Prescriptive	SF	LI	Retrofit	9,740	8%	826	0.00	15	$250	100%	30%	T-STAT-4	11%	35%	87%	38%	6.1
3193	HVAC	Smart Thermostat (Electric)	IQW	SF	LI	Retrofit	9,740	14%	1,364	0.00	15	$250	100%	100%	T-STAT-4	11%	35%	87%	89%	3.0
3194	HVAC	Smart Programmable Thermostat - South (Electric Only)	Residential New Construction	SF	N/A	NC	9,740	8%	826	0.00	15	$250	100%	30%	T-STAT-6	10%	20%	89%	38%	6.1
3195	HVAC	Smart Programmable Thermostat - South (Electric Only)	Residential Prescriptive	MF	NLI	Retrofit	2,744	8%	232	0.00	15	$250	30%	30%	T-STAT-8	11%	35%	35%	38%	1.7
3196	HVAC	Smart Programmable Thermostat - South (Electric Only)	Residential Prescriptive	MF	LI	Retrofit	2,744	8%	232	0.00	15	$250	75%	30%	T-STAT-10	11%	35%	43%	38%	1.7

Appendix B: Residential Measure Assumptions

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
Measure #: Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. **End Use Measure Group:** Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **UCT Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
3197	HVAC	Smart Thermostat (Electric)	IQW	MF	LI	Retrofit	2,744	8%	225	0.00	15	$250	100%	100%	T-STAT-10	11%	35%	87%	89%	0.5
3198	HVAC	Smart Programmable Thermostat - South (Electric Only)	Residential New Construction	MF	N/A	NC	2,744	8%	232	0.00	15	$250	30%	30%	T-STAT-12	10%	20%	31%	38%	1.7
3199	HVAC	Wifi Thermostat - South (Electric Only)	Residential Prescriptive	SF	NLI	Retrofit	9,740	8%	826	0.00	15	$140	100%	36%	T-STAT-2	11%	35%	87%	39%	9.2
3200	HVAC	Wifi Thermostat - South (Electric Only)	Residential Prescriptive	SF	LI	Retrofit	9,740	8%	826	0.00	15	$140	100%	36%	T-STAT-4	11%	35%	87%	39%	9.2
3201	HVAC	Wifi Thermostat - South (Electric Only)	Residential New Construction	SF	N/A	NC	9,740	8%	826	0.00	15	$140	100%	36%	T-STAT-6	11%	0%	92%	39%	9.2
3202	HVAC	Wifi Thermostat - South (Electric Only)	Residential Prescriptive	MF	NLI	Retrofit	2,744	8%	232	0.00	15	$140	75%	36%	T-STAT-8	11%	35%	43%	39%	2.6
3203	HVAC	Wifi Thermostat - South (Electric Only)	Residential Prescriptive	MF	LI	Retrofit	2,744	8%	232	0.00	15	$140	100%	36%	T-STAT-10	11%	35%	87%	39%	2.6
3204	HVAC	Wifi Thermostat - South (Electric Only)	Residential New Construction	MF	N/A	NC	2,744	8%	232	0.00	15	$140	75%	36%	T-STAT-12	11%	0%	62%	39%	2.6
3205	HVAC	Smart Thermostat - South (Electric Only)	Residential Marketplace	SF	NLI	Retrofit	9,740	8%	826	0.00	15	$250	100%	30%	T-STAT-2	11%	35%	87%	38%	6.1
3206	HVAC	Smart Thermostat - South (Electric Only)	Residential Marketplace	SF	LI	Retrofit	9,740	8%	826	0.00	15	$250	100%	30%	T-STAT-4	11%	35%	87%	38%	6.1
3207	HVAC	Smart Thermostat - South (Electric Only)	Residential New Construction	SF	N/A	NC	9,740	8%	826	0.00	15	$250	100%	30%	T-STAT-6	10%	20%	89%	38%	6.1
3208	HVAC	Smart Thermostat - South (Electric Only)	Residential Marketplace	MF	NLI	Retrofit	2,744	8%	232	0.00	15	$250	30%	30%	T-STAT-8	11%	35%	35%	38%	1.7
3209	HVAC	Smart Thermostat - South (Electric Only)	Residential Marketplace	MF	LI	Retrofit	2,744	8%	232	0.00	15	$250	75%	30%	T-STAT-10	11%	35%	43%	38%	1.7
3210	HVAC	Smart Thermostat - South (Electric Only)	Residential New Construction	MF	N/A	NC	2,744	8%	232	0.00	15	$250	30%	30%	T-STAT-12	10%	20%	31%	38%	1.7
3211	HVAC	WiFi Tstat - South (Electric Only)	Residential Marketplace	SF	NLI	Retrofit	9,740	8%	826	0.00	15	$140	100%	36%	T-STAT-2	11%	35%	87%	39%	9.2
3212	HVAC	WiFi Tstat - South (Electric Only)	Residential Marketplace	SF	LI	Retrofit	9,740	8%	826	0.00	15	$140	100%	36%	T-STAT-4	11%	35%	87%	39%	9.2
3213	HVAC	WiFi Tstat - South (Electric Only)	Residential New Construction	SF	N/A	NC	9,740	8%	826	0.00	15	$140	100%	36%	T-STAT-6	11%	0%	92%	39%	9.2
3214	HVAC	WiFi Tstat - South (Electric Only)	Residential Marketplace	MF	NLI	Retrofit	2,744	8%	232	0.00	15	$140	75%	36%	T-STAT-8	11%	35%	43%	39%	2.6
3215	HVAC	WiFi Tstat - South (Electric Only)	Residential Marketplace	MF	LI	Retrofit	2,744	8%	232	0.00	15	$140	100%	36%	T-STAT-10	11%	35%	87%	39%	2.6
3216	HVAC	WiFi Tstat - South (Electric Only)	Residential New Construction	MF	N/A	NC	2,744	8%	232	0.00	15	$140	75%	36%	T-STAT-12	11%	0%	62%	39%	2.6
3217	HVAC	Smart Thermostat - South (Electric Only)	Residential Instant Rebate	SF	NLI	Retrofit	9,740	8%	826	0.00	15	$250	100%	30%	T-STAT-2	11%	35%	87%	38%	6.1
3218	HVAC	Smart Thermostat - South (Electric Only)	Residential Instant Rebate	SF	LI	Retrofit	9,740	8%	826	0.00	15	$250	100%	30%	T-STAT-4	11%	35%	87%	38%	6.1
3219	HVAC	Smart Thermostat - South (Electric Only)	Residential New Construction	SF	N/A	NC	9,740	8%	826	0.00	15	$250	100%	30%	T-STAT-6	10%	20%	89%	38%	6.1
3220	HVAC	Smart Thermostat - South (Electric Only)	Residential Instant Rebate	MF	NLI	Retrofit	2,744	8%	232	0.00	15	$250	30%	30%	T-STAT-8	11%	35%	35%	38%	1.7
3221	HVAC	Smart Thermostat - South (Electric Only)	Residential Instant Rebate	MF	LI	Retrofit	2,744	8%	232	0.00	15	$250	75%	30%	T-STAT-10	11%	35%	43%	38%	1.7
3222	HVAC	Smart Thermostat - South (Electric Only)	Residential New Construction	MF	N/A	NC	2,744	8%	232	0.00	15	$250	30%	30%	T-STAT-12	10%	20%	31%	38%	1.7
3223	HVAC	PTHP Variable Speed SEER 17 11.9 HPSF Upgrade from PTHP Baseline SEER 10.5 HPSF 7.7	Residential Emerging Markets Pilot	SF	N/A	MO	6,485	36%	2,351	1.15	15	$1,434	100%	80%	HP-4	4%	56%	59%	55%	3.0
3224	HVAC	PTHP Variable Speed SEER 17 11.9 HPSF Upgrade from PTHP Baseline SEER 10.5 HPSF 7.7	Residential Emerging Markets Pilot	SF	N/A	NC	6,485	36%	2,351	1.15	15	$1,434	100%	80%	HP-9	4%	0%	47%	55%	3.0
3225	HVAC	PTHP Variable Speed SEER 17 11.9 HPSF Upgrade from PTHP Baseline SEER 10.5 HPSF 7.7	Residential Emerging Markets Pilot	MF	N/A	MO	2,125	37%	777	0.77	15	$1,434	100%	80%	HP-13	4%	56%	59%	55%	1.6
3226	HVAC	PTHP Variable Speed SEER 17 11.9 HPSF Upgrade from PTHP Baseline SEER 10.5 HPSF 7.7	Residential Emerging Markets Pilot	MF	N/A	NC	2,125	37%	777	0.77	15	$1,434	100%	80%	HP-15	4%	0%	47%	55%	1.6
3227	HVAC	PTHP Variable Speed SEER 17 11.9 HPSF Upgrade from PTAC SEER 10.5 Electric Resistance Heat	Residential Emerging Markets Pilot	SF	N/A	MO	6,491	60%	3,924	1.15	15	$1,434	100%	80%	HP-1	6%	56%	59%	55%	3.8

Appendix B: Residential Measure Assumptions

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
Measure #: Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. **End Use Measure Group:** Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **UCT Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
3228	HVAC	PTHP Variable Speed SEER 17 11.9 HPSF Upgrade from PTAC SEER 10.5 Electric Resistance Heat	Residential Emerging Markets Pilot	SF	N/A	NC	6,491	60%	3,924	1.15	15	$1,434	100%	80%	HP-3	6%	0%	47%	55%	3.8
3229	HVAC	PTHP Variable Speed SEER 17 11.9 HPSF Upgrade from PTAC SEER 10.5 Electric Resistance Heat	Residential Emerging Markets Pilot	MF	N/A	MO	3,156	63%	1,987	0.77	15	$1,434	100%	80%	HP-10	6%	56%	59%	55%	2.2
3230	HVAC	PTHP Variable Speed SEER 17 11.9 HPSF Upgrade from PTAC SEER 10.5 Electric Resistance Heat	Residential Emerging Markets Pilot	MF	N/A	NC	3,156	63%	1,987	0.77	15	$1,434	100%	80%	HP-12	6%	0%	47%	55%	2.2
3231	HVAC	Filter whistle	Residential Emerging Markets Pilot	SF	NLI	Retrofit	6,485	1%	46	0.07	5	$3	100%	100%	FW-1	97%	49%	38%	73%	21.8
3232	HVAC	Filter whistle	IQW	SF	LI	Retrofit	6,485	1%	46	0.07	5	$3	100%	100%	FW-2	97%	49%	83%	89%	21.8
3233	HVAC	Filter whistle	Residential Emerging Markets Pilot	SF	N/A	NC	6,485	1%	46	0.07	5	$3	100%	100%	FW-3	97%	0%	47%	73%	21.8
3234	HVAC	Filter whistle	Residential Emerging Markets Pilot	MF	NLI	Retrofit	2,125	1%	19	0.03	5	$3	100%	100%	FW-4	97%	49%	38%	73%	9.0
3235	HVAC	Filter whistle	IQW	MF	LI	Retrofit	2,125	1%	19	0.03	5	$3	100%	100%	FW-5	97%	49%	83%	89%	9.0
3236	HVAC	Filter whistle	Residential Emerging Markets Pilot	MF	N/A	NC	2,125	1%	19	0.03	5	$3	100%	100%	FW-6	97%	0%	47%	73%	9.0
3237	HVAC	ENERGY STAR Room Air Conditioner	Residential Emerging Markets Pilot	SF	N/A	MO	408	8%	32	0.07	12	$40	100%	63%	RAC-1	15%	49%	54%	44%	5.1
3238	HVAC	ENERGY STAR Room Air Conditioner	Residential Emerging Markets Pilot	SF	N/A	NC	408	8%	32	0.07	12	$40	100%	63%	RAC-2	15%	0%	47%	44%	5.1
3239	HVAC	ENERGY STAR Room Air Conditioner	Residential Emerging Markets Pilot	MF	N/A	MO	408	8%	32	0.07	12	$40	100%	63%	RAC-3	15%	49%	54%	44%	5.1
3240	HVAC	ENERGY STAR Room Air Conditioner	Residential Emerging Markets Pilot	MF	N/A	NC	408	8%	32	0.07	12	$40	100%	63%	RAC-4	15%	0%	47%	44%	5.1
3241	HVAC	Smart Room AC	Residential Emerging Markets Pilot	SF	N/A	MO	408	3%	12	0.02	12	$40	75%	63%	RAC-1	15%	49%	54%	44%	1.7
3242	HVAC	Smart Room AC	Residential Emerging Markets Pilot	SF	N/A	NC	408	3%	12	0.02	12	$40	75%	63%	RAC-2	15%	0%	33%	44%	1.7
3243	HVAC	Smart Room AC	Residential Emerging Markets Pilot	MF	N/A	MO	408	3%	12	0.02	12	$40	75%	63%	RAC-3	15%	49%	54%	44%	1.7
3244	HVAC	Smart Room AC	Residential Emerging Markets Pilot	MF	N/A	NC	408	3%	12	0.02	12	$40	75%	63%	RAC-4	15%	0%	33%	44%	1.7
3245	HVAC	Room AC Recycling	Appliance Recycling	SF	N/A	Recycle	314	100%	314	0.21	4	$25	100%	100%	RACR-1	3%	0%	92%	89%	7.1
3246	HVAC	Room AC Recycling	Appliance Recycling	MF	N/A	Recycle	314	100%	314	0.21	4	$25	100%	100%	RACR-2	3%	0%	92%	89%	7.1
3247	HVAC	Smart Vents/Sensors - Heat pump baseline	Residential Emerging Markets Pilot	SF	N/A	Retrofit	6,485	5%	324	0.11	15	$1,625	80%	80%	SVS-1	4%	3%	34%	55%	0.3
3248	HVAC	Smart Vents/Sensors - Heat pump baseline	Residential Emerging Markets Pilot	SF	N/A	NC	6,485	5%	324	0.11	15	$1,625	80%	80%	SVS-2	4%	0%	35%	55%	0.3
3249	HVAC	Smart Vents/Sensors - Heat pump baseline	Residential Emerging Markets Pilot	MF	N/A	Retrofit	2,125	5%	106	0.08	15	$1,040	80%	80%	SVS-3	4%	3%	34%	55%	0.2
3250	HVAC	Smart Vents/Sensors - Heat pump baseline	Residential Emerging Markets Pilot	MF	N/A	NC	2,125	5%	106	0.08	15	$1,040	80%	80%	SVS-4	4%	0%	35%	55%	0.2
3251	HVAC	Smart Vents/Sensors - Furnace baseline	Residential Emerging Markets Pilot	SF	N/A	Retrofit	11,910	5%	595	0.11	15	$1,625	80%	80%	SVS-5	6%	3%	34%	55%	0.4
3252	HVAC	Smart Vents/Sensors - Furnace baseline	Residential Emerging Markets Pilot	SF	N/A	NC	11,910	5%	595	0.11	15	$1,625	80%	80%	SVS-6	6%	0%	35%	55%	0.4
3253	HVAC	Smart Vents/Sensors - Furnace baseline	Residential Emerging Markets Pilot	MF	N/A	Retrofit	3,156	5%	158	0.08	15	$1,040	80%	80%	SVS-7	6%	3%	34%	55%	0.3
3254	HVAC	Smart Vents/Sensors - Furnace baseline	Residential Emerging Markets Pilot	MF	N/A	NC	3,156	5%	158	0.08	15	$1,040	80%	80%	SVS-8	6%	0%	35%	55%	0.3
3255	HVAC	Smart Vents/Sensors - Gas/CAC baseline	Residential Emerging Markets Pilot	SF	N/A	Retrofit	2,442	5%	122	0.11	15	$1,625	80%	80%	SVS-9	87%	3%	34%	55%	0.2
3256	HVAC	Smart Vents/Sensors - Gas/CAC baseline	Residential Emerging Markets Pilot	SF	N/A	NC	2,442	5%	122	0.11	15	$1,625	80%	80%	SVS-10	87%	0%	35%	55%	0.2
3257	HVAC	Smart Vents/Sensors - Gas/CAC baseline	Residential Emerging Markets Pilot	MF	N/A	Retrofit	878	5%	44	0.08	15	$1,040	80%	80%	SVS-11	87%	3%	34%	55%	0.2
3258	HVAC	Smart Vents/Sensors - Gas/CAC baseline	Residential Emerging Markets Pilot	MF	N/A	NC	878	5%	44	0.08	15	$1,040	80%	80%	SVS-12	87%	0%	35%	55%	0.2

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Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
3259	HVAC	Whole House Attic Fan	Residential Emerging Markets Pilot	SF	N/A	Retrofit	2,131	18%	384	0.41	15	$711	100%	80%	WHAF-1	94%	7%	43%	55%	1.7
3260	HVAC	Whole House Attic Fan	Residential Emerging Markets Pilot	SF	N/A	NC	2,131	18%	384	0.41	15	$711	100%	80%	WHAF-2	94%	0%	47%	55%	1.7
3261	HVAC	Whole House Attic Fan	Residential Emerging Markets Pilot	MF	N/A	Retrofit	796	18%	143	0.27	15	$711	80%	80%	WHAF-3	94%	7%	32%	55%	1.0
3262	HVAC	Whole House Attic Fan	Residential Emerging Markets Pilot	MF	N/A	NC	796	18%	143	0.27	15	$711	80%	80%	WHAF-4	94%	0%	35%	55%	1.0
3263	HVAC	Attic Fan	Residential Emerging Markets Pilot	SF	N/A	Retrofit	2,131	8%	170	0.18	15	$125	100%	80%	WHAF-1	94%	8%	43%	55%	4.4
3264	HVAC	Attic Fan	Residential Emerging Markets Pilot	SF	N/A	NC	2,131	8%	170	0.18	15	$125	100%	80%	WHAF-2	94%	0%	47%	55%	4.4
3265	HVAC	Attic Fan	Residential Emerging Markets Pilot	MF	N/A	Retrofit	796	8%	64	0.12	15	$125	100%	80%	WHAF-3	94%	8%	43%	55%	2.6
3266	HVAC	Attic Fan	Residential Emerging Markets Pilot	MF	N/A	NC	796	8%	64	0.12	15	$125	100%	80%	WHAF-4	90%	0%	47%	55%	2.6
3267	HVAC	ENERGY STAR Bath Vent Fan	Residential Emerging Markets Pilot	SF	N/A	Retrofit	49	61%	30	0.02	19	$44	100%	46%	BATH FAN-1	100%	51%	38%	37%	3.7
3268	HVAC	ENERGY STAR Bath Vent Fan	Residential Emerging Markets Pilot	SF	N/A	NC	49	61%	30	0.02	19	$44	100%	46%	BATH FAN-2	100%	0%	47%	37%	3.7
3269	HVAC	ENERGY STAR Bath Vent Fan	Residential Emerging Markets Pilot	MF	N/A	Retrofit	49	61%	30	0.02	19	$44	100%	46%	BATH FAN-3	100%	51%	38%	37%	3.7
3270	HVAC	ENERGY STAR Bath Vent Fan	Residential Emerging Markets Pilot	MF	N/A	NC	49	61%	30	0.02	19	$44	100%	46%	BATH FAN-4	100%	0%	47%	37%	3.7
3271	HVAC	Energy Recovery Ventilator - Heat Pump	Residential Emerging Markets Pilot	SF	N/A	Retrofit	6,485	51%	3,317	0.26	15	$3,000	100%	100%	ERV-1	4%	0%	47%	73%	0.8
3272	HVAC	Energy Recovery Ventilator - Electric Resistance	Residential Emerging Markets Pilot	SF	N/A	Retrofit	11,910	37%	4,396	0.34	15	$3,000	100%	100%	ERV-2	6%	0%	47%	73%	1.0
3273	HVAC	Energy Recovery Ventilator - Heat Pump	Residential Emerging Markets Pilot	SF	N/A	NC	6,485	51%	3,317	0.26	15	$3,000	100%	100%	ERV-3	4%	0%	47%	73%	0.8
3274	HVAC	Energy Recovery Ventilator - Electric Resistance	Residential Emerging Markets Pilot	SF	N/A	NC	11,910	37%	4,396	0.34	15	$3,000	100%	100%	ERV-4	6%	0%	47%	73%	1.0
3275	HVAC	Energy Recovery Ventilator - Heat Pump	Residential Emerging Markets Pilot	MF	N/A	Retrofit	2,125	85%	1,815	0.14	15	$3,000	100%	100%	ERV-5	4%	0%	47%	73%	0.4
3276	HVAC	Energy Recovery Ventilator - Electric Resistance	Residential Emerging Markets Pilot	MF	N/A	Retrofit	3,156	76%	2,404	0.19	15	$3,000	100%	100%	ERV-6	6%	0%	47%	73%	0.6
3277	HVAC	Energy Recovery Ventilator - Heat Pump	Residential Emerging Markets Pilot	MF	N/A	NC	2,125	85%	1,815	0.14	15	$3,000	100%	100%	ERV-7	4%	0%	47%	73%	0.4
3278	HVAC	Energy Recovery Ventilator - Electric Resistance	Residential Emerging Markets Pilot	MF	N/A	NC	3,156	76%	2,404	0.19	15	$3,000	100%	100%	ERV-8	6%	0%	47%	73%	0.6
4001	Lighting	LED Standard	CBL	SF	N/A	MO	37	43%	16	0.00	15	$2	100%	59%	STAN-1	3003%	59%	97%	58%	10.2
4002	Lighting	LED Standard	CBL	SF	N/A	NC	37	43%	16	0.00	15	$2	100%	59%	STAN-2	3003%	0%	99%	58%	10.2
4003	Lighting	LED Standard	CBL	MF	N/A	MO	37	43%	16	0.00	15	$2	100%	59%	STAN-3	1915%	59%	97%	58%	10.2
4004	Lighting	LED Standard	CBL	MF	N/A	NC	37	43%	16	0.00	15	$2	100%	59%	STAN-4	1915%	0%	99%	58%	10.2
4005	Lighting	LED Reflector	Residential Marketplace	SF	NLI	MO	65	75%	49	0.04	15	$3	100%	100%	REFL-1	738%	59%	97%	95%	33.6
4006	Lighting	LED Reflector	Residential Marketplace	SF	NLI	MO	65	75%	49	0.04	15	$3	100%	100%	REFL-1	738%	59%	97%	95%	33.6
4007	Lighting	LED Reflector	Residential Instant Rebate	SF	NLI	MO	65	75%	49	0.04	15	$3	100%	100%	REFL-1	738%	59%	97%	95%	33.6
4008	Lighting	LED Reflector	IQW	SF	LI	MO	65	75%	49	0.04	15	$3	100%	100%	REFL-2	738%	59%	97%	95%	33.6
4009	Lighting	LED Reflector	Residential Marketplace	SF	LI	MO	65	75%	49	0.04	15	$3	100%	100%	REFL-2	738%	59%	97%	95%	33.6
4010	Lighting	LED Reflector	Residential Marketplace	SF	LI	MO	65	75%	49	0.04	15	$3	100%	100%	REFL-2	738%	59%	97%	95%	33.6
4011	Lighting	LED Reflector	Residential Instant Rebate	SF	LI	MO	65	75%	49	0.04	15	$3	100%	100%	REFL-2	738%	59%	97%	95%	33.6
4012	Lighting	LED Reflector	Residential Marketplace	SF	N/A	NC	65	75%	49	0.04	15	$3	100%	100%	REFL-3	738%	0%	99%	95%	33.6
4013	Lighting	LED Reflector	Residential Marketplace	SF	N/A	NC	65	75%	49	0.04	15	$3	100%	100%	REFL-3	738%	0%	99%	95%	33.6
4014	Lighting	LED Reflector	Residential Instant Rebate	SF	N/A	NC	65	75%	49	0.04	15	$3	100%	100%	REFL-3	738%	0%	99%	95%	33.6
4015	Lighting	LED Reflector	Residential Marketplace	MF	NLI	MO	65	75%	49	0.04	15	$3	100%	100%	REFL-4	471%	59%	97%	95%	33.6
4016	Lighting	LED Reflector	Residential Marketplace	MF	NLI	MO	65	75%	49	0.04	15	$3	100%	100%	REFL-4	471%	59%	97%	95%	33.6
4017	Lighting	LED Reflector	Residential Instant Rebate	MF	NLI	MO	65	75%	49	0.04	15	$3	100%	100%	REFL-4	471%	59%	97%	95%	33.6
4018	Lighting	LED Reflector	IQW	MF	LI	MO	65	75%	49	0.04	15	$3	100%	100%	REFL-5	471%	59%	97%	95%	33.6
4019	Lighting	LED Reflector	Residential Marketplace	MF	LI	MO	65	75%	49	0.04	15	$3	100%	100%	REFL-5	471%	59%	97%	95%	33.6
4020	Lighting	LED Reflector	Residential Marketplace	MF	LI	MO	65	75%	49	0.04	15	$3	100%	100%	REFL-5	471%	59%	97%	95%	33.6
4021	Lighting	LED Reflector	Residential Instant Rebate	MF	LI	MO	65	75%	49	0.04	15	$3	100%	100%	REFL-5	471%	59%	97%	95%	33.6

Appendix B: Residential Measure Assumptions

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
Measure #: Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. **End Use Measure Group:** Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **UCT Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
4022	Lighting	LED Reflector	Residential Marketplace	MF	N/A	NC	65	75%	49	0.04	15	$3	100%	100%	REFL-6	471%	0%	99%	95%	33.6
4023	Lighting	LED Reflector	Residential Marketplace	MF	N/A	NC	65	75%	49	0.04	15	$3	100%	100%	REFL-6	471%	0%	99%	95%	33.6
4024	Lighting	LED Reflector	Residential Instant Rebate	MF	N/A	NC	65	75%	49	0.04	15	$3	100%	100%	REFL-6	471%	0%	99%	95%	33.6
4025	Lighting	LED Specialty	Residential Marketplace	SF	NLI	MO	44	75%	33	0.02	15	$2	100%	100%	SPEC-1	446%	59%	97%	95%	29.4
4026	Lighting	LED Specialty	Residential Marketplace	SF	NLI	MO	44	75%	33	0.02	15	$2	100%	100%	SPEC-1	446%	59%	97%	95%	29.4
4027	Lighting	LED Specialty	Residential Instant Rebate	SF	NLI	MO	44	75%	33	0.02	15	$2	100%	100%	SPEC-1	446%	59%	97%	95%	29.4
4028	Lighting	LED Specialty	IQW	SF	LI	MO	44	75%	33	0.02	15	$2	100%	100%	SPEC-2	446%	59%	97%	95%	29.4
4029	Lighting	LED Specialty	Residential Marketplace	SF	LI	MO	44	75%	33	0.02	15	$2	100%	100%	SPEC-2	446%	59%	97%	95%	29.4
4030	Lighting	LED Specialty	Residential Marketplace	SF	LI	MO	44	75%	33	0.02	15	$2	100%	100%	SPEC-2	446%	59%	97%	95%	29.4
4031	Lighting	LED Specialty	Residential Instant Rebate	SF	LI	MO	44	75%	33	0.02	15	$2	100%	100%	SPEC-2	446%	59%	97%	95%	29.4
4032	Lighting	LED Specialty	Residential Marketplace	SF	N/A	NC	44	75%	33	0.02	15	$2	100%	100%	SPEC-3	446%	0%	99%	95%	29.4
4033	Lighting	LED Specialty	Residential Marketplace	SF	N/A	NC	44	75%	33	0.02	15	$2	100%	100%	SPEC-3	446%	0%	99%	95%	29.4
4034	Lighting	LED Specialty	Residential Instant Rebate	SF	N/A	NC	44	75%	33	0.02	15	$2	100%	100%	SPEC-3	446%	0%	99%	95%	29.4
4035	Lighting	LED Specialty	Residential Marketplace	MF	NLI	MO	44	75%	33	0.02	15	$2	100%	100%	SPEC-4	284%	59%	97%	95%	29.4
4036	Lighting	LED Specialty	Residential Marketplace	MF	NLI	MO	44	75%	33	0.02	15	$2	100%	100%	SPEC-4	284%	59%	97%	95%	29.4
4037	Lighting	LED Specialty	Residential Instant Rebate	MF	NLI	MO	44	75%	33	0.02	15	$2	100%	100%	SPEC-4	284%	59%	97%	95%	29.4
4038	Lighting	LED Specialty	IQW	MF	LI	MO	44	75%	33	0.02	15	$2	100%	100%	SPEC-5	284%	59%	97%	95%	29.4
4039	Lighting	LED Specialty	Residential Marketplace	MF	LI	MO	44	75%	33	0.02	15	$2	100%	100%	SPEC-5	284%	59%	97%	95%	29.4
4040	Lighting	LED Specialty	Residential Marketplace	MF	LI	MO	44	75%	33	0.02	15	$2	100%	100%	SPEC-5	284%	59%	97%	95%	29.4
4041	Lighting	LED Specialty	Residential Instant Rebate	MF	LI	MO	44	75%	33	0.02	15	$2	100%	100%	SPEC-5	284%	59%	97%	95%	29.4
4042	Lighting	LED Specialty	Residential Marketplace	MF	N/A	NC	44	75%	33	0.02	15	$2	100%	100%	SPEC-6	284%	0%	99%	95%	29.4
4043	Lighting	LED Specialty	Residential Marketplace	MF	N/A	NC	44	75%	33	0.02	15	$2	100%	100%	SPEC-6	284%	0%	99%	95%	29.4
4044	Lighting	LED Specialty	Residential Instant Rebate	MF	N/A	NC	44	75%	33	0.02	15	$2	100%	100%	SPEC-6	284%	0%	99%	95%	29.4
4045	Lighting	Exterior LED Lamp	Residential Emerging Markets Pilot	SF	NLI	MO	127	72%	92	0.00	7	$2	100%	100%	EXT-1	503%	59%	62%	73%	14.7
4046	Lighting	Exterior LED Lamp	IQW	SF	LI	MO	127	72%	92	0.00	7	$2	100%	100%	EXT-2	503%	59%	97%	95%	14.7
4047	Lighting	Exterior LED Lamp	Residential Emerging Markets Pilot	SF	N/A	NC	127	72%	92	0.00	7	$2	100%	100%	EXT-3	503%	0%	47%	73%	14.7
4048	Lighting	Exterior LED Lamp	Residential Emerging Markets Pilot	MF	NLI	MO	127	72%	92	0.00	7	$2	100%	100%	EXT-4	289%	59%	62%	73%	14.7
4049	Lighting	Exterior LED Lamp	IQW	MF	LI	MO	127	72%	92	0.00	7	$2	100%	100%	EXT-5	289%	59%	97%	95%	14.7
4050	Lighting	Exterior LED Lamp	Residential Emerging Markets Pilot	MF	N/A	NC	127	72%	92	0.00	7	$2	100%	100%	EXT-6	289%	0%	47%	73%	14.7
4051	Lighting	LED Nightlights	Residential Marketplace	SF	NLI	MO	15	93%	14	0.00	12	$3	100%	100%	NIGHT-1	40%	59%	97%	95%	2.1
4052	Lighting	LED Nightlights	Community Connections	SF	LI	MO	15	93%	14	0.00	12	$3	100%	100%	NIGHT-2	40%	59%	97%	95%	2.1
4053	Lighting	LED Nightlights	Community Connections	SF	LI	MO	15	93%	14	0.00	12	$3	100%	100%	NIGHT-2	40%	59%	97%	95%	2.1
4054	Lighting	LED Nightlights	Residential Marketplace	MF	NLI	MO	15	93%	14	0.00	12	$3	100%	100%	NIGHT-3	40%	59%	97%	95%	2.1
4055	Lighting	LED Nightlights	Community Connections	MF	LI	MO	15	93%	14	0.00	12	$3	100%	100%	NIGHT-4	40%	59%	97%	95%	2.1
4056	Lighting	LED Nightlights	Community Connections	MF	LI	MO	15	93%	14	0.00	12	$3	100%	100%	NIGHT-4	40%	59%	97%	95%	2.1
4057	Lighting	Ceiling Fan	Residential Emerging Markets Pilot	SF	N/A	MO	110	75%	82	0.00	10	$46	54%	54%	CEIL-1	92%	59%	62%	40%	1.3
4058	Lighting	Ceiling Fan	Residential Emerging Markets Pilot	SF	N/A	NC	110	75%	82	0.00	10	$46	54%	54%	CEIL-2	92%	0%	31%	40%	1.3
4059	Lighting	Ceiling Fan	Residential Emerging Markets Pilot	MF	N/A	MO	110	75%	82	0.00	10	$46	54%	54%	CEIL-3	98%	59%	62%	40%	1.3
4060	Lighting	Ceiling Fan	Residential Emerging Markets Pilot	MF	N/A	NC	110	75%	82	0.00	10	$46	54%	54%	CEIL-4	98%	0%	31%	40%	1.3
4061	Lighting	LED 3-Way Bulb	Residential Emerging Markets Pilot	SF	N/A	MO	11	75%	9	0.00	15	$3	100%	50%	STAN-1	3003%	59%	62%	38%	4.4
4062	Lighting	LED 3-Way Bulb	Residential Emerging Markets Pilot	SF	N/A	NC	11	75%	9	0.00	15	$3	100%	50%	STAN-2	3003%	0%	47%	38%	4.4
4063	Lighting	LED 3-Way Bulb	Residential Emerging Markets Pilot	MF	N/A	MO	11	75%	9	0.00	15	$3	100%	50%	STAN-3	1915%	59%	62%	38%	4.4
4064	Lighting	LED 3-Way Bulb	Residential Emerging Markets Pilot	MF	N/A	NC	11	75%	9	0.00	15	$3	100%	50%	STAN-4	1915%	0%	47%	38%	4.4
4065	Lighting	Linear LED	Residential Emerging Markets Pilot	SF	N/A	MO	23	44%	10	0.01	9	$7	100%	80%	LINEAR-1	509%	59%	62%	55%	3.8
4066	Lighting	Linear LED	Residential Emerging Markets Pilot	SF	N/A	NC	23	44%	10	0.01	9	$3	100%	80%	LINEAR-2	509%	0%	47%	55%	10.6

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Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
4067	Lighting	Linear LED	Residential Emerging Markets Pilot	MF	N/A	MO	23	44%	10	0.01	9	$7	100%	80%	LINEAR-3	325%	59%	62%	55%	3.8
4068	Lighting	Linear LED	Residential Emerging Markets Pilot	MF	N/A	NC	23	44%	10	0.01	9	$3	100%	80%	LINEAR-4	325%	0%	47%	55%	10.6
4069	Lighting	Smart LED	Residential Emerging Markets Pilot	SF	N/A	MO	19	10%	2	0.00	10	$2	80%	80%	STAN-1	3003%	59%	62%	55%	0.5
4070	Lighting	Smart LED	Residential Emerging Markets Pilot	SF	N/A	NC	19	10%	2	0.00	10	$2	80%	80%	STAN-2	3003%	0%	35%	55%	0.5
4071	Lighting	Smart LED	Residential Emerging Markets Pilot	MF	N/A	MO	19	10%	2	0.00	10	$2	80%	80%	STAN-3	1915%	59%	62%	55%	0.5
4072	Lighting	Smart LED	Residential Emerging Markets Pilot	MF	N/A	NC	19	10%	2	0.00	10	$2	80%	80%	STAN-4	1915%	0%	35%	55%	0.5
4073	Lighting	LED Fixture	Residential Emerging Markets Pilot	SF	N/A	MO	82	59%	49	0.06	15	$26	100%	80%	STAN-1	3003%	59%	62%	55%	6.8
4074	Lighting	LED Fixture	Residential Emerging Markets Pilot	SF	N/A	NC	82	59%	49	0.06	15	$3	100%	80%	STAN-2	3003%	0%	47%	55%	68.2
4075	Lighting	LED Fixture	Residential Emerging Markets Pilot	MF	N/A	MO	82	59%	49	0.06	15	$26	100%	80%	STAN-3	1915%	59%	62%	55%	6.8
4076	Lighting	LED Fixture	Residential Emerging Markets Pilot	MF	N/A	NC	82	59%	49	0.06	15	$3	100%	80%	STAN-4	1915%	0%	47%	55%	68.2
4077	Lighting	Occupancy Sensor	Residential Emerging Markets Pilot	SF	N/A	Retrofit	124	30%	37	0.05	10	$30	100%	80%	OCC-1	1047%	31%	34%	55%	3.2
4078	Lighting	Occupancy Sensor	Residential Emerging Markets Pilot	SF	N/A	NC	124	30%	37	0.05	10	$30	100%	80%	OCC-2	1047%	0%	47%	55%	3.2
4079	Lighting	Occupancy Sensor	Residential Emerging Markets Pilot	MF	N/A	Retrofit	124	30%	37	0.05	10	$30	100%	80%	OCC-3	1047%	31%	34%	55%	3.2
4080	Lighting	Occupancy Sensor	Residential Emerging Markets Pilot	MF	N/A	NC	124	30%	37	0.05	10	$30	100%	80%	OCC-4	1047%	0%	47%	55%	3.2
4081	Lighting	Smart Lighting Switch	Residential Emerging Markets Pilot	SF	N/A	Retrofit	124	17%	21	0.05	10	$43	100%	47%	OCC-1	668%	31%	34%	37%	3.6
4082	Lighting	Smart Lighting Switch	Residential Emerging Markets Pilot	SF	N/A	NC	124	17%	21	0.05	10	$43	100%	47%	OCC-2	668%	0%	47%	37%	3.6
4083	Lighting	Smart Lighting Switch	Residential Emerging Markets Pilot	MF	N/A	Retrofit	124	17%	21	0.05	10	$43	100%	47%	OCC-3	668%	31%	34%	37%	3.6
4084	Lighting	Smart Lighting Switch	Residential Emerging Markets Pilot	MF	N/A	NC	124	17%	21	0.05	10	$43	100%	47%	OCC-4	668%	0%	47%	37%	3.6
4085	Lighting	Exterior Lighting Controls	Residential Emerging Markets Pilot	SF	N/A	Retrofit	146	44%	65	0.03	10	$30	100%	80%	ELC-1	252%	31%	34%	55%	2.5
4086	Lighting	Exterior Lighting Controls	Residential Emerging Markets Pilot	SF	N/A	NC	146	44%	65	0.03	10	$30	100%	80%	ELC-2	252%	0%	47%	55%	2.5
4087	Lighting	Exterior Lighting Controls	Residential Emerging Markets Pilot	MF	N/A	Retrofit	146	44%	65	0.03	10	$30	100%	80%	ELC-3	145%	31%	34%	55%	2.5
4088	Lighting	Exterior Lighting Controls	Residential Emerging Markets Pilot	MF	N/A	NC	146	44%	65	0.03	10	$30	100%	80%	ELC-4	145%	0%	47%	55%	2.5
4089	Lighting	ENERGY STAR LED Trim Kits	Residential Emerging Markets Pilot	SF	N/A	MO	18	70%	13	0.00	15	$5	100%	100%	TRIM-1	446%	59%	62%	73%	2.2
4090	Lighting	ENERGY STAR LED Trim Kits	Residential Emerging Markets Pilot	SF	N/A	NC	18	70%	13	0.00	15	$5	100%	100%	TRIM-2	446%	0%	47%	73%	2.2
4091	Lighting	ENERGY STAR LED Trim Kits	Residential Emerging Markets Pilot	MF	N/A	MO	18	70%	13	0.00	15	$5	100%	100%	TRIM-3	284%	59%	62%	73%	2.2
4092	Lighting	ENERGY STAR LED Trim Kits	Residential Emerging Markets Pilot	MF	N/A	NC	18	70%	13	0.00	15	$5	100%	100%	TRIM-4	284%	0%	47%	73%	2.2
5001	Pool/Pump	Variable Speed Pool Pump	Residential Emerging Markets Pilot	SF	N/A	MO	1,167	26%	308	0.22	10	$314	100%	96%	PUMP-1	8%	35%	46%	68%	1.4
5002	Pool/Pump	Variable Speed Pool Pump	Residential Emerging Markets Pilot	SF	N/A	NC	1,167	26%	308	0.22	10	$314	100%	96%	PUMP-2	8%	0%	47%	68%	1.4
5003	Pool/Pump	Variable Speed Pool Pump	Residential Emerging Markets Pilot	MF	N/A	MO	1,167	26%	308	0.22	10	$314	100%	96%	PUMP-3	8%	35%	46%	68%	1.4
5004	Pool/Pump	Variable Speed Pool Pump	Residential Emerging Markets Pilot	MF	N/A	NC	1,167	26%	308	0.22	10	$314	100%	96%	PUMP-4	8%	0%	47%	68%	1.4
5005	Pool/Pump	Pool Timer	Residential Emerging Markets Pilot	SF	N/A	MO	1,167	40%	467	0.00	2	$25	100%	80%	PUMP-1	8%	35%	46%	55%	1.9
5006	Pool/Pump	Pool Timer	Residential Emerging Markets Pilot	SF	N/A	NC	1,167	40%	467	0.00	2	$25	100%	80%	PUMP-2	8%	0%	47%	55%	1.9

Appendix B: Residential Measure Assumptions

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
Measure #: Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. **End Use Measure Group:** Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **UCT Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
5007	Pool/Pump	Pool Timer	Residential Emerging Markets Pilot	MF	N/A	MO	1,167	40%	467	0.00	2	$25	100%	80%	PUMP-3	8%	35%	46%	55%	1.9
5008	Pool/Pump	Pool Timer	Residential Emerging Markets Pilot	MF	N/A	NC	1,167	40%	467	0.00	2	$25	100%	80%	PUMP-4	8%	0%	47%	55%	1.9
5009	Pool/Pump	Pool Heater (COP 5.5-5.9)	Residential Prescriptive	SF	N/A	MO	2,364	38%	900	0.00	8	$1,250	40%	40%	OOL HEATER	0%	1%	47%	46%	0.6
5010	Pool/Pump	Pool Heater (COP >= 6.0)	Residential Prescriptive	SF	N/A	MO	2,364	52%	1,234	0.00	8	$1,250	80%	80%	OOL HEATER	0%	1%	75%	73%	0.4
5011	Pool/Pump	Pool Heater (COP 5.5-5.9)	Residential Prescriptive	SF	N/A	NC	2,364	38%	900	0.00	8	$1,250	40%	40%	OOL HEATER	0%	0%	47%	46%	0.6
5012	Pool/Pump	Pool Heater (COP >= 6.0)	Residential Prescriptive	SF	N/A	NC	2,364	52%	1,234	0.00	8	$1,250	80%	80%	OOL HEATER	0%	0%	75%	73%	0.4
5013	Pool/Pump	Pool Heater (COP 5.5-5.9)	Residential Prescriptive	MF	N/A	MO	2,364	38%	900	0.00	8	$1,250	40%	40%	OOL HEATER	0%	1%	47%	46%	0.6
5014	Pool/Pump	Pool Heater (COP >= 6.0)	Residential Prescriptive	MF	N/A	MO	2,364	52%	1,234	0.00	8	$1,250	80%	80%	OOL HEATER	0%	1%	75%	73%	0.4
5015	Pool/Pump	Pool Heater (COP 5.5-5.9)	Residential Prescriptive	MF	N/A	NC	2,364	38%	900	0.00	8	$1,250	40%	40%	OOL HEATER	0%	0%	47%	46%	0.6
5016	Pool/Pump	Pool Heater (COP >= 6.0)	Residential Prescriptive	MF	N/A	NC	2,364	52%	1,234	0.00	8	$1,250	8%	8%	OOL HEATER	0%	0%	31%	25%	3.9
5017	Pool/Pump	Well Pump	Residential Emerging Markets Pilot	SF	N/A	MO	411	33%	136	0.02	20	$110	100%	80%	WELL-1	4%	25%	41%	55%	1.5
5018	Pool/Pump	Well Pump	Residential Emerging Markets Pilot	SF	N/A	NC	411	33%	136	0.02	20	$110	100%	80%	WELL-2	4%	0%	47%	55%	1.5
5019	Pool/Pump	Well Pump	Residential Emerging Markets Pilot	MF	N/A	MO	411	33%	136	0.02	20	$110	100%	80%	WELL-3	0%	25%	0%	55%	1.5
5020	Pool/Pump	Well Pump	Residential Emerging Markets Pilot	MF	N/A	NC	411	33%	136	0.02	20	$110	100%	80%	WELL-4	0%	0%	0%	55%	1.5
6001	New Construction	Gold Star HERS Index Score 62 - Electric Heated	Residential New Construction	SF	N/A	NC	9,835	44%	4,598	0.40	25	$2,696	100%	100%	NC-1	11%	0%	47%	73%	1.8
6002	New Construction	Gold Star HERS Index Score 62 - Gas Heated South (Dual)	Residential New Construction	SF	N/A	NC	9,835	12%	1,218	0.40	25	$2,696	100%	100%	NC-2	87%	0%	47%	73%	0.8
6003	New Construction	Gold Star HERS Index Score 63 - Electric Heated	Residential New Construction	SF	N/A	NC	9,835	44%	4,598	0.40	25	$2,504	100%	100%	NC-1	11%	0%	47%	73%	2.0
6004	New Construction	Gold Star HERS Index Score 63 - Gas Heated South (Dual)	Residential New Construction	SF	N/A	NC	9,835	12%	1,218	0.40	25	$2,504	100%	100%	NC-2	87%	0%	47%	73%	0.8
6005	New Construction	Gold Star HERS Index Score 65 - Electric Heated	Residential New Construction	SF	N/A	NC	9,835	16%	1,703	0.40	25	$2,121	100%	100%	NC-1	11%	0%	47%	73%	1.2
6006	New Construction	Gold Star HERS Index Score 65 - Gas Heated South (Dual)	Residential New Construction	SF	N/A	NC	9,835	13%	1,349	0.40	25	$2,121	100%	100%	NC-2	87%	0%	47%	73%	1.0
6007	New Construction	Gold Star HERS Index Score 62 - Electric Heated	Residential New Construction	MF	N/A	NC	9,835	44%	4,598	0.40	25	$2,696	100%	100%	NC-3	11%	0%	47%	73%	1.8
6008	New Construction	Gold Star HERS Index Score 62 - Gas Heated South (Dual)	Residential New Construction	MF	N/A	NC	9,835	12%	1,218	0.40	25	$2,696	100%	100%	NC-4	87%	0%	47%	73%	0.8
6009	New Construction	Gold Star HERS Index Score 63 - Electric Heated	Residential New Construction	MF	N/A	NC	9,835	44%	4,598	0.40	25	$2,504	100%	100%	NC-3	11%	0%	47%	73%	2.0
6010	New Construction	Gold Star HERS Index Score 63 - Gas Heated South (Dual)	Residential New Construction	MF	N/A	NC	9,835	12%	1,218	0.40	25	$2,504	100%	100%	NC-4	87%	0%	47%	73%	0.8
6011	New Construction	Gold Star HERS Index Score 65 - Electric Heated	Residential New Construction	MF	N/A	NC	9,835	16%	1,703	0.40	25	$2,121	100%	100%	NC-3	11%	0%	47%	73%	1.2
6012	New Construction	Gold Star HERS Index Score 65 - Gas Heated South (Dual)	Residential New Construction	MF	N/A	NC	9,835	13%	1,349	0.40	25	$2,121	100%	100%	NC-4	87%	0%	47%	73%	1.0
7001	Plug Loads	Smart Power Strips - Tier 1	Residential Marketplace	SF	NLI	Retrofit	466	5%	25	0.00	4	$10	100%	100%	OWER STRIP	178%	16%	98%	95%	0.5
7002	Plug Loads	Smart Power Strips - Tier 1	Community Connections	SF	LI	Retrofit	466	5%	25	0.00	4	$10	100%	100%	OWER STRIP	178%	16%	98%	95%	0.5
7003	Plug Loads	Smart Power Strips - Tier 1	Community Connections	SF	LI	Retrofit	466	5%	25	0.00	4	$10	100%	100%	OWER STRIP	178%	16%	98%	95%	0.5
7004	Plug Loads	Smart Power Strips - Tier 1	Residential Marketplace	SF	N/A	NC	466	5%	25	0.00	4	$10	100%	100%	OWER STRIP	178%	0%	99%	95%	0.5
7005	Plug Loads	Smart Power Strips - Tier 1	Residential Marketplace	MF	NLI	Retrofit	466	5%	25	0.00	4	$10	100%	100%	OWER STRIP	178%	16%	98%	95%	0.5
7006	Plug Loads	Smart Power Strips - Tier 1	Community Connections	MF	LI	Retrofit	466	5%	25	0.00	4	$10	100%	100%	OWER STRIP	178%	16%	98%	95%	0.5
7007	Plug Loads	Smart Power Strips - Tier 1	Community Connections	MF	LI	Retrofit	466	5%	25	0.00	4	$10	100%	100%	OWER STRIP	178%	16%	98%	95%	0.5
7008	Plug Loads	Smart Power Strips - Tier 1	Residential Marketplace	MF	N/A	NC	466	5%	25	0.00	4	$10	100%	100%	OWER STRIP	178%	0%	99%	95%	0.5
7009	Plug Loads	Smart Power Strips - Tier 2	Residential Emerging Markets Pilot	SF	NLI	Retrofit	466	29%	136	0.02	4	$60	50%	17%	OWER STRIP	100%	16%	32%	23%	3.7
7010	Plug Loads	Smart Power Strips - Tier 2	Community Connections	SF	LI	Retrofit	466	29%	136	0.02	4	$60	100%	17%	OWER STRIP	100%	16%	38%	23%	3.7
7011	Plug Loads	Smart Power Strips - Tier 2	Community Connections	SF	LI	Retrofit	466	29%	136	0.02	4	$60	100%	17%	OWER STRIP	100%	16%	38%	23%	3.7
7012	Plug Loads	Smart Power Strips - Tier 2	Residential Emerging Markets Pilot	SF	N/A	NC	466	29%	136	0.02	4	$60	50%	17%	OWER STRIP	100%	0%	31%	23%	3.7
7013	Plug Loads	Smart Power Strips - Tier 2	Residential Emerging Markets Pilot	MF	NLI	Retrofit	466	29%	136	0.02	4	$60	50%	17%	OWER STRIP	100%	16%	32%	23%	3.7
7014	Plug Loads	Smart Power Strips - Tier 2	Community Connections	MF	LI	Retrofit	466	29%	136	0.02	4	$60	100%	17%	OWER STRIP	100%	16%	38%	23%	3.7

Appendix B: Residential Measure Assumptions

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
Measure #: Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. **End Use Measure Group:** Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **UCT Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
7015	Plug Loads	Smart Power Strips - Tier 2	Community Connections	MF	LI	Retrofit	466	29%	136	0.02	4	$60	100%	17%	OWER STRIP	100%	16%	38%	23%	3.7
7016	Plug Loads	Smart Power Strips - Tier 2	Residential Emerging Markets Pilot	MF	N/A	NC	466	29%	136	0.02	4	$60	50%	17%	OWER STRIP	100%	0%	31%	23%	3.7
7017	Plug Loads	Smart Television	Residential Emerging Markets Pilot	SF	N/A	MO	83	20%	17	0.00	6	$0	100%	100%	TV-1	100%	46%	31%	73%	0.6
7018	Plug Loads	Smart Television	Residential Emerging Markets Pilot	SF	N/A	NC	83	20%	17	0.00	6	$0	100%	100%	TV-2	100%	0%	47%	73%	0.6
7019	Plug Loads	Smart Television	Residential Emerging Markets Pilot	MF	N/A	MO	83	20%	17	0.00	6	$0	100%	100%	TV-3	100%	46%	31%	73%	0.6
7020	Plug Loads	Smart Television	Residential Emerging Markets Pilot	MF	N/A	NC	83	20%	17	0.00	6	$0	100%	100%	TV-4	100%	0%	47%	73%	0.6
7021	Plug Loads	Smart Outlets	Residential Emerging Markets Pilot	SF	N/A	Retrofit	466	6%	28	0.00	7	$50	20%	20%	OUTLET-1	100%	14%	32%	25%	1.1
7022	Plug Loads	Smart Outlets	Residential Emerging Markets Pilot	SF	N/A	NC	466	6%	28	0.00	7	$50	20%	20%	OUTLET-2	100%	0%	31%	25%	1.1
7023	Plug Loads	Smart Outlets	Residential Emerging Markets Pilot	MF	N/A	Retrofit	466	6%	28	0.00	7	$50	20%	20%	OUTLET-3	100%	14%	32%	25%	1.1
7024	Plug Loads	Smart Outlets	Residential Emerging Markets Pilot	MF	N/A	NC	466	6%	28	0.00	7	$50	20%	20%	OUTLET-4	100%	0%	31%	25%	1.1
8001	Shell	Advanced Walls - Electric Only	Residential Emerging Markets Pilot	SF	NLI	Retrofit	9,740	10%	974	0.23	20	$2,470	80%	80%	WALL-1	10%	80%	52%	55%	0.6
8002	Shell	Advanced Walls - Electric Only	Residential Emerging Markets Pilot	SF	LI	Retrofit	9,740	10%	974	0.23	20	$2,470	80%	80%	WALL-3	10%	80%	52%	55%	0.6
8003	Shell	Advanced Walls - Electric Only	Residential Emerging Markets Pilot	MF	NLI	Retrofit	2,744	10%	274	0.23	20	$1,581	80%	80%	WALL-5	10%	80%	52%	55%	0.6
8004	Shell	Advanced Walls - Electric Only	Residential Emerging Markets Pilot	MF	LI	Retrofit	2,744	10%	274	0.23	20	$1,581	80%	80%	WALL-7	10%	80%	52%	55%	0.6
8005	Shell	Advanced Walls - Dual (gas heated)	Residential Emerging Markets Pilot	SF	NLI	Retrofit	2,442	10%	244	0.23	20	$2,470	80%	80%	WALL-2	87%	80%	52%	55%	0.4
8006	Shell	Advanced Walls - Dual (gas heated)	Residential Emerging Markets Pilot	SF	LI	Retrofit	2,442	10%	244	0.23	20	$2,470	80%	80%	WALL-4	87%	80%	52%	55%	0.4
8007	Shell	Advanced Walls - Dual (gas heated)	Residential Emerging Markets Pilot	MF	NLI	Retrofit	878	10%	88	0.23	20	$1,581	80%	80%	WALL-6	87%	80%	52%	55%	0.5
8008	Shell	Advanced Walls - Dual (gas heated)	Residential Emerging Markets Pilot	MF	LI	Retrofit	878	10%	88	0.23	20	$1,581	80%	80%	WALL-8	87%	80%	52%	55%	0.5
8009	Shell	Air Sealing Average Sealing - Heat pump	Residential Marketplace	SF	NLI	Retrofit	6,485	11%	728	0.18	15	$200	100%	100%	AIR SEAL-1	4%	76%	48%	73%	3.7
8010	Shell	Air Sealing Average Sealing - Heat pump	Community Connections	SF	LI	Retrofit	6,485	11%	728	0.18	15	$200	100%	100%	AIR SEAL-10	4%	76%	48%	73%	3.7
8011	Shell	Air Sealing Average Sealing - Heat pump	Residential Marketplace	MF	NLI	Retrofit	2,125	17%	364	0.09	15	$200	100%	100%	AIR SEAL-19	4%	76%	48%	73%	1.9
8012	Shell	Air Sealing Average Sealing - Heat pump	Community Connections	MF	LI	Retrofit	2,125	17%	364	0.09	15	$200	100%	100%	AIR SEAL-28	4%	76%	48%	73%	1.9
8013	Shell	Air Sealing Inadequate Sealing - Heat pump	Residential Marketplace	SF	NLI	Retrofit	6,485	13%	857	0.25	15	$200	100%	100%	AIR SEAL-2	4%	76%	48%	73%	4.8
8014	Shell	Air Sealing Inadequate Sealing - Heat pump	Community Connections	SF	LI	Retrofit	6,485	13%	857	0.25	15	$200	100%	100%	AIR SEAL-11	4%	76%	48%	73%	4.8
8015	Shell	Air Sealing Inadequate Sealing - Heat pump	Residential Marketplace	MF	NLI	Retrofit	2,125	20%	429	0.13	15	$200	100%	100%	AIR SEAL-20	4%	76%	48%	73%	2.4
8016	Shell	Air Sealing Inadequate Sealing - Heat pump	Community Connections	MF	LI	Retrofit	2,125	20%	429	0.13	15	$200	100%	100%	AIR SEAL-29	4%	76%	48%	73%	2.4
8017	Shell	Air Sealing Poor Sealing - Heat pump	Residential Marketplace	SF	NLI	Retrofit	6,485	19%	1,206	0.39	15	$200	100%	100%	AIR SEAL-3	4%	86%	59%	73%	7.0
8018	Shell	Air Sealing Poor Sealing - Heat pump	Community Connections	SF	LI	Retrofit	6,485	19%	1,206	0.39	15	$200	100%	100%	AIR SEAL-12	4%	86%	59%	73%	7.0
8019	Shell	Air Sealing Poor Sealing - Heat pump	Residential Marketplace	MF	NLI	Retrofit	2,125	28%	603	0.19	15	$200	100%	100%	AIR SEAL-21	4%	86%	59%	73%	3.5
8020	Shell	Air Sealing Poor Sealing - Heat pump	Community Connections	MF	LI	Retrofit	2,125	28%	603	0.19	15	$200	100%	100%	AIR SEAL-30	4%	86%	59%	73%	3.5
8021	Shell	Air Sealing Average Sealing - Electric Heating	Residential Marketplace	SF	NLI	Retrofit	9,740	14%	1,332	0.21	15	$200	100%	100%	AIR SEAL-4	6%	76%	48%	73%	5.7
8022	Shell	Air Sealing Average Sealing - Electric Heating	Community Connections	SF	LI	Retrofit	9,740	14%	1,332	0.21	15	$200	100%	100%	AIR SEAL-13	6%	76%	48%	73%	5.7
8023	Shell	Air Sealing Average Sealing - Electric Heating	Residential Marketplace	MF	NLI	Retrofit	2,744	24%	666	0.11	15	$200	100%	100%	AIR SEAL-22	6%	76%	48%	73%	2.9

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Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
8024	Shell	Air Sealing Average Sealing - Electric Heating	Community Connections	MF	LI	Retrofit	2,744	24%	666	0.11	15	$200	100%	100%	AIR SEAL-31	6%	76%	48%	73%	2.9
8025	Shell	Air Sealing Inadequate Sealing - Electric Heating	Residential Marketplace	SF	NLI	Retrofit	9,740	16%	1,539	0.29	15	$200	100%	100%	AIR SEAL-5	6%	76%	48%	73%	7.1
8026	Shell	Air Sealing Inadequate Sealing - Electric Heating	Community Connections	SF	LI	Retrofit	9,740	16%	1,539	0.29	15	$200	100%	100%	AIR SEAL-14	6%	76%	48%	73%	7.1
8027	Shell	Air Sealing Inadequate Sealing - Electric Heating	Residential Marketplace	MF	NLI	Retrofit	2,744	28%	769	0.15	15	$200	100%	100%	AIR SEAL-23	6%	76%	48%	73%	3.5
8028	Shell	Air Sealing Inadequate Sealing - Electric Heating	Community Connections	MF	LI	Retrofit	2,744	28%	769	0.15	15	$200	100%	100%	AIR SEAL-32	6%	76%	48%	73%	3.5
8029	Shell	Air Sealing Poor Sealing - Electric Heating	Residential Marketplace	SF	NLI	Retrofit	9,740	20%	1,926	0.38	15	$200	100%	100%	AIR SEAL-6	6%	86%	59%	73%	8.9
8030	Shell	Air Sealing Poor Sealing - Electric Heating	Community Connections	SF	LI	Retrofit	9,740	20%	1,926	0.38	15	$200	100%	100%	AIR SEAL-15	6%	86%	59%	73%	8.9
8031	Shell	Air Sealing Poor Sealing - Electric Heating	Residential Marketplace	MF	NLI	Retrofit	2,744	35%	963	0.19	15	$200	100%	100%	AIR SEAL-24	6%	86%	59%	73%	4.5
8032	Shell	Air Sealing Poor Sealing - Electric Heating	Community Connections	MF	LI	Retrofit	2,744	35%	963	0.19	15	$200	100%	100%	AIR SEAL-33	6%	86%	59%	73%	4.5
8033	Shell	Air Sealing - Average Sealing - Gas Heating	Residential Marketplace	SF	NLI	Retrofit	2,442	7%	172	0.35	15	$200	100%	100%	AIR SEAL-7	87%	76%	48%	73%	3.8
8034	Shell	Air Sealing - Average Sealing - Gas Heating	Community Connections	SF	LI	Retrofit	2,442	7%	172	0.35	15	$200	100%	100%	AIR SEAL-16	87%	76%	74%	91%	3.8
8035	Shell	Air Sealing - Average Sealing - Gas Heating	Residential Marketplace	MF	NLI	Retrofit	878	10%	86	0.18	15	$200	100%	100%	AIR SEAL-25	87%	76%	48%	73%	1.9
8036	Shell	Air Sealing - Average Sealing - Gas Heating	Community Connections	MF	LI	Retrofit	878	10%	86	0.18	15	$200	100%	100%	AIR SEAL-34	87%	76%	74%	91%	1.9
8037	Shell	Air Sealing - Inadequate Sealing - Gas Heating	Residential Marketplace	SF	NLI	Retrofit	2,442	13%	308	0.39	15	$200	100%	100%	AIR SEAL-8	87%	76%	48%	73%	4.6
8038	Shell	Air Sealing - Inadequate Sealing - Gas Heating	Community Connections	SF	LI	Retrofit	2,442	13%	308	0.39	15	$200	100%	100%	AIR SEAL-17	87%	76%	74%	91%	4.6
8039	Shell	Air Sealing - Inadequate Sealing - Gas Heating	Residential Marketplace	MF	NLI	Retrofit	878	18%	154	0.20	15	$200	100%	100%	AIR SEAL-26	87%	76%	48%	73%	2.3
8040	Shell	Air Sealing - Inadequate Sealing - Gas Heating	Community Connections	MF	LI	Retrofit	878	18%	154	0.20	15	$200	100%	100%	AIR SEAL-35	87%	76%	74%	91%	2.3
8041	Shell	Air Sealing - Poor Sealing - Gas Heating	Residential Marketplace	SF	NLI	Retrofit	2,442	9%	213	0.31	15	$200	100%	100%	AIR SEAL-9	87%	86%	59%	73%	3.5
8042	Shell	Air Sealing - Poor Sealing - Gas Heating	Community Connections	SF	LI	Retrofit	2,442	9%	213	0.31	15	$200	100%	100%	AIR SEAL-18	87%	86%	62%	91%	3.5
8043	Shell	Air Sealing - Poor Sealing - Gas Heating	Residential Marketplace	MF	NLI	Retrofit	878	12%	106	0.16	15	$200	100%	100%	AIR SEAL-27	87%	86%	59%	73%	1.8
8044	Shell	Air Sealing - Poor Sealing - Gas Heating	Community Connections	MF	LI	Retrofit	878	12%	106	0.16	15	$200	100%	100%	AIR SEAL-36	87%	86%	62%	91%	1.8
8045	Shell	Attic Insulation - Average Insulation - Electric Heating	Residential Prescriptive	SF	NLI	Retrofit	9,740	3%	291	0.05	25	$898	50%	50%	ATTIC-1	10%	73%	46%	48%	0.9
8046	Shell	Attic Insulation - Average Insulation - Electric Heating	Residential Prescriptive	SF	LI	Retrofit	9,740	3%	291	0.05	25	$898	100%	100%	ATTIC-7	10%	73%	46%	73%	0.4
8047	Shell	Attic Insulation - Average Insulation - Electric Heating	Residential Prescriptive	MF	NLI	Retrofit	2,744	3%	82	0.01	25	$575	78%	78%	ATTIC-13	10%	73%	46%	67%	0.2
8048	Shell	Attic Insulation - Average Insulation - Electric Heating	Residential Prescriptive	MF	LI	Retrofit	2,744	3%	82	0.01	25	$575	100%	100%	ATTIC-19	10%	73%	46%	73%	0.2
8049	Shell	Attic Insulation - Inadequate Insulation - Electric Heating	Residential Prescriptive	SF	NLI	Retrofit	9,740	7%	649	0.13	25	$1,597	28%	28%	ATTIC-2	10%	73%	46%	37%	2.0
8050	Shell	Attic Insulation - Inadequate Insulation - Electric Heating	Residential Prescriptive	SF	LI	Retrofit	9,740	7%	649	0.13	25	$1,597	100%	100%	ATTIC-8	10%	73%	46%	73%	0.6
8051	Shell	Attic Insulation - Inadequate Insulation - Electric Heating	Residential Prescriptive	MF	NLI	Retrofit	2,744	7%	183	0.04	25	$1,022	44%	44%	ATTIC-14	10%	73%	46%	45%	0.6
8052	Shell	Attic Insulation - Inadequate Insulation - Electric Heating	Residential Prescriptive	MF	LI	Retrofit	2,744	7%	183	0.04	25	$1,022	100%	100%	ATTIC-20	10%	73%	46%	73%	0.2
8053	Shell	Attic Insulation - Poor Insulation - Electric Heating	Residential Prescriptive	SF	NLI	Retrofit	9,740	41%	4,041	0.43	25	$1,597	100%	28%	ATTIC-3	10%	80%	70%	37%	10.1
8054	Shell	Attic Insulation - Poor Insulation - Electric Heating	Residential Prescriptive	SF	LI	Retrofit	9,740	41%	4,041	0.43	25	$1,597	100%	100%	ATTIC-9	10%	80%	52%	73%	2.8
8055	Shell	Attic Insulation - Poor Insulation - Electric Heating	Residential Prescriptive	MF	NLI	Retrofit	2,744	41%	1,138	0.12	25	$1,022	100%	44%	ATTIC-15	10%	80%	70%	45%	2.8

Appendix B: Residential Measure Assumptions

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
Measure #: Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. **End Use Measure Group:** Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **UCT Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
8056	Shell	Attic Insulation - Poor Insulation - Electric Heating	Residential Prescriptive	MF	LI	Retrofit	2,744	41%	1,138	0.12	25	$1,022	100%	100%	ATTIC-21	10%	80%	52%	73%	1.3
8057	Shell	Attic Insulation - Average Insulation - Gas Heating	Residential Prescriptive	SF	NLI	Retrofit	2,442	2%	52	0.08	25	$898	40%	40%	ATTIC-4	87%	73%	46%	42%	0.7
8058	Shell	Attic Insulation - Average Insulation - Gas Heating	IQW	SF	LI	Retrofit	2,442	2%	52	0.08	25	$898	100%	100%	ATTIC-10	87%	73%	77%	91%	0.3
8059	Shell	Attic Insulation - Average Insulation - Gas Heating	Residential Prescriptive	MF	NLI	Retrofit	878	2%	19	0.03	25	$575	63%	63%	ATTIC-16	87%	73%	46%	55%	0.2
8060	Shell	Attic Insulation - Average Insulation - Gas Heating	IQW	MF	LI	Retrofit	878	2%	19	0.03	25	$575	100%	100%	ATTIC-22	87%	73%	77%	91%	0.2
8061	Shell	Attic Insulation - Inadequate Insulation - Gas Heating	Residential Prescriptive	SF	NLI	Retrofit	2,442	4%	99	0.14	25	$1,597	23%	23%	ATTIC-5	87%	73%	46%	33%	1.3
8062	Shell	Attic Insulation - Inadequate Insulation - Gas Heating	IQW	SF	LI	Retrofit	2,442	4%	99	0.14	25	$1,597	100%	100%	ATTIC-11	87%	73%	77%	91%	0.3
8063	Shell	Attic Insulation - Inadequate Insulation - Gas Heating	Residential Prescriptive	MF	NLI	Retrofit	878	4%	35	0.05	25	$1,022	35%	35%	ATTIC-17	87%	73%	46%	40%	0.5
8064	Shell	Attic Insulation - Inadequate Insulation - Gas Heating	IQW	MF	LI	Retrofit	878	4%	35	0.05	25	$1,022	100%	100%	ATTIC-23	87%	73%	77%	91%	0.2
8065	Shell	Attic Insulation - Poor Insulation - Gas Heating	Residential Prescriptive	SF	NLI	Retrofit	2,442	18%	451	0.38	25	$1,597	50%	23%	ATTIC-6	87%	80%	52%	33%	3.9
8066	Shell	Attic Insulation - Poor Insulation - Gas Heating	IQW	SF	LI	Retrofit	2,442	18%	446	0.42	25	$1,597	100%	100%	ATTIC-12	87%	80%	70%	91%	0.9
8067	Shell	Attic Insulation - Poor Insulation - Gas Heating	Residential Prescriptive	MF	NLI	Retrofit	878	18%	162	0.14	25	$1,022	35%	35%	ATTIC-18	87%	80%	52%	40%	1.4
8068	Shell	Attic Insulation - Poor Insulation - Gas Heating	IQW	MF	LI	Retrofit	878	18%	160	0.15	25	$1,022	100%	100%	ATTIC-24	87%	80%	70%	91%	0.5
8069	Shell	Duct Sealing - Average Sealing - Electric Heating	Residential Emerging Markets Pilot	SF	NLI	Retrofit	9,740	3%	298	0.04	20	$450	53%	53%	DUCT-1	10%	76%	48%	40%	1.2
8070	Shell	Duct Sealing - Average Sealing - Electric Heating	Residential Emerging Markets Pilot	SF	LI	Retrofit	9,740	3%	298	0.04	20	$450	100%	100%	DUCT-7	10%	76%	48%	73%	0.7
8071	Shell	Duct Sealing - Average Sealing - Electric Heating	Residential Emerging Markets Pilot	MF	NLI	Retrofit	2,744	3%	84	0.01	20	$288	83%	83%	DUCT-13	10%	76%	48%	57%	0.3
8072	Shell	Duct Sealing - Average Sealing - Electric Heating	Residential Emerging Markets Pilot	MF	LI	Retrofit	2,744	3%	84	0.01	20	$288	100%	100%	DUCT-19	10%	76%	48%	73%	0.3
8073	Shell	Duct Sealing - Inadequate Sealing - Electric Heating	Residential Emerging Markets Pilot	SF	NLI	Retrofit	9,740	5%	485	0.11	20	$450	100%	53%	DUCT-2	10%	90%	66%	40%	2.5
8074	Shell	Duct Sealing - Inadequate Sealing - Electric Heating	Residential Emerging Markets Pilot	SF	LI	Retrofit	9,740	5%	485	0.11	20	$450	100%	100%	DUCT-8	10%	90%	66%	73%	1.3
8075	Shell	Duct Sealing - Inadequate Sealing - Electric Heating	Residential Emerging Markets Pilot	MF	NLI	Retrofit	2,744	5%	137	0.03	20	$288	83%	83%	DUCT-14	10%	90%	66%	57%	0.7
8076	Shell	Duct Sealing - Inadequate Sealing - Electric Heating	Residential Emerging Markets Pilot	MF	LI	Retrofit	2,744	5%	137	0.03	20	$288	100%	100%	DUCT-20	10%	90%	66%	73%	0.6
8077	Shell	Duct Sealing/Insulation - Poor Sealing - Electric Heating	Residential Emerging Markets Pilot	SF	NLI	Retrofit	9,740	13%	1,238	0.28	20	$450	100%	53%	DUCT-3	10%	96%	81%	40%	6.4
8078	Shell	Duct Sealing/Insulation - Poor Sealing - Electric Heating	Residential Emerging Markets Pilot	SF	LI	Retrofit	9,740	13%	1,238	0.28	20	$450	100%	100%	DUCT-9	10%	96%	81%	73%	3.4
8079	Shell	Duct Sealing/Insulation - Poor Sealing - Electric Heating	Residential Emerging Markets Pilot	MF	NLI	Retrofit	2,744	13%	349	157.30	20	$288	100%	83%	DUCT-15	10%	96%	81%	57%	1,514.8
8080	Shell	Duct Sealing/Insulation - Poor Sealing - Electric Heating	Residential Emerging Markets Pilot	MF	LI	Retrofit	2,744	13%	349	157.30	20	$288	100%	100%	DUCT-21	10%	96%	81%	73%	1,262.4
8081	Shell	Duct Sealing - Average Sealing - Gas Heating	Residential Prescriptive	SF	NLI	Retrofit	2,442	5%	117	0.13	20	$450	53%	53%	DUCT-4	87%	76%	48%	50%	1.6
8082	Shell	Duct Sealing - Average Sealing - Gas Heating	IQW	SF	LI	Retrofit	2,442	5%	117	0.13	20	$450	100%	100%	DUCT-10	87%	76%	74%	91%	0.9
8083	Shell	Duct Sealing - Average Sealing - Gas Heating	Residential Prescriptive	MF	NLI	Retrofit	878	5%	42	0.05	20	$288	83%	83%	DUCT-16	87%	76%	48%	72%	0.6
8084	Shell	Duct Sealing - Average Sealing - Gas Heating	IQW	MF	LI	Retrofit	878	5%	42	0.05	20	$288	100%	100%	DUCT-22	87%	76%	74%	91%	0.5
8085	Shell	Duct Sealing - Inadequate Sealing - Gas Heating	Residential Prescriptive	SF	NLI	Retrofit	2,442	7%	163	0.11	20	$450	53%	53%	DUCT-5	87%	90%	66%	50%	1.6
8086	Shell	Duct Sealing - Inadequate Sealing - Gas Heating	IQW	SF	LI	Retrofit	2,442	7%	163	0.11	20	$450	100%	100%	DUCT-11	87%	90%	66%	91%	0.8
8087	Shell	Duct Sealing - Inadequate Sealing - Gas Heating	Residential Prescriptive	MF	NLI	Retrofit	878	7%	59	0.04	20	$288	83%	83%	DUCT-17	87%	90%	66%	72%	0.6

Appendix B: Residential Measure Assumptions

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Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
8088	Shell	Duct Sealing - Inadequate Sealing - Gas Heating	IQW	MF	LI	Retrofit	878	7%	59	0.04	20	$288	100%	100%	DUCT-23	87%	90%	66%	91%	0.5
8089	Shell	Duct Sealing/Insulation - Poor Sealing - Gas Heating	Residential Prescriptive	SF	NLI	Retrofit	2,442	9%	210	0.37	20	$450	100%	53%	DUCT-6	87%	96%	81%	50%	4.2
8090	Shell	Duct Sealing/Insulation - Poor Sealing - Gas Heating	IQW	SF	LI	Retrofit	2,442	7%	165	0.27	20	$450	100%	100%	DUCT-12	87%	96%	81%	91%	1.6
8091	Shell	Duct Sealing/Insulation - Poor Sealing - Gas Heating	Residential Prescriptive	MF	NLI	Retrofit	878	9%	76	0.13	20	$288	100%	83%	DUCT-18	87%	96%	81%	72%	1.5
8092	Shell	Duct Sealing/Insulation - Poor Sealing - Gas Heating	IQW	MF	LI	Retrofit	878	7%	59	0.10	20	$288	100%	100%	DUCT-24	87%	96%	81%	91%	0.9
8093	Shell	Wall Insulation - Electric Only	Residential Prescriptive	SF	NLI	Retrofit	9,740	9%	869	0.07	25	$1,235	50%	36%	WALL-1	10%	80%	52%	41%	2.1
8094	Shell	Wall Insulation - Electric Only	IQW	SF	LI	Retrofit	9,740	6%	560	0.10	25	$1,235	100%	100%	WALL-3	10%	80%	70%	91%	0.6
8095	Shell	Wall Insulation - Electric Only	Residential Prescriptive	MF	NLI	Retrofit	2,744	32%	869	0.07	25	$790	75%	57%	WALL-5	10%	80%	52%	52%	2.1
8096	Shell	Wall Insulation - Electric Only	IQW	MF	LI	Retrofit	2,744	20%	560	0.10	25	$790	100%	100%	WALL-7	10%	80%	70%	91%	0.9
8097	Shell	Wall Insulation - Dual (gas heated)	Residential Prescriptive	SF	NLI	Retrofit	2,442	4%	94	0.09	25	$1,235	29%	29%	WALL-2	87%	80%	52%	37%	0.9
8098	Shell	Wall Insulation - Dual (gas heated)	IQW	SF	LI	Retrofit	2,442	3%	78	0.08	25	$1,235	100%	100%	WALL-4	87%	80%	70%	91%	0.2
8099	Shell	Wall Insulation - Dual (gas heated)	Residential Prescriptive	MF	NLI	Retrofit	878	11%	94	0.09	25	$790	46%	46%	WALL-6	87%	80%	52%	45%	0.9
8100	Shell	Wall Insulation - Dual (gas heated)	IQW	MF	LI	Retrofit	878	9%	78	0.08	25	$790	100%	100%	WALL-8	87%	80%	70%	91%	0.4
8101	Shell	Basement Sidewall Insulation - Heat pump	Residential Emerging Markets Pilot	SF	N/A	Retrofit	6,485	6%	357	0.03	25	$1,204	80%	80%	BSI-1	4%	80%	52%	55%	0.4
8102	Shell	Basement Sidewall Insulation - Heat pump	Residential Emerging Markets Pilot	MF	N/A	Retrofit	2,125	8%	178	0.02	25	$1,204	80%	80%	BSI-2	4%	80%	52%	55%	0.2
8103	Shell	Basement Sidewall Insulation - Electric furnace	Residential Emerging Markets Pilot	SF	N/A	Retrofit	11,910	8%	932	0.03	25	$1,204	80%	80%	BSI-3	6%	80%	52%	55%	0.9
8104	Shell	Basement Sidewall Insulation - Electric furnace	Residential Emerging Markets Pilot	MF	N/A	Retrofit	3,156	15%	466	0.02	25	$1,204	80%	80%	BSI-4	6%	80%	52%	55%	0.5
8105	Shell	Basement Sidewall Insulation - Gas Heating	Residential Emerging Markets Pilot	SF	N/A	Retrofit	2,442	-1%	-31	-0.04	25	$1,204	80%	80%	BSI-5	87%	80%	52%	55%	0.0
8106	Shell	Basement Sidewall Insulation - Gas Heating	Residential Emerging Markets Pilot	MF	N/A	Retrofit	878	-2%	-15	-0.02	25	$1,204	80%	80%	BSI-6	87%	80%	52%	55%	0.0
8107	Shell	Floor Insulation Above Crawlspace - Heat pump	Residential Emerging Markets Pilot	SF	N/A	Retrofit	6,485	1%	38	-0.04	25	$1,204	80%	80%	FLOOR-1	4%	80%	52%	55%	0.0
8108	Shell	Floor Insulation Above Crawlspace - Heat pump	Residential Emerging Markets Pilot	MF	N/A	Retrofit	2,125	1%	19	-0.02	25	$1,204	80%	80%	FLOOR-4	4%	80%	52%	55%	0.0
8109	Shell	Floor Insulation Above Crawlspace - Electric furnace	Residential Emerging Markets Pilot	SF	N/A	Retrofit	11,910	2%	238	-0.03	25	$1,204	80%	80%	FLOOR-2	6%	80%	52%	55%	0.1
8110	Shell	Floor Insulation Above Crawlspace - Electric furnace	Residential Emerging Markets Pilot	MF	N/A	Retrofit	3,156	4%	119	-0.01	25	$1,204	80%	80%	FLOOR-5	6%	80%	52%	55%	0.1
8111	Shell	Floor Insulation Above Crawlspace - Gas Heating	Residential Emerging Markets Pilot	SF	N/A	Retrofit	2,442	-1%	-21	0.00	25	$1,204	80%	80%	FLOOR-3	87%	80%	52%	55%	0.0
8112	Shell	Floor Insulation Above Crawlspace - Gas Heating	Residential Emerging Markets Pilot	MF	N/A	Retrofit	878	-1%	-10	0.00	25	$1,204	80%	80%	FLOOR-6	87%	80%	52%	55%	0.0
8113	Shell	Radiant Barrier - Heat pump	Residential Emerging Markets Pilot	SF	NLI	Retrofit	6,485	15%	978	0.14	25	$720	100%	80%	RB-1	4%	75%	48%	55%	2.1
8114	Shell	Radiant Barrier - Heat pump	Residential Emerging Markets Pilot	SF	LI	Retrofit	6,485	15%	978	0.14	25	$720	100%	80%	RB-2	4%	75%	48%	55%	2.1
8115	Shell	Radiant Barrier - Heat pump	Residential Emerging Markets Pilot	MF	NLI	Retrofit	2,125	22%	474	0.07	25	$720	80%	80%	RB-3	4%	75%	48%	55%	1.0
8116	Shell	Radiant Barrier - Heat pump	Residential Emerging Markets Pilot	MF	LI	Retrofit	2,125	22%	474	0.07	25	$720	100%	80%	RB-4	4%	75%	48%	55%	1.0
8117	Shell	Radiant Barrier - Electric furnace	Residential Emerging Markets Pilot	SF	NLI	Retrofit	11,910	8%	978	0.14	25	$720	100%	80%	RB-5	6%	75%	48%	55%	2.1
8118	Shell	Radiant Barrier - Electric furnace	Residential Emerging Markets Pilot	SF	LI	Retrofit	11,910	8%	978	0.14	25	$720	100%	80%	RB-6	6%	75%	48%	55%	2.1
8119	Shell	Radiant Barrier - Electric furnace	Residential Emerging Markets Pilot	MF	NLI	Retrofit	3,156	15%	474	0.07	25	$720	80%	80%	RB-7	6%	75%	48%	55%	1.0
8120	Shell	Radiant Barrier - Electric furnace	Residential Emerging Markets Pilot	MF	LI	Retrofit	3,156	15%	474	0.07	25	$720	100%	80%	RB-8	6%	75%	48%	55%	1.0
8121	Shell	ENERGY STAR Door - Heat pump	Residential Emerging Markets Pilot	SF	N/A	Retrofit	6,485	5%	319	0.02	20	$1,275	80%	80%	ES DOOR-1	4%	75%	48%	55%	0.3

Appendix B: Residential Measure Assumptions

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
Measure #: Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. **End Use Measure Group:** Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **UCT Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
8122	Shell	ENERGY STAR Door - Heat pump	Residential Emerging Markets Pilot	MF	N/A	Retrofit	2,125	8%	159	0.01	20	$1,275	80%	80%	ES DOOR-4	4%	75%	48%	55%	0.1
8123	Shell	ENERGY STAR Door - Electric furnace	Residential Emerging Markets Pilot	SF	N/A	Retrofit	11,910	2%	197	0.01	20	$1,275	80%	80%	ES DOOR-2	6%	75%	48%	55%	0.2
8124	Shell	ENERGY STAR Door - Electric furnace	Residential Emerging Markets Pilot	MF	N/A	Retrofit	3,156	3%	98	0.01	20	$1,275	80%	80%	ES DOOR-5	6%	75%	48%	55%	0.1
8125	Shell	ENERGY STAR Door - Gas Heating	Residential Emerging Markets Pilot	SF	N/A	Retrofit	2,442	1%	21	0.02	20	$1,275	80%	80%	ES DOOR-3	87%	75%	48%	55%	0.1
8126	Shell	ENERGY STAR Door - Gas Heating	Residential Emerging Markets Pilot	MF	N/A	Retrofit	878	1%	11	0.01	20	$1,275	80%	80%	ES DOOR-6	87%	75%	48%	55%	0.0
8127	Shell	ENERGY STAR Windows - Heat pump	Residential Emerging Markets Pilot	SF	N/A	Retrofit	6,485	6%	400	0.25	20	$11,300	80%	80%	WIND-1	4%	70%	45%	55%	0.1
8128	Shell	ENERGY STAR Windows - Heat pump	Residential Emerging Markets Pilot	MF	N/A	Retrofit	2,125	9%	194	0.12	20	$7,232	80%	80%	WIND-4	4%	70%	45%	55%	0.1
8129	Shell	ENERGY STAR Windows - Electric furnace	Residential Emerging Markets Pilot	SF	N/A	Retrofit	11,910	5%	611	0.25	20	$11,300	80%	80%	WIND-2	6%	70%	45%	55%	0.1
8130	Shell	ENERGY STAR Windows - Electric furnace	Residential Emerging Markets Pilot	MF	N/A	Retrofit	3,156	9%	296	0.12	20	$7,232	80%	80%	WIND-5	6%	70%	45%	55%	0.1
8131	Shell	ENERGY STAR Windows - Gas Heating	Residential Emerging Markets Pilot	SF	N/A	Retrofit	2,442	6%	137	0.25	20	$11,300	80%	80%	WIND-3	87%	70%	45%	55%	0.1
8132	Shell	ENERGY STAR Windows - Gas Heating	Residential Emerging Markets Pilot	MF	N/A	Retrofit	878	8%	67	0.12	20	$7,232	80%	80%	WIND-6	87%	70%	45%	55%	0.1
8133	Shell	Smart Window Coverings - Film/Transformer - Heat pump	Residential Emerging Markets Pilot	SF	N/A	Retrofit	6,485	16%	1,005	0.35	7	$6,780	80%	80%	INDOW FILN	4%	70%	45%	55%	0.1
8134	Shell	Smart Window Coverings - Film/Transformer - Heat pump	Residential Emerging Markets Pilot	MF	N/A	Retrofit	2,125	16%	329	0.23	7	$4,339	80%	80%	INDOW FILN	4%	70%	45%	55%	0.1
8135	Shell	Smart Window Coverings - Film/Transformer - Electric furnace	Residential Emerging Markets Pilot	SF	N/A	Retrofit	11,910	16%	1,846	0.35	7	$6,780	80%	80%	INDOW FILN	6%	70%	45%	55%	0.2
8136	Shell	Smart Window Coverings - Film/Transformer - Electric furnace	Residential Emerging Markets Pilot	MF	N/A	Retrofit	3,156	16%	489	0.23	7	$4,339	80%	80%	INDOW FILN	6%	70%	45%	55%	0.1
8137	Shell	Smart Window Coverings - Film/Transformer - Gas Heating	Residential Emerging Markets Pilot	SF	N/A	Retrofit	2,442	16%	378	0.35	7	$6,780	80%	80%	INDOW FILN	87%	70%	45%	55%	0.1
8138	Shell	Smart Window Coverings - Film/Transformer - Gas Heating	Residential Emerging Markets Pilot	MF	N/A	Retrofit	878	16%	136	0.23	7	$4,339	80%	80%	INDOW FILN	87%	70%	45%	55%	0.1
8139	Shell	Thin Triple Windows - Heat pump	Residential Emerging Markets Pilot	SF	N/A	Retrofit	6,485	35%	2,247	0.67	40	$12,964	80%	80%	WIND-1	4%	70%	45%	55%	0.5
8140	Shell	Thin Triple Windows - Heat pump	Residential Emerging Markets Pilot	MF	N/A	Retrofit	2,125	68%	1,439	0.43	40	$8,297	80%	80%	WIND-4	4%	70%	45%	55%	0.5
8141	Shell	Thin Triple Windows - Electric furnace	Residential Emerging Markets Pilot	SF	N/A	Retrofit	11,910	18%	2,182	0.67	40	$12,964	80%	80%	WIND-2	6%	70%	45%	55%	0.5
8142	Shell	Thin Triple Windows - Electric furnace	Residential Emerging Markets Pilot	MF	N/A	Retrofit	3,156	44%	1,397	0.43	40	$8,297	80%	80%	WIND-5	6%	70%	45%	55%	0.5
8143	Shell	Thin Triple Windows - Gas heating	Residential Emerging Markets Pilot	SF	N/A	Retrofit	2,442	15%	369	0.67	40	$12,964	80%	80%	WIND-3	87%	70%	45%	55%	0.3
8144	Shell	Thin Triple Windows - Gas heating	Residential Emerging Markets Pilot	MF	N/A	Retrofit	878	27%	236	0.43	40	$8,297	80%	80%	WIND-6	87%	70%	45%	55%	0.3
9001	Water Heating	Heat Pump Water Heater-electric resistance heat	Residential Prescriptive	SF	N/A	MO	2,942	85%	2,505	0.34	13	$1,199	100%	42%	HPWH-1	6%	1%	96%	44%	3.6
9002	Water Heating	Heat Pump Water Heater-electric resistance heat	Residential Prescriptive	SF	N/A	NC	2,942	85%	2,505	0.34	13	$1,199	100%	42%	HPWH-4	6%	0%	96%	44%	3.6
9003	Water Heating	Heat Pump Water Heater-electric resistance heat	Residential Instant Rebate	SF	N/A	MO	2,942	87%	2,557	0.35	13	$1,199	100%	42%	HPWH-1	6%	1%	96%	44%	3.7
9004	Water Heating	Heat Pump Water Heater-electric resistance heat	Residential Instant Rebate	SF	N/A	NC	2,942	87%	2,557	0.35	13	$1,199	100%	42%	HPWH-4	6%	0%	96%	44%	3.7
9005	Water Heating	Heat Pump Water Heater-electric resistance heat	Residential Prescriptive	MF	N/A	MO	3,045	82%	2,505	0.34	13	$1,199	100%	42%	HPWH-7	6%	1%	96%	44%	3.6
9006	Water Heating	Heat Pump Water Heater-electric resistance heat	Residential Prescriptive	MF	N/A	NC	3,045	82%	2,505	0.34	13	$1,199	100%	42%	HPWH-10	6%	0%	96%	44%	3.6
9007	Water Heating	Heat Pump Water Heater-electric resistance heat	Residential Instant Rebate	MF	N/A	MO	3,045	84%	2,557	0.35	13	$1,199	100%	42%	HPWH-7	6%	1%	96%	44%	3.7
9008	Water Heating	Heat Pump Water Heater-electric resistance heat	Residential Instant Rebate	MF	N/A	NC	3,045	84%	2,557	0.35	13	$1,199	100%	42%	HPWH-10	6%	0%	96%	44%	3.7

Appendix B: Residential Measure Assumptions

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Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
9009	Water Heating	Heat Pump Water Heater-heat pump heat	Residential Prescriptive	SF	N/A	MO	2,942	85%	2,505	0.34	13	$1,199	100%	42%	HPWH-2	4%	1%	96%	44%	3.6
9010	Water Heating	Heat Pump Water Heater-heat pump heat	Residential Prescriptive	SF	N/A	NC	2,942	85%	2,505	0.34	13	$1,199	100%	42%	HPWH-5	4%	0%	96%	44%	3.6
9011	Water Heating	Heat Pump Water Heater-heat pump heat	Residential Instant Rebate	SF	N/A	MO	2,942	87%	2,557	0.35	13	$1,199	100%	42%	HPWH-2	4%	1%	96%	44%	3.7
9012	Water Heating	Heat Pump Water Heater-heat pump heat	Residential Instant Rebate	SF	N/A	NC	2,942	87%	2,557	0.35	13	$1,199	100%	42%	HPWH-5	4%	0%	96%	44%	3.7
9013	Water Heating	Heat Pump Water Heater-heat pump heat	Residential Prescriptive	MF	N/A	MO	3,045	82%	2,505	0.34	13	$1,199	100%	42%	HPWH-8	4%	1%	96%	44%	3.6
9014	Water Heating	Heat Pump Water Heater-heat pump heat	Residential Prescriptive	MF	N/A	NC	3,045	82%	2,505	0.34	13	$1,199	100%	42%	HPWH-11	4%	0%	96%	44%	3.6
9015	Water Heating	Heat Pump Water Heater-heat pump heat	Residential Instant Rebate	MF	N/A	MO	3,045	84%	2,557	0.35	13	$1,199	100%	42%	HPWH-8	4%	1%	96%	44%	3.7
9016	Water Heating	Heat Pump Water Heater-heat pump heat	Residential Instant Rebate	MF	N/A	NC	3,045	84%	2,557	0.35	13	$1,199	100%	42%	HPWH-11	4%	0%	96%	44%	3.7
9017	Water Heating	Heat Pump Water Heater-gas heat	Residential Prescriptive	SF	N/A	MO	2,942	85%	2,505	0.34	13	$1,199	100%	42%	HPWH-3	28%	1%	96%	44%	3.6
9018	Water Heating	Heat Pump Water Heater-gas heat	Residential Prescriptive	SF	N/A	NC	2,942	85%	2,505	0.34	13	$1,199	100%	42%	HPWH-6	28%	0%	96%	44%	3.6
9019	Water Heating	Heat Pump Water Heater-gas heat	Residential Instant Rebate	SF	N/A	MO	2,942	87%	2,557	0.35	13	$1,199	100%	42%	HPWH-3	28%	1%	96%	44%	3.7
9020	Water Heating	Heat Pump Water Heater-gas heat	Residential Instant Rebate	SF	N/A	NC	2,942	87%	2,557	0.35	13	$1,199	100%	42%	HPWH-6	28%	0%	96%	44%	3.7
9021	Water Heating	Heat Pump Water Heater-gas heat	Residential Prescriptive	MF	N/A	MO	3,045	82%	2,505	0.34	13	$1,199	100%	42%	HPWH-9	28%	1%	96%	44%	3.6
9022	Water Heating	Heat Pump Water Heater-gas heat	Residential Prescriptive	MF	N/A	NC	3,045	82%	2,505	0.34	13	$1,199	100%	42%	HPWH-12	28%	0%	96%	44%	3.6
9023	Water Heating	Heat Pump Water Heater-gas heat	Residential Instant Rebate	MF	N/A	MO	3,045	84%	2,557	0.35	13	$1,199	100%	42%	HPWH-9	28%	1%	96%	44%	3.7
9024	Water Heating	Heat Pump Water Heater-gas heat	Residential Instant Rebate	MF	N/A	NC	3,045	84%	2,557	0.35	13	$1,199	100%	42%	HPWH-12	28%	0%	96%	44%	3.7
9025	Water Heating	Smart Water Heater - Tank Controls and Sensors - electric resistance heat	Residential Emerging Markets Pilot	SF	N/A	MO	2,942	15%	441	0.02	13	$120	100%	80%	HPWH-1	6%	1%	47%	55%	2.6
9026	Water Heating	Smart Water Heater - Tank Controls and Sensors - electric resistance heat	Residential Emerging Markets Pilot	SF	N/A	NC	2,942	15%	441	0.02	13	$120	100%	80%	HPWH-4	6%	0%	47%	55%	2.6
9027	Water Heating	Smart Water Heater - Tank Controls and Sensors - electric resistance heat	Residential Emerging Markets Pilot	MF	N/A	MO	3,045	15%	457	0.02	13	$120	100%	80%	HPWH-7	6%	1%	47%	55%	2.7
9028	Water Heating	Smart Water Heater - Tank Controls and Sensors - electric resistance heat	Residential Emerging Markets Pilot	MF	N/A	NC	3,045	15%	457	0.02	13	$120	100%	80%	HPWH-10	6%	0%	47%	55%	2.7
9029	Water Heating	Smart Water Heater - Tank Controls and Sensors - heat pump heat	Residential Emerging Markets Pilot	SF	N/A	MO	2,942	15%	441	0.02	13	$120	100%	80%	HPWH-2	4%	1%	47%	55%	2.6
9030	Water Heating	Smart Water Heater - Tank Controls and Sensors - heat pump heat	Residential Emerging Markets Pilot	SF	N/A	NC	2,942	15%	441	0.02	13	$120	100%	80%	HPWH-5	4%	0%	47%	55%	2.6
9031	Water Heating	Smart Water Heater - Tank Controls and Sensors - heat pump heat	Residential Emerging Markets Pilot	MF	N/A	MO	3,045	15%	457	0.02	13	$120	100%	80%	HPWH-8	4%	1%	47%	55%	2.7
9032	Water Heating	Smart Water Heater - Tank Controls and Sensors - heat pump heat	Residential Emerging Markets Pilot	MF	N/A	NC	3,045	15%	457	0.02	13	$120	100%	80%	HPWH-11	4%	0%	47%	55%	2.7
9033	Water Heating	Smart Water Heater - Tank Controls and Sensors - gas heat	Residential Emerging Markets Pilot	SF	N/A	MO	2,942	15%	441	0.02	13	$120	100%	80%	HPWH-3	28%	1%	47%	55%	2.6
9034	Water Heating	Smart Water Heater - Tank Controls and Sensors - gas heat	Residential Emerging Markets Pilot	SF	N/A	NC	2,942	15%	441	0.02	13	$120	100%	80%	HPWH-6	28%	0%	47%	55%	2.6
9035	Water Heating	Smart Water Heater - Tank Controls and Sensors - gas heat	Residential Emerging Markets Pilot	MF	N/A	MO	3,045	15%	457	0.02	13	$120	100%	80%	HPWH-9	28%	1%	47%	55%	2.7
9036	Water Heating	Smart Water Heater - Tank Controls and Sensors - gas heat	Residential Emerging Markets Pilot	MF	N/A	NC	3,045	15%	457	0.02	13	$120	100%	80%	HPWH-12	28%	0%	47%	55%	2.7
9037	Water Heating	Thermostatic Restrictor Shower Valve	Residential Emerging Markets Pilot	SF	N/A	Retrofit	2,942	2%	65	0.00	10	$30	80%	80%	TRSV-1	73%	14%	32%	55%	1.2

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Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
9038	Water Heating	Thermostatic Restrictor Shower Valve	Residential Emerging Markets Pilot	SF	N/A	NC	2,942	2%	65	0.00	10	$30	80%	80%	TRSV-2	73%	0%	35%	55%	1.2
9039	Water Heating	Thermostatic Restrictor Shower Valve	Residential Emerging Markets Pilot	MF	N/A	Retrofit	3,045	3%	93	0.00	10	$30	100%	80%	TRSV-3	50%	14%	39%	55%	1.8
9040	Water Heating	Thermostatic Restrictor Shower Valve	Residential Emerging Markets Pilot	MF	N/A	NC	3,045	3%	93	0.00	10	$30	100%	80%	TRSV-4	50%	0%	47%	55%	1.8
9041	Water Heating	Water Heater Timer	Residential Emerging Markets Pilot	SF	N/A	Retrofit	2,942	5%	147	0.02	2	$60	80%	80%	WHT-1	38%	35%	35%	55%	0.4
9042	Water Heating	Water Heater Timer	Residential Emerging Markets Pilot	SF	N/A	NC	2,942	5%	147	0.02	2	$60	80%	80%	WHT-2	38%	0%	35%	55%	0.4
9043	Water Heating	Water Heater Timer	Residential Emerging Markets Pilot	MF	N/A	Retrofit	3,045	5%	152	0.02	2	$60	80%	80%	WHT-3	38%	35%	35%	55%	0.4
9044	Water Heating	Water Heater Timer	Residential Emerging Markets Pilot	MF	N/A	NC	3,045	5%	152	0.02	2	$60	80%	80%	WHT-4	38%	0%	35%	55%	0.4
9045	Water Heating	Drain Water Heat Recovery	Residential Emerging Markets Pilot	SF	N/A	Retrofit	2,942	14%	422	0.04	30	$742	80%	80%	DWHR-1	38%	1%	35%	55%	0.9
9046	Water Heating	Drain Water Heat Recovery	Residential Emerging Markets Pilot	SF	N/A	NC	2,942	14%	422	0.04	30	$742	80%	80%	DWHR-2	38%	0%	35%	55%	0.9
9047	Water Heating	Drain Water Heat Recovery	Residential Emerging Markets Pilot	MF	N/A	Retrofit	3,045	14%	437	0.05	30	$742	80%	80%	DWHR-3	38%	1%	35%	55%	1.0
9048	Water Heating	Drain Water Heat Recovery	Residential Emerging Markets Pilot	MF	N/A	NC	3,045	14%	437	0.05	30	$742	80%	80%	DWHR-4	38%	0%	35%	55%	1.0
9049	Water Heating	Shower Timer	Residential Emerging Markets Pilot	SF	N/A	Retrofit	2,942	0%	13	0.00	2	$5	80%	80%	ST-1	73%	5%	32%	55%	0.2
9050	Water Heating	Shower Timer	Residential Emerging Markets Pilot	SF	N/A	NC	2,942	0%	13	0.00	2	$5	80%	80%	ST-2	73%	0%	35%	55%	0.6
9051	Water Heating	Shower Timer	Residential Emerging Markets Pilot	MF	N/A	Retrofit	3,045	0%	13	0.00	2	$5	80%	80%	ST-3	50%	5%	32%	55%	0.6
9052	Water Heating	Shower Timer	Residential Emerging Markets Pilot	MF	N/A	NC	3,045	0%	13	0.00	2	$5	80%	80%	ST-4	50%	0%	35%	55%	0.6
9053	Water Heating	Low Flow Showerhead 1.5 gpm	Residential Instant Rebate	SF	NLI	Retrofit	2,942	11%	321	0.01	10	$1	100%	100%	LFSH-1	73%	61%	87%	93%	116.2
9054	Water Heating	Low Flow Showerhead 1.5 gpm	Residential Instant Rebate	SF	LI	Retrofit	2,942	11%	321	0.01	10	$1	100%	100%	LFSH-2	73%	61%	87%	93%	116.2
9055	Water Heating	Low Flow Showerhead 1.5 gpm	IQW	SF	LI	Retrofit	2,942	10%	293	0.01	10	$1	100%	100%	LFSH-2	73%	61%	87%	93%	107.5
9056	Water Heating	Low Flow Showerhead 1.5 gpm	Residential Instant Rebate	SF	N/A	NC	2,942	11%	321	0.01	10	$1	100%	100%	LFSH-3	73%	0%	96%	93%	116.2
9057	Water Heating	Low Flow Showerhead 1.5 gpm	Residential Instant Rebate	MF	NLI	Retrofit	3,045	11%	321	0.01	10	$1	100%	100%	LFSH-4	50%	51%	90%	93%	116.2
9058	Water Heating	Low Flow Showerhead 1.5 gpm	Residential Instant Rebate	MF	LI	Retrofit	3,045	11%	321	0.01	10	$1	100%	100%	LFSH-5	50%	51%	90%	93%	116.2
9059	Water Heating	Low Flow Showerhead 1.5 gpm	IQW	MF	LI	Retrofit	3,045	10%	293	0.01	10	$1	100%	100%	LFSH-5	50%	51%	90%	93%	107.5
9060	Water Heating	Low Flow Showerhead 1.5 gpm	Residential Instant Rebate	MF	N/A	NC	3,045	11%	321	0.01	10	$1	100%	100%	LFSH-6	50%	0%	96%	93%	116.2
9061	Water Heating	Kitchen Faucet Aerator 1.5 gpm	Residential Marketplace	SF	NLI	Retrofit	2,942	5%	141	0.01	10	$1	100%	100%	KITCH-1	38%	49%	90%	93%	51.6
9062	Water Heating	Kitchen Faucet Aerator 1.5 gpm	Residential Marketplace	SF	LI	Retrofit	2,942	5%	141	0.01	10	$1	100%	100%	KITCH-2	38%	49%	90%	93%	51.6
9063	Water Heating	Kitchen Faucet Aerator 1.5 gpm	IQW	SF	LI	Retrofit	2,942	4%	117	0.01	10	$1	100%	100%	KITCH-2	38%	49%	90%	93%	44.0
9064	Water Heating	Kitchen Faucet Aerator 1.5 gpm	Residential Marketplace	SF	N/A	NC	2,942	5%	141	0.01	10	$1	100%	100%	KITCH-3	38%	0%	96%	93%	51.6
9065	Water Heating	Kitchen Faucet Aerator 1.5 gpm	Residential Marketplace	MF	NLI	Retrofit	3,045	5%	141	0.01	10	$1	100%	100%	KITCH-4	38%	38%	92%	93%	51.6
9066	Water Heating	Kitchen Faucet Aerator 1.5 gpm	Residential Marketplace	MF	LI	Retrofit	3,045	5%	141	0.01	10	$1	100%	100%	KITCH-5	38%	38%	92%	93%	51.6
9067	Water Heating	Kitchen Faucet Aerator 1.5 gpm	IQW	MF	LI	Retrofit	3,045	4%	117	0.01	10	$1	100%	100%	KITCH-5	38%	38%	92%	93%	44.0
9068	Water Heating	Kitchen Faucet Aerator 1.5 gpm	Residential Marketplace	MF	N/A	NC	3,045	5%	141	0.01	10	$1	100%	100%	KITCH-6	38%	0%	96%	93%	51.6
9069	Water Heating	Bathroom Aerator 1.0 gpm	Residential Marketplace	SF	NLI	Retrofit	2,942	1%	35	0.00	10	$1	100%	100%	BATH-1	88%	49%	90%	93%	13.9
9070	Water Heating	Bathroom Aerator 1.0 gpm	Residential Marketplace	SF	LI	Retrofit	2,942	1%	35	0.00	10	$1	100%	100%	BATH-2	88%	49%	90%	93%	13.9
9071	Water Heating	Bathroom Aerator 1.0 gpm	IQW	SF	LI	Retrofit	2,942	1%	27	0.00	10	$1	100%	100%	BATH-2	88%	49%	90%	93%	11.1
9072	Water Heating	Bathroom Aerator 1.0 gpm	Residential Marketplace	SF	N/A	NC	2,942	1%	35	0.00	10	$1	100%	100%	BATH-3	88%	0%	96%	93%	13.9
9073	Water Heating	Bathroom Aerator 1.0 gpm	Residential Marketplace	MF	NLI	Retrofit	3,045	1%	35	0.00	10	$1	100%	100%	BATH-4	54%	38%	92%	93%	13.9
9074	Water Heating	Bathroom Aerator 1.0 gpm	Residential Marketplace	MF	LI	Retrofit	3,045	1%	35	0.00	10	$1	100%	100%	BATH-5	54%	38%	92%	93%	13.9
9075	Water Heating	Bathroom Aerator 1.0 gpm	IQW	MF	LI	Retrofit	3,045	1%	27	0.00	10	$1	100%	100%	BATH-5	54%	38%	92%	93%	11.1
9076	Water Heating	Bathroom Aerator 1.0 gpm	Residential Marketplace	MF	N/A	NC	3,045	1%	35	0.00	10	$1	100%	100%	BATH-6	54%	0%	96%	93%	13.9
9077	Water Heating	Pipe Wrap	Residential Emerging Markets Pilot	SF	NLI	Retrofit	2,942	3%	89	0.01	15	$9	100%	100%	PIPE-1	38%	17%	37%	73%	7.7
9078	Water Heating	Pipe Wrap	IQW	SF	LI	Retrofit	2,942	3%	89	0.01	15	$9	100%	100%	PIPE-2	38%	17%	95%	93%	7.7
9079	Water Heating	Pipe Wrap	Residential Emerging Markets Pilot	MF	NLI	Retrofit	3,045	3%	89	0.01	15	$9	100%	100%	PIPE-3	38%	17%	37%	73%	7.7
9080	Water Heating	Pipe Wrap	IQW	MF	LI	Retrofit	3,045	3%	89	0.01	15	$9	100%	100%	PIPE-4	38%	17%	95%	93%	7.7

Appendix B: Residential Measure Assumptions

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
Measure #: Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. **End Use Measure Group:** Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **UCT Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

Measure #	End-Use	Measure Name	Program	Home Type	Income Type	Replacement Type	Base Annual Electric kWh Usage	% Elec Savings	Per Unit Elec Savings (kWh)	Per Unit Summer kW Savings	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	UCT Score
9081	Water Heating	Water Heater Temperature Setback	Residential Emerging Markets Pilot	SF	NLI	Retrofit	2,942	3%	82	0.01	2	$10	100%	100%	WHTS-1	38%	54%	39%	73%	1.0
9082	Water Heating	Water Heater Temperature Setback	IQW	SF	LI	Retrofit	2,942	3%	82	0.01	2	$10	100%	100%	WHTS-2	38%	54%	89%	93%	1.0
9083	Water Heating	Water Heater Temperature Setback	Residential Emerging Markets Pilot	MF	NLI	Retrofit	3,045	3%	82	0.01	2	$10	100%	100%	WHTS-3	38%	54%	39%	73%	1.0
9084	Water Heating	Water Heater Temperature Setback	IQW	MF	LI	Retrofit	3,045	3%	82	0.01	2	$10	100%	100%	WHTS-4	38%	54%	89%	93%	1.0

Appendix C. C&I Sector Measure Detail

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
1	CompressedAir	Efficient Air Compressors (VSD)	Biz-Prescriptive	Assembly	ROB	1,583	1,583	21%	329	0.00	13	$127	100%	59%	80%	1	100%	33%	92.7%	76.7%	83.1%	5.5
2	CompressedAir	Efficient Air Nozzles	Biz-Prescriptive	Assembly	Retro	1,480	1,480	50%	740	0.00	15	$50	100%	81%	81%	2	35%	33%	92.7%	91.1%	91.1%	15.8
3	CompressedAir	AODD Pump Controls	Biz-Custom	Assembly	Retro	103,919	103,919	35%	36,372	0.00	10	$1,150	100%	50%	50%	3	10%	33%	92.7%	72.6%	72.6%	38.2
4	CompressedAir	Compressed Air - Custom	Biz-Custom	Assembly	Retro	5	5	20%	1	0.00	10	$0	100%	47%	47%	4	50%	33%	92.7%	64.2%	64.2%	6.0
5	CompressedAir	Retro-commissioning_Compressed Air Optimization	Biz-Custom RCx	Assembly	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	5	50%	33%	92.7%	64.2%	64.2%	3.2
6	Cooking	Commercial Combination Oven (Electric)	Biz-Prescriptive	Assembly	ROB	38,561	38,561	48%	18,432	0.00	12	$16,884	75%	6%	15%	1	18%	53%	77.5%	62.4%	62.4%	14.1
7	Cooking	Commercial Electric Convection Oven	Biz-Prescriptive	Assembly	ROB	12,193	12,193	15%	1,879	0.00	12	$1,706	75%	21%	51%	1	18%	53%	77.6%	62.4%	62.4%	4.4
8	Cooking	Commercial Electric Griddle	Biz-Prescriptive	Assembly	ROB	17,056	17,056	15%	2,596	0.00	12	$3,604	25%	15%	15%	2	14%	17%	41.9%	33.6%	33.6%	2.8
9	Cooking	Commercial Electric Steam Cooker	Biz-Prescriptive	Assembly	ROB	19,549	19,549	67%	13,162	0.00	12	$2,490	100%	24%	55%	3	6%	45%	88.0%	81.1%	83.5%	18.0
10	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz-Prescriptive	Assembly	ROB	39,306	39,306	44%	17,369	0.00	15	$1,000	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	11.7
11	Cooking	Dishwasher High Temp Door (Energy Star)	Biz-Prescriptive	Assembly	ROB	26,901	26,901	32%	8,586	0.00	15	$1,100	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	5.2
12	Cooking	Energy efficient electric fryer	Biz-Prescriptive	Assembly	ROB	18,955	18,955	17%	3,274	0.00	12	$1,500	100%	5%	13%	5	27%	24%	88.0%	57.2%	59.4%	23.2
13	Cooking	Insulated Holding Cabinets (Full Size)	Biz-Prescriptive	Assembly	ROB	13,697	13,697	68%	9,314	0.00	12	$1,200	100%	35%	55%	6	3%	16%	88.0%	83.6%	84.9%	12.7
14	Cooking	Insulated Holding Cabinets (Half-Size)	Biz-Prescriptive	Assembly	ROB	4,383	4,383	60%	2,630	0.00	12	$1,500	100%	10%	25%	6	3%	16%	88.0%	52.6%	57.6%	10.1
15	Cooling	Air Conditioner - 13 IEER (5-20 Tons)	Biz-Prescriptive	Assembly	ROB	1,030	1,030	6%	63	0.00	15	$63	100%	48%	55%	1	20%	20%	92.7%	50.9%	53.4%	4.7
16	Cooling	Air Conditioner - 14 IEER (5-20 Tons)	Biz-Prescriptive	Assembly	ROB	1,030	1,030	13%	132	0.00	15	$127	100%	24%	55%	1	20%	20%	92.7%	43.4%	54.0%	9.7
17	Cooling	Air Conditioner - 17 IEER (5-20 Tons)	Biz-Prescriptive	Assembly	ROB	1,030	1,030	28%	291	0.00	15	$127	100%	24%	55%	1	20%	20%	92.7%	61.3%	73.6%	21.4
18	Cooling	Air Conditioner - 21 IEER (5-20 Tons)	Biz-Prescriptive	Assembly	ROB	1,030	1,030	42%	432	0.00	15	$127	100%	24%	55%	1	20%	20%	92.7%	71.4%	78.7%	31.7
19	Cooling	Air Conditioner - 12.1 IEER (20+ Tons)	Biz-Prescriptive	Assembly	ROB	1,102	1,102	6%	64	0.00	15	$30	100%	100%	100%	2	20%	20%	92.7%	92.7%	92.7%	4.7
20	Cooling	Air Conditioner - 13 IEER (20+ Tons)	Biz-Prescriptive	Assembly	ROB	1,102	1,102	12%	136	0.00	15	$37	100%	81%	81%	2	20%	20%	92.7%	86.3%	86.3%	10.0
21	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz-Prescriptive	Assembly	ROB	1,102	1,102	20%	224	0.00	15	$37	100%	81%	81%	2	20%	20%	92.7%	88.8%	88.8%	16.4
22	Cooling	Air Conditioner - 21 IEER (20+ Tons)	Biz-Prescriptive	Assembly	ROB	1,102	1,102	46%	504	0.00	15	$37	100%	81%	81%	2	20%	20%	92.7%	91.0%	91.0%	37.0
23	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz-Custom	Assembly	Retro	1,047	1,047	7%	73	0.00	3	$5	100%	50%	50%	3	41%	50%	92.7%	70.5%	70.5%	14.6
24	Cooling	Air Side Economizer	Biz-Custom	Assembly	Retro	1,030	1,030	20%	206	0.00	10	$84	75%	25%	25%	4	41%	20%	81.0%	51.0%	51.0%	3.9
25	Cooling	Advanced Rooftop Controls	Biz-Prescriptive	Assembly	Retro	1,047	1,047	8%	85	0.00	10	$100	100%	100%	100%	5	41%	20%	92.7%	92.7%	92.7%	0.3
26	Cooling	HVAC Occupancy Controls	Biz-Custom	Assembly	ROB	2,900	2,900	20%	580	0.00	15	$537	100%	11%	11%	6	41%	20%	92.7%	36.0%	36.0%	12.0
27	Cooling	Air Conditioner - 16 SEER (<5 Tons)	Biz-Prescriptive	Assembly	ROB	897	897	13%	112	0.00	15	$47	100%	64%	80%	7	26%	20%	92.7%	77.3%	82.5%	8.2
28	Cooling	Air Conditioner - 17 SEER (<5 Tons)	Biz-Prescriptive	Assembly	ROB	897	897	18%	158	0.00	15	$206	100%	15%	36%	7	26%	20%	92.7%	36.0%	40.6%	11.6
29	Cooling	Air Conditioner - 18 SEER(<5 Tons)	Biz-Prescriptive	Assembly	ROB	897	897	22%	199	0.00	15	$206	100%	15%	36%	7	26%	20%	92.7%	39.6%	46.0%	14.7
30	Cooling	Air Conditioner - 21 SEER(<5 Tons)	Biz-Prescriptive	Assembly	ROB	897	897	33%	299	0.00	15	$253	100%	12%	30%	7	26%	20%	92.7%	42.9%	48.2%	22.0
31	Cooling	Smart Thermostat	Biz-Prescriptive	Assembly	ROB	897	897	14%	127	0.00	11	$175	57%	57%	57%	8	26%	12%	48.4%	48.4%	48.4%	1.3
32	Cooling	PTAC - <7,000 Btuh - lodging	Biz-Prescriptive	Assembly	ROB	1,056	1,056	8%	89	0.00	8	$84	100%	36%	36%	9	0%	20%	92.7%	47.9%	47.9%	3.6
33	Cooling	PTAC - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Assembly	ROB	1,158	1,158	7%	84	0.00	8	$84	100%	36%	36%	10	0%	20%	92.7%	46.6%	46.6%	3.4
34	Cooling	PTAC - >15,000 Btuh - lodging	Biz-Prescriptive	Assembly	ROB	1,323	1,323	10%	126	0.00	8	$84	100%	36%	55%	11	0%	20%	92.7%	54.1%	64.5%	5.1
35	Cooling	Air Cooled Chiller	Biz-Prescriptive	Assembly	ROB	917	917	6%	51	0.00	23	$126	100%	24%	55%	12	33%	15%	92.7%	32.0%	35.8%	6.5
36	Cooling	Chiller Tune-up	Biz-Prescriptive	Assembly	Retro	1,047	1,047	7%	73	0.00	3	$8	100%	100%	100%	13	33%	50%	92.7%	92.7%	92.7%	4.9
37	Cooling	HVAC/Chiller Custom	Biz-Custom	Assembly	Retro	5	5	20%	1	0.00	20	$1	100%	7%	7%	14	100%	20%	92.7%	36.0%	36.0%	30.3
38	Cooling	Window Film	Biz-Prescriptive	Assembly	Retro	6,000	6,000	4%	264	0.00	10	$154	100%	65%	65%	15	100%	20%	92.7%	73.1%	73.1%	3.2
39	Cooling	Triple Pane Windows	Biz-Custom	Assembly	ROB	6,000	6,000	6%	360	0.00	25	$700	100%	5%	5%	15	100%	20%	92.7%	36.0%	36.0%	24.5
40	Cooling	Energy Recovery Ventilator	Biz-Custom	Assembly	Retro	1,102	1,102	32%	355	0.00	15	$1,500	25%	2%	2%	16	100%	2%	31.4%	21.8%	21.8%	13.2
41	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz-Prescriptive	Assembly	ROB	1,671	1,671	4%	71	0.00	16	$87	100%	46%	46%	1	33%	20%	92.7%	45.8%	45.8%	2.8
42	Heating	Heat Pump - 17 SEER (<5 Tons)	Biz-Prescriptive	Assembly	ROB	1,671	1,671	9%	152	0.00	16	$442	25%	9%	23%	1	33%	20%	44.0%	36.0%	36.0%	5.4
43	Heating	Heat Pump - 18 SEER(<5 Tons)	Biz-Prescriptive	Assembly	ROB	1,671	1,671	13%	217	0.00	16	$507	50%	8%	20%	1	33%	20%	44.0%	36.0%	36.0%	7.7
44	Heating	Heat Pump - 21 SEER(<5 Tons)	Biz-Prescriptive	Assembly	ROB	1,671	1,671	20%	339	0.00	16	$507	75%	8%	20%	1	33%	20%	57.4%	36.0%	36.0%	12.2
45	Heating	Geothermal HP - SEER 20.3 (<5 Tons)	Biz-Prescriptive	Assembly	ROB	1,671	1,671	23%	385	0.00	25	$2,576	25%	2%	2%	1	33%	20%	44.0%	36.0%	36.0%	17.3
46	Heating	Geothermal HP - SEER 21.5 (<5 Tons)	Biz-Prescriptive	Assembly	ROB	1,671	1,671	27%	457	0.00	25	$2,576	25%	2%	4%	1	33%	20%	44.0%	36.0%	36.0%	20.0
47	Heating	Geothermal HP - SEER 23.1 (<5 Tons)	Biz-Prescriptive	Assembly	ROB	1,671	1,671	32%	541	0.00	25	$2,576	25%	2%	4%	1	33%	20%	44.0%	36.0%	36.0%	23.0
48	Heating	Geothermal HP - SEER 29.3 (<5 Tons)	Biz-Prescriptive	Assembly	ROB	1,671	1,671	47%	785	0.00	25	$2,576	25%	2%	4%	1	33%	20%	44.0%	36.0%	36.0%	29.6
49	Heating	Heat Pump - 14.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Assembly	ROB	2,023	2,023	11%	231	0.00	16	$100	100%	40%	55%	2	26%	20%	92.7%	68.3%	73.8%	31.8
50	Heating	Heat Pump - 15.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Assembly	ROB	2,023	2,023	17%	338	0.00	16	$136	100%	30%	55%	2	26%	20%	92.7%	66.1%	74.9%	35.4
51	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Assembly	ROB	2,109	2,109	15%	322	0.00	16	$100	100%	40%	55%	2	26%	20%	92.7%	74.4%	78.1%	36.2
52	Heating	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Assembly	ROB	2,109	2,109	20%	428	0.00	16	$139	100%	29%	55%	2	26%	20%	92.7%	71.0%	77.6%	39.6
53	Heating	Geothermal HP - SEER 20.3 (5-20 Tons)	Biz-Prescriptive	Assembly	ROB	1,841	1,841	30%	556	0.00	25	$2,576	50%	2%	4%	2	26%	20%	44.0%	36.0%	36.0%	36.1
54	Heating	Geothermal HP - SEER 21.5 (5-20 Tons)	Biz-Prescriptive	Assembly	ROB	1,841	1,841	34%	628	0.00	25	$2,576	50%	2%	4%	2	26%	20%	44.0%	36.0%	36.0%	38.8
55	Heating	Geothermal HP - SEER 23.1 (5-20 Tons)	Biz-Prescriptive	Assembly	ROB	1,974	1,974	43%	844	0.00	25	$2,576	50%	2%	4%	2	26%	20%	44.0%	36.0%	36.0%	44.7
56	Heating	Geothermal HP - SEER 29.3 (5-20 Tons)	Biz-Prescriptive	Assembly	ROB	1,974	1,974	55%	1,088	0.00	25	$2,576	75%	2%	4%	2	26%	20%	48.3%	36.0%	36.0%	51.3
57	Heating	Variable Refrigerant Flow Heat Pump	Biz-Custom	Assembly	ROB	1,571	1,571	15%	239	0.00	16	$224	100%	11%	11%	2	26%	2%	92.7%	32.4%	32.4%	17.9
58	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz-Prescriptive	Assembly	ROB	2,215	2,215	10%	220	0.00	16	$100	100%	40%	55%	3	26%	20%	92.7%	67.1%	73.0%	28.4
59	Heating	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	Biz-Prescriptive	Assembly	ROB	2,215	2,215	16%	354	0.00	16	$175	100%	23%	55%	3	26%	20%	92.7%	56.7%	71.6%	33.2
60	Heating	Geothermal HP - SEER 20.3 (20+ Tons)	Biz-Prescriptive	Assembly	ROB	2,109	2,109	39%	824	0.00	25	$2,576	100%	2%	4%	3	26%	20%	92.7%	36.0%	36.0%	70.2
61	Heating	Geothermal HP - SEER 21.5 (20+ Tons)	Biz-Prescriptive	Assembly	ROB	2,109	2,109	42%	895	0.00	25	$2,576	100%	2%	4%	3	26%	20%	92.7%	36.0%	36.0%	72.9
62	Heating	Geothermal HP - SEER 23.1 (20+ Tons)	Biz-Prescriptive	Assembly	ROB	2,109	2,109	46%	979	0.00	25	$2,576	100%	2%	4%	3	26%	20%	92.7%	36.0%	36.0%	75.9
63	Heating	Geothermal HP - SEER 29.3 (20+ Tons)	Biz-Prescriptive	Assembly	ROB	2,109	2,109	58%	1,223	0.00	25	$2,576	100%	2%	4%	3	26%	20%	92.7%	36.0%	36.0%	82.5
64	Heating	Mini Split Ductless Heat Pump Cold Climate (Tiers & sizes TBD)	Biz-Prescriptive	Assembly	ROB	1,671	1,671	20%	339	0.00	16	$224	100%	18%	45%	4	15%	20%	92.7%	50.1%	58.2%	12.2
65	Heating	PTHP - <7,000 Btuh - lodging	Biz-Custom	Assembly	ROB	1,829	1,829	5%	86	0.00	8	$130	100%	100%	100%	5	0%	10%	92.7%	74.2%	74.2%	0.7
66	Heating	PTHP - >15,000 Btuh - lodging	Biz-Prescriptive	Assembly	ROB	2,245	2,245	18%	410	0.00	8	$130	100%	100%	100%	6	0%	10%	92.7%	92.7%	92.7%	3.6
67	Heating	PTHP - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Assembly	ROB	2,015	2,015	11%	213	0.00	8	$130	100%	100%	100%	7	0%	10%	92.7%	92.7%	92.7%	1.8
68	HotWater	Heat Pump Water Heater	Biz-Prescriptive	Assembly	ROB	3,027	3,027	67%	2,027	0.00	15	$1,115	100%	45%	45%	1	100%	0%	84.0%	60.9%	60.9%	3.4
69	HotWater	Hot Water Pipe Insulation	Biz-Custom	Assembly	Retro	3,027	3,027	2%	61	0.00	20	$60	75%	10%	10%	2	100%	80%	86.0%	84.0%	84.0%	9.8
70	HotWater	Faucet Aerator	Biz-Custom	Assembly	Retro	389	389	32%	126	0.00	10	$8	100%	50%	50%	3	20%	90%	93.0%	92.0%	92.0%	25.8
71	HotWater	Low Flow Pre-Rinse Sprayers	Biz-Prescriptive	Assembly	ROB	18,059	18,059	54%	9,789	0.00	5	$60	100%	17%	42%	4	20%	80%	86.0%	84.0%	84.0%	199.3
72	HotWater	ENERGY STAR Commercial Washing Machines	Biz-Prescriptive	Assembly	ROB	1,552	1,552	43%	671	0.00	7	$250	75%	28%	28%	5	25%	33%	79.3%	64.6%	64.6%	2.9

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
73	InteriorLighting	LED T8 Tube Replacement	Biz-Prescriptive Light	Assembly	Retro	80	80	45%	36	0.00	15	$5	100%	100%	100%	1	56%	40%	94.6%	94.6%	94.6%	7.9
74	InteriorLighting	LED troffer retrofit kit, 2'X2' and 2'X4'	Biz-Prescriptive Light	Assembly	Retro	181	181	50%	91	0.00	15	$70	100%	36%	55%	1	56%	40%	94.6%	52.0%	54.5%	4.0
75	InteriorLighting	LED troffer, 2'X2' and 2'X4'	Biz-Prescriptive Light	Assembly	Retro	181	181	50%	91	0.00	15	$70	100%	36%	55%	1	56%	40%	94.6%	52.0%	54.5%	4.0
76	InteriorLighting	Bi-Level Lighting Fixture – Stairwells, Hallways	Biz-Custom Light	Assembly	Retro	181	181	74%	135	0.00	10	$274	25%	5%	6%	2	1%	40%	58.0%	49.0%	49.0%	5.1
77	InteriorLighting	LED high bay fixture	Biz-Prescriptive Light	Assembly	Retro	1,687	1,687	68%	1,147	0.00	15	$330	100%	35%	55%	3	1%	34%	94.6%	76.4%	82.6%	11.0
78	InteriorLighting	LED Mogul-base HID Lamp Replacing High Bay HID	Biz-Prescriptive Light	Assembly	Retro	1,687	1,687	66%	1,119	0.00	15	$330	100%	35%	55%	3	1%	34%	94.6%	75.9%	82.3%	10.7
79	InteriorLighting	LED low bay fixture	Biz-Prescriptive Light	Assembly	Retro	359	359	61%	218	0.00	15	$44	100%	68%	80%	4	34%	34%	94.6%	89.3%	91.2%	8.0
80	InteriorLighting	LED Mogul-base HID Lamp Replacing Low Bay HID	Biz-Prescriptive Light	Assembly	Retro	359	359	59%	211	0.00	15	$44	100%	68%	80%	4	34%	34%	94.6%	89.1%	91.1%	7.7
81	InteriorLighting	LED Screw-In Lamps (Directional)	Biz-Prescriptive Light	Assembly	ROB	150	150	86%	128	0.00	10	$1	100%	100%	100%	6	0%	43%	94.6%	94.6%	94.6%	113.7
82	InteriorLighting	LED downlight fixture	Biz-Prescriptive Light	Assembly	Retro	124	124	68%	84	0.00	15	$27	100%	19%	46%	6	8%	45%	94.6%	67.3%	78.0%	18.5
83	InteriorLighting	LED Screw-In Lamps (Omnidirectional & Decorative)	Biz-Prescriptive Light	Assembly	ROB	113	113	81%	92	0.00	10	$1	100%	100%	100%	5	1%	20%	94.6%	94.6%	94.6%	81.0
84	InteriorLighting	DeLamp Fluorescent Fixture Average Lamp Wattage 28W	Biz-Prescriptive Light	Assembly	Retro	67	67	100%	67	0.00	11	$4	100%	100%	100%	7	56%	0%	94.6%	94.6%	94.6%	14.1
85	InteriorLighting	Occupancy Sensors	Biz-Prescriptive Light	Assembly	Retro	305	305	30%	91	0.00	10	$65	50%	31%	31%	8	95%	10%	52.9%	42.4%	42.4%	2.3
86	InteriorLighting	Daylighting Controls	Biz-Prescriptive Light	Assembly	Retro	390	390	30%	117	0.00	10	$58	100%	35%	55%	8	95%	10%	94.6%	58.5%	72.7%	6.5
87	InteriorLighting	Dual Occupancy & Daylighting Controls	Biz-Custom Light	Assembly	Retro	174	174	44%	77	0.00	10	$75	75%	40%	50%	8	95%	10%	69.9%	30.4%	34.2%	2.0
88	InteriorLighting	Central Lighting Monitoring & Controls (non-networked)	Biz-Custom Light	Assembly	Retro	41,703	41,703	20%	8,341	0.00	12	$3,700	100%	23%	29%	8	95%	10%	94.6%	44.1%	47.7%	4.6
89	InteriorLighting	Network Lighting Controls - Wireless (WiFi)	Biz-Custom Light	Assembly	Retro	1	1	49%	1	0.00	15	$1	100%	12%	15%	8	95%	10%	94.6%	28.0%	28.0%	10.9
90	InteriorLighting	Luminaire Level Lighting Controls w/ HVAC Control	Biz-Custom Light	Assembly	Retro	174	174	65%	113	0.00	15	$90	100%	13%	16%	8	91%	10%	94.6%	28.0%	28.0%	10.9
91	InteriorLighting	LED Exit Sign - 4 Watt Fixture (2 lamp)	Biz-Prescriptive Light	Assembly	Retro	69	69	43%	29	0.00	5	$33	92%	92%	92%	9	1%	75%	87.4%	87.4%	87.4%	0.3
92	InteriorLighting	Lighting - Custom	Biz-Custom Light	Assembly	Retro	4	4	25%	1	0.00	15	$1	100%	10%	13%	10	100%	0%	94.6%	21.4%	21.7%	10.9
93	ExteriorLighting	LED wallpack (existing W<250)	Biz-Prescriptive Light	Assembly	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	1	12%	46%	94.6%	56.6%	70.8%	5.8
94	ExteriorLighting	LED parking lot fixture (existing W≥250)	Biz-Prescriptive Light	Assembly	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	2	11%	54%	67.8%	63.2%	63.2%	4.4
95	ExteriorLighting	LED parking lot fixture (existing W<250)	Biz-Prescriptive Light	Assembly	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	3	11%	54%	94.6%	63.2%	70.8%	5.8
96	ExteriorLighting	LED outdoor pole decorative fixture (existing W≥250)	Biz-Prescriptive Light	Assembly	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	17%	17%	4	11%	54%	67.8%	63.2%	63.2%	3.4
97	ExteriorLighting	LED parking garage fixture (existing W≥250)	Biz-Prescriptive Light	Assembly	Retro	3,235	3,235	60%	1,953	0.00	6	$756	50%	13%	33%	5	11%	69%	78.3%	75.2%	75.2%	4.7
98	ExteriorLighting	LED parking garage fixture (existing W<250)	Biz-Prescriptive Light	Assembly	Retro	1,742	1,742	66%	1,154	0.00	6	$248	100%	18%	45%	6	11%	69%	94.6%	77.6%	83.9%	6.2
99	ExteriorLighting	LED Mogul-base HID Lamp Replacing Exterior HID (existing W≥250)	Biz-Prescriptive Light	Assembly	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	7	11%	46%	62.1%	56.6%	56.6%	4.4
100	ExteriorLighting	LED Mogul-base HID Lamp Replacing Exterior HID (existing W<250)	Biz-Prescriptive Light	Assembly	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	8	11%	46%	94.6%	56.6%	70.8%	5.8
101	ExteriorLighting	Bi-Level Lighting Fixture – Garages	Biz-Custom Light	Assembly	Retro	181	181	69%	125	0.00	10	$274	5%	5%	6%	9	11%	20%	44.0%	31.9%	31.9%	3.9
102	ExteriorLighting	LED fuel pump canopy fixture (existing W<250)	Biz-Prescriptive Light	Assembly	Retro	0	0	0%	0	0.00	12	$0	0%	0%		10	0%	54%	94.6%	94.6%	94.6%	0.0
103	ExteriorLighting	LED fuel pump canopy fixture (existing W≥250)	Biz-Prescriptive Light	Assembly	Retro	0	0	0%	0	0.00	12	$0	0%	0%		11	0%	54%	94.6%	94.6%	94.6%	0.0
104	Miscellaneous	Vending Machine Controller - Non-Refrigerated	Biz-Prescriptive	Assembly	Retro	385	385	61%	237	0.00	5	$233	11%	11%	11%	1	5%	30%	51.0%	44.0%	44.0%	1.9
105	Miscellaneous	Miscellaneous Custom	Biz-Custom	Assembly	Retro	7	7	2%	0	0.00	10	$0	75%	25%	25%	2	44%	10%	37.0%	23.4%	23.4%	3.3
106	Miscellaneous	Kitchen Exhaust Hood Demand Ventilation Control System	Biz-Prescriptive	Assembly	ROB	9,932	9,932	50%	4,966	0.00	20	$1,180	100%	11%	27%	3	31%	10%	94.6%	73.8%	78.0%	39.7
107	Miscellaneous	High Efficiency Hand Dryers	Biz-Custom	Assembly	Retro	262	262	83%	217	0.00	10	$483	25%	4%	4%	4	5%	10%	37.0%	23.4%	23.4%	10.5
108	Miscellaneous	Ozone Commercial Laundry	Biz-Custom	Assembly	Retro	2,984	2,984	25%	746	0.00	10	$20,310	0%	0%	0%	5	0%	2%	31.4%	16.6%	16.6%	3.9
109	Miscellaneous	ENERGY STAR Uninterrupted Power Supply	Biz-Custom	Assembly	ROB	3,096	3,096	3%	85	0.00	15	$59	100%	14%	14%	6	1%	70%	94.6%	76.0%	76.0%	8.8
110	Motors	Cogged V-Belt	Biz-Custom	Assembly	Retro	17,237	17,237	3%	534	0.00	15	$384	100%	14%	14%	1	50%	10%	83.4%	32.2%	32.2%	9.2
111	Motors	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz-Custom	Assembly	Retro	1,902	1,902	38%	731	0.00	15	$200	100%	30%	30%	2	100%	10%	83.4%	52.4%	52.4%	11.6
112	Motors	Power Drive Systems	Biz-Custom	Assembly	Retro	4	4	23%	1	0.00	15	$0	100%	37%	37%	2	100%	10%	83.4%	53.4%	53.4%	9.2
113	Motors	Switch Reluctance Motors	Biz-Custom	Assembly	Retro	33,406	33,406	31%	10,222	0.00	15	$528	100%	50%	50%	2	100%	1%	83.4%	64.1%	64.1%	26.3
114	Motors	Escalators Motor Efficiency Controllers	Biz-Custom	Assembly	Retro	7,500	7,500	20%	1,500	0.00	10	$5,000	3%	3%	3%	3	0%	10%	37.0%	26.3%	26.3%	7.3
115	Office_NonPC	Energy Star Printer/Copier/Fax	Biz-Custom	Assembly	ROB	551	551	40%	223	0.00	6	$0	0%			1	30%	90%	94.6%	92.0%	92.0%	0.0
116	Office_NonPC	Smart Power Strip – Commercial Use	Biz-Custom	Assembly	Retro	1,086	1,086	10%	109	0.00	7	$50	50%	22%	22%	2	35%	15%	71.8%	42.0%	42.0%	2.8
117	Office_NonPC	Plug Load Occupancy Sensor	Biz-Custom	Assembly	Retro	1,126	1,126	15%	169	0.00	8	$70	75%	24%	24%	2	35%	15%	85.4%	47.6%	47.6%	3.2
118	Office_PC	Electrically Commutated Plug Fans in data centers	Biz-Custom	Assembly	Retro	86,783	86,783	18%	15,778	0.00	15	$480	100%	50%	50%	1	65%	20%	94.6%	74.6%	74.6%	50.8
119	Office_PC	Energy Star Server	Biz-Custom	Assembly	ROB	1,621	1,621	23%	368	0.00	8	$118	100%	31%	31%	1	65%	25%	94.6%	58.2%	58.2%	4.5
120	Office_PC	Server Virtualization	Biz-Custom	Assembly	Retro	2	2	45%	1	0.00	8	$0	75%	25%	25%	1	65%	25%	85.8%	49.3%	49.3%	3.2
121	Office_PC	High Efficiency CRAC unit	Biz-Custom	Assembly	ROB	541	541	30%	162	0.00	15	$63	100%	26%	26%	2	65%	20%	94.6%	51.1%	51.1%	8.1
122	Office_PC	Computer Room Air Conditioner Economizer	Biz-Custom	Assembly	Retro	764	764	47%	358	0.00	15	$82	100%	44%	44%	2	65%	20%	94.6%	66.1%	66.1%	5.6
123	Office_PC	Data Center Hot/Cold Aisle Configuration	Biz-Custom	Assembly	Retro	4	4	25%	1	0.00	15	$0	100%	25%	25%	3	3%	10%	94.6%	49.3%	49.3%	7.7
124	Office_PC	Energy Star Laptop	Biz-Custom	Assembly	ROB	126	126	33%	41	0.00	4	$0	0%			4	11%	85%	94.6%	88.0%	88.0%	0.0
125	Office_PC	Energy Star Monitor	Biz-Custom	Assembly	ROB	72	72	21%	15	0.00	4	$0	0%			5	25%	85%	94.6%	88.0%	88.0%	0.0
126	Refrigeration	Strip Curtains	Biz-Custom	Assembly	Retro	0	0	0%	0	0.00	4	$0	0%	0%		1	11%	30%	88.0%	70.4%	70.4%	0.0
127	Refrigeration	Bare Suction Line	Biz-Custom	Assembly	Retro	23	23	93%	21	0.00	15	$4	100%	50%	50%	2	0%	50%	88.0%	66.5%	66.5%	8.1
128	Refrigeration	Floating Head Pressure Controls	Biz-Custom	Assembly	Retro	1,112	1,112	25%	278	0.00	15	$431	25%	6%	6%	3	7%	25%	47.5%	40.0%	40.0%	5.6
129	Refrigeration	Saturated Suction Controls	Biz-Custom	Assembly	Retro	831	831	50%	416	0.00	15	$559	100%	7%	7%	4	2%	10%	88.0%	28.0%	28.0%	13.7
130	Refrigeration	Compressor Retrofit	Biz-Custom	Assembly	Retro	813	813	20%	163	0.00	15	$477	25%	3%	3%	5	24%	25%	47.5%	39.4%	39.4%	13.8
131	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz-Prescriptive	Assembly	Retro	2,440	2,440	65%	1,586	0.00	15	$305	100%	13%	33%	6	7%	80%	88.0%	84.0%	84.0%	30.7
132	Refrigeration	Evaporator Fan Motor Controls	Biz-Custom	Assembly	Retro	1,912	1,912	25%	478	0.00	13	$162	100%	30%	30%	7	7%	25%	88.0%	61.7%	61.7%	7.0
133	Refrigeration	Variable Speed Condenser Fan	Biz-Custom	Assembly	Retro	2,960	2,960	50%	1,480	0.00	15	$1,170	50%	13%	13%	8	9%	25%	59.5%	40.0%	40.0%	5.6
134	Refrigeration	Refrigeration Economizer	Biz-Custom	Assembly	Retro	7	7	2%	0	0.00	10	$0	100%	50%	50%	9	34%	10%	88.0%	41.1%	41.1%	4.2
135	Refrigeration	Anti-Sweat Heater Controls MT	Biz-Prescriptive	Assembly	Retro	579	579	59%	338	0.00	10	$170	75%	44%	44%	10	12%	25%	81.8%	72.4%	72.4%	2.1
136	Refrigeration	Auto Door Closer, Cooler	Biz-Custom	Assembly	Retro	471,500	471,500	0%	943	0.00	8	$157	100%	50%	50%	11	9%	50%	88.0%	66.9%	66.9%	5.8
137	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz-Custom	Assembly	Retro	1,584	1,584	36%	578	0.00	12	$686	50%	8%	8%	11	3%	25%	47.9%	40.0%	40.0%	7.1
138	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz-Prescriptive	Assembly	Retro	2,440	2,440	65%	1,586	0.00	15	$305	100%	13%	33%	12	2%	80%	88.0%	84.0%	84.0%	30.7
139	Refrigeration	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	Biz-Custom	Assembly	Retro	1,911	1,911	26%	504	0.00	10	$96	100%	50%	50%	12	2%	2%	88.0%	66.5%	66.5%	5.8
140	Refrigeration	Energy Star Reach-In Refrigerator, Glass Doors	Biz-Prescriptive	Assembly	ROB	2,140	2,140	29%	629	0.00	12	$1,239	25%	6%	14%	13	11%	54%	67.8%	63.2%	63.2%	5.6
141	Refrigeration	Energy Star Reach-In Refrigerator, Solid Doors	Biz-Prescriptive	Assembly	ROB	1,410	1,410	20%	281	0.00	12	$1,211	6%	6%	6%	14	11%	54%	67.8%	63.2%	63.2%	2.5
142	Refrigeration	Anti-Sweat Heater Controls LT	Biz-Prescriptive	Assembly	Retro	2,016	2,016	68%	1,361	0.00	10	$170	100%	44%	55%	15	4%	25%	88.0%	84.3%	85.0%	8.3
143	Refrigeration	Auto Door Closer, Freezer	Biz-Custom	Assembly	Retro	419,455	419,455	1%	2,307	0.00	8	$157	100%	50%	50%	16	4%	50%	88.0%	68.9%	68.9%	13.9
144	Refrigeration	Display Case Door Retrofit, Low Temp	Biz-Custom	Assembly	Retro	2,922	2,922	50%	1,453	0.00	12	$686	100%	21%	21%	16	4%	25%	88.0%	49.7%	49.7%	7.1

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
145	Refrigeration	Energy Star Reach-In Freezer, Glass Doors	Biz-Prescriptive	Assembly	ROB	6,374	6,374	20%	1,275	0.00	12	$1,651	25%	21%	21%	17	4%	54%	67.8%	63.2%	63.2%	2.3
146	Refrigeration	Energy Star Reach-In Freezer, Solid Doors	Biz-Prescriptive	Assembly	ROB	4,522	4,522	7%	305	0.00	12	$1,521	23%	23%	23%	18	4%	54%	67.8%	63.2%	63.2%	0.5
147	Refrigeration	Refrigeration - Custom	Biz-Custom	Assembly	ROB	7	7	2%	0	0.00	10	$0	75%	25%	25%	19	90%	25%	47.5%	39.4%	39.4%	3.3
148	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz-Custom RCx	Assembly	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	20	90%	25%	88.0%	65.9%	65.9%	3.2
149	Refrigeration	Energy Star Ice Machine	Biz-Prescriptive	Assembly	ROB	6,993	6,993	10%	721	0.00	15	$1,426	25%	18%	18%	21	7%	44%	60.8%	55.2%	55.2%	2.1
150	Refrigeration	Vending Machine Controller - Refrigerated	Biz-Prescriptive	Assembly	Retro	1,586	1,586	34%	537	0.00	5	$245	25%	16%	16%	22	2%	30%	65.5%	61.1%	61.1%	2.7
151	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz-Prescriptive	Assembly	Retro	273	273	89%	243	0.00	9	$11	100%	45%	55%	23	7%	35%	88.0%	86.7%	86.9%	30.9
152	Refrigeration	LED Refrigerated Display Case Lighting Controls	Biz-Prescriptive	Assembly	Retro	522	522	27%	141	0.00	10	$15	100%	100%	100%	24	7%	18%	88.0%	88.0%	88.0%	6.6
153	Ventilation	Demand Controlled Ventilation	Biz-Custom	Assembly	Retro	1,698	1,698	20%	340	0.00	15	$227	100%	15%	15%	1	100%	13%	92.7%	39.4%	39.4%	9.4
154	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz-Prescriptive	Assembly	Retro	1,902	1,902	38%	731	0.00	15	$200	100%	30%	55%	2	100%	13%	92.7%	74.0%	79.4%	11.6
155	WholeBldg_HVAC	HVAC - Energy Management System	Biz-Custom RCx	Assembly	Retro	13	13	8%	1	0.00	15	$0	100%	25%	25%	1	100%	20%	92.7%	51.6%	51.6%	8.8
156	WholeBldg_HVAC	Guest room energy management system	Biz-Custom	Assembly	Retro	0	0	0%	0	0.00	15	$260	0%		0%	2	100%	20%	92.7%	74.2%	74.2%	0.0
157	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz-Custom RCx	Assembly	Retro	10	10	10%	1	0.00	15	$0	100%	25%	25%	3	100%	0%	92.7%	51.6%	51.6%	8.8
158	WholeBuilding	WholeBlg - Com RET	Biz-Custom	Assembly	Retro	7	7	15%	1	0.00	12	$0	100%	25%	25%	1	90%	0%	92.7%	51.6%	51.6%	7.3
159	WholeBuilding	WholeBlg - Custom (Other)	Biz-Custom	Assembly	Retro	5	5	20%	1	0.00	12	$0	100%	25%	25%	2	90%	0%	92.7%	51.6%	51.6%	7.3
160	WholeBuilding	Power Distribution Equipment Upgrades (Transformers)	Biz-Custom	Assembly	Retro	1,150	1,150	1%	6	0.00	30	$8	100%	9%	9%	3	100%	20%	92.7%	36.0%	36.0%	17.1
161	WholeBldg_NC	WholeBlg - Com NC	Biz-Custom	Assembly	NC	4	4	25%	1	0.00	12	$0	100%	50%	50%	1	100%	60%	83.4%	68.0%	68.0%	7.6
162	Behavioral	COM Competitions	Biz-Custom	Assembly	Retro	53	53	2%	1	0.00	2	$0	100%	50%	50%	1	100%	0%	50.0%	50.0%	50.0%	3.9
163	Behavioral	Business Energy Reports	Biz-Custom	Assembly	Retro	0	0	0%	0	0.00	2	$0	0%		0%	1	100%	0%	50.0%	50.0%	50.0%	0.0
164	Behavioral	Building Benchmarking	Biz-Custom	Assembly	Retro	0	0	0%	0	0.00	2	$0	0%		0%	1	100%	0%	50.0%	50.0%	50.0%	0.0
165	Behavioral	Strategic Energy Management	Biz-Custom SEM	Assembly	Retro	0	0	0%	0	0.00	2	$0	0%		0%	1	100%	0%	50.0%	50.0%	50.0%	0.0
166	Behavioral	BEIMS	Biz-Custom	Assembly	Retro	20	20	5%	1	0.00	2	$0	23%	23%	23%	1	100%	2%	50.0%	50.0%	50.0%	0.8
167	Behavioral	Building Operator Certification	Biz-Custom	Assembly	Retro	10	10	3%	0	0.00	3	$0	14%	14%	14%	1	100%	2%	50.0%	50.0%	50.0%	1.7
168	CompressedAir	Efficient Air Compressors (VSD)	Biz-Prescriptive	Education	ROB	1,583	1,583	21%	329	0.00	13	$127	100%	59%	80%	1	100%	33%	92.7%	76.7%	83.1%	5.5
169	CompressedAir	Efficient Air Nozzles	Biz-Prescriptive	Education	Retro	1,480	1,480	50%	740	0.00	15	$50	100%	81%	81%	2	35%	33%	92.7%	91.1%	91.1%	15.8
170	CompressedAir	AODD Pump Controls	Biz-Custom	Education	Retro	103,919	103,919	35%	36,372	0.00	10	$1,150	100%	50%	50%	3	10%	33%	92.7%	72.6%	72.6%	38.2
171	CompressedAir	Compressed Air - Custom	Biz-Custom	Education	Retro	5	5	20%	1	0.00	10	$0	100%	47%	47%	4	50%	33%	92.7%	64.2%	64.2%	6.0
172	CompressedAir	Retro-commissioning_Compressed Air Optimization	Biz-Custom RCx	Education	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	5	50%	33%	92.7%	64.2%	64.2%	3.2
173	Cooking	Commercial Combination Oven (Electric)	Biz-Prescriptive	Education	ROB	38,561	38,561	48%	18,432	0.00	12	$16,884	75%	6%	15%	1	18%	53%	77.5%	62.4%	62.4%	14.1
174	Cooking	Commercial Electric Convection Oven	Biz-Prescriptive	Education	ROB	12,193	12,193	15%	1,879	0.00	12	$1,706	75%	21%	51%	1	18%	53%	77.6%	62.4%	62.4%	4.4
175	Cooking	Commercial Electric Griddle	Biz-Prescriptive	Education	ROB	17,056	17,056	15%	2,596	0.00	12	$3,604	25%	15%	15%	2	14%	17%	41.9%	33.6%	33.6%	2.8
176	Cooking	Commercial Electric Steam Cooker	Biz-Prescriptive	Education	ROB	19,549	19,549	67%	13,162	0.00	12	$2,490	100%	24%	55%	3	6%	45%	88.0%	81.1%	83.5%	18.0
177	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz-Prescriptive	Education	ROB	39,306	39,306	44%	17,369	0.00	15	$1,000	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	11.7
178	Cooking	Dishwasher High Temp Door (Energy Star)	Biz-Prescriptive	Education	ROB	26,901	26,901	32%	8,586	0.00	15	$1,100	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	5.2
179	Cooking	Energy efficient electric fryer	Biz-Prescriptive	Education	ROB	18,955	18,955	17%	3,274	0.00	12	$1,500	100%	5%	13%	5	27%	24%	88.0%	57.2%	59.4%	23.2
180	Cooking	Insulated Holding Cabinets (Full Size)	Biz-Prescriptive	Education	ROB	13,697	13,697	68%	9,314	0.00	12	$1,200	100%	35%	55%	6	3%	16%	88.0%	83.6%	84.9%	12.7
181	Cooking	Insulated Holding Cabinets (Half-Size)	Biz-Prescriptive	Education	ROB	4,383	4,383	60%	2,630	0.00	12	$1,500	100%	10%	25%	6	3%	16%	88.0%	52.6%	57.6%	10.1
182	Cooling	Air Conditioner - 13 IEER (5-20 Tons)	Biz-Prescriptive	Education	ROB	723	723	6%	44	0.00	15	$63	100%	48%	55%	1	23%	20%	92.7%	43.0%	46.7%	4.3
183	Cooling	Air Conditioner - 14 IEER (5-20 Tons)	Biz-Prescriptive	Education	ROB	723	723	13%	93	0.00	15	$127	100%	24%	55%	1	23%	20%	92.7%	36.8%	47.5%	9.0
184	Cooling	Air Conditioner - 17 IEER (5-20 Tons)	Biz-Prescriptive	Education	ROB	723	723	28%	204	0.00	15	$127	100%	24%	55%	1	23%	20%	92.7%	52.5%	66.4%	19.8
185	Cooling	Air Conditioner - 21 IEER (5-20 Tons)	Biz-Prescriptive	Education	ROB	723	723	42%	303	0.00	15	$127	100%	24%	55%	1	23%	20%	92.7%	62.5%	74.3%	29.3
186	Cooling	Air Conditioner - 12.1 IEER (20+ Tons)	Biz-Prescriptive	Education	ROB	773	773	6%	45	0.00	15	$30	100%	100%	100%	2	23%	20%	92.7%	92.7%	92.7%	4.3
187	Cooling	Air Conditioner - 13 IEER (20+ Tons)	Biz-Prescriptive	Education	ROB	773	773	12%	95	0.00	15	$37	100%	81%	81%	2	23%	20%	92.7%	83.5%	83.5%	9.2
188	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz-Prescriptive	Education	ROB	773	773	20%	157	0.00	15	$37	100%	81%	81%	2	23%	20%	92.7%	87.1%	87.1%	15.2
189	Cooling	Air Conditioner - 21 IEER (20+ Tons)	Biz-Prescriptive	Education	ROB	773	773	46%	354	0.00	15	$37	100%	81%	81%	2	23%	20%	92.7%	90.2%	90.2%	34.3
190	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz-Custom	Education	Retro	735	735	7%	51	0.00	3	$5	100%	50%	50%	3	46%	50%	92.7%	69.0%	69.0%	13.6
191	Cooling	Air Side Economizer	Biz-Custom	Education	Retro	723	723	20%	145	0.00	10	$84	50%	17%	17%	4	46%	20%	65.4%	41.8%	41.8%	3.9
192	Cooling	Advanced Rooftop Controls	Biz-Prescriptive	Education	Retro	735	735	14%	107	0.00	10	$100	100%	100%	100%	5	46%	20%	92.7%	92.7%	92.7%	0.4
193	Cooling	HVAC Occupancy Controls	Biz-Custom	Education	ROB	1,113	1,113	20%	223	0.00	15	$537	4%	4%	4%	6	46%	20%	44.0%	36.0%	36.0%	5.6
194	Cooling	Air Conditioner - 16 SEER (<5 Tons)	Biz-Prescriptive	Education	ROB	630	630	13%	79	0.00	15	$47	100%	64%	80%	7	3%	20%	92.7%	72.3%	79.7%	7.6
195	Cooling	Air Conditioner - 17 SEER (<5 Tons)	Biz-Prescriptive	Education	ROB	630	630	18%	111	0.00	15	$206	100%	15%	36%	7	3%	20%	92.7%	36.0%	36.0%	10.8
196	Cooling	Air Conditioner - 18 SEER(<5 Tons)	Biz-Prescriptive	Education	ROB	630	630	22%	140	0.00	15	$206	100%	15%	36%	7	3%	20%	92.7%	36.0%	38.7%	13.6
197	Cooling	Air Conditioner - 21 SEER(<5 Tons)	Biz-Prescriptive	Education	ROB	630	630	33%	210	0.00	15	$253	100%	12%	30%	7	3%	20%	92.7%	36.5%	40.3%	20.3
198	Cooling	Smart Thermostat	Biz-Prescriptive	Education	ROB	630	630	14%	89	0.00	11	$175	57%	57%	57%	8	3%	12%	40.4%	40.4%	40.4%	1.1
199	Cooling	PTAC - <7,000 Btuh - lodging	Biz-Prescriptive	Education	ROB	741	741	8%	63	0.00	8	$84	100%	36%	36%	9	0%	20%	92.7%	40.0%	40.0%	3.3
200	Cooling	PTAC - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Education	ROB	813	813	7%	59	0.00	8	$84	100%	36%	36%	10	0%	20%	92.7%	39.1%	39.1%	3.1
201	Cooling	PTAC - >15,000 Btuh - lodging	Biz-Prescriptive	Education	ROB	928	928	10%	88	0.00	8	$84	100%	36%	55%	11	0%	20%	92.7%	47.7%	54.1%	4.7
202	Cooling	Air Cooled Chiller	Biz-Prescriptive	Education	ROB	644	644	6%	36	0.00	23	$126	100%	24%	55%	12	51%	15%	92.7%	32.0%	32.0%	6.1
203	Cooling	Chiller Tune-up	Biz-Prescriptive	Education	Retro	735	735	7%	51	0.00	3	$8	100%	100%	100%	13	51%	50%	92.7%	92.7%	92.7%	4.5
204	Cooling	HVAC/Chiller Custom	Biz-Custom	Education	Retro	5	5	20%	1	0.00	20	$1	100%	7%	7%	14	100%	20%	92.7%	36.0%	36.0%	30.3
205	Cooling	Window Film	Biz-Prescriptive	Education	Retro	6,000	6,000	4%	264	0.00	10	$154	100%	65%	65%	15	100%	20%	92.7%	73.1%	73.1%	3.2
206	Cooling	Triple Pane Windows	Biz-Custom	Education	ROB	6,000	6,000	6%	360	0.00	25	$700	100%	5%	5%	15	100%	20%	92.7%	36.0%	36.0%	24.5
207	Cooling	Energy Recovery Ventilator	Biz-Custom	Education	Retro	773	773	19%	148	0.00	15	$1,500	25%	1%	1%	16	100%	2%	31.4%	21.8%	21.8%	33.2
208	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz-Prescriptive	Education	ROB	2,196	2,196	3%	72	0.00	16	$87	100%	46%	46%	1	5%	20%	92.7%	46.3%	46.3%	2.8
209	Heating	Heat Pump - 17 SEER (<5 Tons)	Biz-Prescriptive	Education	ROB	2,196	2,196	8%	172	0.00	16	$442	50%	9%	23%	1	5%	20%	44.0%	36.0%	36.0%	5.7
210	Heating	Heat Pump - 18 SEER(<5 Tons)	Biz-Prescriptive	Education	ROB	2,196	2,196	11%	247	0.00	16	$507	50%	8%	20%	1	5%	20%	44.0%	36.0%	36.0%	8.1
211	Heating	Heat Pump - 21 SEER(<5 Tons)	Biz-Prescriptive	Education	ROB	2,196	2,196	16%	361	0.00	16	$507	75%	8%	20%	1	5%	20%	59.6%	36.0%	36.0%	12.5
212	Heating	Geothermal HP - SEER 20.3 (<5 Tons)	Biz-Prescriptive	Education	ROB	2,196	2,196	22%	475	0.00	25	$2,576	25%	2%	4%	1	5%	20%	44.0%	36.0%	36.0%	19.2
213	Heating	Geothermal HP - SEER 21.5 (<5 Tons)	Biz-Prescriptive	Education	ROB	2,196	2,196	26%	571	0.00	25	$2,576	25%	2%	4%	1	5%	20%	44.0%	36.0%	36.0%	22.4
214	Heating	Geothermal HP - SEER 23.1 (<5 Tons)	Biz-Prescriptive	Education	ROB	2,196	2,196	31%	684	0.00	25	$2,576	25%	2%	4%	1	5%	20%	44.0%	36.0%	36.0%	26.0
215	Heating	Geothermal HP - SEER 29.3 (<5 Tons)	Biz-Prescriptive	Education	ROB	2,196	2,196	46%	1,013	0.00	25	$2,576	50%	2%	4%	1	5%	20%	44.0%	36.0%	36.0%	34.5
216	Heating	Heat Pump - 14.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Education	ROB	2,619	2,619	10%	262	0.00	16	$100	100%	40%	55%	2	42%	20%	92.7%	71.1%	75.6%	32.3

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
217	Heating	Heat Pump - 15.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Education	ROB	2,619	2,619	15%	395	0.00	16	$136	100%	30%	55%	2	42%	20%	92.7%	70.0%	76.9%	36.2
218	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Education	ROB	2,717	2,717	12%	332	0.00	16	$100	100%	40%	55%	2	42%	20%	92.7%	74.9%	78.4%	36.3
219	Heating	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Education	ROB	2,717	2,717	17%	467	0.00	16	$139	100%	29%	55%	2	42%	20%	92.7%	72.5%	78.6%	40.2
220	Heating	Geothermal HP - SEER 20.3 (5-20 Tons)	Biz-Prescriptive	Education	ROB	2,397	2,397	28%	676	0.00	25	$2,576	50%	2%	4%	2	42%	20%	44.0%	36.0%	36.0%	38.7
221	Heating	Geothermal HP - SEER 21.5 (5-20 Tons)	Biz-Prescriptive	Education	ROB	2,397	2,397	32%	772	0.00	25	$2,576	50%	2%	4%	2	42%	20%	44.0%	36.0%	36.0%	41.9
222	Heating	Geothermal HP - SEER 23.1 (5-20 Tons)	Biz-Prescriptive	Education	ROB	2,490	2,490	39%	977	0.00	25	$2,576	50%	2%	4%	2	42%	20%	44.0%	36.0%	36.0%	47.5
223	Heating	Geothermal HP - SEER 29.3 (5-20 Tons)	Biz-Prescriptive	Education	ROB	2,490	2,490	52%	1,306	0.00	25	$2,576	75%	2%	4%	2	42%	20%	51.8%	36.0%	36.0%	56.0
224	Heating	Variable Refrigerant Flow Heat Pump	Biz-Custom	Education	ROB	2,003	2,003	8%	168	0.00	16	$224	100%	7%	7%	2	42%	2%	92.7%	26.8%	26.8%	23.1
225	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz-Prescriptive	Education	ROB	2,791	2,791	8%	227	0.00	16	$100	100%	40%	55%	3	42%	20%	92.7%	67.9%	73.5%	28.5
226	Heating	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	Biz-Prescriptive	Education	ROB	2,791	2,791	14%	386	0.00	16	$175	100%	23%	55%	3	42%	20%	92.7%	59.7%	73.1%	33.7
227	Heating	Geothermal HP - SEER 20.3 (20+ Tons)	Biz-Prescriptive	Education	ROB	2,717	2,717	37%	996	0.00	25	$2,576	100%	2%	4%	3	42%	20%	92.7%	36.0%	36.0%	74.0
228	Heating	Geothermal HP - SEER 21.5 (20+ Tons)	Biz-Prescriptive	Education	ROB	2,717	2,717	40%	1,092	0.00	25	$2,576	100%	2%	4%	3	42%	20%	92.7%	36.0%	36.0%	77.2
229	Heating	Geothermal HP - SEER 23.1 (20+ Tons)	Biz-Prescriptive	Education	ROB	2,717	2,717	44%	1,205	0.00	25	$2,576	100%	2%	4%	3	42%	20%	92.7%	36.0%	36.0%	80.8
230	Heating	Geothermal HP - SEER 29.3 (20+ Tons)	Biz-Prescriptive	Education	ROB	2,717	2,717	56%	1,534	0.00	25	$2,576	100%	2%	4%	3	42%	20%	92.7%	36.0%	36.0%	89.2
231	Heating	Mini Split Ductless Heat Pump Cold Climate (Tiers & sizes TBD)	Biz-Prescriptive	Education	ROB	2,196	2,196	16%	361	0.00	16	$224	100%	18%	45%	4	12%	20%	92.7%	51.2%	60.3%	12.5
232	Heating	PTHP - <7,000 Btuh - lodging	Biz-Custom	Education	ROB	2,448	2,448	2%	60	0.00	8	$130	100%	100%	100%	5	0%	10%	92.7%	74.2%	74.2%	0.7
233	Heating	PTHP - >15,000 Btuh - lodging	Biz-Prescriptive	Education	ROB	2,852	2,852	10%	288	0.00	8	$130	100%	100%	100%	6	0%	10%	92.7%	92.7%	92.7%	3.3
234	Heating	PTHP - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Education	ROB	2,651	2,651	6%	149	0.00	8	$130	100%	100%	100%	7	0%	10%	92.7%	92.7%	92.7%	1.7
235	HotWater	Heat Pump Water Heater	Biz-Prescriptive	Education	ROB	5,042	5,042	67%	3,377	0.00	15	$1,115	100%	45%	55%	1	100%	4%	84.0%	72.3%	75.0%	5.6
236	HotWater	Hot Water Pipe Insulation	Biz-Custom	Education	Retro	5,042	5,042	2%	101	0.00	20	$60	100%	17%	17%	2	100%	80%	86.0%	84.0%	84.0%	9.8
237	HotWater	Faucet Aerator	Biz-Custom	Education	Retro	467	467	32%	151	0.00	10	$8	100%	50%	50%	3	20%	90%	93.0%	92.0%	92.0%	33.4
238	HotWater	Low Flow Pre-Rinse Sprayers	Biz-Prescriptive	Education	ROB	18,059	18,059	54%	9,789	0.00	5	$60	100%	17%	42%	4	20%	80%	86.0%	84.0%	84.0%	199.3
239	HotWater	ENERGY STAR Commercial Washing Machines	Biz-Prescriptive	Education	ROB	1,552	1,552	43%	671	0.00	7	$250	75%	28%	28%	5	25%	33%	79.3%	64.6%	64.6%	2.9
240	InteriorLighting	LED T8 Tube Replacement	Biz-Prescriptive Light	Education	Retro	116	116	45%	52	0.00	15	$5	100%	100%	100%	1	84%	40%	94.6%	94.6%	94.6%	11.4
241	InteriorLighting	LED troffer retrofit kit, 2'X2' and 2'X4'	Biz-Prescriptive Light	Education	Retro	262	262	50%	131	0.00	15	$70	100%	36%	55%	1	84%	40%	94.6%	55.2%	70.6%	5.8
242	InteriorLighting	LED troffer, 2'X2' and 2'X4'	Biz-Prescriptive Light	Education	Retro	262	262	50%	131	0.00	15	$70	100%	36%	55%	1	84%	40%	94.6%	55.2%	70.6%	5.8
243	InteriorLighting	Bi-Level Lighting Fixture – Stairwells, Hallways	Biz-Custom Light	Education	Retro	262	262	74%	195	0.00	10	$274	25%	7%	9%	2	1%	40%	58.0%	50.6%	50.7%	4.8
244	InteriorLighting	LED high bay fixture	Biz-Prescriptive Light	Education	Retro	2,440	2,440	68%	1,660	0.00	15	$330	100%	35%	55%	3	5%	34%	94.6%	82.6%	86.9%	15.9
245	InteriorLighting	LED Mogul-base HID Lamp Replacing High Bay HID	Biz-Prescriptive Light	Education	Retro	2,440	2,440	66%	1,619	0.00	15	$330	100%	35%	55%	3	5%	34%	94.6%	82.3%	86.7%	15.5
246	InteriorLighting	LED low bay fixture	Biz-Prescriptive Light	Education	Retro	520	520	61%	316	0.00	15	$44	100%	68%	80%	4	6%	34%	94.6%	90.9%	92.3%	11.6
247	InteriorLighting	LED Mogul-base HID Lamp Replacing Low Bay HID	Biz-Prescriptive Light	Education	Retro	520	520	59%	305	0.00	15	$44	100%	68%	80%	4	6%	34%	94.6%	90.8%	92.2%	11.2
248	InteriorLighting	LED Screw-In Lamps (Directional)	Biz-Prescriptive Light	Education	ROB	229	229	86%	197	0.00	6	$1	100%	100%	100%	6	0%	43%	94.6%	94.6%	94.6%	107.5
249	InteriorLighting	LED downlight fixture	Biz-Prescriptive Light	Education	Retro	180	180	68%	121	0.00	15	$27	100%	19%	46%	6	3%	45%	94.6%	77.1%	83.7%	26.8
250	InteriorLighting	LED Screw-In Lamps (Omnidirectional & Decorative)	Biz-Prescriptive Light	Education	ROB	173	173	81%	140	0.00	6	$1	100%	100%	100%	5	0%	20%	94.6%	94.6%	94.6%	76.6
251	InteriorLighting	DeLamp Fluorescent Fixture Average Lamp Wattage 28W	Biz-Prescriptive Light	Education	Retro	97	97	100%	97	0.00	11	$4	100%	100%	100%	7	84%	0%	94.6%	94.6%	94.6%	20.4
252	InteriorLighting	Occupancy Sensors	Biz-Prescriptive Light	Education	Retro	440	440	30%	132	0.00	10	$65	75%	31%	31%	8	95%	10%	83.2%	55.1%	55.1%	3.2
253	InteriorLighting	Daylighting Controls	Biz-Prescriptive Light	Education	Retro	564	564	30%	169	0.00	10	$58	100%	35%	55%	8	95%	10%	94.6%	72.7%	80.1%	7.9
254	InteriorLighting	Dual Occupancy & Daylighting Controls	Biz-Custom Light	Education	Retro	252	252	44%	111	0.00	10	$75	100%	40%	50%	8	95%	10%	94.6%	37.3%	44.7%	2.9
255	InteriorLighting	Central Lighting Monitoring & Controls (non-networked)	Biz-Custom Light	Education	Retro	41,703	41,703	20%	8,341	0.00	12	$3,700	100%	23%	29%	8	95%	10%	94.6%	44.1%	47.7%	4.6
256	InteriorLighting	Network Lighting Controls - Wireless (WiFi)	Biz-Custom Light	Education	Retro	3	3	49%	1	0.00	15	$0	100%	34%	44%	8	95%	10%	94.6%	60.4%	63.0%	9.6
257	InteriorLighting	Luminaire Level Lighting Controls w/ HVAC Control	Biz-Custom Light	Education	Retro	337	337	65%	219	0.00	15	$90	100%	24%	32%	8	97%	10%	94.6%	48.0%	51.6%	9.6
258	InteriorLighting	LED Exit Sign - 4 Watt Fixture (2 lamp)	Biz-Prescriptive Light	Education	Retro	66	66	43%	28	0.00	5	$33	92%	92%	92%	9	1%	75%	87.0%	87.0%	87.0%	0.3
259	InteriorLighting	Lighting - Custom	Biz-Custom Light	Education	Retro	4	4	25%	1	0.00	15	$1	100%	15%	20%	10	100%	0%	94.6%	32.0%	33.1%	9.6
260	ExteriorLighting	LED wallpack (existing W<250)	Biz-Prescriptive Light	Education	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	1	12%	46%	94.6%	56.6%	70.8%	5.8
261	ExteriorLighting	LED parking lot fixture (existing W≥250)	Biz-Prescriptive Light	Education	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	2	11%	54%	67.8%	63.2%	63.2%	4.4
262	ExteriorLighting	LED parking lot fixture (existing W<250)	Biz-Prescriptive Light	Education	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	3	11%	54%	94.6%	63.2%	70.8%	5.8
263	ExteriorLighting	LED outdoor pole decorative fixture (existing W≥250)	Biz-Prescriptive Light	Education	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	17%	17%	4	11%	54%	67.8%	63.2%	63.2%	3.4
264	ExteriorLighting	LED parking garage fixture (existing W≥250)	Biz-Prescriptive Light	Education	Retro	3,235	3,235	60%	1,953	0.00	6	$756	50%	13%	33%	5	11%	69%	78.3%	75.2%	75.2%	4.7
265	ExteriorLighting	LED parking garage fixture (existing W<250)	Biz-Prescriptive Light	Education	Retro	1,742	1,742	66%	1,154	0.00	6	$248	100%	18%	45%	6	11%	69%	94.6%	77.6%	83.9%	6.2
266	ExteriorLighting	LED Mogul-base HID Lamp Replacing Exterior HID (existing W≥250)	Biz-Prescriptive Light	Education	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	7	11%	46%	62.1%	56.6%	56.6%	4.4
267	ExteriorLighting	LED Mogul-base HID Lamp Replacing Exterior HID (existing W<250)	Biz-Prescriptive Light	Education	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	8	11%	46%	94.6%	56.6%	70.8%	5.8
268	ExteriorLighting	Bi-Level Lighting Fixture – Garages	Biz-Custom Light	Education	Retro	262	262	69%	181	0.00	10	$274	25%	7%	9%	9	11%	20%	44.0%	33.2%	33.5%	3.9
269	ExteriorLighting	LED fuel pump canopy fixture (existing W<250)	Biz-Prescriptive Light	Education	Retro	0	0	0%	0	0.00	12	$0	0%	0%		10	0%	54%	94.6%	94.6%	94.6%	0.0
270	ExteriorLighting	LED fuel pump canopy fixture (existing W≥250)	Biz-Prescriptive Light	Education	Retro	0	0	0%	0	0.00	12	$0	0%	0%		11	0%	54%	94.6%	94.6%	94.6%	0.0
271	Miscellaneous	Vending Machine Controller - Non-Refrigerated	Biz-Prescriptive	Education	Retro	385	385	61%	237	0.00	5	$233	11%	11%	11%	1	5%	30%	51.0%	44.0%	44.0%	1.9
272	Miscellaneous	Miscellaneous Custom	Biz-Custom	Education	Retro	7	7	2%	0	0.00	10	$0	75%	25%	25%	2	0%	10%	37.0%	23.4%	23.4%	3.3
273	Miscellaneous	Kitchen Exhaust Hood Demand Ventilation Control System	Biz-Prescriptive	Education	ROB	9,932	9,932	50%	4,966	0.00	20	$1,180	100%	11%	27%	3	42%	10%	94.6%	73.8%	78.0%	39.7
274	Miscellaneous	High Efficiency Hand Dryers	Biz-Custom	Education	Retro	2,093	2,093	83%	1,737	0.00	10	$483	100%	36%	36%	4	5%	10%	94.6%	61.9%	61.9%	8.2
275	Miscellaneous	Ozone Commercial Laundry	Biz-Custom	Education	Retro	2,984	2,984	25%	746	0.00	10	$20,310	0%	0%	0%	5	0%	2%	31.4%	16.6%	16.6%	3.9
276	Miscellaneous	ENERGY STAR Uninterrupted Power Supply	Biz-Custom	Education	ROB	3,096	3,096	3%	85	0.00	15	$59	100%	14%	14%	6	1%	70%	94.6%	76.0%	76.0%	8.8
277	Motors	Cogged V-Belt	Biz-Custom	Education	Retro	17,237	17,237	3%	534	0.00	15	$384	100%	14%	14%	1	50%	10%	83.4%	32.2%	32.2%	9.2
278	Motors	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz-Custom	Education	Retro	1,902	1,902	38%	731	0.00	15	$200	100%	30%	30%	2	100%	10%	83.4%	52.4%	52.4%	11.6
279	Motors	Power Drive Systems	Biz-Custom	Education	Retro	4	4	23%	1	0.00	15	$0	100%	37%	37%	2	100%	10%	83.4%	53.4%	53.4%	9.2
280	Motors	Switch Reluctance Motors	Biz-Custom	Education	Retro	33,406	33,406	31%	10,222	0.00	15	$528	100%	50%	50%	2	100%	1%	83.4%	64.1%	64.1%	26.3
281	Motors	Escalators Motor Efficiency Controllers	Biz-Custom	Education	Retro	7,500	7,500	20%	1,500	0.00	10	$5,000	3%	3%	3%	3	0%	10%	37.0%	26.3%	26.3%	7.3
282	Office_NonPC	Energy Star Printer/Copier/Fax	Biz-Custom	Education	ROB	551	551	40%	223	0.00	6	$0	0%			1	30%	90%	94.6%	92.0%	92.0%	0.0
283	Office_NonPC	Smart Power Strip – Commercial Use	Biz-Custom	Education	Retro	1,086	1,086	10%	109	0.00	7	$50	50%	22%	22%	2	35%	15%	71.8%	42.0%	42.0%	2.8
284	Office_NonPC	Plug Load Occupancy Sensor	Biz-Custom	Education	Retro	1,126	1,126	15%	169	0.00	8	$70	75%	24%	24%	2	35%	15%	85.4%	47.6%	47.6%	3.2
285	Office_PC	Electrically Commutated Plug Fans in data centers	Biz-Custom	Education	Retro	86,783	86,783	18%	15,778	0.00	15	$480	100%	50%	50%	1	65%	20%	94.6%	74.6%	74.6%	50.8
286	Office_PC	Energy Star Server	Biz-Custom	Education	ROB	1,621	1,621	23%	368	0.00	8	$118	100%	31%	31%	1	65%	25%	94.6%	58.2%	58.2%	4.5
287	Office_PC	Server Virtualization	Biz-Custom	Education	Retro	2	2	45%	1	0.00	8	$0	75%	25%	25%	1	65%	25%	85.8%	49.3%	49.3%	3.2
288	Office_PC	High Efficiency CRAC unit	Biz-Custom	Education	ROB	541	541	30%	162	0.00	15	$63	100%	26%	26%	2	65%	20%	94.6%	51.1%	51.1%	8.1

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
289	Office_PC	Computer Room Air Conditioner Economizer	Biz-Custom	Education	Retro	764	764	47%	358	0.00	15	$82	100%	44%	44%	2	65%	20%	94.6%	66.1%	66.1%	5.6
290	Office_PC	Data Center Hot/Cold Aisle Configuration	Biz-Custom	Education	Retro	4	4	25%	1	0.00	15	$0	100%	25%	25%	3	3%	10%	94.6%	49.3%	49.3%	7.7
291	Office_PC	Energy Star Laptop	Biz-Custom	Education	ROB	126	126	33%	41	0.00	4	$0	0%			4	11%	85%	94.6%	88.0%	88.0%	0.0
292	Office_PC	Energy Star Monitor	Biz-Custom	Education	ROB	72	72	21%	15	0.00	4	$0	0%			5	25%	85%	94.6%	88.0%	88.0%	0.0
293	Refrigeration	Strip Curtains	Biz-Custom	Education	Retro	0	0	0%	0	0.00	4	$0	0%	0%		1	11%	30%	88.0%	70.4%	70.4%	0.0
294	Refrigeration	Bare Suction Line	Biz-Custom	Education	Retro	23	23	93%	21	0.00	15	$4	100%	50%	50%	2	0%	50%	88.0%	66.5%	66.5%	8.1
295	Refrigeration	Floating Head Pressure Controls	Biz-Custom	Education	Retro	1,112	1,112	25%	278	0.00	15	$431	25%	6%	6%	3	7%	25%	47.5%	40.0%	40.0%	5.6
296	Refrigeration	Saturated Suction Controls	Biz-Custom	Education	Retro	831	831	50%	416	0.00	15	$559	100%	7%	7%	4	2%	10%	88.0%	28.0%	28.0%	13.7
297	Refrigeration	Compressor Retrofit	Biz-Custom	Education	Retro	813	813	20%	163	0.00	15	$477	25%	3%	3%	5	25%	25%	47.5%	39.4%	39.4%	13.8
298	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz-Prescriptive	Education	Retro	2,440	2,440	65%	1,586	0.00	15	$305	100%	13%	33%	6	7%	80%	88.0%	84.0%	84.0%	30.7
299	Refrigeration	Evaporator Fan Motor Controls	Biz-Custom	Education	Retro	1,912	1,912	25%	478	0.00	13	$162	100%	30%	30%	7	7%	25%	88.0%	61.7%	61.7%	7.0
300	Refrigeration	Variable Speed Condenser Fan	Biz-Custom	Education	Retro	2,960	2,960	50%	1,480	0.00	15	$1,170	50%	13%	13%	8	9%	25%	59.5%	40.0%	40.0%	5.6
301	Refrigeration	Refrigeration Economizer	Biz-Custom	Education	Retro	7	7	2%	0	0.00	10	$0	100%	50%	50%	9	35%	10%	88.0%	41.1%	41.1%	4.2
302	Refrigeration	Anti-Sweat Heater Controls MT	Biz-Prescriptive	Education	Retro	579	579	59%	338	0.00	10	$170	75%	44%	44%	10	12%	75%	82.5%	80.0%	80.0%	2.1
303	Refrigeration	Auto Door Closer, Cooler	Biz-Custom	Education	Retro	471,500	471,500	0%	943	0.00	8	$157	100%	50%	50%	11	9%	50%	88.0%	66.9%	66.9%	5.8
304	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz-Custom	Education	Retro	1,584	1,584	36%	578	0.00	12	$686	50%	8%	8%	11	3%	25%	47.9%	40.0%	40.0%	7.1
305	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz-Prescriptive	Education	Retro	2,440	2,440	65%	1,586	0.00	15	$305	100%	13%	33%	12	2%	80%	88.0%	84.0%	84.0%	30.7
306	Refrigeration	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	Biz-Custom	Education	Retro	1,911	1,911	26%	504	0.00	10	$96	100%	50%	50%	12	2%	2%	88.0%	66.5%	66.5%	5.8
307	Refrigeration	Energy Star Reach-In Refrigerator, Glass Doors	Biz-Prescriptive	Education	ROB	2,140	2,140	29%	629	0.00	12	$1,239	25%	6%	14%	13	12%	54%	67.8%	63.2%	63.2%	5.6
308	Refrigeration	Energy Star Reach-In Refrigerator, Solid Doors	Biz-Prescriptive	Education	ROB	1,410	1,410	20%	281	0.00	12	$1,211	6%	6%	6%	14	12%	54%	67.8%	63.2%	63.2%	2.5
309	Refrigeration	Anti-Sweat Heater Controls LT	Biz-Prescriptive	Education	Retro	2,016	2,016	68%	1,361	0.00	10	$170	100%	44%	55%	15	4%	75%	88.0%	84.3%	85.0%	8.3
310	Refrigeration	Auto Door Closer, Freezer	Biz-Custom	Education	Retro	419,455	419,455	1%	2,307	0.00	8	$157	100%	50%	50%	16	4%	50%	88.0%	68.9%	68.9%	13.9
311	Refrigeration	Display Case Door Retrofit, Low Temp	Biz-Custom	Education	Retro	2,922	2,922	50%	1,453	0.00	12	$686	100%	21%	21%	16	4%	25%	88.0%	49.7%	49.7%	7.1
312	Refrigeration	Energy Star Reach-In Freezer, Glass Doors	Biz-Prescriptive	Education	ROB	6,374	6,374	20%	1,275	0.00	12	$1,651	25%	21%	21%	17	4%	54%	67.8%	63.2%	63.2%	2.3
313	Refrigeration	Energy Star Reach-In Freezer, Solid Doors	Biz-Prescriptive	Education	ROB	4,522	4,522	7%	305	0.00	12	$1,521	23%	23%	23%	18	4%	54%	67.8%	63.2%	63.2%	0.5
314	Refrigeration	Refrigeration - Custom	Biz-Custom	Education	ROB	7	7	2%	0	0.00	10	$0	75%	25%	25%	19	90%	25%	47.5%	39.4%	39.4%	3.3
315	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz-Custom RCx	Education	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	20	90%	25%	88.0%	65.9%	65.9%	3.2
316	Refrigeration	Energy Star Ice Machine	Biz-Prescriptive	Education	ROB	6,993	6,993	10%	721	0.00	15	$1,426	25%	18%	18%	21	4%	44%	60.8%	55.2%	55.2%	2.1
317	Refrigeration	Vending Machine Controller - Refrigerated	Biz-Prescriptive	Education	Retro	1,586	1,586	34%	537	0.00	5	$245	25%	16%	16%	22	3%	30%	65.5%	61.1%	61.1%	2.7
318	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz-Prescriptive	Education	Retro	273	273	89%	243	0.00	9	$11	100%	45%	55%	23	7%	35%	88.0%	86.7%	86.9%	30.9
319	Refrigeration	LED Refrigerated Display Case Lighting Controls	Biz-Prescriptive	Education	Retro	522	522	27%	141	0.00	10	$15	100%	100%	100%	24	7%	18%	88.0%	88.0%	88.0%	6.6
320	Ventilation	Demand Controlled Ventilation	Biz-Custom	Education	Retro	2,223	2,223	20%	445	0.00	15	$227	100%	20%	20%	1	100%	22%	92.7%	43.8%	43.8%	9.0
321	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz-Prescriptive	Education	Retro	1,902	1,902	38%	731	0.00	15	$200	100%	30%	55%	2	100%	22%	92.7%	74.0%	79.4%	11.6
322	WholeBldg_HVAC	HVAC - Energy Management System	Biz-Custom RCx	Education	Retro	13	13	8%	1	0.00	15	$0	100%	25%	25%	1	100%	20%	92.7%	51.6%	51.6%	8.8
323	WholeBldg_HVAC	Guest room energy management system	Biz-Custom	Education	Retro	0	0	0%	0	0.00	15	$260	0%		0%	2	100%	20%	92.7%	74.2%	74.2%	0.0
324	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz-Custom RCx	Education	Retro	10	10	10%	1	0.00	15	$0	100%	25%	25%	3	100%	0%	92.7%	51.6%	51.6%	8.8
325	WholeBuilding	WholeBlg - Com RET	Biz-Custom	Education	Retro	7	7	15%	1	0.00	12	$0	100%	25%	25%	1	90%	0%	92.7%	51.6%	51.6%	7.3
326	WholeBuilding	WholeBlg - Custom (Other)	Biz-Custom	Education	Retro	5	5	20%	1	0.00	12	$0	100%	25%	25%	2	90%	0%	92.7%	51.6%	51.6%	7.3
327	WholeBuilding	Power Distribution Equipment Upgrades (Transformers)	Biz-Custom	Education	Retro	1,150	1,150	1%	6	0.00	30	$8	100%	9%	9%	3	100%	20%	92.7%	36.0%	36.0%	17.1
328	WholeBldg_NC	WholeBlg - Com NC	Biz-Custom	Education	NC	4	4	25%	1	0.00	12	$0	100%	50%	50%	1	100%	60%	83.4%	68.0%	68.0%	7.6
329	Behavioral	COM Competitions	Biz-Custom	Education	Retro	0	0	0%	0	0.00	2	$0	0%		0%	1	100%	0%	50.0%	50.0%	50.0%	0.0
330	Behavioral	Business Energy Reports	Biz-Custom	Education	Retro	0	0	0%	0	0.00	2	$0	0%		0%	1	100%	0%	50.0%	50.0%	50.0%	0.0
331	Behavioral	Building Benchmarking	Biz-Custom	Education	Retro	83	83	1%	1	0.00	2	$0	45%	45%	45%	1	100%	0%	50.0%	50.0%	50.0%	0.8
332	Behavioral	Strategic Energy Management	Biz-Custom SEM	Education	Retro	33	33	3%	1	0.00	5	$0	75%	37%	37%	1	100%	0%	50.0%	50.0%	50.0%	2.1
333	Behavioral	BEIMS	Biz-Custom	Education	Retro	43	43	2%	1	0.00	2	$0	23%	23%	23%	1	100%	2%	50.0%	50.0%	50.0%	0.8
334	Behavioral	Building Operator Certification	Biz-Custom	Education	Retro	41	41	3%	1	0.00	3	$0	75%	50%	50%	1	100%	2%	50.0%	50.0%	50.0%	2.0
335	CompressedAir	Efficient Air Compressors (VSD)	Biz-Prescriptive	Food Sales	ROB	1,583	1,583	21%	329	0.00	13	$127	100%	59%	80%	1	100%	33%	92.7%	76.7%	83.1%	5.5
336	CompressedAir	Efficient Air Nozzles	Biz-Prescriptive	Food Sales	Retro	1,480	1,480	50%	740	0.00	15	$50	100%	81%	81%	2	35%	33%	92.7%	91.1%	91.1%	15.8
337	CompressedAir	AODD Pump Controls	Biz-Custom	Food Sales	Retro	103,919	103,919	35%	36,372	0.00	10	$1,150	100%	50%	50%	3	10%	33%	92.7%	72.6%	72.6%	38.2
338	CompressedAir	Compressed Air - Custom	Biz-Custom	Food Sales	Retro	5	5	20%	1	0.00	10	$0	100%	47%	47%	4	50%	33%	92.7%	64.2%	64.2%	6.0
339	CompressedAir	Retro-commissioning_Compressed Air Optimization	Biz-Custom RCx	Food Sales	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	5	50%	33%	92.7%	64.2%	64.2%	3.2
340	Cooking	Commercial Combination Oven (Electric)	Biz-Prescriptive	Food Sales	ROB	38,561	38,561	48%	18,432	0.00	12	$16,884	75%	6%	15%	1	18%	53%	77.5%	62.4%	62.4%	14.1
341	Cooking	Commercial Electric Convection Oven	Biz-Prescriptive	Food Sales	ROB	12,193	12,193	15%	1,879	0.00	12	$1,706	75%	21%	51%	1	18%	53%	77.6%	62.4%	62.4%	4.4
342	Cooking	Commercial Electric Griddle	Biz-Prescriptive	Food Sales	ROB	17,056	17,056	15%	2,596	0.00	12	$3,604	25%	15%	15%	2	14%	17%	41.9%	33.6%	33.6%	2.8
343	Cooking	Commercial Electric Steam Cooker	Biz-Prescriptive	Food Sales	ROB	19,549	19,549	67%	13,162	0.00	12	$2,490	100%	24%	55%	3	6%	45%	88.0%	81.1%	83.5%	18.0
344	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz-Prescriptive	Food Sales	ROB	39,306	39,306	44%	17,369	0.00	15	$1,000	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	11.7
345	Cooking	Dishwasher High Temp Door (Energy Star)	Biz-Prescriptive	Food Sales	ROB	26,901	26,901	32%	8,586	0.00	15	$1,100	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	5.2
346	Cooking	Energy efficient electric fryer	Biz-Prescriptive	Food Sales	ROB	18,955	18,955	17%	3,274	0.00	12	$1,500	100%	5%	13%	5	27%	24%	88.0%	57.2%	59.4%	23.2
347	Cooking	Insulated Holding Cabinets (Full Size)	Biz-Prescriptive	Food Sales	ROB	13,697	13,697	68%	9,314	0.00	12	$1,200	100%	35%	55%	6	3%	16%	88.0%	83.6%	84.9%	12.7
348	Cooking	Insulated Holding Cabinets (Half-Size)	Biz-Prescriptive	Food Sales	ROB	4,383	4,383	60%	2,630	0.00	12	$1,500	100%	10%	25%	6	3%	16%	88.0%	52.6%	57.6%	10.1
349	Cooling	Air Conditioner - 13 IEER (5-20 Tons)	Biz-Prescriptive	Food Sales	ROB	1,399	1,399	6%	86	0.00	15	$63	100%	48%	55%	1	19%	20%	92.7%	56.5%	61.7%	5.1
350	Cooling	Air Conditioner - 14 IEER (5-20 Tons)	Biz-Prescriptive	Food Sales	ROB	1,399	1,399	13%	180	0.00	15	$127	100%	24%	55%	1	19%	20%	92.7%	50.2%	62.8%	10.6
351	Cooling	Air Conditioner - 17 IEER (5-20 Tons)	Biz-Prescriptive	Food Sales	ROB	1,399	1,399	28%	395	0.00	15	$127	100%	24%	55%	1	19%	20%	92.7%	69.7%	77.7%	23.3
352	Cooling	Air Conditioner - 21 IEER (5-20 Tons)	Biz-Prescriptive	Food Sales	ROB	1,399	1,399	42%	586	0.00	15	$127	100%	24%	55%	1	19%	20%	92.7%	76.1%	81.4%	34.6
353	Cooling	Air Conditioner - 12.1 IEER (20+ Tons)	Biz-Prescriptive	Food Sales	ROB	1,497	1,497	6%	87	0.00	15	$30	100%	100%	100%	2	19%	20%	92.7%	92.7%	92.7%	5.1
354	Cooling	Air Conditioner - 13 IEER (20+ Tons)	Biz-Prescriptive	Food Sales	ROB	1,497	1,497	12%	184	0.00	15	$37	100%	81%	81%	2	19%	20%	92.7%	88.0%	88.0%	10.9
355	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz-Prescriptive	Food Sales	ROB	1,497	1,497	20%	304	0.00	15	$37	100%	81%	81%	2	19%	20%	92.7%	89.8%	89.8%	17.9
356	Cooling	Air Conditioner - 21 IEER (20+ Tons)	Biz-Prescriptive	Food Sales	ROB	1,497	1,497	46%	684	0.00	15	$37	100%	81%	81%	2	19%	20%	92.7%	91.4%	91.4%	40.4
357	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz-Custom	Food Sales	Retro	1,422	1,422	7%	100	0.00	3	$5	100%	50%	50%	3	38%	50%	92.7%	71.5%	71.5%	15.8
358	Cooling	Air Side Economizer	Biz-Custom	Food Sales	Retro	1,399	1,399	20%	280	0.00	10	$84	100%	33%	33%	4	38%	20%	92.7%	58.7%	58.7%	3.9
359	Cooling	Advanced Rooftop Controls	Biz-Prescriptive	Food Sales	Retro	1,422	1,422	5%	68	0.00	10	$100	100%	100%	100%	5	38%	20%	92.7%	92.7%	92.7%	0.3
360	Cooling	HVAC Occupancy Controls	Biz-Custom	Food Sales	ROB	2,900	2,900	20%	580	0.00	15	$537	100%	11%	11%	6	38%	20%	92.7%	36.0%	36.0%	12.0

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
361	Cooling	Air Conditioner - 16 SEER (<5 Tons)	Biz-Prescriptive	Food Sales	ROB	1,219	1,219	13%	152	0.00	15	$47	100%	64%	80%	7	23%	20%	92.7%	80.4%	85.0%	9.0
362	Cooling	Air Conditioner - 17 SEER (<5 Tons)	Biz-Prescriptive	Food Sales	ROB	1,219	1,219	18%	215	0.00	15	$206	100%	15%	36%	7	23%	20%	92.7%	40.8%	47.7%	12.7
363	Cooling	Air Conditioner - 18 SEER(<5 Tons)	Biz-Prescriptive	Food Sales	ROB	1,219	1,219	22%	271	0.00	15	$206	100%	15%	36%	7	23%	20%	92.7%	46.3%	52.1%	16.0
364	Cooling	Air Conditioner - 21 SEER(<5 Tons)	Biz-Prescriptive	Food Sales	ROB	1,219	1,219	33%	406	0.00	15	$253	100%	12%	30%	7	23%	20%	92.7%	49.9%	53.8%	24.0
365	Cooling	Smart Thermostat	Biz-Prescriptive	Food Sales	ROB	1,219	1,219	14%	173	0.00	11	$175	75%	57%	57%	8	23%	12%	68.9%	53.9%	53.9%	1.5
366	Cooling	PTAC - <7,000 Btuh - lodging	Biz-Prescriptive	Food Sales	ROB	1,434	1,434	8%	121	0.00	8	$84	100%	36%	55%	9	38%	20%	92.7%	53.5%	63.4%	3.9
367	Cooling	PTAC - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Food Sales	ROB	1,573	1,573	7%	114	0.00	8	$84	100%	36%	55%	10	38%	20%	92.7%	52.5%	61.5%	3.7
368	Cooling	PTAC - >15,000 Btuh - lodging	Biz-Prescriptive	Food Sales	ROB	1,796	1,796	10%	171	0.00	8	$84	100%	36%	55%	11	38%	20%	92.7%	63.0%	71.7%	5.5
369	Cooling	Air Cooled Chiller	Biz-Prescriptive	Food Sales	ROB	1,246	1,246	6%	70	0.00	23	$126	100%	24%	55%	12	0%	15%	92.7%	32.0%	40.9%	7.0
370	Cooling	Chiller Tune-up	Biz-Prescriptive	Food Sales	Retro	1,422	1,422	7%	100	0.00	3	$8	100%	100%	100%	13	0%	50%	92.7%	92.7%	92.7%	5.3
371	Cooling	HVAC/Chiller Custom	Biz-Custom	Food Sales	Retro	5	5	20%	1	0.00	20	$1	100%	7%	7%	14	100%	20%	92.7%	36.0%	36.0%	30.3
372	Cooling	Window Film	Biz-Prescriptive	Food Sales	Retro	6,000	6,000	4%	264	0.00	10	$154	100%	65%	65%	15	100%	20%	92.7%	73.1%	73.1%	3.2
373	Cooling	Triple Pane Windows	Biz-Custom	Food Sales	ROB	6,000	6,000	6%	360	0.00	25	$700	100%	5%	5%	15	100%	20%	92.7%	36.0%	36.0%	24.5
374	Cooling	Energy Recovery Ventilator	Biz-Custom	Food Sales	Retro	1,497	1,497	6%	96	0.00	15	$1,500	1%	1%	1%	16	100%	2%	31.4%	21.8%	21.8%	13.3
375	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz-Prescriptive	Food Sales	ROB	1,581	1,581	5%	81	0.00	16	$87	100%	46%	46%	1	31%	20%	92.7%	48.7%	48.7%	2.9
376	Heating	Heat Pump - 17 SEER (<5 Tons)	Biz-Prescriptive	Food Sales	ROB	1,581	1,581	10%	162	0.00	16	$442	50%	9%	23%	1	31%	20%	44.0%	36.0%	36.0%	5.6
377	Heating	Heat Pump - 18 SEER(<5 Tons)	Biz-Prescriptive	Food Sales	ROB	1,581	1,581	15%	231	0.00	16	$507	50%	8%	20%	1	31%	20%	44.0%	36.0%	36.0%	7.9
378	Heating	Heat Pump - 21 SEER(<5 Tons)	Biz-Prescriptive	Food Sales	ROB	1,581	1,581	24%	378	0.00	16	$507	100%	8%	20%	1	31%	20%	92.7%	36.0%	36.2%	12.8
379	Heating	Geothermal HP - SEER 20.3 (<5 Tons)	Biz-Prescriptive	Food Sales	ROB	1,581	1,581	24%	386	0.00	25	$2,576	25%	2%	2%	1	31%	20%	44.0%	36.0%	36.0%	17.3
380	Heating	Geothermal HP - SEER 21.5 (<5 Tons)	Biz-Prescriptive	Food Sales	ROB	1,581	1,581	29%	452	0.00	25	$2,576	25%	2%	4%	1	31%	20%	44.0%	36.0%	36.0%	19.9
381	Heating	Geothermal HP - SEER 23.1 (<5 Tons)	Biz-Prescriptive	Food Sales	ROB	1,581	1,581	34%	531	0.00	25	$2,576	25%	2%	4%	1	31%	20%	44.0%	36.0%	36.0%	22.7
382	Heating	Geothermal HP - SEER 29.3 (<5 Tons)	Biz-Prescriptive	Food Sales	ROB	1,581	1,581	48%	755	0.00	25	$2,576	25%	2%	4%	1	31%	20%	44.0%	36.0%	36.0%	28.9
383	Heating	Heat Pump - 14.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Food Sales	ROB	1,941	1,941	13%	246	0.00	16	$100	100%	40%	55%	2	26%	20%	92.7%	69.9%	74.7%	32.0
384	Heating	Heat Pump - 15.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Food Sales	ROB	1,941	1,941	18%	353	0.00	16	$136	100%	30%	55%	2	26%	20%	92.7%	67.3%	75.5%	35.6
385	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Food Sales	ROB	2,032	2,032	18%	366	0.00	16	$100	100%	40%	55%	2	26%	20%	92.7%	76.2%	79.4%	36.8
386	Heating	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Food Sales	ROB	2,032	2,032	23%	468	0.00	16	$139	100%	29%	55%	2	26%	20%	92.7%	72.6%	78.6%	40.2
387	Heating	Geothermal HP - SEER 20.3 (5-20 Tons)	Biz-Prescriptive	Food Sales	ROB	1,758	1,758	32%	563	0.00	25	$2,576	50%	2%	4%	2	26%	20%	44.0%	36.0%	36.0%	36.3
388	Heating	Geothermal HP - SEER 21.5 (5-20 Tons)	Biz-Prescriptive	Food Sales	ROB	1,758	1,758	36%	630	0.00	25	$2,576	50%	2%	4%	2	26%	20%	44.0%	36.0%	36.0%	38.9
389	Heating	Geothermal HP - SEER 23.1 (5-20 Tons)	Biz-Prescriptive	Food Sales	ROB	1,938	1,938	46%	887	0.00	25	$2,576	50%	2%	4%	2	26%	20%	44.0%	36.0%	36.0%	45.6
390	Heating	Geothermal HP - SEER 29.3 (5-20 Tons)	Biz-Prescriptive	Food Sales	ROB	1,938	1,938	57%	1,112	0.00	25	$2,576	75%	2%	4%	2	26%	20%	48.8%	36.0%	36.0%	51.8
391	Heating	Variable Refrigerant Flow Heat Pump	Biz-Custom	Food Sales	ROB	1,528	1,528	21%	325	0.00	16	$224	100%	15%	15%	2	26%	2%	92.7%	38.8%	38.8%	14.8
392	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz-Prescriptive	Food Sales	ROB	2,176	2,176	11%	250	0.00	16	$100	100%	40%	55%	3	26%	20%	92.7%	70.2%	75.0%	28.8
393	Heating	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	Biz-Prescriptive	Food Sales	ROB	2,176	2,176	18%	388	0.00	16	$175	100%	23%	55%	3	26%	20%	92.7%	59.9%	73.1%	33.7
394	Heating	Geothermal HP - SEER 20.3 (20+ Tons)	Biz-Prescriptive	Food Sales	ROB	2,032	2,032	41%	837	0.00	25	$2,576	100%	2%	4%	3	26%	20%	92.7%	36.0%	36.0%	70.5
395	Heating	Geothermal HP - SEER 21.5 (20+ Tons)	Biz-Prescriptive	Food Sales	ROB	2,032	2,032	44%	904	0.00	25	$2,576	100%	2%	4%	3	26%	20%	92.7%	36.0%	36.0%	73.1
396	Heating	Geothermal HP - SEER 23.1 (20+ Tons)	Biz-Prescriptive	Food Sales	ROB	2,032	2,032	48%	982	0.00	25	$2,576	100%	2%	4%	3	26%	20%	92.7%	36.0%	36.0%	76.0
397	Heating	Geothermal HP - SEER 29.3 (20+ Tons)	Biz-Prescriptive	Food Sales	ROB	2,032	2,032	59%	1,207	0.00	25	$2,576	100%	2%	4%	3	26%	20%	92.7%	36.0%	36.0%	82.2
398	Heating	Mini Split Ductless Heat Pump Cold Climate (Tiers & sizes TBD)	Biz-Prescriptive	Food Sales	ROB	1,581	1,581	24%	378	0.00	16	$224	100%	18%	45%	4	8%	20%	92.7%	52.1%	61.8%	12.8
399	Heating	PTHP - <7,000 Btuh - lodging	Biz-Custom	Food Sales	ROB	1,701	1,701	7%	117	0.00	8	$130	100%	100%	100%	5	3%	10%	92.7%	74.2%	74.2%	0.8
400	Heating	PTHP - >15,000 Btuh - lodging	Biz-Prescriptive	Food Sales	ROB	2,190	2,190	25%	557	0.00	8	$130	100%	100%	100%	6	3%	10%	92.7%	92.7%	92.7%	3.9
401	Heating	PTHP - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Food Sales	ROB	1,905	1,905	15%	289	0.00	8	$130	100%	100%	100%	7	3%	10%	92.7%	92.7%	92.7%	2.0
402	HotWater	Heat Pump Water Heater	Biz-Prescriptive	Food Sales	ROB	4,687	4,687	67%	3,139	0.00	15	$1,115	100%	45%	55%	1	100%	0%	84.0%	71.2%	74.1%	5.2
403	HotWater	Hot Water Pipe Insulation	Biz-Custom	Food Sales	Retro	4,687	4,687	2%	94	0.00	20	$60	100%	16%	16%	2	100%	80%	86.0%	84.0%	84.0%	9.8
404	HotWater	Faucet Aerator	Biz-Custom	Food Sales	Retro	284	284	32%	92	0.00	10	$8	100%	50%	50%	3	20%	90%	93.0%	92.0%	92.0%	13.5
405	HotWater	Low Flow Pre-Rinse Sprayers	Biz-Prescriptive	Food Sales	ROB	18,059	18,059	54%	9,789	0.00	5	$60	100%	17%	42%	4	20%	80%	86.0%	84.0%	84.0%	199.3
406	HotWater	ENERGY STAR Commercial Washing Machines	Biz-Prescriptive	Food Sales	ROB	1,552	1,552	43%	671	0.00	7	$250	75%	28%	28%	5	25%	33%	79.3%	64.6%	64.6%	2.9
407	InteriorLighting	LED T8 Tube Replacement	Biz-Prescriptive Light	Food Sales	Retro	197	197	45%	88	0.00	9	$5	100%	100%	100%	1	84%	40%	94.6%	94.6%	94.6%	10.2
408	InteriorLighting	LED troffer retrofit kit, 2'X2' and 2'X4'	Biz-Prescriptive Light	Food Sales	Retro	445	445	50%	223	0.00	9	$70	100%	36%	55%	1	84%	40%	94.6%	74.8%	81.4%	5.2
409	InteriorLighting	LED troffer, 2'X2' and 2'X4'	Biz-Prescriptive Light	Food Sales	Retro	445	445	50%	223	0.00	9	$70	100%	36%	55%	1	84%	40%	94.6%	74.8%	81.4%	5.2
410	InteriorLighting	Bi-Level Lighting Fixture – Stairwells, Hallways	Biz-Custom Light	Food Sales	Retro	445	445	74%	331	0.00	10	$274	50%	12%	16%	2	1%	40%	58.0%	52.0%	52.0%	4.3
411	InteriorLighting	LED high bay fixture	Biz-Prescriptive Light	Food Sales	Retro	4,147	4,147	68%	2,821	0.00	9	$330	100%	35%	55%	3	5%	34%	94.6%	88.3%	90.2%	14.2
412	InteriorLighting	LED Mogul-base HID Lamp Replacing High Bay HID	Biz-Prescriptive Light	Food Sales	Retro	4,147	4,147	66%	2,751	0.00	9	$330	100%	35%	55%	3	5%	34%	94.6%	88.1%	90.1%	13.8
413	InteriorLighting	LED low bay fixture	Biz-Prescriptive Light	Food Sales	Retro	883	883	61%	537	0.00	9	$44	100%	68%	80%	4	7%	34%	94.6%	92.4%	93.2%	10.3
414	InteriorLighting	LED Mogul-base HID Lamp Replacing Low Bay HID	Biz-Prescriptive Light	Food Sales	Retro	883	883	59%	519	0.00	9	$44	100%	68%	80%	4	7%	34%	94.6%	92.3%	93.2%	10.0
415	InteriorLighting	LED Screw-In Lamps (Directional)	Biz-Prescriptive Light	Food Sales	ROB	308	308	86%	264	0.00	4	$1	100%	100%	100%	6	0%	43%	94.6%	94.6%	94.6%	86.4
416	InteriorLighting	LED downlight fixture	Biz-Prescriptive Light	Food Sales	Retro	306	306	68%	206	0.00	9	$27	100%	19%	46%	6	3%	45%	94.6%	85.1%	88.8%	23.9
417	InteriorLighting	LED Screw-In Lamps (Omnidirectional & Decorative)	Biz-Prescriptive Light	Food Sales	ROB	233	233	81%	188	0.00	4	$1	100%	100%	100%	5	0%	20%	94.6%	94.6%	94.6%	61.6
418	InteriorLighting	DeLamp Fluorescent Fixture Average Lamp Wattage 28W	Biz-Prescriptive Light	Food Sales	Retro	164	164	100%	164	0.00	11	$4	100%	100%	100%	7	84%	0%	94.6%	94.6%	94.6%	28.0
419	InteriorLighting	Occupancy Sensors	Biz-Prescriptive Light	Food Sales	Retro	749	749	30%	225	0.00	10	$65	100%	31%	55%	8	95%	10%	94.6%	74.8%	82.4%	4.9
420	InteriorLighting	Daylighting Controls	Biz-Prescriptive Light	Food Sales	Retro	959	959	30%	288	0.00	10	$58	100%	35%	55%	8	95%	10%	94.6%	82.5%	86.9%	9.4
421	InteriorLighting	Dual Occupancy & Daylighting Controls	Biz-Custom Light	Food Sales	Retro	428	428	44%	188	0.00	10	$75	100%	40%	50%	8	95%	10%	94.6%	56.6%	60.1%	3.9
422	InteriorLighting	Central Lighting Monitoring & Controls (non-networked)	Biz-Custom Light	Food Sales	Retro	41,703	41,703	20%	8,341	0.00	12	$3,700	100%	23%	29%	8	95%	10%	94.6%	44.1%	47.7%	4.6
423	InteriorLighting	Network Lighting Controls - Wireless (WiFi)	Biz-Custom Light	Food Sales	Retro	4	4	49%	2	0.00	15	$1	100%	29%	38%	8	95%	10%	94.6%	56.0%	58.8%	8.9
424	InteriorLighting	Luminaire Level Lighting Controls w/ HVAC Control	Biz-Custom Light	Food Sales	Retro	428	428	65%	278	0.00	15	$90	100%	31%	40%	8	97%	10%	94.6%	58.0%	60.6%	8.9
425	InteriorLighting	LED Exit Sign - 4 Watt Fixture (2 lamp)	Biz-Prescriptive Light	Food Sales	Retro	64	64	43%	28	0.00	5	$33	92%	92%	92%	9	1%	75%	86.8%	86.8%	86.8%	0.3
426	InteriorLighting	Lighting - Custom	Biz-Custom Light	Food Sales	Retro	4	4	25%	1	0.00	15	$0	100%	21%	28%	10	100%	0%	94.6%	41.2%	44.8%	8.9
427	ExteriorLighting	LED wallpack (existing W<250)	Biz-Prescriptive Light	Food Sales	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	1	12%	46%	94.6%	56.6%	70.8%	5.8
428	ExteriorLighting	LED parking lot fixture (existing W≥250)	Biz-Prescriptive Light	Food Sales	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	2	11%	54%	67.8%	63.2%	63.2%	4.4
429	ExteriorLighting	LED parking lot fixture (existing W<250)	Biz-Prescriptive Light	Food Sales	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	3	11%	54%	94.6%	63.2%	70.8%	5.8
430	ExteriorLighting	LED outdoor pole decorative fixture (existing W≥250)	Biz-Prescriptive Light	Food Sales	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	17%	17%	4	11%	54%	67.8%	63.2%	63.2%	3.4
431	ExteriorLighting	LED parking garage fixture (existing W≥250)	Biz-Prescriptive Light	Food Sales	Retro	3,235	3,235	60%	1,953	0.00	6	$756	50%	13%	33%	5	11%	69%	78.3%	75.2%	75.2%	4.7
432	ExteriorLighting	LED parking garage fixture (existing W<250)	Biz-Prescriptive Light	Food Sales	Retro	1,742	1,742	66%	1,154	0.00	6	$248	100%	18%	45%	6	11%	69%	94.6%	77.6%	83.9%	6.2

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
433	ExteriorLighting	LED Mogul-base HID Lamp Replacing Exterior HID (existing W≥250)	Biz-Prescriptive Light	Food Sales	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	7	11%	46%	62.1%	56.6%	56.6%	4.4
434	ExteriorLighting	LED Mogul-base HID Lamp Replacing Exterior HID (existing W<250)	Biz-Prescriptive Light	Food Sales	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	8	11%	46%	94.6%	56.6%	70.8%	5.8
435	ExteriorLighting	Bi-Level Lighting Fixture – Garages	Biz-Custom Light	Food Sales	Retro	445	445	69%	307	0.00	10	$274	25%	11%	15%	9	11%	20%	44.0%	36.0%	36.0%	3.9
436	ExteriorLighting	LED fuel pump canopy fixture (existing W<250)	Biz-Prescriptive Light	Food Sales	Retro	0	0	0%	0	0.00	12	$0	0%	0%		10	0%	54%	94.6%	94.6%	94.6%	0.0
437	ExteriorLighting	LED fuel pump canopy fixture (existing W≥250)	Biz-Prescriptive Light	Food Sales	Retro	0	0	0%	0	0.00	12	$0	0%	0%		11	0%	54%	94.6%	94.6%	94.6%	0.0
438	Miscellaneous	Vending Machine Controller - Non-Refrigerated	Biz-Prescriptive	Food Sales	Retro	385	385	61%	237	0.00	5	$233	11%	11%	11%	1	5%	30%	51.0%	44.0%	44.0%	1.9
439	Miscellaneous	Miscellaneous Custom	Biz-Custom	Food Sales	Retro	7	7	2%	0	0.00	10	$0	75%	25%	25%	2	37%	10%	37.0%	23.4%	23.4%	3.3
440	Miscellaneous	Kitchen Exhaust Hood Demand Ventilation Control System	Biz-Prescriptive	Food Sales	ROB	9,932	9,932	50%	4,966	0.00	20	$1,180	100%	11%	27%	3	13%	10%	94.6%	73.8%	78.0%	39.7
441	Miscellaneous	High Efficiency Hand Dryers	Biz-Custom	Food Sales	Retro	3,819	3,819	83%	3,170	0.00	10	$483	100%	50%	50%	4	5%	10%	94.6%	70.6%	70.6%	8.4
442	Miscellaneous	Ozone Commercial Laundry	Biz-Custom	Food Sales	Retro	2,984	2,984	25%	746	0.00	10	$20,310	0%	0%	0%	5	0%	2%	31.4%	16.6%	16.6%	3.9
443	Miscellaneous	ENERGY STAR Uninterrupted Power Supply	Biz-Custom	Food Sales	ROB	3,096	3,096	3%	85	0.00	15	$59	100%	14%	14%	6	0%	70%	94.6%	76.0%	76.0%	8.8
444	Motors	Cogged V-Belt	Biz-Custom	Food Sales	Retro	19,471	19,471	3%	604	0.00	15	$384	100%	16%	16%	1	50%	10%	83.4%	34.4%	34.4%	8.8
445	Motors	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz-Custom	Food Sales	Retro	1,902	1,902	38%	731	0.00	15	$200	100%	30%	30%	2	100%	10%	83.4%	52.4%	52.4%	11.6
446	Motors	Power Drive Systems	Biz-Custom	Food Sales	Retro	4	4	23%	1	0.00	15	$0	100%	37%	37%	2	100%	10%	83.4%	53.4%	53.4%	8.8
447	Motors	Switch Reluctance Motors	Biz-Custom	Food Sales	Retro	37,735	37,735	31%	11,547	0.00	15	$528	100%	50%	50%	2	100%	1%	83.4%	64.4%	64.4%	29.8
448	Motors	Escalators Motor Efficiency Controllers	Biz-Custom	Food Sales	Retro	7,500	7,500	20%	1,500	0.00	10	$5,000	3%	3%	3%	3	0%	10%	37.0%	26.3%	26.3%	7.3
449	Office_NonPC	Energy Star Printer/Copier/Fax	Biz-Custom	Food Sales	ROB	551	551	40%	223	0.00	6	$0	0%			1	30%	90%	94.6%	92.0%	92.0%	0.0
450	Office_NonPC	Smart Power Strip – Commercial Use	Biz-Custom	Food Sales	Retro	1,086	1,086	10%	109	0.00	7	$50	50%	22%	22%	2	35%	15%	71.8%	42.0%	42.0%	2.8
451	Office_NonPC	Plug Load Occupancy Sensor	Biz-Custom	Food Sales	Retro	1,126	1,126	15%	169	0.00	8	$70	75%	24%	24%	2	35%	15%	85.4%	47.6%	47.6%	3.2
452	Office_PC	Electrically Commutated Plug Fans in data centers	Biz-Custom	Food Sales	Retro	86,783	86,783	18%	15,778	0.00	15	$480	100%	50%	50%	1	65%	20%	94.6%	74.6%	74.6%	50.8
453	Office_PC	Energy Star Server	Biz-Custom	Food Sales	ROB	1,621	1,621	23%	368	0.00	8	$118	100%	31%	31%	1	65%	25%	94.6%	58.2%	58.2%	4.5
454	Office_PC	Server Virtualization	Biz-Custom	Food Sales	Retro	2	2	45%	1	0.00	8	$0	75%	25%	25%	1	65%	25%	85.8%	49.3%	49.3%	3.2
455	Office_PC	High Efficiency CRAC unit	Biz-Custom	Food Sales	ROB	541	541	30%	162	0.00	15	$63	100%	26%	26%	2	65%	20%	94.6%	51.1%	51.1%	8.1
456	Office_PC	Computer Room Air Conditioner Economizer	Biz-Custom	Food Sales	Retro	764	764	47%	358	0.00	15	$82	100%	44%	44%	2	65%	20%	94.6%	66.1%	66.1%	5.6
457	Office_PC	Data Center Hot/Cold Aisle Configuration	Biz-Custom	Food Sales	Retro	4	4	25%	1	0.00	15	$0	100%	25%	25%	3	3%	10%	94.6%	49.3%	49.3%	7.7
458	Office_PC	Energy Star Laptop	Biz-Custom	Food Sales	ROB	126	126	33%	41	0.00	4	$0	0%			4	11%	85%	94.6%	88.0%	88.0%	0.0
459	Office_PC	Energy Star Monitor	Biz-Custom	Food Sales	ROB	72	72	21%	15	0.00	4	$0	0%			5	25%	85%	94.6%	88.0%	88.0%	0.0
460	Refrigeration	Strip Curtains	Biz-Custom	Food Sales	Retro	412	412	50%	206	0.00	4	$10	100%	50%	50%	1	16%	30%	88.0%	69.3%	69.3%	9.4
461	Refrigeration	Bare Suction Line	Biz-Custom	Food Sales	Retro	23	23	93%	21	0.00	15	$4	100%	50%	50%	2	1%	50%	88.0%	66.5%	66.5%	8.1
462	Refrigeration	Floating Head Pressure Controls	Biz-Custom	Food Sales	Retro	1,112	1,112	25%	278	0.00	15	$431	25%	6%	6%	3	11%	25%	47.5%	40.0%	40.0%	5.6
463	Refrigeration	Saturated Suction Controls	Biz-Custom	Food Sales	Retro	831	831	50%	416	0.00	15	$559	100%	7%	7%	4	2%	10%	88.0%	28.0%	28.0%	13.7
464	Refrigeration	Compressor Retrofit	Biz-Custom	Food Sales	Retro	813	813	20%	163	0.00	15	$477	25%	3%	3%	5	37%	25%	47.5%	39.4%	39.4%	13.8
465	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz-Prescriptive	Food Sales	Retro	2,440	2,440	65%	1,586	0.00	15	$305	100%	13%	33%	6	10%	80%	88.0%	84.0%	84.0%	30.7
466	Refrigeration	Evaporator Fan Motor Controls	Biz-Custom	Food Sales	Retro	1,912	1,912	25%	478	0.00	13	$162	100%	30%	30%	7	10%	25%	88.0%	61.7%	61.7%	7.0
467	Refrigeration	Variable Speed Condenser Fan	Biz-Custom	Food Sales	Retro	2,960	2,960	50%	1,480	0.00	15	$1,170	50%	13%	13%	8	14%	25%	59.5%	40.0%	40.0%	5.6
468	Refrigeration	Refrigeration Economizer	Biz-Custom	Food Sales	Retro	7	7	2%	0	0.00	10	$0	100%	50%	50%	9	52%	10%	88.0%	41.1%	41.1%	4.2
469	Refrigeration	Anti-Sweat Heater Controls MT	Biz-Prescriptive	Food Sales	Retro	579	579	59%	338	0.00	10	$170	75%	44%	44%	10	8%	75%	82.5%	80.0%	80.0%	2.1
470	Refrigeration	Auto Door Closer, Cooler	Biz-Custom	Food Sales	Retro	471,500	471,500	0%	943	0.00	8	$157	100%	50%	50%	11	6%	50%	88.0%	66.9%	66.9%	5.8
471	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz-Custom	Food Sales	Retro	1,584	1,584	36%	578	0.00	12	$686	50%	8%	8%	11	2%	25%	47.9%	40.0%	40.0%	7.1
472	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz-Prescriptive	Food Sales	Retro	2,440	2,440	65%	1,586	0.00	15	$305	100%	13%	33%	12	1%	80%	88.0%	84.0%	84.0%	30.7
473	Refrigeration	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	Biz-Custom	Food Sales	Retro	1,911	1,911	26%	504	0.00	10	$96	100%	50%	50%	12	1%	2%	88.0%	66.5%	66.5%	5.8
474	Refrigeration	Energy Star Reach-In Refrigerator, Glass Doors	Biz-Prescriptive	Food Sales	ROB	2,140	2,140	29%	629	0.00	12	$1,239	25%	6%	14%	13	8%	54%	67.8%	63.2%	63.2%	5.6
475	Refrigeration	Energy Star Reach-In Refrigerator, Solid Doors	Biz-Prescriptive	Food Sales	ROB	1,410	1,410	20%	281	0.00	12	$1,211	6%	6%	6%	14	8%	54%	67.8%	63.2%	63.2%	2.5
476	Refrigeration	Anti-Sweat Heater Controls LT	Biz-Prescriptive	Food Sales	Retro	2,016	2,016	68%	1,361	0.00	10	$170	100%	44%	55%	15	3%	75%	88.0%	84.3%	85.0%	8.3
477	Refrigeration	Auto Door Closer, Freezer	Biz-Custom	Food Sales	Retro	419,455	419,455	1%	2,307	0.00	8	$157	100%	50%	50%	16	3%	50%	88.0%	68.9%	68.9%	13.9
478	Refrigeration	Display Case Door Retrofit, Low Temp	Biz-Custom	Food Sales	Retro	2,922	2,922	50%	1,453	0.00	12	$686	100%	21%	21%	16	3%	25%	88.0%	49.7%	49.7%	7.1
479	Refrigeration	Energy Star Reach-In Freezer, Glass Doors	Biz-Prescriptive	Food Sales	ROB	6,374	6,374	20%	1,275	0.00	12	$1,651	25%	21%	21%	17	3%	54%	67.8%	63.2%	63.2%	2.3
480	Refrigeration	Energy Star Reach-In Freezer, Solid Doors	Biz-Prescriptive	Food Sales	ROB	4,522	4,522	7%	305	0.00	12	$1,521	23%	23%	23%	18	3%	54%	67.8%	63.2%	63.2%	0.5
481	Refrigeration	Refrigeration - Custom	Biz-Custom	Food Sales	ROB	7	7	2%	0	0.00	10	$0	75%	25%	25%	19	90%	25%	47.5%	39.4%	39.4%	3.3
482	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz-Custom RCx	Food Sales	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	20	90%	25%	88.0%	65.9%	65.9%	3.2
483	Refrigeration	Energy Star Ice Machine	Biz-Prescriptive	Food Sales	ROB	6,993	6,993	10%	721	0.00	15	$1,426	25%	18%	18%	21	0%	44%	60.8%	55.2%	55.2%	2.1
484	Refrigeration	Vending Machine Controller - Refrigerated	Biz-Prescriptive	Food Sales	Retro	1,586	1,586	34%	537	0.00	5	$245	25%	16%	16%	22	0%	30%	65.5%	61.1%	61.1%	2.7
485	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz-Prescriptive	Food Sales	Retro	273	273	89%	243	0.00	9	$11	100%	45%	55%	23	5%	35%	88.0%	86.7%	86.9%	30.9
486	Refrigeration	LED Refrigerated Display Case Lighting Controls	Biz-Prescriptive	Food Sales	Retro	522	522	27%	141	0.00	10	$15	100%	100%	100%	24	5%	18%	88.0%	88.0%	88.0%	6.6
487	Ventilation	Demand Controlled Ventilation	Biz-Custom	Food Sales	Retro	2,658	2,658	20%	532	0.00	15	$227	100%	23%	23%	1	100%	14%	92.7%	49.6%	49.6%	12.3
488	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz-Prescriptive	Food Sales	Retro	1,902	1,902	38%	731	0.00	15	$200	100%	30%	55%	2	100%	14%	92.7%	74.0%	79.4%	11.6
489	WholeBldg_HVAC	HVAC - Energy Management System	Biz-Custom RCx	Food Sales	Retro	13	13	8%	1	0.00	15	$0	100%	25%	25%	1	100%	20%	92.7%	51.6%	51.6%	8.8
490	WholeBldg_HVAC	Guest room energy management system	Biz-Custom	Food Sales	Retro	0	0	0%	0	0.00	15	$260	0%		0%	2	100%	20%	92.7%	74.2%	74.2%	0.0
491	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz-Custom RCx	Food Sales	Retro	10	10	10%	1	0.00	15	$0	100%	25%	25%	3	100%	0%	92.7%	51.6%	51.6%	8.8
492	WholeBuilding	WholeBlg - Com RET	Biz-Custom	Food Sales	Retro	7	7	15%	1	0.00	12	$0	100%	25%	25%	1	90%	0%	92.7%	51.6%	51.6%	7.3
493	WholeBuilding	WholeBlg - Custom (Other)	Biz-Custom	Food Sales	Retro	5	5	20%	1	0.00	12	$0	100%	25%	25%	2	90%	0%	92.7%	51.6%	51.6%	7.3
494	WholeBuilding	Power Distribution Equipment Upgrades (Transformers)	Biz-Custom	Food Sales	Retro	1,150	1,150	1%	6	0.00	30	$8	100%	9%	9%	3	100%	20%	92.7%	36.0%	36.0%	17.1
495	WholeBldg_NC	WholeBlg - Com NC	Biz-Custom	Food Sales	NC	4	4	25%	1	0.00	12	$0	100%	50%	50%	1	100%	60%	83.4%	68.0%	68.0%	7.6
496	Behavioral	COM Competitions	Biz-Custom	Food Sales	Retro	0	0	0%	0	0.00	2	$0	0%		0%	1	100%	0%	50.0%	50.0%	50.0%	0.0
497	Behavioral	Business Energy Reports	Biz-Custom	Food Sales	Retro	0	0	0%	0	0.00	2	$0	0%		0%	1	100%	0%	50.0%	50.0%	50.0%	0.0
498	Behavioral	Building Benchmarking	Biz-Custom	Food Sales	Retro	0	0	0%	0	0.00	2	$0	0%		0%	1	100%	0%	50.0%	50.0%	50.0%	0.0
499	Behavioral	Strategic Energy Management	Biz-Custom SEM	Food Sales	Retro	0	0	0%	0	0.00	5	$0	0%		0%	1	100%	0%	50.0%	50.0%	50.0%	0.0
500	Behavioral	BEIMS	Biz-Custom	Food Sales	Retro	20	20	5%	1	0.00	2	$0	23%	23%	23%	1	100%	2%	50.0%	50.0%	50.0%	0.8
501	Behavioral	Building Operator Certification	Biz-Custom	Food Sales	Retro	10	10	2%	0	0.00	3	$0	14%	14%	14%	1	100%	2%	50.0%	50.0%	50.0%	1.7
502	CompressedAir	Efficient Air Compressors (VSD)	Biz-Prescriptive	Food Service	ROB	1,583	1,583	21%	329	0.00	13	$127	100%	59%	80%	1	100%	33%	92.7%	76.7%	83.1%	5.5
503	CompressedAir	Efficient Air Nozzles	Biz-Prescriptive	Food Service	Retro	1,480	1,480	50%	740	0.00	15	$50	100%	81%	81%	2	35%	33%	92.7%	91.1%	91.1%	15.8
504	CompressedAir	AODD Pump Controls	Biz-Custom	Food Service	Retro	103,919	103,919	35%	36,372	0.00	10	$1,150	100%	50%	50%	3	10%	33%	92.7%	72.6%	72.6%	38.2

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
505	CompressedAir	Compressed Air - Custom	Biz-Custom	Food Service	Retro	5	5	20%	1	0.00	10	$0	100%	47%	47%	4	50%	33%	92.7%	64.2%	64.2%	6.0
506	CompressedAir	Retro-commissioning_Compressed Air Optimization	Biz-Custom RCx	Food Service	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	5	50%	33%	92.7%	64.2%	64.2%	3.2
507	Cooking	Commercial Combination Oven (Electric)	Biz-Prescriptive	Food Service	ROB	38,561	38,561	48%	18,432	0.00	12	$16,884	75%	6%	15%	1	18%	53%	77.5%	62.4%	62.4%	14.1
508	Cooking	Commercial Electric Convection Oven	Biz-Prescriptive	Food Service	ROB	12,193	12,193	15%	1,879	0.00	12	$1,706	75%	21%	51%	1	18%	53%	77.6%	62.4%	62.4%	4.4
509	Cooking	Commercial Electric Griddle	Biz-Prescriptive	Food Service	ROB	17,056	17,056	15%	2,596	0.00	12	$3,604	25%	15%	15%	2	14%	17%	41.9%	33.6%	33.6%	2.8
510	Cooking	Commercial Electric Steam Cooker	Biz-Prescriptive	Food Service	ROB	19,549	19,549	67%	13,162	0.00	12	$2,490	100%	24%	55%	3	6%	45%	88.0%	81.1%	83.5%	18.0
511	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz-Prescriptive	Food Service	ROB	39,306	39,306	44%	17,369	0.00	15	$1,000	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	11.7
512	Cooking	Dishwasher High Temp Door (Energy Star)	Biz-Prescriptive	Food Service	ROB	26,901	26,901	32%	8,586	0.00	15	$1,100	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	5.2
513	Cooking	Energy efficient electric fryer	Biz-Prescriptive	Food Service	ROB	18,955	18,955	17%	3,274	0.00	12	$1,500	100%	5%	13%	5	27%	24%	88.0%	57.2%	59.4%	23.2
514	Cooking	Insulated Holding Cabinets (Full Size)	Biz-Prescriptive	Food Service	ROB	13,697	13,697	68%	9,314	0.00	12	$1,200	100%	35%	55%	6	3%	16%	88.0%	83.6%	84.9%	12.7
515	Cooking	Insulated Holding Cabinets (Half-Size)	Biz-Prescriptive	Food Service	ROB	4,383	4,383	60%	2,630	0.00	12	$1,500	100%	10%	25%	6	3%	16%	88.0%	52.6%	57.6%	10.1
516	Cooling	Air Conditioner - 13 IEER (5-20 Tons)	Biz-Prescriptive	Food Service	ROB	1,000	1,000	6%	62	0.00	15	$63	100%	48%	55%	1	18%	20%	92.7%	50.3%	53.0%	4.6
517	Cooling	Air Conditioner - 14 IEER (5-20 Tons)	Biz-Prescriptive	Food Service	ROB	1,000	1,000	13%	129	0.00	15	$127	100%	24%	55%	1	18%	20%	92.7%	42.6%	53.5%	9.7
518	Cooling	Air Conditioner - 17 IEER (5-20 Tons)	Biz-Prescriptive	Food Service	ROB	1,000	1,000	28%	282	0.00	15	$127	100%	24%	55%	1	18%	20%	92.7%	60.3%	73.2%	21.2
519	Cooling	Air Conditioner - 21 IEER (5-20 Tons)	Biz-Prescriptive	Food Service	ROB	1,000	1,000	42%	419	0.00	15	$127	100%	24%	55%	1	18%	20%	92.7%	70.9%	78.3%	31.5
520	Cooling	Air Conditioner - 12.1 IEER (20+ Tons)	Biz-Prescriptive	Food Service	ROB	1,070	1,070	6%	62	0.00	15	$30	100%	100%	100%	2	18%	20%	92.7%	92.7%	92.7%	4.7
521	Cooling	Air Conditioner - 13 IEER (20+ Tons)	Biz-Prescriptive	Food Service	ROB	1,070	1,070	12%	132	0.00	15	$37	100%	81%	81%	2	18%	20%	92.7%	86.1%	86.1%	9.9
522	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz-Prescriptive	Food Service	ROB	1,070	1,070	20%	217	0.00	15	$37	100%	81%	81%	2	18%	20%	92.7%	88.7%	88.7%	16.3
523	Cooling	Air Conditioner - 21 IEER (20+ Tons)	Biz-Prescriptive	Food Service	ROB	1,070	1,070	46%	489	0.00	15	$37	100%	81%	81%	2	18%	20%	92.7%	90.9%	90.9%	36.8
524	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz-Custom	Food Service	Retro	1,017	1,017	7%	71	0.00	3	$5	100%	50%	50%	3	36%	50%	92.7%	70.4%	70.4%	14.5
525	Cooling	Air Side Economizer	Biz-Custom	Food Service	Retro	1,000	1,000	20%	200	0.00	10	$84	75%	24%	24%	4	36%	20%	80.8%	50.0%	50.0%	3.9
526	Cooling	Advanced Rooftop Controls	Biz-Prescriptive	Food Service	Retro	1,017	1,017	3%	26	0.00	10	$100	100%	100%	100%	5	36%	20%	92.7%	92.7%	92.7%	0.1
527	Cooling	HVAC Occupancy Controls	Biz-Custom	Food Service	ROB	2,900	2,900	20%	580	0.00	15	$537	100%	11%	11%	6	36%	20%	92.7%	36.0%	36.0%	12.0
528	Cooling	Air Conditioner - 16 SEER (<5 Tons)	Biz-Prescriptive	Food Service	ROB	871	871	13%	109	0.00	15	$47	100%	64%	80%	7	27%	20%	92.7%	76.9%	82.3%	8.2
529	Cooling	Air Conditioner - 17 SEER (<5 Tons)	Biz-Prescriptive	Food Service	ROB	871	871	18%	154	0.00	15	$206	100%	15%	36%	7	27%	20%	92.7%	36.0%	40.2%	11.6
530	Cooling	Air Conditioner - 18 SEER(<5 Tons)	Biz-Prescriptive	Food Service	ROB	871	871	22%	194	0.00	15	$206	100%	15%	36%	7	27%	20%	92.7%	39.2%	45.3%	14.6
531	Cooling	Air Conditioner - 21 SEER(<5 Tons)	Biz-Prescriptive	Food Service	ROB	871	871	33%	290	0.00	15	$253	100%	12%	30%	7	27%	20%	92.7%	42.1%	47.6%	21.8
532	Cooling	Smart Thermostat	Biz-Prescriptive	Food Service	ROB	871	871	14%	123	0.00	11	$175	57%	57%	57%	8	27%	12%	47.8%	47.8%	47.8%	1.3
533	Cooling	PTAC - <7,000 Btuh - lodging	Biz-Prescriptive	Food Service	ROB	1,025	1,025	8%	87	0.00	8	$84	100%	36%	36%	9	36%	20%	92.7%	47.3%	47.3%	3.6
534	Cooling	PTAC - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Food Service	ROB	1,124	1,124	7%	82	0.00	8	$84	100%	36%	36%	10	36%	20%	92.7%	45.9%	45.9%	3.4
535	Cooling	PTAC - >15,000 Btuh - lodging	Biz-Prescriptive	Food Service	ROB	1,284	1,284	10%	122	0.00	8	$84	100%	36%	55%	11	36%	20%	92.7%	53.6%	63.6%	5.0
536	Cooling	Air Cooled Chiller	Biz-Prescriptive	Food Service	ROB	890	890	6%	50	0.00	23	$126	100%	24%	55%	12	0%	15%	92.7%	32.0%	35.2%	6.5
537	Cooling	Chiller Tune-up	Biz-Prescriptive	Food Service	Retro	1,017	1,017	7%	71	0.00	3	$8	100%	100%	100%	13	0%	50%	92.7%	92.7%	92.7%	4.8
538	Cooling	HVAC/Chiller Custom	Biz-Custom	Food Service	Retro	5	5	20%	1	0.00	20	$1	100%	7%	7%	14	100%	20%	92.7%	36.0%	36.0%	30.3
539	Cooling	Window Film	Biz-Prescriptive	Food Service	Retro	6,000	6,000	4%	264	0.00	10	$154	100%	65%	65%	15	100%	20%	92.7%	73.1%	73.1%	3.2
540	Cooling	Triple Pane Windows	Biz-Custom	Food Service	ROB	6,000	6,000	6%	360	0.00	25	$700	100%	5%	5%	15	100%	20%	92.7%	36.0%	36.0%	24.5
541	Cooling	Energy Recovery Ventilator	Biz-Custom	Food Service	Retro	1,070	1,070	0%	0	0.00	15	$1,500	0%		0%	16	100%	2%	92.7%	74.2%	74.2%	0.0
542	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz-Prescriptive	Food Service	ROB	1,899	1,899	4%	75	0.00	16	$87	100%	46%	46%	1	36%	20%	92.7%	47.1%	47.1%	2.8
543	Heating	Heat Pump - 17 SEER (<5 Tons)	Biz-Prescriptive	Food Service	ROB	1,899	1,899	9%	165	0.00	16	$442	50%	9%	23%	1	36%	20%	44.0%	36.0%	36.0%	5.6
544	Heating	Heat Pump - 18 SEER(<5 Tons)	Biz-Prescriptive	Food Service	ROB	1,899	1,899	12%	236	0.00	16	$507	50%	8%	20%	1	36%	20%	44.0%	36.0%	36.0%	7.9
545	Heating	Heat Pump - 21 SEER(<5 Tons)	Biz-Prescriptive	Food Service	ROB	1,899	1,899	19%	363	0.00	16	$507	75%	8%	20%	1	36%	20%	59.7%	36.0%	36.0%	12.6
546	Heating	Geothermal HP - SEER 20.3 (<5 Tons)	Biz-Prescriptive	Food Service	ROB	1,899	1,899	23%	429	0.00	25	$2,576	25%	2%	4%	1	36%	20%	44.0%	36.0%	36.0%	18.2
547	Heating	Geothermal HP - SEER 21.5 (<5 Tons)	Biz-Prescriptive	Food Service	ROB	1,899	1,899	27%	511	0.00	25	$2,576	25%	2%	4%	1	36%	20%	44.0%	36.0%	36.0%	21.1
548	Heating	Geothermal HP - SEER 23.1 (<5 Tons)	Biz-Prescriptive	Food Service	ROB	1,899	1,899	32%	608	0.00	25	$2,576	25%	2%	4%	1	36%	20%	44.0%	36.0%	36.0%	24.4
549	Heating	Geothermal HP - SEER 29.3 (<5 Tons)	Biz-Prescriptive	Food Service	ROB	1,899	1,899	47%	887	0.00	25	$2,576	25%	2%	4%	1	36%	20%	44.0%	36.0%	36.0%	31.7
550	Heating	Heat Pump - 14.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Food Service	ROB	2,289	2,289	11%	251	0.00	16	$100	100%	40%	55%	2	24%	20%	92.7%	70.3%	75.0%	32.1
551	Heating	Heat Pump - 15.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Food Service	ROB	2,289	2,289	16%	371	0.00	16	$136	100%	30%	55%	2	24%	20%	92.7%	68.5%	76.1%	35.9
552	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Food Service	ROB	2,382	2,382	14%	341	0.00	16	$100	100%	40%	55%	2	24%	20%	92.7%	75.3%	78.7%	36.4
553	Heating	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Food Service	ROB	2,382	2,382	19%	460	0.00	16	$139	100%	29%	55%	2	24%	20%	92.7%	72.3%	78.4%	40.1
554	Heating	Geothermal HP - SEER 20.3 (5-20 Tons)	Biz-Prescriptive	Food Service	ROB	2,086	2,086	30%	617	0.00	25	$2,576	50%	2%	4%	2	24%	20%	44.0%	36.0%	36.0%	37.5
555	Heating	Geothermal HP - SEER 21.5 (5-20 Tons)	Biz-Prescriptive	Food Service	ROB	2,086	2,086	34%	699	0.00	25	$2,576	50%	2%	4%	2	24%	20%	44.0%	36.0%	36.0%	40.4
556	Heating	Geothermal HP - SEER 23.1 (5-20 Tons)	Biz-Prescriptive	Food Service	ROB	2,215	2,215	42%	924	0.00	25	$2,576	50%	2%	4%	2	24%	20%	44.0%	36.0%	36.0%	46.4
557	Heating	Geothermal HP - SEER 29.3 (5-20 Tons)	Biz-Prescriptive	Food Service	ROB	2,215	2,215	54%	1,203	0.00	25	$2,576	75%	2%	4%	2	24%	20%	50.3%	36.0%	36.0%	53.8
558	Heating	Variable Refrigerant Flow Heat Pump	Biz-Custom	Food Service	ROB	1,768	1,768	13%	232	0.00	16	$224	100%	10%	10%	2	24%	2%	92.7%	32.0%	32.0%	18.3
559	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz-Prescriptive	Food Service	ROB	2,485	2,485	9%	234	0.00	16	$100	100%	40%	55%	3	24%	20%	92.7%	68.6%	73.9%	28.6
560	Heating	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	Biz-Prescriptive	Food Service	ROB	2,485	2,485	15%	380	0.00	16	$175	100%	23%	55%	3	24%	20%	92.7%	59.3%	72.8%	33.6
561	Heating	Geothermal HP - SEER 20.3 (20+ Tons)	Biz-Prescriptive	Food Service	ROB	2,382	2,382	38%	913	0.00	25	$2,576	100%	2%	4%	3	24%	20%	92.7%	36.0%	36.0%	72.2
562	Heating	Geothermal HP - SEER 21.5 (20+ Tons)	Biz-Prescriptive	Food Service	ROB	2,382	2,382	42%	995	0.00	25	$2,576	100%	2%	4%	3	24%	20%	92.7%	36.0%	36.0%	75.1
563	Heating	Geothermal HP - SEER 23.1 (20+ Tons)	Biz-Prescriptive	Food Service	ROB	2,382	2,382	46%	1,091	0.00	25	$2,576	100%	2%	4%	3	24%	20%	92.7%	36.0%	36.0%	78.3
564	Heating	Geothermal HP - SEER 29.3 (20+ Tons)	Biz-Prescriptive	Food Service	ROB	2,382	2,382	58%	1,370	0.00	25	$2,576	100%	2%	4%	3	24%	20%	92.7%	36.0%	36.0%	85.7
565	Heating	Mini Split Ductless Heat Pump Cold Climate (Tiers & sizes TBD)	Biz-Prescriptive	Food Service	ROB	1,899	1,899	19%	363	0.00	16	$224	100%	18%	45%	4	17%	20%	92.7%	51.3%	60.5%	12.6
566	Heating	PTHP - <7,000 Btuh - lodging	Biz-Custom	Food Service	ROB	2,091	2,091	4%	84	0.00	8	$130	100%	100%	100%	5	0%	10%	92.7%	74.2%	74.2%	0.7
567	Heating	PTHP - >15,000 Btuh - lodging	Biz-Prescriptive	Food Service	ROB	2,525	2,525	16%	398	0.00	8	$130	100%	100%	100%	6	0%	10%	92.7%	92.7%	92.7%	3.5
568	Heating	PTHP - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Food Service	ROB	2,291	2,291	9%	207	0.00	8	$130	100%	100%	100%	7	0%	10%	92.7%	92.7%	92.7%	1.8
569	HotWater	Heat Pump Water Heater	Biz-Prescriptive	Food Service	ROB	5,521	5,521	67%	3,698	0.00	15	$1,115	100%	45%	55%	1	100%	4%	84.0%	73.6%	76.0%	6.1
570	HotWater	Hot Water Pipe Insulation	Biz-Custom	Food Service	Retro	5,521	5,521	2%	110	0.00	20	$60	100%	18%	18%	2	100%	80%	86.0%	84.0%	84.0%	9.8
571	HotWater	Faucet Aerator	Biz-Custom	Food Service	Retro	973	973	32%	315	0.00	10	$8	100%	50%	50%	3	20%	90%	93.0%	92.0%	92.0%	44.5
572	HotWater	Low Flow Pre-Rinse Sprayers	Biz-Prescriptive	Food Service	ROB	18,059	18,059	54%	9,789	0.00	5	$60	100%	17%	42%	4	20%	80%	86.0%	84.0%	84.0%	199.3
573	HotWater	ENERGY STAR Commercial Washing Machines	Biz-Prescriptive	Food Service	ROB	1,552	1,552	43%	671	0.00	7	$250	75%	28%	28%	5	25%	33%	79.3%	64.6%	64.6%	2.9
574	InteriorLighting	LED T8 Tube Replacement	Biz-Prescriptive Light	Food Service	Retro	206	206	45%	92	0.00	9	$5	100%	100%	100%	1	57%	40%	94.6%	94.6%	94.6%	10.9
575	InteriorLighting	LED troffer retrofit kit, 2'X2' and 2'X4'	Biz-Prescriptive Light	Food Service	Retro	467	467	50%	234	0.00	9	$70	100%	36%	55%	1	57%	40%	94.6%	75.8%	82.0%	5.5
576	InteriorLighting	LED troffer, 2'X2' and 2'X4'	Biz-Prescriptive Light	Food Service	Retro	467	467	50%	234	0.00	9	$70	100%	36%	55%	1	57%	40%	94.6%	75.8%	82.0%	5.5

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
577	InteriorLighting	Bi-Level Lighting Fixture – Stairwells, Hallways	Biz-Custom Light	Food Service	Retro	467	467	74%	347	0.00	10	$274	50%	13%	16%	2	1%	40%	58.0%	52.0%	52.0%	4.3
578	InteriorLighting	LED high bay fixture	Biz-Prescriptive Light	Food Service	Retro	4,346	4,346	68%	2,957	0.00	9	$330	100%	35%	55%	3	9%	34%	94.6%	88.6%	90.4%	15.1
579	InteriorLighting	LED Mogul-base HID Lamp Replacing High Bay HID	Biz-Prescriptive Light	Food Service	Retro	4,346	4,346	66%	2,883	0.00	9	$330	100%	35%	55%	3	9%	34%	94.6%	88.4%	90.3%	14.8
580	InteriorLighting	LED low bay fixture	Biz-Prescriptive Light	Food Service	Retro	926	926	61%	563	0.00	9	$44	100%	68%	80%	4	25%	34%	94.6%	92.5%	93.3%	11.0
581	InteriorLighting	LED Mogul-base HID Lamp Replacing Low Bay HID	Biz-Prescriptive Light	Food Service	Retro	926	926	59%	543	0.00	9	$44	100%	68%	80%	4	25%	34%	94.6%	92.4%	93.2%	10.7
582	InteriorLighting	LED Screw-In Lamps (Directional)	Biz-Prescriptive Light	Food Service	ROB	415	415	86%	356	0.00	4	$1	100%	100%	100%	6	0%	43%	94.6%	94.6%	94.6%	105.7
583	InteriorLighting	LED downlight fixture	Biz-Prescriptive Light	Food Service	Retro	320	320	68%	216	0.00	9	$27	100%	19%	46%	6	8%	45%	94.6%	85.6%	89.0%	25.5
584	InteriorLighting	LED Screw-In Lamps (Omnidirectional & Decorative)	Biz-Prescriptive Light	Food Service	ROB	314	314	81%	254	0.00	4	$1	100%	100%	100%	5	1%	20%	94.6%	94.6%	94.6%	75.4
585	InteriorLighting	DeLamp Fluorescent Fixture Average Lamp Wattage 28W	Biz-Prescriptive Light	Food Service	Retro	172	172	100%	172	0.00	11	$4	100%	100%	100%	7	57%	0%	94.6%	94.6%	94.6%	29.9
586	InteriorLighting	Occupancy Sensors	Biz-Prescriptive Light	Food Service	Retro	785	785	30%	235	0.00	10	$65	100%	31%	55%	8	95%	10%	94.6%	75.8%	83.1%	5.0
587	InteriorLighting	Daylighting Controls	Biz-Prescriptive Light	Food Service	Retro	1,005	1,005	30%	301	0.00	10	$58	100%	35%	55%	8	95%	10%	94.6%	83.2%	87.3%	9.3
588	InteriorLighting	Dual Occupancy & Daylighting Controls	Biz-Custom Light	Food Service	Retro	448	448	44%	197	0.00	10	$75	100%	40%	50%	8	95%	10%	94.6%	57.6%	60.9%	4.2
589	InteriorLighting	Central Lighting Monitoring & Controls (non-networked)	Biz-Custom Light	Food Service	Retro	41,703	41,703	20%	8,341	0.00	12	$3,700	100%	23%	29%	8	95%	10%	94.6%	44.1%	47.7%	4.6
590	InteriorLighting	Network Lighting Controls - Wireless (WiFi)	Biz-Custom Light	Food Service	Retro	4	4	49%	2	0.00	15	$1	100%	30%	40%	8	95%	10%	94.6%	57.6%	60.2%	9.0
591	InteriorLighting	Luminaire Level Lighting Controls w/ HVAC Control	Biz-Custom Light	Food Service	Retro	448	448	65%	291	0.00	15	$90	100%	32%	42%	8	92%	10%	94.6%	59.2%	61.8%	9.0
592	InteriorLighting	LED Exit Sign - 4 Watt Fixture (2 lamp)	Biz-Prescriptive Light	Food Service	Retro	66	66	43%	28	0.00	5	$33	92%	92%	92%	9	1%	75%	87.1%	87.1%	87.1%	0.3
593	InteriorLighting	Lighting - Custom	Biz-Custom Light	Food Service	Retro	4	4	25%	1	0.00	15	$0	100%	22%	29%	10	100%	0%	94.6%	43.3%	46.9%	9.0
594	ExteriorLighting	LED wallpack (existing W<250)	Biz-Prescriptive Light	Food Service	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	1	12%	46%	94.6%	56.6%	70.8%	5.8
595	ExteriorLighting	LED parking lot fixture (existing W≥250)	Biz-Prescriptive Light	Food Service	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	2	11%	54%	67.8%	63.2%	63.2%	4.4
596	ExteriorLighting	LED parking lot fixture (existing W<250)	Biz-Prescriptive Light	Food Service	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	3	11%	54%	94.6%	63.2%	70.8%	5.8
597	ExteriorLighting	LED outdoor pole decorative fixture (existing W≥250)	Biz-Prescriptive Light	Food Service	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	17%	17%	4	11%	54%	67.8%	63.2%	63.2%	3.4
598	ExteriorLighting	LED parking garage fixture (existing W≥250)	Biz-Prescriptive Light	Food Service	Retro	3,235	3,235	60%	1,953	0.00	6	$756	50%	13%	33%	5	11%	69%	78.3%	75.2%	75.2%	4.7
599	ExteriorLighting	LED parking garage fixture (existing W<250)	Biz-Prescriptive Light	Food Service	Retro	1,742	1,742	66%	1,154	0.00	6	$248	100%	18%	45%	6	11%	69%	94.6%	77.6%	83.9%	6.2
600	ExteriorLighting	LED Mogul-base HID Lamp Replacing Exterior HID (existing W≥250)	Biz-Prescriptive Light	Food Service	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	7	11%	46%	62.1%	56.6%	56.6%	4.4
601	ExteriorLighting	LED Mogul-base HID Lamp Replacing Exterior HID (existing W<250)	Biz-Prescriptive Light	Food Service	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	8	11%	46%	94.6%	56.6%	70.8%	5.8
602	ExteriorLighting	Bi-Level Lighting Fixture – Garages	Biz-Custom Light	Food Service	Retro	467	467	69%	322	0.00	10	$274	25%	12%	15%	9	11%	20%	44.0%	36.0%	36.0%	3.9
603	ExteriorLighting	LED fuel pump canopy fixture (existing W<250)	Biz-Prescriptive Light	Food Service	Retro	0	0	0%	0	0.00	12	$0	0%	0%		10	0%	54%	94.6%	94.6%	94.6%	0.0
604	ExteriorLighting	LED fuel pump canopy fixture (existing W≥250)	Biz-Prescriptive Light	Food Service	Retro	0	0	0%	0	0.00	12	$0	0%	0%		11	0%	54%	94.6%	94.6%	94.6%	0.0
605	Miscellaneous	Vending Machine Controller - Non-Refrigerated	Biz-Prescriptive	Food Service	Retro	385	385	61%	237	0.00	5	$233	11%	11%	11%	1	5%	30%	51.0%	44.0%	44.0%	1.9
606	Miscellaneous	Miscellaneous Custom	Biz-Custom	Food Service	Retro	7	7	2%	0	0.00	10	$0	75%	25%	25%	2	30%	10%	37.0%	23.4%	23.4%	3.3
607	Miscellaneous	Kitchen Exhaust Hood Demand Ventilation Control System	Biz-Prescriptive	Food Service	ROB	9,932	9,932	50%	4,966	0.00	20	$1,180	100%	11%	27%	3	18%	10%	94.6%	73.8%	78.0%	39.7
608	Miscellaneous	High Efficiency Hand Dryers	Biz-Custom	Food Service	Retro	1,909	1,909	83%	1,585	0.00	10	$483	100%	33%	33%	4	5%	10%	94.6%	59.6%	59.6%	6.4
609	Miscellaneous	Ozone Commercial Laundry	Biz-Custom	Food Service	Retro	2,984	2,984	25%	746	0.00	10	$20,310	0%	0%	0%	5	0%	2%	31.4%	16.6%	16.6%	3.9
610	Miscellaneous	ENERGY STAR Uninterrupted Power Supply	Biz-Custom	Food Service	ROB	3,096	3,096	3%	85	0.00	15	$59	100%	14%	14%	6	0%	70%	94.6%	76.0%	76.0%	8.8
611	Motors	Cogged V-Belt	Biz-Custom	Food Service	Retro	17,237	17,237	3%	534	0.00	15	$384	100%	14%	14%	1	50%	10%	83.4%	32.2%	32.2%	9.2
612	Motors	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz-Custom	Food Service	Retro	1,902	1,902	38%	731	0.00	15	$200	100%	30%	30%	2	100%	10%	83.4%	52.4%	52.4%	11.6
613	Motors	Power Drive Systems	Biz-Custom	Food Service	Retro	4	4	23%	1	0.00	15	$0	100%	37%	37%	2	100%	10%	83.4%	53.4%	53.4%	9.2
614	Motors	Switch Reluctance Motors	Biz-Custom	Food Service	Retro	33,406	33,406	31%	10,222	0.00	15	$528	100%	50%	50%	2	100%	1%	83.4%	64.1%	64.1%	26.3
615	Motors	Escalators Motor Efficiency Controllers	Biz-Custom	Food Service	Retro	7,500	7,500	20%	1,500	0.00	10	$5,000	3%	3%	3%	3	0%	10%	37.0%	26.3%	26.3%	7.3
616	Office_NonPC	Energy Star Printer/Copier/Fax	Biz-Custom	Food Service	ROB	551	551	40%	223	0.00	6	$0	0%			1	30%	90%	94.6%	92.0%	92.0%	0.0
617	Office_NonPC	Smart Power Strip – Commercial Use	Biz-Custom	Food Service	Retro	1,086	1,086	10%	109	0.00	7	$50	50%	22%	22%	2	35%	15%	71.8%	42.0%	42.0%	2.8
618	Office_NonPC	Plug Load Occupancy Sensor	Biz-Custom	Food Service	Retro	1,126	1,126	15%	169	0.00	8	$70	75%	24%	24%	2	35%	15%	85.4%	47.6%	47.6%	3.2
619	Office_PC	Electrically Commutated Plug Fans in data centers	Biz-Custom	Food Service	Retro	86,783	86,783	18%	15,778	0.00	15	$480	100%	50%	50%	1	65%	20%	94.6%	74.6%	74.6%	50.8
620	Office_PC	Energy Star Server	Biz-Custom	Food Service	ROB	1,621	1,621	23%	368	0.00	8	$118	100%	31%	31%	1	65%	25%	94.6%	58.2%	58.2%	4.5
621	Office_PC	Server Virtualization	Biz-Custom	Food Service	Retro	2	2	45%	1	0.00	8	$0	75%	25%	25%	1	65%	25%	85.8%	49.3%	49.3%	3.2
622	Office_PC	High Efficiency CRAC unit	Biz-Custom	Food Service	ROB	541	541	30%	162	0.00	15	$63	100%	26%	26%	2	65%	20%	94.6%	51.1%	51.1%	8.1
623	Office_PC	Computer Room Air Conditioner Economizer	Biz-Custom	Food Service	Retro	764	764	47%	358	0.00	15	$82	100%	44%	44%	2	65%	20%	94.6%	66.1%	66.1%	5.6
624	Office_PC	Data Center Hot/Cold Aisle Configuration	Biz-Custom	Food Service	Retro	4	4	25%	1	0.00	15	$0	100%	25%	25%	3	3%	10%	94.6%	49.3%	49.3%	7.7
625	Office_PC	Energy Star Laptop	Biz-Custom	Food Service	ROB	126	126	33%	41	0.00	4	$0	0%			4	11%	85%	94.6%	88.0%	88.0%	0.0
626	Office_PC	Energy Star Monitor	Biz-Custom	Food Service	ROB	72	72	21%	15	0.00	4	$0	0%			5	25%	85%	94.6%	88.0%	88.0%	0.0
627	Refrigeration	Strip Curtains	Biz-Custom	Food Service	Retro	88	88	50%	44	0.00	4	$10	100%	43%	43%	1	17%	30%	88.0%	65.2%	65.2%	2.3
628	Refrigeration	Bare Suction Line	Biz-Custom	Food Service	Retro	23	23	93%	21	0.00	15	$4	100%	50%	50%	2	1%	50%	88.0%	66.5%	66.5%	8.1
629	Refrigeration	Floating Head Pressure Controls	Biz-Custom	Food Service	Retro	1,112	1,112	25%	278	0.00	15	$431	25%	6%	6%	3	11%	25%	47.5%	40.0%	40.0%	5.6
630	Refrigeration	Saturated Suction Controls	Biz-Custom	Food Service	Retro	831	831	50%	416	0.00	15	$559	100%	7%	7%	4	2%	10%	88.0%	28.0%	28.0%	13.7
631	Refrigeration	Compressor Retrofit	Biz-Custom	Food Service	Retro	813	813	20%	163	0.00	15	$477	25%	3%	3%	5	38%	25%	47.5%	39.4%	39.4%	13.8
632	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz-Prescriptive	Food Service	Retro	2,440	2,440	65%	1,586	0.00	15	$305	100%	13%	33%	6	11%	80%	88.0%	84.0%	84.0%	30.7
633	Refrigeration	Evaporator Fan Motor Controls	Biz-Custom	Food Service	Retro	1,912	1,912	25%	478	0.00	13	$162	100%	30%	30%	7	11%	25%	88.0%	61.7%	61.7%	7.0
634	Refrigeration	Variable Speed Condenser Fan	Biz-Custom	Food Service	Retro	2,960	2,960	50%	1,480	0.00	15	$1,170	50%	13%	13%	8	14%	25%	59.5%	40.0%	40.0%	5.6
635	Refrigeration	Refrigeration Economizer	Biz-Custom	Food Service	Retro	7	7	2%	0	0.00	10	$0	100%	50%	50%	9	53%	10%	88.0%	41.1%	41.1%	4.2
636	Refrigeration	Anti-Sweat Heater Controls MT	Biz-Prescriptive	Food Service	Retro	579	579	59%	338	0.00	10	$170	75%	44%	44%	10	6%	75%	82.5%	80.0%	80.0%	2.1
637	Refrigeration	Auto Door Closer, Cooler	Biz-Custom	Food Service	Retro	471,500	471,500	0%	943	0.00	8	$157	100%	50%	50%	11	4%	50%	88.0%	66.9%	66.9%	5.8
638	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz-Custom	Food Service	Retro	1,584	1,584	36%	578	0.00	12	$686	50%	8%	8%	11	2%	25%	47.9%	40.0%	40.0%	7.1
639	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz-Prescriptive	Food Service	Retro	2,440	2,440	65%	1,586	0.00	15	$305	100%	13%	33%	12	1%	80%	88.0%	84.0%	84.0%	30.7
640	Refrigeration	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	Biz-Custom	Food Service	Retro	1,911	1,911	26%	504	0.00	10	$96	100%	50%	50%	12	1%	2%	88.0%	66.5%	66.5%	5.8
641	Refrigeration	Energy Star Reach-In Refrigerator, Glass Doors	Biz-Prescriptive	Food Service	ROB	2,140	2,140	29%	629	0.00	12	$1,239	25%	6%	14%	13	6%	54%	67.8%	63.2%	63.2%	5.6
642	Refrigeration	Energy Star Reach-In Refrigerator, Solid Doors	Biz-Prescriptive	Food Service	ROB	1,410	1,410	20%	281	0.00	12	$1,211	6%	6%	6%	14	6%	54%	67.8%	63.2%	63.2%	2.5
643	Refrigeration	Anti-Sweat Heater Controls LT	Biz-Prescriptive	Food Service	Retro	2,016	2,016	68%	1,361	0.00	10	$170	100%	44%	55%	15	2%	75%	88.0%	84.3%	85.0%	8.3
644	Refrigeration	Auto Door Closer, Freezer	Biz-Custom	Food Service	Retro	419,455	419,455	1%	2,307	0.00	8	$157	100%	50%	50%	16	2%	50%	88.0%	68.9%	68.9%	13.9
645	Refrigeration	Display Case Door Retrofit, Low Temp	Biz-Custom	Food Service	Retro	2,922	2,922	50%	1,453	0.00	12	$686	100%	21%	21%	16	2%	25%	88.0%	49.7%	49.7%	7.1
646	Refrigeration	Energy Star Reach-In Freezer, Glass Doors	Biz-Prescriptive	Food Service	ROB	6,374	6,374	20%	1,275	0.00	12	$1,651	25%	21%	21%	17	2%	54%	67.8%	63.2%	63.2%	2.3
647	Refrigeration	Energy Star Reach-In Freezer, Solid Doors	Biz-Prescriptive	Food Service	ROB	4,522	4,522	7%	305	0.00	12	$1,521	23%	23%	23%	18	2%	54%	67.8%	63.2%	63.2%	0.5
648	Refrigeration	Refrigeration - Custom	Biz-Custom	Food Service	ROB	7	7	2%	0	0.00	10	$0	75%	25%	25%	19	90%	25%	47.5%	39.4%	39.4%	3.3

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
649	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz-Custom RCx	Food Service	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	20	90%	25%	88.0%	65.9%	65.9%	3.2
650	Refrigeration	Energy Star Ice Machine	Biz-Prescriptive	Food Service	ROB	6,993	6,993	10%	721	0.00	15	$1,426	25%	18%	18%	21	5%	44%	60.8%	55.2%	55.2%	2.1
651	Refrigeration	Vending Machine Controller - Refrigerated	Biz-Prescriptive	Food Service	Retro	1,586	1,586	34%	537	0.00	5	$245	25%	16%	16%	22	0%	30%	65.5%	61.1%	61.1%	2.7
652	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz-Prescriptive	Food Service	Retro	273	273	89%	243	0.00	9	$11	100%	45%	55%	23	4%	35%	88.0%	86.7%	86.9%	30.9
653	Refrigeration	LED Refrigerated Display Case Lighting Controls	Biz-Prescriptive	Food Service	Retro	522	522	27%	141	0.00	10	$15	100%	100%	100%	24	4%	18%	88.0%	88.0%	88.0%	6.6
654	Ventilation	Demand Controlled Ventilation	Biz-Custom	Food Service	Retro	2,669	2,669	20%	534	0.00	15	$227	100%	24%	24%	1	100%	15%	92.7%	49.7%	49.7%	7.7
655	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz-Prescriptive	Food Service	Retro	1,902	1,902	38%	731	0.00	15	$200	100%	30%	55%	2	100%	15%	92.7%	74.0%	79.4%	11.6
656	WholeBldg_HVAC	HVAC - Energy Management System	Biz-Custom RCx	Food Service	Retro	13	13	8%	1	0.00	15	$0	100%	25%	25%	1	100%	20%	92.7%	51.6%	51.6%	8.8
657	WholeBldg_HVAC	Guest room energy management system	Biz-Custom	Food Service	Retro	0	0	0%	0	0.00	15	$260	0%		0%	2	100%	20%	92.7%	74.2%	74.2%	0.0
658	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz-Custom RCx	Food Service	Retro	10	10	10%	1	0.00	15	$0	100%	25%	25%	3	100%	0%	92.7%	51.6%	51.6%	8.8
659	WholeBuilding	WholeBlg - Com RET	Biz-Custom	Food Service	Retro	7	7	15%	1	0.00	12	$0	100%	25%	25%	1	90%	0%	92.7%	51.6%	51.6%	7.3
660	WholeBuilding	WholeBlg - Custom (Other)	Biz-Custom	Food Service	Retro	5	5	20%	1	0.00	12	$0	100%	25%	25%	2	90%	0%	92.7%	51.6%	51.6%	7.3
661	WholeBuilding	Power Distribution Equipment Upgrades (Transformers)	Biz-Custom	Food Service	Retro	1,150	1,150	1%	6	0.00	30	$8	100%	9%	9%	3	100%	20%	92.7%	36.0%	36.0%	17.1
662	WholeBldg_NC	WholeBlg - Com NC	Biz-Custom	Food Service	NC	4	4	25%	1	0.00	12	$0	100%	50%	50%	1	100%	60%	83.4%	68.0%	68.0%	7.6
663	Behavioral	COM Competitions	Biz-Custom	Food Service	Retro	53	53	2%	1	0.00	2	$0	100%	50%	50%	1	100%	0%	50.0%	50.0%	50.0%	3.9
664	Behavioral	Business Energy Reports	Biz-Custom	Food Service	Retro	0	0	0%	0	0.00	2	$0	0%		0%	1	100%	0%	50.0%	50.0%	50.0%	0.0
665	Behavioral	Building Benchmarking	Biz-Custom	Food Service	Retro	0	0	0%	0	0.00	2	$0	0%		0%	1	100%	0%	50.0%	50.0%	50.0%	0.0
666	Behavioral	Strategic Energy Management	Biz-Custom SEM	Food Service	Retro	0	0	0%	0	0.00	5	$0	0%		0%	1	100%	0%	50.0%	50.0%	50.0%	0.0
667	Behavioral	BEIMS	Biz-Custom	Food Service	Retro	20	20	5%	1	0.00	2	$0	23%	23%	23%	1	100%	2%	50.0%	50.0%	50.0%	0.8
668	Behavioral	Building Operator Certification	Biz-Custom	Food Service	Retro	40	40	3%	1	0.00	3	$0	75%	50%	50%	1	100%	2%	50.0%	50.0%	50.0%	2.0
669	CompressedAir	Efficient Air Compressors (VSD)	Biz-Prescriptive	Health	ROB	1,583	1,583	21%	329	0.00	13	$127	100%	59%	80%	1	100%	33%	92.7%	76.7%	83.1%	5.5
670	CompressedAir	Efficient Air Nozzles	Biz-Prescriptive	Health	Retro	1,480	1,480	50%	740	0.00	15	$50	100%	81%	81%	2	35%	33%	92.7%	91.1%	91.1%	15.8
671	CompressedAir	AODD Pump Controls	Biz-Custom	Health	Retro	103,919	103,919	35%	36,372	0.00	10	$1,150	100%	50%	50%	3	10%	33%	92.7%	72.6%	72.6%	38.2
672	CompressedAir	Compressed Air - Custom	Biz-Custom	Health	Retro	5	5	20%	1	0.00	10	$0	100%	47%	47%	4	50%	33%	92.7%	64.2%	64.2%	6.0
673	CompressedAir	Retro-commissioning_Compressed Air Optimization	Biz-Custom RCx	Health	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	5	50%	33%	92.7%	64.2%	64.2%	3.2
674	Cooking	Commercial Combination Oven (Electric)	Biz-Prescriptive	Health	ROB	38,561	38,561	48%	18,432	0.00	12	$16,884	75%	6%	15%	1	18%	53%	77.5%	62.4%	62.4%	14.1
675	Cooking	Commercial Electric Convection Oven	Biz-Prescriptive	Health	ROB	12,193	12,193	15%	1,879	0.00	12	$1,706	75%	21%	51%	1	18%	53%	77.6%	62.4%	62.4%	4.4
676	Cooking	Commercial Electric Griddle	Biz-Prescriptive	Health	ROB	17,056	17,056	15%	2,596	0.00	12	$3,604	25%	15%	15%	2	14%	17%	41.9%	33.6%	33.6%	2.8
677	Cooking	Commercial Electric Steam Cooker	Biz-Prescriptive	Health	ROB	19,549	19,549	67%	13,162	0.00	12	$2,490	100%	24%	55%	3	6%	45%	88.0%	81.1%	83.5%	18.0
678	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz-Prescriptive	Health	ROB	39,306	39,306	44%	17,369	0.00	15	$1,000	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	11.7
679	Cooking	Dishwasher High Temp Door (Energy Star)	Biz-Prescriptive	Health	ROB	26,901	26,901	32%	8,586	0.00	15	$1,100	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	5.2
680	Cooking	Energy efficient electric fryer	Biz-Prescriptive	Health	ROB	18,955	18,955	17%	3,274	0.00	12	$1,500	100%	5%	13%	5	27%	24%	88.0%	57.2%	59.4%	23.2
681	Cooking	Insulated Holding Cabinets (Full Size)	Biz-Prescriptive	Health	ROB	13,697	13,697	68%	9,314	0.00	12	$1,200	100%	35%	55%	6	3%	16%	88.0%	83.6%	84.9%	12.7
682	Cooking	Insulated Holding Cabinets (Half-Size)	Biz-Prescriptive	Health	ROB	4,383	4,383	60%	2,630	0.00	12	$1,500	100%	10%	25%	6	3%	16%	88.0%	52.6%	57.6%	10.1
683	Cooling	Air Conditioner - 13 IEER (5-20 Tons)	Biz-Prescriptive	Health	ROB	2,159	2,159	6%	133	0.00	15	$63	100%	48%	55%	1	24%	20%	92.7%	69.4%	72.3%	6.0
684	Cooling	Air Conditioner - 14 IEER (5-20 Tons)	Biz-Prescriptive	Health	ROB	2,159	2,159	13%	278	0.00	15	$127	100%	24%	55%	1	24%	20%	92.7%	59.7%	72.9%	12.4
685	Cooling	Air Conditioner - 17 IEER (5-20 Tons)	Biz-Prescriptive	Health	ROB	2,159	2,159	28%	610	0.00	15	$127	100%	24%	55%	1	24%	20%	92.7%	76.6%	81.7%	27.3
686	Cooling	Air Conditioner - 21 IEER (5-20 Tons)	Biz-Prescriptive	Health	ROB	2,159	2,159	42%	905	0.00	15	$127	100%	24%	55%	1	24%	20%	92.7%	80.6%	84.8%	40.5
687	Cooling	Air Conditioner - 12.1 IEER (20+ Tons)	Biz-Prescriptive	Health	ROB	2,311	2,311	6%	134	0.00	15	$30	100%	100%	100%	2	24%	20%	92.7%	92.7%	92.7%	6.0
688	Cooling	Air Conditioner - 13 IEER (20+ Tons)	Biz-Prescriptive	Health	ROB	2,311	2,311	12%	284	0.00	15	$37	100%	81%	81%	2	24%	20%	92.7%	89.6%	89.6%	12.7
689	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz-Prescriptive	Health	ROB	2,311	2,311	20%	469	0.00	15	$37	100%	81%	81%	2	24%	20%	92.7%	90.9%	90.9%	21.0
690	Cooling	Air Conditioner - 21 IEER (20+ Tons)	Biz-Prescriptive	Health	ROB	2,311	2,311	46%	1,056	0.00	15	$37	100%	81%	81%	2	24%	20%	92.7%	91.9%	91.9%	47.3
691	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz-Custom	Health	Retro	2,195	2,195	7%	154	0.00	3	$5	100%	50%	50%	3	48%	50%	92.7%	72.4%	72.4%	18.3
692	Cooling	Air Side Economizer	Biz-Custom	Health	Retro	2,159	2,159	20%	432	0.00	10	$84	100%	50%	50%	4	48%	20%	92.7%	65.1%	65.1%	4.0
693	Cooling	Advanced Rooftop Controls	Biz-Prescriptive	Health	Retro	2,195	2,195	0%	0	0.00	10	$100	0%		100%	5	48%	20%	92.7%	92.7%	92.7%	0.0
694	Cooling	HVAC Occupancy Controls	Biz-Custom	Health	ROB	1,150	1,150	20%	230	0.00	15	$537	100%	4%	4%	6	48%	20%	92.7%	36.0%	36.0%	25.5
695	Cooling	Air Conditioner - 16 SEER (<5 Tons)	Biz-Prescriptive	Health	ROB	1,882	1,882	13%	235	0.00	15	$47	100%	64%	80%	7	0%	20%	92.7%	83.8%	87.7%	10.5
696	Cooling	Air Conditioner - 17 SEER (<5 Tons)	Biz-Prescriptive	Health	ROB	1,882	1,882	18%	332	0.00	15	$206	100%	15%	36%	7	0%	20%	92.7%	50.5%	55.3%	14.9
697	Cooling	Air Conditioner - 18 SEER(<5 Tons)	Biz-Prescriptive	Health	ROB	1,882	1,882	22%	418	0.00	15	$206	100%	15%	36%	7	0%	20%	92.7%	54.3%	63.1%	18.7
698	Cooling	Air Conditioner - 21 SEER(<5 Tons)	Biz-Prescriptive	Health	ROB	1,882	1,882	33%	627	0.00	15	$253	100%	12%	30%	7	0%	20%	92.7%	59.2%	66.0%	28.1
699	Cooling	Smart Thermostat	Biz-Prescriptive	Health	ROB	1,882	1,882	14%	266	0.00	11	$175	100%	57%	57%	8	0%	12%	92.7%	66.2%	66.2%	1.9
700	Cooling	PTAC - <7,000 Btuh - lodging	Biz-Prescriptive	Health	ROB	2,214	2,214	8%	187	0.00	8	$84	100%	36%	55%	9	0%	20%	92.7%	65.6%	73.2%	4.6
701	Cooling	PTAC - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Health	ROB	2,428	2,428	7%	176	0.00	8	$84	100%	36%	55%	10	0%	20%	92.7%	63.9%	72.3%	4.4
702	Cooling	PTAC - >15,000 Btuh - lodging	Biz-Prescriptive	Health	ROB	2,773	2,773	10%	264	0.00	8	$84	100%	36%	55%	11	0%	20%	92.7%	73.0%	77.8%	6.5
703	Cooling	Air Cooled Chiller	Biz-Prescriptive	Health	ROB	1,923	1,923	6%	108	0.00	23	$126	100%	24%	55%	12	52%	15%	92.7%	39.5%	50.7%	8.0
704	Cooling	Chiller Tune-up	Biz-Prescriptive	Health	Retro	2,195	2,195	7%	154	0.00	3	$8	100%	100%	100%	13	52%	50%	92.7%	92.7%	92.7%	6.1
705	Cooling	HVAC/Chiller Custom	Biz-Custom	Health	Retro	5	5	20%	1	0.00	20	$1	100%	7%	7%	14	100%	20%	92.7%	36.0%	36.0%	30.3
706	Cooling	Window Film	Biz-Prescriptive	Health	Retro	6,000	6,000	4%	264	0.00	10	$154	100%	65%	65%	15	100%	20%	92.7%	73.1%	73.1%	3.2
707	Cooling	Triple Pane Windows	Biz-Custom	Health	ROB	6,000	6,000	6%	360	0.00	25	$700	100%	5%	5%	15	100%	20%	92.7%	36.0%	36.0%	24.5
708	Cooling	Energy Recovery Ventilator	Biz-Custom	Health	Retro	2,311	2,311	43%	1,003	0.00	15	$1,500	100%	7%	7%	16	100%	2%	92.7%	24.5%	24.5%	21.3
709	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz-Prescriptive	Health	ROB	3,186	3,186	4%	142	0.00	16	$87	100%	46%	55%	1	0%	20%	92.7%	61.4%	66.7%	3.8
710	Heating	Heat Pump - 17 SEER (<5 Tons)	Biz-Prescriptive	Health	ROB	3,186	3,186	9%	298	0.00	16	$442	50%	9%	23%	1	0%	20%	44.0%	36.0%	36.0%	7.6
711	Heating	Heat Pump - 18 SEER(<5 Tons)	Biz-Prescriptive	Health	ROB	3,186	3,186	13%	425	0.00	16	$507	75%	8%	20%	1	0%	20%	64.7%	36.0%	38.4%	10.7
712	Heating	Heat Pump - 21 SEER(<5 Tons)	Biz-Prescriptive	Health	ROB	3,186	3,186	21%	673	0.00	16	$507	100%	8%	20%	1	0%	20%	92.7%	44.8%	47.9%	17.1
713	Heating	Geothermal HP - SEER 20.3 (<5 Tons)	Biz-Prescriptive	Health	ROB	3,186	3,186	23%	744	0.00	25	$2,576	25%	2%	4%	1	0%	20%	44.0%	36.0%	36.0%	25.0
714	Heating	Geothermal HP - SEER 21.5 (<5 Tons)	Biz-Prescriptive	Health	ROB	3,186	3,186	28%	881	0.00	25	$2,576	25%	2%	4%	1	0%	20%	44.0%	36.0%	36.0%	29.1
715	Heating	Geothermal HP - SEER 23.1 (<5 Tons)	Biz-Prescriptive	Health	ROB	3,186	3,186	33%	1,040	0.00	25	$2,576	50%	2%	4%	1	0%	20%	44.0%	36.0%	36.0%	33.7
716	Heating	Geothermal HP - SEER 29.3 (<5 Tons)	Biz-Prescriptive	Health	ROB	3,186	3,186	47%	1,502	0.00	25	$2,576	50%	2%	4%	1	0%	20%	44.0%	36.0%	36.0%	45.0
717	Heating	Heat Pump - 14.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Health	ROB	3,871	3,871	12%	453	0.00	16	$100	100%	40%	55%	2	25%	20%	92.7%	78.7%	81.2%	35.1
718	Heating	Heat Pump - 15.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Health	ROB	3,871	3,871	17%	659	0.00	16	$136	100%	30%	55%	2	25%	20%	92.7%	77.7%	81.8%	40.1
719	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Health	ROB	4,038	4,038	16%	642	0.00	16	$100	100%	40%	55%	2	25%	20%	92.7%	81.7%	84.0%	40.9
720	Heating	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Health	ROB	4,038	4,038	21%	845	0.00	16	$139	100%	29%	55%	2	25%	20%	92.7%	79.9%	83.5%	45.7

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
721	Heating	Geothermal HP - SEER 20.3 (5-20 Tons)	Biz-Prescriptive	Health	ROB	3,518	3,518	31%	1,077	0.00	25	$2,576	50%	2%	4%	2	25%	20%	44.0%	36.0%	36.0%	47.3
722	Heating	Geothermal HP - SEER 21.5 (5-20 Tons)	Biz-Prescriptive	Health	ROB	3,518	3,518	34%	1,213	0.00	25	$2,576	75%	2%	4%	2	25%	20%	50.5%	36.0%	36.0%	51.4
723	Heating	Geothermal HP - SEER 23.1 (5-20 Tons)	Biz-Prescriptive	Health	ROB	3,796	3,796	43%	1,650	0.00	25	$2,576	75%	2%	4%	2	25%	20%	55.8%	36.0%	36.0%	62.0
724	Heating	Geothermal HP - SEER 29.3 (5-20 Tons)	Biz-Prescriptive	Health	ROB	3,796	3,796	56%	2,112	0.00	25	$2,576	100%	2%	4%	2	25%	20%	92.7%	36.0%	36.0%	73.3
725	Heating	Variable Refrigerant Flow Heat Pump	Biz-Custom	Health	ROB	3,014	3,014	17%	502	0.00	16	$224	100%	22%	22%	2	25%	2%	92.7%	48.0%	48.0%	11.6
726	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz-Prescriptive	Health	ROB	4,261	4,261	10%	439	0.00	16	$100	100%	40%	55%	3	25%	20%	92.7%	78.3%	81.0%	31.6
727	Heating	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	Biz-Prescriptive	Health	ROB	4,261	4,261	16%	699	0.00	16	$175	100%	23%	55%	3	25%	20%	92.7%	73.9%	80.2%	38.3
728	Heating	Geothermal HP - SEER 20.3 (20+ Tons)	Biz-Prescriptive	Health	ROB	4,038	4,038	40%	1,597	0.00	25	$2,576	100%	2%	4%	3	25%	20%	92.7%	36.0%	36.0%	86.9
729	Heating	Geothermal HP - SEER 21.5 (20+ Tons)	Biz-Prescriptive	Health	ROB	4,038	4,038	43%	1,733	0.00	25	$2,576	100%	2%	4%	3	25%	20%	92.7%	36.0%	36.0%	90.9
730	Heating	Geothermal HP - SEER 23.1 (20+ Tons)	Biz-Prescriptive	Health	ROB	4,038	4,038	47%	1,893	0.00	25	$2,576	100%	2%	4%	3	25%	20%	92.7%	36.0%	36.0%	95.6
731	Heating	Geothermal HP - SEER 29.3 (20+ Tons)	Biz-Prescriptive	Health	ROB	4,038	4,038	58%	2,355	0.00	25	$2,576	100%	2%	4%	3	25%	20%	92.7%	36.2%	36.7%	106.9
732	Heating	Mini Split Ductless Heat Pump Cold Climate (Tiers & sizes TBD)	Biz-Prescriptive	Health	ROB	3,186	3,186	21%	673	0.00	16	$224	100%	18%	45%	4	50%	20%	92.7%	67.0%	74.6%	17.1
733	Heating	PTHP - <7,000 Btuh - lodging	Biz-Custom	Health	ROB	3,474	3,474	5%	180	0.00	8	$130	100%	100%	100%	5	0%	10%	92.7%	74.2%	74.2%	1.0
734	Heating	PTHP - >15,000 Btuh - lodging	Biz-Prescriptive	Health	ROB	4,311	4,311	20%	860	0.00	8	$130	100%	100%	100%	6	0%	10%	92.7%	92.7%	92.7%	4.7
735	Heating	PTHP - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Health	ROB	3,842	3,842	12%	446	0.00	8	$130	100%	100%	100%	7	0%	10%	92.7%	92.7%	92.7%	2.4
736	HotWater	Heat Pump Water Heater	Biz-Prescriptive	Health	ROB	6,995	6,995	67%	4,684	0.00	15	$1,115	100%	45%	55%	1	100%	14%	84.0%	76.3%	78.2%	7.8
737	HotWater	Hot Water Pipe Insulation	Biz-Custom	Health	Retro	6,995	6,995	2%	140	0.00	20	$60	100%	23%	23%	2	100%	80%	86.0%	84.0%	84.0%	9.8
738	HotWater	Faucet Aerator	Biz-Custom	Health	Retro	2,017	2,017	33%	657	0.00	10	$14	100%	50%	50%	3	20%	90%	93.0%	92.0%	92.0%	50.4
739	HotWater	Low Flow Pre-Rinse Sprayers	Biz-Prescriptive	Health	ROB	18,059	18,059	54%	9,789	0.00	5	$60	100%	17%	42%	4	20%	80%	86.0%	84.0%	84.0%	199.3
740	HotWater	ENERGY STAR Commercial Washing Machines	Biz-Prescriptive	Health	ROB	1,552	1,552	43%	671	0.00	7	$250	75%	28%	28%	5	25%	33%	79.3%	64.6%	64.6%	2.9
741	InteriorLighting	LED T8 Tube Replacement	Biz-Prescriptive Light	Health	Retro	225	225	45%	101	0.00	9	$5	100%	100%	100%	1	78%	40%	94.6%	94.6%	94.6%	10.1
742	InteriorLighting	LED troffer retrofit kit, 2'X2' and 2'X4'	Biz-Prescriptive Light	Health	Retro	509	509	50%	255	0.00	9	$70	100%	36%	55%	1	78%	40%	94.6%	77.5%	83.2%	5.1
743	InteriorLighting	LED troffer, 2'X2' and 2'X4'	Biz-Prescriptive Light	Health	Retro	509	509	50%	255	0.00	9	$70	100%	36%	55%	1	78%	40%	94.6%	77.5%	83.2%	5.1
744	InteriorLighting	Bi-Level Lighting Fixture – Stairwells, Hallways	Biz-Custom Light	Health	Retro	509	509	74%	378	0.00	10	$274	50%	14%	18%	2	1%	40%	58.0%	52.0%	52.0%	4.3
745	InteriorLighting	LED high bay fixture	Biz-Prescriptive Light	Health	Retro	4,737	4,737	68%	3,223	0.00	9	$330	100%	35%	55%	3	5%	34%	94.6%	89.1%	90.8%	14.1
746	InteriorLighting	LED Mogul-base HID Lamp Replacing High Bay HID	Biz-Prescriptive Light	Health	Retro	4,737	4,737	66%	3,143	0.00	9	$330	100%	35%	55%	3	5%	34%	94.6%	88.9%	90.7%	13.7
747	InteriorLighting	LED low bay fixture	Biz-Prescriptive Light	Health	Retro	1,009	1,009	61%	613	0.00	9	$44	100%	68%	80%	4	12%	34%	94.6%	92.7%	93.4%	10.3
748	InteriorLighting	LED Mogul-base HID Lamp Replacing Low Bay HID	Biz-Prescriptive Light	Health	Retro	1,009	1,009	59%	592	0.00	9	$44	100%	68%	80%	4	12%	34%	94.6%	92.6%	93.3%	9.9
749	InteriorLighting	LED Screw-In Lamps (Directional)	Biz-Prescriptive Light	Health	ROB	385	385	86%	331	0.00	3	$1	100%	100%	100%	6	0%	43%	94.6%	94.6%	94.6%	65.4
750	InteriorLighting	LED downlight fixture	Biz-Prescriptive Light	Health	Retro	349	349	68%	236	0.00	9	$27	100%	19%	46%	6	4%	45%	94.6%	86.5%	89.5%	23.7
751	InteriorLighting	LED Screw-In Lamps (Omnidirectional & Decorative)	Biz-Prescriptive Light	Health	ROB	291	291	81%	236	0.00	3	$1	100%	100%	100%	5	1%	20%	94.6%	94.6%	94.6%	46.6
752	InteriorLighting	DeLamp Fluorescent Fixture Average Lamp Wattage 28W	Biz-Prescriptive Light	Health	Retro	187	187	100%	187	0.00	11	$4	100%	100%	100%	7	78%	0%	94.6%	94.6%	94.6%	27.9
753	InteriorLighting	Occupancy Sensors	Biz-Prescriptive Light	Health	Retro	855	855	30%	257	0.00	10	$65	100%	31%	55%	8	95%	10%	94.6%	77.5%	84.2%	5.5
754	InteriorLighting	Daylighting Controls	Biz-Prescriptive Light	Health	Retro	1,095	1,095	30%	329	0.00	10	$58	100%	35%	55%	8	95%	10%	94.6%	84.3%	88.1%	10.2
755	InteriorLighting	Dual Occupancy & Daylighting Controls	Biz-Custom Light	Health	Retro	489	489	44%	215	0.00	10	$75	100%	40%	50%	8	95%	10%	94.6%	59.2%	62.2%	3.9
756	InteriorLighting	Central Lighting Monitoring & Controls (non-networked)	Biz-Custom Light	Health	Retro	41,703	41,703	20%	8,341	0.00	12	$3,700	100%	23%	29%	8	95%	10%	94.6%	44.1%	47.7%	4.6
757	InteriorLighting	Network Lighting Controls - Wireless (WiFi)	Biz-Custom Light	Health	Retro	4	4	49%	2	0.00	15	$0	100%	49%	50%	8	95%	10%	94.6%	68.3%	68.5%	7.8
758	InteriorLighting	Luminaire Level Lighting Controls w/ HVAC Control	Biz-Custom Light	Health	Retro	489	489	65%	318	0.00	15	$90	100%	35%	46%	8	96%	10%	94.6%	61.4%	64.0%	7.8
759	InteriorLighting	LED Exit Sign - 4 Watt Fixture (2 lamp)	Biz-Prescriptive Light	Health	Retro	70	70	43%	30	0.00	5	$33	92%	92%	92%	9	1%	75%	87.6%	87.6%	87.6%	0.3
760	InteriorLighting	Lighting - Custom	Biz-Custom Light	Health	Retro	4	4	25%	1	0.00	15	$0	100%	25%	32%	10	100%	0%	94.6%	49.2%	52.8%	7.8
761	ExteriorLighting	LED wallpack (existing W<250)	Biz-Prescriptive Light	Health	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	1	12%	46%	94.6%	56.6%	70.8%	5.8
762	ExteriorLighting	LED parking lot fixture (existing W≥250)	Biz-Prescriptive Light	Health	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	2	11%	54%	67.8%	63.2%	63.2%	4.4
763	ExteriorLighting	LED parking lot fixture (existing W<250)	Biz-Prescriptive Light	Health	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	3	11%	54%	94.6%	63.2%	70.8%	5.8
764	ExteriorLighting	LED outdoor pole decorative fixture (existing W≥250)	Biz-Prescriptive Light	Health	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	17%	17%	4	11%	54%	67.8%	63.2%	63.2%	3.4
765	ExteriorLighting	LED parking garage fixture (existing W≥250)	Biz-Prescriptive Light	Health	Retro	3,235	3,235	60%	1,953	0.00	6	$756	50%	13%	33%	5	11%	69%	78.3%	75.2%	75.2%	4.7
766	ExteriorLighting	LED parking garage fixture (existing W<250)	Biz-Prescriptive Light	Health	Retro	1,742	1,742	66%	1,154	0.00	6	$248	100%	18%	45%	6	11%	69%	94.6%	77.6%	83.9%	6.2
767	ExteriorLighting	LED Mogul-base HID Lamp Replacing Exterior HID (existing W≥250)	Biz-Prescriptive Light	Health	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	7	11%	46%	62.1%	56.6%	56.6%	4.4
768	ExteriorLighting	LED Mogul-base HID Lamp Replacing Exterior HID (existing W<250)	Biz-Prescriptive Light	Health	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	8	11%	46%	94.6%	56.6%	70.8%	5.8
769	ExteriorLighting	Bi-Level Lighting Fixture – Garages	Biz-Custom Light	Health	Retro	509	509	69%	351	0.00	10	$274	25%	13%	17%	9	11%	20%	44.0%	36.0%	36.0%	3.9
770	ExteriorLighting	LED fuel pump canopy fixture (existing W<250)	Biz-Prescriptive Light	Health	Retro	0	0	0%	0	0.00	12	$0	0%	0%		10	0%	54%	94.6%	94.6%	94.6%	0.0
771	ExteriorLighting	LED fuel pump canopy fixture (existing W≥250)	Biz-Prescriptive Light	Health	Retro	0	0	0%	0	0.00	12	$0	0%	0%		11	0%	54%	94.6%	94.6%	94.6%	0.0
772	Miscellaneous	Vending Machine Controller - Non-Refrigerated	Biz-Prescriptive	Health	Retro	385	385	61%	237	0.00	5	$233	11%	11%	11%	1	5%	30%	51.0%	44.0%	44.0%	1.9
773	Miscellaneous	Miscellaneous Custom	Biz-Custom	Health	Retro	7	7	2%	0	0.00	10	$0	75%	25%	25%	2	0%	10%	37.0%	23.4%	23.4%	3.3
774	Miscellaneous	Kitchen Exhaust Hood Demand Ventilation Control System	Biz-Prescriptive	Health	ROB	9,932	9,932	50%	4,966	0.00	20	$1,180	100%	11%	27%	3	28%	10%	94.6%	73.8%	78.0%	39.7
775	Miscellaneous	High Efficiency Hand Dryers	Biz-Custom	Health	Retro	1,909	1,909	83%	1,585	0.00	10	$483	100%	33%	33%	4	5%	10%	94.6%	59.6%	59.6%	6.3
776	Miscellaneous	Ozone Commercial Laundry	Biz-Custom	Health	Retro	2,984	2,984	25%	746	0.00	10	$20,310	0%	0%	0%	5	2%	2%	31.4%	16.6%	16.6%	3.9
777	Miscellaneous	ENERGY STAR Uninterrupted Power Supply	Biz-Custom	Health	ROB	3,096	3,096	3%	85	0.00	15	$59	100%	14%	14%	6	0%	70%	94.6%	76.0%	76.0%	8.8
778	Motors	Cogged V-Belt	Biz-Custom	Health	Retro	17,237	17,237	3%	534	0.00	15	$384	100%	14%	14%	1	50%	10%	83.4%	32.2%	32.2%	9.2
779	Motors	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz-Custom	Health	Retro	1,902	1,902	38%	731	0.00	15	$200	100%	30%	30%	2	100%	10%	83.4%	52.4%	52.4%	11.6
780	Motors	Power Drive Systems	Biz-Custom	Health	Retro	4	4	23%	1	0.00	15	$0	100%	37%	37%	2	100%	10%	83.4%	53.4%	53.4%	9.2
781	Motors	Switch Reluctance Motors	Biz-Custom	Health	Retro	33,406	33,406	31%	10,222	0.00	15	$528	100%	50%	50%	2	100%	1%	83.4%	64.1%	64.1%	26.3
782	Motors	Escalators Motor Efficiency Controllers	Biz-Custom	Health	Retro	7,500	7,500	20%	1,500	0.00	10	$5,000	3%	3%	3%	3	0%	10%	37.0%	26.3%	26.3%	7.3
783	Office_NonPC	Energy Star Printer/Copier/Fax	Biz-Custom	Health	ROB	551	551	40%	223	0.00	6	$0	0%			1	5%	90%	94.6%	92.0%	92.0%	0.0
784	Office_NonPC	Smart Power Strip – Commercial Use	Biz-Custom	Health	Retro	1,086	1,086	10%	109	0.00	7	$50	50%	22%	22%	2	35%	15%	71.8%	42.0%	42.0%	2.8
785	Office_NonPC	Plug Load Occupancy Sensor	Biz-Custom	Health	Retro	1,126	1,126	15%	169	0.00	8	$70	75%	24%	24%	2	35%	15%	85.4%	47.6%	47.6%	3.2
786	Office_PC	Electrically Commutated Plug Fans in data centers	Biz-Custom	Health	Retro	86,783	86,783	18%	15,778	0.00	15	$480	100%	50%	50%	1	65%	20%	94.6%	74.6%	74.6%	50.8
787	Office_PC	Energy Star Server	Biz-Custom	Health	ROB	1,621	1,621	23%	368	0.00	8	$118	100%	31%	31%	1	65%	25%	94.6%	58.2%	58.2%	4.5
788	Office_PC	Server Virtualization	Biz-Custom	Health	Retro	2	2	45%	1	0.00	8	$0	75%	25%	25%	1	65%	25%	85.8%	49.3%	49.3%	3.2
789	Office_PC	High Efficiency CRAC unit	Biz-Custom	Health	ROB	541	541	30%	162	0.00	15	$63	100%	26%	26%	2	65%	20%	94.6%	51.1%	51.1%	8.1
790	Office_PC	Computer Room Air Conditioner Economizer	Biz-Custom	Health	Retro	764	764	47%	358	0.00	15	$82	100%	44%	44%	2	65%	20%	94.6%	66.1%	66.1%	5.6
791	Office_PC	Data Center Hot/Cold Aisle Configuration	Biz-Custom	Health	Retro	4	4	25%	1	0.00	15	$0	100%	25%	25%	3	3%	10%	94.6%	49.3%	49.3%	7.7
792	Office_PC	Energy Star Laptop	Biz-Custom	Health	ROB	126	126	33%	41	0.00	4	$0	0%			4	11%	85%	94.6%	88.0%	88.0%	0.0

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
793	Office_PC	Energy Star Monitor	Biz-Custom	Health	ROB	72	72	21%	15	0.00	4	$0	0%			5	25%	85%	94.6%	88.0%	88.0%	0.0
794	Refrigeration	Strip Curtains	Biz-Custom	Health	Retro	0	0	0%	0	0.00	4	$0	0%	0%		1	5%	30%	88.0%	70.4%	70.4%	0.0
795	Refrigeration	Bare Suction Line	Biz-Custom	Health	Retro	23	23	93%	21	0.00	15	$4	100%	50%	50%	2	0%	50%	88.0%	66.5%	66.5%	8.1
796	Refrigeration	Floating Head Pressure Controls	Biz-Custom	Health	Retro	1,112	1,112	25%	278	0.00	15	$431	25%	6%	6%	3	4%	25%	47.5%	40.0%	40.0%	5.6
797	Refrigeration	Saturated Suction Controls	Biz-Custom	Health	Retro	831	831	50%	416	0.00	15	$559	100%	7%	7%	4	2%	10%	88.0%	28.0%	28.0%	13.7
798	Refrigeration	Compressor Retrofit	Biz-Custom	Health	Retro	813	813	20%	163	0.00	15	$477	25%	3%	3%	5	12%	25%	47.5%	39.4%	39.4%	13.8
799	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz-Prescriptive	Health	Retro	2,440	2,440	65%	1,586	0.00	15	$305	100%	13%	33%	6	3%	80%	88.0%	84.0%	84.0%	30.7
800	Refrigeration	Evaporator Fan Motor Controls	Biz-Custom	Health	Retro	1,912	1,912	25%	478	0.00	13	$162	100%	30%	30%	7	3%	25%	88.0%	61.7%	61.7%	7.0
801	Refrigeration	Variable Speed Condenser Fan	Biz-Custom	Health	Retro	2,960	2,960	50%	1,480	0.00	15	$1,170	50%	13%	13%	8	5%	25%	59.5%	40.0%	40.0%	5.6
802	Refrigeration	Refrigeration Economizer	Biz-Custom	Health	Retro	7	7	2%	0	0.00	10	$0	100%	50%	50%	9	17%	10%	88.0%	41.1%	41.1%	4.2
803	Refrigeration	Anti-Sweat Heater Controls MT	Biz-Prescriptive	Health	Retro	579	579	59%	338	0.00	10	$170	75%	44%	44%	10	17%	25%	81.8%	72.4%	72.4%	2.1
804	Refrigeration	Auto Door Closer, Cooler	Biz-Custom	Health	Retro	471,500	471,500	0%	943	0.00	8	$157	100%	50%	50%	11	13%	50%	88.0%	66.9%	66.9%	5.8
805	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz-Custom	Health	Retro	1,584	1,584	36%	578	0.00	12	$686	50%	8%	8%	11	5%	25%	47.9%	40.0%	40.0%	7.1
806	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz-Prescriptive	Health	Retro	2,440	2,440	65%	1,586	0.00	15	$305	100%	13%	33%	12	3%	80%	88.0%	84.0%	84.0%	30.7
807	Refrigeration	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	Biz-Custom	Health	Retro	1,911	1,911	26%	504	0.00	10	$96	100%	50%	50%	12	3%	2%	88.0%	66.5%	66.5%	5.8
808	Refrigeration	Energy Star Reach-In Refrigerator, Glass Doors	Biz-Prescriptive	Health	ROB	2,140	2,140	29%	629	0.00	12	$1,239	25%	6%	14%	13	17%	54%	67.8%	63.2%	63.2%	5.6
809	Refrigeration	Energy Star Reach-In Refrigerator, Solid Doors	Biz-Prescriptive	Health	ROB	1,410	1,410	20%	281	0.00	12	$1,211	6%	6%	6%	14	17%	54%	67.8%	63.2%	63.2%	2.5
810	Refrigeration	Anti-Sweat Heater Controls LT	Biz-Prescriptive	Health	Retro	2,016	2,016	68%	1,361	0.00	10	$170	100%	44%	55%	15	6%	25%	88.0%	84.3%	85.0%	8.3
811	Refrigeration	Auto Door Closer, Freezer	Biz-Custom	Health	Retro	419,455	419,455	1%	2,307	0.00	8	$157	100%	50%	50%	16	6%	50%	88.0%	68.9%	68.9%	13.9
812	Refrigeration	Display Case Door Retrofit, Low Temp	Biz-Custom	Health	Retro	2,922	2,922	50%	1,453	0.00	12	$686	100%	21%	21%	16	6%	25%	88.0%	49.7%	49.7%	7.1
813	Refrigeration	Energy Star Reach-In Freezer, Glass Doors	Biz-Prescriptive	Health	ROB	6,374	6,374	20%	1,275	0.00	12	$1,651	25%	21%	21%	17	6%	54%	67.8%	63.2%	63.2%	2.3
814	Refrigeration	Energy Star Reach-In Freezer, Solid Doors	Biz-Prescriptive	Health	ROB	4,522	4,522	7%	305	0.00	12	$1,521	23%	23%	23%	18	6%	54%	67.8%	63.2%	63.2%	0.5
815	Refrigeration	Refrigeration - Custom	Biz-Custom	Health	ROB	7	7	2%	0	0.00	10	$0	75%	25%	25%	19	90%	25%	47.5%	39.4%	39.4%	3.3
816	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz-Custom RCx	Health	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	20	90%	25%	88.0%	65.9%	65.9%	3.2
817	Refrigeration	Energy Star Ice Machine	Biz-Prescriptive	Health	ROB	6,993	6,993	10%	721	0.00	15	$1,426	25%	18%	18%	21	6%	44%	60.8%	55.2%	55.2%	2.1
818	Refrigeration	Vending Machine Controller - Refrigerated	Biz-Prescriptive	Health	Retro	1,586	1,586	34%	537	0.00	5	$245	25%	16%	16%	22	3%	30%	65.5%	61.1%	61.1%	2.7
819	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz-Prescriptive	Health	Retro	273	273	89%	243	0.00	9	$11	100%	45%	55%	23	10%	35%	88.0%	86.7%	86.9%	30.9
820	Refrigeration	LED Refrigerated Display Case Lighting Controls	Biz-Prescriptive	Health	Retro	522	522	27%	141	0.00	10	$15	100%	100%	100%	24	10%	18%	88.0%	88.0%	88.0%	6.6
821	Ventilation	Demand Controlled Ventilation	Biz-Custom	Health	Retro	2,639	2,639	20%	528	0.00	15	$227	100%	23%	23%	1	100%	33%	92.7%	49.3%	49.3%	9.4
822	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz-Prescriptive	Health	Retro	1,902	1,902	38%	731	0.00	15	$200	100%	30%	55%	2	100%	33%	92.7%	74.0%	79.4%	11.6
823	WholeBldg_HVAC	HVAC - Energy Management System	Biz-Custom RCx	Health	Retro	13	13	8%	1	0.00	15	$0	100%	25%	25%	1	100%	20%	92.7%	51.6%	51.6%	8.8
824	WholeBldg_HVAC	Guest room energy management system	Biz-Custom	Health	Retro	0	0	0%	0	0.00	15	$260	0%		0%	2	100%	20%	92.7%	74.2%	74.2%	0.0
825	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz-Custom RCx	Health	Retro	10	10	10%	1	0.00	15	$0	100%	25%	25%	3	100%	0%	92.7%	51.6%	51.6%	8.8
826	WholeBuilding	WholeBlg - Com RET	Biz-Custom	Health	Retro	7	7	15%	1	0.00	12	$0	100%	25%	25%	1	90%	0%	92.7%	51.6%	51.6%	7.3
827	WholeBuilding	WholeBlg - Custom (Other)	Biz-Custom	Health	Retro	5	5	20%	1	0.00	12	$0	100%	25%	25%	2	90%	0%	92.7%	51.6%	51.6%	7.3
828	WholeBuilding	Power Distribution Equipment Upgrades (Transformers)	Biz-Custom	Health	Retro	1,150	1,150	1%	6	0.00	30	$8	100%	9%	9%	3	100%	20%	92.7%	36.0%	36.0%	17.1
829	WholeBldg_NC	WholeBlg - Com NC	Biz-Custom	Health	NC	4	4	25%	1	0.00	12	$0	100%	50%	50%	1	100%	60%	83.4%	68.0%	68.0%	7.6
830	Behavioral	COM Competitions	Biz-Custom	Health	Retro	0	0	0%	0	0.00	2	$0	0%		0%	1	100%	0%	50.0%	50.0%	50.0%	0.0
831	Behavioral	Business Energy Reports	Biz-Custom	Health	Retro	0	0	0%	0	0.00	2	$0	0%		0%	1	100%	0%	50.0%	50.0%	50.0%	0.0
832	Behavioral	Building Benchmarking	Biz-Custom	Health	Retro	114	114	1%	1	0.00	2	$0	45%	45%	45%	1	100%	0%	50.0%	50.0%	50.0%	0.8
833	Behavioral	Strategic Energy Management	Biz-Custom SEM	Health	Retro	33	33	3%	1	0.00	5	$0	75%	37%	37%	1	100%	0%	50.0%	50.0%	50.0%	2.1
834	Behavioral	BEIMS	Biz-Custom	Health	Retro	20	20	5%	1	0.00	2	$0	23%	23%	23%	1	100%	2%	50.0%	50.0%	50.0%	0.8
835	Behavioral	Building Operator Certification	Biz-Custom	Health	Retro	20	20	3%	0	0.00	3	$0	27%	27%	27%	1	100%	2%	50.0%	50.0%	50.0%	1.7
836	CompressedAir	Efficient Air Compressors (VSD)	Biz-Prescriptive	Lodging	ROB	1,583	1,583	21%	329	0.00	13	$127	100%	59%	80%	1	100%	33%	92.7%	76.7%	83.1%	5.5
837	CompressedAir	Efficient Air Nozzles	Biz-Prescriptive	Lodging	Retro	1,480	1,480	50%	740	0.00	15	$50	100%	81%	81%	2	35%	33%	92.7%	91.1%	91.1%	15.8
838	CompressedAir	AODD Pump Controls	Biz-Custom	Lodging	Retro	103,919	103,919	35%	36,372	0.00	10	$1,150	100%	50%	50%	3	10%	33%	92.7%	72.6%	72.6%	38.2
839	CompressedAir	Compressed Air - Custom	Biz-Custom	Lodging	Retro	5	5	20%	1	0.00	10	$0	100%	47%	47%	4	50%	33%	92.7%	64.2%	64.2%	6.0
840	CompressedAir	Retro-commissioning_Compressed Air Optimization	Biz-Custom RCx	Lodging	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	5	50%	33%	92.7%	64.2%	64.2%	3.2
841	Cooking	Commercial Combination Oven (Electric)	Biz-Prescriptive	Lodging	ROB	38,561	38,561	48%	18,432	0.00	12	$16,884	75%	6%	15%	1	18%	53%	77.5%	62.4%	62.4%	14.1
842	Cooking	Commercial Electric Convection Oven	Biz-Prescriptive	Lodging	ROB	12,193	12,193	15%	1,879	0.00	12	$1,706	75%	21%	51%	1	18%	53%	77.6%	62.4%	62.4%	4.4
843	Cooking	Commercial Electric Griddle	Biz-Prescriptive	Lodging	ROB	17,056	17,056	15%	2,596	0.00	12	$3,604	25%	15%	15%	2	14%	17%	41.9%	33.6%	33.6%	2.8
844	Cooking	Commercial Electric Steam Cooker	Biz-Prescriptive	Lodging	ROB	19,549	19,549	67%	13,162	0.00	12	$2,490	100%	24%	55%	3	6%	45%	88.0%	81.1%	83.5%	18.0
845	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz-Prescriptive	Lodging	ROB	39,306	39,306	44%	17,369	0.00	15	$1,000	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	11.7
846	Cooking	Dishwasher High Temp Door (Energy Star)	Biz-Prescriptive	Lodging	ROB	26,901	26,901	32%	8,586	0.00	15	$1,100	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	5.2
847	Cooking	Energy efficient electric fryer	Biz-Prescriptive	Lodging	ROB	18,955	18,955	17%	3,274	0.00	12	$1,500	100%	5%	13%	5	27%	24%	88.0%	57.2%	59.4%	23.2
848	Cooking	Insulated Holding Cabinets (Full Size)	Biz-Prescriptive	Lodging	ROB	13,697	13,697	68%	9,314	0.00	12	$1,200	100%	35%	55%	6	3%	16%	88.0%	83.6%	84.9%	12.7
849	Cooking	Insulated Holding Cabinets (Half-Size)	Biz-Prescriptive	Lodging	ROB	4,383	4,383	60%	2,630	0.00	12	$1,500	100%	10%	25%	6	3%	16%	88.0%	52.6%	57.6%	10.1
850	Cooling	Air Conditioner - 13 IEER (5-20 Tons)	Biz-Prescriptive	Lodging	ROB	1,391	1,391	6%	86	0.00	15	$63	100%	48%	55%	1	12%	20%	92.7%	56.3%	61.5%	5.1
851	Cooling	Air Conditioner - 14 IEER (5-20 Tons)	Biz-Prescriptive	Lodging	ROB	1,391	1,391	13%	179	0.00	15	$127	100%	24%	55%	1	12%	20%	92.7%	50.1%	62.6%	10.6
852	Cooling	Air Conditioner - 17 IEER (5-20 Tons)	Biz-Prescriptive	Lodging	ROB	1,391	1,391	28%	393	0.00	15	$127	100%	24%	55%	1	12%	20%	92.7%	69.5%	77.6%	23.3
853	Cooling	Air Conditioner - 21 IEER (5-20 Tons)	Biz-Prescriptive	Lodging	ROB	1,391	1,391	42%	583	0.00	15	$127	100%	24%	55%	1	12%	20%	92.7%	76.0%	81.3%	34.5
854	Cooling	Air Conditioner - 12.1 IEER (20+ Tons)	Biz-Prescriptive	Lodging	ROB	1,488	1,488	6%	86	0.00	15	$30	100%	100%	100%	2	12%	20%	92.7%	92.7%	92.7%	5.1
855	Cooling	Air Conditioner - 13 IEER (20+ Tons)	Biz-Prescriptive	Lodging	ROB	1,488	1,488	12%	183	0.00	15	$37	100%	81%	81%	2	12%	20%	92.7%	87.9%	87.9%	10.9
856	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz-Prescriptive	Lodging	ROB	1,488	1,488	20%	302	0.00	15	$37	100%	81%	81%	2	12%	20%	92.7%	89.8%	89.8%	17.9
857	Cooling	Air Conditioner - 21 IEER (20+ Tons)	Biz-Prescriptive	Lodging	ROB	1,488	1,488	46%	680	0.00	15	$37	100%	81%	81%	2	12%	20%	92.7%	91.4%	91.4%	40.3
858	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz-Custom	Lodging	Retro	1,414	1,414	7%	99	0.00	3	$5	100%	50%	50%	3	25%	50%	92.7%	71.5%	71.5%	15.8
859	Cooling	Air Side Economizer	Biz-Custom	Lodging	Retro	1,391	1,391	20%	278	0.00	10	$84	100%	33%	33%	4	25%	20%	92.7%	58.6%	58.6%	3.9
860	Cooling	Advanced Rooftop Controls	Biz-Prescriptive	Lodging	Retro	1,414	1,414	0%	0	0.00	10	$100	0%		100%	5	25%	20%	92.7%	92.7%	92.7%	0.0
861	Cooling	HVAC Occupancy Controls	Biz-Custom	Lodging	ROB	9,967	9,967	20%	1,993	0.00	15	$537	100%	37%	37%	6	25%	20%	92.7%	60.6%	60.6%	10.1
862	Cooling	Air Conditioner - 16 SEER (<5 Tons)	Biz-Prescriptive	Lodging	ROB	1,212	1,212	13%	152	0.00	15	$47	100%	64%	80%	7	0%	20%	92.7%	80.3%	85.0%	9.0
863	Cooling	Air Conditioner - 17 SEER (<5 Tons)	Biz-Prescriptive	Lodging	ROB	1,212	1,212	18%	214	0.00	15	$206	100%	15%	36%	7	0%	20%	92.7%	40.7%	47.6%	12.7
864	Cooling	Air Conditioner - 18 SEER(<5 Tons)	Biz-Prescriptive	Lodging	ROB	1,212	1,212	22%	269	0.00	15	$206	100%	15%	36%	7	0%	20%	92.7%	46.1%	52.0%	16.0

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
865	Cooling	Air Conditioner - 21 SEER(<5 Tons)	Biz-Prescriptive	Lodging	ROB	1,212	1,212	33%	404	0.00	15	$253	100%	12%	30%	7	0%	20%	92.7%	49.8%	53.7%	23.9
866	Cooling	Smart Thermostat	Biz-Prescriptive	Lodging	ROB	1,212	1,212	14%	172	0.00	11	$175	75%	57%	57%	8	0%	12%	68.8%	53.8%	53.8%	1.5
867	Cooling	PTAC - <7,000 Btuh - lodging	Biz-Prescriptive	Lodging	ROB	1,426	1,426	8%	121	0.00	8	$84	100%	36%	55%	9	25%	20%	92.7%	53.4%	63.2%	3.9
868	Cooling	PTAC - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Lodging	ROB	1,564	1,564	7%	114	0.00	8	$84	100%	36%	55%	10	25%	20%	92.7%	52.5%	61.3%	3.7
869	Cooling	PTAC - >15,000 Btuh - lodging	Biz-Prescriptive	Lodging	ROB	1,786	1,786	10%	170	0.00	8	$84	100%	36%	55%	11	25%	20%	92.7%	62.8%	71.6%	5.5
870	Cooling	Air Cooled Chiller	Biz-Prescriptive	Lodging	ROB	1,239	1,239	6%	69	0.00	23	$126	100%	24%	55%	12	50%	15%	92.7%	32.0%	40.8%	7.0
871	Cooling	Chiller Tune-up	Biz-Prescriptive	Lodging	Retro	1,414	1,414	7%	99	0.00	3	$8	100%	100%	100%	13	50%	50%	92.7%	92.7%	92.7%	5.3
872	Cooling	HVAC/Chiller Custom	Biz-Custom	Lodging	Retro	5	5	20%	1	0.00	20	$1	100%	7%	7%	14	100%	20%	92.7%	36.0%	36.0%	30.3
873	Cooling	Window Film	Biz-Prescriptive	Lodging	Retro	6,000	6,000	4%	264	0.00	10	$154	100%	65%	65%	15	100%	20%	92.7%	73.1%	73.1%	3.2
874	Cooling	Triple Pane Windows	Biz-Custom	Lodging	ROB	6,000	6,000	6%	360	0.00	25	$700	100%	5%	5%	15	100%	20%	92.7%	36.0%	36.0%	24.5
875	Cooling	Energy Recovery Ventilator	Biz-Custom	Lodging	Retro	1,488	1,488	0%	0	0.00	15	$1,500	0%		0%	16	100%	2%	92.7%	74.2%	74.2%	0.0
876	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz-Prescriptive	Lodging	ROB	2,641	2,641	4%	104	0.00	16	$87	100%	46%	46%	1	0%	20%	92.7%	53.3%	53.3%	3.3
877	Heating	Heat Pump - 17 SEER (<5 Tons)	Biz-Prescriptive	Lodging	ROB	2,641	2,641	9%	229	0.00	16	$442	50%	9%	23%	1	0%	20%	44.0%	36.0%	36.0%	6.6
878	Heating	Heat Pump - 18 SEER(<5 Tons)	Biz-Prescriptive	Lodging	ROB	2,641	2,641	12%	329	0.00	16	$507	50%	8%	20%	1	0%	20%	44.0%	36.0%	36.0%	9.3
879	Heating	Heat Pump - 21 SEER(<5 Tons)	Biz-Prescriptive	Lodging	ROB	2,641	2,641	19%	504	0.00	16	$507	100%	8%	20%	1	0%	20%	92.7%	38.9%	41.0%	14.6
880	Heating	Geothermal HP - SEER 20.3 (<5 Tons)	Biz-Prescriptive	Lodging	ROB	2,641	2,641	23%	597	0.00	25	$2,576	25%	2%	4%	1	0%	20%	44.0%	36.0%	36.0%	21.8
881	Heating	Geothermal HP - SEER 21.5 (<5 Tons)	Biz-Prescriptive	Lodging	ROB	2,641	2,641	27%	712	0.00	25	$2,576	25%	2%	4%	1	0%	20%	44.0%	36.0%	36.0%	25.4
882	Heating	Geothermal HP - SEER 23.1 (<5 Tons)	Biz-Prescriptive	Lodging	ROB	2,641	2,641	32%	845	0.00	25	$2,576	25%	2%	4%	1	0%	20%	44.0%	36.0%	36.0%	29.5
883	Heating	Geothermal HP - SEER 29.3 (<5 Tons)	Biz-Prescriptive	Lodging	ROB	2,641	2,641	47%	1,234	0.00	25	$2,576	50%	2%	4%	1	0%	20%	44.0%	36.0%	36.0%	39.2
884	Heating	Heat Pump - 14.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Lodging	ROB	3,184	3,184	11%	349	0.00	16	$100	100%	40%	55%	2	29%	20%	92.7%	75.6%	78.9%	33.5
885	Heating	Heat Pump - 15.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Lodging	ROB	3,184	3,184	16%	516	0.00	16	$136	100%	30%	55%	2	29%	20%	92.7%	74.5%	79.8%	38.0
886	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Lodging	ROB	3,314	3,314	14%	475	0.00	16	$100	100%	40%	55%	2	29%	20%	92.7%	79.1%	81.6%	38.4
887	Heating	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Lodging	ROB	3,314	3,314	19%	640	0.00	16	$139	100%	29%	55%	2	29%	20%	92.7%	77.0%	81.4%	42.7
888	Heating	Geothermal HP - SEER 20.3 (5-20 Tons)	Biz-Prescriptive	Lodging	ROB	2,902	2,902	30%	858	0.00	25	$2,576	50%	2%	4%	2	29%	20%	44.0%	36.0%	36.0%	42.6
889	Heating	Geothermal HP - SEER 21.5 (5-20 Tons)	Biz-Prescriptive	Lodging	ROB	2,902	2,902	34%	972	0.00	25	$2,576	50%	2%	4%	2	29%	20%	44.0%	36.0%	36.0%	46.3
890	Heating	Geothermal HP - SEER 23.1 (5-20 Tons)	Biz-Prescriptive	Lodging	ROB	3,081	3,081	42%	1,285	0.00	25	$2,576	75%	2%	4%	2	29%	20%	51.5%	36.0%	36.0%	54.1
891	Heating	Geothermal HP - SEER 29.3 (5-20 Tons)	Biz-Prescriptive	Lodging	ROB	3,081	3,081	54%	1,673	0.00	25	$2,576	75%	2%	4%	2	29%	20%	56.4%	36.0%	36.0%	63.9
892	Heating	Variable Refrigerant Flow Heat Pump	Biz-Custom	Lodging	ROB	2,460	2,460	13%	323	0.00	16	$224	100%	14%	14%	2	29%	2%	92.7%	38.6%	38.6%	14.8
893	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz-Prescriptive	Lodging	ROB	3,457	3,457	9%	325	0.00	16	$100	100%	40%	55%	3	29%	20%	92.7%	74.6%	78.2%	29.9
894	Heating	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	Biz-Prescriptive	Lodging	ROB	3,457	3,457	15%	529	0.00	16	$175	100%	23%	55%	3	29%	20%	92.7%	68.8%	77.4%	35.8
895	Heating	Geothermal HP - SEER 20.3 (20+ Tons)	Biz-Prescriptive	Lodging	ROB	3,314	3,314	38%	1,270	0.00	25	$2,576	100%	2%	4%	3	29%	20%	92.7%	36.0%	36.0%	79.8
896	Heating	Geothermal HP - SEER 21.5 (20+ Tons)	Biz-Prescriptive	Lodging	ROB	3,314	3,314	42%	1,384	0.00	25	$2,576	100%	2%	4%	3	29%	20%	92.7%	36.0%	36.0%	83.4
897	Heating	Geothermal HP - SEER 23.1 (20+ Tons)	Biz-Prescriptive	Lodging	ROB	3,314	3,314	46%	1,517	0.00	25	$2,576	100%	2%	4%	3	29%	20%	92.7%	36.0%	36.0%	87.5
898	Heating	Geothermal HP - SEER 29.3 (20+ Tons)	Biz-Prescriptive	Lodging	ROB	3,314	3,314	58%	1,906	0.00	25	$2,576	100%	2%	4%	3	29%	20%	92.7%	36.0%	36.0%	97.2
899	Heating	Mini Split Ductless Heat Pump Cold Climate (Tiers & sizes TBD)	Biz-Prescriptive	Lodging	ROB	2,641	2,641	19%	504	0.00	16	$224	100%	18%	45%	4	28%	20%	92.7%	58.3%	69.7%	14.6
900	Heating	PTHP - <7,000 Btuh - lodging	Biz-Custom	Lodging	ROB	2,908	2,908	4%	116	0.00	8	$130	100%	100%	100%	5	5%	10%	92.7%	74.2%	74.2%	0.8
901	Heating	PTHP - >15,000 Btuh - lodging	Biz-Prescriptive	Lodging	ROB	3,512	3,512	16%	554	0.00	8	$130	100%	100%	100%	6	5%	10%	92.7%	92.7%	92.7%	3.9
902	Heating	PTHP - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Lodging	ROB	3,187	3,187	9%	287	0.00	8	$130	100%	100%	100%	7	5%	10%	92.7%	92.7%	92.7%	2.0
903	HotWater	Heat Pump Water Heater	Biz-Prescriptive	Lodging	ROB	6,347	6,347	67%	4,250	0.00	15	$1,115	100%	45%	55%	1	100%	4%	84.0%	75.3%	77.4%	7.0
904	HotWater	Hot Water Pipe Insulation	Biz-Custom	Lodging	Retro	6,347	6,347	2%	127	0.00	20	$60	100%	21%	21%	2	100%	80%	86.0%	84.0%	84.0%	9.8
905	HotWater	Faucet Aerator	Biz-Custom	Lodging	Retro	117	117	32%	38	0.00	10	$8	100%	47%	47%	3	20%	90%	93.0%	92.0%	92.0%	12.1
906	HotWater	Low Flow Pre-Rinse Sprayers	Biz-Prescriptive	Lodging	ROB	18,059	18,059	54%	9,789	0.00	5	$60	100%	17%	42%	4	20%	80%	86.0%	84.0%	84.0%	199.3
907	HotWater	ENERGY STAR Commercial Washing Machines	Biz-Prescriptive	Lodging	ROB	1,552	1,552	43%	671	0.00	7	$250	75%	28%	28%	5	25%	33%	79.3%	64.6%	64.6%	2.9
908	InteriorLighting	LED T8 Tube Replacement	Biz-Prescriptive Light	Lodging	Retro	229	229	45%	103	0.00	8	$5	100%	100%	100%	1	46%	40%	94.6%	94.6%	94.6%	10.4
909	InteriorLighting	LED troffer retrofit kit, 2'X2' and 2'X4'	Biz-Prescriptive Light	Lodging	Retro	519	519	50%	260	0.00	8	$70	100%	36%	55%	1	46%	40%	94.6%	77.9%	83.5%	5.2
910	InteriorLighting	LED troffer, 2'X2' and 2'X4'	Biz-Prescriptive Light	Lodging	Retro	519	519	50%	260	0.00	8	$70	100%	36%	55%	1	46%	40%	94.6%	77.9%	83.5%	5.2
911	InteriorLighting	Bi-Level Lighting Fixture – Stairwells, Hallways	Biz-Custom Light	Lodging	Retro	519	519	74%	386	0.00	10	$274	50%	14%	18%	2	1%	40%	58.0%	52.0%	52.0%	4.3
912	InteriorLighting	LED high bay fixture	Biz-Prescriptive Light	Lodging	Retro	4,832	4,832	68%	3,288	0.00	8	$330	100%	35%	55%	3	6%	34%	94.6%	89.2%	90.8%	14.4
913	InteriorLighting	LED Mogul-base HID Lamp Replacing High Bay HID	Biz-Prescriptive Light	Lodging	Retro	4,832	4,832	66%	3,206	0.00	8	$330	100%	35%	55%	3	6%	34%	94.6%	89.0%	90.7%	14.1
914	InteriorLighting	LED low bay fixture	Biz-Prescriptive Light	Lodging	Retro	1,029	1,029	61%	626	0.00	8	$44	100%	68%	80%	4	5%	34%	94.6%	92.7%	93.4%	10.5
915	InteriorLighting	LED Mogul-base HID Lamp Replacing Low Bay HID	Biz-Prescriptive Light	Lodging	Retro	1,029	1,029	59%	604	0.00	8	$44	100%	68%	80%	4	5%	34%	94.6%	92.6%	93.4%	10.2
916	InteriorLighting	LED Screw-In Lamps (Directional)	Biz-Prescriptive Light	Lodging	ROB	68	68	86%	58	0.00	3	$1	100%	100%	100%	6	0%	43%	94.6%	94.6%	94.6%	42.5
917	InteriorLighting	LED downlight fixture	Biz-Prescriptive Light	Lodging	Retro	356	356	68%	241	0.00	8	$27	100%	19%	46%	6	37%	45%	94.6%	86.7%	89.6%	24.3
918	InteriorLighting	LED Screw-In Lamps (Omnidirectional & Decorative)	Biz-Prescriptive Light	Lodging	ROB	51	51	81%	42	0.00	3	$1	100%	100%	100%	5	6%	20%	94.6%	94.6%	94.6%	30.3
919	InteriorLighting	DeLamp Fluorescent Fixture Average Lamp Wattage 28W	Biz-Prescriptive Light	Lodging	Retro	191	191	100%	191	0.00	11	$4	100%	100%	100%	7	46%	0%	94.6%	94.6%	94.6%	31.6
920	InteriorLighting	Occupancy Sensors	Biz-Prescriptive Light	Lodging	Retro	872	872	30%	262	0.00	10	$65	100%	31%	55%	8	95%	10%	94.6%	77.9%	84.5%	5.6
921	InteriorLighting	Daylighting Controls	Biz-Prescriptive Light	Lodging	Retro	1,117	1,117	30%	335	0.00	10	$58	100%	35%	55%	8	95%	10%	94.6%	84.5%	88.2%	10.4
922	InteriorLighting	Dual Occupancy & Daylighting Controls	Biz-Custom Light	Lodging	Retro	498	498	44%	219	0.00	10	$75	100%	40%	50%	8	95%	10%	94.6%	59.6%	62.5%	4.5
923	InteriorLighting	Central Lighting Monitoring & Controls (non-networked)	Biz-Custom Light	Lodging	Retro	41,703	41,703	20%	8,341	0.00	12	$3,700	100%	23%	29%	8	95%	10%	94.6%	44.1%	47.7%	4.6
924	InteriorLighting	Network Lighting Controls - Wireless (WiFi)	Biz-Custom Light	Lodging	Retro	4	4	49%	2	0.00	15	$1	100%	34%	44%	8	95%	10%	94.6%	60.4%	63.0%	8.6
925	InteriorLighting	Luminaire Level Lighting Controls w/ HVAC Control	Biz-Custom Light	Lodging	Retro	498	498	65%	324	0.00	15	$90	100%	36%	47%	8	57%	10%	94.6%	61.9%	64.5%	8.6
926	InteriorLighting	LED Exit Sign - 4 Watt Fixture (2 lamp)	Biz-Prescriptive Light	Lodging	Retro	67	67	43%	29	0.00	5	$33	92%	92%	92%	9	1%	75%	87.2%	87.2%	87.2%	0.3
927	InteriorLighting	Lighting - Custom	Biz-Custom Light	Lodging	Retro	4	4	25%	1	0.00	15	$0	100%	24%	31%	10	100%	0%	94.6%	47.6%	51.2%	8.6
928	ExteriorLighting	LED wallpack (existing W<250)	Biz-Prescriptive Light	Lodging	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	1	12%	46%	94.6%	56.6%	70.8%	5.8
929	ExteriorLighting	LED parking lot fixture (existing W≥250)	Biz-Prescriptive Light	Lodging	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	2	11%	54%	67.8%	63.2%	63.2%	4.4
930	ExteriorLighting	LED parking lot fixture (existing W<250)	Biz-Prescriptive Light	Lodging	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	3	11%	54%	94.6%	63.2%	70.8%	5.8
931	ExteriorLighting	LED outdoor pole decorative fixture (existing W≥250)	Biz-Prescriptive Light	Lodging	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	17%	17%	4	11%	54%	67.8%	63.2%	63.2%	3.4
932	ExteriorLighting	LED parking garage fixture (existing W≥250)	Biz-Prescriptive Light	Lodging	Retro	3,235	3,235	60%	1,953	0.00	6	$756	50%	13%	33%	5	11%	69%	78.3%	75.2%	75.2%	4.7
933	ExteriorLighting	LED parking garage fixture (existing W<250)	Biz-Prescriptive Light	Lodging	Retro	1,742	1,742	66%	1,154	0.00	6	$248	100%	18%	45%	6	11%	69%	94.6%	77.6%	83.9%	6.2
934	ExteriorLighting	LED Mogul-base HID Lamp Replacing Exterior HID (existing W≥250)	Biz-Prescriptive Light	Lodging	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	7	11%	46%	62.1%	56.6%	56.6%	4.4
935	ExteriorLighting	LED Mogul-base HID Lamp Replacing Exterior HID (existing W<250)	Biz-Prescriptive Light	Lodging	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	8	11%	46%	94.6%	56.6%	70.8%	5.8
936	ExteriorLighting	Bi-Level Lighting Fixture – Garages	Biz-Custom Light	Lodging	Retro	519	519	69%	358	0.00	10	$274	50%	13%	17%	9	11%	20%	49.2%	36.0%	36.0%	3.9

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
937	ExteriorLighting	LED fuel pump canopy fixture (existing W<250)	Biz-Prescriptive Light	Lodging	Retro	0	0	0%	0	0.00	12	$0	0%	0%		10	0%	54%	94.6%	94.6%	94.6%	0.0
938	ExteriorLighting	LED fuel pump canopy fixture (existing W≥250)	Biz-Prescriptive Light	Lodging	Retro	0	0	0%	0	0.00	12	$0	0%	0%		11	0%	54%	94.6%	94.6%	94.6%	0.0
939	Miscellaneous	Vending Machine Controller - Non-Refrigerated	Biz-Prescriptive	Lodging	Retro	385	385	61%	237	0.00	5	$233	11%	11%	11%	1	5%	30%	51.0%	44.0%	44.0%	1.9
940	Miscellaneous	Miscellaneous Custom	Biz-Custom	Lodging	Retro	7	7	2%	0	0.00	10	$0	75%	25%	25%	2	41%	10%	37.0%	23.4%	23.4%	3.3
941	Miscellaneous	Kitchen Exhaust Hood Demand Ventilation Control System	Biz-Prescriptive	Lodging	ROB	9,932	9,932	50%	4,966	0.00	20	$1,180	100%	11%	27%	3	25%	10%	94.6%	73.8%	78.0%	39.7
942	Miscellaneous	High Efficiency Hand Dryers	Biz-Custom	Lodging	Retro	262	262	83%	217	0.00	10	$483	25%	4%	4%	4	5%	10%	37.0%	23.4%	23.4%	6.1
943	Miscellaneous	Ozone Commercial Laundry	Biz-Custom	Lodging	Retro	2,984	2,984	25%	746	0.00	10	$20,310	0%	0%	0%	5	2%	2%	31.4%	16.6%	16.6%	3.9
944	Miscellaneous	ENERGY STAR Uninterrupted Power Supply	Biz-Custom	Lodging	ROB	3,096	3,096	3%	85	0.00	15	$59	100%	14%	14%	6	0%	70%	94.6%	76.0%	76.0%	8.8
945	Motors	Cogged V-Belt	Biz-Custom	Lodging	Retro	29,207	29,207	3%	905	0.00	15	$384	100%	24%	24%	1	50%	10%	83.4%	43.5%	43.5%	7.7
946	Motors	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz-Custom	Lodging	Retro	1,902	1,902	38%	731	0.00	15	$200	100%	30%	30%	2	100%	10%	83.4%	52.4%	52.4%	11.6
947	Motors	Power Drive Systems	Biz-Custom	Lodging	Retro	4	4	23%	1	0.00	15	$0	100%	37%	37%	2	100%	10%	83.4%	53.4%	53.4%	7.7
948	Motors	Switch Reluctance Motors	Biz-Custom	Lodging	Retro	56,602	56,602	31%	17,320	0.00	15	$528	100%	50%	50%	2	100%	1%	83.4%	65.2%	65.2%	44.6
949	Motors	Escalators Motor Efficiency Controllers	Biz-Custom	Lodging	Retro	7,500	7,500	20%	1,500	0.00	10	$5,000	3%	3%	3%	3	0%	10%	37.0%	26.3%	26.3%	7.3
950	Office_NonPC	Energy Star Printer/Copier/Fax	Biz-Custom	Lodging	ROB	551	551	40%	223	0.00	6	$0	0%			1	5%	90%	94.6%	92.0%	92.0%	0.0
951	Office_NonPC	Smart Power Strip – Commercial Use	Biz-Custom	Lodging	Retro	1,086	1,086	10%	109	0.00	7	$50	50%	22%	22%	2	35%	15%	71.8%	42.0%	42.0%	2.8
952	Office_NonPC	Plug Load Occupancy Sensor	Biz-Custom	Lodging	Retro	1,126	1,126	15%	169	0.00	8	$70	75%	24%	24%	2	35%	15%	85.4%	47.6%	47.6%	3.2
953	Office_PC	Electrically Commutated Plug Fans in data centers	Biz-Custom	Lodging	Retro	86,783	86,783	18%	15,778	0.00	15	$480	100%	50%	50%	1	65%	20%	94.6%	74.6%	74.6%	50.8
954	Office_PC	Energy Star Server	Biz-Custom	Lodging	ROB	1,621	1,621	23%	368	0.00	8	$118	100%	31%	31%	1	65%	25%	94.6%	58.2%	58.2%	4.5
955	Office_PC	Server Virtualization	Biz-Custom	Lodging	Retro	2	2	45%	1	0.00	8	$0	75%	25%	25%	1	65%	25%	85.8%	49.3%	49.3%	3.2
956	Office_PC	High Efficiency CRAC unit	Biz-Custom	Lodging	ROB	541	541	30%	162	0.00	15	$63	100%	26%	26%	2	65%	20%	94.6%	51.1%	51.1%	8.1
957	Office_PC	Computer Room Air Conditioner Economizer	Biz-Custom	Lodging	Retro	764	764	47%	358	0.00	15	$82	100%	44%	44%	2	65%	20%	94.6%	66.1%	66.1%	5.6
958	Office_PC	Data Center Hot/Cold Aisle Configuration	Biz-Custom	Lodging	Retro	4	4	25%	1	0.00	15	$0	100%	25%	25%	3	3%	10%	94.6%	49.3%	49.3%	7.7
959	Office_PC	Energy Star Laptop	Biz-Custom	Lodging	ROB	126	126	33%	41	0.00	4	$0	0%			4	11%	85%	94.6%	88.0%	88.0%	0.0
960	Office_PC	Energy Star Monitor	Biz-Custom	Lodging	ROB	72	72	21%	15	0.00	4	$0	0%			5	25%	85%	94.6%	88.0%	88.0%	0.0
961	Refrigeration	Strip Curtains	Biz-Custom	Lodging	Retro	0	0	0%	0	0.00	4	$0	0%	0%		1	10%	30%	88.0%	70.4%	70.4%	0.0
962	Refrigeration	Bare Suction Line	Biz-Custom	Lodging	Retro	23	23	93%	21	0.00	15	$4	100%	50%	50%	2	0%	50%	88.0%	66.5%	66.5%	8.1
963	Refrigeration	Floating Head Pressure Controls	Biz-Custom	Lodging	Retro	1,112	1,112	25%	278	0.00	15	$431	25%	6%	6%	3	7%	25%	47.5%	40.0%	40.0%	5.6
964	Refrigeration	Saturated Suction Controls	Biz-Custom	Lodging	Retro	831	831	50%	416	0.00	15	$559	100%	7%	7%	4	2%	10%	88.0%	28.0%	28.0%	13.7
965	Refrigeration	Compressor Retrofit	Biz-Custom	Lodging	Retro	813	813	20%	163	0.00	15	$477	25%	3%	3%	5	23%	25%	47.5%	39.4%	39.4%	13.8
966	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz-Prescriptive	Lodging	Retro	2,440	2,440	65%	1,586	0.00	15	$305	100%	13%	33%	6	6%	80%	88.0%	84.0%	84.0%	30.7
967	Refrigeration	Evaporator Fan Motor Controls	Biz-Custom	Lodging	Retro	1,912	1,912	25%	478	0.00	13	$162	100%	30%	30%	7	6%	25%	88.0%	61.7%	61.7%	7.0
968	Refrigeration	Variable Speed Condenser Fan	Biz-Custom	Lodging	Retro	2,960	2,960	50%	1,480	0.00	15	$1,170	50%	13%	13%	8	9%	25%	59.5%	40.0%	40.0%	5.6
969	Refrigeration	Refrigeration Economizer	Biz-Custom	Lodging	Retro	7	7	2%	0	0.00	10	$0	100%	50%	50%	9	32%	10%	88.0%	41.1%	41.1%	4.2
970	Refrigeration	Anti-Sweat Heater Controls MT	Biz-Prescriptive	Lodging	Retro	579	579	59%	338	0.00	10	$170	75%	44%	44%	10	11%	25%	81.8%	72.4%	72.4%	2.1
971	Refrigeration	Auto Door Closer, Cooler	Biz-Custom	Lodging	Retro	471,500	471,500	0%	943	0.00	8	$157	100%	50%	50%	11	8%	50%	88.0%	66.9%	66.9%	5.8
972	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz-Custom	Lodging	Retro	1,584	1,584	36%	578	0.00	12	$686	50%	8%	8%	11	3%	25%	47.9%	40.0%	40.0%	7.1
973	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz-Prescriptive	Lodging	Retro	2,440	2,440	65%	1,586	0.00	15	$305	100%	13%	33%	12	2%	80%	88.0%	84.0%	84.0%	30.7
974	Refrigeration	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	Biz-Custom	Lodging	Retro	1,911	1,911	26%	504	0.00	10	$96	100%	50%	50%	12	2%	2%	88.0%	66.5%	66.5%	5.8
975	Refrigeration	Energy Star Reach-In Refrigerator, Glass Doors	Biz-Prescriptive	Lodging	ROB	2,140	2,140	29%	629	0.00	12	$1,239	25%	6%	14%	13	11%	54%	67.8%	63.2%	63.2%	5.6
976	Refrigeration	Energy Star Reach-In Refrigerator, Solid Doors	Biz-Prescriptive	Lodging	ROB	1,410	1,410	20%	281	0.00	12	$1,211	6%	6%	6%	14	11%	54%	67.8%	63.2%	63.2%	2.5
977	Refrigeration	Anti-Sweat Heater Controls LT	Biz-Prescriptive	Lodging	Retro	2,016	2,016	68%	1,361	0.00	10	$170	100%	44%	55%	15	4%	25%	88.0%	84.3%	85.0%	8.3
978	Refrigeration	Auto Door Closer, Freezer	Biz-Custom	Lodging	Retro	419,455	419,455	1%	2,307	0.00	8	$157	100%	50%	50%	16	4%	50%	88.0%	68.9%	68.9%	13.9
979	Refrigeration	Display Case Door Retrofit, Low Temp	Biz-Custom	Lodging	Retro	2,922	2,922	50%	1,453	0.00	12	$686	100%	21%	21%	16	4%	25%	88.0%	49.7%	49.7%	7.1
980	Refrigeration	Energy Star Reach-In Freezer, Glass Doors	Biz-Prescriptive	Lodging	ROB	6,374	6,374	20%	1,275	0.00	12	$1,651	25%	21%	21%	17	4%	54%	67.8%	63.2%	63.2%	2.3
981	Refrigeration	Energy Star Reach-In Freezer, Solid Doors	Biz-Prescriptive	Lodging	ROB	4,522	4,522	7%	305	0.00	12	$1,521	23%	23%	23%	18	4%	54%	67.8%	63.2%	63.2%	0.5
982	Refrigeration	Refrigeration - Custom	Biz-Custom	Lodging	ROB	7	7	2%	0	0.00	10	$0	75%	25%	25%	19	90%	25%	47.5%	39.4%	39.4%	3.3
983	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz-Custom RCx	Lodging	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	20	90%	25%	88.0%	65.9%	65.9%	3.2
984	Refrigeration	Energy Star Ice Machine	Biz-Prescriptive	Lodging	ROB	6,993	6,993	10%	721	0.00	15	$1,426	25%	18%	18%	21	10%	44%	60.8%	55.2%	55.2%	2.1
985	Refrigeration	Vending Machine Controller - Refrigerated	Biz-Prescriptive	Lodging	Retro	1,586	1,586	34%	537	0.00	5	$245	25%	16%	16%	22	4%	30%	65.5%	61.1%	61.1%	2.7
986	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz-Prescriptive	Lodging	Retro	273	273	89%	243	0.00	9	$11	100%	45%	55%	23	7%	35%	88.0%	86.7%	86.9%	30.9
987	Refrigeration	LED Refrigerated Display Case Lighting Controls	Biz-Prescriptive	Lodging	Retro	522	522	27%	141	0.00	10	$15	100%	100%	100%	24	7%	18%	88.0%	88.0%	88.0%	6.6
988	Ventilation	Demand Controlled Ventilation	Biz-Custom	Lodging	Retro	2,639	2,639	20%	528	0.00	15	$227	100%	23%	23%	1	100%	22%	92.7%	49.3%	49.3%	9.4
989	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz-Prescriptive	Lodging	Retro	1,902	1,902	38%	731	0.00	15	$200	100%	30%	55%	2	100%	22%	92.7%	74.0%	79.4%	11.6
990	WholeBldg_HVAC	HVAC - Energy Management System	Biz-Custom RCx	Lodging	Retro	13	13	8%	1	0.00	15	$0	100%	25%	25%	1	15%	20%	92.7%	51.6%	51.6%	8.8
991	WholeBldg_HVAC	Guest room energy management system	Biz-Custom	Lodging	Retro	7,167	7,167	19%	1,382	0.00	15	$260	100%	50%	50%	2	85%	20%	92.7%	65.3%	65.3%	5.9
992	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz-Custom RCx	Lodging	Retro	10	10	10%	1	0.00	15	$0	100%	25%	25%	3	100%	0%	92.7%	51.6%	51.6%	8.8
993	WholeBuilding	WholeBlg - Com RET	Biz-Custom	Lodging	Retro	7	7	15%	1	0.00	12	$0	100%	25%	25%	1	90%	0%	92.7%	51.6%	51.6%	7.3
994	WholeBuilding	WholeBlg - Custom (Other)	Biz-Custom	Lodging	Retro	5	5	20%	1	0.00	12	$0	100%	25%	25%	2	90%	0%	92.7%	51.6%	51.6%	7.3
995	WholeBuilding	Power Distribution Equipment Upgrades (Transformers)	Biz-Custom	Lodging	Retro	1,150	1,150	1%	6	0.00	30	$8	100%	9%	9%	3	100%	20%	92.7%	36.0%	36.0%	17.1
996	WholeBldg_NC	WholeBlg - Com NC	Biz-Custom	Lodging	NC	4	4	25%	1	0.00	12	$0	100%	50%	50%	1	100%	60%	83.4%	68.0%	68.0%	7.6
997	Behavioral	COM Competitions	Biz-Custom	Lodging	Retro	53	53	2%	1	0.00	2	$0	100%	50%	50%	1	100%	0%	50.0%	50.0%	50.0%	3.9
998	Behavioral	Business Energy Reports	Biz-Custom	Lodging	Retro	313	313	0%	1	0.00	2	$0	50%	50%	50%	1	100%	0%	50.0%	50.0%	50.0%	0.8
999	Behavioral	Building Benchmarking	Biz-Custom	Lodging	Retro	263	263	0%	1	0.00	2	$0	45%	45%	45%	1	100%	0%	50.0%	50.0%	50.0%	0.8
1000	Behavioral	Strategic Energy Management	Biz-Custom SEM	Lodging	Retro	0	0	0%	0	0.00	5	$0	0%		0%	1	100%	0%	50.0%	50.0%	50.0%	0.0
1001	Behavioral	BEIMS	Biz-Custom	Lodging	Retro	20	20	5%	1	0.00	2	$0	23%	23%	23%	1	100%	2%	50.0%	40.0%	40.0%	0.8
1002	Behavioral	Building Operator Certification	Biz-Custom	Lodging	Retro	12	12	3%	0	0.00	3	$0	25%	17%	17%	1	100%	2%	50.0%	40.0%	40.0%	1.7
1003	CompressedAir	Efficient Air Compressors (VSD)	Biz-Prescriptive	Retail	ROB	1,583	1,583	21%	329	0.00	13	$127	100%	59%	80%	1	100%	33%	92.7%	76.7%	83.1%	5.5
1004	CompressedAir	Efficient Air Nozzles	Biz-Prescriptive	Retail	Retro	1,480	1,480	50%	740	0.00	15	$50	100%	81%	81%	2	35%	33%	92.7%	91.1%	91.1%	15.8
1005	CompressedAir	AODD Pump Controls	Biz-Custom	Retail	Retro	103,919	103,919	35%	36,372	0.00	10	$1,150	100%	50%	50%	3	10%	33%	92.7%	72.6%	72.6%	38.2
1006	CompressedAir	Compressed Air - Custom	Biz-Custom	Retail	Retro	5	5	20%	1	0.00	10	$0	100%	47%	47%	4	50%	33%	92.7%	64.2%	64.2%	6.0
1007	CompressedAir	Retro-commissioning_Compressed Air Optimization	Biz-Custom RCx	Retail	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	5	50%	33%	92.7%	64.2%	64.2%	3.2
1008	Cooking	Commercial Combination Oven (Electric)	Biz-Prescriptive	Retail	ROB	38,561	38,561	48%	18,432	0.00	12	$16,884	75%	6%	15%	1	18%	53%	77.5%	62.4%	62.4%	14.1

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
1009	Cooking	Commercial Electric Convection Oven	Biz-Prescriptive	Retail	ROB	12,193	12,193	15%	1,879	0.00	12	$1,706	75%	21%	51%	1	18%	53%	77.6%	62.4%	62.4%	4.4
1010	Cooking	Commercial Electric Griddle	Biz-Prescriptive	Retail	ROB	17,056	17,056	15%	2,596	0.00	12	$3,604	25%	15%	15%	2	14%	17%	41.9%	33.6%	33.6%	2.8
1011	Cooking	Commercial Electric Steam Cooker	Biz-Prescriptive	Retail	ROB	19,549	19,549	67%	13,162	0.00	12	$2,490	100%	24%	55%	3	6%	45%	88.0%	81.1%	83.5%	18.0
1012	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz-Prescriptive	Retail	ROB	39,306	39,306	44%	17,369	0.00	15	$1,000	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	11.7
1013	Cooking	Dishwasher High Temp Door (Energy Star)	Biz-Prescriptive	Retail	ROB	26,901	26,901	32%	8,586	0.00	15	$1,100	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	5.2
1014	Cooking	Energy efficient electric fryer	Biz-Prescriptive	Retail	ROB	18,955	18,955	17%	3,274	0.00	12	$1,500	100%	5%	13%	5	27%	24%	88.0%	57.2%	59.4%	23.2
1015	Cooking	Insulated Holding Cabinets (Full Size)	Biz-Prescriptive	Retail	ROB	13,697	13,697	68%	9,314	0.00	12	$1,200	100%	35%	55%	6	3%	16%	88.0%	83.6%	84.9%	12.7
1016	Cooking	Insulated Holding Cabinets (Half-Size)	Biz-Prescriptive	Retail	ROB	4,383	4,383	60%	2,630	0.00	12	$1,500	100%	10%	25%	6	3%	16%	88.0%	52.6%	57.6%	10.1
1017	Cooling	Air Conditioner - 13 IEER (5-20 Tons)	Biz-Prescriptive	Retail	ROB	1,273	1,273	6%	78	0.00	15	$63	100%	48%	55%	1	15%	20%	92.7%	54.4%	58.5%	4.9
1018	Cooling	Air Conditioner - 14 IEER (5-20 Tons)	Biz-Prescriptive	Retail	ROB	1,273	1,273	13%	164	0.00	15	$127	100%	24%	55%	1	15%	20%	92.7%	48.3%	59.8%	10.3
1019	Cooling	Air Conditioner - 17 IEER (5-20 Tons)	Biz-Prescriptive	Retail	ROB	1,273	1,273	28%	359	0.00	15	$127	100%	24%	55%	1	15%	20%	92.7%	67.3%	76.6%	22.7
1020	Cooling	Air Conditioner - 21 IEER (5-20 Tons)	Biz-Prescriptive	Retail	ROB	1,273	1,273	42%	533	0.00	15	$127	100%	24%	55%	1	15%	20%	92.7%	74.8%	80.6%	33.6
1021	Cooling	Air Conditioner - 12.1 IEER (20+ Tons)	Biz-Prescriptive	Retail	ROB	1,362	1,362	6%	79	0.00	15	$30	100%	100%	100%	2	15%	20%	92.7%	92.7%	92.7%	5.0
1022	Cooling	Air Conditioner - 13 IEER (20+ Tons)	Biz-Prescriptive	Retail	ROB	1,362	1,362	12%	168	0.00	15	$37	100%	81%	81%	2	15%	20%	92.7%	87.5%	87.5%	10.6
1023	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz-Prescriptive	Retail	ROB	1,362	1,362	20%	276	0.00	15	$37	100%	81%	81%	2	15%	20%	92.7%	89.6%	89.6%	17.4
1024	Cooling	Air Conditioner - 21 IEER (20+ Tons)	Biz-Prescriptive	Retail	ROB	1,362	1,362	46%	623	0.00	15	$37	100%	81%	81%	2	15%	20%	92.7%	91.3%	91.3%	39.3
1025	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz-Custom	Retail	Retro	1,294	1,294	7%	91	0.00	3	$5	100%	50%	50%	3	29%	50%	92.7%	71.2%	71.2%	15.4
1026	Cooling	Air Side Economizer	Biz-Custom	Retail	Retro	1,273	1,273	20%	255	0.00	10	$84	100%	30%	30%	4	29%	20%	92.7%	56.8%	56.8%	3.9
1027	Cooling	Advanced Rooftop Controls	Biz-Prescriptive	Retail	Retro	1,294	1,294	8%	106	0.00	10	$100	100%	100%	100%	5	29%	20%	92.7%	92.7%	92.7%	0.4
1028	Cooling	HVAC Occupancy Controls	Biz-Custom	Retail	ROB	2,900	2,900	20%	580	0.00	15	$537	100%	11%	11%	6	29%	20%	92.7%	36.0%	36.0%	12.0
1029	Cooling	Air Conditioner - 16 SEER (<5 Tons)	Biz-Prescriptive	Retail	ROB	1,109	1,109	13%	139	0.00	15	$47	100%	64%	80%	7	23%	20%	92.7%	79.5%	84.3%	8.7
1030	Cooling	Air Conditioner - 17 SEER (<5 Tons)	Biz-Prescriptive	Retail	ROB	1,109	1,109	18%	196	0.00	15	$206	100%	15%	36%	7	23%	20%	92.7%	39.3%	45.5%	12.3
1031	Cooling	Air Conditioner - 18 SEER(<5 Tons)	Biz-Prescriptive	Retail	ROB	1,109	1,109	22%	246	0.00	15	$206	100%	15%	36%	7	23%	20%	92.7%	44.0%	50.4%	15.5
1032	Cooling	Air Conditioner - 21 SEER(<5 Tons)	Biz-Prescriptive	Retail	ROB	1,109	1,109	33%	370	0.00	15	$253	100%	12%	30%	7	23%	20%	92.7%	47.9%	52.2%	23.3
1033	Cooling	Smart Thermostat	Biz-Prescriptive	Retail	ROB	1,109	1,109	14%	157	0.00	11	$175	75%	57%	57%	8	23%	12%	66.5%	52.4%	52.4%	1.4
1034	Cooling	PTAC - <7,000 Btuh - lodging	Biz-Prescriptive	Retail	ROB	1,305	1,305	8%	110	0.00	8	$84	100%	36%	55%	9	15%	20%	92.7%	52.0%	60.4%	3.8
1035	Cooling	PTAC - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Retail	ROB	1,431	1,431	7%	104	0.00	8	$84	100%	36%	36%	10	15%	20%	92.7%	50.9%	50.9%	3.6
1036	Cooling	PTAC - >15,000 Btuh - lodging	Biz-Prescriptive	Retail	ROB	1,635	1,635	10%	156	0.00	8	$84	100%	36%	55%	11	15%	20%	92.7%	60.0%	69.9%	5.4
1037	Cooling	Air Cooled Chiller	Biz-Prescriptive	Retail	ROB	1,133	1,133	6%	64	0.00	23	$126	100%	24%	55%	12	32%	15%	92.7%	32.0%	39.5%	6.8
1038	Cooling	Chiller Tune-up	Biz-Prescriptive	Retail	Retro	1,294	1,294	7%	91	0.00	3	$8	100%	100%	100%	13	32%	50%	92.7%	92.7%	92.7%	5.1
1039	Cooling	HVAC/Chiller Custom	Biz-Custom	Retail	Retro	5	5	20%	1	0.00	20	$1	100%	7%	7%	14	100%	20%	92.7%	36.0%	36.0%	30.3
1040	Cooling	Window Film	Biz-Prescriptive	Retail	Retro	6,000	6,000	4%	264	0.00	10	$154	100%	65%	65%	15	100%	20%	92.7%	73.1%	73.1%	3.2
1041	Cooling	Triple Pane Windows	Biz-Custom	Retail	ROB	6,000	6,000	6%	360	0.00	25	$700	100%	5%	5%	15	100%	20%	92.7%	36.0%	36.0%	24.5
1042	Cooling	Energy Recovery Ventilator	Biz-Custom	Retail	Retro	1,362	1,362	11%	156	0.00	15	$1,500	1%	1%	1%	16	100%	2%	31.4%	21.8%	21.8%	6.7
1043	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz-Prescriptive	Retail	ROB	1,841	1,841	4%	83	0.00	16	$87	100%	46%	46%	1	35%	20%	92.7%	49.2%	49.2%	2.9
1044	Heating	Heat Pump - 17 SEER (<5 Tons)	Biz-Prescriptive	Retail	ROB	1,841	1,841	9%	173	0.00	16	$442	50%	9%	23%	1	35%	20%	44.0%	36.0%	36.0%	5.7
1045	Heating	Heat Pump - 18 SEER(<5 Tons)	Biz-Prescriptive	Retail	ROB	1,841	1,841	13%	247	0.00	16	$507	50%	8%	20%	1	35%	20%	44.0%	36.0%	36.0%	8.1
1046	Heating	Heat Pump - 21 SEER(<5 Tons)	Biz-Prescriptive	Retail	ROB	1,841	1,841	21%	392	0.00	16	$507	100%	8%	20%	1	35%	20%	92.7%	36.0%	36.9%	13.0
1047	Heating	Geothermal HP - SEER 20.3 (<5 Tons)	Biz-Prescriptive	Retail	ROB	1,841	1,841	23%	431	0.00	25	$2,576	25%	2%	4%	1	35%	20%	44.0%	36.0%	36.0%	18.3
1048	Heating	Geothermal HP - SEER 21.5 (<5 Tons)	Biz-Prescriptive	Retail	ROB	1,841	1,841	28%	510	0.00	25	$2,576	25%	2%	4%	1	35%	20%	44.0%	36.0%	36.0%	21.1
1049	Heating	Geothermal HP - SEER 23.1 (<5 Tons)	Biz-Prescriptive	Retail	ROB	1,841	1,841	33%	602	0.00	25	$2,576	25%	2%	4%	1	35%	20%	44.0%	36.0%	36.0%	24.3
1050	Heating	Geothermal HP - SEER 29.3 (<5 Tons)	Biz-Prescriptive	Retail	ROB	1,841	1,841	47%	869	0.00	25	$2,576	25%	2%	4%	1	35%	20%	44.0%	36.0%	36.0%	31.4
1051	Heating	Heat Pump - 14.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Retail	ROB	2,239	2,239	12%	264	0.00	16	$100	100%	40%	55%	2	22%	20%	92.7%	71.2%	75.7%	32.3
1052	Heating	Heat Pump - 15.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Retail	ROB	2,239	2,239	17%	383	0.00	16	$136	100%	30%	55%	2	22%	20%	92.7%	69.3%	76.6%	36.1
1053	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Retail	ROB	2,336	2,336	16%	375	0.00	16	$100	100%	40%	55%	2	22%	20%	92.7%	76.5%	79.6%	36.9
1054	Heating	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Retail	ROB	2,336	2,336	21%	492	0.00	16	$139	100%	29%	55%	2	22%	20%	92.7%	73.4%	79.1%	40.5
1055	Heating	Geothermal HP - SEER 20.3 (5-20 Tons)	Biz-Prescriptive	Retail	ROB	2,034	2,034	31%	625	0.00	25	$2,576	50%	2%	4%	2	22%	20%	44.0%	36.0%	36.0%	37.6
1056	Heating	Geothermal HP - SEER 21.5 (5-20 Tons)	Biz-Prescriptive	Retail	ROB	2,034	2,034	35%	703	0.00	25	$2,576	50%	2%	4%	2	22%	20%	44.0%	36.0%	36.0%	40.5
1057	Heating	Geothermal HP - SEER 23.1 (5-20 Tons)	Biz-Prescriptive	Retail	ROB	2,198	2,198	44%	959	0.00	25	$2,576	50%	2%	4%	2	22%	20%	44.0%	36.0%	36.0%	47.1
1058	Heating	Geothermal HP - SEER 29.3 (5-20 Tons)	Biz-Prescriptive	Retail	ROB	2,198	2,198	56%	1,226	0.00	25	$2,576	75%	2%	4%	2	22%	20%	50.7%	36.0%	36.0%	54.2
1059	Heating	Variable Refrigerant Flow Heat Pump	Biz-Custom	Retail	ROB	1,744	1,744	17%	296	0.00	16	$224	100%	13%	13%	2	22%	2%	92.7%	36.8%	36.8%	15.6
1060	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz-Prescriptive	Retail	ROB	2,467	2,467	10%	256	0.00	16	$100	100%	40%	55%	3	22%	20%	92.7%	70.7%	75.3%	28.9
1061	Heating	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	Biz-Prescriptive	Retail	ROB	2,467	2,467	16%	407	0.00	16	$175	100%	23%	55%	3	22%	20%	92.7%	61.5%	73.9%	34.0
1062	Heating	Geothermal HP - SEER 20.3 (20+ Tons)	Biz-Prescriptive	Retail	ROB	2,336	2,336	40%	927	0.00	25	$2,576	100%	2%	4%	3	22%	20%	92.7%	36.0%	36.0%	72.5
1063	Heating	Geothermal HP - SEER 21.5 (20+ Tons)	Biz-Prescriptive	Retail	ROB	2,336	2,336	43%	1,005	0.00	25	$2,576	100%	2%	4%	3	22%	20%	92.7%	36.0%	36.0%	75.3
1064	Heating	Geothermal HP - SEER 23.1 (20+ Tons)	Biz-Prescriptive	Retail	ROB	2,336	2,336	47%	1,097	0.00	25	$2,576	100%	2%	4%	3	22%	20%	92.7%	36.0%	36.0%	78.5
1065	Heating	Geothermal HP - SEER 29.3 (20+ Tons)	Biz-Prescriptive	Retail	ROB	2,336	2,336	58%	1,364	0.00	25	$2,576	100%	2%	4%	3	22%	20%	92.7%	36.0%	36.0%	85.6
1066	Heating	Mini Split Ductless Heat Pump Cold Climate (Tiers & sizes TBD)	Biz-Prescriptive	Retail	ROB	1,841	1,841	21%	392	0.00	16	$224	100%	18%	45%	4	11%	20%	92.7%	52.7%	62.9%	13.0
1067	Heating	PTHP - <7,000 Btuh - lodging	Biz-Custom	Retail	ROB	2,006	2,006	5%	106	0.00	8	$130	100%	100%	100%	5	3%	10%	92.7%	74.2%	74.2%	0.8
1068	Heating	PTHP - >15,000 Btuh - lodging	Biz-Prescriptive	Retail	ROB	2,495	2,495	20%	507	0.00	8	$130	100%	100%	100%	6	3%	10%	92.7%	92.7%	92.7%	3.8
1069	Heating	PTHP - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Retail	ROB	2,220	2,220	12%	263	0.00	8	$130	100%	100%	100%	7	3%	10%	92.7%	92.7%	92.7%	1.9
1070	HotWater	Heat Pump Water Heater	Biz-Prescriptive	Retail	ROB	4,687	4,687	67%	3,139	0.00	15	$1,115	100%	45%	55%	1	100%	8%	84.0%	71.2%	74.1%	5.2
1071	HotWater	Hot Water Pipe Insulation	Biz-Custom	Retail	Retro	4,687	4,687	2%	94	0.00	20	$60	100%	16%	16%	2	100%	80%	86.0%	84.0%	84.0%	9.8
1072	HotWater	Faucet Aerator	Biz-Custom	Retail	Retro	284	284	32%	92	0.00	10	$8	100%	50%	50%	3	20%	90%	93.0%	92.0%	92.0%	13.5
1073	HotWater	Low Flow Pre-Rinse Sprayers	Biz-Prescriptive	Retail	ROB	18,059	18,059	54%	9,789	0.00	5	$60	100%	17%	42%	4	20%	80%	86.0%	84.0%	84.0%	199.3
1074	HotWater	ENERGY STAR Commercial Washing Machines	Biz-Prescriptive	Retail	ROB	1,552	1,552	43%	671	0.00	7	$250	75%	28%	28%	5	25%	33%	79.3%	64.6%	64.6%	2.9
1075	InteriorLighting	LED T8 Tube Replacement	Biz-Prescriptive Light	Retail	Retro	153	153	45%	68	0.00	12	$5	100%	100%	100%	1	75%	40%	94.6%	94.6%	94.6%	11.1
1076	InteriorLighting	LED troffer retrofit kit, 2'X2' and 2'X4'	Biz-Prescriptive Light	Retail	Retro	346	346	50%	173	0.00	12	$70	100%	36%	55%	1	75%	40%	94.6%	67.7%	77.0%	5.6
1077	InteriorLighting	LED troffer, 2'X2' and 2'X4'	Biz-Prescriptive Light	Retail	Retro	346	346	50%	173	0.00	12	$70	100%	36%	55%	1	75%	40%	94.6%	67.7%	77.0%	5.6
1078	InteriorLighting	Bi-Level Lighting Fixture – Stairwells, Hallways	Biz-Custom Light	Retail	Retro	346	346	74%	257	0.00	10	$274	25%	9%	12%	2	1%	40%	58.0%	52.0%	52.0%	4.4
1079	InteriorLighting	LED high bay fixture	Biz-Prescriptive Light	Retail	Retro	3,225	3,225	68%	2,194	0.00	12	$330	100%	35%	55%	3	3%	34%	94.6%	86.0%	89.0%	15.5
1080	InteriorLighting	LED Mogul-base HID Lamp Replacing High Bay HID	Biz-Prescriptive Light	Retail	Retro	3,225	3,225	66%	2,140	0.00	12	$330	100%	35%	55%	3	3%	34%	94.6%	85.7%	88.8%	15.1

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
1081	InteriorLighting	LED low bay fixture	Biz-Prescriptive Light	Retail	Retro	687	687	61%	417	0.00	12	$44	100%	68%	80%	4	16%	34%	94.6%	91.8%	92.8%	11.3
1082	InteriorLighting	LED Mogul-base HID Lamp Replacing Low Bay HID	Biz-Prescriptive Light	Retail	Retro	687	687	59%	403	0.00	12	$44	100%	68%	80%	4	16%	34%	94.6%	91.7%	92.8%	10.9
1083	InteriorLighting	LED Screw-In Lamps (Directional)	Biz-Prescriptive Light	Retail	ROB	257	257	86%	221	0.00	5	$1	100%	100%	100%	6	0%	43%	94.6%	94.6%	94.6%	96.3
1084	InteriorLighting	LED downlight fixture	Biz-Prescriptive Light	Retail	Retro	238	238	68%	161	0.00	12	$27	100%	19%	46%	6	4%	45%	94.6%	81.8%	86.8%	26.0
1085	InteriorLighting	LED Screw-In Lamps (Omnidirectional & Decorative)	Biz-Prescriptive Light	Retail	ROB	194	194	81%	157	0.00	5	$1	100%	100%	100%	5	0%	20%	94.6%	94.6%	94.6%	68.7
1086	InteriorLighting	DeLamp Fluorescent Fixture Average Lamp Wattage 28W	Biz-Prescriptive Light	Retail	Retro	128	128	100%	128	0.00	11	$4	100%	100%	100%	7	75%	0%	94.6%	94.6%	94.6%	23.8
1087	InteriorLighting	Occupancy Sensors	Biz-Prescriptive Light	Retail	Retro	582	582	30%	175	0.00	10	$65	100%	31%	55%	8	95%	10%	94.6%	67.6%	78.4%	3.9
1088	InteriorLighting	Daylighting Controls	Biz-Prescriptive Light	Retail	Retro	746	746	30%	224	0.00	10	$58	100%	35%	55%	8	95%	10%	94.6%	78.5%	84.1%	8.0
1089	InteriorLighting	Dual Occupancy & Daylighting Controls	Biz-Custom Light	Retail	Retro	333	333	44%	146	0.00	10	$75	100%	40%	50%	8	95%	10%	94.6%	48.4%	54.6%	3.4
1090	InteriorLighting	Central Lighting Monitoring & Controls (non-networked)	Biz-Custom Light	Retail	Retro	41,703	41,703	20%	8,341	0.00	12	$3,700	100%	23%	29%	8	95%	10%	94.6%	44.1%	47.7%	4.6
1091	InteriorLighting	Network Lighting Controls - Wireless (WiFi)	Biz-Custom Light	Retail	Retro	3	3	49%	1	0.00	15	$1	100%	23%	29%	8	95%	10%	94.6%	44.2%	47.8%	9.7
1092	InteriorLighting	Luminaire Level Lighting Controls w/ HVAC Control	Biz-Custom Light	Retail	Retro	333	333	65%	216	0.00	15	$90	100%	24%	31%	8	95%	10%	94.6%	47.3%	50.9%	9.7
1093	InteriorLighting	LED Exit Sign - 4 Watt Fixture (2 lamp)	Biz-Prescriptive Light	Retail	Retro	67	67	43%	29	0.00	5	$33	92%	92%	92%	9	1%	75%	87.2%	87.2%	87.2%	0.3
1094	InteriorLighting	Lighting - Custom	Biz-Custom Light	Retail	Retro	4	4	25%	1	0.00	15	$1	100%	17%	23%	10	100%	0%	94.6%	34.7%	35.8%	9.7
1095	ExteriorLighting	LED wallpack (existing W<250)	Biz-Prescriptive Light	Retail	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	1	12%	46%	94.6%	56.6%	70.8%	5.8
1096	ExteriorLighting	LED parking lot fixture (existing W≥250)	Biz-Prescriptive Light	Retail	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	2	11%	54%	67.8%	63.2%	63.2%	4.4
1097	ExteriorLighting	LED parking lot fixture (existing W<250)	Biz-Prescriptive Light	Retail	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	3	11%	54%	94.6%	63.2%	70.8%	5.8
1098	ExteriorLighting	LED outdoor pole decorative fixture (existing W≥250)	Biz-Prescriptive Light	Retail	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	17%	17%	4	11%	54%	67.8%	63.2%	63.2%	3.4
1099	ExteriorLighting	LED parking garage fixture (existing W≥250)	Biz-Prescriptive Light	Retail	Retro	3,235	3,235	60%	1,953	0.00	6	$756	50%	13%	33%	5	11%	69%	78.3%	75.2%	75.2%	4.7
1100	ExteriorLighting	LED parking garage fixture (existing W<250)	Biz-Prescriptive Light	Retail	Retro	1,742	1,742	66%	1,154	0.00	6	$248	100%	18%	45%	6	11%	69%	94.6%	77.6%	83.9%	6.2
1101	ExteriorLighting	LED Mogul-base HID Lamp Replacing Exterior HID (existing W≥250)	Biz-Prescriptive Light	Retail	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	7	11%	46%	62.1%	56.6%	56.6%	4.4
1102	ExteriorLighting	LED Mogul-base HID Lamp Replacing Exterior HID (existing W<250)	Biz-Prescriptive Light	Retail	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	8	11%	46%	94.6%	56.6%	70.8%	5.8
1103	ExteriorLighting	Bi-Level Lighting Fixture – Garages	Biz-Custom Light	Retail	Retro	346	346	69%	239	0.00	10	$274	25%	9%	11%	9	11%	20%	44.0%	36.0%	36.0%	3.9
1104	ExteriorLighting	LED fuel pump canopy fixture (existing W<250)	Biz-Prescriptive Light	Retail	Retro	0	0	0%	0	0.00	12	$0	0%	0%		10	0%	54%	94.6%	94.6%	94.6%	0.0
1105	ExteriorLighting	LED fuel pump canopy fixture (existing W≥250)	Biz-Prescriptive Light	Retail	Retro	0	0	0%	0	0.00	12	$0	0%	0%		11	0%	54%	94.6%	94.6%	94.6%	0.0
1106	Miscellaneous	Vending Machine Controller - Non-Refrigerated	Biz-Prescriptive	Retail	Retro	385	385	61%	237	0.00	5	$233	11%	11%	11%	1	5%	30%	51.0%	44.0%	44.0%	1.9
1107	Miscellaneous	Miscellaneous Custom	Biz-Custom	Retail	Retro	7	7	2%	0	0.00	10	$0	75%	25%	25%	2	36%	10%	37.0%	23.4%	23.4%	3.3
1108	Miscellaneous	Kitchen Exhaust Hood Demand Ventilation Control System	Biz-Prescriptive	Retail	ROB	9,932	9,932	50%	4,966	0.00	20	$1,180	100%	11%	27%	3	0%	10%	94.6%	73.8%	78.0%	39.7
1109	Miscellaneous	High Efficiency Hand Dryers	Biz-Custom	Retail	Retro	1,909	1,909	83%	1,585	0.00	10	$483	100%	33%	33%	4	5%	10%	94.6%	59.6%	59.6%	7.2
1110	Miscellaneous	Ozone Commercial Laundry	Biz-Custom	Retail	Retro	2,984	2,984	25%	746	0.00	10	$20,310	0%	0%	0%	5	0%	2%	31.4%	16.6%	16.6%	3.9
1111	Miscellaneous	ENERGY STAR Uninterrupted Power Supply	Biz-Custom	Retail	ROB	3,096	3,096	3%	85	0.00	15	$59	100%	14%	14%	6	5%	70%	94.6%	76.0%	76.0%	8.8
1112	Motors	Cogged V-Belt	Biz-Custom	Retail	Retro	14,670	14,670	3%	455	0.00	15	$384	100%	12%	12%	1	50%	10%	83.4%	28.8%	28.8%	9.9
1113	Motors	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz-Custom	Retail	Retro	1,902	1,902	38%	731	0.00	15	$200	100%	30%	30%	2	100%	10%	83.4%	52.4%	52.4%	11.6
1114	Motors	Power Drive Systems	Biz-Custom	Retail	Retro	4	4	23%	1	0.00	15	$0	100%	37%	37%	2	100%	10%	83.4%	53.4%	53.4%	9.9
1115	Motors	Switch Reluctance Motors	Biz-Custom	Retail	Retro	28,430	28,430	31%	8,700	0.00	15	$528	100%	50%	50%	2	100%	1%	83.4%	63.7%	63.7%	22.4
1116	Motors	Escalators Motor Efficiency Controllers	Biz-Custom	Retail	Retro	7,500	7,500	20%	1,500	0.00	10	$5,000	3%	3%	3%	3	0%	10%	37.0%	26.3%	26.3%	7.3
1117	Office_NonPC	Energy Star Printer/Copier/Fax	Biz-Custom	Retail	ROB	551	551	40%	223	0.00	6	$0	0%			1	30%	90%	94.6%	92.0%	92.0%	0.0
1118	Office_NonPC	Smart Power Strip – Commercial Use	Biz-Custom	Retail	Retro	1,086	1,086	10%	109	0.00	7	$50	50%	22%	22%	2	35%	15%	71.8%	42.0%	42.0%	2.8
1119	Office_NonPC	Plug Load Occupancy Sensor	Biz-Custom	Retail	Retro	1,126	1,126	15%	169	0.00	8	$70	75%	24%	24%	2	35%	15%	85.4%	47.6%	47.6%	3.2
1120	Office_PC	Electrically Commutated Plug Fans in data centers	Biz-Custom	Retail	Retro	86,783	86,783	18%	15,778	0.00	15	$480	100%	50%	50%	1	65%	20%	94.6%	74.6%	74.6%	50.8
1121	Office_PC	Energy Star Server	Biz-Custom	Retail	ROB	1,621	1,621	23%	368	0.00	8	$118	100%	31%	31%	1	65%	25%	94.6%	58.2%	58.2%	4.5
1122	Office_PC	Server Virtualization	Biz-Custom	Retail	Retro	2	2	45%	1	0.00	8	$0	75%	25%	25%	1	65%	25%	85.8%	49.3%	49.3%	3.2
1123	Office_PC	High Efficiency CRAC unit	Biz-Custom	Retail	ROB	541	541	30%	162	0.00	15	$63	100%	26%	26%	2	65%	20%	94.6%	51.1%	51.1%	8.1
1124	Office_PC	Computer Room Air Conditioner Economizer	Biz-Custom	Retail	Retro	764	764	47%	358	0.00	15	$82	100%	44%	44%	2	65%	20%	94.6%	66.1%	66.1%	5.6
1125	Office_PC	Data Center Hot/Cold Aisle Configuration	Biz-Custom	Retail	Retro	4	4	25%	1	0.00	15	$0	100%	25%	25%	3	3%	10%	94.6%	49.3%	49.3%	7.7
1126	Office_PC	Energy Star Laptop	Biz-Custom	Retail	ROB	126	126	33%	41	0.00	4	$0	0%			4	11%	85%	94.6%	88.0%	88.0%	0.0
1127	Office_PC	Energy Star Monitor	Biz-Custom	Retail	ROB	72	72	21%	15	0.00	4	$0	0%			5	25%	85%	94.6%	88.0%	88.0%	0.0
1128	Refrigeration	Strip Curtains	Biz-Custom	Retail	Retro	0	0	0%	0	0.00	4	$0	0%	0%		1	6%	30%	88.0%	70.4%	70.4%	0.0
1129	Refrigeration	Bare Suction Line	Biz-Custom	Retail	Retro	23	23	93%	21	0.00	15	$4	100%	50%	50%	2	0%	50%	88.0%	66.5%	66.5%	8.1
1130	Refrigeration	Floating Head Pressure Controls	Biz-Custom	Retail	Retro	1,112	1,112	25%	278	0.00	15	$431	25%	6%	6%	3	4%	25%	47.5%	40.0%	40.0%	5.6
1131	Refrigeration	Saturated Suction Controls	Biz-Custom	Retail	Retro	831	831	50%	416	0.00	15	$559	100%	7%	7%	4	2%	10%	88.0%	28.0%	28.0%	13.7
1132	Refrigeration	Compressor Retrofit	Biz-Custom	Retail	Retro	813	813	20%	163	0.00	15	$477	25%	3%	3%	5	13%	25%	47.5%	39.4%	39.4%	13.8
1133	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz-Prescriptive	Retail	Retro	2,440	2,440	65%	1,586	0.00	15	$305	100%	13%	33%	6	4%	80%	88.0%	84.0%	84.0%	30.7
1134	Refrigeration	Evaporator Fan Motor Controls	Biz-Custom	Retail	Retro	1,912	1,912	25%	478	0.00	13	$162	100%	30%	30%	7	4%	25%	88.0%	61.7%	61.7%	7.0
1135	Refrigeration	Variable Speed Condenser Fan	Biz-Custom	Retail	Retro	2,960	2,960	50%	1,480	0.00	15	$1,170	50%	13%	13%	8	5%	25%	59.5%	40.0%	40.0%	5.6
1136	Refrigeration	Refrigeration Economizer	Biz-Custom	Retail	Retro	7	7	2%	0	0.00	10	$0	100%	50%	50%	9	18%	10%	88.0%	41.1%	41.1%	4.2
1137	Refrigeration	Anti-Sweat Heater Controls MT	Biz-Prescriptive	Retail	Retro	579	579	59%	338	0.00	10	$170	75%	44%	44%	10	18%	75%	82.5%	80.0%	80.0%	2.1
1138	Refrigeration	Auto Door Closer, Cooler	Biz-Custom	Retail	Retro	471,500	471,500	0%	943	0.00	8	$157	100%	50%	50%	11	13%	50%	88.0%	66.9%	66.9%	5.8
1139	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz-Custom	Retail	Retro	1,584	1,584	36%	578	0.00	12	$686	50%	8%	8%	11	5%	25%	47.9%	40.0%	40.0%	7.1
1140	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz-Prescriptive	Retail	Retro	2,440	2,440	65%	1,586	0.00	15	$305	100%	13%	33%	12	3%	80%	88.0%	84.0%	84.0%	30.7
1141	Refrigeration	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	Biz-Custom	Retail	Retro	1,911	1,911	26%	504	0.00	10	$96	100%	50%	50%	12	3%	2%	88.0%	66.5%	66.5%	5.8
1142	Refrigeration	Energy Star Reach-In Refrigerator, Glass Doors	Biz-Prescriptive	Retail	ROB	2,140	2,140	29%	629	0.00	12	$1,239	25%	6%	14%	13	17%	54%	67.8%	63.2%	63.2%	5.6
1143	Refrigeration	Energy Star Reach-In Refrigerator, Solid Doors	Biz-Prescriptive	Retail	ROB	1,410	1,410	20%	281	0.00	12	$1,211	6%	6%	6%	14	17%	54%	67.8%	63.2%	63.2%	2.5
1144	Refrigeration	Anti-Sweat Heater Controls LT	Biz-Prescriptive	Retail	Retro	2,016	2,016	68%	1,361	0.00	10	$170	100%	44%	55%	15	6%	75%	88.0%	84.3%	85.0%	8.3
1145	Refrigeration	Auto Door Closer, Freezer	Biz-Custom	Retail	Retro	419,455	419,455	1%	2,307	0.00	8	$157	100%	50%	50%	16	6%	50%	88.0%	68.9%	68.9%	13.9
1146	Refrigeration	Display Case Door Retrofit, Low Temp	Biz-Custom	Retail	Retro	2,922	2,922	50%	1,453	0.00	12	$686	100%	21%	21%	16	6%	25%	88.0%	49.7%	49.7%	7.1
1147	Refrigeration	Energy Star Reach-In Freezer, Glass Doors	Biz-Prescriptive	Retail	ROB	6,374	6,374	20%	1,275	0.00	12	$1,651	25%	21%	21%	17	6%	54%	67.8%	63.2%	63.2%	2.3
1148	Refrigeration	Energy Star Reach-In Freezer, Solid Doors	Biz-Prescriptive	Retail	ROB	4,522	4,522	7%	305	0.00	12	$1,521	23%	23%	23%	18	6%	54%	67.8%	63.2%	63.2%	0.5
1149	Refrigeration	Refrigeration - Custom	Biz-Custom	Retail	ROB	7	7	2%	0	0.00	10	$0	75%	25%	25%	19	90%	25%	47.5%	39.4%	39.4%	3.3
1150	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz-Custom RCx	Retail	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	20	90%	25%	88.0%	65.9%	65.9%	3.2
1151	Refrigeration	Energy Star Ice Machine	Biz-Prescriptive	Retail	ROB	6,993	6,993	10%	721	0.00	15	$1,426	25%	18%	18%	21	3%	44%	60.8%	55.2%	55.2%	2.1
1152	Refrigeration	Vending Machine Controller - Refrigerated	Biz-Prescriptive	Retail	Retro	1,586	1,586	34%	537	0.00	5	$245	25%	16%	16%	22	3%	30%	65.5%	61.1%	61.1%	2.7

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
1153	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz-Prescriptive	Retail	Retro	273	273	89%	243	0.00	9	$11	100%	45%	55%	23	11%	35%	88.0%	86.7%	86.9%	30.9
1154	Refrigeration	LED Refrigerated Display Case Lighting Controls	Biz-Prescriptive	Retail	Retro	522	522	27%	141	0.00	10	$15	100%	100%	100%	24	11%	18%	88.0%	88.0%	88.0%	6.6
1155	Ventilation	Demand Controlled Ventilation	Biz-Custom	Retail	Retro	2,798	2,798	20%	560	0.00	15	$227	100%	25%	25%	1	100%	18%	92.7%	51.2%	51.2%	10.7
1156	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz-Prescriptive	Retail	Retro	1,902	1,902	38%	731	0.00	15	$200	100%	30%	55%	2	100%	18%	92.7%	74.0%	79.4%	11.6
1157	WholeBldg_HVAC	HVAC - Energy Management System	Biz-Custom RCx	Retail	Retro	13	13	8%	1	0.00	15	$0	100%	25%	25%	1	100%	20%	92.7%	51.6%	51.6%	8.8
1158	WholeBldg_HVAC	Guest room energy management system	Biz-Custom	Retail	Retro	0	0	0%	0	0.00	15	$260	0%		0%	2	100%	20%	92.7%	74.2%	74.2%	0.0
1159	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz-Custom RCx	Retail	Retro	10	10	10%	1	0.00	15	$0	100%	25%	25%	3	100%	0%	92.7%	51.6%	51.6%	8.8
1160	WholeBuilding	WholeBlg - Com RET	Biz-Custom	Retail	Retro	7	7	15%	1	0.00	12	$0	100%	25%	25%	1	90%	0%	92.7%	51.6%	51.6%	7.3
1161	WholeBuilding	WholeBlg - Custom (Other)	Biz-Custom	Retail	Retro	5	5	20%	1	0.00	12	$0	100%	25%	25%	2	90%	0%	92.7%	51.6%	51.6%	7.3
1162	WholeBuilding	Power Distribution Equipment Upgrades (Transformers)	Biz-Custom	Retail	Retro	1,150	1,150	1%	6	0.00	30	$8	100%	9%	9%	3	100%	20%	92.7%	36.0%	36.0%	17.1
1163	WholeBldg_NC	WholeBlg - Com NC	Biz-Custom	Retail	NC	4	4	25%	1	0.00	12	$0	100%	50%	50%	1	100%	60%	83.4%	68.0%	68.0%	7.6
1164	Behavioral	COM Competitions	Biz-Custom	Retail	Retro	53	53	2%	1	0.00	2	$0	100%	50%	50%	1	100%	0%	50.0%	40.0%	40.0%	3.9
1165	Behavioral	Business Energy Reports	Biz-Custom	Retail	Retro	313	313	0%	1	0.00	2	$0	50%	50%	50%	1	100%	0%	50.0%	40.0%	40.0%	0.8
1166	Behavioral	Building Benchmarking	Biz-Custom	Retail	Retro	97	97	1%	1	0.00	2	$0	45%	45%	45%	1	100%	0%	50.0%	40.0%	40.0%	0.8
1167	Behavioral	Strategic Energy Management	Biz-Custom SEM	Retail	Retro	0	0	0%	0	0.00	5	$0	0%		0%	1	100%	0%	50.0%	40.0%	40.0%	0.0
1168	Behavioral	BEIMS	Biz-Custom	Retail	Retro	20	20	5%	1	0.00	2	$0	23%	23%	23%	1	100%	2%	50.0%	40.0%	40.0%	0.8
1169	Behavioral	Building Operator Certification	Biz-Custom	Retail	Retro	14	14	3%	0	0.00	3	$0	25%	20%	20%	1	100%	2%	50.0%	40.0%	40.0%	1.7
1170	CompressedAir	Efficient Air Compressors (VSD)	Biz-Prescriptive	Office	ROB	1,583	1,583	21%	329	0.00	13	$127	100%	59%	80%	1	100%	33%	92.7%	76.7%	83.1%	5.5
1171	CompressedAir	Efficient Air Nozzles	Biz-Prescriptive	Office	Retro	1,480	1,480	50%	740	0.00	15	$50	100%	81%	81%	2	35%	33%	92.7%	91.1%	91.1%	15.8
1172	CompressedAir	AODD Pump Controls	Biz-Custom	Office	Retro	103,919	103,919	35%	36,372	0.00	10	$1,150	100%	50%	50%	3	10%	33%	92.7%	72.6%	72.6%	38.2
1173	CompressedAir	Compressed Air - Custom	Biz-Custom	Office	Retro	5	5	20%	1	0.00	10	$0	100%	47%	47%	4	50%	33%	92.7%	64.2%	64.2%	6.0
1174	CompressedAir	Retro-commissioning_Compressed Air Optimization	Biz-Custom RCx	Office	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	5	50%	33%	92.7%	64.2%	64.2%	3.2
1175	Cooking	Commercial Combination Oven (Electric)	Biz-Prescriptive	Office	ROB	38,561	38,561	48%	18,432	0.00	12	$16,884	75%	6%	15%	1	18%	53%	77.5%	62.4%	62.4%	14.1
1176	Cooking	Commercial Electric Convection Oven	Biz-Prescriptive	Office	ROB	12,193	12,193	15%	1,879	0.00	12	$1,706	75%	21%	51%	1	18%	53%	77.6%	62.4%	62.4%	4.4
1177	Cooking	Commercial Electric Griddle	Biz-Prescriptive	Office	ROB	17,056	17,056	15%	2,596	0.00	12	$3,604	25%	15%	15%	2	14%	17%	41.9%	33.6%	33.6%	2.8
1178	Cooking	Commercial Electric Steam Cooker	Biz-Prescriptive	Office	ROB	19,549	19,549	67%	13,162	0.00	12	$2,490	100%	24%	55%	3	6%	45%	88.0%	81.1%	83.5%	18.0
1179	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz-Prescriptive	Office	ROB	39,306	39,306	44%	17,369	0.00	15	$1,000	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	11.7
1180	Cooking	Dishwasher High Temp Door (Energy Star)	Biz-Prescriptive	Office	ROB	26,901	26,901	32%	8,586	0.00	15	$1,100	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	5.2
1181	Cooking	Energy efficient electric fryer	Biz-Prescriptive	Office	ROB	18,955	18,955	17%	3,274	0.00	12	$1,500	100%	5%	13%	5	27%	24%	88.0%	57.2%	59.4%	23.2
1182	Cooking	Insulated Holding Cabinets (Full Size)	Biz-Prescriptive	Office	ROB	13,697	13,697	68%	9,314	0.00	12	$1,200	100%	35%	55%	6	3%	16%	88.0%	83.6%	84.9%	12.7
1183	Cooking	Insulated Holding Cabinets (Half-Size)	Biz-Prescriptive	Office	ROB	4,383	4,383	60%	2,630	0.00	12	$1,500	100%	10%	25%	6	3%	16%	88.0%	52.6%	57.6%	10.1
1184	Cooling	Air Conditioner - 13 IEER (5-20 Tons)	Biz-Prescriptive	Office	ROB	1,278	1,278	6%	79	0.00	15	$63	100%	48%	55%	1	26%	20%	92.7%	54.4%	58.7%	4.9
1185	Cooling	Air Conditioner - 14 IEER (5-20 Tons)	Biz-Prescriptive	Office	ROB	1,278	1,278	13%	164	0.00	15	$127	100%	24%	55%	1	26%	20%	92.7%	48.4%	59.9%	10.3
1186	Cooling	Air Conditioner - 17 IEER (5-20 Tons)	Biz-Prescriptive	Office	ROB	1,278	1,278	28%	361	0.00	15	$127	100%	24%	55%	1	26%	20%	92.7%	67.4%	76.6%	22.7
1187	Cooling	Air Conditioner - 21 IEER (5-20 Tons)	Biz-Prescriptive	Office	ROB	1,278	1,278	42%	535	0.00	15	$127	100%	24%	55%	1	26%	20%	92.7%	74.8%	80.7%	33.7
1188	Cooling	Air Conditioner - 12.1 IEER (20+ Tons)	Biz-Prescriptive	Office	ROB	1,367	1,367	6%	79	0.00	15	$30	100%	100%	100%	2	26%	20%	92.7%	92.7%	92.7%	5.0
1189	Cooling	Air Conditioner - 13 IEER (20+ Tons)	Biz-Prescriptive	Office	ROB	1,367	1,367	12%	168	0.00	15	$37	100%	81%	81%	2	26%	20%	92.7%	87.5%	87.5%	10.6
1190	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz-Prescriptive	Office	ROB	1,367	1,367	20%	277	0.00	15	$37	100%	81%	81%	2	26%	20%	92.7%	89.6%	89.6%	17.4
1191	Cooling	Air Conditioner - 21 IEER (20+ Tons)	Biz-Prescriptive	Office	ROB	1,367	1,367	46%	625	0.00	15	$37	100%	81%	81%	2	26%	20%	92.7%	91.3%	91.3%	39.3
1192	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz-Custom	Office	Retro	1,299	1,299	7%	91	0.00	3	$5	100%	50%	50%	3	51%	50%	92.7%	71.2%	71.2%	15.4
1193	Cooling	Air Side Economizer	Biz-Custom	Office	Retro	1,278	1,278	20%	256	0.00	10	$84	100%	30%	30%	4	51%	20%	92.7%	56.9%	56.9%	3.9
1194	Cooling	Advanced Rooftop Controls	Biz-Prescriptive	Office	Retro	1,299	1,299	2%	23	0.00	10	$100	100%	100%	100%	5	51%	20%	92.7%	92.7%	92.7%	0.1
1195	Cooling	HVAC Occupancy Controls	Biz-Custom	Office	ROB	2,900	2,900	20%	580	0.00	15	$537	100%	11%	11%	6	51%	20%	92.7%	36.0%	36.0%	12.0
1196	Cooling	Air Conditioner - 16 SEER (<5 Tons)	Biz-Prescriptive	Office	ROB	1,113	1,113	13%	139	0.00	15	$47	100%	64%	80%	7	8%	20%	92.7%	79.6%	84.3%	8.8
1197	Cooling	Air Conditioner - 17 SEER (<5 Tons)	Biz-Prescriptive	Office	ROB	1,113	1,113	18%	196	0.00	15	$206	100%	15%	36%	7	8%	20%	92.7%	39.4%	45.6%	12.4
1198	Cooling	Air Conditioner - 18 SEER(<5 Tons)	Biz-Prescriptive	Office	ROB	1,113	1,113	22%	247	0.00	15	$206	100%	15%	36%	7	8%	20%	92.7%	44.1%	50.5%	15.6
1199	Cooling	Air Conditioner - 21 SEER(<5 Tons)	Biz-Prescriptive	Office	ROB	1,113	1,113	33%	371	0.00	15	$253	100%	12%	30%	7	8%	20%	92.7%	48.0%	52.3%	23.3
1200	Cooling	Smart Thermostat	Biz-Prescriptive	Office	ROB	1,113	1,113	14%	158	0.00	11	$175	75%	57%	57%	8	8%	12%	66.6%	52.4%	52.4%	1.4
1201	Cooling	PTAC - <7,000 Btuh - lodging	Biz-Prescriptive	Office	ROB	1,310	1,310	8%	111	0.00	8	$84	100%	36%	55%	9	7%	20%	92.7%	52.0%	60.5%	3.8
1202	Cooling	PTAC - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Office	ROB	1,437	1,437	7%	104	0.00	8	$84	100%	36%	36%	10	7%	20%	92.7%	51.0%	51.0%	3.6
1203	Cooling	PTAC - >15,000 Btuh - lodging	Biz-Prescriptive	Office	ROB	1,641	1,641	10%	156	0.00	8	$84	100%	36%	55%	11	7%	20%	92.7%	60.1%	70.0%	5.4
1204	Cooling	Air Cooled Chiller	Biz-Prescriptive	Office	ROB	1,138	1,138	6%	64	0.00	23	$126	100%	24%	55%	12	34%	15%	92.7%	32.0%	39.6%	6.8
1205	Cooling	Chiller Tune-up	Biz-Prescriptive	Office	Retro	1,299	1,299	7%	91	0.00	3	$8	100%	100%	100%	13	34%	50%	92.7%	92.7%	92.7%	5.1
1206	Cooling	HVAC/Chiller Custom	Biz-Custom	Office	Retro	5	5	20%	1	0.00	20	$1	100%	7%	7%	14	100%	20%	92.7%	36.0%	36.0%	30.3
1207	Cooling	Window Film	Biz-Prescriptive	Office	Retro	6,000	6,000	4%	264	0.00	10	$154	100%	65%	65%	15	100%	20%	92.7%	73.1%	73.1%	3.2
1208	Cooling	Triple Pane Windows	Biz-Custom	Office	ROB	6,000	6,000	6%	360	0.00	25	$700	100%	5%	5%	15	100%	20%	92.7%	36.0%	36.0%	24.5
1209	Cooling	Energy Recovery Ventilator	Biz-Custom	Office	Retro	1,367	1,367	70%	952	0.00	15	$1,500	100%	6%	6%	16	100%	2%	92.7%	23.3%	23.3%	34.7
1210	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz-Prescriptive	Office	ROB	1,703	1,703	5%	80	0.00	16	$87	100%	46%	46%	1	8%	20%	92.7%	48.4%	48.4%	2.9
1211	Heating	Heat Pump - 17 SEER (<5 Tons)	Biz-Prescriptive	Office	ROB	1,703	1,703	10%	165	0.00	16	$442	50%	9%	23%	1	8%	20%	44.0%	36.0%	36.0%	5.6
1212	Heating	Heat Pump - 18 SEER(<5 Tons)	Biz-Prescriptive	Office	ROB	1,703	1,703	14%	235	0.00	16	$507	50%	8%	20%	1	8%	20%	44.0%	36.0%	36.0%	7.9
1213	Heating	Heat Pump - 21 SEER(<5 Tons)	Biz-Prescriptive	Office	ROB	1,703	1,703	22%	377	0.00	16	$507	100%	8%	20%	1	8%	20%	92.7%	36.0%	36.2%	12.8
1214	Heating	Geothermal HP - SEER 20.3 (<5 Tons)	Biz-Prescriptive	Office	ROB	1,703	1,703	24%	404	0.00	25	$2,576	25%	2%	4%	1	8%	20%	44.0%	36.0%	36.0%	17.7
1215	Heating	Geothermal HP - SEER 21.5 (<5 Tons)	Biz-Prescriptive	Office	ROB	1,703	1,703	28%	477	0.00	25	$2,576	25%	2%	4%	1	8%	20%	44.0%	36.0%	36.0%	20.4
1216	Heating	Geothermal HP - SEER 23.1 (<5 Tons)	Biz-Prescriptive	Office	ROB	1,703	1,703	33%	562	0.00	25	$2,576	25%	2%	4%	1	8%	20%	44.0%	36.0%	36.0%	23.4
1217	Heating	Geothermal HP - SEER 29.3 (<5 Tons)	Biz-Prescriptive	Office	ROB	1,703	1,703	47%	807	0.00	25	$2,576	25%	2%	4%	1	8%	20%	44.0%	36.0%	36.0%	30.0
1218	Heating	Heat Pump - 14.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Office	ROB	2,077	2,077	12%	250	0.00	16	$100	100%	40%	55%	2	26%	20%	92.7%	70.2%	75.0%	32.1
1219	Heating	Heat Pump - 15.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Office	ROB	2,077	2,077	17%	362	0.00	16	$136	100%	30%	55%	2	26%	20%	92.7%	67.9%	75.8%	35.8
1220	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Office	ROB	2,170	2,170	17%	361	0.00	16	$100	100%	40%	55%	2	26%	20%	92.7%	76.0%	79.3%	36.7
1221	Heating	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Office	ROB	2,170	2,170	22%	470	0.00	16	$139	100%	29%	55%	2	26%	20%	92.7%	72.6%	78.6%	40.2
1222	Heating	Geothermal HP - SEER 20.3 (5-20 Tons)	Biz-Prescriptive	Office	ROB	1,886	1,886	31%	587	0.00	25	$2,576	50%	2%	4%	2	26%	20%	44.0%	36.0%	36.0%	36.8
1223	Heating	Geothermal HP - SEER 21.5 (5-20 Tons)	Biz-Prescriptive	Office	ROB	1,886	1,886	35%	659	0.00	25	$2,576	50%	2%	4%	2	26%	20%	44.0%	36.0%	36.0%	39.5
1224	Heating	Geothermal HP - SEER 23.1 (5-20 Tons)	Biz-Prescriptive	Office	ROB	2,050	2,050	44%	908	0.00	25	$2,576	50%	2%	4%	2	26%	20%	44.0%	36.0%	36.0%	46.1

Appendix C: C&I Measure Assumptions

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
1225	Heating	Geothermal HP - SEER 29.3 (5-20 Tons)	Biz-Prescriptive	Office	ROB	2,050	2,050	56%	1,154	0.00	25	$2,576	75%	2%	4%	2	26%	20%	49.5%	36.0%	36.0%	52.7
1226	Heating	Variable Refrigerant Flow Heat Pump	Biz-Custom	Office	ROB	1,624	1,624	18%	297	0.00	16	$224	100%	13%	13%	2	26%	2%	92.7%	36.9%	36.9%	15.6
1227	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz-Prescriptive	Office	ROB	2,301	2,301	11%	247	0.00	16	$100	100%	40%	55%	3	26%	20%	92.7%	69.9%	74.8%	28.8
1228	Heating	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	Biz-Prescriptive	Office	ROB	2,301	2,301	17%	389	0.00	16	$175	100%	23%	55%	3	26%	20%	92.7%	60.0%	73.2%	33.7
1229	Heating	Geothermal HP - SEER 20.3 (20+ Tons)	Biz-Prescriptive	Office	ROB	2,170	2,170	40%	871	0.00	25	$2,576	100%	2%	4%	3	26%	20%	92.7%	36.0%	36.0%	71.3
1230	Heating	Geothermal HP - SEER 21.5 (20+ Tons)	Biz-Prescriptive	Office	ROB	2,170	2,170	43%	943	0.00	25	$2,576	100%	2%	4%	3	26%	20%	92.7%	36.0%	36.0%	74.0
1231	Heating	Geothermal HP - SEER 23.1 (20+ Tons)	Biz-Prescriptive	Office	ROB	2,170	2,170	47%	1,028	0.00	25	$2,576	100%	2%	4%	3	26%	20%	92.7%	36.0%	36.0%	77.0
1232	Heating	Geothermal HP - SEER 29.3 (20+ Tons)	Biz-Prescriptive	Office	ROB	2,170	2,170	59%	1,274	0.00	25	$2,576	100%	2%	4%	3	26%	20%	92.7%	36.0%	36.0%	83.6
1233	Heating	Mini Split Ductless Heat Pump Cold Climate (Tiers & sizes TBD)	Biz-Prescriptive	Office	ROB	1,703	1,703	22%	377	0.00	16	$224	100%	18%	45%	4	30%	20%	92.7%	52.0%	61.7%	12.8
1234	Heating	PTHP - <7,000 Btuh - lodging	Biz-Custom	Office	ROB	1,849	1,849	6%	107	0.00	8	$130	100%	100%	100%	5	3%	10%	92.7%	74.2%	74.2%	0.8
1235	Heating	PTHP - >15,000 Btuh - lodging	Biz-Prescriptive	Office	ROB	2,324	2,324	22%	509	0.00	8	$130	100%	100%	100%	6	3%	10%	92.7%	92.7%	92.7%	3.8
1236	Heating	PTHP - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Office	ROB	2,054	2,054	13%	264	0.00	8	$130	100%	100%	100%	7	3%	10%	92.7%	92.7%	92.7%	1.9
1237	HotWater	Heat Pump Water Heater	Biz-Prescriptive	Office	ROB	4,536	4,536	67%	3,038	0.00	15	$1,115	100%	45%	55%	1	100%	11%	84.0%	70.7%	73.7%	5.0
1238	HotWater	Hot Water Pipe Insulation	Biz-Custom	Office	Retro	4,536	4,536	2%	91	0.00	20	$60	100%	15%	15%	2	100%	80%	86.0%	84.0%	84.0%	9.8
1239	HotWater	Faucet Aerator	Biz-Custom	Office	Retro	545	545	32%	176	0.00	10	$8	100%	50%	50%	3	20%	90%	93.0%	92.0%	92.0%	35.6
1240	HotWater	Low Flow Pre-Rinse Sprayers	Biz-Prescriptive	Office	ROB	18,059	18,059	54%	9,789	0.00	5	$60	100%	17%	42%	4	20%	80%	86.0%	84.0%	84.0%	199.3
1241	HotWater	ENERGY STAR Commercial Washing Machines	Biz-Prescriptive	Office	ROB	1,552	1,552	43%	671	0.00	7	$250	75%	28%	28%	5	25%	33%	79.3%	64.6%	64.6%	2.9
1242	InteriorLighting	LED T8 Tube Replacement	Biz-Prescriptive Light	Office	Retro	115	115	45%	51	0.00	15	$5	100%	100%	100%	1	78%	40%	94.6%	94.6%	94.6%	10.6
1243	InteriorLighting	LED troffer retrofit kit, 2'X2' and 2'X4'	Biz-Prescriptive Light	Office	Retro	260	260	50%	130	0.00	15	$70	100%	36%	55%	1	78%	40%	94.6%	54.8%	70.4%	5.4
1244	InteriorLighting	LED troffer, 2'X2' and 2'X4'	Biz-Prescriptive Light	Office	Retro	260	260	50%	130	0.00	15	$70	100%	36%	55%	1	78%	40%	94.6%	54.8%	70.4%	5.4
1245	InteriorLighting	Bi-Level Lighting Fixture – Stairwells, Hallways	Biz-Custom Light	Office	Retro	260	260	74%	193	0.00	10	$274	25%	7%	9%	2	1%	40%	58.0%	50.5%	50.7%	4.8
1246	InteriorLighting	LED high bay fixture	Biz-Prescriptive Light	Office	Retro	2,423	2,423	68%	1,649	0.00	15	$330	100%	35%	55%	3	6%	34%	94.6%	82.5%	86.9%	14.7
1247	InteriorLighting	LED Mogul-base HID Lamp Replacing High Bay HID	Biz-Prescriptive Light	Office	Retro	2,423	2,423	66%	1,608	0.00	15	$330	100%	35%	55%	3	6%	34%	94.6%	82.2%	86.6%	14.4
1248	InteriorLighting	LED low bay fixture	Biz-Prescriptive Light	Office	Retro	516	516	61%	314	0.00	15	$44	100%	68%	80%	4	11%	34%	94.6%	90.9%	92.2%	10.7
1249	InteriorLighting	LED Mogul-base HID Lamp Replacing Low Bay HID	Biz-Prescriptive Light	Office	Retro	516	516	59%	303	0.00	15	$44	100%	68%	80%	4	11%	34%	94.6%	90.7%	92.2%	10.4
1250	InteriorLighting	LED Screw-In Lamps (Directional)	Biz-Prescriptive Light	Office	ROB	283	283	86%	243	0.00	7	$1	100%	100%	100%	6	0%	43%	94.6%	94.6%	94.6%	126.7
1251	InteriorLighting	LED downlight fixture	Biz-Prescriptive Light	Office	Retro	179	179	68%	121	0.00	15	$27	100%	19%	46%	6	4%	45%	94.6%	76.9%	83.6%	24.8
1252	InteriorLighting	LED Screw-In Lamps (Omnidirectional & Decorative)	Biz-Prescriptive Light	Office	ROB	214	214	81%	173	0.00	7	$1	100%	100%	100%	5	1%	20%	94.6%	94.6%	94.6%	90.3
1253	InteriorLighting	DeLamp Fluorescent Fixture Average Lamp Wattage 28W	Biz-Prescriptive Light	Office	Retro	96	96	100%	96	0.00	11	$4	100%	100%	100%	7	78%	0%	94.6%	94.6%	94.6%	18.8
1254	InteriorLighting	Occupancy Sensors	Biz-Prescriptive Light	Office	Retro	438	438	30%	131	0.00	10	$65	75%	31%	31%	8	95%	10%	83.1%	54.7%	54.7%	3.1
1255	InteriorLighting	Daylighting Controls	Biz-Prescriptive Light	Office	Retro	560	560	30%	168	0.00	10	$58	100%	35%	55%	8	95%	10%	94.6%	72.5%	80.0%	7.7
1256	InteriorLighting	Dual Occupancy & Daylighting Controls	Biz-Custom Light	Office	Retro	250	250	44%	110	0.00	10	$75	100%	40%	50%	8	95%	10%	94.6%	37.2%	44.4%	2.7
1257	InteriorLighting	Central Lighting Monitoring & Controls (non-networked)	Biz-Custom Light	Office	Retro	41,703	41,703	20%	8,341	0.00	12	$3,700	100%	23%	29%	8	95%	10%	94.6%	44.1%	47.7%	4.6
1258	InteriorLighting	Network Lighting Controls - Wireless (WiFi)	Biz-Custom Light	Office	Retro	5	5	49%	2	0.00	15	$1	100%	40%	50%	8	95%	10%	94.6%	64.4%	66.5%	7.5
1259	InteriorLighting	Luminaire Level Lighting Controls w/ HVAC Control	Biz-Custom Light	Office	Retro	589	589	65%	383	0.00	15	$90	100%	43%	50%	8	96%	10%	94.6%	65.6%	67.1%	7.5
1260	InteriorLighting	LED Exit Sign - 4 Watt Fixture (2 lamp)	Biz-Prescriptive Light	Office	Retro	70	70	43%	30	0.00	5	$33	92%	92%	92%	9	1%	75%	87.6%	87.6%	87.6%	0.3
1261	InteriorLighting	Lighting - Custom	Biz-Custom Light	Office	Retro	4	4	25%	1	0.00	15	$1	100%	17%	21%	10	100%	0%	94.6%	33.6%	34.7%	7.5
1262	ExteriorLighting	LED wallpack (existing W<250)	Biz-Prescriptive Light	Office	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	1	12%	46%	94.6%	56.6%	70.8%	5.8
1263	ExteriorLighting	LED parking lot fixture (existing W≥250)	Biz-Prescriptive Light	Office	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	2	11%	54%	67.8%	63.2%	63.2%	4.4
1264	ExteriorLighting	LED parking lot fixture (existing W<250)	Biz-Prescriptive Light	Office	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	3	11%	54%	94.6%	63.2%	70.8%	5.8
1265	ExteriorLighting	LED outdoor pole decorative fixture (existing W≥250)	Biz-Prescriptive Light	Office	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	17%	17%	4	11%	54%	67.8%	63.2%	63.2%	3.4
1266	ExteriorLighting	LED parking garage fixture (existing W≥250)	Biz-Prescriptive Light	Office	Retro	3,235	3,235	60%	1,953	0.00	6	$756	50%	13%	33%	5	11%	69%	78.3%	75.2%	75.2%	4.7
1267	ExteriorLighting	LED parking garage fixture (existing W<250)	Biz-Prescriptive Light	Office	Retro	1,742	1,742	66%	1,154	0.00	6	$248	100%	18%	45%	6	11%	69%	94.6%	77.6%	83.9%	6.2
1268	ExteriorLighting	LED Mogul-base HID Lamp Replacing Exterior HID (existing W≥250)	Biz-Prescriptive Light	Office	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	7	11%	46%	62.1%	56.6%	56.6%	4.4
1269	ExteriorLighting	LED Mogul-base HID Lamp Replacing Exterior HID (existing W<250)	Biz-Prescriptive Light	Office	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	8	11%	46%	94.6%	56.6%	70.8%	5.8
1270	ExteriorLighting	Bi-Level Lighting Fixture – Garages	Biz-Custom Light	Office	Retro	260	260	69%	179	0.00	10	$274	25%	7%	9%	9	11%	20%	44.0%	33.2%	33.4%	3.9
1271	ExteriorLighting	LED fuel pump canopy fixture (existing W<250)	Biz-Prescriptive Light	Office	Retro	0	0	0%	0	0.00	12	$0	0%	0%		10	0%	54%	94.6%	94.6%	94.6%	0.0
1272	ExteriorLighting	LED fuel pump canopy fixture (existing W≥250)	Biz-Prescriptive Light	Office	Retro	0	0	0%	0	0.00	12	$0	0%	0%		11	0%	54%	94.6%	94.6%	94.6%	0.0
1273	Miscellaneous	Vending Machine Controller - Non-Refrigerated	Biz-Prescriptive	Office	Retro	385	385	61%	237	0.00	5	$233	11%	11%	11%	1	5%	30%	51.0%	44.0%	44.0%	1.9
1274	Miscellaneous	Miscellaneous Custom	Biz-Custom	Office	Retro	7	7	2%	0	0.00	10	$0	75%	25%	25%	2	31%	10%	37.0%	23.4%	23.4%	3.3
1275	Miscellaneous	Kitchen Exhaust Hood Demand Ventilation Control System	Biz-Prescriptive	Office	ROB	9,932	9,932	50%	4,966	0.00	20	$1,180	100%	11%	27%	3	31%	10%	94.6%	73.8%	78.0%	39.7
1276	Miscellaneous	High Efficiency Hand Dryers	Biz-Custom	Office	Retro	262	262	83%	217	0.00	10	$483	25%	4%	4%	4	5%	10%	37.0%	23.4%	23.4%	8.6
1277	Miscellaneous	Ozone Commercial Laundry	Biz-Custom	Office	Retro	2,984	2,984	25%	746	0.00	10	$20,310	0%	0%	0%	5	3%	2%	31.4%	16.6%	16.6%	3.9
1278	Miscellaneous	ENERGY STAR Uninterrupted Power Supply	Biz-Custom	Office	ROB	3,096	3,096	3%	85	0.00	15	$59	100%	14%	14%	6	1%	70%	94.6%	76.0%	76.0%	8.8
1279	Motors	Cogged V-Belt	Biz-Custom	Office	Retro	9,092	9,092	3%	282	0.00	15	$384	75%	7%	7%	1	50%	10%	52.9%	28.0%	28.0%	12.5
1280	Motors	Pump and Fan Variable Frequency Drive Controls (Pumps)	Biz-Custom	Office	Retro	1,902	1,902	38%	731	0.00	15	$200	100%	30%	30%	2	100%	10%	83.4%	52.4%	52.4%	11.6
1281	Motors	Power Drive Systems	Biz-Custom	Office	Retro	4	4	23%	1	0.00	15	$0	100%	37%	37%	2	100%	10%	83.4%	53.4%	53.4%	12.5
1282	Motors	Switch Reluctance Motors	Biz-Custom	Office	Retro	17,620	17,620	31%	5,392	0.00	15	$528	100%	50%	50%	2	100%	1%	83.4%	61.8%	61.8%	13.9
1283	Motors	Escalators Motor Efficiency Controllers	Biz-Custom	Office	Retro	7,500	7,500	20%	1,500	0.00	10	$5,000	3%	3%	3%	3	0%	10%	37.0%	26.3%	26.3%	7.3
1284	Office_NonPC	Energy Star Printer/Copier/Fax	Biz-Custom	Office	ROB	551	551	40%	223	0.00	6	$0	0%			1	30%	90%	94.6%	92.0%	92.0%	0.0
1285	Office_NonPC	Smart Power Strip – Commercial Use	Biz-Custom	Office	Retro	1,086	1,086	10%	109	0.00	7	$50	50%	22%	22%	2	35%	15%	71.8%	42.0%	42.0%	2.8
1286	Office_NonPC	Plug Load Occupancy Sensor	Biz-Custom	Office	Retro	1,126	1,126	15%	169	0.00	8	$70	75%	24%	24%	2	35%	15%	85.4%	47.6%	47.6%	3.2
1287	Office_PC	Electrically Commutated Plug Fans in data centers	Biz-Custom	Office	Retro	86,783	86,783	18%	15,778	0.00	15	$480	100%	50%	50%	1	65%	20%	94.6%	74.6%	74.6%	50.8
1288	Office_PC	Energy Star Server	Biz-Custom	Office	ROB	1,621	1,621	23%	368	0.00	8	$118	100%	31%	31%	1	65%	25%	94.6%	58.2%	58.2%	4.5
1289	Office_PC	Server Virtualization	Biz-Custom	Office	Retro	2	2	45%	1	0.00	8	$0	75%	25%	25%	1	65%	25%	85.8%	49.3%	49.3%	3.2
1290	Office_PC	High Efficiency CRAC unit	Biz-Custom	Office	ROB	541	541	30%	162	0.00	15	$63	100%	26%	26%	2	65%	20%	94.6%	51.1%	51.1%	8.1
1291	Office_PC	Computer Room Air Conditioner Economizer	Biz-Custom	Office	Retro	764	764	47%	358	0.00	15	$82	100%	44%	44%	2	65%	20%	94.6%	66.1%	66.1%	5.6
1292	Office_PC	Data Center Hot/Cold Aisle Configuration	Biz-Custom	Office	Retro	4	4	25%	1	0.00	15	$0	100%	25%	25%	3	3%	10%	94.6%	49.3%	49.3%	7.7
1293	Office_PC	Energy Star Laptop	Biz-Custom	Office	ROB	126	126	33%	41	0.00	4	$0	0%			4	11%	85%	94.6%	88.0%	88.0%	0.0
1294	Office_PC	Energy Star Monitor	Biz-Custom	Office	ROB	72	72	21%	15	0.00	4	$0	0%			5	25%	85%	94.6%	88.0%	88.0%	0.0
1295	Refrigeration	Strip Curtains	Biz-Custom	Office	Retro	0	0	0%	0	0.00	4	$0	0%	0%		1	1%	30%	88.0%	70.4%	70.4%	0.0
1296	Refrigeration	Bare Suction Line	Biz-Custom	Office	Retro	23	23	93%	21	0.00	15	$4	100%	50%	50%	2	0%	50%	88.0%	66.5%	66.5%	8.1

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
1297	Refrigeration	Floating Head Pressure Controls	Biz-Custom	Office	Retro	1,112	1,112	25%	278	0.00	15	$431	25%	6%	6%	3	1%	25%	47.5%	40.0%	40.0%	5.6
1298	Refrigeration	Saturated Suction Controls	Biz-Custom	Office	Retro	831	831	50%	416	0.00	15	$559	100%	7%	7%	4	2%	10%	88.0%	28.0%	28.0%	13.7
1299	Refrigeration	Compressor Retrofit	Biz-Custom	Office	Retro	813	813	20%	163	0.00	15	$477	25%	3%	3%	5	2%	25%	47.5%	39.4%	39.4%	13.8
1300	Refrigeration	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	Biz-Prescriptive	Office	Retro	2,440	2,440	65%	1,586	0.00	15	$305	100%	13%	33%	6	1%	80%	88.0%	84.0%	84.0%	30.7
1301	Refrigeration	Evaporator Fan Motor Controls	Biz-Custom	Office	Retro	1,912	1,912	25%	478	0.00	13	$162	100%	30%	30%	7	1%	25%	88.0%	61.7%	61.7%	7.0
1302	Refrigeration	Variable Speed Condenser Fan	Biz-Custom	Office	Retro	2,960	2,960	50%	1,480	0.00	15	$1,170	50%	13%	13%	8	1%	25%	59.5%	40.0%	40.0%	5.6
1303	Refrigeration	Refrigeration Economizer	Biz-Custom	Office	Retro	7	7	2%	0	0.00	10	$0	100%	50%	50%	9	3%	10%	88.0%	41.1%	41.1%	4.2
1304	Refrigeration	Anti-Sweat Heater Controls MT	Biz-Prescriptive	Office	Retro	579	579	59%	338	0.00	10	$170	75%	44%	44%	10	20%	25%	81.8%	72.4%	72.4%	2.1
1305	Refrigeration	Auto Door Closer, Cooler	Biz-Custom	Office	Retro	471,500	471,500	0%	943	0.00	8	$157	100%	50%	50%	11	15%	50%	88.0%	66.9%	66.9%	5.8
1306	Refrigeration	Display Case Door Retrofit, Medium Temp	Biz-Custom	Office	Retro	1,584	1,584	36%	578	0.00	12	$686	50%	8%	8%	11	6%	25%	47.9%	40.0%	40.0%	7.1
1307	Refrigeration	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	Biz-Prescriptive	Office	Retro	2,440	2,440	65%	1,586	0.00	15	$305	100%	13%	33%	12	3%	80%	88.0%	84.0%	84.0%	30.7
1308	Refrigeration	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	Biz-Custom	Office	Retro	1,911	1,911	26%	504	0.00	10	$96	100%	50%	50%	12	3%	2%	88.0%	66.5%	66.5%	5.8
1309	Refrigeration	Energy Star Reach-In Refrigerator, Glass Doors	Biz-Prescriptive	Office	ROB	2,140	2,140	29%	629	0.00	12	$1,239	25%	6%	14%	13	19%	54%	67.8%	63.2%	63.2%	5.6
1310	Refrigeration	Energy Star Reach-In Refrigerator, Solid Doors	Biz-Prescriptive	Office	ROB	1,410	1,410	20%	281	0.00	12	$1,211	6%	6%	6%	14	19%	54%	67.8%	63.2%	63.2%	2.5
1311	Refrigeration	Anti-Sweat Heater Controls LT	Biz-Prescriptive	Office	Retro	2,016	2,016	68%	1,361	0.00	10	$170	100%	44%	55%	15	7%	25%	88.0%	84.3%	85.0%	8.3
1312	Refrigeration	Auto Door Closer, Freezer	Biz-Custom	Office	Retro	419,455	419,455	1%	2,307	0.00	8	$157	100%	50%	50%	16	7%	50%	88.0%	68.9%	68.9%	13.9
1313	Refrigeration	Display Case Door Retrofit, Low Temp	Biz-Custom	Office	Retro	2,922	2,922	50%	1,453	0.00	12	$686	100%	21%	21%	16	7%	25%	88.0%	49.7%	49.7%	7.1
1314	Refrigeration	Energy Star Reach-In Freezer, Glass Doors	Biz-Prescriptive	Office	ROB	6,374	6,374	20%	1,275	0.00	12	$1,651	25%	21%	21%	17	6%	54%	67.8%	63.2%	63.2%	2.3
1315	Refrigeration	Energy Star Reach-In Freezer, Solid Doors	Biz-Prescriptive	Office	ROB	4,522	4,522	7%	305	0.00	12	$1,521	23%	23%	23%	18	6%	54%	67.8%	63.2%	63.2%	0.5
1316	Refrigeration	Refrigeration - Custom	Biz-Custom	Office	ROB	7	7	2%	0	0.00	10	$0	75%	25%	25%	19	90%	25%	47.5%	39.4%	39.4%	3.3
1317	Refrigeration	Retro-commissioning_Refrigerator Optimization	Biz-Custom RCx	Office	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	20	90%	25%	88.0%	65.9%	65.9%	3.2
1318	Refrigeration	Energy Star Ice Machine	Biz-Prescriptive	Office	ROB	6,993	6,993	10%	721	0.00	15	$1,426	25%	18%	18%	21	9%	44%	60.8%	55.2%	55.2%	2.1
1319	Refrigeration	Vending Machine Controller - Refrigerated	Biz-Prescriptive	Office	Retro	1,586	1,586	34%	537	0.00	5	$245	25%	16%	16%	22	9%	30%	65.5%	61.1%	61.1%	2.7
1320	Refrigeration	LED Refrigerated Display Case Lighting Average 6W/LF	Biz-Prescriptive	Office	Retro	273	273	89%	243	0.00	9	$11	100%	45%	55%	23	12%	35%	88.0%	86.7%	86.9%	30.9
1321	Refrigeration	LED Refrigerated Display Case Lighting Controls	Biz-Prescriptive	Office	Retro	522	522	27%	141	0.00	10	$15	100%	100%	100%	24	12%	18%	88.0%	88.0%	88.0%	6.6
1322	Ventilation	Demand Controlled Ventilation	Biz-Custom	Office	Retro	2,644	2,644	20%	529	0.00	15	$227	100%	23%	23%	1	100%	49%	92.7%	59.1%	59.1%	6.5
1323	Ventilation	Pump and Fan Variable Frequency Drive Controls (Fans)	Biz-Prescriptive	Office	Retro	1,902	1,902	38%	731	0.00	15	$200	100%	30%	55%	2	100%	49%	92.7%	74.0%	79.4%	11.6
1324	WholeBldg_HVAC	HVAC - Energy Management System	Biz-Custom RCx	Office	Retro	13	13	8%	1	0.00	15	$0	100%	25%	25%	1	100%	20%	92.7%	51.6%	51.6%	8.8
1325	WholeBldg_HVAC	Guest room energy management system	Biz-Custom	Office	Retro	0	0	0%	0	0.00	15	$260	0%		0%	2	100%	20%	92.7%	74.2%	74.2%	0.0
1326	WholeBldg_HVAC	Retro-commissioning_Bld Optimization	Biz-Custom RCx	Office	Retro	10	10	10%	1	0.00	15	$0	100%	25%	25%	3	100%	0%	92.7%	51.6%	51.6%	8.8
1327	WholeBuilding	WholeBlg - Com RET	Biz-Custom	Office	Retro	7	7	15%	1	0.00	12	$0	100%	25%	25%	1	90%	0%	92.7%	51.6%	51.6%	7.3
1328	WholeBuilding	WholeBlg - Custom (Other)	Biz-Custom	Office	Retro	5	5	20%	1	0.00	12	$0	100%	25%	25%	2	90%	0%	92.7%	51.6%	51.6%	7.3
1329	WholeBuilding	Power Distribution Equipment Upgrades (Transformers)	Biz-Custom	Office	Retro	1,150	1,150	1%	6	0.00	30	$8	100%	9%	9%	3	100%	20%	92.7%	36.0%	36.0%	17.1
1330	WholeBldg_NC	WholeBlg - Com NC	Biz-Custom	Office	NC	4	4	25%	1	0.00	12	$0	100%	50%	50%	1	100%	60%	83.4%	68.0%	68.0%	7.6
1331	Behavioral	COM Competitions	Biz-Custom	Office	Retro	53	53	2%	1	0.00	2	$0	100%	50%	50%	1	100%	0%	50.0%	40.0%	40.0%	3.9
1332	Behavioral	Business Energy Reports	Biz-Custom	Office	Retro	0	0	0%	0	0.00	2	$0	0%		0%	1	100%	0%	50.0%	40.0%	40.0%	0.0
1333	Behavioral	Building Benchmarking	Biz-Custom	Office	Retro	114	114	1%	1	0.00	2	$0	45%	45%	45%	1	100%	0%	50.0%	40.0%	40.0%	0.8
1334	Behavioral	Strategic Energy Management	Biz-Custom SEM	Office	Retro	33	33	3%	1	0.00	5	$0	75%	37%	37%	1	100%	0%	50.0%	40.0%	40.0%	2.1
1335	Behavioral	BEIMS	Biz-Custom	Office	Retro	29	29	4%	1	0.00	2	$0	23%	23%	23%	1	100%	2%	50.0%	40.0%	40.0%	0.8
1336	Behavioral	Building Operator Certification	Biz-Custom	Office	Retro	16	16	3%	0	0.00	3	$0	25%	22%	22%	1	100%	2%	50.0%	40.0%	40.0%	1.7
1337	CompressedAir	Efficient Air Compressors (VSD)	Biz-Prescriptive	Warehouse	ROB	1,583	1,583	21%	329	0.00	13	$127	100%	59%	80%	1	100%	33%	92.7%	76.7%	83.1%	5.5
1338	CompressedAir	Efficient Air Nozzles	Biz-Prescriptive	Warehouse	Retro	1,480	1,480	50%	740	0.00	15	$50	100%	81%	81%	2	35%	33%	92.7%	91.1%	91.1%	15.8
1339	CompressedAir	AODD Pump Controls	Biz-Custom	Warehouse	Retro	103,919	103,919	35%	36,372	0.00	10	$1,150	100%	50%	50%	3	10%	33%	92.7%	72.6%	72.6%	38.2
1340	CompressedAir	Compressed Air - Custom	Biz-Custom	Warehouse	Retro	5	5	20%	1	0.00	10	$0	100%	47%	47%	4	50%	33%	92.7%	64.2%	64.2%	6.0
1341	CompressedAir	Retro-commissioning_Compressed Air Optimization	Biz-Custom RCx	Warehouse	Retro	3	3	30%	1	0.00	5	$0	100%	47%	47%	5	50%	33%	92.7%	64.2%	64.2%	3.2
1342	Cooking	Commercial Combination Oven (Electric)	Biz-Prescriptive	Warehouse	ROB	38,561	38,561	48%	18,432	0.00	12	$16,884	75%	6%	15%	1	18%	53%	77.5%	62.4%	62.4%	14.1
1343	Cooking	Commercial Electric Convection Oven	Biz-Prescriptive	Warehouse	ROB	12,193	12,193	15%	1,879	0.00	12	$1,706	75%	21%	51%	1	18%	53%	77.6%	62.4%	62.4%	4.4
1344	Cooking	Commercial Electric Griddle	Biz-Prescriptive	Warehouse	ROB	17,056	17,056	15%	2,596	0.00	12	$3,604	25%	15%	15%	2	14%	17%	41.9%	33.6%	33.6%	2.8
1345	Cooking	Commercial Electric Steam Cooker	Biz-Prescriptive	Warehouse	ROB	19,549	19,549	67%	13,162	0.00	12	$2,490	100%	24%	55%	3	6%	45%	88.0%	81.1%	83.5%	18.0
1346	Cooking	Dishwasher Low Temp Door (Energy Star)	Biz-Prescriptive	Warehouse	ROB	39,306	39,306	44%	17,369	0.00	15	$1,000	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	11.7
1347	Cooking	Dishwasher High Temp Door (Energy Star)	Biz-Prescriptive	Warehouse	ROB	26,901	26,901	32%	8,586	0.00	15	$1,100	100%	100%	100%	4	26%	61%	88.0%	88.0%	88.0%	5.2
1348	Cooking	Energy efficient electric fryer	Biz-Prescriptive	Warehouse	ROB	18,955	18,955	17%	3,274	0.00	12	$1,500	100%	5%	13%	5	27%	24%	88.0%	57.2%	59.4%	23.2
1349	Cooking	Insulated Holding Cabinets (Full Size)	Biz-Prescriptive	Warehouse	ROB	13,697	13,697	68%	9,314	0.00	12	$1,200	100%	35%	55%	6	3%	16%	88.0%	83.6%	84.9%	12.7
1350	Cooking	Insulated Holding Cabinets (Half-Size)	Biz-Prescriptive	Warehouse	ROB	4,383	4,383	60%	2,630	0.00	12	$1,500	100%	10%	25%	6	3%	16%	88.0%	52.6%	57.6%	10.1
1351	Cooling	Air Conditioner - 13 IEER (5-20 Tons)	Biz-Prescriptive	Warehouse	ROB	828	828	6%	51	0.00	15	$63	100%	48%	55%	1	31%	20%	92.7%	46.4%	49.6%	4.4
1352	Cooling	Air Conditioner - 14 IEER (5-20 Tons)	Biz-Prescriptive	Warehouse	ROB	828	828	13%	106	0.00	15	$127	100%	24%	55%	1	31%	20%	92.7%	39.2%	50.3%	9.3
1353	Cooling	Air Conditioner - 17 IEER (5-20 Tons)	Biz-Prescriptive	Warehouse	ROB	828	828	28%	234	0.00	15	$127	100%	24%	55%	1	31%	20%	92.7%	54.6%	69.8%	20.3
1354	Cooling	Air Conditioner - 21 IEER (5-20 Tons)	Biz-Prescriptive	Warehouse	ROB	828	828	42%	347	0.00	15	$127	100%	24%	55%	1	31%	20%	92.7%	66.4%	76.1%	30.2
1355	Cooling	Air Conditioner - 12.1 IEER (20+ Tons)	Biz-Prescriptive	Warehouse	ROB	886	886	6%	51	0.00	15	$30	100%	100%	100%	2	31%	20%	92.7%	92.7%	92.7%	4.5
1356	Cooling	Air Conditioner - 13 IEER (20+ Tons)	Biz-Prescriptive	Warehouse	ROB	886	886	12%	109	0.00	15	$37	100%	81%	81%	2	31%	20%	92.7%	84.7%	84.7%	9.5
1357	Cooling	Air Conditioner - 14.3 IEER (20+ Tons)	Biz-Prescriptive	Warehouse	ROB	886	886	20%	180	0.00	15	$37	100%	81%	81%	2	31%	20%	92.7%	87.9%	87.9%	15.6
1358	Cooling	Air Conditioner - 21 IEER (20+ Tons)	Biz-Prescriptive	Warehouse	ROB	886	886	46%	405	0.00	15	$37	100%	81%	81%	2	31%	20%	92.7%	90.6%	90.6%	35.2
1359	Cooling	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	Biz-Custom	Warehouse	Retro	842	842	7%	59	0.00	3	$5	100%	50%	50%	3	62%	50%	92.7%	69.7%	69.7%	14.0
1360	Cooling	Air Side Economizer	Biz-Custom	Warehouse	Retro	828	828	20%	166	0.00	10	$84	75%	20%	20%	4	62%	20%	79.1%	43.9%	43.9%	3.9
1361	Cooling	Advanced Rooftop Controls	Biz-Prescriptive	Warehouse	Retro	842	842	1%	6	0.00	10	$100	100%	100%	100%	5	62%	20%	92.7%	92.7%	92.7%	0.0
1362	Cooling	HVAC Occupancy Controls	Biz-Custom	Warehouse	ROB	426	426	20%	85	0.00	15	$537	2%	2%	2%	6	62%	20%	44.0%	36.0%	36.0%	5.6
1363	Cooling	Air Conditioner - 16 SEER (<5 Tons)	Biz-Prescriptive	Warehouse	ROB	722	722	13%	90	0.00	15	$47	100%	64%	80%	7	38%	20%	92.7%	74.4%	80.9%	7.8
1364	Cooling	Air Conditioner - 17 SEER (<5 Tons)	Biz-Prescriptive	Warehouse	ROB	722	722	18%	127	0.00	15	$206	100%	15%	36%	7	38%	20%	92.7%	36.0%	37.0%	11.1
1365	Cooling	Air Conditioner - 18 SEER(<5 Tons)	Biz-Prescriptive	Warehouse	ROB	722	722	22%	160	0.00	15	$206	100%	15%	36%	7	38%	20%	92.7%	36.0%	40.8%	13.9
1366	Cooling	Air Conditioner - 21 SEER(<5 Tons)	Biz-Prescriptive	Warehouse	ROB	722	722	33%	241	0.00	15	$253	100%	12%	30%	7	38%	20%	92.7%	38.9%	43.1%	20.9
1367	Cooling	Smart Thermostat	Biz-Prescriptive	Warehouse	ROB	722	722	14%	102	0.00	11	$175	57%	57%	57%	8	38%	12%	43.3%	43.3%	43.3%	1.2
1368	Cooling	PTAC - <7,000 Btuh - lodging	Biz-Prescriptive	Warehouse	ROB	849	849	8%	72	0.00	8	$84	100%	36%	36%	9	0%	20%	92.7%	42.7%	42.7%	3.4

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base (Existing) Annual Electric	Base (Standard) Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	MAP Incentive (%)	RAP Incentive (%)	PP Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	MAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	UCT Score
1369	Cooling	PTAC - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Warehouse	ROB	931	931	7%	68	0.00	8	$84	100%	36%	36%	10	0%	20%	92.7%	41.2%	41.2%	3.2
1370	Cooling	PTAC - >15,000 Btuh - lodging	Biz-Prescriptive	Warehouse	ROB	1,064	1,064	10%	101	0.00	8	$84	100%	36%	55%	11	0%	20%	92.7%	50.4%	57.5%	4.8
1371	Cooling	Air Cooled Chiller	Biz-Prescriptive	Warehouse	ROB	738	738	6%	41	0.00	23	$126	100%	24%	55%	12	0%	15%	92.7%	32.0%	32.0%	6.2
1372	Cooling	Chiller Tune-up	Biz-Prescriptive	Warehouse	Retro	842	842	7%	59	0.00	3	$8	100%	100%	100%	13	0%	50%	92.7%	92.7%	92.7%	4.7
1373	Cooling	HVAC/Chiller Custom	Biz-Custom	Warehouse	Retro	5	5	20%	1	0.00	20	$1	100%	7%	7%	14	100%	20%	92.7%	36.0%	36.0%	30.3
1374	Cooling	Window Film	Biz-Prescriptive	Warehouse	Retro	6,000	6,000	4%	264	0.00	10	$154	100%	65%	65%	15	100%	20%	92.7%	73.1%	73.1%	3.2
1375	Cooling	Triple Pane Windows	Biz-Custom	Warehouse	ROB	6,000	6,000	6%	360	0.00	25	$700	100%	5%	5%	15	100%	20%	92.7%	36.0%	36.0%	24.5
1376	Cooling	Energy Recovery Ventilator	Biz-Custom	Warehouse	Retro	886	886	0%	0	0.00	15	$1,500	0%		0%	16	100%	2%	92.7%	74.2%	74.2%	0.0
1377	Heating	Heat Pump - 16 SEER (<5 Tons)	Biz-Prescriptive	Warehouse	ROB	1,653	1,653	4%	64	0.00	16	$87	100%	46%	46%	1	26%	20%	92.7%	43.3%	43.3%	2.7
1378	Heating	Heat Pump - 17 SEER (<5 Tons)	Biz-Prescriptive	Warehouse	ROB	1,653	1,653	9%	142	0.00	16	$442	25%	9%	23%	1	26%	20%	44.0%	36.0%	36.0%	5.3
1379	Heating	Heat Pump - 18 SEER(<5 Tons)	Biz-Prescriptive	Warehouse	ROB	1,653	1,653	12%	203	0.00	16	$507	50%	8%	20%	1	26%	20%	44.0%	36.0%	36.0%	7.4
1380	Heating	Heat Pump - 21 SEER(<5 Tons)	Biz-Prescriptive	Warehouse	ROB	1,653	1,653	19%	310	0.00	16	$507	75%	8%	20%	1	26%	20%	54.8%	36.0%	36.0%	11.8
1381	Heating	Geothermal HP - SEER 20.3 (<5 Tons)	Biz-Prescriptive	Warehouse	ROB	1,653	1,653	22%	372	0.00	25	$2,576	25%	2%	2%	1	26%	20%	44.0%	36.0%	36.0%	17.0
1382	Heating	Geothermal HP - SEER 21.5 (<5 Tons)	Biz-Prescriptive	Warehouse	ROB	1,653	1,653	27%	443	0.00	25	$2,576	25%	2%	4%	1	26%	20%	44.0%	36.0%	36.0%	19.7
1383	Heating	Geothermal HP - SEER 23.1 (<5 Tons)	Biz-Prescriptive	Warehouse	ROB	1,653	1,653	32%	527	0.00	25	$2,576	25%	2%	4%	1	26%	20%	44.0%	36.0%	36.0%	22.6
1384	Heating	Geothermal HP - SEER 29.3 (<5 Tons)	Biz-Prescriptive	Warehouse	ROB	1,653	1,653	47%	771	0.00	25	$2,576	25%	2%	4%	1	26%	20%	44.0%	36.0%	36.0%	29.3
1385	Heating	Heat Pump - 14.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Warehouse	ROB	1,989	1,989	11%	216	0.00	16	$100	100%	40%	55%	2	21%	20%	92.7%	66.6%	72.7%	31.6
1386	Heating	Heat Pump - 15.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	Biz-Prescriptive	Warehouse	ROB	1,989	1,989	16%	319	0.00	16	$136	100%	30%	55%	2	21%	20%	92.7%	64.5%	74.1%	35.1
1387	Heating	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Warehouse	ROB	2,070	2,070	14%	291	0.00	16	$100	100%	40%	55%	2	21%	20%	92.7%	72.9%	76.9%	35.7
1388	Heating	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	Biz-Prescriptive	Warehouse	ROB	2,070	2,070	19%	394	0.00	16	$139	100%	29%	55%	2	21%	20%	92.7%	69.3%	76.7%	39.1
1389	Heating	Geothermal HP - SEER 20.3 (5-20 Tons)	Biz-Prescriptive	Warehouse	ROB	1,814	1,814	29%	533	0.00	25	$2,576	50%	2%	4%	2	21%	20%	44.0%	36.0%	36.0%	35.7
1390	Heating	Geothermal HP - SEER 21.5 (5-20 Tons)	Biz-Prescriptive	Warehouse	ROB	1,814	1,814	33%	605	0.00	25	$2,576	50%	2%	4%	2	21%	20%	44.0%	36.0%	36.0%	38.4
1391	Heating	Geothermal HP - SEER 23.1 (5-20 Tons)	Biz-Prescriptive	Warehouse	ROB	1,921	1,921	41%	795	0.00	25	$2,576	50%	2%	4%	2	21%	20%	44.0%	36.0%	36.0%	43.6
1392	Heating	Geothermal HP - SEER 29.3 (5-20 Tons)	Biz-Prescriptive	Warehouse	ROB	1,921	1,921	54%	1,039	0.00	25	$2,576	75%	2%	4%	2	21%	20%	47.4%	36.0%	36.0%	50.2
1393	Heating	Variable Refrigerant Flow Heat Pump	Biz-Custom	Warehouse	ROB	1,535	1,535	13%	192	0.00	16	$224	100%	9%	9%	2	21%	2%	92.7%	29.2%	29.2%	20.9
1394	Heating	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	Biz-Prescriptive	Warehouse	ROB	2,155	2,155	9%	199	0.00	16	$100	100%	40%	55%	3	21%	20%	92.7%	64.3%	71.3%	28.1
1395	Heating	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	Biz-Prescriptive	Warehouse	ROB	2,155	2,155	15%	326	0.00	16	$175	100%	23%	55%	3	21%	20%	92.7%	54.6%	70.1%	32.8
1396	Heating	Geothermal HP - SEER 20.3 (20+ Tons)	Biz-Prescriptive	Warehouse	ROB	2,070	2,070	38%	789	0.00	25	$2,576	100%	2%	4%	3	21%	20%	92.7%	36.0%	36.0%	69.5
1397	Heating	Geothermal HP - SEER 21.5 (20+ Tons)	Biz-Prescriptive	Warehouse	ROB	2,070	2,070	42%	860	0.00	25	$2,576	100%	2%	4%	3	21%	20%	92.7%	36.0%	36.0%	72.2
1398	Heating	Geothermal HP - SEER 23.1 (20+ Tons)	Biz-Prescriptive	Warehouse	ROB	2,070	2,070	46%	944	0.00	25	$2,576	100%	2%	4%	3	21%	20%	92.7%	36.0%	36.0%	75.2
1399	Heating	Geothermal HP - SEER 29.3 (20+ Tons)	Biz-Prescriptive	Warehouse	ROB	2,070	2,070	57%	1,188	0.00	25	$2,576	100%	2%	4%	3	21%	20%	92.7%	36.0%	36.0%	81.8
1400	Heating	Mini Split Ductless Heat Pump Cold Climate (Tiers & sizes TBD)	Biz-Prescriptive	Warehouse	ROB	1,653	1,653	19%	310	0.00	16	$224	100%	18%	45%	4	33%	20%	92.7%	48.3%	55.1%	11.8
1401	Heating	PTHP - <7,000 Btuh - lodging	Biz-Custom	Warehouse	ROB	1,823	1,823	4%	69	0.00	8	$130	100%	100%	100%	5	0%	10%	92.7%	74.2%	74.2%	0.7
1402	Heating	PTHP - >15,000 Btuh - lodging	Biz-Prescriptive	Warehouse	ROB	2,191	2,191	15%	330	0.00	8	$130	100%	100%	100%	6	0%	10%	92.7%	92.7%	92.7%	3.4
1403	Heating	PTHP - 7,000 to 15,000 Btuh - lodging	Biz-Prescriptive	Warehouse	ROB	1,994	1,994	9%	171	0.00	8	$130	100%	100%	100%	7	0%	10%	92.7%	92.7%	92.7%	1.7
1404	HotWater	Heat Pump Water Heater	Biz-Prescriptive	Warehouse	ROB	3,027	3,027	67%	2,027	0.00	15	$1,115	100%	45%	45%	1	100%	0%	84.0%	60.9%	60.9%	3.4
1405	HotWater	Hot Water Pipe Insulation	Biz-Custom	Warehouse	Retro	3,027	3,027	2%	61	0.00	20	$60	75%	10%	10%	2	100%	80%	86.0%	84.0%	84.0%	9.8
1406	HotWater	Faucet Aerator	Biz-Custom	Warehouse	Retro	195	195	32%	63	0.00	10	$8	100%	50%	50%	3	20%	90%	93.0%	92.0%	92.0%	13.1
1407	HotWater	Low Flow Pre-Rinse Sprayers	Biz-Prescriptive	Warehouse	ROB	18,059	18,059	54%	9,789	0.00	5	$60	100%	17%	42%	4	20%	80%	86.0%	84.0%	84.0%	199.3
1408	HotWater	ENERGY STAR Commercial Washing Machines	Biz-Prescriptive	Warehouse	ROB	1,552	1,552	43%	671	0.00	7	$250	75%	28%	28%	5	25%	33%	79.3%	64.6%	64.6%	2.9
1409	InteriorLighting	LED T8 Tube Replacement	Biz-Prescriptive Light	Warehouse	Retro	110	110	45%	49	0.00	15	$5	100%	100%	100%	1	64%	40%	94.6%	94.6%	94.6%	11.4
1410	InteriorLighting	LED troffer retrofit kit, 2'X2' and 2'X4'	Biz-Prescriptive Light	Warehouse	Retro	248	248	50%	124	0.00	15	$70	100%	36%	55%	1	64%	40%	94.6%	52.3%	68.6%	5.8
1411	InteriorLighting	LED troffer, 2'X2' and 2'X4'	Biz-Prescriptive Light	Warehouse	Retro	248	248	50%	124	0.00	15	$70	100%	36%	55%	1	64%	40%	94.6%	52.3%	68.6%	5.8
1412	InteriorLighting	Bi-Level Lighting Fixture – Stairwells, Hallways	Biz-Custom Light	Warehouse	Retro	248	248	74%	184	0.00	10	$274	25%	7%	9%	2	1%	40%	58.0%	50.1%	50.3%	4.7
1413	InteriorLighting	LED high bay fixture	Biz-Prescriptive Light	Warehouse	Retro	2,310	2,310	68%	1,571	0.00	15	$330	100%	35%	55%	3	23%	34%	94.6%	81.8%	86.4%	15.8
1414	InteriorLighting	LED Mogul-base HID Lamp Replacing High Bay HID	Biz-Prescriptive Light	Warehouse	Retro	2,310	2,310	66%	1,532	0.00	15	$330	100%	35%	55%	3	23%	34%	94.6%	81.5%	86.1%	15.4
1415	InteriorLighting	LED low bay fixture	Biz-Prescriptive Light	Warehouse	Retro	492	492	61%	299	0.00	15	$44	100%	68%	80%	4	9%	34%	94.6%	90.7%	92.1%	11.5
1416	InteriorLighting	LED Mogul-base HID Lamp Replacing Low Bay HID	Biz-Prescriptive Light	Warehouse	Retro	492	492	59%	289	0.00	15	$44	100%	68%	80%	4	9%	34%	94.6%	90.6%	92.0%	11.1
1417	InteriorLighting	LED Screw-In Lamps (Directional)	Biz-Prescriptive Light	Warehouse	ROB	352	352	86%	302	0.00	6	$1	100%	100%	100%	6	0%	43%	94.6%	94.6%	94.6%	135.5
1418	InteriorLighting	LED downlight fixture	Biz-Prescriptive Light	Warehouse	Retro	170	170	68%	115	0.00	15	$27	100%	19%	46%	6	4%	45%	94.6%	76.0%	83.0%	26.6
1419	InteriorLighting	LED Screw-In Lamps (Omnidirectional & Decorative)	Biz-Prescriptive Light	Warehouse	ROB	266	266	81%	215	0.00	6	$1	100%	100%	100%	5	0%	20%	94.6%	94.6%	94.6%	96.6
1420	InteriorLighting	DeLamp Fluorescent Fixture Average Lamp Wattage 28W	Biz-Prescriptive Light	Warehouse	Retro	91	91	100%	91	0.00	11	$4	100%	100%	100%	7	64%	0%	94.6%	94.6%	94.6%	20.2
1421	InteriorLighting	Occupancy Sensors	Biz-Prescriptive Light	Warehouse	Retro	417	417	30%	125	0.00	10	$65	75%	31%	31%	8	95%	10%	82.5%	52.2%	52.2%	2.9
1422	InteriorLighting	Daylighting Controls	Biz-Prescriptive Light	Warehouse	Retro	534	534	30%	160	0.00	10	$58	100%	35%	55%	8	95%	10%	94.6%	71.3%	79.2%	6.7
1423	InteriorLighting	Dual Occupancy & Daylighting Controls	Biz-Custom Light	Warehouse	Retro	238	238	44%	105	0.00	10	$75	100%	40%	50%	8	95%	10%	94.6%	36.5%	42.4%	2.9
1424	InteriorLighting	Central Lighting Monitoring & Controls (non-networked)	Biz-Custom Light	Warehouse	Retro	41,703	41,703	20%	8,341	0.00	12	$3,700	100%	23%	29%	8	95%	10%	94.6%	44.1%	47.7%	4.6
1425	InteriorLighting	Network Lighting Controls - Wireless (WiFi)	Biz-Custom Light	Warehouse	Retro	3	3	49%	1	0.00	15	$1	100%	23%	30%	8	95%	10%	94.6%	45.2%	48.8%	9.7
1426	InteriorLighting	Luminaire Level Lighting Controls w/ HVAC Control	Biz-Custom Light	Warehouse	Retro	338	338	65%	220	0.00	15	$90	100%	24%	32%	8	96%	10%	94.6%	48.2%	51.8%	9.7
1427	InteriorLighting	LED Exit Sign - 4 Watt Fixture (2 lamp)	Biz-Prescriptive Light	Warehouse	Retro	63	63	43%	27	0.00	5	$33	92%	92%	92%	9	1%	75%	86.5%	86.5%	86.5%	0.3
1428	InteriorLighting	Lighting - Custom	Biz-Custom Light	Warehouse	Retro	4	4	25%	1	0.00	15	$1	100%	14%	19%	10	100%	0%	94.6%	30.0%	31.2%	9.7
1429	ExteriorLighting	LED wallpack (existing W<250)	Biz-Prescriptive Light	Warehouse	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	1	12%	46%	94.6%	56.6%	70.8%	5.8
1430	ExteriorLighting	LED parking lot fixture (existing W≥250)	Biz-Prescriptive Light	Warehouse	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	13%	33%	2	11%	54%	67.8%	63.2%	63.2%	4.4
1431	ExteriorLighting	LED parking lot fixture (existing W<250)	Biz-Prescriptive Light	Warehouse	Retro	856	856	66%	567	0.00	12	$248	100%	18%	45%	3	11%	54%	94.6%	63.2%	70.8%	5.8
1432	ExteriorLighting	LED outdoor pole decorative fixture (existing W≥250)	Biz-Prescriptive Light	Warehouse	Retro	1,589	1,589	60%	959	0.00	12	$756	50%	17%	17%	4	11%	54%	67.8%	63.2%	63.2%	3.4
1433	ExteriorLighting	LED parking garage fixture (existing W≥250)	Biz-Prescriptive Light	Warehouse	Retro	3,235	3,235	60%	1,953	0.00	6	$756	50%	13%	33%	5	11%	69%	78.3%	75.2%	75.2%	4.7

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

prepared for

CENTERPOINT ENERGY

CenterPoint Energy

2022 Demand Side Management Market Potential Study

May 22,
2023

FINAL REPORT

prepared by

GDS ASSOCIATES INC

Attachment 6.3 All-Source RFP

All-Source
Request for Proposals

CenterPoint Energy Indiana South

Issued 5/11/2022
NOI, NDA, and Respondent Application Due 5/27/2022
Proposals Due 7/5/2022

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
1898 & Co.	1898 & Co., part of Burns & McDonnell
CenterPoint	CenterPoint Energy Indiana South
CNP	CenterPoint
COD	Commercial Operating Date
CSP	Curtailment Service Providers
DA	Definitive Agreement
DIR	Dispatchable Intermittent Resource
DR	Demand Response
EPC	Engineering, Procurement, and Construction
GI	Generation Interconnection
GIA	Generator Interconnection Agreement
ICAP	Installed Capacity
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
LCOE	Levelized Cost of Energy
LMR	Load Modifying Resource
LRZ	Local Resource Zone
MISO	Midcontinent Independent System Operator
MW	Megawatt
MWh	Megawatt-Hour
NCF	Net Capacity Factor
NDA	Non-Disclosure Agreement
NRIS	Network Resource Interconnection Service
OVEC	Ohio Valley Electric Corporation
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
RFP	Request for Proposal

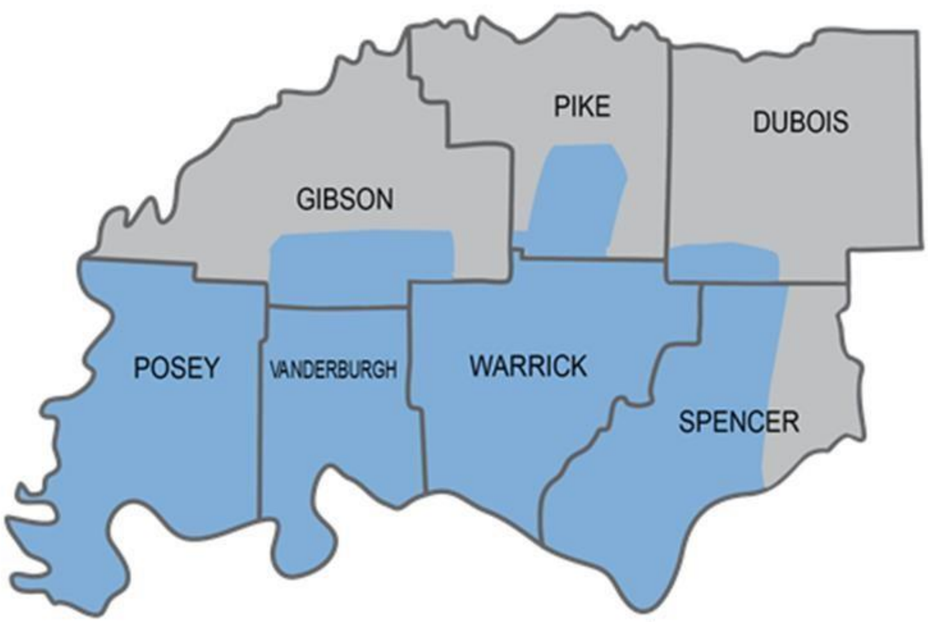
1.0 RFP OVERVIEW

1.1 Introduction

CenterPoint Energy Indiana South (CenterPoint) is a subsidiary of CenterPoint Energy, headquartered in Houston, Texas. CenterPoint provides energy delivery services to 142,000 electric customers located in southwestern Indiana. CenterPoint also owns and operates electric generation to serve its electric customers and optimizes those assets in the wholesale power market.

CenterPoint's electric customers are currently served by a mixed portfolio including 1,000 megawatts (MW) of coalfired generation, up to 160 MW of gas-fired generation and 54 MWs of solar coupled with 1 MW of storage. The portfolio also contains 3 MW from a landfill gas to electric project and purchases from the Ohio Valley Electric Corporation (OVEC) of up to 32 MW, wind purchases of up to 80 MW, and purchases from the Midcontinent Independent System Operator (MISO) power pool as needed to meet CenterPoint's load requirements.

Figure 1: CenterPoint Electric Service Area



1.2 Purpose

CenterPoint has issued this all-source Request for Proposals (RFP) seeking power supply and demand-side Proposals for capacity and unit-contingent energy to meet the needs of its customers. For asset purchases, capacity contracts, and power purchase agreements (PPAs), the capacity is required to be fully accredited prior to March 1st 2027; however, earlier delivery of projects and capacity products is encouraged. CenterPoint intends to submit an updated Integrated Resource Plan (2022/2023 IRP) to the Indiana Utility Regulatory Commission (IURC) in the first half of 2023 which will evaluate existing resources and identify the preferred resource options to meet capacity and energy requirements. Information on CenterPoint IRPs can be found at https://midwest.centerpointenergy.com/irp. Only resources capable of firm deliverability to MISO Local Resource Zone (LRZ) 6 will be considered.

CenterPoint prefers Proposals for resources that are directly interconnected to CenterPoint's system or Proposals that reflect all the costs and characteristics of the resource necessary for energy to be financially settled or delivered to CenterPoint's load node (SIGE.SIGW). All potential agreements are subject to IURC and CenterPoint Board of Director's approval and are not effective until such approval is final.

All Proposals must be submitted via the All-Source Request for Proposal website (http://CenterPoint2022ASRFP.rfpmanager.biz/) no later than the Proposal Submittal Due Date shown in Section 2.3. CenterPoint reserves the right in its sole discretion to modify this schedule for any reason.

In connection with this RFP, CenterPoint has retained the services of an independent third-party consultant, 1898 & Co., a division of Burns & McDonnell, to help manage the RFP process and work with CenterPoint to perform the quantitative and qualitative evaluations of all Proposals. However, CenterPoint will make final decisions (subject to IURC review, as applicable) at its sole discretion.

All Respondents will directly interface with 1898 & Co. for all communications, including questions, RFP clarification issues, and Proposal submission. All questions related to this RFP should be submitted via the RFP Website. If for any reason there are technical issues with bid or question submittal the following email address can be contacted CenterPointRFP@1898andco.com.

CenterPoint has concluded that it is in the best interest of its customers to seek resources that qualify as MISO internal resources (i.e. not pseudo-tied into MISO) with physical deliverability utilizing Network Resource Integration Service (NRIS). However, as described in the RFP requirements below, Proposals for resources located outside of MISO and which can show firm deliverability to MISO LRZ 6 may still qualify for consideration under this RFP. CenterPoint is issuing this all-source RFP for supply-side and demand-side capacity resources to identify viable resources available to CenterPoint in the marketplace to meet the needs of its customers. Dependent upon further evaluation of aging resources and subject to IRP results, the exact capacity need of CenterPoint has not yet been identified. The IRP will evaluate a wide number of potential resource portfolio combinations, and it is likely the 2022/2023 IRP will have scenarios that result in a need for 500 MW or greater. Therefore, Respondents are encouraged to offer multiple projects and/or resource blocks depending on their availability. In addition, CenterPoint wil consider Proposals for up to 350 MW of short-term capacity as described below.

CenterPoint is seeking to provide reliable power supply resources for its customers. This RFP is issued to either acquire or contract for:

- Existing or planned utility-scale solar, wind, and storage (standalone or paired) resources described further in Section 4.0.
- Existing or planned thermal resources described further in Section 5.0
- LMR/DR products described further in Section 6.0.
- Short and long-term capacity only contracts described further in Section 7.0

Accordingly, you are invited to submit a written, binding Proposal in accordance with the requirements described in this RFP and subject to the following dates. See Section 2.3 for additional information about milestone dates.

Table 1: RFP Milestone Dates

Milestone	Date
Issue RFP	Wednesday, May 11, 2022
Notice of Intent with Application Documents Due	Friday, May 27, 2022
Proposals Due	Tuesday, July 5, 2022

2.0 INFORMATION AND SCHEDULE

2.1 Information Provided to Potential Respondents

This RFP and all its Appendices are available on the RFP website (http://CenterPoint2022ASRFP.rfpmanager.biz/). Interested parties are expected to be able to download this RFP with its required forms and complete the forms in Microsoft Word, Microsoft Excel[1], and/or PDF format. Respondents should upload and submit properly completed forms by the specified due date to the RFP website. 1898 & Co. will accept only Proposals that are complete. Proposals that are nonconforming, not complete, mailed, or hand delivered may be deemed ineligible and may not be considered for further evaluation. By submitting a Proposal in response to this RFP, the Respondent certifies that it has not divulged, discussed, or compared any commercial terms of its Proposal with any other party (including any other Respondent and/or prospective Respondent), and has not colluded whatsoever with any other party.

2.2 Information on the RFP Website

The information on the RFP website (http://CenterPoint2022ASRFP.rfpmanager.biz/) contains the following:

- This RFP and associated appendices
- Frequently asked questions and answers about this RFP
- Updates on this RFP process and other relevant information

Phone calls and verbal conversations with Respondents regarding this RFP are not permitted before the Proposal Submittal Due Date. All Respondents will directly interface with 1898 & Co. through the RFP website and email for all communications regarding this resource request. Proposals will be opened in private by 1898 & Co. on a confidential basis, but written questions will not be considered confidential. Individual questions submitted on the website before the submittal due date will be answered and responses will be posted on the website or sent back via email to the Respondent as soon as practical. Responses to select questions may be placed on the RFP website for the benefit of all Respondents, with any identifying information redacted from the question.

Proposals will be reviewed by 1898 & Co. for completeness, and offers that do not include the information requirements of this RFP may be notified by 1898 & Co. and allowed five business days to conform. After Proposals are submitted, 1898 & Co. will review, and both quantitatively and qualitatively evaluate all conforming Proposals. Respondents may be contacted for additional data or clarifications during the evaluation process by 1898 & Co.

[1] Microsoft Excel format is required for the submission of Appendix D.

Any Respondents contacted for further clarifications may or may not be invited to begin further negotiations of terms and details of the offers.

2.3 Schedule

CenterPoint has retained 1898 & Co. to act as an independent third-party consultant to assist with this RFP. All Respondents will directly interface with 1898 & Co. for all communications, including questions, RFP clarification issues, and Proposal submission. All questions should be submitted to the website, and as required, additional correspondence concerning this RFP should be sent via email to CenterPointRFP@1898andco.com.

The schedule below provides the timeline for conducting this resource solicitation. CenterPoint reserves the right to modify this schedule in its sole discretion.

Table 2: RFP Schedule

Step	Date
RFP Issued	Wednesday, May 11, 2022
Notice of Intent, NDA, and Respondent Application Due	5:00 p.m. CDT, Friday, May 27, 2022
Pre-Bid Meeting	3:00 p.m. CDT, Wednesday, June 1, 2022
Proposal Submittal Due Date	5:00 p.m. CDT, Tuesday, July 5, 2022
Initial Proposal Review and Evaluation Period	Wednesday, July 6, 2022 – Thursday, August 11, 2022
Proposal Evaluation Completion Target and Short List to CenterPoint	Friday, August 12, 2022
Due Diligence and Negotiations Period	Q3-Q4 2022

3.0 RFP GENERAL REQUIREMENTS

Proposals must meet the general minimum eligibility requirements described below. 1898 & Co. will screen all Proposals for compliance with these requirements. Proposals that fail to meet one or more of the general minimum eligibility requirements may be disqualified from further consideration as part of this RFP process. Respondents should refer to the Proposal Checklist in Appendix E for high-level guidance on Proposal requirements.

For a Proposal to be eligible under this RFP, it must:

- Offer MISO LRZ 6 zonal resource credits (e.g. NRIS transmission service or other fully deliverable resource).
- Have an existing MISO Generator Interconnection Agreement (GIA), be in the MISO generator interconnection queue, or provide justification how the resource is able to meet CenterPoint's timing needs absent current queue position. CenterPoint will consider Proposals that aim to reuse existing interconnection rights for retiring generation facilities.
- Be in service and operational prior to 3/1/2027.

3.1 General Requirements for Generation Facility Proposals

Respondents should provide sufficient detail to fully evaluate the "all-in" physical, electrical, and economic attributes of any Proposal. In all cases, Respondents shall describe the expected useful life of all facilities included in their Proposals. If a facility does not have black start capability installed but could be made black start capable, Proposals should indicate the estimated costs to construct and operate and include the estimated construction timeline. Respondents shall provide their best estimate of interconnection costs and/or other costs to deliver energy into MISO to a single point of interconnection or other energy settlement node.

3.1.1 Name and Location

Respondents shall state the name of the generating facility, the county where the generating facility is located, the owner of the facility, and the commercial pricing node associated with the facility, if applicable. The facility must be qualified to receive Zonal Resource Credits for Zone 6 consistent with MISO's Module E Planning Resource Auction. Should the facility not be qualified in Zone 6, Respondents shall detail in their Proposals the means by which Zonal Resource Credits will be delivered/fulfilled in Zone 6.

3.1.2 Capacity Characteristics

Respondents shall state the nameplate capacity, net summer operating capacity, net winter operating capacity and, for existing facilities, the awarded unforced capacity (UCAP) of the generation facility for the last five MISO planning years. Respondents shall specifically identify any known derates affecting the facility.

Respondents also should provide the expected UCAP for the first five MISO planning years beginning in the first year after the proposed facility's commercial operation date based on current MISO rules for the applicable generating technology.

3.1.2.1 Interconnection, Capacity Availability and Deliverability

Respondents must identify the specific point(s) of interconnection. CenterPoint has a preference for the type of transmission service to be NRIS, but will consider other Proposals as long as capacity is fully deliverable and accreditable. Proposals for facilities without existing firm deliverability should include cost estimates including transmission and/or interconnection studies associated with securing such deliverability. The GIA or most recent available Definitive Planning Phase (DPP) Study results should be included if applicable.

The Proposal should also include nodal economic analyses (at COD, 2030, and 2035) showing expected unit economic metrics (including congestion impacts on energy production and cost to deliver) for the project at the proposed delivery point(s).

CenterPoint reserves the right to reject any Proposal that does not include the full cost of any known or potential interconnection costs or network upgrades that may be required to provide firm deliverability to MISO LRZ 6 and/or that does not include interconnection, reliability, and/or economic analyses supporting interconnection and transmission requirements. Such materials should include a technical description and estimated costs of network upgrades from studies completed or underway.

CenterPoint will consider Proposals that plan to re-use existing injection rights under an interconnection agreement currently occupied by a retiring generating facility. Qualifying Proposals shall include a discussion of the required MISO studies, project ownership, and timing of commercial operation under the existing interconnection agreement as applicable. Respondents shall include an estimate of the costs required to build gen-tie lines connecting a project to the point of interconnection and shall not assume that existing transmission lines or other utility easements will be available to host the gen-tie circuit.

3.1.3 Technical and Economic Detail

3.1.3.1 Generation Technology

Respondents shall describe the generation technology of the facility, including the make, model, and name of the supplier of all major equipment. All Proposals to sell a generation facility to CenterPoint must utilize an existing, proven technology, with demonstrated reliable generation performance that is capable of sustained, predictable operation.

3.1.3.2 Dispatch, Emissions, and Performance Characteristics

Dispatch, emissions and performance characteristics will vary between different types of generation facilities, but shall be provided by Respondents as applicable including but not limited to load levels, ramp rates, heat rates, fuel consumption, expected energy production based on actual or typical weather, operating limitations, etc. Please refer to Sections 4.0, 5.0, 6.0, and 7.0 of this document for additional resource-specific requirements.

Regarding any major current and/or historical operational limitations, Respondents shall provide a description of the root causes of the limitations (e.g. original equipment manufacturer (OEM) design, material condition of the facility, environmental permits, etc.). To the extent that expected performance deviates from observed performance, the Respondent shall provide the basis for the assumption.

3.1.3.3 Revenues, Operating Costs, and Taxes

Respondents proposing new generation facilities must provide reasonable estimates for all of the following requested details associated with plant revenues and costs, including market revenues, fixed and variable operations costs, expected upgrades and service timing, and taxes.

For existing generation facilities, Respondents shall provide a detailed breakout of the facility's actual annual revenues for each of the past five years. This will include energy, capacity, and ancillary service market revenues, as well as any other revenues the facility earned, including any congestion revenue (positive or negative), as well as uplift revenues. Associated with these revenues, Respondents shall state the estimated annual output in MWh as well as the operation and maintenance costs of the facility on a fixed ($) and variable ($/MWh) basis and provide the actual annual operation and maintenance costs of the facility for each of the past five years in nominal dollars.

Respondents shall provide a detailed breakout of the generation facility's estimated and actual annual fixed costs for the following categories: labor, benefits, materials, and all others for the past five years. Respondents shall provide a breakdown of the number of people employed at the facility, including permanent and contracted employees, and whether those employees are organized under any labor agreement.

If fixed or variable costs for the generation facility are expected to change in the foreseeable future (e.g., following planned upgrades, etc.), the Respondent should provide both the new expected cost(s) and the year(s) in which the costs are expected to change.

Respondents shall also describe any state, local, and property taxes and tax abatements associated with the generation facility.

3.1.4 Operating Considerations

3.1.4.1 Operating Data

Respondents proposing new or planned generating facilities shall include reasonable estimates for all of the following requested operating data points. Proposals shall include the manufacturer or developer quoted expected performance and, if available, historical performance of similar facilities in MISO.

For an existing generation facility, Respondents shall provide historical operating data consisting of:

- The commercial operation date (COD) of the facility
- The annual run-time hours (per unit, if applicable)
- The annual operating cycles per year (per unit, if applicable)
- The annual facility capacity and availability factors
- The equivalent forced outage rate demand (EFORd)

The above annual data may be limited to the most recent five years. The EFORd should correspond to the UCAP amounts awarded for the last five MISO Planning Years. Respondents shall provide a breakdown of EFORd by failure mode or North American Electric Reliability Corporation/Generating Availability Data System category. Respondents shall provide a description of the major contributors to the generation facility EFORd. If there are particular costs associated with maintaining the EFORd of a generation facility, those must be provided. Generating facilities considered a Dispatchable Intermittent Resource (DIR) in MISO shall provide historical curtailments over the most recent years. New facilities shall put forth a best effort forecast of curtailments by MISO.

For an existing generation facility, Respondents shall provide details on any current generation facility equipment issues and concerns, including any operation outside recommended parameters established by OEM, compromised equipment, etc. Respondents shall provide historical information on such issues and concerns, how they were resolved, and the associated costs for the past 10 years or since the beginning of operation.

Respondents shall provide the following maintenance history for the past 10 years or since the beginning of operation: (i) dates of last full unit inspection and findings based on OEM recommendations; and (ii) outstanding OEM recommendations remaining to be implemented, including the cost and outage duration for any major maintenance requirements expected over the coming ten years. Respondents shall provide the annual reports for major planned and forced outages over the past five years.

3.1.4.2 Operating Plan

Proposals should include a summary of the operating plan for the generation facility. Such plan should include software management system(s) and personnel roles and responsibilities for operating, maintaining, and servicing the facility, including any contractual arrangements. Respondent shall provide an overview of key scheduled outage and maintenance plans, as well as plans for procuring and maintaining key spare parts.

3.1.5 Environmental Considerations

New and existing resources must be in compliance with all applicable environmental rules and regulations. To the extent applicable, all environmental attributes, including emission reduction credits and/or allowances in any form (emissions credits, offsets, financial credits, etc.), related to the power being purchased, should be conveyed to CenterPoint. Respondents shall describe any operating limitations imposed by permitting or environmental compliance that limit plant availability and shall provide a description of any identified environmental liabilities (e.g., potential site remediation requirements, etc.) for the facility.

3.1.6 Permitting

The generation facility must have all relevant environmental, site-use and all other ministerial and discretionary permits necessary for construction and/or operation and maintenance. Existing facilities without such permits may be disqualified from consideration at CenterPoint's sole discretion. Respondents shall provide a description of all permits currently in place for the construction and/or operation and maintenance of the facility and must state whether there are any provisions that would prohibit the assignment of such permits and/or any consents required for the assignment of such permits.

3.1.7 Financial Considerations

3.1.7.1 Acquisition Price / Capital Expenditures

Respondents shall submit an acquisition price with their Proposal, representing their best and final price, consisting of a single fixed payment that is inclusive of all monetary consideration for the generation facility including, but not limited to, costs associated with interconnection, engineering studies, siting, permitting, acquisition, construction, ancillary facilities, working inventory, and contractual arrangements (e.g., for fuel supply and transportation, maintenance, pollution control bonds, etc.). Different transaction structures may warrant a schedule of payments as described below, but the acquisition price should represent the total all-in purchase amount required to close the transaction and achieve complete commercial operation of the generating facility. Respondents must provide details regarding any liabilities that CenterPoint might assume as a buyer of a generation facility.

3.1.7.2 Other Contractual Commitments

Respondents shall provide a description, including detailed cost information, of any other contracts that are necessary to operate the generating facility, including, but not limited to, long-term service agreements, state union labor contracts and/or technical support contracts, agreements related to capacity and/or energy sales from the facility and any capacity offers submitted to any independent system operator/regional transmission organization related to the generation facility that, if accepted, would be binding on CenterPoint as a result of an acquisition. Respondents must also state whether there are any provisions that would prohibit the assignment and/or affect the performance obligations of either party under the respective contract, including transfer or cancellation fees.

3.1.8 Legal Considerations

3.1.8.1 Legal Proceedings, Liabilities & Risks

The Proposal shall include a summary of all material actions, suits, claims or proceedings (threatened or pending) against Respondent, its Guarantor (if applicable) or involving the generation facility or the site as of the Proposal due date, including existing liabilities whether or not publicly disclosed, including but not limited to those related to employment and labor laws, environmental laws, or contractual disputes for the development, construction, maintenance, fueling, or operation of the facility.

3.1.8.2 Material Contingencies

Proposals that have material contingencies, such as for financing, may not be considered.

3.1.9 Other

All Proposals for new generation facilities must have a well-defined and credible development plan for Respondent to complete the development, construction, and commissioning of the facility on their proposed development timeline. Respondents submitting Proposals for new or planned facilities should review the Development Risk evaluation metric and be sure to discuss key development milestones in their Proposal.

Quality Proposals should provide information to assess the following:

- **(Key contractual arrangements)** Roles and responsibilities of the companies involved in the design, development, procurement, and construction of the facility. Information about key contributors including the status of contractual relationship with each key contributor, key contractual assurances, guarantees, warranties or commitments supporting the Proposal, (e.g. executed EPC contract), and any past experience of Respondent working with each key contributor.
- **(EPC)** Description of status of major equipment procurement, as well as processes for engineering, procurement, and construction bids and awards.
- **(Site control)** Description of the facility site and Respondent's rights (i.e., whether owned, leased, under option) to such site. Please indicate whether additional land rights are necessary for the development, construction, and/or operation of the facility.
- **(Schedule)** Discussion of the development schedule and associated risks and risk mitigation plans for that schedule, including whether there are contract commitments from contractors supporting the proposed schedule. The Respondent should be prepared to document and commit to a proposed development schedule, which should include a COD.
- **(Financing)** Discussion of the financing arrangements secured by the Respondent, including an overview of the sources of funds, and level of commitment from debt, equity, or other investors; Respondent's or guarantors' senior unsecured debt and/or corporate issuer ratings documentation from Moody's and Standard & Poor's showing the name of the rating agency, the type of rating, and the rating of the Respondent or guarantor.
- **(Permits and zoning)** Discussion on permitting, including a list of all required permits, permitting status of each, and key risks to securing necessary future permit approvals. Respondents should provide all applicable zoning requirement language for the project location (e.g. county, city, township, etc.) and describe current status of project zoning.
- **(Interconnection)** Description of status in MISO queue process and presentation of documents described in Section 3.1.2.1.

Respondents shall assume for the purposes of Proposal pricing that development schedule, budget, permits and approval risk will be their sole responsibility.

3.2 Eligible Transaction Structures

The following are eligible project transaction structures as part of this RFP. Resource-specific requirements and attributes are provided further down in Sections 4.0 - 7.0 pertaining to specific types of resources. Term sheets containing additional key assumptions for particular contract- and resource-type combinations have been developed and are included in the appendices.

3.2.1 Power Purchase Agreement (PPA)

CenterPoint will consider meeting some or all of its resource requirements through short, medium and/or long-term PPAs. CenterPoint will only consider PPAs that have a term of five years or greater.

3.2.1.1 Price

Respondents shall submit an annual power purchase price ($ and/or $/MWh as applicable) consisting of a payment that is inclusive of all monetary consideration for the capacity, energy, RECs, and, if applicable, ancillary facilities and contractual arrangements related to the generation facility. The contract price shall include all costs of interconnection, including possible MISO and affected system network upgrade costs, and transmission owner interconnection facility and substation upgrade costs. Respondents must provide a flat pricing option (i.e. fixed price for the term of the contract) with each Proposal, and may also include optional escalating pricing options for CenterPoint's consideration.

3.2.1.1.1 Energy Settlement Location

As described further in the evaluation section below, CenterPoint has a preference for Proposals that include all costs to have energy financially settled or directly delivered to CenterPoint's load node (SIGE.SIGW). However, CenterPoint will consider pricing options for Proposals that settle at the facility's point of interconnection (busbar) or Indiana Hub.

3.2.2 Asset Purchase

CenterPoint will accept Proposals for new, planned, or existing generation facilities that are complete and operational in advance of the expected acquisition date. CenterPoint will only consider offers for facilities that have an estimated remaining useful life of five (5) or more years from acquisition date.

3.2.2.1 Location

CenterPoint has a preference for projects located near its load. However, CenterPoint will accept Proposals for new or planned generation facilities that will be complete and operational in advance of the expected acquisition date. A project will be defined as complete and commercially operable if, and only if, it includes all facilities necessary to generate and deliver energy into MISO to at least one single point of interconnection within MISO.

3.2.2.2 Tax Credits

Respondents shall state the qualifications of the project for any applicable tax credits and provide relevant documentation. Respondents should provide a discussion of the method for acquiring tax incentives through safe harbor and attest whether safe harbored equipment is specifically dedicated to the project.

3.2.2.3 Tax Abatements

Respondents shall include a discussion of any tax abatements acquired by the project. Respondents should provide all terms, conditions, and relevant documentation related to tax abatements.

3.2.3 Renewable Project in Development

CenterPoint has a preference for Asset Purchase Proposals as described above in Section 3.2.2. However, CenterPoint will accept Asset Purchase Proposals for Generating Facilities in which ownership transfer of the project occurs prior to project completion; however, such Proposals must provide a definite path to completion. Proposals for Projects in Development must include pricing for completion of the project following transfer of ownership and must otherwise adhere to the Proposal requirements specified in Section 3.2.2 and elsewhere in this document including the Term Sheets provided in Appendices F, G and H. The Term Sheets contemplate asset transfer at completion; however, Proposals with a pre-completion transaction structure shall provide the same protections and commitments contemplated in the Term Sheets. Deviations shall be detailed in the Proposal narrative. Proposals must include discussion of the development schedule and associated risks and risk mitigation plans for that schedule, including commitments from contractors supporting the proposed schedule. The Respondent shall document and commit to a proposed development schedule up to and including commercial operation.

3.2.4 Demand-Side Contracts

CenterPoint will consider LMR and DR resources from one or more MISO customers or curtailment service providers (CSP). LMR suppliers must be located entirely within MISO LRZ 6. Proposals for LMRs/DRs are to be for assets that are eligible to participate in MISO LRZ 6 and can meet the additional performance requirements of CenterPoint as described in Section 6.0 below. Proposals for LMRs/DRs may be combined with another power supply Proposal or may be submitted on a standalone basis. CenterPoint will consider LMR/DR Proposals that have a term of one year or longer, consistent with MISO planning years.

3.2.5 Capacity Only Contracts

CenterPoint is also is seeking to procure MISO Zone 6 Zonal Resource Credits (ZRC) for the 2023/2024 and 2024/2025 MISO Planning Years. As such, the capacity must be physically located or fully delivered to MISO Local Resource Zone (LRZ) 6. Similarly, CenterPoint will consider Proposals for longer-term Market Capacity Products that meet the requirements specified in Section 7.0 below.

3.3 Respondent Pre-Qualification: Notice of Intent and Non-Disclosure Agreement

Respondents to this RFP are required to fill out and sign pre-qualification documents in their present form -- Appendix A: Notice of Intent to Respond, Appendix B: Non-Disclosure Agreement (NDA), and Appendix C: Pre-Qualification Application. Respondents shall submit the signed forms to the RFP website (http://CenterPoint2022ASRFP.rfpmanager.biz/) by 5:00 p.m. CDT on May 27, 2022. Respondents may download the forms from the RFP website.

3.4 Multiple Proposals

Respondents may submit up to three Proposals (Projects) at no cost in response to this RFP. Respondents submitting more than three separate responses will incur a Proposal Evaluation Fee for each additional Proposal (Project) submitted. The non-refundable fee for evaluating each additional Proposal (Project) is $5,000. This sum will serve to defray evaluation costs. Respondents can find instructions for paying fees for their Proposal(s) on the RFP website (http://CenterPoint2022ASRFP.rfpmanager.biz/).

CenterPoint encourages Respondents to offer their Projects in a variety of ways and each Project offered with multiple options will be considered as a single Proposal. For example, Projects that are offered under multiple transaction structures (e.g. PPA or Asset Purchase) will count as one Proposal as it relates to the evaluation fee. Projects that offer various PPA term lengths and/or energy settlement locations (Project busbar, CenterPoint's load node, or Indiana Hub) will also be considered as one Proposal. In addition, Projects that are proposed both as standalone generating assets (e.g. solar) and also paired with storage will be considered as one Proposal as it relates to the fee. CenterPoint and 1898 & Co. will have sole discretion to determine whether a submission is deemed a single Proposal or multiple Proposals.

3.5 Proposal Pricing and Duration

Respondents shall make best efforts to offer Proposals with firm pricing not subject to any revisions during the evaluation, short-list selection and IRP process. As such, **pricing shall reflect the transaction price under <u>current</u> conditions (i.e. steel and other commodities, major equipment costs, tariffs and other duties, shipping costs, labor costs, availability of tax benefits, etc.).** For example, only current, active solar module tariffs in effect at the time of Proposal submission should be included and any potential future tariffs that may be levied should not be included in pricing. Likewise, Proposal pricing shall assume EPC costs such as material and labor as observed today, and shall not make assumptions as to the increase or decrease of costs at some future time.

Respondents shall provide cost assumptions in Appendix D and may provide further detailed justification for cost assumptions in the Proposal narrative. Proposals that base pricing on assumptions out of line with current conditions may be disqualified. All pricing should be provided in Appendix D in terms of US dollars as of the date the term of the contract begins and not subject to a currency exchange rate adjustment. CenterPoint is not obligated to provide an opportunity in the evaluation schedule for Respondents to refresh or update their pricing before the final selection(s) are made (if any).

3.6 Acknowledgment of RFP Terms and Conditions

The submission of a Proposal shall constitute Respondent's acknowledgment and acceptance of all the terms, conditions, and requirements of this RFP.

3.7 RFP Response Summary Information

All Proposals must include a table of contents and provide concise and complete information on the additional topics described below, organized as follows:

3.7.1 Executive Summary

Please provide a one-page executive summary of the Proposal in the form of a cover letter. Include the facility's location, age or development status, MISO generator interconnection project number, ICAP size, the primary contact's name, email, and phone number, and an overview of the major features of the Proposal. The Executive Summary must be signed by an officer of the Respondent who is duly authorized to commit the firm to carry out the proposed transaction should CenterPoint accept the Proposal (this does not have to be the primary contact). A Table of Contents should be the first page and immediately precede the Executive Summary.

3.7.2 Respondent's Information and Experience

Please include information on the Respondent's corporate structure (including identification of any parent companies), the project's financing plan, the Respondent's most recent credit rating, quarterly report containing unaudited consolidated financial statements that is signed and verified by an authorized officer of Respondent attesting to its accuracy, a copy of Respondent's annual report for the prior three years containing audited consolidated financial statements and a summary of Respondent's relevant experience. Please describe any current litigation or environmental fines involving the Respondent within the last five years, including but not limited to, any litigation, settlements of litigation or fines, that could potentially affect the facility or its operation. Please identify all bankruptcy or insolvency proceedings relating to the Respondent in any way. Please describe any litigation the Respondent or its parent company have been a party to in the last six years related to PPAs, asset purchases, capacity contracts or other transactions similar to those solicited in this RFP. All financial statements, annual reports and other large documents may be referenced via a website address.

Generating Facility Proposals shall include a list of projects with a brief description of Respondent's experience in the areas of development, financing, permitting, ownership, construction, and operation of all utility-scale power generation facilities.

4.0 PROPOSALS INCLUDING RENEWABLES & BATTERY STORAGE

4.1 Additional Requirements – Renewable and Storage Resources

Proposals for renewable and storage resources such as wind, solar, standalone storage, or storage paired with solar or other renewable projects (Renewable Resources) will be considered when submitted in response to this RFP. This section of the RFP provides additional requirements applicable to Proposals that include one or more renewable or storage resource(s). In addition, please see applicable Term Sheets (additional key pricing assumptions) in Appendices F, G and H

4.2 Wind Energy Proposals

CenterPoint is seeking Proposals for wind energy projects with an installed capacity (ICAP) of 50 MWac or greater but will consider Proposals for projects of any size. In addition to the general requirements provided in Section 3.0, the following additional requirements apply to any Proposal that includes a wind project:

- Major Component Data: The Proposal shall provide details on major components (such as turbines, blades, transformers, circuit breakers, switchgear, all protection and control systems, etc.) including manufacturer, country-of-origin, individual turbine ratings, rotor diameter and hub height.
- Location: CenterPoint has a preference for wind projects located in MISO Zone 6 as well as MISO Zone 4 and MISO Zone 5 but will also consider Proposals for projects located elsewhere. Proposals for facilities without existing firm deliverability to MISO LRZ 6 shall include cost estimates and transmission studies associated with securing such deliverability.
- Site control and layout: Proposals for wind projects shall include discussion of the project turbine layout and status of land acquisition required to site the layout. Respondents shall include a discussion of any nearby land features or facilities imposing land-use constraints including, but not limited to, wetlands, airports and other FAA facilities, zoning restrictions, etc.
- Permits and zoning: Respondents shall include a discussion of permitting status for the project including zoning status and restrictions such as setbacks, tip height limits, etc.
- Expected performance: Proposals shall include P50 expected annual production in MWh or NCF. Respondents shall provide the wind data or describe the data set used to estimate production.
- Price: Any Asset Purchase Proposal must clearly state all terms and obligations of the parties associated with the proposed transaction, including the disposition of Production Tax Credits. PPA Proposals may also include an option to purchase the assets, and shall clearly state the terms of such purchase option.
    - For purposes of incorporating the effect of tax benefits in Proposal pricing, Respondents shall apply tax law **currently in effect** at the time of Proposal submission and clearly state which tax assumptions are used. Respondents may optionally provide a discussion on the pricing impacts of possible future scenarios; however, a Proposal may be disqualified if it does not at a minimum provide pricing applying only **current laws**.

- To the extent RECs are included in a Proposal they must be registered with North American Renewables Registry.

4.3 Solar Energy Proposals

CenterPoint is seeking Proposals for solar energy projects with an installed capacity (ICAP) of 50 MWac or greater but will consider Proposals for projects of any size. In addition to the general requirements provided in Section 3.0 the following additional requirements will apply to any Proposal that includes a solar energy project:

- Major Component Data: The Proposal shall provide details on major components (such as solar panels, racking, inverters, transformers, circuit breakers, switchgear, all protection and control systems, etc.) including manufacturer, country-of-origin, individual panel ratings, and whether the panels will be fixed or tracking. The Proposal shall also include information on the inverters to be included in the project, including the manufacturer, size of individual inverters, and the type/configuration of the inverter system.
- Location: CenterPoint has a preference for solar projects located in MISO Zone 6 but will also consider Proposals for projects located elsewhere. Proposals for facilities without existing firm deliverability to MISO LRZ 6 shall include cost estimates and transmission studies associated with securing such deliverability.
- Site control and layout: Proposals for solar projects shall include discussion of the project panel/array layout(s) and status of land acquisition required to site the layout. Respondents shall include a discussion of any nearby land features or facilities imposing land-use constraints including, but not limited to, wetlands, zoning restrictions, etc. Respondents shall also include a description of civil work that will be required to prepare the land for solar installation as well as the contiguity of the land parcels used for the project. If possible Proposals should include layout drawings and schematics for the project.
- Permits and zoning: Respondents shall include a discussion of permitting status for the project including zoning status and restrictions such as setbacks, vegetation screening requirements, etc.
- Expected performance: Proposals shall include P50 expected annual production in MWh or NCF. Respondents shall provide the solar data or describe the data set used to estimate production.
- Price: Any Asset Purchase Proposal must clearly state all terms and obligations of the parties associated with the proposed transaction, including the disposition of Investment Tax Credit. PPA Proposals may also include an option to purchase the assets, and shall clearly state the terms of such purchase option.
    - For purposes of incorporating the effect of tax benefits in Proposal pricing, Respondents shall apply tax law **currently in effect** at the time of Proposal submission and clearly state which tax assumptions are used. Respondents may optionally provide a discussion on the pricing impacts of possible future scenarios; however, a Proposal may be disqualified if it does not at a minimum provide pricing applying only **current laws**.
- To the extent RECs are included in a Proposal they must be registered with North American Renewables Registry.

4.4 Energy Storage Proposals

CenterPoint is seeking Proposals for energy storage projects with an installed capacity (ICAP) of 25 MW or greater and a minimum duration of 4 hours; however, Proposals for storage projects of any size and duration will be considered. In addition to the general requirements provided in Section 3.0 the following additional requirements will apply to any Proposal that includes stand-alone storage or storage paired with other renewable technologies (e.g. solar + storage):

- Major Component Data: The Proposal shall provide details on major components (such as cells/modules, inverter, BMS, container system, climate control, fire protection, transformers, circuit breakers, switchgear, and control systems, etc.) including manufacturer, country-of-origin, etc.
- Location: CenterPoint has a preference for storage projects located in MISO Zone 6 but will also consider Proposals for projects located elsewhere. Proposals for facilities without existing firm deliverability to MISO LRZ 6 shall include cost estimates and transmission studies associated with securing such deliverability.
- Expected performance: Proposals shall include the system efficiency (i.e. roundtrip efficiency), overbuild, annual augmentation, maximum/warranty daily and annual cycles, etc. Proposals should include a description of the control strategy and dispatch control ownership.
- Price: Any Asset Purchase Proposal must clearly state all terms and obligations of the parties associated with the proposed transaction, including the disposition of Investment Tax Credit if applicable.
    - For purposes of incorporating the effect of tax benefits in Proposal pricing, Respondents shall apply tax law **currently in effect** at the time of Proposal submission and clearly state which tax assumptions are used. Respondents may optionally provide a discussion on the pricing impacts of possible future scenarios; however, a Proposal may be disqualified if it does not at a minimum provide pricing applying only **current laws**.

4.5 Evaluation Methodology

The following table summarizes the criteria that will be used to evaluate renewable and battery storage resource Proposals. Further definitions of each criteria and how they will be evaluated are outlined in Section 8.0.

Table 3: Renewables and Storage Scoring Criteria Summary

Category	Total points (out of 500)	Allocation
LCOE Evaluation (30%)	150	Proportionately from 0 (awarded to highest LCOE in group) to 150 (lowest LCOE in group)
Energy Settlement Location (20%)	100	• Max points given to energy financially settled or directly delivered to SIGE.SIGW • 90 points to projects located in service territory[2] • 75 points to Zone 6 outside CenterPoint territory • 25 points to projects in MISO that are outside Zone 6 • 0 points otherwise
Interconnection and Development Status (20%)	100	• Points awarded equally to 4 milestones. Max points for completed GIA & cost cap including interconnection agreement re-use • 75 completed Facilities Study (during DPP2-3) & offered cost cap • 50 competed System Impact Study (during DPP1) & offered cost cap • 25 offered cost cap • 0 points otherwise
Project Risk Factor (30%)	150	• Credit and Financial Plan – 30 points awarded proportional to CNP internal score from 0-10 • Development Experience – 30 points awarded proportional to MW in service, max of 1,500 • Site Control – 30 points proportional from 0%-100% of site control verified by provided docs • Permits – 30 points for Proposals showing all permits needed for construction/operation • Zoning – 30 points for Proposals showing completed zoning requirements

[2] For purchase options where delivery to SIGE.SIGW is not applicable, 100 points will be awarded to projects located in CenterPoint's service territory

5.0 PROPOSALS INCLUDING THERMAL RESOURCES

5.1 Additional Requirements – Thermal Resources

Proposals for thermal generating resources such as coal, natural gas, hydrogen or nuclear units will be considered when submitted in response to this RFP. This section of the RFP provides additional requirements applicable to Proposals that include one or more thermal resource(s).

5.2 Dispatch, Emissions, and Performance Characteristics for Thermal Resources

Respondents shall provide the dispatch and emissions characteristics of the generation facility in Appendix D, including, but not limited to:

- Minimum load level
- Maximum load level
- Ramp rates (up and down)
- Number of gas turbines that can be started simultaneously (if applicable)
- Heat rate curve for typical operations, including the minimum load and full load heat rates
  - If applicable, Respondent shall also provide heat rate curves for summer and winter seasons
- Fuel consumption and heat rate during startup, including startup time and the total number of hours annually the facility can be assumed to be in startup mode
- Fuel consumption and heat rate when the facility is being shut down, including how long shutdown takes and the total number of hours annually the facility can be assumed to be in shutdown mode
- An estimation of the total number of hours annually that the facility operates at full load
- Capability reductions as a result of ambient temperature increases
- Supplemental firing capability, including black start capability, and any operating limitations caused by such factors of design
- Emissions rates in units of lb/MWh at relevant dispatch levels (startup, minimum, mid and full loading) and seasons (summer, winter, shoulder) for nitrogen oxides (NO_X), sulfur dioxide (SO_2), carbon dioxide (CO_2), volatile organic compounds (VOC), particulate matter (PM) and carbon monoxide (CO)
- Any other operational limitations that reduce unit availability or reduce a unit's ability to dispatch or regulate

5.3 Operating Considerations

In addition to the instructions provided above in Section 3.0 Respondents shall provide the following data specific to thermal resources.

5.3.1 Operating Data

Respondents shall provide details on any current generation facility equipment issues and concerns, including the potential drivers and recommended mitigation procedures for the issues and/or concerns. These may include, but are not limited to, any operation of the turbine, generator, or boiler outside recommended parameters established by OEM, compromised turbine or compressor blades, etc. Respondents shall provide a list of any redundant equipment that is currently bypassed or out of service, and the related reason. Respondents shall also provide historical information on such issues and concerns that have arisen, how they were resolved, and the associated costs for the last ten years of operation, or for the commercial life of the generation facility, whichever is lesser.

5.3.2 Fuel Supply

Proposals shall describe, to the extent possible, fuel sourcing strategy, including from where their fuel is sourced. Respondents shall provide a description, including detailed cost information, contract duration, and material contract terms (including whether fuel contracts are take or pay, minimum volume requirements, price reopeners, assignability or termination provisions) of all fuel purchase, storage, and transport agreements related to the generation facility Proposal. Cost of fuel commodities shall be provided separately from the cost of fuel transportation. Respondents also must list any provisions or other considerations that would prohibit or impair the assignment and/or affect the performance obligations of either party under the respective contract(s). Respondents shall describe fuel purchase and transport to the generation facility, as well as any existing or known potential operational restrictions or impediments on such fuel purchase and transportation. Respondents also are required to provide a description of the existing fuel supply (and storage) infrastructure serving the generation facility, including the infrastructure for the delivery of secondary fuel for dual-fuel resources. However, CenterPoint, through this RFP, is exploring the potential purchase of generation facilities, and it is CenterPoint's sole discretion whether to assume any contract or contracts associated with the proposed generation facility related to fuel commodities and/or fuel transportation.

Proposals shall describe the generation facility's ability to access a reliable fuel supply that would support operation for any hour throughout the year, including the plant's onsite fuel storage and dual-fuel capabilities, if applicable. Proposals for gas generators shall indicate whether the facility is dual-fuel capable and Proposals should include an indication of the days of onsite fuel storage available. Gas generators without dual fuel capability shall provide information on the costs required to make the facility dual fuel capable to the extent that such cost estimates are available. Natural gas fired facilities shall have firm gas transportation contracts in place for the amount of gas capacity necessary to fulfill the amount of UCAP being bid. Proposals that do not include firm gas supply may be disqualified.

5.4 Environmental Considerations

In addition to the instructions provided above Respondents shall provide the following data specific to thermal resources.

5.4.1 Emissions and Waste Disposal Compliance

To the extent applicable, all environmental attributes, including emission reduction credits and/or allowances, related to the power being purchased should be conveyed to CenterPoint. This includes, but is not limited to, any and all credits in any form (emissions credits, offsets, financial credits, etc.) or baseline emissions associated with both known and unknown pollutants, including but not limited to SO_2, NO_X, Mercury (Hg), and CO_2. Any and all environmental liabilities, including compliance with known and future or unknown regulations or laws will be the sole responsibility of the generation producer or PPA seller.

For Asset Purchase Proposals, the Seller will retain all pre-closing environmental liabilities and obligations as well as all known future environmental liabilities and obligations, in each case associated with the real and personal property transferred with or as part of a Sale of the Plant. This includes both on and off-site liabilities. The Buyer will assume all other post-closing environmental liabilities and obligations. For purposes of facility design, Seller should assume that the unit will be required to meet the proposed New Source Performance Standards for Greenhouse Gases (40 Code of Federal Regulations (CFR) part 60, subpart TTTT).

5.4.2 Water Supply

Respondents shall provide a detailed description of the water supply, including but not limited to, contract term, water usage, and cost of water for the generation facility. Respondents shall also provide the status of the facility's National Pollutant Discharge Elimination System (NPDES) permits, including, but not limited to, permit conditions, permit violations reported over the last five years, the timing of next permit renewal, and any other known concerns.

If applicable, Respondents shall provide a summary of the facility's water chemistry program, including key systems and suppliers, and its performance in the most recent year.

5.4.3 Permits

As stated above, the generation facility must have all relevant environmental and other permits necessary for operation and maintenance. Respondents shall provide a description of all permits currently in place for the operation and maintenance of the facility (e.g., Spill Prevention Containment and Control plans, Title IV and Title V permits of the Clean Air Act, Cap and Trade Permits, NPDES permits, Water Withdrawal, and Pollution Incident Prevention Plan, etc.).

Respondents shall describe any operating limitations imposed by permitting or environmental compliance that limit plant availability.

Respondents shall provide a description of any identified environmental liabilities (e.g., potential site remediation requirements, etc.) for the facility.

5.5 Evaluation Methodology

The following table summarizes the criteria that will be used to evaluate thermal resource Proposals. Further definitions of each criteria and how they will be evaluated are outlined in Section 8.0.

Table 4: Thermal Facility Scoring Criteria Summary

Category	Total points (out of 500)	Allocation
LCOE Evaluation (30%)	150	Proportionately from 0 (awarded to highest LCOE in group) to 150 (lowest LCOE in group)
Energy Settlement Location (20%)	100	• Max points given to energy financially settled or directly delivered to SIGE.SIGW • 90 points to projects located in service territory[3] • 75 points to projects in LRZ 6 outside of CenterPoint's service territory • 25 points to projects that settle in MISO outside of LRZ 6 • 0 points otherwise
Interconnection and Development Status (20%)	100	• Points awarded equally to 4 milestones. Max points for completed GIA & cost cap including interconnection agreement re-use • 75 completed Facilities Study (during DPP2-3) & offered cost cap • 50 competed System Impact Study (during DPP1) & offered cost cap • 25 offered cost cap • 0 points otherwise
Project Risk Factor (30%)	150	• Credit and Financial Plan – 30 points awarded proportional to CNP internal score from 0-10 • Development Experience – 30 points awarded proportional to MW in service, max of 1,500 • Fuel Risk - 15 • Operational Control – 15 • Site Control – 30 points proportional from 0%-100% of site control verified by provided docs • Permits – 15 points for Proposals showing all permits needed for construction/operation • Zoning – 15 points for Proposals showing completed zoning requirements

[3] For purchase options where delivery to SIGE.SIGW is not applicable, 100 points will be awarded to projects located in CenterPoint's service territory

6.0 PROPOSALS INCLUDING LOAD MODIFYING RESOURCES/DEMAND RESOURCES

LMRs/DRs are demand-side resources and behind the meter generation not typically modeled or measured as part of MISO's operations but used during capacity shortages to help meet the energy balance. CenterPoint will consider LMRs/DRs from one or more MISO customers or curtailment service providers (CSP). LMR suppliers must be located entirely within MISO LRZ 6. Proposals for LMRs/DRs are to be for assets that are eligible to participate in MISO LRZ 6 and can meet the additional performance requirements of CenterPoint as described in Sections 6.1 and 6.3. In addition, for LMRs/DRs located within Indiana, Respondent must identify how the Proposal conforms with any requirements of the local utility and state law in order to offer resources for capacity accreditation within the MISO market under Module E Capacity Tracking.

Proposals for LMRs/DRs may be combined with another power supply Proposal or may be submitted on a standalone basis. CenterPoint will consider LMR/DR Proposals that have a term of one year or longer, consistent with MISO planning years.

6.1 Product Definition

To be eligible for participation in this RFP, the LMR/DR offered by a supplier must:

- Meet LMR/DR Requirements for participation in MISO as a demand-side resource, including any future changes to MISO's requirements for LMRs/DRs for the term of the Proposal
- Meet the additional performance requirements described in Section 6.3
- For capacity accreditation, the Proposal must be sourced from locations entirely within MISO LRZ 6
- Use an existing, proven technology that has demonstrated reliable demand reduction, which may include use of Behind the Meter Generation (as defined by MISO)
- Reduce load by a predetermined amount when notified by CenterPoint of a Curtailment Event without further direction or communication by or from CenterPoint.

6.2 Purchase Agreement

If selected, the LMR/DRs supplier and CenterPoint will negotiate a mutually acceptable agreement to govern any commercial relationship established by the parties. With respect to a Proposal from a CSP, CenterPoint will not be responsible for making payments to, communicating with, or managing the relationship or performance of any customer within an aggregation, and the CSP shall be solely responsible for the same in all respects. To mitigate risk, CenterPoint will require the LMR/DR supplier to provide collateral upon execution of a

LMR/DR Proposal. CenterPoint reserves the right to determine the form of that collateral requirement for a winning Proposal.

6.3 Curtailment Events: Notification and Performance Requirements

LMRs/DRs must meet notification and performance requirements applicable to a Curtailment Event, as defined and described herein and comply with MISO current and future testing requirements. A Curtailment Event shall be initiated by either CenterPoint or MISO as described futher in Section 6.3.1.

6.3.1 Notification, Performance, and Test Requirements

Curtailment Events initiated by MISO: For Curtailment Events initiated by MISO, LMR/DR suppliers shall agree to and be capable of meeting, throughout the entire term of the Proposal, all notification and performance requirements applicable to Capacity Performance demand resources. The supplier shall comply with all MISO Module E Capacity Tracking measurement and verification requirements.

Curtailment Events initiated by CenterPoint: Suppliers shall also agree to and be capable of meeting the following additional notification and performance requirements applicable to Curtailment Events initiated solely by CenterPoint:

- Suppliers shall curtail Actual Measured Load to Firm Contract Load within the proposed notification time specified in the Proposal.
- Notification of a Curtailment Event initiated solely by CenterPoint will consist of an electronic message issued by CenterPoint to a device or devices such as telephone, facsimile, or email, selected and provided by the supplier and approved by CenterPoint. Two-way information capability shall be incorporated by CenterPoint and the supplier in order to provide confirmation of receipt of notification messages. CenterPoint will provide the supplier a notification of when Curtailment Events have ended. Operation, maintenance, and functionality of communication devices for receipt of notifications selected by the supplier shall be the sole responsibility of the supplier, and receipt of notifications set out in this paragraph shall be the sole responsibility of the supplier.
- During the entire period of a Curtailment Event initiated by CenterPoint, the supplier's Actual Measured Load must remain at or below its Firm Contract Load. A supplier's Actual Measured Load shall be determined by integrating the megawatts used over every clock hour (hour-ending).

6.3.2 Remedies for Non-Performance

A supplier whose Actual Measured Load exceeds its Firm Contract Load will be subject to performance penalties which may include, but not be limited to, refunding to CenterPoint monthly payments under the agreement.

A supplier shall be responsible for, and shall indemnify CenterPoint for, any non-performance penalties, costs, charges, or other amounts assessed by MISO and incurred by CenterPoint as a result of non-performance attributable to the supplier's LMR/DR, including but not limited to any Capacity Resource Deficiency Charges, Non-Performance Charges, or similar charges or penalties under the MISO agreements. In no event shall the penalties listed above for non-performance during a Curtailment Event be less than the sum of any MISO non-performance penalties, costs, charges, or other amounts incurred by CenterPoint as a result of non-performance attributable to the supplier's LMR/DR and the Curtailment Event charge.

6.4 Proposal Requirements

6.4.1 Acquisition Price

Suppliers shall submit an acquisition price consisting of a single fixed amount denominated in units of dollars per megawatt-day ($/MW-day), which is to apply for the term of the Proposal. If a Proposal is accepted, the supplier will be compensated in an amount equal to the monthly Curtailable Load times the Acquisition Price. The Proposal shall include all monetary consideration for the LMR/DR offered. Suppliers must submit their best and final price with their Proposal.

Should CenterPoint execute an agreement with a Respondent, the contract price between CenterPoint and the Respondent will be the Acquisition Price submitted in its respective Proposal through this RFP process.

6.4.2 Product Description

A Proposal shall include a description of the individual LMR/DR customer(s) and expected load drop values (kW), equipment, and technology that will be deployed and make available any other information required by MISO to meet its registration process, and for CSPs, plans for recruiting, engaging, and maintaining Program Participants.

Proposals should discuss the experience, qualifications, and financial strength of the supplier and other key contributors including the specific number of months the supplier has been providing LMR/DR services in MISO. Responses should indicate whether the supplier has ever been assessed a performance penalty in association with the resource and if so, when any penalties were assessed. For CSPs, Proposals should describe well-defined roles and responsibilities of the supplier and its participants. The supplier should describe successful protocols, if any, they have employed in the MISO LRZ 6 or other MISO zones for dispatching their LMR/DR.

While the product definition requires a load reduction upon notification by CenterPoint or MISO of a Curtailment Event, there is a preference for resources that can provide a more rapid response and/or ramp up or down in response to specific control signals. Respondents are urged to detail the full, demonstrated capability of the proposed resource in accordance with the evaluation criteria included in Section 8.0.

For planned LMRs/DRs, the supplier must fully describe specific plans detailing what equipment or technology it will deploy and/or utilize to support its operations. For CSPs, Proposals must describe supplier's processes for aggregating participants, how the supplier intends to recruit and engage participants, and/or provide lists of participants. The Proposal also must describe curtailment systems and procedures, budgeting for and structure of dispute resolution, and plans for communicating with participants in connection with a curtailment period.

6.4.3 Technical Requirements

CenterPoint shall acquire all rights, titles, and interests in the LMR/DR including all the potential capacity and energy revenues. Suppliers must agree to cooperate with CenterPoint in providing information needed to meet all MISO LMR/DR information requirements.

The supplier will assume all responsibilities and liabilities associated with providing LMRs/DRs. Accordingly, Proposals offering LMRs/DRs must include acknowledgment and agreement that the supplier is responsible for the following non-exhaustive list of activities and obligations:

- Managing load reductions, including all notices, communications, controls, equipment, or other processes required
- If the supplier is a CSP, determining the number of participants, in its aggregation, the number of interruptible hours per customer, and the size of each participant's load reduction
- If the supplier is a CSP, paying any participants according to the CSP's agreement with those participants. Such agreements shall be independent of CenterPoint's agreement with the CSP and must hold CenterPoint harmless for any direct or indirect obligations or liability associated with the program
- Paying penalties assessed due to the non-performance of the LMR/DR

The agreement shall reflect that it will be the supplier's responsibility to reimburse CenterPoint for any penalties, fees, or charges resulting from non-performance of its LMR/DR, including replacement capacity to maintain CenterPoint's Planning Reserve Margin(PRM) requirement, and the supplier's obligation to indemnify and hold CenterPoint harmless against any claim arising from such non-performance. In the case of a supplier who is a CSP, the agreement will additionally set forth CSP's responsibility to reimburse CenterPoint for any penalties, fees, or charges resulting from non-performance of any CSP participant, and CSP's obligation to indemnify and hold CenterPoint harmless against any claim arising from such CSP participants' non-performance.

6.5 Evaluation Methodology

The following evaluation criteria will be used to evaluate Proposals including other LMR/DRs. Since there is a wide range of potential products which could be offered within this category, adjustments may be made on scoring criteria to accurately compare bids within categories to each other. Further definitions of each criteria and how they will be evaluated are outlined in Section 8.0.

Table 5: Demand-Side Contracts Scoring Criteria Summary

Category	Total points (out of 500)	Allocation
Cost Evaluation (40%)	200	Scaled proportional to the cost of similar Proposals.
Historical Performance (20%)	100	Awarded based on time in-service and absence of a non-performance penalty.
Response Time (20%)	100	Awarded based on response time to specific control signals.
Project Risk Factor (20%)	100	Allocated based on material risk of reduced deliverability.

6.6 Contract Execution

CenterPoint does not, by this RFP, obligate itself to purchase any LMR/DR, or to execute an agreement with any Respondent who submits an offer to sell a LMR/DR to CenterPoint. CenterPoint may, in its discretion, reject any or all Proposals to sell a LMR/DR to CenterPoint, as such are described in this RFP.

Selection of a Proposal as a finalist shall not be construed as a commitment by CenterPoint to execute an agreement. Execution of any agreement is contingent upon CenterPoint receiving all required regulatory approvals and completion of such due diligence as CenterPoint in its sole discretion determines is reasonable to confirm the qualifications and performance of a given LMR/DR. During the period between when 1898 & Co. makes its recommendation(s) to CenterPoint, and the date of execution of the agreement, CenterPoint may conduct additional due diligence on the Proposal.

7.0 CAPACITY OFFERS

7.1 General Requirements – Short Term Capacity Offers

CenterPoint is seeking to procure MISO Zone 6 Zonal Resource Credits (ZRC) for the 2023/2024 and 2024/2025 Planning Years. As such, the capacity must be physically located or fully delivered to MISO Local Resource Zone (LRZ) 6.

Table 6: Short Term Capacity

MISO Planning Year	Planning Year 2023 - 2024 (366 Days)	Planning Year 2024 - 2025 (365 Days)
Product	MISO Zone 6 Zonal Resource Credits	MISO Zone 6 Zonal Resource Credits
Volume	Up to 350 MW	Up to 350 MW

7.2 Long Term Capacity Offers

CenterPoint will also consider longer-term offers for capacity through 2040.

7.3 Terms and Conditions for Capacity Offers

- All bids shall be firm once submitted and shall remain firm through the end of the notification period.
- CenterPoint reserves the right to request clarification of information submitted and to request additional information from any Respondent.
- Capacity (Zonal Resource Credits) must be deliverable and delivered to MISO LRZ 6.
    - Capacity sourced from other MISO Local Resource Zones is acceptable provided the Respondent assumes the risk of any MISO imposed delivery charges and risks associated with MISO Import/Export limits.
- Respondents must be able and commit to transferring capacity to CenterPoint within MISO's Module E Capacity Tracking System ("MECT") tool in accordance with the MISO Tariff and associated business practice manuals for use in meeting Planning Reserve Margin Requirements.
- CenterPoint may require credit support dependent upon the term, overall value, and risks associated with individual Respondents. Such credit support may take the form of;
    - Letter of Credit ("LOC") from a financial institution acceptable to CenterPoint in its sole discretion, or Cash Escrow.

- CenterPoint reserves the right to award all or part of its requirements to one or more Respondents.

7.4 Pricing

Respondents shall provide Proposal pricing in units of $/MW-day for capacity fully delivered to MISO LRZ 6.

7.5 Evaluation Methodology

The following table summarizes the criteria that will be used to evaluate capacity offers. Further definitions of each criteria and how they will be evaluated are outlined in Section 8.0.

Table 7: Capacity Only Scoring Criteria Summary

Category	Total points (out of 500)	Allocation
Cost Evaluation (60%)	300	Scaled proportional to the cost of similar Proposals.
Project Risk Factor (40%)	200	• 200 located in MISO Zone 6 • 150 located in MISO Central Zones • 100 located in MISO North • 50 located outside of MISO North

8.0 PROPOSAL EVALUATION AND CONTRACT NEGOTIATIONS

8.1 Initial Proposal Review

An initial review of the Proposals will be performed by 1898 & Co. Proposals will be reviewed for completeness. Proposals that do not include all of the required information as described herein may be deemed ineligible and may not be considered for further evaluation. If it appears that certain information has inadvertently been omitted from a Proposal, 1898 & Co. may, but is not obligated to, contact the Respondent to obtain the missing information, per Section 2.2. These communications will be initiated via email (CenterPointRFP@1898andco.com).

Each complete Proposal will be evaluated by quantitative and qualitative factors. The evaluation criteria outlined in this section are intended to relatively compare each Proposal to analogous submissions and will be the starting guidelines for the evaluation. If needed, the scoring may be adjusted to provide distinction between Proposals. This evaluation will be used to determine which projects are most capable of providing CenterPoint customers with a safe, reliable, and affordable power supply. Project scoring will be used to narrow the field down to a short list.

8.2 Evaluation Criteria - Generation Facility

1898 & Co. will quantitatively and qualitatively evaluate all conforming generation facility Proposals' ability to meet power supply needs. During this evaluation process, 1898 & Co. may or may not choose to initiate more detailed clarification discussions with one or more Respondents. Discussions with a Respondent shall in no way be construed as commencing contract negotiations.

Table 8: Renewables and Storage Scoring Criteria Summary

Category	Total points (out of 500)	Allocation
LCOE Evaluation (30%)	150	Proportionately from 0 (awarded to highest LCOE in group) to 150 (lowest LCOE in group)
Energy Settlement Location (20%)	100	• Max points given to energy financially settled or directly delivered to SIGE.SIGW • 90 points to projects located in service territory[4] • 75 points to projects in LRZ 6 outside of CenterPoint's service territory • 25 points to projects that settle in MISO outside of LRZ 6 • 0 points otherwise
Interconnection and Development Status (20%)	100	• Points awarded equally to 4 milestones. Max points for completed GIA & cost cap • 75 completed Facilities Study (during DPP2-3) & offered cost cap • 50 competed System Impact Study (during DPP1) & offered cost cap • 25 offered cost cap • 0 points otherwise
Project Risk Factor (30%)	150	• Credit and Financial Plan – 30 points awarded proportional to CNP internal score from 0-10 • Development Experience – 30 points awarded proportional to MW in service, max of 1,500 • Site Control – 30 points proportional from 0%-100% of site control verified by provided docs • Permits – 30 points for Proposals showing all permits needed for construction/operation • Zoning – 30 points for Proposals showing completed zoning requirements

[4] For purchase options where delivery to SIGE.SIGW is not applicable, 100 points will be awarded to projects located in CenterPoint's service territory

Table 9: Thermal Facility Scoring Criteria Summary

Category	Total points (out of 500)	Allocation
LCOE Evaluation (30%)	150	Proportionately from 0 (awarded to highest LCOE in group) to 150 (lowest LCOE in group)
Energy Settlement Location (20%)	100	• Max points given to energy financially settled or directly delivered to SIGE.SIGW • 90 points to projects located in service territory[5] • 75 points to projects in LRZ 6 outside of CenterPoint's service territory • 25 points to projects that settle in MISO outside of LRZ 6 • 0 points otherwise
Interconnection and Development Status (20%)	100	• Points awarded equally to 4 milestones. Max points for completed GIA & cost cap • 75 completed Facilities Study (during DPP2-3) & offered cost cap • 50 competed System Impact Study (during DPP1) & offered cost cap • 25 offered cost cap • 0 points otherwise
Project Risk Factor (30%)	150	• Credit and Financial Plan – 30 points awarded proportional to CNP internal score from 0-10 • Development Experience – 30 points awarded proportional to MW in service, max of 1,500 • Fuel Risk - 15 • Operational Control – 15 • Site Control – 30 points proportional from 0%-100% of site control verified by provided docs • Permits – 15 points for Proposals showing all permits needed for construction/operation • Zoning – 15 points for Proposals showing completed zoning requirements

[5] For purchase options where delivery to SIGE.SIGW is not applicable, 100 points will be awarded to projects located in CenterPoint's service territory

8.2.1 Levelized Cost of Energy - 150 Points

The initial evaluation will be primarily based on a comparison of each Proposal's Levelized Cost of Energy (LCOE). A LCOE allows for Proposals within asset classes, which have different sizes, pricing, operating characteristics, ownership structures, etc. to be evaluated and compared to each other on an equivalent economic basis. The LCOE analysis will incorporate all costs associated with an asset purchase or PPA. These costs will include the applicable purchase or PPA cost, fixed costs, and variable operating expenses across standard technology respective operating parameters. The levelized value of these costs over this time period are then divided by the energy produced by the respective Proposal.

CenterPoint specific assumptions used in this analysis will be in accordance with CenterPoint's 2022/2023 IRP assumptions, including but not limited to

- Discount rate
- Capital recovery factor
- Escalation
- Fixed operations and maintenance expenses
- Variable operations and maintenance expense

The LCOE evaluation is a screening level economic evaluation which will determine the cost of energy provided by each Proposal relative to similar technology types. Proposals within an evaluation class with the lowest LCOE will receive full scoring for this metric. Points awarded to higher cost Proposals will be scaled inversely proportional with the highest cost Proposal receiving 0 points for this metric.

The rules for performing the LCOE analysis will be determined by 1898 & Co. and CenterPoint in advance of the receipt and review of any Proposals. However, as part of the process of evaluating Proposals, cases may arise where, in order to adequately project asset costs or to facilitate a comparison between qualified Proposals, the rules related to the LCOE analysis may require review and/or adjustment. To the extent that any additions or adjustments are required, such additions or adjustments will be made solely by 1898 & Co. In such cases, any and all rules will be applied consistently across all Respondents.

While performing LCOE analyses of Proposals, 1898 & Co. may request additional or clarifying information from a given Respondent regarding resource performance, operating costs, or other factors that influence the LCOE calculation for a given resource. This evaluation may also include grid congestion analysis. Requests for additional information may be required to ensure that all qualified Proposals are fairly and consistently evaluated. Consistent with Section 2.2, in such cases, Respondents will be required to respond within five business days of receipt of such request. 1898 & Co. will not consider unsolicited updates from Respondents related to the cost of any power supply resource.

8.2.2 Energy Settlement Location - 100 points

CenterPoint has a preference for Proposals that include all costs to have energy financially settled or directly delivered to CenterPoint's load node (SIGE.SIGW). Proposals that settle at SIGE.SIGW will receive 100 points. Proposals that settle at a node in CenterPoint electric service territory will receive 90 points. Proposals that settle at Indiana Hub will receive 50 points. Proposals that settle at a different node in LRZ 6, but outside of CenterPoint electric service territory will receive 25 points. Proposals that settle at a node outside of LRZ 6 will receive 0 points.

8.2.3 Interconnection and Development Status - 100 Points

Existing resources will receive full credit under this evaluation category. Plants that have not achieved commercial operation but that are in the MISO Generation Interconnection (GI) Queue will be awarded points based on the Definitive Planning Phase they are in. Facilities failing to meet critical development milestones may be disqualified from consideration at CenterPoint's sole discretion.

Up to 100 points will be will awarded based on the achievement of certain development milestones towards the facility COD. Four milestones have been selected and 25 points will be awarded for each equally. The selected milestones are as follows:

- Completed a MISO System Impact Study
- Completed a MISO Facilities Study
- Executed a MISO Generator Interconnection Agreement
- A maximum limit on interconnection and network upgrade costs that will be passed through to CenterPoint is included in the Proposal

8.2.4 Project Risk Factors - 150 Points

The Project Risk Factors attempt to identify and score potential risks which may compromise the future performance of the asset. In situations where the level of risk is not accurately represented, scoring may be adjusted. Potential considerations include, but may not be limited to the following:

- Credit and financial plan - Proposals will be evaluated based on a rating 0 through 10 (financial score) that takes into account credit ratings from S&P, Moody's, and D&B, years in business, and provided financial statements. The points will be awarded as percent of the maximum financial score as shown below[6]:
$$Points\ Awarded = \frac{Financial\ Score}{10} \times 30$$
- Development experience - Relevant technology development experience is an important risk factor. Proposals will receive up to 30 points based on the following formula:
$$Points\ Awarded = \frac{Nameplate\ MW\ In\ Service\ (same\ technology\ as\ proposed)}{1{,}500} \times 30$$
- Site Control - Proposals will receive points proportionately based on the amount of verifiable site control. Respondents should be as detailed and thorough as possible

[6] CenterPoint reserves the right to re-evaluate credit rating and exclude Respondents at its sole discretion.

in describing and providing evidence of site control. Proposals will receive up to 30 points based on the following formula:

$$Points\ Awarded = \frac{Percent\ of\ Verifiable\ Site\ Control}{100\%} \times 30$$

- Permits - Proposals that have all permits necessary for construction and operation will receive max points. Partial points may be assigned based on level of documentation provided.
- Zoning - Proposals that have fulfilled zoning requirements will receive max points. Partial points may be assigned based on level of documentation provided.
- Fuel risk - For applicable Proposals, sites with firm and reliable fuel supply will receive max points.
- Operational control - Proposals which offer CenterPoint operational control will receive max points

Any such risks shall be disclosed along with a description of the associated measures taken to mitigate the risk. Failure to disclose a reasonably foreseeable risk or risks may be a basis to disqualify a Proposal.

Proposals with no such risks as determined by 1898 & Co. will receive the full number of points available in this category. Proposals with asset or project-specific risks that are not able to be fully mitigated may receive fewer points depending on 1898 & Co.'s assessment.

8.3 Evaluation Criteria – LM/DR Resources

Burns & McDonnell will quantitatively and qualitatively evaluate all conforming LMR/DR Proposals. During this evaluation process, Burns & McDonnell may or may not choose to initiate more detailed clarification discussions with one or more Respondents. Discussions with a Respondent shall in no way be construed as commencing contract negotiations. A more detailed quantitative evaluation for select bidders will consider production cost models and nodal analysis.

CenterPoint will accept Proposals from LMR and DR providers that meet the requirements as established in this RFP and conform to MISO requirements. These requirements include but are not limited to, the ability to respond to Curtailment Events initiated either by MISO or by CenterPoint.

LMR/DR Proposals will be evaluated across the following criteria:

Table 10: Demand-Side Resources Scoring Criteria Summary

Category	Total points (out of 500)	Allocation
Cost Evaluation (40%)	200	Proportionately from 0 (awarded to highest cost in group) to 200 (lowest cost in group)
Historical Performance (20%)	100	Awarded based on time in-service and absence of a non-performance penalty.
Response Time (20%)	100	Awarded based on response time to specific control signals.
Project Risk Factor (20%)	150	Allocated based on material risk of reduced deliverability.

8.3.1 Cost Evaluation - 200 Points

The cost of each Proposal will be evaluated based on the annual payment per MW for the LMR/DR. The lowest $/MW cost Proposal will receive 200 points for the cost evaluation category. Points awarded to higher cost Proposals will be scaled inversely proportional with the highest cost Proposal receiving 0 points for this metric.

8.3.2 Historical Performance - 100 Points

An end use customer or CSP with a historical performance record of successfully providing demand response services for three or more years without being assessed a non-performance penalty will receive 100 points for this category.

An end use customer or CSP that has provided such services for between one year and three years without being assessed a non-performance penalty will receive 50 points for this category.

An end use customer or CSP that has not provided such services in the past or that has been assessed a non-performance penalty will receive zero points for this category.

8.3.3 Response Time - 100 Points

While the product defines a load reduction response time within a Respondent's Proposal, there is a preference for resources that can provide a more rapid response to specific control signals.

Proposals for LMR/DR that have the ability to follow a real-time signal will be awarded 100 points for the response time category. Proposals for LMR/DR that can achieve the load reduction target within 30 minutes of notification will receive 75 points for this category. Proposals for LMR/DR that can achieve the load reduction target within 60 minutes of notification will receive 50 points for this category. Proposals for LMR/DR that can achieve the load reduction target within 120 minutes of notification will receive 25 points for this category.

8.3.4 Proposal Risk Factors - 100 Points

The Proposal risk factors category will be used to adjust the overall scoring in cases where there is a material risk identified that may create concerns about the ability of the provider to deliver on their Proposal or that may create a material uncertainty about the cost to CenterPoint or its customers, significant regulatory uncertainty, or other considerations.

8.4 Evaluation Criteria - Capacity Offers

Table 11: Capacity Only Scoring Criteria Summary

Category	Total points (out of 500)	Allocation
Cost Evaluation (60%)	300	Proportionately from 0 (awarded to highest cost in group) to 300 (lowest cost in group)
Project Risk Factor (40%)	200	• 200 points to resources located in MISO Zone 6 • 150 points to resources located in MISO Central Zones • 100 points to resources located in MISO North • 50 points to resources located within MISO but outside of MISO North

8.4.1 Cost Evaluation - 300 Points

The cost of each Proposal will be evaluated based on the annual payment per MW for the Capacity. The lowest $/MW cost Proposal will receive 300 points for the cost evaluation category. Points awarded to higher cost Proposals will be scaled inversely proportional with the highest cost Proposal receiving 0 points for this metric.

8.4.2 Proposal Risk Factors - 200 Points

This category is intended to capture deliverability risk. Points will be awarded according to the proximity of the resource to LRZ 6 with max points awarded to resources located in LRZ 6 and decreasing points allocated to offers located in more remote resource zones.

8.5 Discussion of Proposals During Evaluation Period

CenterPoint may or may not select candidates for further discussions. CenterPoint will contact any selected Respondent in writing to confirm interest in commencing contract negotiations. All negotiations will begin with CenterPoint's standard contract as a starting point. CenterPoint's commencement of and participation in negotiations shall not be construed as a commitment to execute a contract. If a contract is negotiated, it will not be effective unless and until it is fully executed with the receipt of all required regulatory approvals.

8.6 Selection of Highest Scoring Proposal(s)

Proposals will be rank ordered consistent with the RFP evaluation criteria. Resources will be selected consistent with the RFP evaluation, short-term capacity needs, and the IRP determined need. CenterPoint will seek to secure, subject to CenterPoint board approval, resources consistent with the preferred portfolio identified in the 2022/2023 IRP. There is no assurance that the individual, highest-scoring qualified Proposal(s) will be selected.

8.7 Contract Execution

CenterPoint does not, by this RFP, obligate itself to purchase any generation facility or facilities, or to execute an Asset Purchase, PPA, or capacity contract with any Respondent. CenterPoint may, in its discretion, reject any or all Proposals, as such are described in this RFP.

Selection of a winning Proposal shall not be construed as a commitment by CenterPoint to execute an agreement. During the period between 1898 & Co.'s delivery of results to CenterPoint and the date of execution of any agreement, CenterPoint will conduct additional due diligence on the Proposal which may include, but not be limited to, onsite visits, management interviews, legal and regulatory due diligence, and detailed engineering assessments and facility dispatch modeling.

9.0 PROPOSAL SUBMISSION

All Proposal documents must be submitted to the RFP website (http://CenterPoint2022ASRFP.rfpmanager.biz/).

9.1 Format and Documentation

All Proposals submitted in response to this RFP must be received by 1898 & Co. to the website (http://CenterPoint2022ASRFP.rfpmanager.biz/) no later than the Proposal Submittal Due Date shown in Section 2.3. 1898 & Co. and CenterPoint will not evaluate Proposals as part of this RFP process if submitted after this date and time. Multiple Proposals submitted by the same Respondent must be identified and submitted separately. Financial statements, annual reports, technical specification documents, and other large documents can be sent electronically to the RFP email address. Each Respondent must submit the following prior to the Proposal deadline:

1. Appendix A: Notice of Intent to Respond
2. Appendix B: Non-Disclosure Agreement (NDA) in its present form
3. Appendix C: Application
4. Appendix D: Proposal Data in Excel format

9.2 Certification

1. A Respondent's Proposal must certify that: There are no pending legal or civil actions that would impair the Respondent's ability to perform its obligations under the proposed PPA, Asset Purchase Agreement or Capacity Contract.
2. The Respondent has not directly or indirectly induced or solicited any other Respondent to submit a false Proposal.
3. The Respondent has not solicited or induced any other person, firm, or corporation to refrain from submitting a Proposal.
4. The Respondent has not sought by collusion to obtain any advantage over any other Respondent.

10.0 RESERVATION OF RIGHTS

Nothing contained in this RFP shall be construed to require or obligate CenterPoint to select any Proposals or limit the ability of CenterPoint to reject all Proposals in its sole and exclusive discretion. CenterPoint further reserves the right to withdraw and terminate this RFP at any time prior to the Proposal Submittal Due Date, selection of projects or execution of a contract. All final contracts will be contingent on IURC and CenterPoint board approval.

All Proposals submitted to CenterPoint pursuant to this RFP shall become the exclusive property of CenterPoint and may be used for any reasonable purpose by CenterPoint. CenterPoint and 1898 & Co. shall consider materials provided by Respondent in response to this RFP to be confidential only if such materials are clearly designated as Confidential. Respondents should be aware that their Proposal, even if marked Confidential, may be subject to discovery and disclosure in regulatory or judicial proceedings that may or may not be initiated by CenterPoint. Respondents may be required to justify the requested confidential treatment under the provisions of a protective order issued in such proceedings. If required by an order of an agency or court of competent jurisdiction, CenterPoint may produce the material in response to such order without prior consultation with the Respondent.

11.0 CONFIDENTIALITY OF INFORMATION

All Proposals submitted in response to this RFP become the responsibility of 1898 & Co. and CenterPoint upon submittal. Respondents desiring confidential treatment by 1898 & Co. and CenterPoint should clearly identify each page of information considered to be confidential or proprietary. Consistent with the RFP NDA (Appendix B), 1898 & Co. will take reasonable precautions and use reasonable efforts to maintain the confidentiality of all information so identified. CenterPoint reserves the right to release any Proposals, or portions thereof, to agents, attorneys, or consultants for purposes of Proposal evaluation. Regardless of the confidentiality claimed, however, and regardless of the provisions of this RFP, all such information may be subject to review by, and disclosable by CenterPoint, to the appropriate state authority, or any other governmental authority or judicial body with jurisdiction relating to these matters, and may also be subject to discovery by other parties subject to fully executed NDAs/confidentiality agreements. Further, because CenterPoint is conducting this RFP as part of the IRP public advisory process, CenterPoint will disclose the UCAP MW offered, technology/resource type, average price, general location, proposed ownership structure, and Proposal duration of all Proposals unless a given technology has less than three Respondents in order to inform stakeholders of the summary results of the RFP.

12.0 REGULATORY APPROVALS

Pursuant to the terms of the definitive agreement(s), the Respondent will agree to use its reasonable best efforts, including, if necessary, providing data and testimony, to obtain any and all State, Federal, or other regulatory approvals required for the consummation of the transaction.

Please note in particular that approval by the IURC and MISO may be required before the transaction can be consummated between the selected Respondent and CenterPoint. In addition to disclosure to state authorities or any other governmental authorities or judicial bodies heretofore described, as part of the regulatory process, responses to the RFP may be provided to parties who have executed a NDA/confidentiality agreement, specifically acknowledging that they are neither affiliated with any party responding to the RFP or serving as a conduit for any party responding to the RFP.

13.0 CREDIT QUALIFICATION AND COLLATERAL

CenterPoint will review the creditworthiness of Respondents and the risk associated with any potential transaction to determine what credit requirements may be necessary to protect CenterPoint's ability to serve its customers in a reliable manner. For Proposal pricing purposes, Respondents shall assume that required project collateral shall be in the form of (i) a payment and performance bond, (ii) letter of credit or (iii) a guaranty from a creditworthy parent company ("A" / "A2"). Respondents should also include in their Proposal how they expect to meet these requirements.

For asset purchases, Respondents shall have the obligation to post Definitive Agreement (DA) collateral at the execution of the definitive agreement and will be in force until the transfer of title to CenterPoint.

For PPAs and LM/DR contracts, Respondents may be required to post operating collateral over the term of any agreement consistent with the terms and conditions of final agreements as negotiated between CenterPoint and the supplier.

Respondents shall refer to the Term Sheets in Appendix F, Appendix G, and Appendix H for resource-specific requirements. CenterPoint and 1898 & Co. reserves the right to require a Respondent to post collateral in an amount that exceeds the amounts listed herein as conditions warrant. Unless otherwise specified in the Term Sheets, the following table shall apply:

Table 12: Collateral

Asset	Collateral Amount
Asset Purchase	$75/kW at execution of definitive agreement
Asset Purchase	$150/kW at regulatory approval
Power Purchase Agreement	12-months expected revenues
LM/DR Resource Agreement	12-months expected revenues

14.0 MISCELLANEOUS

14.1 Non-Exclusive Nature of RFP

CenterPoint may procure more or less than the amount of assets solicited in this RFP from one or more Respondent(s). Respondents are advised that any definitive agreement executed by CenterPoint and any selected Respondent may not be an exclusive contract for the provision of assets. In submitting a Proposal(s), Respondent will be deemed to have acknowledged that CenterPoint may contract with others for the same or similar deliverables or may otherwise obtain the same or similar deliverables by other means and on different terms.

14.2 Information Provided in RFP

The information provided in this RFP, or on the RFP website (http://CenterPoint2020RFP.rfpmanager.biz/), has been prepared to assist Respondents in evaluating this RFP. It does not purport to contain all the information that may be relevant to Respondent in satisfying its due diligence efforts. CenterPoint makes no representation or warranty, express or implied, as to the accuracy, reliability or completeness of the information in this RFP, and shall not be liable for any representation, expressed or implied, in this RFP or any omissions from this RFP, or any information provided to a Respondent by any other source.

14.3 Proposal Costs

CenterPoint shall not reimburse Respondent and Respondent is responsible for any cost incurred in the preparation or submission of a Proposal(s), in negotiations for an agreement, and/or any other activity contemplated by the Proposal(s) submitted in connection with this RFP. The information provided in this RFP, or on CenterPoint's RFP website, has been prepared to assist Respondents in evaluating this RFP. It does not purport to contain all the information that may be relevant to Respondent in satisfying its due diligence efforts.

14.4 Indemnity

Supplementing Respondent's assumption of liability pursuant to this RFP, Respondent shall indemnify, hold harmless and defend CenterPoint, its affiliates, and its and their respective officers, employees and agents, from any and all damages, liabilities, claims, expenses (including reasonable attorneys' fees), losses, judgments, proceedings or investigations incurred by, or asserted against, CenterPoint, its affiliates, and its and their respective officers, employees or agents, arising from, or are related to, this RFP, or the execution or performance of one or more definitive agreements.

14.5 Hold Harmless

Respondent shall hold CenterPoint, its affiliates, and its and their respective officers, employees and agents, harmless from all damages and costs, including, but not limited, to legal costs in connection with all claims, expenses, losses, proceedings or investigations that arise as a result of this RFP or the award of a Proposal pursuant to the RFP or the execution or performance of a definitive agreement.

14.6 Further Assurances

By submitting a Proposal, Respondent agrees, at its expense, to enter into additional agreements, and to provide additional information and documents, in either case as requested by 1898 & Co. in order to facilitate: (a) the review of a Proposal, (b) the execution of one or more definitive agreements, or (c) the procurement of regulatory approvals required for the effectiveness of one or more definitive agreements.

14.7 Licenses and Permits

Respondent shall obtain, at its cost and expense, all licenses and permits that may be required by any governmental body or agency necessary to conduct Respondent's business or to perform hereunder. Respondent's subcontractors, employees, agents and representatives of each in performance hereunder shall comply with all applicable governmental laws, ordinances, rules, regulations, orders and all other governmental requirements.

APPENDIX A – NOTICE OF INTENT TO RESPOND

ALL-SOURCE REQUEST FOR PROPOSALS

APPENDIX A - NOTICE OF INTENT TO RESPOND

Contact Information			
Company			
Primary Contact			
Name			
Title			
Telephone			
E-mail			
Mailing Address			
Signature of Respondent		Date	

Project Information			
Count	Technology Type (Solar, Wind, Natural Gas, etc.)	Capacity Offered (MW)	Contract Type (Capacity, Energy, RECs)
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			

Due: 5:00 p.m. CDT, Friday, May 27, 2022

E-mail: CenterPointRFP@1898andco.com

APPENDIX B – NON-DISCLOSURE AGREEMENT

MUTUAL CONFIDENTIALITY AGREEMENT

THIS MUTUAL CONFIDENTIALITY AGREEMENT (this "Agreement") is dated as of this ____ day of ______________, 2022 (the "Effective Date"), by and between Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South, an Indiana corporation with its principal place of business located at CenterPoint Energy Plaza, 211 NW Riverside Drive, Evansville, Indiana 47708 ("CEI South") and COMPANY NAME, a STATE TYPE OF COMPANY with its principal place of business located at ADDRESS ("Counterparty Short Name") each a "Party" and collectively, the "Parties".

WHEREAS, CEI South and Counterparty Short Name intend to discuss and evaluate proposals regarding possible energy/capacity transactions that could be entered into between CEI South and the Counterparty Short Name (the "Transaction"), which discussions may include sharing of bid proposal information received from Counterparty Short Name during the 2022 competitive request for proposal ("RFP") process (the "2022 RFP Process") administered by 1898 & Co.℠, a division of Burns & McDonnell Engineering Company, Inc. on behalf of CEI South . Through the process of evaluating the 2022 RFP Process and the Transaction, each Party may disclose (and may have in the past disclosed) certain information to the other Party, which the Parties desire to maintain as confidential.

NOW, THEREFORE, in consideration of the disclosure of certain information, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties hereto mutually agree as follows:

1. Confidentiality Obligations.

(a) The Party receiving Confidential Information (the "Receiving Party") hereby agrees, subject to Sections 3 and 4 below, to treat as strictly confidential and in accordance with this Agreement all Confidential Information of the other Party (the "Disclosing Party"). The term "Confidential Information" shall include (i) any and all proprietary, competitively sensitive, trade secret, financial or other information, data, studies, forecasts, compilations, reports, interpretations, records, statements, documents and notes, as well as product design, drawings, specifications, engineering data, process information, manufacturing information, sales and marketing plans, programs, strategies, methods and means, know-how, samples, materials, and devices, and any technology (whether oral, written or electronic) related to the Disclosing Party (collectively, "Items") and obtained, directly or indirectly (whether in the past or in the future) by the Receiving Party or its officers, directors, employees, independent contractors, professional advisors, agents, affiliates, or representatives ("Representatives"), (ii) any Items based upon Items obtained by the Receiving Party or its Representatives, regardless of who prepared such Items, (iii) the fact that either Party is providing the other Party with Confidential Information, and (iv) the fact that the Parties are negotiating, considering, or engaging in the Transaction and/or relationship between them.

(b) Without limitation to the terms of Section 1(a), each Party further agrees, subject to Sections 3 and 4 below:

(i) to (A) treat all of the Disclosing Party's Confidential Information in accordance with the restrictions of this Agreement; (B) keep all of the Disclosing Party's

Confidential Information strictly confidential, (C) take all precautions with the Disclosing Party's Confidential Information that it takes with its own confidential information, and (D) not use any of the Disclosing Party's Confidential Information, in whole or in part, for any purpose other than in connection with (1) evaluating the 2022 RFP Process, (2) developing and submitting CEI South's 2022/2023 Integrated Resource Plan (the "2022/2023 IRP") to the Indiana Utility Regulatory Commission (the "Commission"), (3) reviewing or submitting CEI South's information required for Regional Transmission Organization ("RTO")/Independent System Operator ("ISO") studies and analysis, (4) negotiating, considering, or engaging in the Transaction, and/or (5) subsequent petitions for approval of a new generation resource arising from the 2022 RFP Process, 2022/2023 IRP, or the Transaction (a "Resource Proceeding"); and

(ii) to (A) not, directly or indirectly, disclose or make available, in whole or in part, any Confidential Information to any other person, except its Representatives who have a need to know the Confidential Information in connection with the Transaction, (B) explain the confidentiality obligations contained herein to any such Representative, (C) use its reasonable best efforts to monitor and ensure that such Representatives comply with the terms of this Agreement, and promptly provide the Disclosing Party with written notice of any violation by such Representative of this Agreement, and (D) be responsible and liable to the Disclosing Party for any violation by such Representatives of the terms of this Agreement; and

(iii) to (A) not file or submit the Confidential Information, or any portions thereof, to the Commission except under seal and pursuant to the terms of a Protective Order protecting such information from public disclosure, (B) take care to protect any and all of the Disclosing Party's Confidential Information in a Resource Proceeding, any other docketed proceeding, resource planning process, or regulatory submission before the Commission from public disclosure through redacted public filings and other similar measures available to Receiving Party to protect Disclosing Party's Confidential Information, (C) treat Confidential Information produced pursuant to this Agreement subject to the terms of any Protective Order issued by the Commission or any other authorized state or federal agency or court with jurisdiction, and (D) advise Disclosing Party as soon as practical of any such use in a Resource Proceeding, other docketed proceeding, resource planning process, or regulatory submission before the Commission and the protections in place for the Confidential Information.

2. Return of Information. If either Party at any time does not intend to continue to actively pursue the Transaction or good faith discussions related thereto, it shall promptly advise the other Party in writing of that fact. The Receiving Party shall return (or destroy if it cannot be returned) all tangible representations of all Confidential Information (whether provided to such Party by the Disclosing Party or its Representatives or whether created by the Receiving Party or a third party), within forty-eight (48) hours of a written request for the return of such items by the Disclosing Party. Notwithstanding the foregoing, the Receiving Party and its Representatives may retain one copy of any Confidential Information to the extent relevant to comply with any legal, regulatory, or documented internal retention obligation. Further, the Receiving Party and its Representatives may retain that portion of Confidential Information that may be found in electronic archives of its computer backup systems. Notwithstanding the return or retention of Confidential Information, in accordance with this Section 2, each Party shall continue to be bound by its other

obligations of confidentiality contained in this Agreement until the later of the eventual destruction of all Confidential Information, or the expiration of the confidentiality obligations set forth in this Agreement.

3. Exclusions. The obligations set forth in this Agreement shall continue in force indefinitely, but shall not apply to a Party with respect to any Confidential Information which:

(a) is or subsequently comes within the public domain, without any fault of or violation of this Agreement by the Receiving Party;

(b) is disclosed independently to the Receiving Party on a non-confidential basis by a third party that is not subject to any duty of confidentiality with respect to such information;

(c) the Receiving Party can demonstrate through written documentation was known by such Party before it was disclosed to such Party by the Disclosing Party; or

(d) the Receiving Party can demonstrate through written documentation was independently developed by such Party, without the use, directly or indirectly, of any of the Disclosing Party's Confidential Information.

4. Obligations of Law. The Receiving Party may disclose Confidential Information of the Disclosing Party to the extent that it is required pursuant to any applicable court order, administrative order, law, statute, regulation, or other official order by any government or agency or department thereof, to disclose such information, provided that the Receiving Party, if reasonably practicable and to the extent legally permissible, first provides the Disclosing Party with written notice of the disclosure within a reasonable period of time prior to the disclosure and allows the Disclosing Party the option, at its cost, of challenging the obligation to disclose the information, and further provided that any such disclosure is limited to that required by law, as determined by the Receiving Party's counsel, and that the Receiving Party uses reasonable efforts to continue to preserve the confidentiality of any information so disclosed. Notwithstanding the foregoing, CEI South may disclose Confidential Information to parties to a Resource Proceeding, other docketed proceeding, resource planning process, or regulatory submission before the Commission requesting such information through lawful discovery provided such parties have executed binding non-disclosure agreements with CEI South and agree to be bound to such non-disclosure agreement and protect the information from public disclosure.

5. No Representations. Except as expressly set forth in a separate writing, (i) neither Party nor any of its Representatives adopts responsibility for or makes any representation, express or implied, with respect to the accuracy or completeness of any information provided to the Receiving Party; (ii) neither Party shall have any obligation to disclose any particular Confidential Information to the other Party, and each Party may, in its sole discretion, withhold and/or refuse to disclose any particular item of Confidential Information to the other Party; and (iii) neither Party nor any of its Representatives shall have any liability resulting from or related to the use of the Disclosing Party's Confidential Information or any inaccuracy or other defect in such Confidential Information.

6. No Obligation. Neither Party is under any obligation as a result of this Agreement to accept any offer or proposal which may be made by or on behalf of the other Party, or to continue negotiations between the Parties. Neither this Agreement nor any disclosure of Confidential

Information hereunder shall be deemed to (a) create any partnership, joint venture, employment, agency or other joint relationship between the Parties, (b) bind either Party to any business transaction, relationship or arrangement between them (without a separate agreement therefor) or (c) constitute a grant of any intellectual property or other right or license in any Confidential Information by the Disclosing Party to the Receiving Party. No contract or agreement providing for any transaction regarding the Transaction shall be deemed to exist, and neither Party shall be under any legal obligation of any kind whatsoever to enter into any such transaction by virtue of this or any written or oral expression with respect to such a transaction by any of its Representatives unless and until a definitive agreement with respect to such transaction has been executed and delivered by each Party thereto. Notwithstanding anything in this Agreement, and subject only to the Receiving Party maintaining the confidentiality of Confidential Information per the requirements of this Agreement, either Party may (i) withdraw from discussions with the other Party at any time and for any reason; (ii) conduct its business operations and activities in the normal course; and (iii) disclose its own confidential information to third parties. For the sake of clarity, this Agreement imposes no exclusive relationship of any kind as between the Parties, and each Party may pursue opportunities of any kind or nature, including competing opportunities.

7. Remedies. Each Party hereby acknowledges that a violation by it of this Agreement would result in irreparable harm to the Disclosing Party and that damages would be an inadequate remedy. Each Party, therefore, agrees that in addition to all remedies at law, the Disclosing Party shall be entitled to equitable relief, including, but not limited to, the right to obtain an injunction to secure the specific performance of this Agreement and/or to prevent a breach or contemplated breach of this Agreement, without any requirement that such Party post a bond as a condition of such relief. In no event shall either Party be liable for consequential, incidental, indirect, special, or punitive damages, by reason of or in connection with a breach of this Agreement.

8. Term. Unless terminated sooner by a Party hereto by sending notice to the other Party, this Agreement shall expire the earlier of (a) two (2) years from the Effective Date, or (b) the date on which the Parties enter into a definitive agreement with respect to the Transaction. The non-disclosure and use restriction obligations for Confidential Information under this Agreement shall survive any termination or expiration of this Agreement and remain in effect for the longer of (a) four (4) years from the Effective Date, or (b) during such period during which Confidential Information retains its status as a trade secret or qualifies as confidential under applicable law.)

9. Choice of Law; Jurisdiction. The terms and conditions of this Agreement shall be governed, construed, interpreted and enforced in accordance with the domestic laws of the State of Indiana, without giving effect to any choice of law or conflict of law provision or rule (whether of the State of Indiana or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than the State of Indiana.

10. Successors and Assigns. This Agreement shall be binding upon and inure to the benefit of the Parties and their respective successors and lawful assigns. Notwithstanding the foregoing, this Agreement may not be assigned by either Party, unless the non-assigning Party consents to such assignment, which consent shall not be unreasonably delayed, conditioned or withheld. Any Confidential Information retained by the assigning Party shall continue to be governed fully by this Agreement.

11. Amendment. This Agreement cannot be amended, altered or modified, and no provision hereof may be waived, unless done so in a writing, signed by a duly authorized

representative of the Party against whom such modification or waiver is sought to be enforced. A waiver by any Party of any breach or failure to comply with any provision of this Agreement by the other Party shall not be construed as or constitute a continuing waiver of such provision or a waiver of any other breach of or failure to comply with any other provision of this Agreement.

12. Severability. The Parties believe that every provision of this Agreement is effective and valid under applicable law, and whenever possible, each provision of this Agreement shall be interpreted in such a manner as to be effective and valid. If any provision of this Agreement is held, in whole or in part, to be invalid, the remainder of such provision and this Agreement shall remain in full force and effect, with the invalid provision or condition being stricken only to the extent necessary to comply with any conflicting law.

13. Entire Agreement. This Agreement constitutes the entire agreement between the Parties with respect to the subject matter of this Agreement.

14. Notices. All notices and demands required or permitted by this Agreement shall be in writing, and shall be deemed properly made: (a) upon personal delivery to the relevant address set forth on the first page of this Agreement or such other relevant address as may be specified in writing by the relevant Party; or (b) upon deposit in the U.S. mail, registered or certified mail, or with a recognized overnight courier, postage prepaid, addressed to the relevant address set forth on the first page of this Agreement or such other relevant address as may be specified in writing by the relevant Party. Proof of sending any notice or demand shall be the responsibility of the sender.

15. Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be considered an original counterpart, and shall become a binding agreement when each Party shall have executed one counterpart and delivered it to the other Party.

IN WITNESS WHEREOF, the Parties have executed this Agreement as of the Effective Date.

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH

By: ________________________________

Print Name: ____________________________

Position: ______________________________

COUNTERPARTY

By: ________________________________

Print Name: ____________________________

Position: ______________________________

APPENDIX C – APPLICATION

Respondent's Credit-Related Information

Provide the following data to enable CenterPoint to assess the financial viability of the Respondent as well as the entity providing the credit support on behalf of the Respondent (if applicable). Include any additional sheets and materials with this Appendix as necessary. As necessary, please specify whether the information provided is for the Respondent, its parent, or the entity providing the credit support on behalf of the Respondent.

Full Legal Name of the Respondent: ____

Dun & Bradstreet No. of Respondent: ____

Type of Organization: (Corporation, Partnership, etc.) ____

State of Organization: ____

Respondent's Percent Ownership in Proposal: ____

Full Legal Name(s) of Parent Corporation: ____

Entity Providing Credit Support on Behalf of Respondent (if applicable): ______________________________

Dun & Bradstreet No. of Entity Providing Credit Support: ____

Address for each entity referenced (provide additional sheets, if necessary): __________________________

____

Type of Relationship: ____

Current Senior Unsecured Debt Rating from each of S&P and Moody's Rating Agencies (specify the entity these ratings are for): ____

____

OR, if Respondent does not have a current Senior Unsecured Debt Rating, then Tangible Net Worth (total assets minus intangible assets (e.g., goodwill) minus total liabilities):______________________________

Pending Legal Disputes, if any (describe): ____

____

General description of Respondent's ability to construct, operate and maintain project, to the extent applicable:

____

____

Financial Statements of the Respondent or its Credit Support Provider, where applicable, must include Income Statement, Balance Sheet, Statement of Cash Flows, all notes corresponding to those financial statements and applicable schedules for three most recent fiscal years and financial report for the most recent quarter or year-to-date period. Also, if available, please provide copies of the Annual Reports and/or 10K for the three most recent fiscal years and quarterly report (10Q) for the most recent quarter ended, if available. If such reports are available electronically, please provide link.

____

APPENDIX D – PROPOSAL DATA

SEE ATTACHMENT: APPENDIX D - PROPOSAL DATA.XLSX

APPENDIX E – PROPOSAL CHECKLIST

CENTERPOINT ENERGY ALL-SOURCE REQUEST FOR PROPOSALS

APPENDIX E - PROPOSAL CHECKLIST

Application Documents:

☐Appendix A – Notice of Intent to Respond

☐Appendix B – Non-Disclosure Agreement

☐Appendix C – Application

☐Appendix D – Proposal Data (multiple in case of Project variations)

☐Proposal Executive Summary & Narrative

Supporting Documents:

☐Generator Interconnection Agreement or DPP Results (if available)

☐Audited or unaudited financial statements including balance sheets, income statements, and cash flow statements for the proposed asset(s) for the past three years (if existing)

Content Requirements:

☐Table of Contents

☐Executive Summary

☐Summary of relevant experience

☐Describe interconnection status and method for firm deliverability to LRZ 6 if not located in the zone

☐Describe annual and/or expected capacity characteristics

☐Provide full description of technical and economic detail and operating characteristics

☐Describe status of meeting all zoning requirements for the project location

☐Describe status of acquiring all permits (Federal, State, local) necessary for construction and operation of the project

☐Describe status of acquiring site control for the project

☐Describe any other contractual commitments of the project that would be binding for CenterPoint upon acquisition

☐Describe any current litigation or environmental fines involving the Respondent within the last five years, including but not limited to, any litigation, settlements of litigation or fines, that could potentially affect the facility or its operation

☐ Describe all bankruptcy or insolvency proceedings relating to the Respondent in any way

☐ Describe any litigation related to PPAs, asset purchases or other offers similar to the transactions solicited in this RFP that the Respondent or its parent company have been a party to in the last six years

☐Describe tax assumptions and status of acquiring all applicable tax credits for the project including safe harbored materials

☐Discussion regarding roles and responsibilities of any 3rd party companies involved in the project's development, construction, or operations

☐Describe status of major equipment procurement for the project

☐Development schedule and associated risks and risk mitigation plans for the project with resource in-service and operational prior to 3/1/2027

☐Discussion of any financing arrangements related to the project

☐"All-in price" including at a minimum 1 flat pricing option for PPAs (if applicable) and incorporating **current** market assumptions

☐ Incorporates pricing assumptions in the term sheets if applicable; explains deviations and pricing impacts if applicable

☐Discussion of resource-specific requirements (Sections 4.0 – 7.0)

☐Certifications. See Section 9.2

APPENDIX F – SOLAR BTA TERM SHEET

SOLAR BUILD TRANSFER AGREEMENT (“BTA”) KEY ASSUMPTIONS

The following are key assumptions upon which Respondents should base their proposals. If a proposal deviates from these key assumptions, Respondent shall indicate how it deviates as well as the price impact.

Security	Developer Security: • Five (5) business days after submission for approval to the Indiana Utility Regulatory Commission (“***IURC***”), $[75,000]/MWac of planned nameplate capacity • Five (5) business days after approval by the IURC and through Final Completion, $[150,000]/MWac of planned nameplate capacity • Five (5) business days after after Final Completion, through five years after Final Completion, $[75,000]/MWac of planned nameplate capacity. Form of Developer Security: (i) a payment and performance bond, (ii) letter of credit or (iii) a guaranty from a creditworthy parent company (“A” / “A2”) EPC Contractor: at least equal to the contract price set forth in the EPC Agreement as applicable; which is permitted to decrease as the Project progresses
Warranties for Work and Equipment under the EPC Agreement	EPC Contractor: 2 year standard warranty from Closing; will cover serial defect occurrence with respect to any defects occurring in the lesser (x) [10]% or (y) an agreed number of individual units of major equipment (i.e., modules, inverters, raking/trackers) or more of the same or substantially similar component(s) resulting from the same failure mode from the same manufacturer. If a serial defect has occurred, EPC Contractor will provide an additional one (1) years of warranty in addition to the base warranty.
Firm Date Conditions	“***Firm Date Conditions***” shall include (for Buyer and Developer) that Buyer has received approval by the Indiana Utility Regulatory Commission (IURC) for cost recovery through rates for the Project (“***IURC Approval***”). Failure to obtain IURC Approval prior to the Firm Date may result in termination of the agreement without any further obligations by either party.
Indemnification and Limitations of Liability under the BTA and Development Agreements	A. Developer will indemnify Buyer and the other Buyer indemnified parties from and against any and all losses resulting from: • Breach of Developer’s reps or warranties (subject to a 100% cap for fundamental reps, 25% cap for all other reps other than tax reps);[1] • Breach by Developer of its covenants, agreements or obligations pursuant to the BTA or ancillary agreements (subject to a 100% cap); • Developer’s fraud or willful misconduct; • Loss in value of, or any inability to claim or otherwise take advantage of, the [•]% ITC and accelerated depreciation (MACRS); • Construction costs required to cause the Project to achieve final completion; and • All pre-closing liabilities.
Taxes	Developer will be responsible for all sales, conveyance, transfer, excise, real estate transfer, business and occupation and similar taxes assessed with respect to or imposed on either Party related to Buyer’s acquisition of the Project Company (or otherwise) in connection with the Proposed Transaction.
Liquidated Damages	Delay Liquidated Damages: [$200 per MW per day] (based on the Planned Nameplate Capacity) for each day (a) the Project fails to achieve Mechanical Completion on or before the Outside Closing Date (subject to an agreed escalation and long-stop date) or (b) the Project fails to achieve Substantial Completion on or before the Guaranteed Substantial Completion Date.

[1] A pro-sandbagging provision will be included, and Buyer will be able to seek indemnification (and exercise any other remedies, including termination of the BTA) for any updates to disclosure schedules that reflect a breach of Developer’s reps and warranties.

APPENDIX G – WIND BTA TERM SHEET

WIND BUILD TRANSFER AGREEMENT ("BTA") KEY ASSUMPTIONS

The following are key assumptions upon which Respondents should base their proposals. If a proposal deviates from these key assumptions, Respondent shall indicate how it deviates as well as the price impact.

Security	Developer Security: • Five (5) business days after submission for approval to the Indiana Utility Regulatory Commission ("***IURC***"), $[75,000]/MWac of planned nameplate capacity • Five (5) business days after approval by the IURC and through two years after Final Completion, $[150,000]/MWac of planned nameplate capacity • Five (5) business days after two years after Final Completion, through five years after Final Completion, $[75,000]/MWac of planned nameplate capacity. Form of Developer Security: (i) a payment and performance bond, (ii) letter of credit or (iii) a guaranty from a creditworthy parent company ("A" / "A2") Turbine Supplier/EPC Contractor: at least equal to the contract price set forth in the TSA/EPC Agreement as applicable; which is permitted to decrease as the Project progresses
Warranties for Work and Equipment under the EPC Agreement and TSA	EPC Contractor: 2 year standard warranty from Closing TSA: 5 year standard warranty from Closing; will cover serial defect occurrence with respect to any defects occurring in the lesser (x) [10]% or (y) an agreed number of individual units of equipment or more of the same or substantially similar component(s) resulting from the same failure mode from the same manufacturer. If a serial defect has occurred, Turbine Supplier will provide an additional three (3) years of warranty in addition to the base warranty.
Firm Date Conditions	"***Firm Date Conditions***" shall include (for Buyer and Developer) that Buyer has received approval by the Indiana Utility Regulatory Commission (IURC) for cost recovery through rates for the Project ("***IURC Approval***"). Failure to obtain IURC Approval prior to the Firm Date may result in termination of the agreement without any further obligations by either party.
Indemnification and Limitations of Liability under the BTA and Development Agreements	A. Developer will indemnify Buyer and the other Buyer indemnified parties from and against any and all losses resulting from: • Breach of Developer's reps or warranties (subject to a 100% cap for fundamental reps, 25% cap for all other reps other than tax reps);[1] • Breach by Developer of its covenants, agreements or obligations pursuant to the BTA or ancillary agreements (subject to a 100% cap); • Developer's fraud or willful misconduct; • Loss in value of, or any inability to claim or otherwise take advantage of, the [•]% PTC and accelerated depreciation (MACRS) ("***PTC and Depreciation Benefits***"); • Construction costs required to cause the Project to achieve final completion; and • All pre-closing liabilities.
Taxes	Developer will be responsible for all sales, conveyance, transfer, excise, real estate transfer, business and occupation and similar taxes assessed with respect to or imposed on either Party related to Buyer's acquisition of the Project Company (or otherwise) in connection with the Proposed Transaction.
Liquidated Damages	Delay Liquidated Damages: [$200 per MW per day] (based on the Planned Nameplate Capacity) for each day the Project fails to achieve Substantial Completion on or before the Outside Closing Date (subject to an agreed escalation and long-stop date).

[1] A pro-sandbagging provision will be included, and Buyer will be able to seek indemnification (and exercise any other remedies, including termination of the BTA) for any updates to disclosure schedules that reflect a breach of Developer's reps and warranties.

APPENDIX H – WIND OR SOLAR PPA TERM SHEET

WIND/SOLAR POWER PURCHASE AGREEMENT (PPA) KEY ASSUMPTIONS

The following are key assumptions upon which Respondents should base their proposals. If a proposal deviates from these key assumptions, Respondent shall indicate how it deviates as well as the price impact.

Energy Delivery Point	SELLER shall be responsible for all costs necessary to deliver energy to the Energy Delivery Point. Proposals should clearly define the Energy Delivery Point, i.e. Point of Interconnection, SIGE.SIGW or other energy settlement node as directed in the RFP.
Product	Product shall include (1) all as-available wind/solar energy generated by the Project and (2) all services and attributes associated with such energy and the Project, including (a) all capacity attributes, (b) all ancillary products, and (c) all renewable energy credits ("RECs"). BUYER shall only be obligated to pay for energy and applicable services and attributes delivered from the Project to the Energy Delivery Point. Throughout the Delivery Term, SELLER shall ensure that the Project qualifies for Green-e certified RECs, and SELLER shall use commercially reasonable efforts to cause the Project to qualify for all applicable attributes and RECs that may become available throughout the Delivery Term, at Seller's cost and expense, subject to a maximum annual compliance cost cap of [•].
Guaranteed Commercial Operation Date	SELLER shall pay the Delay Damage Rate for each day that COD occurs past the Guaranteed Commercial Operation Date. If COD has not occurred by the Outside Commercial Operation Date (without regard to any possible extensions for force majeure), BUYER (a) may terminate the PPA and (b) may draw on the full Development Security. Delay Damage Rate: two-hundred dollars ($200) / MW (AC) of the Planned Nameplate Capacity Rating.
IURC Approval	BUYER will have no obligation to receive, accept or pay for any Products until BUYER has received satisfactory approval, in BUYER'S sole judgement, from the Indiana Utility Regulatory Commission to recover the costs of the PPA through its retail rates.
Performance Guarantee	Greater than ninety percent (90%) of the Expected Contract Quantity over every two consecutive operational year period. If performance is less than this SELLER to pay BUYER liquidated damages equal to "Market Price" over the applicable COD Price, multiplied by the MWhs of output shortfall. BUYER may terminate PPA if Project fails to deliver at least seventy-five percent (75%) of the Expected Contract Quantity for two consecutive operational years.
Capacity Deficit Damages	If the final nameplate capacity rating is less than the planned nameplate capacity rating of [•] MW (AC) (the "Planned Nameplate Capacity Rating"), but not less than ninety-five (95%) of the Planned Nameplate Capacity Rating, SELLER shall make a onetime payment to BUYER in an amount equal to (a) the difference between (i) the final nameplate capacity rating and (ii) the Planned Nameplate Capacity Rating in MWs, (b) multiplied by two-hundred thousand dollars ($200,000) per MW ("Capacity Deficit Damages"). Upon payment of Capacity Deficit Damages, the schedule setting forth the Expected Contract Quantity shall be adjusted by the same ratio.
Project Milestones	Failure to achieve certain "Critical Milestones" during Project development, construction, commissioning and operation to be agreed by the Parties by the agreed dates will require the payment of damages at the Delay Damage Rate and, if not cured within specified timeframes, will permit the early termination of the PPA by BUYER and the BUYER'S retention of certain Development Security.
Seller's Security	Development Security. Prior to COD, equal to seventy-five thousand dollars ($75,000) per MW (AC), posted within five (5) business days after the execution of PPA. Operating Security. Within five (5) business days after COD, equal to one hundred fifty thousand dollars ($150,000) per MW (AC) of the final nameplate capacity of the Project. Development Security and Operating Security shall be in the form of either (a) an irrevocable letter of credit from a qualified institution or (b) a cash deposit.
Seasonal Maintenance	To the extent possible considering prudent industry practices, SELLER shall avoid planned maintenance during the months of peak capacity accreditation (e.g. for Solar PPAs, May, June, July, and August). Any planned maintenance during such months must be approved by BUYER, in its sole discretion.
Right of First Offer	If BUYER terminates PPA (a) prior to COD due to an extended force majeure event or (b) due to a SELLER event of default, BUYER shall have a Right of First Offer for agreements for offtake of Product (or any component of Product) from the Project for twenty four (24) months from the termination date.

1898 & CO
PART OF BURNS & McDONNELL

9400 Ward Parkway

Kansas City, MO

Attachment 6.5 Conversion Studies (CT conversion, FB Culley Conversion, and Cogen)

CT Conversion Study

Memorandum

Date: September 16, 2022

To: BJ Reynolds
Director of Power Supply Construction
CenterPoint Energy
812.491.5435

Subject: SC-to-CC Conversion Unit Assessment

INTRODUCTION

CenterPoint Energy ("CenterPoint") has retained 1898 & Co., a part of Burns & McDonnell Engineering Company, Inc. ("1898 & Co.") to evaluate a new generation technology option. This option involves converting A.B. Brown simple cycle gas turbine ("SCGT") units #5 and #6 into a 2x1 combined cycle ("CCGT") unit. The intent of this assessment is to provide capital cost, O&M costs, and performance information sufficient to support Integrated Resource Planning ("IRP") efforts.

It is the understanding of 1898 & Co. that this Memo will be used for preliminary information in support of CenterPoint's generation planning process. Any technologies of interest to CenterPoint should be followed by additional detailed studies to further investigate the technology and its direct application within CenterPoint's long-term plans.

Study Basis and Assumptions

The assumptions below govern the overall approach of the Study:

- All estimates are screening-level in nature, do not reflect guaranteed costs, and are not intended for budgetary purposes.
- All information is preliminary and should not be used for construction purposes.
- All capital cost and O&M costs are stated in 2022 US dollars ("USD"). Escalation is excluded.
- Estimates assume an Engineer, Procure, Construct ("EPC") fixed price contract for project execution.
- Ambient conditions are based on the following:
  - Winter Conditions: 5°F
  - Average Ambient Conditions: 59°F
  - Summer Conditions: 90°F

Evaluated Technology

CenterPoint is considering converting existing SCGT's (A.B. Brown #5 & #6) into a CCGT capable of greater capacity and improved efficiency compared to the SCGTs. The basic principle of the CCGT plant is to utilize natural gas to produce power in a gas turbine which can be converted to electric power by a coupled generator, and to also use the hot exhaust gases from the gas turbine to produce steam in a heat recovery steam generator (HRSG). This steam is then used to drive a steam turbine and generator to produce electric power. The use of both gas and steam turbine cycles (Brayton and Rankine) in a single plant to produce electricity results in high conversion efficiencies and low emissions.

Combined cycle plants are designed for capacity factors consistent with intermediate or base load operation, and therefore it is expected that NOx and CO emissions will need to be controlled. An SCR will be required to reduce NOx emissions to 2 ppmvd at 15 percent O_2. It is expected that an oxidation catalyst will also be required to reduce CO and VOC emissions. This assessment assumes CO emissions will be controlled to 2 ppmvd CO at 15 percent O_2.

Performance Estimates
The CCGT base load performance at ISO conditions is shown in Table 1. Additional performance cases including summer and winter performances are included Appendix A.

Table 1: Estimated CCGT Performance

Base Load @ 59 °F	
Net Plant Output, kW	716,900
Net Plant Heat Rate, Btu/kWh	6,480

Operating and Maintenance Cost Estimates
1898 & Co. developed a screening-level O&M cost estimate including a breakout for fixed operations and maintenance and variable operations and maintenance.

Operating and Maintenance Assumptions
- O&M costs were estimated assuming average ambient conditions and average hot air production.
- Fixed O&M cost estimates include labor, office and administration, training, contract labor, safety, building and ground maintenance, communication, and laboratory expenses.
- Variable O&M costs include routine maintenance, makeup water, water treatment, water disposal, and other consumables.
- O&M costs exclude property taxes and insurance.

Operating and Maintenance Cost Estimates Summary
The total O&M cost is summarized below in Table 2.

Table 2: Operating and Maintenance Cost Estimate

Description	Cost Estimate
Fixed O&M Costs	[redacted]
Variable O&M Costs	
Major Maintenance Cost	

Capital Cost Estimates
1898 & Co. developed a screening-level (Association for the Advancement of Cost Engineering ("AACE") Class V) capital cost estimate including a break-out of anticipated owner's cost.

Cost Estimate Assumptions
A detailed scope assumptions matrix is included in Appendix B. The following assumptions govern the capital cost estimates:

- Capital cost include demolishing the existing SCGT stack.
- No additional demolition is included. No costs are included to address any pre-existing underground tanks, piping, duct bank, cabling, etc..
- The site is assumed to be cleared and graded.
- Electrical scope is assumed to end at the high side of the GSU.

Cost Estimate Exclusions
The following costs are excluded from all estimates:

- Financing fees
- Interest during construction
- Escalation
- Performance and payment bond
- Sales tax
- Property insurance
- Transmission Interconnect / Switchyard
- Water rights

Capital Cost Estimate Summary
The total installed cost of the facility is shown in Table 3. All costs are estimated in 2022 USD. For a further breakdown on the CCGT conversion capital cost estimates, see Appendix A.

Table 3: Capital Cost Estimate (2022$MM)

Description		Cost Estimate
Total Direct Cost		[redacted]
Total Indirect Cost		[redacted]
Total EPC Project Cost		[redacted]
Owner's Cost		[redacted]
Total Project Cost		$495.0 MM

STATEMENT OF LIMITATIONS
Estimates and projections prepared by 1898 & Co. relating to performance, operating and maintenance costs, capital costs are based on experience, qualifications, and judgement as a professional consultant.

1898 & Co. has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding, and market conditions or other factors affecting such estimates or projections. Actual rates, costs, performance ratings, schedules, etc., may vary from the data provided.

CONCLUSIONS AND RECOMMENDATIONS

This study provides capital cost, O&M costs, and performance information to support CenterPoint's consideration of a simple-cycle to combined-cycle conversion. Information provided in this Memo is preliminary in nature and is intended to support screening of generation opportunities. If this opportunity is appealing, CenterPoint should pursue additional studies to define project scope, equipment design, and schedule for the development of the project.

1898 & Co. appreciates the opportunity to support CenterPoint with this evaluation. If you have any questions regarding this memo, please contact Chad Swope at chad.swope@1898andco.com | 816.548.1329.

Sincerely,

Chad Swope, P.E.
Project Manager

Appendix A – CCGT Conversion Technology Assessment Summary Table
Appendix B – CCGT Conversion Scope Assumptions

F.B. Culley Conversion Study

Coal to Gas Conversion Feasibility Study

CenterPoint Energy

FB Culley Generating Station Coal to Gas Conversion
Project No. 148484

Revision 1
August 2022

Coal to Gas Conversion Feasibility Study

prepared for

CenterPoint Energy
FB Culley Generating Station Coal to Gas Conversion
Yankeetown, Indiana

Project No. 148484

Revision 1
August 2022

prepared by

Burns & McDonnell Engineering Co.
Kansas City, MO

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
AQCS	Air Quality Control Systems
B&W	Babcock & Wilcox
BMS	Burner Management System
BOP	Balance of Plant
CCR	Coal Combustion Residuals
CO	carbon monoxide
CO_2e	carbon dioxide equivalent
CPE	CenterPoint Energy
DCS	distributed control system
Dth/d	decatherm/day
ELG	Effluent Limitation Guidelines
ESP	Electrostatic Precipitator
FD	forced draft
FGR	flue gas recirculation
ft/min	feet per minute
GE	General Electric
HP	high pressure
I/O	input/output
in	inch
LNB	Low NOx Burner
mcf/h	thousand cubic feet per hour

Abbreviation	**Term/Phrase/Name**
MFT	master fuel trip
MMBtu/hr	million British thermal unit per hour
MW	megawatts
NDE	non-destructive evaluation
NFPA	National Fire Protection Association
NO_x	nitrogen oxide
NPV	Net Present Value
OEM	original equipment manufacturer
OFA	overfire air
P&IDs	piping and instrumentation diagram
PCU	Process Control Unit
PSD	Prevention of Significant Deterioration
psig	pounds per square inch gauge
SCR	Selective Catalytic Reduction
SO_2	sulfur dioxide
UV	ultraviolet
VOC	volatile organic compounds

1.0 EXECUTIVE SUMMARY

CenterPoint Energy (CPE) is considering a 100% coal to natural gas fuel conversion at the FB Culley power station, Units 2 & 3, located near Yankeetown, Indiana. The conversion would require a new natural gas firing system and a reconfigured DCS for Units 2 and 3. The units presently use natural gas for ignition and burn a variety of local coals.

CPE retained Burns & McDonnell to provide a conceptual engineering design and AACE Class V estimate for converting both units. This report summarizes the conceptual engineering, performance impacts, and cost estimates for CPE to evaluate the feasibility of the 100% fuel conversion.

1.1 Purpose

The purpose of this report is to provide the overall scope, schedule, and capital costs required to procure and construct a 100% coal to gas conversion project based on the assumptions documented herein, and to provide general information to support project feasibility evaluations.

1.2 Project Configuration Summary

FB Culley Power Station Units 2 & 3 both have Babcock & Wilcox (B&W) steam generators in operation. Both units are presently pulverized coal-fired, firing a variety of local bituminous coals. Gross generation is 100 megawatts (MW) for Unit 2, and 287 MW for Unit 3.

Unit 2, commissioned in 1965, has a B&W 1,290 psi/955°F non-reheat steam generator (B&W boiler contract RB-419) that produces steam to power a steam turbine-generator set. The boiler fires bituminous coal in a front wall firing arrangement via three EL-76 ball and race coal pulverizers located on the basement floor on the front of the boiler. Each the three pulverizers feeds pulverized coal to four (4) burners on one of three front wall burner elevations, for a total of twelve (12) burners. Burner (and pulverizer) decks are labeled 2A, 2B and 2C from top elevation to bottom elevation.

The boiler was retrofit with low NO_X burners in 1994. Each burner has its own natural gas igniter sized to be at least 10% of the maximum heat input of the main coal burner. The igniters are used to warm the boiler prior to lighting off a pulverizer. The unit does not have an overfire air system.

Two forced draft (FD) fans force air through a Ljungstrom bi-sector air preheater, and on to the windbox where it is distributed to the twelve burners in an open windbox on the front wall of the unit. The unit was converted to balanced draft with ID Fan-VFDs in the late 1980's. In the mid-1990's connections to a common LS-FGD, with FB Culley #3, were made and over the course of time, the use of the legacy chimney has been converted to an unfired vent. Unit 2 is presently fitted with a 1980s vintage electrostatic precipitator (ESP) and Unit 3 was fitted with a fabric filter in 2004-2005.

The Unit 2 firing arrangement that will be analyzed for this study will be to continue the routine ability to operate at full load (100 MW) by retaining only the top eight (8) burners and replacing them with natural gas burners. Each burner will have its own safety shut off valve. It is assumed that the existing gas igniters will be reused. A case study for an Overfire air (OFA) system and a case study for a flue gas recirculation (FGR) system will be discussed.

Unit 3, commissioned in 1973, has a B&W 2,000 kpph/1005°F/1005°F steam generator (B&W boiler contract RB-458) that produces steam to power a steam turbine-generator set. The boiler fires bituminous coal in an opposed-firing arrangement via six (6) EL-76 ball and race coal pulverizers located on the ground floor on the front of the boiler. The boiler has been upgraded for additional steam flow from the original design criteria. Each of the six pulverizers feeds pulverized coal to four (4) burners on one of three front wall or three rear wall burner elevations, for a total of twenty-four (24) burners. Burner (and pulverizer) decks are labeled 3C, 3D and 3B from top elevation to bottom elevation on the front wall, and 3A, 3F and 3E from top elevation to bottom elevation on the rear wall.

Each burner has its own natural gas igniter sized to be at least 10% of the maximum heat input of the main coal burner. The igniters are used to warm the boiler prior to lighting off a pulverizer.

Unit 3 boiler has been retrofit with a selective catalytic reduction (SCR) system. The purpose of an SCR system is to reduce the NO_X emissions rate from the boiler. There is a natural gas duct burner as a part of the SCR addition. Modifications were made to bypass the air heater with combustion air.

The Unit 3 firing arrangement that will be analyzed for this study will be to continue the routine ability to operate at full load (287 MW) by retaining only the top sixteen (16) burners and replacing them with natural gas burners. Every two burners will have a safety shut-off valve. It is assumed that the existing gas igniters will be reused. A case study for an OFA system and a case study for a FGR system will be discussed.

1.3 Estimated Performance and Air Emissions Summary

Based on recent relevant results on similar units, the existing boilers are estimated to be capable of firing natural gas without a reduction in steam flow. It may not be possible to reach the full superheat or reheat steam temperature. BMcD estimates that both boilers will be within 50°F of design steam temperatures and can likely make design temperatures at full load conditions. The increased water production from firing natural gas will decrease the boiler efficiency 4% to 6%. The water content by volume in the flue gas leaving the flue gas economizer with natural gas will be about 18% as compared to 9% with the design fuel. The extra water carries significant heat that is not transferred to the steam. Gas-fired baseline data was not available, so the gross heat rate was estimated.

Table 1-1: Existing Coal Unit Performance Summary

Culley Unit No.	Unit Full Load (Mw)	Estimated NO_X (lb/mmBtu)	Calculated Heat Data	
			Heat Input (mmBtu/hr)	Heat Rate (Btu/kw-hr)
2	100	0.20	1,198	12,000 est.
3	287	0.45	2,870	10,000

Table 1- 2: Estimated Natural Gas Unit Performance Summary Low NOx Burners Only

Culley Unit No.	Unit Full Load (Mw)	Estimated NO_X (lb/mmBtu)	Calculated Heat Data	
			Heat Input (mmBtu/hr)	Heat Rate (Btu/kw-hr)
2	100	0.22	1,246 – 1,270	12,458 – 12,679
3	287	0.22	2,879 -2,935	10,033 – 10,225

Table 1- 3: Estimated Natural Gas Unit Performance Summary with OFA

Culley Unit No.	Unit Full Load (Mw)	Estimated NO_X (lb/mmBtu)	Calculated Heat Data	
			Heat Input (mmBtu/hr)	Heat Rate (Btu/kw-hr)
2	100	0.15	1,246 – 1,270	12,458 – 12,679
3	287	0.15	2,879 -2,935	10,033 – 10,225

Table 1- 4: Estimated Natural Gas Unit Performance Summary with FGR and no SCR

Culley Unit No.	Unit Full Load (Mw)	Estimated NO_X (lb/mmBtu)	Calculated Heat Data	
			Heat Input (mmBtu/hr)	Heat Rate (Btu/kw-hr)
2	100	0.08	1,246 – 1,270	12,458 – 12,679
3	287	0.08	2,879 -2,935	10,033 – 10,225

Table 1- 5: Estimated Natural Gas Unit Performance Summary with SCR

Culley Unit No.	Unit Full Load (Mw)	Estimated NO_X (lb/mmBtu)	Calculated Heat Data	
			Heat Input (mmBtu/hr)	Heat Rate (Btu/kw-hr)
3	287	0.05	2,879 -2,935	10,033 – 10,225

1.4 Contracting Approach

The selected contracting strategy for this feasibility study is the multiple contracts approach with the Owner directly contracting a burner supplier to design the new fuel delivery system, new burners and any potential OFA or FGR modifications and utilizing the Unit 3 SCR. A balance of plant contractor will implement the installation of the equipment. The burner supplier would be responsible for all skids downstream of the emergency shut off valve station and the new burners, igniters, and accessories to make them work. The Owner could buy a BMS and DCS upgrade package separately from the equipment or installation provider. All installation would be provided through a single contractor with an owner's engineer responsible for administrating. The contracting approach assumes an O/E would provide balance of plant design, develop specifications for procurement and construction and contract administration of the project

1.5 Indicative Schedule

A preliminary schedule duration was developed. The durations listed in Table 1-2 below are for both units including an assumed offsite pipeline construction of 12 months after permitting. The schedule assumes that both units will be converted concurrently. If the unit construction is staggered, the estimated durations will increase six months. The critical path for each option will typically run through receipt of gas burner equipment, construction, and continuing through startup and commissioning. This schedule assumes CP Energy will start preliminary engineering and design concurrently with an application for the air permit. An indicative project schedule is shown below in Table 1- 4.

Table 1- 4: Indicative Schedule

Schedule Line Item	100% Natural Gas
Permitting (months)	12
Gas Line to Plant Concurrent (Eng/Pro)	18
Engineering & Procurement (months)	16
Construction (months)	6
Startup (months)	2
Total Project Duration (months)	**30**

*Complete Spring/Fall 2025

1.6 Capital Costs

The capital cost for the gas conversion is presented in Table 1- 5 below. These costs represent a total for the plant which includes both units.

Table 1- 5: Total Plant Capital Costs (2022$)

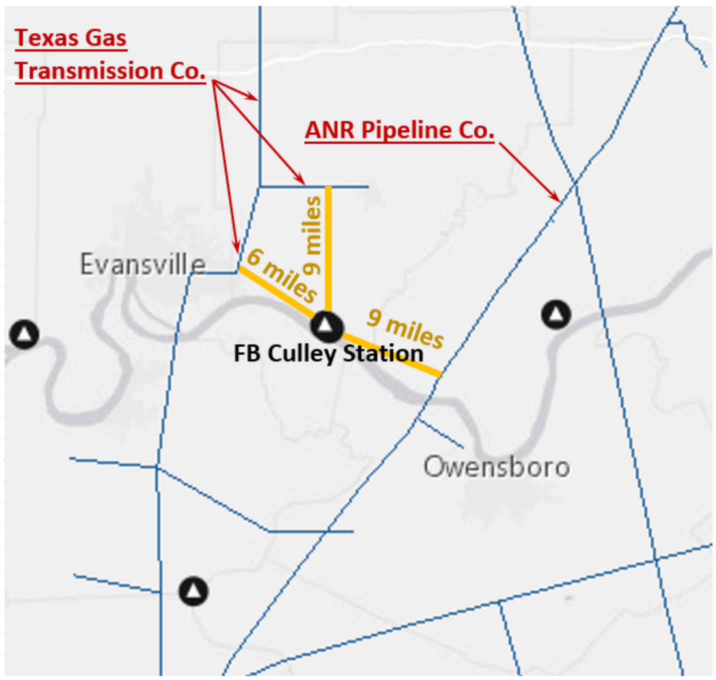
Capital Cost Line Item	Unit 2	Unit 3
Procurement & Construction	[redacted]	
Project Indirects		
Project Costs		
Owner Costs		
Owner Contingency		
Total Onsite Costs – Base Case	**$24,673,642**	**$30,658,448**
Option 1 - OFA	[redacted]	
Option 2 – FGR		

[redacted]

2.0 INTRODUCTION

CenterPoint Energy is investigating the feasibility of a 100% coal to gas conversion at the FB Culley Power Station near Yankeetown, Indiana. Presently Units 2 & 3 both start-up with natural gas and operate with a variety of regional bituminous coals. Potential gas supply pipelines in the area are by Texas Gas Transmission Co. and by ANR Pipeline Co. Texas Gas Transmission Co. has two lines in the area, one about 6 miles to the northwest, and another about 9 miles due north. ANR Pipeline Co. has one line about 9 miles to the southeast (straight down river) Both as indicated in Figure 2- 1, below.

Figure 2- 1 – Pipeline to Coal plant



This study will evaluate the costs to retrofit the units and provide the expected performance from both steam generators. The 100 percent coal to gas conversion will provide a low-cost alternative to continue the use of the units and brings natural gas infrastructure onsite.

CenterPoint Energy retained Burns & McDonnell to provide an estimate similar to an AACE Class V cost estimate for the two units. This report summarizes the conceptual design and presents the project costs to be used by CenterPoint Energy in evaluating the project feasibility.

2.1 Study Scope

The scope of work included preparing the following major conceptual design documents:

1. Identify costs of conversion of the existing burners and burner management system to fire exclusively on natural gas per NFPA 85.
2. Re-use of the existing control room, plant auxiliaries and the cooling cycle equipment.
3. Allowances for boiler, piping, and turbine/generator assessments will be continued.
4. Identify a potential location for the natural gas pressure reducing/metering station on the site and the piping necessary to supply fuel to the boilers from that location.
   - Quantity of natural gas required for full load on both units.
5. Identify cost of boiler modifications, such as furnace refractory or tube modifications necessary for the normal operation of the unit on natural gas
   - Option for OFA and FGR system implementation costs
6. Identify costs for demolition of equipment along the burner front and other areas necessary for the operation on natural gas
   - Cost options for abandon in place versus demolition
7. Identify costs associated with modifications to the existing scrubbers, baghouses, SCR, stack, including fans, to allow for the operation on natural gas.

2.2 Objectives

The objectives of this study were to establish the conceptual design for the two boilers firing systems, provide a predicted performance, provide an overall project schedule, and provide a capital cost estimate to support project feasibility cost evaluations. CenterPoint Energy can use the information from this report to evaluate the natural gas conversion cost against other generation options.

2.3 Limitations and Qualifications

The costs presented within this report are subject to:

- Design changes for enhanced efficiency/operational flexibility.
- Final negotiation of the Terms and Conditions with the contractors and the major equipment suppliers.
- Final geotechnical report findings.
- Final topographical survey.
- Final determination/negotiation of the project schedule.
- Final selection of the equipment.
- Final permit requirements.
- Changes in federal regulations.
- Full evaluation of existing underground interferences.

3.0 PROJECT DEFINITION

The assumptions that formed the basis of the plant conceptual design, predicted performance and cost estimate are summarized in this report. The assumptions were developed through meetings with CP Energy and recent work on other similar coal to gas conversions that are relevant to this application. Some of the key assumptions are as follows:

- The units must be able to routinely operate at the present maximum gross generation, 100 MW for Unit 2 and 287 MW for Unit 3.
- The units will be required to operate over its full operating range.
- The units will cycle from minimum load to maximum load daily, sometimes on and off daily.
- The natural gas supply to the site and the pressure reducing / distribution / metering station will be permitted and built by others.
    - The station should have redundant distribution capabilities to allow for maintenance.
    - All gas piping on site should be above ground.

3.1 Reference Documents

CP Energy provided significant Unit 2 & 3 data for the purposes of developing a conceptual design. The information included:

- Boiler drawings & equipment drawings
- Performance data
- Operation and maintenance manuals for boilers and AQCS systems
- Fan curves & data
- General arrangement drawing
- EPA website CEMS data

3.2 General Design Criteria

The Plant is expected to be operated as a load following facility on 100 percent natural gas. Daily on/off cycling of the plant may be required. Considerations for daily cycling and impacts on existing equipment have not been included in this report. Determining a new low load would require an independent study to identify the existing low load limitation. It should be expected that the units can achieve a low load of 30% when firing gas, assuming the limitation is something other than the firing system.

For purposes of estimating the following design criteria is being used:

- Unit 2: 1,270 mmBtu/hr of natural gas to obtain 100 gross megawatts
- Unit 3: 2,935 mmBtu/hr of natural gas to obtain 287 gross megawatts
- Full plant load capacity would equal 4,204 mmBtu/hr of natural gas not including ignition system. The ignition system is sized for 10% of the firing system.
- Unit 2 airflow requirements of 1,348 kpph at 2% O_2, 15% air heater leakage, and 6% deterioration in boiler efficiency due to gas firing
- Unit 3 airflow requirements of 3,115 kpph at 2% O_2, 15% air heater leakage, and 6% deterioration in boiler efficiency due to gas firing
- We have evaluated 7%, 10%, 12% and 15% air heater leakage from the air to the flue gas side of the air heater.
- Unit 2 total forced draft fan requirement for airflow is 1,348 kpph or 325,496 acfm (163 kacfm per fan) at 105°F.
- Unit 3 total forced draft fan requirement for airflow is 3,115 kpph or 752,305acfm (376 kacfm per fan) at 105°F.
- Each existing Unit 2 forced draft fans test block capacity is unknown at this time.
- Each existing Unit 3 forced draft fan test block capacity is 365 kacfm at 105°F.

The plant will be controlled using the existing control room and distributed control system (DCS). The DCS at FB Culley utilizes an Emerson platform; the control system was upgraded in 1996. The existing BMS IO will be reused to the greatest extend possible. Many other plant systems will be removed from service and additional IO cards can be reused for the BMS as needed.

The existing combustion controls logic will be modified to accommodate the new gas burners, gas supply equipment, and gas interlocks. The existing master fuel trip (MFT) cabinet will be modified to accommodate the new configuration. Fuel firing, air flow, and interlock logic will be reviewed and implemented based on the logic diagrams provided by the burner supplier. Additional modifications to the balance of plant (BOP) logic will be made to remove systems that are out of service and add logic for gas supply skids.

The graphics will also require evaluation and modification with the coal to gas conversion. During detailed design, the Engineer will evaluate the existing graphics compared to the instrument list changes and updated piping configuration provided by the burner supplier to develop graphic update sketches.

An Engineer will be onsite for a portion of the outage to assist with I/O checkout and resolve any logic or graphic issues. Tuning of the air flow, drum level, furnace draft, throttle pressure control, steam temperature control, and other miscellaneous BOP loops will be required by a DCS tuner during startup.

The existing plant operators will need to be trained for natural gas operation. Plant operations personnel can be reduced by as much as 50% as the gas-fired plant will have significantly less equipment operating and require less maintenance, this assumes a full complement to start with. Startup on natural gas ignition system will be easier and reduce costs significantly.

3.2.1 Plant Design Summary

Conceptual design of the new gas conversion system is summarized here. Documents provided were used to produce the conceptual design presented below. Engineer used recent coal to gas conversion experience to estimate total distance for piping and vents. Experience form recent projects was used in determining total number of I/O points to be replaced.

3.2.1.1 Plant Location and Layout

The FB Culley power plant is located near Yankeetown, Indiana on the Ohio River just south of Indiana State Highway 66. The two units are located next to one another but have separate control rooms and turbine decks. The two units share a combined chimney stack is due east of the boilers. The proposed gas yard will be located in the north of the boilers. This keeps the main high pressure (HP) yard a good distance from the existing plant. The new gas pipeline will approach from the north or northeast. From the location of the M&R yard an 800 foot above ground pipe will be routed to the corner of the Unit 3. The pipe will then wye into two emergency shutoff valves. The emergency shutoff valve or NFPA 850 valve will send one pipe to each of the Units.

A single low-pressure skid would control gas to each unit firing equipment and have 100% redundant gas trains for both main gas burners. The burner double block and bleed skids at each burner front will provide the final control for the fuel burning equipment. The regulation station locations shown on the site layout in Appendix A are indicative locations for estimating only. Final regulating station locations will be decided during detailed design.

Figure 3- 1 – Site layout

No modifications to existing roads, switchyard, coal yard, or other plant areas are included. Existing building and structure modifications may not be required.

3.2.1.2 Plant Utilities and Infrastructures

3.2.1.2.1 Water Supply & Discharge

The discontinued use of coal after the 100 percent gas conversion would have an impact to water requirements at the FB Culley plant site. When firing gaseous fuel, ash sluicing won't be necessary for bottom ash or fly ash. Plant wash downs will be decreased as the plant will be cleaner without fly ash concerns.

While water supply and wastewater streams will be decreased, CPE must still comply with any Coal Combustion Residuals (CCR) or Effluent Limitation Guidelines (ELG) regulations. Natural gas conversion does not eliminate all these concerns.

3.2.1.3 Buildings and Enclosure

No changes will be made to the existing boiler house building. The gas yard equipment will not be enclosed. The new fuel gas control valve stations for the conversion will be housed in the existing boiler house with potential minimal structural modifications for valve station locations.

3.2.2 Unit Modifications

BMcD believes that the existing forced draft fans have enough capacity to supply 100% of the air required for complete combustion at a 2.0% O_2 design condition. the primary air fans on both units will no longer be operational.

BMcD has reviewed the information provided by CPE and based on this review the units do not appear to require any internal boiler modifications to fire near 100 percent on natural gas. The units are estimated to reach full load capacity with no modifications to internal heat transfer surface, forced draft fans or induced draft fans.

For the cost estimate to this study all coal pipes will be removed back to a section underneath the lowest burner deck on Unit 2. Coal pipes in the way of the burner front will be removed on unit 2. Some of the coal pipes on the outside will remain in place.

100% Gas Conversion: This will allow 100 percent natural gas single fuel operation. There will not be any coal systems in service. The boiler is estimated to be capable of operating on 100 percent natural gas with the appropriate fuel supply and burners.

Each unit specific fuel control valve skid will supply gas at up to 50 psig to both the main burners and the ignitors using two separate gas trains. The burner regulation stations will drop the pressure further for the final burner pressure.

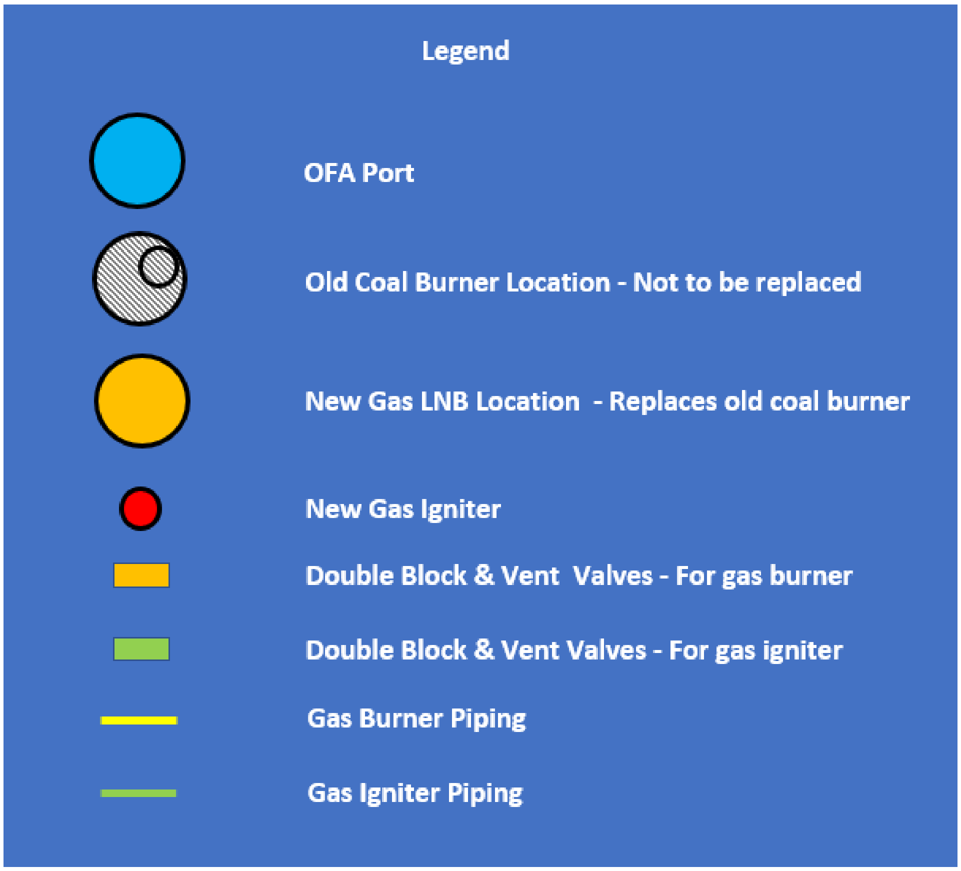
The burner fuel control skids will be located as close as possible to the burner decks in the boiler house. In addition to the fuel piping, vent pipe will be required per National Fire Protection Association (NFPA) 85. This vent piping will be required on both the front and rear elevations of the boiler for Unit 3 and the front elevations on Unit 2. The vent pipe runs from the skid all the way to the top of the structure.

Burns & McDonnell pipe sizing criteria for fuel gas is as follows:

- 10” – 24” Pipe and larger: < 5000 ft/min Line Velocity

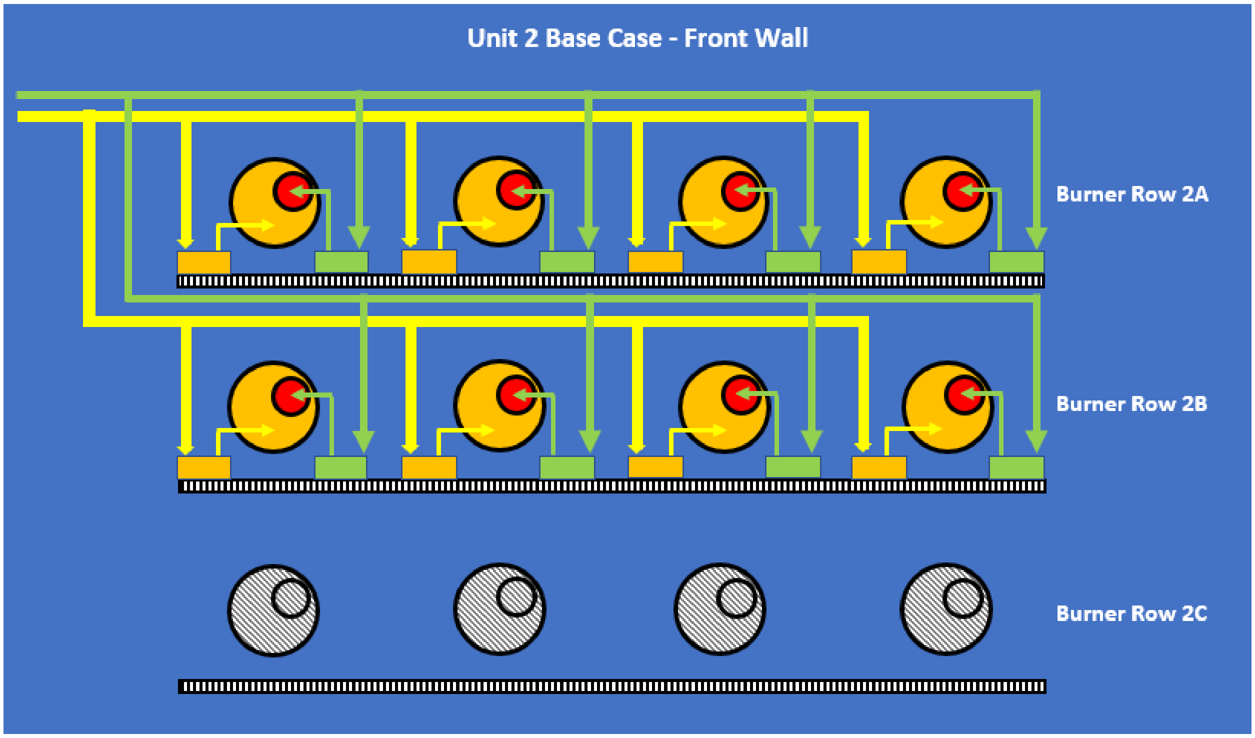
This design criteria provides lower velocities, resulting in less potential for noise and pipe vibrations. The velocity increase after the final double block and bleed valving that leads to the burner or ignitor may be as high as 166 fps or 9,960 fpm depending on the designer of the equipment.

Figure 3- 2 – Legend of symbols for Subsequent Figures



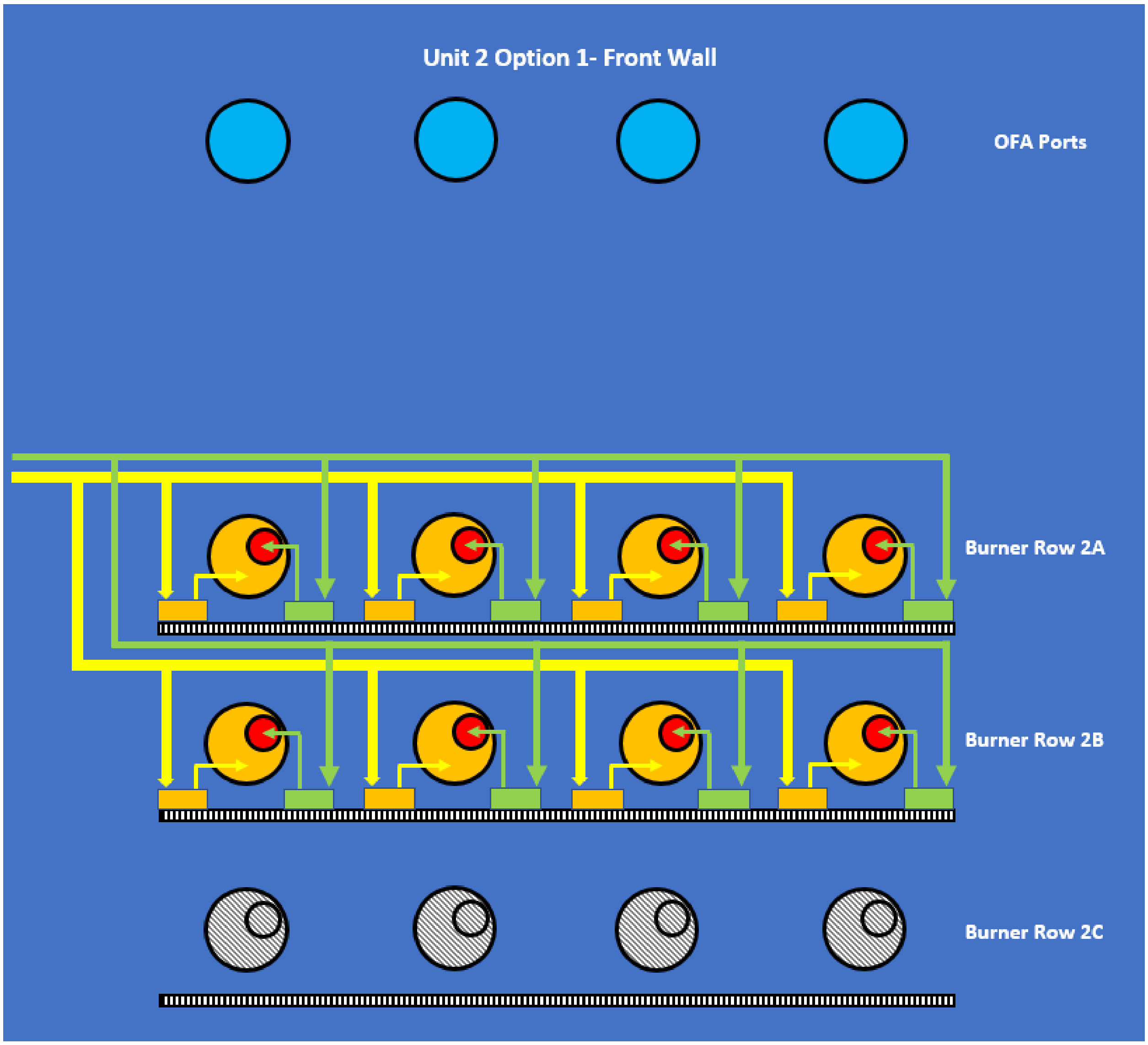
For Unit 2 Base Case: The Base Case is for new gas-fired LNBs, only. Only the upper eight (out of the existing twelve) burners will be retained for service after the fuel conversion. Each of the eight burners will be designed to operate at 160 mmBtu/hr. A detailed study of each system will be required after the procurement of the new firing equipment. The new burners will each have a new flame scanner requiring 15 scfm of cooling air.

Figure 3- 3 – Equipment Arrangement Sketch, Unit 2, Base Case



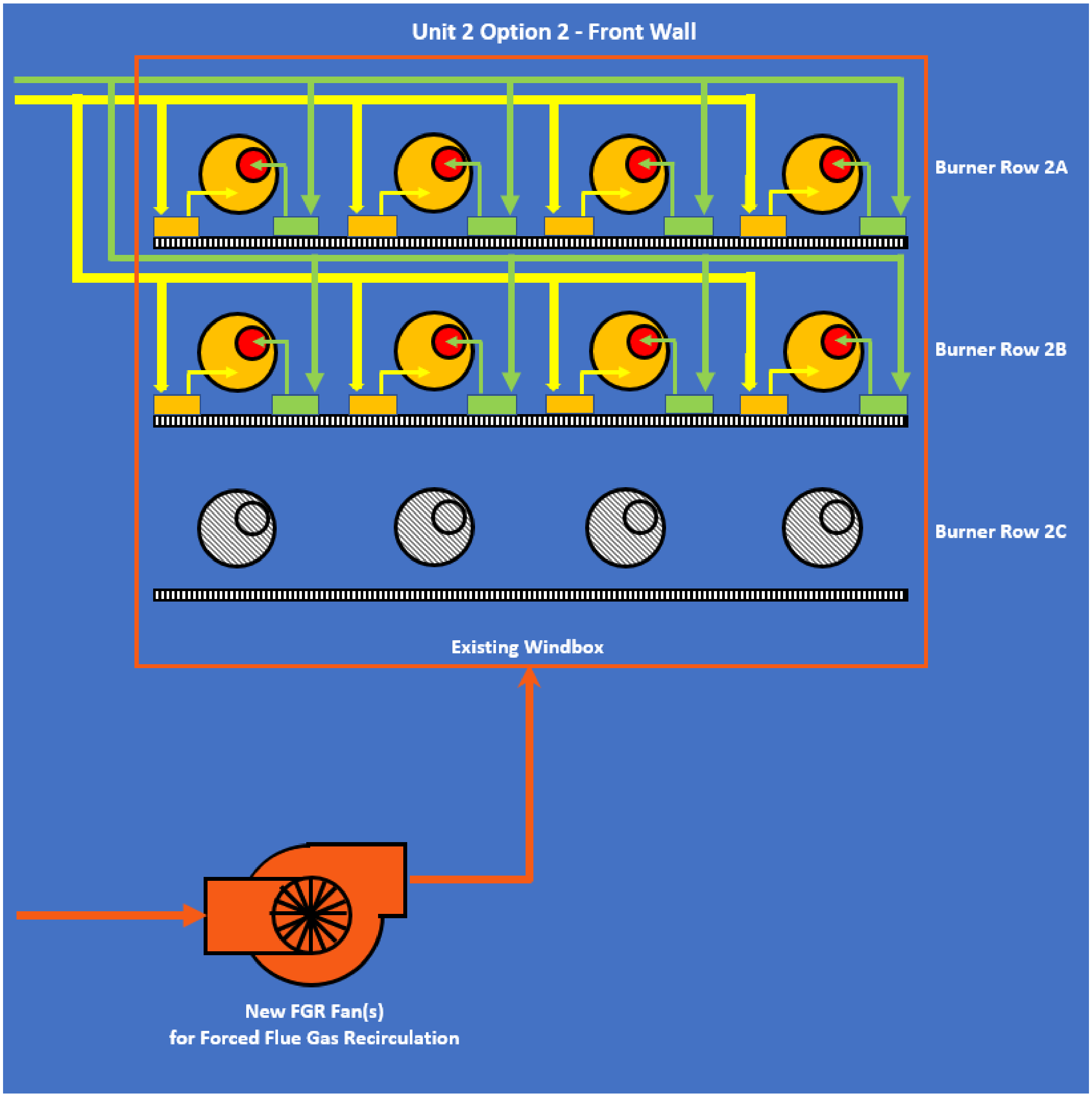
For Unit 2 Option 1: Option 1 is the same as the Base Case, but with an OFA system added. Each of the upper eight burners will be designed to operate at 160 mmBtu/hr. Economizer exit O_2 will not change, and the OFA ports will draw secondary air off the top of the open windbox, thus forcing the burner stoichiometry down to about 0.90 to further reduce NO_X.

Figure 3- 4 – Equipment Arrangement Sketch, Unit 2, Option 1



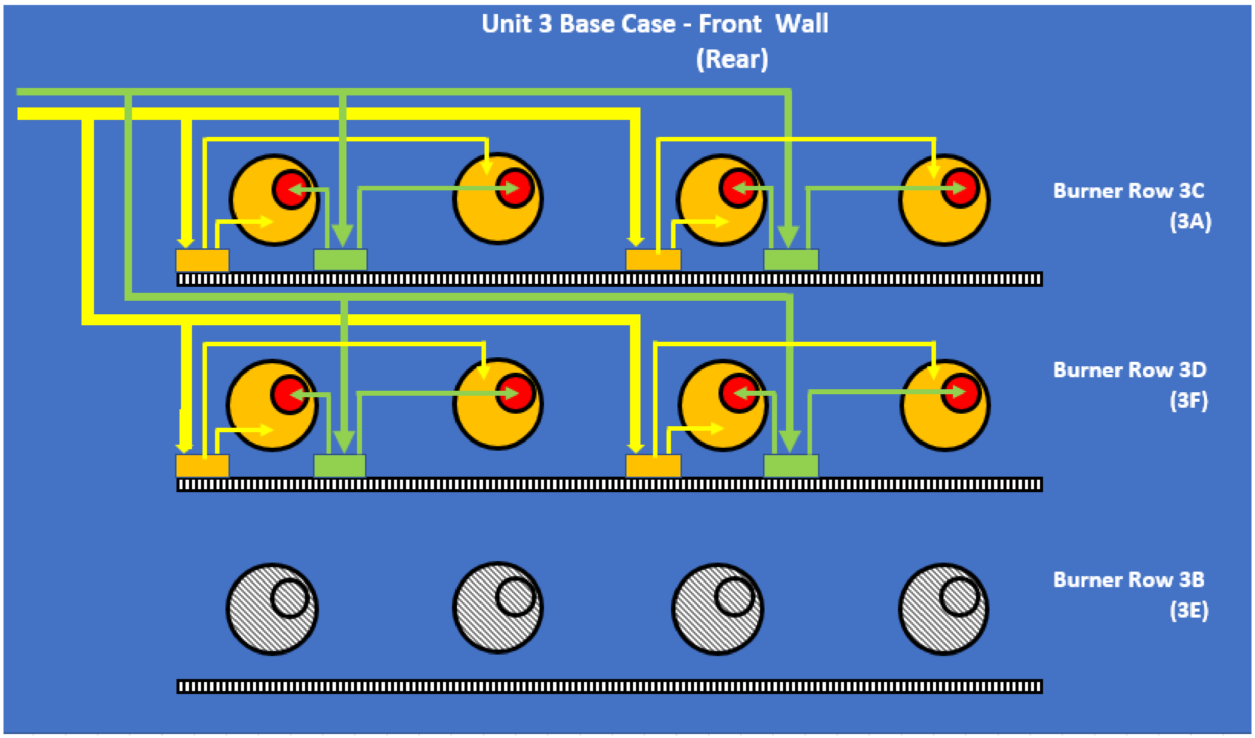
For Unit 2 Option 2: Option 2 is the same as the Base Case, but with a forced Flue Gas Recirculation (FGR) system added (and no OFA). Each of the upper eight burners will be designed to operate at 160 mmBtu/hr. Economizer exit O_2 will not change, and a new forced FGR system will be installed. The forced FGR system pushes flue gas directly back to the windbox rather than into the FD Fan suction, thus avoiding any additional FD Fan duty.

Figure 3- 5 – Equipment Arrangement Sketch, Unit 2, Option 2



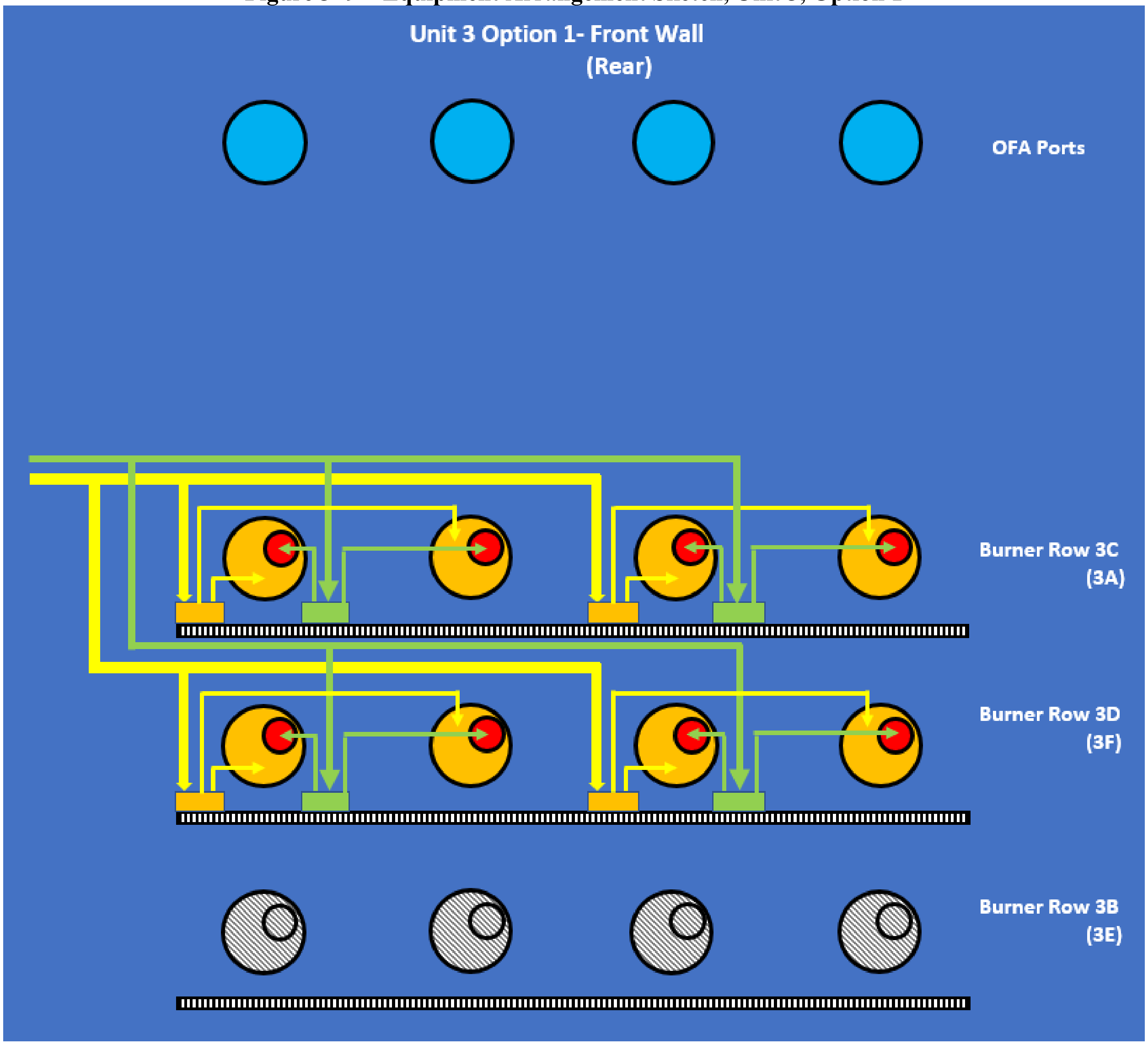
For Unit 3 Base Case: The Base Case is for new gas-fired LNBs, only. Only the upper sixteen (out of the existing twenty-four) burners will be retained for service after the fuel conversion. Each of the sixteen burners will be designed to operate at 185 mmBtu/hr. A detailed study of each system will be required after the procurement of the new firing equipment. The new burners will each have a new flame scanner requiring 15 scfm of cooling air.

Figure 3- 6 – Equipment Arrangement Sketch, Unit 3, Base Case



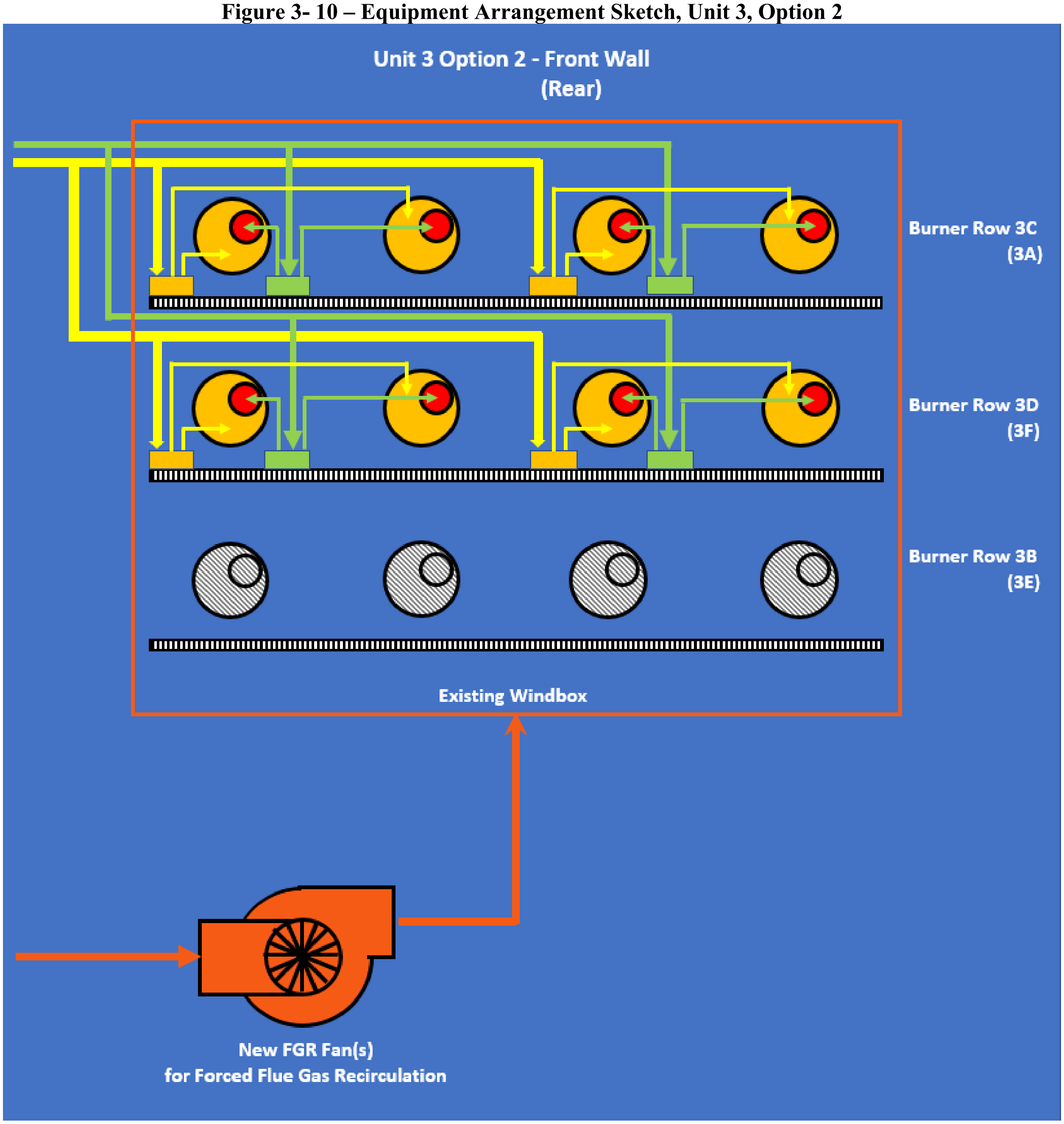
For Unit 3 Option 1: Option 1 is the same as the Base Case, but with an OFA system added. Each of the upper twelve burners will be designed to operate at 185 mmBtu/hr. Economizer exit O_2 will not change, and the OFA ports will draw secondary air off the top of the open windbox, thus forcing the burner stoichiometry down to about 0.90 to further reduce NO_X.

Figure 3- 9 – Equipment Arrangement Sketch, Unit 3, Option 1



For Unit 3 Option 2: Option 2 is the same as the Base Case, but with a forced Flue Gas Recirculation (FGR) system added (and no OFA). Each of the upper twelve burners will be designed to operate at 185 mmBtu/hr. Economizer exit O_2 will not change, and a new forced FGR system will be installed. The forced FGR system pushes flue gas directly back to the windbox rather than into the FD Fan suction, thus avoiding any additional FD Fan duty.

Figure 3- 10 – Equipment Arrangement Sketch, Unit 3, Option 2



The table below shows the total quantities for each of the above cases.

Figure 3- 11 – Quantity of Fuel Burning Equipment per Case

Gas Fuel Burning Equipment Quantities						
Description	**Unit 2**			**Unit 3**		
	Base Case	**Option 1**	**Option 2**	**Base Case**	**Option 1**	**Option 2**
New Burners	8	8	8	16	16	16
New Igniters	0	0	0	0	0	0
New Scanners	16	16	16	32	32	32
Burners DB&V	8	8	8	8	8	8
Igniters DB&V	0	0	0	0	0	0
Total Vents	10	10	10	10	10	10
OFA Ports	0	4	0	0	8	0
FGR Fans	0	0	1	0	0	1

3.2.3 Switchyard

No switchyard modifications will be required.

3.2.4 Flue Gas Desulfurization

When firing natural gas, a flue gas desulfurization system is not necessary since the sulfur content of natural gas is an order of magnitude less than coal fuels. This would dictate that the existing Unit 2 and 3 FGD could be decommissioned. With the FGD out of service, the stack would see air heater outlet temperatures. If mitigating flue gas temperature is required for the stack then spraying some water, using the FGD spraying equipment, into the flue gas can reduce the temperature, if required.

BMcD suggest removing the mist eliminators and any FRP in the system that could potentially be compromised by higher temperatures.

An alternative to using the existing spray machines would be to add a grid of nozzles to the last duct prior to the stack with a redundant system designing specifically for lowering temperature, if required. A price for this system including installation has not yet been developed and is not included in the cost estimates. This system would remove the need for using a sprayer at a low inefficient load.

3.2.5 Selective Catalytic Reduction

Unit 3 has been retrofitted with a selective catalytic reduction (SCR) system for the purposes of reducing NOx emissions from the flue gas generated by burning coal. The NOx emissions are estimated to be 0.45 lb of NOx/mmBtu currently entering the SCR. Typical gas burners without additional NOx reduction technologies can reduce this emissions rate to 0.22 lb/mmBtu. It is estimated that 80% NOx reduction is easily achieved with an SCR while burning gas. BMcD recommend using 0.05 lb/mmBtu for a new NOx emission target on Unit 3.

The economizer surface area has been increased from the original design. At lower loads a natural gas duct burner is required to increase the temperature of the flue gas prior to entering the SCR system. The SCR catalysts require a minimum temperature of the flue gas to be effective.

The SCR system can also be fitted with CO catalysts to lower CO or VOC if required. BMcD is still evaluating the potential need for a layer of CO catalyst. Generally there is not a need for a layer of CO catalyst when converting from coal to 100% gas firing.

3.2.6 Baghouse

Unit 3 has a baghouse. When firing natural gas, a particulate control device is typically not necessary since natural gas is a gaseous fuel and there are no substantial ash particles. Bags are typically rated to operate in temperatures up to 350 F so this shouldn’t raise any issues for Unit 3. The baghouse can be decommissioned once the unit has operated for a few months and any ash within the boiler or ductwork has worked its way out. Once the unit has gone through a self-cleaning process, the bags can be removed to lower the pressure drop through the system. Removal of the bags could be done consecutively while the unit is online if the baghouse is fitted with spare compartments to allow online bag changes/removal. If this method is used, the removal of the baghouse bags could be completed by existing staffing, so no capital expenditure is accounted for.

3.2.7 Air Pre-Heater

Unit 2 and 3 have two Ljungstrom bi-sector air preheaters. This is the best arrangement for a coal to gas conversion project. All the air supplied for combustion air both primary and secondary travels through the FD fan. A possible limitation to generating full load is air heater air in-leakage. This air in-leakage bypasses the boiler and is not available for combustion. Tightening air heater seals in the outage prior to gas only operation maybe warranted. BMcD recommend measuring actual air heater leakage and evaluating the need for significant maintenance. The costs for significant air heater repair are not included in this cost estimate.

3.2.8 Plant Performance Impacts

Burning natural gas will be less efficient than burning coal. The main impact on boiler efficiency is from hydrogen losses due to the higher hydrogen content of the natural gas fuel. The byproduct of combusting hydrogen is water vapor, and additional heat is needed to vaporize this water and heat it to the exiting economizer temperature. This heat is lost in the flue gas rather than absorbed in the boiler's water walls to create steam. We estimate a 4 - 6% loss as compared to the design fuel.

On the other hand, natural gas is more efficient than coal when it comes to dry gas losses due to less combustion air and excess air needed for proper stoichiometries. Approximately 10 percent excess air is needed for proper combustion of natural gas vs. 18 - 20 percent excess air for coal. Less flue gas flow for burning natural gas equates to smaller losses for heating the flue gas. For this study we have assumed an economizer exit O_2 of 2.0% to be conservative while firing gas.

The reduced natural gas-fired boiler efficiency requires an increase in total heat input to reach the same steam generation. Overall, there will be a reduction in auxiliary power requirements for a gas-fired boiler thus increasing the net plant output accordingly. This study assumes a 30 percent savings in auxiliary loads for pulverizers, coal handling, soot blowers, ash handling, baghouse, scrubber, etc. that will not be operated on 100 percent natural gas. The 30 percent savings has been confirmed to be a conservative estimate based on auxiliary load information from other plants.

BMcD review of the existing boilers estimates they are both capable of firing 100% natural gas without a reduction in steam flow and maybe only a slight reduction in steam temperature. The boiler may achieve the same existing coal steam flow conditions natural gas without any modifications to the existing boiler surface area or other boiler modifications. The boiler efficiency will drop by approximately 4% to 6% percentage points on 100 percent natural gas.

3.3 Natural Gas Supply

Burns & McDonnell investigated the flow requirements at CenterPoint Energy for a 100% conversion from coal to natural gas. The total calculated flow requirement is 4,205 mmBtu/hr for both units to meet full load. This does not include any gas to maintain gas heaters in the M&R yard if needed. Costs regarding bringing gas to the site are outside of the scope of this report. B&McD recommend heated gas to avoid excessive ice and moisture around the burners.

3.4 Project Schedule

The schedule for this project was developed as generic durations to provide an indicative project duration. This schedule assumes CPE will submit the air permit application for approval and concurrently start preliminary engineering and design. It is also assumed the project for 100 percent gas conversion will not trip PSD. The project schedule is shown below in Table 3-1. This schedule shows the durations for one-unit conversion including all onsite work. This includes the offsite pipeline based on other similar jobs. The overall duration depends on how construction and tie-in outages would be staggered. Add six months for the second unit

Table 3- 1: Indicative Schedule

Schedule Line Item	100% Natural Gas
Permitting (months)	12
Gas Line to Plant Concurrent (Eng/Pro)	18
Engineering & Procurement (months)	16
Construction (months)	6
Startup (months)	2
Total Project Duration (months)	**30**

3.4.1 Major Equipment

The natural gas burners and large gas regulators will be the longest lead time for on-site equipment. Vendors have recently quoted lead times of 9-12 months for 100 percent conversion equipment. The schedule may be affected depending on who is selected to provide the burner equipment. It is recommended to perform independent third-party modeling to confirm the best-case combustion equipment required prior to writing a specification to procure fuel burning equipment.

3.4.2 Construction

For onsite work, major construction activities will include the new onsite gas pipeline and fuel yard work, pre-outage pipe hanging, demolition of existing equipment after shutdown, boiler modifications including mechanical during shutdown, and electrical work. Construction, outside the M&R yard, is estimated at six months for complete installation for a 100 percent conversion.

3.4.3 Startup

Startup will be approximately two months. The units will be fired and tuned for optimal performance. Since the steam side will not be affected, no additional steam blows or cleanings will be necessary.

4.0 PROJECT COSTS

The capital cost summary is shown below. The project costs include escalation and are shown as 2022$. A project contingency of [redacted] percent is included to cover the accuracy of the estimate for the scope defined in this report. The costs presented in Table 4- 1 are total for the plant including all three units.

Table 4- 1: Total Plant Capital Costs

Capital Cost Line Item	Unit 2	Case 3
Procurement & Construction	[redacted]	[redacted]
Project Indirects	[redacted]	[redacted]
Project Costs	[redacted]	[redacted]
Owner Costs	[redacted]	[redacted]
Owner Contingency	[redacted]	[redacted]
Total Onsite Costs – Base Case	**$24,673,642**	**$30,658,448**
Option 1 - OFA	[redacted]	[redacted]
Option 2 – FGR	[redacted]	[redacted]

4.1 Cost Estimate Basis

The purpose of the cost estimate basis is to generally describe the scope of the cost estimate and the methodology for estimating the costs.

4.1.1 Contracting Approach

The cost estimate was assembled using multiple prime contract approach. The Owner is responsible for the purchase of all equipment, while each prime contractor is responsible for their subcontracts, and labor. The associated risk for the Owner of using multiple contractors is accounted for in the total project contingency. Costs to administer the contract, participate in OEM's meetings, and review submittals are included under engineering cost.

4.1.2 Engineered Equipment

An OEM or the burner supplier will provide the majority of the major equipment. The burner supplier scope is described above for the various cases. Budgetary and real pricing for similar equipment were used to build-up the pricing for this study.

Civil scope for this project is very limited. Scope includes excavation and backfill for the onsite natural gas pipeline and finishing work around the gas yard areas. No new roads or grading are required.

4.1.3 Concrete

The gas yard metering and regulation stations are assumed to be field erected and placed on concrete pads. The valve stations and metering in the boiler house will be mounted to the existing floor slab, existing steel, or new steel platforms. Minimal concrete will be required for the conversion. The production rates and material prices were developed from Burns & McDonnell previous project estimates for construction in the project area.

4.1.4 Structural Steel

Miscellaneous steel such as pipe rack, grating, handrail, etc. are included for structure access that is not otherwise provided as part of the equipment contracts. An allowance is also included to cover additional steel platforms for valve stations if existing areas are too tight. Final valve station locations will be decided during detailed design. The production rates and material prices were developed from Burns & McDonnell previous project estimates for construction in the project area.

4.1.5 Piping

The piping scope of work includes above grade gas supply piping from the gas yard to the boiler house, burner supply piping, and vent lines. The piping scope covers purchase of pipe, fittings, flanges, valves, specials, bolt-up kits, supports, and pre-fabricated pipe. The piping scope of work does include applicable non-destructive evaluation (NDE) and pressure testing. The piping scope of work does not include allowances for underground interferences.

The piping estimate was based on a take-off from the similar sized units. Using these quantities, costs for bulk material, valves, and pipe fabrication was based on Burns & McDonnell recent project pricing. The production rates were developed from Burns & McDonnell previous project estimates for construction in the project area.

4.1.6 Electrical

The auxiliary power requirements for burning natural gas are generally lower than that required for burning coal. Abandonment of the pulverizers for a 100 percent conversion will free up considerable load from the auxiliary power system. Power will be required for the new flame scanners, valves, and blowers, but it is assumed that the existing power distribution can accommodate these additional minor loads (for the startup and co-firing cases as well). New control wiring has been included from the burner devices to the existing burner junction boxes. New marshalling control wiring has also been included from the burner junction boxes back to the DCS. It is assumed that the existing cable tray around the boiler has adequate space to accommodate the new cable. The production rates and material prices were developed from Burns & McDonnell previous project estimates for construction in the project area.

4.1.7 Instrumentation & Controls

The majority of instrumentation for this project is either skid-mounted or included in the burner supplier scope. The skid-mounted regulating skids and valve stations can be specified such that all instrumentation is installed and wired to a junction box. Some instrumentation will be installed separately for the field erected gas yard metering and regulation. This results in negligible BOP instrumentation installation work. As described in the General Design Criteria section, the worst-case scenario was assumed where new DCS I/O modules would be necessary to accommodate the BMS modifications. An internal estimate was developed for this DCS cost that includes both hardware and software modifications.

4.2 Indirects

The following methods were used for indirects:

- Cost for construction management and construction indirects were based on a percentage of the project costs based on similar past projects. Costs include construction management staff expenses including travel and living expenses, temporary buildings and utilities, and site maintenance. Additional construction management provided by the contractors is included in the wage rates used in this estimate.
- Cost for engineering was based on a percentage of the project costs based on similar past projects. The engineering estimate includes costs for office and field engineering as well as all per diems, expenses, and general overhead and administrative costs. The engineering estimate also includes costs to review submittals from major equipment OEMs and contract administration tasks such as attending progress meeting, expediting drawing submittals, and reviewing progress report.
- Cost for startup was based on a percentage of the project costs based on similar past projects.

4.2.1 Taxes

All taxes are excluded from the estimate.

4.2.2 Construction Labor Basis

The estimate was developed on the basis that there will be a sufficient labor pool to draw from the Yankeetown area to support the project. The productivity factors were developed based on Burns & McDonnell project history for labor in the regional area.

4.2.2.1 Labor Wage Rates & Expenses

Wage rates were taken from the 2022 RSMeans Construction Labor Rates for the Yankeetown area. The wage rates include wages, fringes, general liability and workers compensation insurance, overtime, per diem, incentives and contractor indirects.

4.2.2.2 Work Hours

The estimate assumes a 5-day, 50-hour week to incentivize labor. The shifts are based on a 50-hour work week with 25 percent of hours of overtime per day at one and a half times base wage rate for overtime pay.

4.2.2.3 Labor Per Diem

Craft per diem included in the craft wage rates.

4.2.3 Escalation

Escalation was not included with the project costs.

4.2.4 Contingency

A project contingency was included to cover typical final accuracy of pricing, commodity estimates, and accuracy of the defined project scope. Typically the level of contingency is set by the amount of scope definition provided, the amount of engineering and estimating conducted by the owner's engineer and CPE prior to providing cost certainty on the project price, and the amount of risk born by the prime contractors (performance, schedule, scope, payment, etc.). This contingency is NOT intended to cover changes in the general project scope (i.e. addition of buildings, addition of redundant equipment, addition of systems, etc.) NOR major shifts in market conditions that could result in significant increases in contractor margins, major shortages of qualified labor, significant increases in escalation, or major changes in the cost of money (interest rate on loans). A 25 percent contingency was included as a typical allowance for this indirect cost.

4.2.5 Owner Costs

[redacted]

5.0 CONCLUSIONS

Both Unit 2 and Unit 3 would result in a coal to 100% gas conversion that would be at or near the existing capacity when operating for full load.

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Co-gen Unit Study

Memorandum

Date: September 16, 2022

To: BJ Reynolds
Director of Power Supply Construction
CenterPoint Energy
812.491.5435

Subject: Co-gen Unit Assessment

INTRODUCTION

CenterPoint Energy ("CenterPoint") has retained 1898 & Co., a part of Burns & McDonnell Engineering Company, Inc. ("1898 & Co.") to evaluate a new cogeneration technology option. This option involves utilizing excess steam from an adjacent industrial facility to produce electricity via a steam turbine. The intent of this assessment is to provide capital cost, O&M costs, and performance information sufficient to support Integrated Resource Planning ("IRP") efforts.

It is the understanding of 1898 & Co. that this Memo will be used for preliminary information in support of CenterPoint's generation planning process. Any technologies of interest to CenterPoint should be followed by additional detailed studies to further investigate the technology and its direct application within CenterPoint's long-term plans.

Study Basis and Assumptions

The assumptions below govern the overall approach of the Study:

- All estimates are screening-level in nature, do not reflect guaranteed costs, and are not intended for budgetary purposes.
- All information is preliminary and should not be used for construction purposes.
- All capital cost and O&M costs are stated in 2022 US dollars ("USD"). Escalation is excluded.
- Estimates assume an Engineer, Procure, Construct ("EPC") fixed price contract for project execution.
- Ambient conditions are based on the following:
    - Winter Conditions: 5°F
    - Average Ambient Conditions: 59°F
    - Summer Conditions: 90°F

TECHNOLOGY EVALUATION

A large new industrial customer is requesting to partner with CenterPoint on a cogeneration facility. The industrial facility has sufficient waste heat in the form of steam to produce approximately 22 MW of electricity. 1898 & Co. performed a screening-level evaluation of a cogeneration technology to assist CenterPoint with understanding the likelihood of further development.

Evaluated Technology

The proposed co-gen facility utilizes the industrial customer's waste heat in the form of steam by using it to drive a steam turbine and generator to produce electric power. The steam turbine is a multistage condensing steam turbine with a four-pole generator with gearbox. The exhaust steam is condensed in a surface condenser. Cooling water is supplied by a 2-cell mechanical draft cooling tower via 2x50% circulating water pumps. The condensate is then returned to the industrial facility through 2x100% condensate pumps.

Since the co-gen will utilize steam from the industrial facility waste heat to produce electricity, there are no additional air emissions. No emissions controls technology is required.

Performance Estimates

The steam is assumed to come directly from the industrial customer and at the steam conditions shown in Table 1. The estimated co-gen performance is shown in Table 2.

Table 1: Steam Conditions

Description	Value
Steam Pressure, psig	650
Steam Temperature, °F	740
Steam Flow, kpph	165

Table 2: Co-Gen Performance

Description	Value
Gross Plant Output, MW	23.2
Auxiliary Load, kW	900
Net Plant Output, MW	22.3

Operating and Maintenance Cost Estimates

1898 & Co. developed a screening-level O&M cost estimate including a breakout for fixed operations and maintenance and variable operations and maintenance.

Operating and Maintenance Assumptions

- O&M costs were estimated assuming average annual conditions.
- Fixed O&M cost estimates include labor, office and administration, training, contract labor, safety, building and ground maintenance, communication, and laboratory expenses.
- Variable O&M costs include routine maintenance, makeup water, water treatment, water disposal, and other consumables.
- Variable O&M costs are assuming the facility is operating at full load capacity.
- O&M costs exclude property taxes and insurance.

Operating and Maintenance Cost Estimates Summary

The total O&M cost is summarized below in Table 3.

Table 3: Operating and Maintenance Cost Estimate

Description	Cost Estimate
Fixed O&M Costs	[redacted]
Variable O&M Costs	

Capital Cost Estimates

1898 & Co. developed a screening-level, Association for the Advancement of Cost Engineering ("AACE") Class V capital cost estimate including a break-out of anticipated owner's cost.

Cost Estimate Assumptions

A detailed scope assumptions matrix is included in Appendix B. The following assumptions govern the capital cost estimates:

- The interface point for all piping is assumed to be at the facility property boundary.
- Steam quality is assumed to meet steam turbine OEM requirements.
- All water treatment is assumed to be performed by the industrial customer and is not included in the scope.
- Spare steam turbine bladed rotor is included to support shorter maintenance outages.
- Electrical scope is assumed to end at the generator terminals. The STG will generate electricity at 13.8 kV and is assumed to tie directly into the industrial customer's system.

Cost Estimate Exclusions

The following costs are excluded from all estimates:

- Financing fees
- Interest during construction
- Escalation
- Performance and payment bond
- Sales tax
- Property insurance
- Transmission Interconnect / Switchyard
- Water rights

Capital Cost Estimate Summary

The total installed cost of the facility is shown in Table 4. All costs are estimated in 2022 USD. For a further breakdown on the Cogeneration capital cost estimates, see Appendix A.

Table 4: Capital Cost Estimate (2022$MM)

Description	Cost Estimate
Total Direct Cost	[redacted]
Total Indirect Cost	
EPC Project Cost	
Owner's Cost	
Total Project Cost	$63.0 MM

STATEMENT OF LIMITATIONS

Estimates and projections prepared by 1898 & Co. relating to performance, operating and maintenance costs, capital costs are based on experience, qualifications, and judgement as a professional consultant. 1898 & Co. has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding, and market conditions or other factors affecting such estimates or projections. Actual rates, costs, performance ratings, schedules, etc., may vary from the data provided.

CONCLUSIONS AND RECOMMENDATIONS

This study provides capital cost, O&M costs, and performance information to support CenterPoint's consideration of a cogeneration opportunity with an industrial facility. Information provided in this Memo is preliminary in nature and is intended to support screening of generation opportunities. If this opportunity is appealing, CenterPoint should pursue additional studies to define project scope, equipment design, and schedule for the development of the project.

1898 & Co. appreciates the opportunity to support CenterPoint with this evaluation. If you have any questions regarding this memo, please contact Chad Swope at chad.swope@1898andco.com | 816.548.1329.

Sincerely,

Chad Swope, P.E.
Project Manager

Appendix A – Cogeneration Technology Assessment Summary Table
Appendix B – Cogeneration Scope Assumptions

Attachment 6.6 ACE Rule Heat Rate Study

FINAL

EPA ACE HEAT RATE STUDY

B&V PROJECT NO. 402338
B&V FILE NO. 40.0004

PREPARED FOR

Vectren

16 JANUARY 2020

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Executive Summary

The Affordable Clean Energy (ACE) rule, finalized by the United States Environmental Protection Agency (EPA) on June 19, 2019, establishes new standards for reducing greenhouse gas (GHG) emissions for coal-fired electric utility generating units (EGUs) based on the “best system of emission reduction” (BSER). First proposed in August 2018, the rule, Docket ID No. EPA-HQ-OAR-2017-0355: FRL-9995-70-OAR, “Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations,” focuses on measures that can be implemented within the fence line of existing EGU facilities. As such, the EPA concluded that BSER be limited to heat rate improvements (efficiency improvements) for existing coal-fired EGUs. Within ACE, the EPA identified a list of candidate technologies and measures to achieve heat rate improvements (HRI).

In anticipation of the final rule, Vectren requested that Black & Veatch assess these candidate technologies for improvements at four coal fired plants (A.B. Brown Unit 1, A.B. Brown Unit 2, Culley Unit 2, and Culley Unit 3) to meet the goals of the ACE rule. Black & Veatch reviewed the characteristic of the four plants and examined each plant according to several BSER alternatives:

- Steam turbine blade path upgrades.
- Redesign or replacement of the economizer.
- Air heater and duct leakage control.
- Variable frequency drive (VFD) deployment.
- Neural networks.
- Intelligent sootblowing (ISB).
- Various improved operations and maintenance (O&M) practices.

Several factors influenced the recommendations for upgrades at the four plants; these factors are discussed in detail in Section 3.0. A summary of Black & Veatch’s assessment and recommendations is as follows:

- The existing steam turbines at A.B. Brown Units 1 and 2 have been upgraded to full dense pack and no significant improvement in heat rate would result in additional upgrades; a turbine blade path upgrade would improve heat rate at F.B. Culley Unit 3 (1.4 to 1.6 percent). Steam turbine blade path upgrades options for F.B. Culley Unit 2 would improve heat rate by 1.3 to 1.5 percent, at a cost of $10.4 million.
- Economizer upgrades are not recommended for A.B. Brown Units 1 and 2 or F.B. Culley Unit 3 at this time; upgrades at F.B. Culley Unit 2 would require significant investment and require further study. A boiler modeling study of the potential benefits of reducing economizer surface area at A.B. Brown Units 1 and 2 or F.B. Culley Unit 3 found that although there was a potential reduction in natural gas use for the gas burners, the net impact upon the units was negative.
- Recommendations were provided for improving unit air heaters at all four units.

- Estimated costs are provided for VFD improvements for the FD and ID Fans at A.B. Brown Units 1 and 2. VFD improvements were studied for the FD fans at F.B. Culley Units 2 and 3 as both units ID fans have already been upgraded with VFDs.
- The deployment of VFDs for circulating water pumps was studied at all four units, but in no instance was it found to be a cost-effective HRI option.
- Estimated costs are provided for neural network deployment at all four units.
- F.B. Culley Unit 2 is the only unit that could benefit from ISB; the other units already use this technology.
- Improved O&M practices include heat rate improvement training, on-site heat rate appraisals, and improved condenser cleanliness strategies; these techniques may result in improvements at all four units.

Overall, many opportunities exist for heat rate improvement at the A.B. Brown and F.B. Culley units in compliance with the EPA-ACE rule. The decision of which heat rate improvements should be pursued must be based upon the long-term plans for the continued operation of the units, and the specific cost/benefit factors for each improvement found in Appendix B.

Recommendations

The following recommendations have been made for the units, based upon their past performance and current operations, as well as the expected future payback potential.

- For the A.B. Brown 1, A.B. Brown 2, and F.B. Culley 3 units upgrades to the air heaters and repair and remediation of ductwork and air quality control systems leakage appears to have a high value to the plants. In the case of air heater upgrades the improvement in heat transfer will improve the boiler efficiency, and the reduction in air heater leakage will reduce station service by reducing the air and gas main fan flow requirements. Reductions in duct leakage and leakage in air quality control equipment leakage will significantly improve induced draft fan performance and will reduce station service. There will also be the ancillary benefit of improved operations and efficiency of the air quality control equipment for emissions reduction.

  F.B. Culley Unit 2 was found to have a poor cost/benefit ratio for these upgrades due to its very low capacity factor and net generation, as well as its relatively short remaining useful life. F.B. Culley Unit 3 on the other hand was found to have the best potential benefit from air heater and duct leakage improvements from the standpoint of improvement per capital dollar spent.

- Steam turbine and blade path upgrades were analyzed for F.B. Culley Units 2 and 3 (A.B. Brown Units 1 and 2 were judged not to benefit from them sufficiently to warrant further upgrades, due to their relatively recent dense pack refurbishments) but only upgrades respective to F.B. Culley Unit 3 were found to be technically feasible and cost-effective at this time. However, as the New Source Review (NSR) exemption portion of EPA-ACE has been deferred and will be proposed in a separate action at a later date, pursuing steam turbine upgrades at this time should be done under the consideration of the potential for triggering NSR.

- Variable frequency drive deployment was found to be only advantageous for the induced draft fans on A.B. Brown Units 1 and 2. For all other systems and the F.B. Culley units, either VFDs had already been deployed to critical systems, or there was no acceptable cost/benefit to further deployment.
- Deploying a neural network or other boiler optimization system was found to be beneficial for all units except F.B. Culley Unit 2, which again was excluded due to its low capacity factor and output. Even modest improvements in optimization could result in significant improvements to heat rate and overall unit control and emissions.
- Heat rate awareness training was found to be a very good cost/benefit for all the units and could yield significant improvements in operations practices and responses to controllable losses at both plants. Targeted heat rate assessment, while difficult to quantify exactly, is expected based upon Black & Veatch experience to have a very high return on investment, and numerous examples have been provided in the text from past projects.
- The addition of more circulating water temperature measurements leaving the condenser would also improve accuracy of results by better capturing temperature stratification in the return piping.

Summary of Costs

The following table provides a summary of costs associated with the recommended ACE technologies for each unit. Additional detailed cost estimates for each unit can be found in Appendix B.

Table ES-1 A.B. Brown Unit 1 Summary of ACE Technology Costs

Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)
Air Heater Basket, Seal, and Sector Plate Replacement	850	0.50	57.88
Air Heater (Steam Coil) System Repairs	350	0.10	11.6

Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)
Circulating Water Pumps	2,100	N/A	N/A
Induced Draft Fans VFD Deployment	2,900	2.39	276.5
Forced Draft Fans VFD Deployment	2,000	0.43	50.3
Deployment of A Neural Network for Combustion Control and Boiler Excess Air Reduction. (0.25% to 0.75% Reduction in Excess O_2)	500	0.23 to 0.60	26.6 to 69.5
Heat Rate Improvement Training	15	0.30	34.7
On-Site Heat Rate Appraisals	Variable	Variable	N/A
Improved Condenser Cleaning Strategies	N/A	0.15	17.4

Table ES-2 A.B. Brown Unit 2 Summary of ACE Technology Costs

Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)
Air Heater Basket, Seal, and Sector Plate Replacement	850	0.50	55.0
Air Heater (Steam Coil) System Repairs	350	0.10	11.0
Circulating Water Pumps	2,100	N/A	N/A
Induced Draft Fans VFD Deployment	2,900	1.33	146.3
Forced Draft Fans VFD Deployment	2,000	0.26	28.6
Deployment of A Neural Network for Combustion Control and Boiler Excess Air Reduction. (0.25% to 0.75% Reduction in Excess O_2)	500	0.30 to 0.60	25.3 to 66.0
Heat Rate Improvement Training	15	0.30	33.0
On-Site Heat Rate Appraisals	Variable	Variable	N/A
Improved Condenser Cleaning Strategies	N/A	Negligible	Negligible

Table ES-3 F.B. Culley Unit 2 Summary of ACE Technology Costs

Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)
Air Heater Basket, Seal, and Sector Plate Replacement	476	0.50	63.2
Circulating Water Pumps	900	N/A	N/A
Forced Draft Fans VFD Deployment	2,000	0.48	60.9
Deployment of A Neural Network for Combustion Control and Boiler Excess Air Reduction. (0.25% to 0.75% Reduction in Excess O_2)	500	0.26 to 0.62	32.9 to 78.4
Boiler Feed Pump VFD Deployment	600	0.6	75.8
Synchronized Controlled Sootblowing System Designed to Alleviate Excessive Use of Steam, Air or Water That Have A Negative Effect on Heat Rate.	350	0.10	12.64
Heat Rate Improvement Training	15	0.30	37.9
On-Site Heat Rate Appraisals	Variable	Variable	N/A
Improved Condenser Cleaning Strategies	N/A	0.42	53.1

Table ES-4 F.B. Culley Unit 3 Summary of ACE Technology Costs

Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)
HP/IP Upgrades	19,900	1.5	158.3
Air Heater Basket, Seal, and Sector Plate Replacement	750	0.50	52.8
Air Heater (Steam Coil) System Repairs	350	0.10	10.6
Circulating Water Pumps	2,100	N/A	N/A
Forced Draft Fans VFD Deployment	2,000	0.51	54.3
Deployment of A Neural Network for Combustion Control and Boiler Excess Air Reduction. (0.25% to 0.75% Reduction in Excess O_2)	500	0.25 to 0.62	26.4 to 65.4
Heat Rate Improvement Training	15	0.30	31.7
On-Site Heat Rate Appraisals	Variable	Variable	N/A
Improved Condenser Cleaning Strategies	N/A	0.44	46.4

1.0 Introduction

Vectren requested that Black & Veatch support its efforts to analyze a potential response to the United States Environmental Protection Agency (EPA) Docket ID No. EPA-HQ-OAR-2017-0355: FRL-9995-70-OAR, "Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations;" known as the Affordable Clean Energy (ACE) rule. Vectren operates the A.B. Brown Unit 1, A.B. Brown Unit 2, F.B. Culley Unit 2, and F.B. Culley Unit 3 coal-fired electric generating units (EGUs) and specifically requested that Black & Veatch develop a high-level assessment report identifying opportunities to improve plant efficiency to meet ACE rule goals.

To meet these goals, Black & Veatch prepared a high-level description of four primary heat rate improvement (HRI) projects that have been proposed by the EPA as the best system of emission reduction (BSER). Estimates of HRI, annual carbon dioxide (CO_2) reduction, and a rough order-of-magnitude capital cost estimate were developed for each alternative.

Black & Veatch performed a high-level assessment to consider the technical and economic feasibility of items that have been seen as beneficial in previous ACE studies. Financial benefits would be confirmed by integrated resource plan (IRP) modeling; specific modifications would then be reviewed in a detailed effort to confirm the performance and financial benefits.

1.1 AN OVERVIEW OF EPA-ACE

On June 19, 2019, EPA issued the ACE rule, a replacement to the previous presidential administration's Clean Power Plan (CPP) to regulate CO_2 emissions from existing coal-fired power plants. ACE regulates EGUs based on the BSER. Unlike the CPP, ACE focuses on only those measures which can be implemented within the fence line of existing EGU facilities. As such, EPA has determined BSER to be limited to heat rate improvement (HRI) measures (efficiency improvements) for existing coal-fired EGUs at the individual unit level. The lower a unit's heat rate, the more efficiently it will convert heat input to electrical output, consuming less fuel per kilowatt-hour (kWh) and emitting lower amounts of CO_2. To aid operators and state agencies in determining which measures should be considered when determining BSER, EPA developed a list of 7 HRI candidate technologies. According to EPA, these technologies have been shown to be reliable, efficient, cost-effective, and broadly achievable for a source category across the country. The technologies include:

- Steam turbine blade path upgrades.
- Redesign or replacement of the economizer.
- Air heater and duct leakage control.
- Variable frequency drive (VFD) deployment.
- Neural networks/Intelligent sootblowing (ISB).
- Boiler feed pump upgrade/overhaul
- Various improved operations and maintenance (O&M) practices.

The EPA has responsibility under the CAA to provide a range of reductions and costs associated with each of the candidate technologies. The ranges of expected reductions for each technology are to be used as guidance, but the states will be expected to evaluate each affected unit individually. For reference, EPA's summary of HRI measures and the range of their HRI potential (%) by EGU size is included in Table 1-1. These ranges represent the degree of emission reduction achievable for each technology, however the EPA acknowledges that a specific unit may have the potential for more or less emission reduction based on the unit's specific characteristics. According to the preamble to the final rule, HRI potential will be determined by source-specific factors including, but not limited to, the EGU's past and projected utilization rate, maintenance history, and remaining useful life[1].

Table 1-1 EPA's Summary of HRI Measures and Range of HRI Potential (%) by EGU Size

HRI MEASURE	<200 MW		200-500 MW		>500 MW	
	MIN	MAX	MIN	MAX	MIN	MAX
Neural Network/Intelligent Sootblowers	0.5	1.4	0.3	1.0	0.3	0.9
Boiler Feed Pumps	0.2	0.5	0.2	0.5	0.2	0.5
Air Heater & Duct Leakage Control	0.1	0.4	0.1	0.4	0.1	0.4
Variable Frequency Drives	0.2	0.9	0.2	1.0	0.2	1.0
Blade Path Upgrade (Steam Turbine)	0.9	2.7	1.0	2.9	1.0	2.9
Redesign/Replace Economizer	0.5	0.9	0.5	1.0	0.5	1.0
Improved Operating and Maintenance (O&M) Practices	Can range from 0 to >2.0% depending on the unit's historical O&M practices.					

Ultimately, it is the EPA's role to determine the possible BSERs and the degree of emission control achievable for each technology, and it is the states' role to create plans establishing unit-specific standards (in a lbm CO_2/MWh format) that reflect the application of the BSER. Each state will be required to submit plans (or a State Implementation Plan [SIP]) to the EPA explaining how the state applied the BSER to each source and what other factors were considered when developing the unit-specific standards. In addition to the performance standards, states will also propose compliance deadlines for each EGU, as well as monitoring, recordkeeping and reporting requirements in their plans. These plans will be due to the EPA in three years (July 2022). Upon submittal, the EPA will have 12 months to determine whether or not to approve the plan.

[1] This could have the most significant implications for F.B. Culley Unit 2.

The emission limits and requirements for Vectren's affected EGUs will ultimately be established by IDEM. States are afforded considerable flexibility in determining emission standards for each unit as each state is more familiar with the existing sources within their jurisdictions. States are to use the guidelines EPA provided to evaluate each applicable EGU within its jurisdiction with regards to the utilization of each of the candidate technologies, equipment upgrades, and best O&M practices in establishing a standard of performance for that source. Physical and cost considerations will limit or prevent full implementation of the listed technologies and each state will consider these factors when establishing the standards of performance required. The remaining useful life of the source and other source-specific factors will also be considered by the states when establishing the standards of performance for each unit.

It will be the states' responsibilities to determine how these factors will be taken into consideration when establishing the standards. One approach that states may use is a top-down analysis that examines technical feasibility and cost effectiveness when determining an appropriate standard. Black & Veatch notes that variations of this type of analysis have been used by EPA in multiple regulatory programs to determine appropriate controls (e.g., BACT, RACT, BART, etc.). Such an analysis of the candidate BSER technologies could entail the following steps:

1. Identify all technologies (This step has already been done by the rule);
2. Eliminate technically infeasible options;
3. Rank remaining technologies by effectiveness;
4. Evaluate the most effective controls – entails energy, environmental, and economic impacts – cost effectiveness could entail a consideration of remaining useful life to ultimately determine the cost of a technology on the basis of dollars per lbm CO_2/MWh improvement.
5. Select the appropriate technology and set a standard of performance in terms of a lbm CO_2/MWh emission rate.

Black & Veatch notes that such an approach could provide state agencies such as IDEM with the defensible approach that they seek to avoid potential legal vulnerabilities while at the same time allowing Vectren to implement the most cost-effective option. Given the lack of specificity in the Rule, IDEM and their stakeholders have been afforded a great deal of latitude in designing the SIP. Therefore, early engagement with IDEM is encouraged in order to influence and assist in their determinations of the appropriate performance standard to include in the SIP for Vectren's affected units.

Numerous lawsuits have already been filed against the ACE rule, however, no stay (delay in rule administration) has been requested to this point. As with many environmental rules, industry sentiment is that the Rule's fate could be determined by the 2020 presidential election. In the meantime, however, Black & Veatch would expect that states will begin to gather information in order to begin designing their SIPs.

1.2 EPA'S INTEGRATED PLANNING MODEL

To assess the potential costs and benefits associated with the ACE rule, the EPA used the Integrated Planning Model (IPM) in support of final rulemaking. According to EPA documentation on the latest version of the model (EPA Platform v6, November 2018), "IPM is a multi-regional [...] model of the U.S. electric power sector" that provides "[...] forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand, environmental, transmission, dispatch, and reliability constraints." Historically, EPA has used the IPM to forecast power sector behavior and examine the impact of potential air pollution control policies. The EPA has used this model for over two decades to evaluate the economic and emission impacts of potential environmental regulations. Specifically, EPA has used v6 to develop regulatory impact analyses in support of the Cross-State Air Pollution Rule (CSAPR), the greenhouse gas New Source Performance Standard (NSPS) for new, modified, and reconstructed electric utility generating units (NSPS Subpart TTTT), the Mercury and Air Toxics Rule (MATS), the Regional Haze Rule, 316b, and ELG/CCR regulations.

The EPA IPM is quite complex and utilizes numerous inputs to characterize the power sector including:

- Power System Operation
- Generation Resources
- Emission Control Technologies
- CO_2 Capture, Transport, and Storage
- Coal Characteristics (i.e., Supply Curves and Transportation Matrix)
- Natural Gas Market Characteristics
- Other Fuel Assumptions
- Financial Assumptions

These inputs are processed in the model in order to arrive at outputs quantifying sector-wide emissions, costs, capacity expansion, retrofit decisions, fuel consumption and prices, and electricity generation and prices. Finally, these outputs can be fed into a post-processor in order to forecast individual boiler-level data, retail electricity price projections, and outputs needed to assess the impacts on air quality via air quality modeling. According to the model documentation, "The model has been tailored to meet the unique environmental considerations important to EPA, while also fully capturing the detailed and complex economic and electric dispatch dynamics of power plants across the country."

The IPM model was not designed to evaluate the technological or economic feasibility of the various BSER technologies for a single ACE-affected unit, but, rather, is intended to be used to holistically evaluate the impacts of EPA rulemakings on the entire power sector. Additionally, the model appears overly complex, such that it could be time-consuming and provide a false sense of accuracy when used to evaluate the technologies as part of an ACE study. As such, it is unlikely that the IPM would/should ever be utilized to evaluate the BSER technologies as a part of a state ACE compliance plan.

1.3 POTENTIAL NEW SOURCE REVIEW CHANGES

To accommodate and facilitate the HRI projects associated with the ACE rulemaking, EPA has proposed changes to the New Source Review (NSR) permitting program. Under the current regulations, modifications to stationary sources, such as EGUs, that increase annual emissions of regulated pollutants at or above certain regulatory thresholds are subject to NSR permitting requirements. EPA is now proposing to incorporate a comparison of hourly emissions into the NSR applicability assessment for EGUs. Under this approach, the maximum actual emissions values measured on an hourly basis before the project and the projected hourly emission rate that will occur after the proposed modification would be compared to determine if an emission increase would result. If no *hourly* emissions increase will occur, NSR would not be applicable.

However, if hourly emissions were determined to increase, the emissions analysis must continue per the traditional methodology where an assessment of both project-specific overall emissions increases, and plant-wide net emissions increases on an annual basis would need to be calculated to determine if NSR permitting requirements would apply. Black & Veatch notes that this proposed rule-making is considered particularly vulnerable to legal challenges. Therefore, an evaluation of the potential applicability of NSR to each of the BSER options examined in this report may be prudent in order to provide Vectren a full picture of the costs project timeline associated with the various options. Additionally, EPA has noted in the final rule, that costs associated with permitting NSR applicable projects can be included in the economic evaluation of the various ACE technologies.

2.0 Existing Plant Characteristics

This section briefly describes the baseline characteristics of each unit. The average and summary annual performance data for each unit that were used to calculate the potential heat rate benefits of applicable technologies can be found in Section 4.0.

A.B. Brown Units 1 and 2 are "sister units" in that they share many common characteristics. Each unit is a nominal 265-megawatt (MW) gross and 245 MW net unit, featuring a subcritical pulverized coal furnace with reheat steam and designed for bituminous coal from the Illinois Basin. A.B. Brown Unit 1 was commissioned in 1979, and A.B. Brown Unit 2 in 1986. Each unit employs low-nitrogen oxide (NO_X) burners and a selective catalytic reduction system (SCR) for NO_X control, and a scrubber for sulfur dioxide (SO_2) control. Unit 1 uses a pulse-jet fabric filter baghouse, and Unit 2 uses a cold-side electrostatic precipitator for particulate removal. Heat rejection is provided by mechanical draft cooling towers.

F.B. Culley Unit 2 is a nominal 100 MW gross and 90 MW net unit, featuring a non-reheat subcritical pulverized coal furnace designed for bituminous coal from the Illinois Basin. F.B. Culley Unit 2 was commissioned in 1966. The unit employs low-NO_X burners for NO_X control and a scrubber for SO_2 control. The unit uses a cold-side electrostatic precipitator for particulate removal. Cooling water is provided by the Ohio River.

F.B. Culley Unit 3 is a nominal 287 MW gross and 270 MW net unit, featuring a subcritical pulverized coal furnace with reheat steam and designed for bituminous coal from the Illinois Basin. F.B. Culley Unit 3 was commissioned in 1973. The unit employs low-NO_X burners and an SCR system for NO_X control and a scrubber for SO_2 control. The unit uses a pulse-jet fabric filter (PJFF) baghouse for particulate removal. Cooling water is provided by the Ohio River.

3.1 Description of Heat Rate Improvement Alternatives

This preliminary heat rate project screening was based on a high-level analysis of A.B. Brown Unit 1 and on Black & Veatch's experience with similar projects. The projects depicted herein were selected from HRI projects detailed by the EPA in its ACE rule as BSER projects. A detailed table summarizing the benefits and costs is included in Appendix B.

3.2 UNIT STEAM TURBINE BLADE PATH UPGRADES

Black & Veatch reviewed the steam turbine blade path upgrade option for each of the existing plants. The specific steam turbine upgrades are described for each individual plant in the following subsections.

3.2.1 A.B. Brown Unit 1 Steam Turbine Blade Path Upgrades

Black & Veatch reviewed steam turbine blade path upgrade. The A.B. Brown Unit 1 steam turbine had a full dense pack upgrade installed in 2012. In 2016, extensive high-pressure/ intermediate-pressure (HP/IP) repairs were made because of a main stop valve bypass failure. Black & Veatch estimates that there would not be any significant improvement with a steam turbine upgrade now, considering the relatively shorter duration since the last steam path upgrade and the potential cost associated with it.

3.2.2 A.B. Brown Unit 2 Steam Turbine Blade Path Upgrades

Black & Veatch reviewed the steam turbine blade path upgrade. The A.B. Brown Unit 2 steam turbine had a full dense pack upgrade installed in 2013. Black & Veatch estimates that there would not be any significant improvement with a steam turbine upgrade now, considering the relatively shorter duration since the last steam path upgrade and the potential cost associated with it.

3.2.3 F.B. Culley Unit 2 Steam Turbine Blade Path Upgrades

The Culley Unit 2 steam turbine is a GE non-reheat steam turbine with a two-flow low-pressure turbine with 20 inch last stage blades. Black & Veatch performed a review of the steam turbine blade path upgrade. As a result of this investigation, two heat balance model of the Culley Unit 2 steam turbine were developed:

- Base: Best match of the Culley Unit 2 Thermal Kit heat balance 328 HB 706 rating flow (guarantee) +5%. (Valve-Wide-Open, Normal Pressure (VWO-NP) case).
- Upgrade Scenario: The entire steam path HP/LP (High-Pressure and Low-Pressure turbines) are upgraded.

This analysis is based on the incremental improvement in steam turbine efficiency, and the differential performance is more important than the absolute performance. The performance improvements and pricing estimates are based on in house data and past project experience. However, steam turbine manufacturers should be contacted to confirm performance and pricing.

3.1.3.1 Base Case

The Base case model is matched to the original thermal kit heat balance 328 HB 706, which is the rating flow (guarantee) +5%. The condenser pressure was set to 1.5 in HgA to keep the basis consistent across the models for comparison against various upgrade options. This Base model was then used to run four cases: Rating flow + 5%, guarantee load (rated pressure and rated flow, corresponding to thermal kit heat balance 332 HB 827), 80% of guarantee load (rated pressure and reduced flow, corresponding to thermal kit heat balance 332 HB 829), and 60% of guarantee load (rated pressure and reduced flow, corresponding to thermal kit heat balance 332 HB 831).

3.1.3.2 Upgrade Scenario: HP/LP Steam Path Upgrades

In this model, the HP and LP sectional efficiencies were increased from approximately 86.9% and 69.9%, to approximately 87.9% and 71.9% respectively. The advanced age of the Culley Unit 2 steam turbine makes it difficult to estimate exactly how much efficiency could be gained in each section and further analysis should be completed by a steam turbine manufacturer. This model was then used to run four cases: Rating flow + 5%, guarantee load, 80% of guarantee load, and 60% of guarantee load. In each of the cases the boiler steam generation was reduced such that the steam turbine power output matches the value found in the corresponding cases in the original design (STG OEM Thermal Kit).

Tables 3-1 through 3-4 show the results of the turbine modeling conducted by Black & Veatch for this study. For comparison purposes, it was assumed that a boiler efficiency of 88.3% (HHV basis) applies regardless of the magnitude and type of boiler upgrades that may be required. This boiler efficiency is provided by the Vectren data in the Culley Unit 3 snapshot data and was assumed to be the same for Culley Unit 2 for the purposes of this modeling to allow for a comparison between the units.

Table 3-1 Culley Unit 2 Steam Turbine Modeling Results – Rating Flow +5%

		ORIGINAL HEAT BALANCE	UPGRADE HP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	99,765	99,766
Gross Turbine Heat Rate	Btu/kWh	9,012	8,881
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-131
Turbine Heat Rate Improvement	%	N/A	1.5%
Boiler Heat Input (HHV)	MBtu/h	1,018.4	1,003.6
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-14.8
Boiler Heat Input (HHV) Improvement	%	N/A	1.5%
Gross Plant Heat Rate (HHV)	Btu/kWh	10,208	10,060
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-136
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.5%
*See the explanation above regarding the choice of the boiler efficiency value.			

Table 3-2 Culley Unit 2 Steam Turbine Modeling Results – Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	95,500	95,501
Gross Turbine Heat Rate	Btu/kWh	9,002	8,870
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-131
Turbine Heat Rate Improvement	%	N/A	1.5%
Boiler Heat Input (HHV)	MBtu/h	973.8	959.6
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-14.2
Boiler Heat Input (HHV) Improvement	%	N/A	1.5%
Gross Plant Heat Rate (HHV)	Btu/kWh	10,197	10,048
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-136
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.5%
* See the explanation above regarding the choice of the boiler efficiency value.			

Table 3-3 Culley Unit 2 Steam Turbine Modeling Results – 80% of Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	76,239	76,239
Gross Turbine Heat Rate	Btu/kWh	8,977	8,856
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-121
Turbine Heat Rate Improvement	%	N/A	1.4%
Boiler Heat Input (HHV)	MBtu/h	775.3	764.8
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-10.5
Boiler Heat Input (HHV) Improvement	%	N/A	1.4%
Gross Plant Heat Rate (HHV)	Btu/kWh	10,169	10,032
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-138
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.4%
* See the explanation above regarding the choice of the boiler efficiency value.			

Table 3-4 Culley Unit 2 Steam Turbine Modeling Results – 60% of Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
Gross STG Gross Output	kW	56,672	56,672
Gross Turbine Heat Rate	Btu/kWh	9,133	9,020
Turbine Heat Rate Change	Btu/kWh	N/A	-113
Turbine Heat Rate Improvement	%	N/A	1.2%
Boiler Heat Input (HHV)	MBtu/h	586.3	579.0
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-7.3
Boiler Heat Input (HHV) Improvement	%	N/A	1.2%
Gross Plant Heat Rate (HHV)	Btu/kWh	10,346	10,217
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-129
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.2%
* See the explanation above regarding the choice of the boiler efficiency value.			

The estimate capital cost and HRI for the turbine upgrade option is as follows:

Full Steam Path Upgrade

Total Installed Capital Cost:	$10.4 million
Heat Rate (efficiency) Improvement:	1.3-1.5%

3.1.4 F.B. Culley Unit 3 Steam Turbine Blade Path Upgrades

The F.B. Culley Unit 3 steam turbine is a GE reheat steam turbine with a two-flow LP turbine and 26-inch last stage blade length for the LP end. Black & Veatch reviewed the steam turbine blade path upgrade. As a result of this investigation, heat balance cases were developed for the F.B. Culley Unit 3 steam turbine:[2]

- Base Case: Best match of the F.B. Culley Unit 3 thermal kit heat balance 534 HB 894 (guarantee).
- Upgrade Scenario: The entire HP/IP/LP steam path is upgraded.

This analysis is based on the incremental improvement in steam turbine efficiency, and the differential performance is more important than the absolute performance. The performance improvements and pricing estimates are based on in-house data and past project experience and are believed to be achievable. However, steam turbine manufacturers should be contacted to confirm performance and pricing.

3.1.4.1 Base Case

The Base Case model is matched to the thermal kit heat balance 534 HB 894, which is the guarantee case. The condenser pressure was set to 3.5 in. HgA to keep the basis consistent across the models for comparison against various upgrade options. This Base Case model was then used to run three cases: Guarantee load (rated pressure and rated flow, corresponding to thermal kit heat balance 534 HB 894); 80 percent of guarantee load (rated pressure and reduced flow, corresponding to thermal kit heat balance 170X450-21); and 60 percent of guarantee load (rated pressure and reduced flow, corresponding to thermal kit heat balance 170X450-22).

3.1.4.2 Upgrade Scenario: HP/IP/LP Steam Path Upgrades

In this model, the HP, IP, and LP sectional efficiencies were increased from approximately 86.7 percent, 88.2 percent, and 89.3 percent to approximately 90 percent, 90 percent, and 92 percent, respectively[3]. This model was then used to run three cases: Guarantee load; 80 percent of guarantee load; and 60 percent of guarantee load. In each of the cases, the boiler steam generation was reduced so that the steam turbine power output matched the values found in the corresponding cases in the original design (STG OEM thermal kit).

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[2] Additional cases could be evaluated which look at the difference between current performance if the blades and turbine are newly overhauled, versus a new upgrade. Another possibility is developing a map of turbine performance over an expected life between major turbine outages and maintenance activities. Those require more detailed studies which mandate input from the STG OEM with a reference upgrade design, which is beyond the scope of this EPA-ACE analysis.

[3] Based upon OEM data.

Tables 3-5 through 3-7 show the results of the turbine modeling conducted by Black & Veatch for this study. For comparison purposes, it was assumed that a boiler efficiency of 88.3 percent (HHV basis) applies regardless of the magnitude and type of boiler upgrades that may be required.

Table 3-5 F.B. Culley Unit 3 Steam Turbine Modeling Results – Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/IP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	288,360	288,367
Gross Turbine Heat Rate	Btu/kWh	8,219	8,085
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-134
Turbine Heat Rate Improvement	%	N/A	1.6%
Boiler Heat Input (HHV)	MBtu/h	2,684.7	2,640.9
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-43.8
Boiler Heat Input (HHV) Improvement	%	N/A	1.6%
Gross Plant Heat Rate (HHV)	Btu/kWh	9,310	9,158
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-152
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.6%
*This boiler efficiency takes its basis from the F.B. Culley Unit 3 data snapshot, collected on May 27, 2019.			

Table 3-6 F.B. Culley Unit 3 Steam Turbine Modeling Results – 80% of Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/IP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	236,806	236,817
Gross Turbine Heat Rate	Btu/kWh	8,254	8,129
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-125
Turbine Heat Rate Improvement	%	N/A	1.5%
Boiler Heat Input (HHV)	MBtu/h	2,214.1	2,180.7
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-33.4
Boiler Heat Input (HHV) Improvement	%	N/A	1.5%
Gross Plant Heat Rate (HHV)	Btu/kWh	9,350	9,208
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-142
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.5%
*This boiler efficiency takes its basis from the F.B. Culley Unit 3 data snapshot, collected on May 27, 2019.			

Table 3-7 F.B. Culley Unit 3 Steam Turbine Modeling Results – 60% of Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/IP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	178,684	178,683
Gross Turbine Heat Rate	Btu/kWh	8,451	8,333
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-118
Turbine Heat Rate Improvement	%	N/A	1.4%
Boiler Heat Input (HHV)	MBtu/h	1,710.6	1,686.7
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-23.9
Boiler Heat Input (HHV) Improvement	%	N/A	1.4%
Gross Plant Heat Rate (HHV)	Btu/kWh	9,573	9,440
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-134
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.4%
*This boiler efficiency takes its basis from the F.B. Culley Unit 3 data snapshot, collected on May 27, 2019.			

The estimate capital cost and HRI for the turbine upgrade options is as follows:

Full Steam Path Upgrade

Total Installed capital cost: $19.9 million

Heat Rate (efficiency) improvement: 1.4-1.6%

3.2 UNIT ECONOMIZER REDESIGN OR UPGRADES

3.2.1 Economizer Upgrades Under EPA ACE

One of the primary BSER under the EPA ACE is the prospect of upgrades to, or even complete replacement of, the economizer. The overarching goal in economizer upgrades or replacement is to improve heat transfer from the flue gas to add heat to the boiler water/steam circuit and, thus, improve boiler efficiency. According to the performance estimates included in the EPA ACE proposal, redesign or replacement of the economizer should yield a heat rate improvement from 0.5 percent to 0.9 percent for units under 200 MW, and from 0.5 percent to 1.1 percent for units ranging from 200 MW to 500 MW. The EPA specifically states that economizer replacements are often avoided because of concerns over triggering New Source Review (NSR); for this reason, the EPA ACE is intended to provide power plants with the flexibility to make these changes.

However, there are many risks associated with redesign or replacement of the economizer:

- Most commonly, projects that consider increasing economizer tube surface area are ones which consider adding tube passes to either the upstream or the downstream portion of the economizer(s). This is because most economizers have a dense tube packing that disallows addition of tube assemblies across the furnace width. However, in the boiler backpass region, space constraints often limit the ability to add more than 2 or 3 tube passes. Thus, making significant changes to the economizer may not be possible at many units.
- Even the addition of a single pass of tubes requires an extended boiler outage; significant construction preparation and welding/tie-in work are required to add tubes to the economizer. The replacement power cost and lost opportunity/contract cost of this outage can be significant if it is not combined with a previously planned outage (such as, for steam turbine upgrades).
- Replacement of entire economizers is not generally done within the industry because of the large expense involved. When it has been undertaken in recent years, the most common reasons are either to replace a badly eroded economizer, or to replace an economizer with spiral-finned tubes with one with bare tubes to reduce tube fouling (especially after conversions to Powder River Basin coals).
- Changing tube surface area will often change the balance of heat transfer between the radiative and connective sections, as well as the main steam and reheat steam circuitry. This is especially true in the case of units that employ a split backpass design with gas biasing reheat control. Prediction of the complex interactions between the water, main steam, and reheat steam circuits in both the radiative and convective sections typically requires detailed boiler modeling.
- Adding tube surface to an economizer will reduce the flue gas temperature exiting the economizer, which could reduce operations flexibility if an SCR is positioned downstream of the economizer. Reduced flue gas temperatures will increase the minimum load possible with the SCR in service and could require a system such as an economizer gas bypass or in-duct burners to allow for SCR operation with these reduced temperatures. Both of these reparative measures will worsen the plant heat rate, thus negating the benefit of the upgraded economizer.
- Reduced flue gas temperatures entering the air heater will help improve the overall boiler efficiency but can also lead to operations problems should the cold-end average temperature be reduced below the recommended point for the type of fuel that is being burned and its sulfur content. In addition, ammonium bisulfate deposition can be increased in some cases where the flue gas inlet temperature at the air heaters is reduced from normal.
- In some cases, flue gas temperatures could be reduced to the point where other downstream air quality control equipment (such as an electrostatic precipitator or fabric filter baghouse) could be at risk for corrosion damage.

- While it is possible to add an economizer downstream of the SCR system to reduce the impact on the flue gas temperature entering the SCR, such installations are unusual and often require variable water bypass circuitry to maintain good temperature control.

Assessment of the ability of a unit to accommodate changes in the economizer tube surface area typically requires plant modeling of some sort, whether utilizing a combined first-principles and empirical model (such as the Electric Power Research Institute's [EPRI's] Vista program), or even a highly detailed (and expensive) computation fluid dynamics model of the entire boiler circuit and downstream affected equipment. The following section is a high-level overview of economizer upgrades, while the further sections provide more detail through the use of Vista modelling software.

Cost estimation for economizer upgrades is highly variable and depends on the amount of work conducted, the site spacing and access, other boiler or plant modifications that are required, etc. The EPA ACE rule advises in Table 2 that the cost to redesign or replace an economizer can be up to $3.74 million for a 200 MW unit or up to $6.35 million for a 500 MW unit.

3.2.2 A.B. Brown Units 1 and 2 Economizer Redesign or Upgrades

Plant personnel report that because of low SCR inlet temperatures, A.B. Brown Units 1 and 2 require natural gas duct burners to be operated to maintain temperatures over the minimum SCR inlet temperature of 625° F. An example of the gas duct burner operation as a function of gross output is shown for Unit 1 on Figure 3-1.

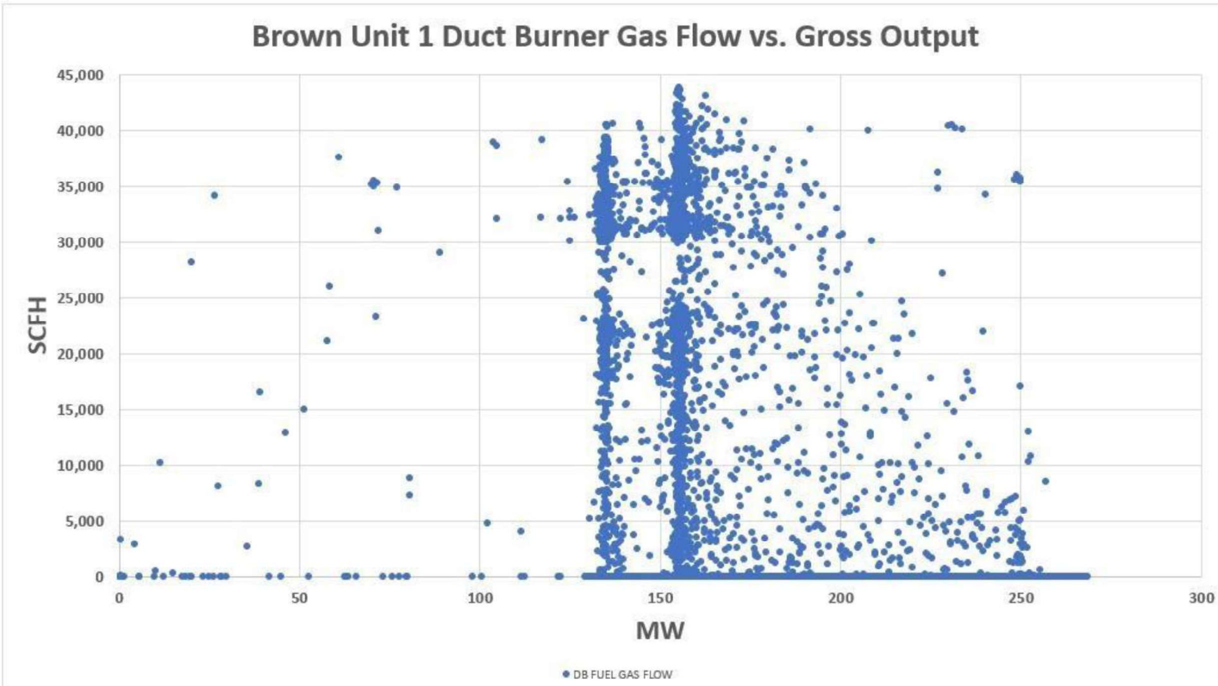


Figure 3-1 A.B. Brown Unit 1 Economizer Gas Flow vs. Gas Outlet

Plant personnel stated that the high gas use of the duct burners is a concern from a heat rate standpoint, although, unlike the case of F.B. Culley Unit 3, there was no estimate on the overall annual heat rate impact. Given this situation at A.B. Brown Units 1 and 2, adding economizer tube surface area is not recommended at this time. It is possible that reducing the economizer tube surface area could improve the plant heat rate by reducing the natural gas usage, and a next-phase study could easily determine this by employing coordinated plant modeling with a boiler-SCR-air heater model across the typical operating load ranges of the units.

3.2.3 F.B. Culley Unit 2 Economizer Redesign or Upgrades

F.B. Culley Unit 2 has maintained its original economizer design, and as it does not have an SCR system, it does not suffer from the constraint of reduced flue gas temperatures limiting operation. As a result, it is possible that economizer modifications could result in a significant heat rate benefit to the unit, especially as the F.B. Culley Unit 2 economizer gas outlet temperature appears to be high at higher loads (over 700° F at times). Refer to Figure 3-2.

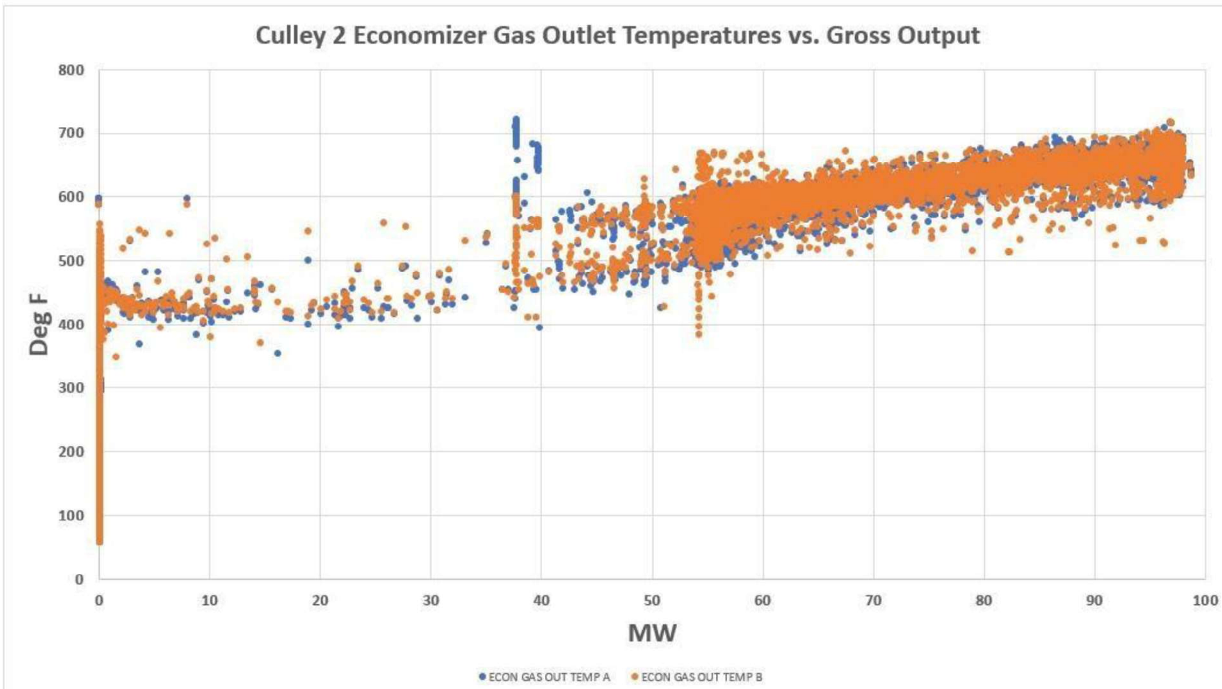


Figure 3-2 F.B. Culley Unit 2 Economizer Gas Outlet Temperature Versus Gross Output

The estimated costs and logistics of such a change to the economizers requires significant investigation as a next-phase effort. Assuming no header relocation is needed, and neglecting the loss of contract availability, such a cost is estimated at about $40,000 to 50,000 per British thermal unit per kilowatt-hour (Btu/kWh) for the improvement, or between $2 million to $4 million. For a small, non-reheat unit such as F.B. Culley Unit 2, such an investment may not be warranted at this juncture unless the unit was expected to operate for a significant length of time so that a sufficient payback period could be realized. When the expected future load factor and remaining plant life are taken into account, it is nearly impossible to justify an investment in this area of the plant.

3.2.4 F.B. Culley Unit 3 Economizer Redesign or Upgrades

According to plant personnel, the F.B. Culley Unit 3 economizer was replaced in 1994 with a tube configuration that had additional tube surface area relative to the original design. The goal of this upgrade was to reduce flue gas exit temperatures and improve cycle efficiency, and in that respect, it was successful. However, when the SCR system was added in 2003, the lower flue gas temperatures exiting the economizer resulted in the need for natural gas duct burners to maintain the minimum SCR flue gas inlet temperature of 625° F. The economizer was replaced again in 2008 but was not changed to the original design because of concerns about triggering NSR. Refer to Figure 3-3.

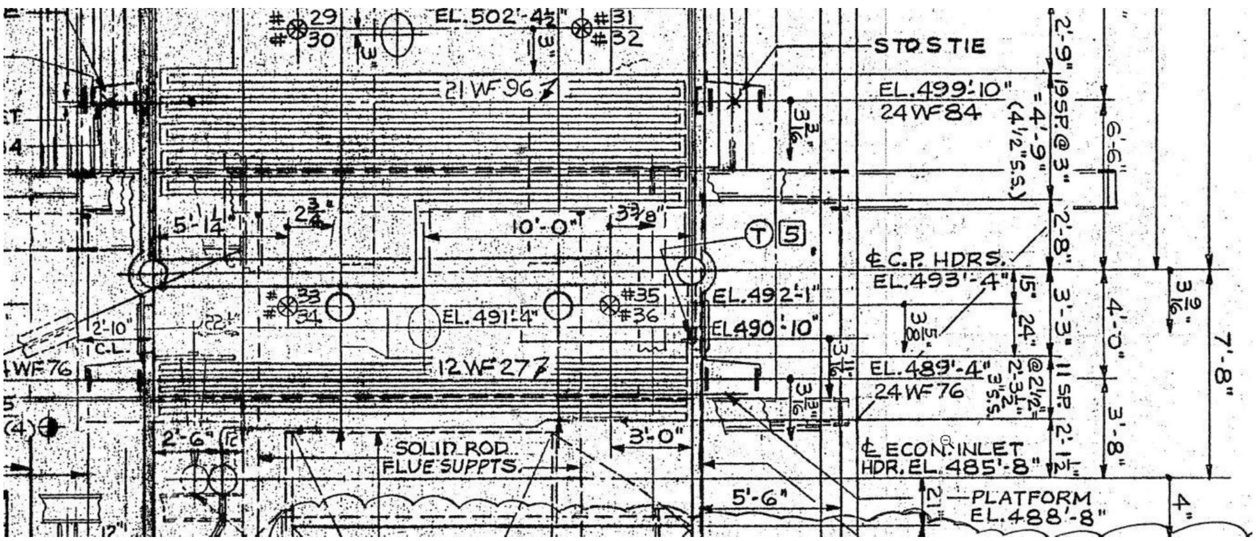


Figure 3-3 F.B. Culley Unit 3 Original Economizer Design

F.B. Culley Unit 3 is required to utilize significant amounts of natural gas via in-duct burners upstream of the SCR system to maintain SCR operating temperatures at anything less than 75 to 80 percent of full load. A plot of operational data, comparing the natural gas burner fuel flow rate versus the unit gross output, is shown by Figure 3-4.

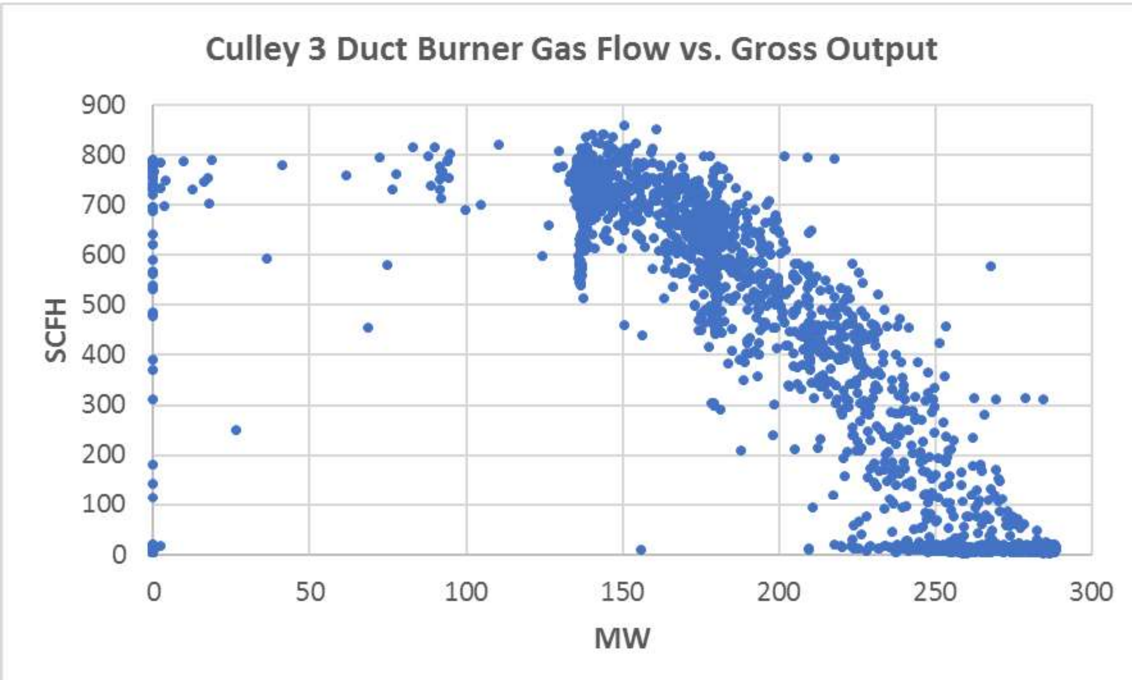


Figure 3-4 F.B. Culley Unit 3 Duct Burner Gas Flow Versus Gross Output

Given this situation at F.B. Culley Unit 3, adding economizer tube surface area is not recommended at this time. It is possible that reducing the economizer tube surface area could improve the plant heat rate by reducing the natural gas usage, and a next-phase study could easily determine this by employing coordinated plant modeling with a boiler-SCR-air heater model across the typical operating load ranges of the units. Plant personnel report that natural gas heat input to the duct burners comprised nearly 2 percent of the total heat input to the unit for 2018 and 2019 to date.

3.2.5 Economizer Analysis using Vista

Based on the analysis and discussion in the above sections, an analysis of the benefit of reducing natural gas flow to the duct burners by reducing the size of the economizer section was performed for A.B. Brown 1 and F.B. Culley 3. To assess the economizer, Black &Veatch created a base case and then investigated three options: removing 1, 2, and 3 tube passes.

Using data provided by Vectren engineering personnel, an EPRI Vista fuel quality impact model was created for A.B. Brown 1 and F.B. Culley 3. The Vista program contains a detailed linear heat transfer model that has the power to conduct “what if” analyses upon tube banks surface area configurations, and this model was utilized successfully for this study. Several simulations of tube configurations that would decrease the heat transfer area of the economizer were analyzed, and these are detailed in this section. A schematic of the current economizer for A.B. Brown 1 is depicted below (F.B. Culley 3 is depicted in Figure 3-3):

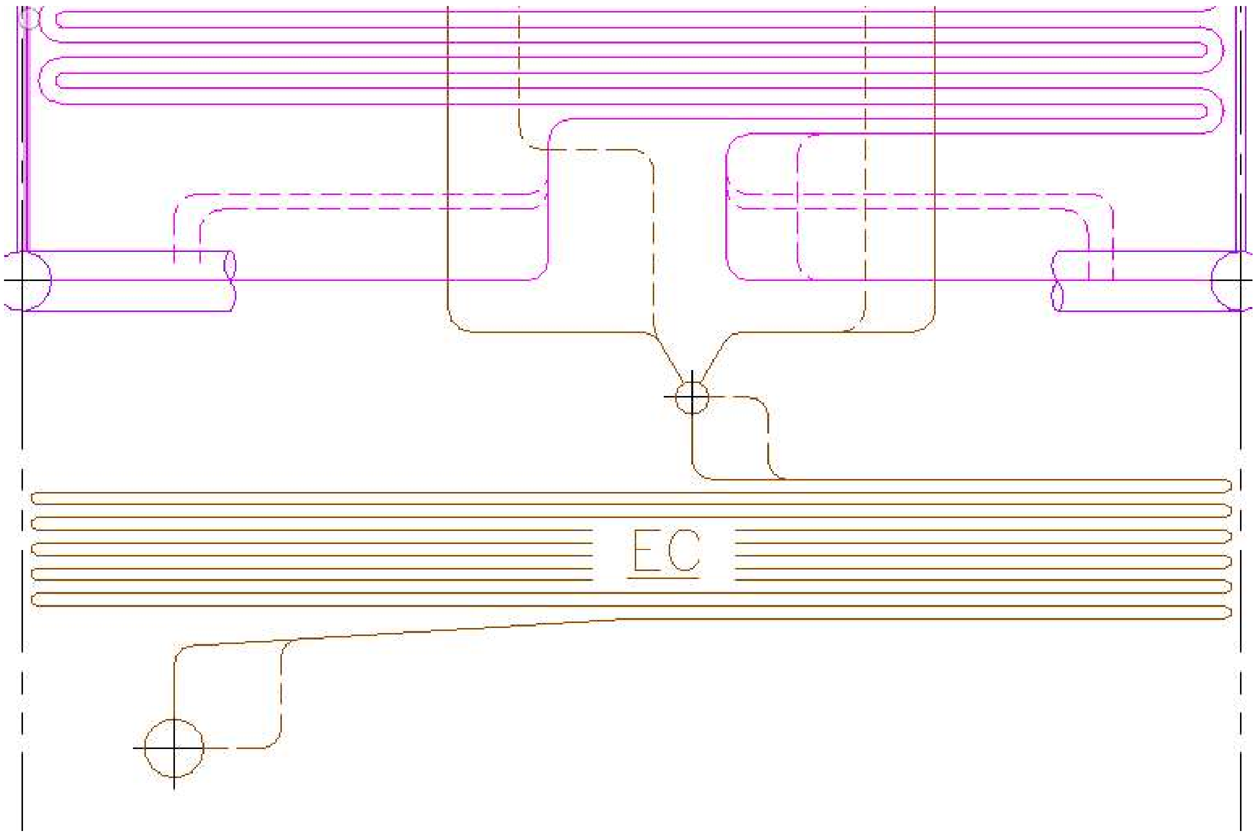


Figure 3-5 A.B. Brown 1 Economizer

3.2.5.1 A.B. Brown Units 1 and 2 Economizer Analysis Results

After calibrating the Vista model of A.B. Brown 1 to 264 MW gross from data collected on August 9, 2018, the following scenarios were run, with the following results.

- Baseline case – SCR inlet temperature = 651 °F.
- Removing 1 pass to the lower economizer – SCR inlet temperature = 662 °F.
- Removing 2 pass to the lower economizer – SCR inlet temperature = 675 °F.
- Removing 3 passes to the lower economizer – SCR inlet temperature = 690 °F.

The results above were from running the model at full load. The graph below shows the unit load vs. the duct burner natural gas flow.

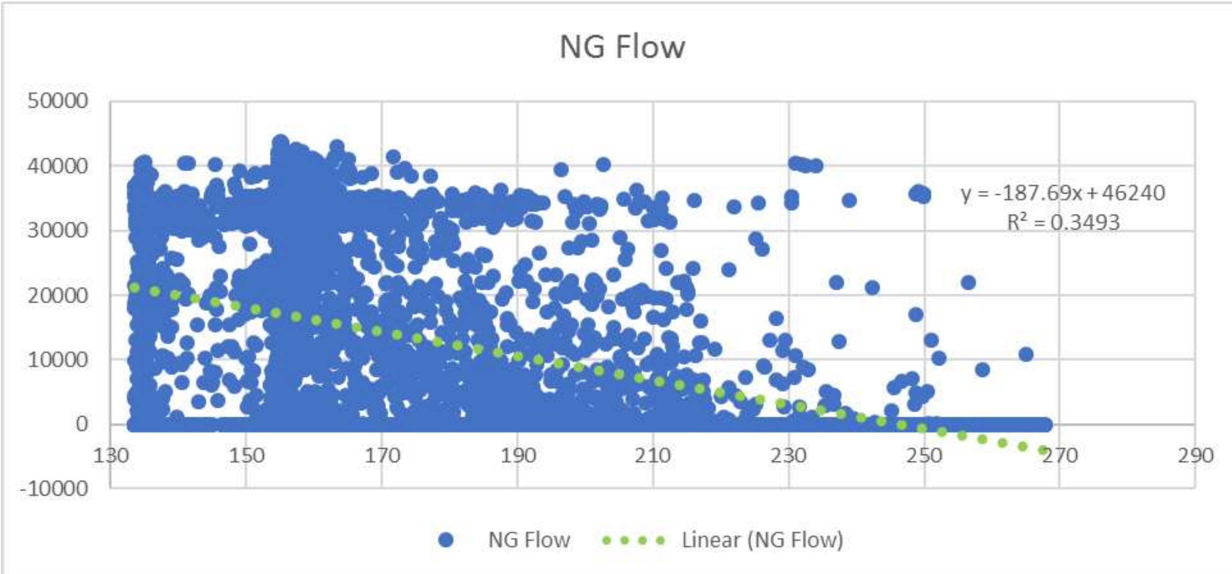


Figure 3-6 Load vs. Temperature and Flow

Linear regression was used to determine the natural gas flow; however, the correlation between natural gas flow and load was poor (R^2 of 0.35). This may warrant further investigation into the measurement or control methodology of the natural gas flow for the duct burners. Also, A.B. Brown 1 does not have an online measurement for the economizer flue gas outlet temperature. If this temperature was measured and tracked in the data historian, it would significantly improve the analysis of the data.

This reduction in economizer surface area comes at a cost in heat rate. From the analysis a reduction in the economizer surface area produces the following heat rate impacts on an overall basis:

- Baseline case – 0% difference.
- Removing 1 pass to the lower economizer – 0.17 % worsening.
- Removing 2 passes to the lower economizer – 0.36 % worsening.
- Removing 3 passes to the lower economizer – 0.61 % worsening.

This heat rate impact had the following effects on fuel burn rate at full load:

- Removing 1 pass to the lower economizer – 4.23 MMBtu/hr increase.
- Removing 2 passes to the lower economizer – 8.91 MMBtu/hr increase.
- Removing 3 passes to the lower economizer – 15.06 MMBtu/hr increase.

Should a change be made to the economizer tube surface area, the estimated costs and logistics of such a change to the economizers, assuming no header relocation is needed and neglecting the loss of contract availability, are expected to range from $750,000 to $1,400,000 depending upon the amount of modification. Complete replacement of the economizer was not estimated during this effort, nor was any addition to hot reheat surface or any other modifications.

3.2.5.2 F.B. Culley Unit 3 Economizer Analysis Results

After calibrating the Vista model of F.B. Culley 3 to 286 MW gross from data collected on May 27, 2019, the following scenarios were run, with the following results.

- Baseline case – SCR inlet temperature = 649 °F.
- Removing 1 pass to the lower economizer – SCR inlet temperature = 656 °F.
- Removing 2 pass to the lower economizer – SCR inlet temperature = 663 °F.
- Removing 3 passes to the lower economizer – SCR inlet temperature = 670 °F.

The results above were from running the model at full load. The graph below shows unit load vs. SCR inlet temperature, economizer gas outlet temperature, and duct burner natural gas flow. The delta-temperature below the minimum acceptable SCR inlet temperature of 625 °F was also plotted.

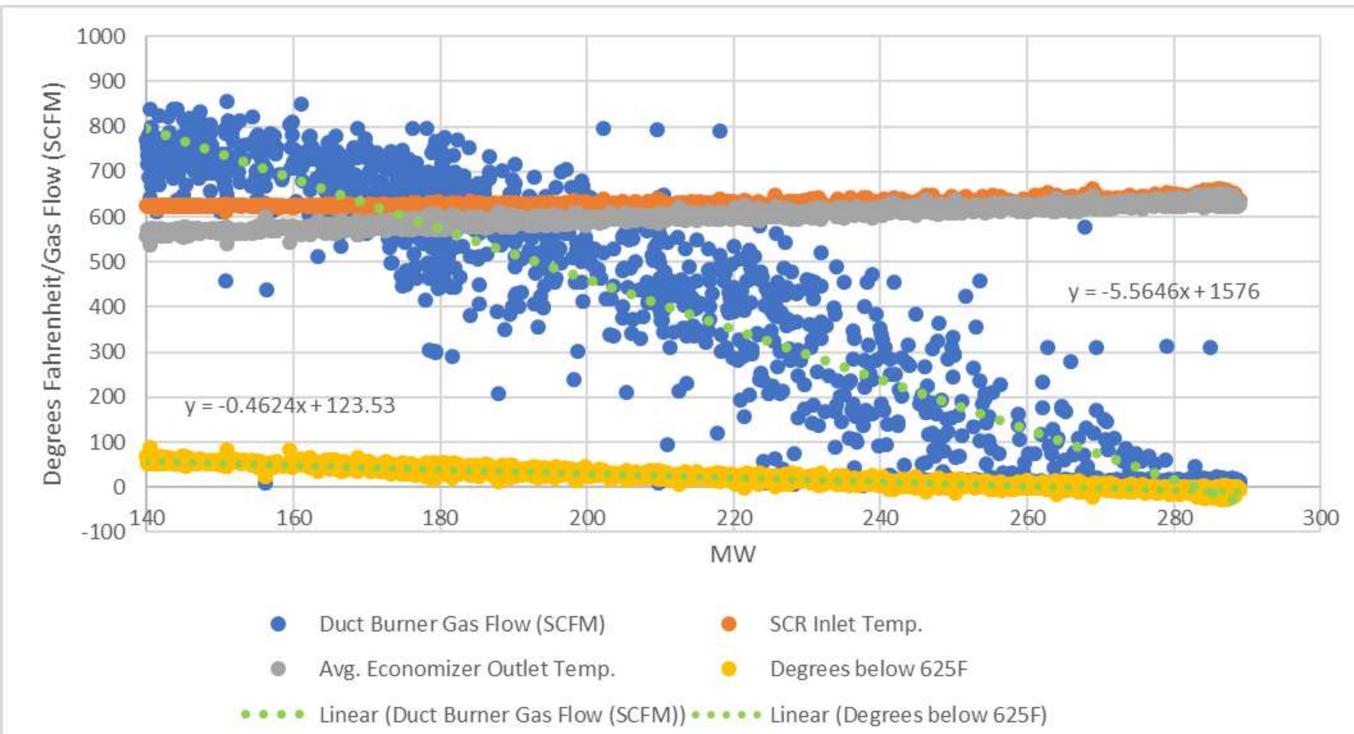


Figure 3-7 Load vs. Temperature and Flow

Using linear regression, the temperature difference calculated from Vista was used to determine new loads without using the duct burner and the gas flow savings for each economizer pass reduction"

- Removing 1 pass to the lower economizer – New load without duct burner use - 252MW, Gas Flow savings - 174 SCFM (10.6 MMBtu).

- Removing 2 passes to the lower economizer – New load without duct burner use- 237MW, Gas Flow savings - 257 SCFM (15.7 MMBtu).
- Removing 3 passes to the lower economizer – New load without duct burner use- 222MW, Gas Flow savings - 341 SCFM, (20.8 MMBtu).

This reduction does come at a cost in heat rate. From the analysis a reduction in the economizer surface area produces the following heat rate impacts on an overall basis:

- Baseline case – 0% difference.
- Removing 1 pass to the lower economizer - 0.14% worsening.
- Removing 2 passes to the lower economizer – 0.28% worsening.
- Removing 3 passes to the lower economizer – 0.43% worsening.

This heat rate impact had the following effects on fuel burn rate at full load:

- Removing 1 pass to the lower economizer – 3.22 MMBtu/hr increase.
- Removing 2 passes to the lower economizer – 6.6 MMBtu/hr increase.
- Removing 3 passes to the lower economizer – 10.16 MMBtu/hr increase.

From examining the results listed above, removing a portion of the economizer would results in an energy savings. Given the cost differential of $3.00 per MMBtu for natural gas compared to Vectren's $2.22 per MMBtu for coal, the savings in natural gas flow at full load would be approximately $5.76 per hour for the 1 pass case and $8.30 per hour for the 3-pass case. Assuming that savings would be realized over 70% of the year (8760 hours). This would result in $151k in savings for the first year for the base case and $244k in savings for the first year for the alternate case.

Should a change be made to the economizer tube surface area, the estimated costs and logistics of such a change to the economizers, assuming no header relocation is needed and neglecting the loss of contract availability are expected to range from $750,000 to $1,400,000 depending upon the amount of modification. Complete replacement of the economizer was not estimated during this effort, nor was any addition to hot reheat surface or any other modifications.

3.3 AIR HEATER AND LEAKAGE CONTROL UPGRADES

A core opportunity for net plant heat rate (NPHR) improvement is solidifying the operational reliability and process integrity of the combustion air draft system and flue gas draft system. The gas-to-air regenerative air heaters are a critical nexus between these two subsystems. Similarly, balanced draft units are susceptible to the effects of air in-leakage in the flue gas draft system because of the negative (internal) operating pressure of the flue gas ductwork. The following sections outline the NPHR improvement initiatives targeting the existing regenerative air heaters and mitigating the detrimental effects of flue gas draft system duct air in-leakage. The A.B.

Brown Unit 1, A.B. Brown Unit 2, F.B. Culley Unit 2, and F.B. Culley Unit 3 considerations are addressed in the following sections.

3.3.1 A.B. Brown Unit 1 Air Heater and Leakage Control Upgrades

The main NPHR benefit of air heater and flue gas ductwork leakage control repairs/upgrades is due to reducing the duty of the unit's combustion air and flue gas induced draft fans, thus reducing the unit's overall auxiliary load.

Excessive air heater and flue gas duct leakage presents additional issues beyond degradation in NPHR, however. Air in-leakage can also result in tempering of flue gas and causing corrosive flue gas acid gasses to condense on air heater cold end baskets and ductwork components. Reduction in air heater and flue gas duct leakage can improve overall equipment life, reduce capital investment for repair and reduce operation and maintenance (O&M) costs caused by flue gas acid gas corrosion. Additionally, the following are some other characteristics of air in-leakage that can negatively impact draft system and air quality control equipment performance:

- Higher velocities from additional mass flow, potentially reducing the life expectancy of pulse jet fabric filter (PJFF) bags.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak of cold combustion air mixing with hot flue gas out of air heater), causing flue gas to be closer to acid dew point and increasing the potential for equipment corrosion throughout the flue gas draft system.

The following subsections provide further discussion of air heater and leakage control upgrades. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of HRI projects. The typical information and results provided for such projects can be used to assess and further screen the potential benefits. Future efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

3.3.1.1 Air Heater

As previously noted, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas induced draft fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reduce the temperature of the flue gas, and increase the mass and volumetric flow of the flue gas, which results in a higher flue gas-induced draft fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The two air heaters of A.B. Brown Unit 1 are regenerative Ljungström type air heaters with rotating baskets. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals that are misaligned or out of adjustment will result in increased air heater leakage rates. The A.B. Brown Unit 1 air heaters are regularly inspected by the OEM, including an assessment of the air heater seals and replacement if required during all planned outages. Prior to the SCR installation, the original design air leakage for the A.B. Brown Unit 1 air heaters was approximately 7 percent to 8 percent. The installation of the SCR units has resulted in a corresponding increase of the full load air-to-gas side differential pressure by several inches of water column (when combustion air and flue gas pressures are compared). Additionally, the hot end sector plates have been replaced for A.B. Brown Unit 1, and the OEM recommendation is to replace the cold-end sectors plates. Air heater leakage is closely monitored for A.B. Brown Unit 1 because of the detrimental effect of oxygen on the dual alkali scrubbers within the air quality control system (AQCS).

According to feedback from Vectren operations personnel, positive contact seals have been attempted for the A.B. Brown Unit 1 air heaters in the past but were removed from service because of failures during operation. The air heaters now utilize the original seal types. More frequent in situ monitoring or installation of permanent probes measuring flue gas oxygen content at the induced draft (ID) fan inlet would allow for more accurate trending of the air in-leakage over time. This information would assist with planned outage maintenance and would provide ancillary benefits such as reducing ID fan power consumption and improved heat rate due to dry gas loss reduction.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial because the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule, for every 40° F decrease in air heater gas outlet temperature, a 1.0 percent increase in boiler efficiency can be expected. The reduction in leakage previously discussed is expected to increase the measured average air heater gas outlet temperature. This increase would not be expected to negatively impact boiler efficiency as the air heater no-leak gas outlet temperature would remain the same. Black & Veatch expects that air heater upgrades that could lower the no-leak temperature by 20° F are attainable without an in-depth analysis of the air preheat system and acid gas dew points. This would increase boiler efficiency by about 0.5 percent.

However, if additional efficiency gains are desired, additional analyses of the air preheat system and acid gas dew points with the air heater performance would be required to ensure the average gas temperature does not encroach upon the acid gas dew point at all loads. It is expected that the air heater gas outlet temperature could be lowered by another 10 to 15° F, improving boiler efficiency by another 0.25 percent. To achieve this, upgrades to the air preheat system and air-side and/or gas-side air heater bypasses would likely be required to maintain air heater gas outlet temperatures above the acid dew point at lower loads and during colder times of the year.

It should be noted that internal air heater condition should also be assessed to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR.

An additional area of opportunity for NPHR improvement related to the A.B. Brown Unit 1 air heaters is the potential reduction of the air heater cold-end setpoint temperature for A.B. Brown Unit 1.

According to unit operating data provided by Vectren, A.B. Brown Unit 1 maintains a consistent air heater cold-end temperature near 325 to 330° F (measured at the ID fan inlet for A.B. Brown Unit 1). This temperature target is considered above the recommended setpoint, given the potential acid gas dew point temperature, which is likely below 300° F. The gradual reduction of the air heater cold-end setpoint (e.g., reduction by 5 degrees every few months) would be a zero-cost (i.e., can be implemented via changes to setpoints within the existing control system) means of improving NPHR and not negatively impacting beneficial reuse of the fly ash. Changes to the condition of the draft system could be monitored during the regularly scheduled maintenance outages. While plant personnel report that generally speaking dew point temperatures have not been a problem at the unit, they nonetheless would be concerned about any significant reduction in air heater gas outlet temperature which takes the unit into an unfamiliar operating regime.

Air heater bypasses have been installed on the A.B. Brown Unit 1 draft system. This system provides a backup for the existing air preheating steam coil systems for cold-end temperature control for periods of extreme cold weather or a coil being taken out of service. Upgrades to the steam coil system would allow for fewer uses of the air heater (air-side) bypass during the year and fewer instances of the associated heat rate penalty during the intermittent use of the bypass.

3.3.1.2 Ductwork

The ductwork system can be divided between the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health.

The combustion air ductwork system operates at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakages will increase the duty of the combustion air fans and result in an increase in the combustion air fan auxiliary load, thus negatively impacting the unit's NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. For balanced draft units, the differential in flue gas ductwork internal pressure compared to ambient increases (i.e., becomes more negative) as the flue gas progresses from the furnace, through the draft system, and to the inlet of the ID fans. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans and result in an increase in the flue gas ID fan auxiliary load, thus negatively impacting the unit's NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion.

The ductwork inspection activities and the air heater upgrades discussed in the previous section would be expected to be incorporated during the regularly scheduled O&M outages. The A.B. Brown Unit 1 forecast for scheduled maintenance outages is outlined in Table 3-8.

Table 3-8 A.B. Brown Unit 1 O&M Scheduled Outage Intervals (2020-2039)

YEAR	A.B. BROWN UNIT 1 O&M - SCHEDULED OUTAGE
2020	--
2021	3 weeks
2022	Major
2023	--
2024	3 weeks
2025	3 weeks
2026	--
2027	3 weeks
2028	3 weeks
2029	--
2030	3 weeks
2031	Major
2032	--
2033	3 weeks
2034	3 weeks
2035	--
2036	3 weeks
2037	3 weeks
2038	--
2039	3 weeks

To determine the overall cost associated with improving the ductwork leakage rates, field examinations and tests must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator (or similar system) to locate and catalog the leaks would be required. Leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e., areas closer to the discharge of the combustion air forced draft/primary air [FD/PA]) fans or areas closer to the inlet of the flue gas induced draft fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

Draft system leakage testing data for A.B. Brown Unit 1 were not available for review or incorporation into this analysis. Therefore, Black & Veatch has not assessed any NPHR impacts regarding reducing flue gas draft system leakage other than that discussed for the air heaters. The following activities can be implemented to improve the existing air heater units and find draft system leakage points. With the availability of additional data, the following estimates could be further refined, and the following heat rate benefits would likely increase.

Air Heater Basket, Seal, and Sector Plate Replacement

Total Installed Capital Cost:	$850,000
Heat Rate (efficiency) Improvement:	0.5% (assumes 20 °F air heater gas outlet temperature improvement)

Air Preheater (Steam Coil) System Repairs

Total Installed Capital Cost:	$350,000
Heat Rate (efficiency) Improvement:	0.1% (applicable to intermittent periods when steam coils would be used)

3.3.2 A.B. Brown Unit 2 Air Heater and Leakage Control Upgrades

The main NPHR benefit of air heater and flue gas ductwork leakage control repairs/upgrades results from reducing the duty of the unit's combustion air and flue gas induced draft fans, thus reducing the unit's overall auxiliary load demand.

Excessive air heater and flue gas duct leakage presents additional issues beyond degradation in NPHR, however. Air in-leakage can also result in tempering of flue gas and causing corrosive flue gas acid gasses to condense on air heater cold end baskets and ductwork components, resulting in degradation of equipment materials. Reduction in air heater and flue gas duct leakage can improve overall equipment life, reduce capital investment for repair, and reduce O&M costs caused by flue gas acid gas corrosion. Additionally, the following are some other characteristics of air in-leakage that can negatively impact draft system and air quality control equipment performance:

- Higher velocities from additional mass flow reducing the ability of an electrostatic precipitator to capture ash.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak of cold combustion air mixing with hot flue gas out of air heater), causing flue gas to be

closer to acid dew point increasing the potential for equipment corrosion throughout flue gas draft system.

The following subsections provide further discussion of air heater and leakage control upgrades. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of heat rate improvement projects. The typical information and results provided for such projects can be used to assess and further screen the potential benefit. Future efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

3.3.2.1 Air Heater

As previously noted, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas ID fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reducing the temperature of the flue gas, and increasing the mass and volumetric flow of the flue gas, resulting in a higher flue gas ID fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The two air heaters of A.B. Brown Unit 2 are regenerative Ljungström type air heaters with rotating baskets. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals that are misaligned or out of adjustment will result in increased air heater leakage rates. The A.B. Brown Unit 2 air heaters are regularly inspected by the OEM, including an assessment of the air heater seals and replacement if required during all planned outages. Prior to the SCR installation, the original design air leakage for the A.B. Brown Unit 2 air heaters was approximately 7 to 8 percent. The installation of the SCR units has resulted in a corresponding increase of the full load air-to-gas side differential pressure by several inches of water column (when combustion air and flue gas pressures are compared). Additionally, the hot end sector plates have been replaced for A.B. Brown Unit 2, and the OEM recommendation is to replace the cold-end sectors plates. Air heater leakage is closely monitored for A.B. Brown Unit 2 because of the detrimental effect of oxygen on the dual alkali scrubbers within the AQCS.

According to feedback from Vectren operations personnel, positive contact seals have been attempted for the A.B. Brown Unit 2 air heaters in the past but were removed from service because of failures during operation. The air heaters now utilize the original seal types. More frequent in-situ monitoring or installation of permanent probes measuring flue gas oxygen content at the ID fan inlet would allow for more accurate trending of the air in-leakage trends over time. This information would assist with planned outage maintenance and would provide ancillary benefits such as reducing ID fan power consumption and improved heat rate due to dry gas loss reduction.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial because the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule, for every 40° F decrease in air heater gas outlet temperature, a 1.0 percent increase in boiler efficiency can be expected. The reduction in leakage previously discussed is expected to increase the measured average air heater gas outlet temperature. This increase would not be expected to negatively impact boiler efficiency as the air heater no-leak gas outlet temperature would remain the same. Black & Veatch expects that air heater upgrades that could lower the no-leak temperature by 20° F are attainable without an in-depth analysis of the air preheat system and acid gas dew points. This would increase boiler efficiency by about 0.5 percent.

However, if additional efficiency gains are desired, additional analyses of the air preheat system and acid gas dew points with the air heater performance would be required to ensure the average gas temperature does not encroach upon the acid gas dew point at all loads. It is expected that the air heater gas outlet temperature could be lowered by another 10 to 15° F, improving boiler efficiency by another 0.25 percent. Upgrades to the air preheat system and air-side and/or gas-side air heater bypasses are expected to be likely, however, to maintain air heater gas outlet temperatures above the acid dew point at lower loads and during colder times of the year.

It should be noted that internal air heater condition should also be assessed to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR.

An additional area of opportunity for NPHR improvement related to the A.B. Brown Unit 2 air heaters is the potential reduction of the air heater cold-end setpoint temperature for A.B. Brown Unit 2.

According to unit operating data provided by Vectren, A.B. Brown Unit 2 maintains a consistent air heater cold-end temperature near 325 to 330° F (measured at the ID fan inlet for A.B. Brown Unit 2). This temperature target is considered above the recommended setpoint, given the potential acid gas dew point temperature, which is likely below 300° F. The gradual reduction of the air heater cold-end setpoint (e.g., reduction by 5 degrees every few months) would be a zero-cost (i.e., can be implemented via changes to setpoints within the existing control system) means of improving NPHR and not negatively impacting beneficial reuse of the fly ash. Changes to the condition of the draft system could be monitored during the regularly scheduled maintenance outages.

Air heater bypasses have been installed on the A.B. Brown Unit 2 draft system. This system provides a backup for the existing air preheating steam coil systems for cold-end temperature control for periods of extreme cold weather or a coil being taken out of service. Upgrades to the steam coil system would allow for fewer uses of the air heater (air-side) bypass during the year and fewer instances of the associated heat rate penalty during the intermittent use of the bypass.

3.3.2.2 Ductwork

The ductwork system can be divided between the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health.

The combustion air ductwork system operates at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakages will increase the duty of the combustion air fans and result in an increase in the combustion air fan auxiliary load, thus negatively impacting the unit's NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. For balanced draft units, the differential in flue gas ductwork internal pressure compared to ambient increases (i.e., becomes more negative) as the flue gas progresses from the furnace, through the draft system and to the inlet of the ID fans. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans and result in an increase in the flue gas ID fan auxiliary load, thus negatively impacting the unit's NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion.

Ductwork inspection activities and the air heater upgrades discussed in the previous section would be expected to be incorporated during the regularly scheduled O&M outages. The A.B. Brown Unit 2 forecast for scheduled maintenance outages is outlined in Table 3-9.

Table 3-9 A.B. Brown Unit 2 O&M Scheduled Outage Intervals (2020-2039)

YEAR	A.B. BROWN UNIT 2 O&M - SCHEDULED OUTAGE
2020	3 weeks
2021	3 weeks
2022	--
2023	Major
2024	3 weeks
2025	--
2026	3 weeks
2027	3 weeks
2028	--
2029	3 weeks
2030	3 weeks
2031	--
2032	3 weeks
2033	Major
2034	--
2035	3 weeks
2036	Major
2037	--
2038	3 weeks
2039	Major

To determine the overall cost associated with improving the ductwork leakage rates field examinations and tests must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator (or similar system) to locate and catalog the leaks would be required. Leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e., areas closer to the discharge of the combustion air fans or areas closer to the inlet of the flue gas ID fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

Draft system leakage testing data for A.B. Brown Unit 2 were not available for review/incorporation into this analysis. Therefore, Black & Veatch has not assessed any NPHR impacts regarding reducing flue gas draft system leakage other than that discussed for the air heaters. The following activities can be implemented to improve the existing air heater units and find draft system leakage points. With the availability of additional data, the following estimates could be further refined, and the following heat rate benefits could likely increase.

Air Heater Basket, Seal, and Sector Plate Replacement

Total Installed Capital Cost:	$850,000
Heat Rate (efficiency) Improvement:	0.5% (assumes 20° F air heater gas outlet temperature improvement)

Air Preheater (Steam Coil) System Repairs

Total Installed Capital Cost:	$350,000
Heat Rate (efficiency) Improvement:	0.1% (applicable to intermittent periods when steam coils would be used)

3.3.3 F.B. Culley Unit 2 Air Heater and Leakage Control Upgrades

The main NPHR benefit of air heater and flue gas ductwork leakage control repairs/upgrades is a result of reducing the duty of the unit's combustion air and flue gas induced draft fans, thus reducing the unit's overall auxiliary load demand.

Excessive air heater and flue gas duct leakage presents additional issues beyond degradation in NPHR, however. Air in-leakage can also result in tempering of flue gas, causing corrosive flue gas acid gases to condense on air heater cold end baskets and ductwork components. Reduction in air heater and flue gas duct leakage can improve overall equipment life, reduce capital investment for repair, and reduce O&M costs caused by flue gas acid gas corrosion. Additionally, the following are some other characteristics of air in-leakage that can negatively impact draft system and air quality control equipment performance:

- Higher velocities from additional mass flow, potentially reducing the life expectancy of PJFF bags.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak by of cold combustion air mixing with hot flue gas out of air heater), causing flue gas to be closer to acid dew point and increasing the potential for equipment corrosion throughout flue the gas draft system.

The following subsections provide further discussion of air heater and leakage control upgrades. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of heat rate improvement projects. The typical information and results provided for such projects can be used to assess and further screen the potential benefit. Future efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

3.3.3.1 Air Heater

As previously noted, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas ID fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reducing the temperature of the flue gas, and increasing the mass and volumetric flow of the flue gas, resulting in a higher flue gas ID fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The F.B. Culley Unit 2 air heater is a regenerative Ljungström type air heater with rotating baskets. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals that are misaligned or out of adjustment will result in increased air heater leakage rates. The F.B. Culley Unit 2 air heaters are regularly inspected by the OEM, including an assessment of the air heater seals and replacement if required during all planned outages. More frequent in situ monitoring or installation of permanent probes measuring flue gas oxygen content at the ID fan inlet would allow for more accurate trending of the air in-leakage over time. This information would assist with planned outage maintenance and would provide ancillary benefits such as reducing ID fan power consumption and improved heat rate from a dry gas loss reduction.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial because the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule, for every 40° F decrease in air heater gas outlet temperature, a 1.0 percent increase in boiler efficiency can be expected. The reduction in leakage previously discussed is expected to increase the measured average air heater gas outlet temperature. This increase would not be expected to negatively impact boiler efficiency because the air heater no-leak gas outlet temperature would remain the same. Black & Veatch expects that air heater upgrades that could lower the no-leak temperature by 20° F are attainable without an in-depth analysis of the air preheat system and acid gas dew points. This would increase boiler efficiency by about 0.5 percent.

However, if additional efficiency gains are desired, additional analyses of the air preheat system and acid gas dew points with the air heater performance would be required to ensure the average gas temperature does not encroach upon the acid gas dew point at all loads. It is expected that the air heater gas outlet temperature could be lowered by another 10 to 15° F, improving boiler efficiency by another 0.25 percent.

The F.B. Culley Unit 2 air preheater (steam coil) units are reportedly in good condition and operate reliably; because of this, there were no recommendations or perceived improvements to unit performance as a result of additional capital budget spending for the air preheater units.

It should be noted that an internal air heater conditional assessment should also be made to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR.

An additional area of opportunity for NPHR improvement related to the F.B. Culley Unit 2 air heaters is the potential reduction of the air heater cold-end setpoint temperature for F.B. Culley Unit 2.

According to unit operating data provided by Vectren, F.B. Culley Unit 2 maintains a consistent air heater cold-end temperature near 325 to 330°F (measured at the ID fan inlet for F.B. Culley Unit 2). This temperature target is considered above the recommended setpoint, given the potential acid gas dew point temperature, which is likely below 300° F. The gradual reduction of the air heater cold-end setpoint (e.g., reduction by 5 degrees every few months) would be a zero-cost (i.e., can be implemented via changes to setpoints within the existing control system) means of improving NPHR and not negatively impacting beneficial reuse of the fly ash. Changes to the condition of the draft system could be monitored during the regularly scheduled maintenance outages.

3.3.3.2 Ductwork

The ductwork system can be divided between the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health.

The combustion air ductwork system operates at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakages will increase the duty of the combustion air fans and result in an increase in the combustion air fan auxiliary load, thus negatively impacting the unit's NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. For balanced draft units, the differential in flue gas ductwork internal pressure compared to ambient increases (i.e., becomes more negative) as the flue gas progresses from the furnace, through the draft system, and to the inlet of the ID fans. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans and result in an increase in the flue gas induced draft fan auxiliary load, thus negatively impacting the units NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion.

Ductwork inspection activities and the air heater upgrades discussed in the previous section would be expected to be incorporated during the regularly scheduled O&M outages. The F.B. Culley Unit 2 forecast for scheduled maintenance outages is outlined in Table 3-10.

Table 3-10 F.B. Culley Unit 2 O&M Scheduled Outage Intervals (2020-2039)

YEAR	F.B. CULLEY UNIT 2 O&M - SCHEDULED OUTAGE
2020	3 weeks
2021	--
2022	3 weeks
2023	--
2024	Major
2025	--
2026	3 weeks
2027	--
2028	3 weeks
2029	--
2030	3 weeks
2031	--
2032	3 weeks
2033	--
2034	Major
2035	--
2036	3 weeks
2037	--
2038	3 weeks
2039	--

To determine the overall cost associated with improving the ductwork leakage rates field examinations and tests must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator (or similar system) to locate and catalog the leaks would be required. Leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e., areas closer to the discharge of the combustion air fans or areas closer to the inlet of the flue gas ID fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

Draft system leakage testing data for F.B. Culley Unit 2 were not available for review or incorporation into this analysis. Therefore, Black & Veatch has not assessed any NPHR impacts regarding reducing flue gas draft system leakage other than that discussed for the air heaters. The following activities can be implemented to improve the existing air heater units and find draft system leakage points. With the availability of additional data, the following estimates could be further refined, and the following heat rate benefits would likely increase.

Air Heater Basket, Seal, and Sector Plate Replacement

Total Installed Capital Cost:	$476,000
Heat Rate (efficiency) Improvement:	0.5% (assumes 20° F air heater gas outlet temperature improvement)

3.3.4 F.B. Culley Unit 3 Air Heater and Leakage Control Upgrades

The main NPHR benefit of air heater and flue gas ductwork leakage control repairs/upgrades is as a result of reducing the duty of the unit's combustion air and flue gas induced draft fans thus reducing the units overall auxiliary load demand.

Excessive air heater and flue gas duct leakage presents additional issues beyond degradation in NPHR, however. Air in-leakage can also result in tempering of flue gas, causing corrosive flue gas acid gases to condense on air heater cold end baskets and ductwork components. Reduction in air heater and flue gas duct leakage can improve overall equipment life, reduce capital investment for repair, and reduce O&M costs caused by flue gas acid gas corrosion. Additionally, the following are some other characteristics of air in-leakage that can negatively impact draft system and air quality control equipment performance:

- Higher velocities from additional mass flow, potentially reducing the life expectancy of PJFF bags.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak-by of cold combustion air mixing with hot flue gas out of air heater), causing flue gas to be closer to acid dew point and increasing the potential for equipment corrosion throughout the flue gas draft system.

The following subsections provide further discussion of air heater and leakage control upgrades. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of heat rate improvement projects. The typical information and results provided for such projects can be used to assess and further screen the potential benefit. Future efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

3.3.4.1 Air Heater

As previously noted, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas ID fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reducing the temperature of the flue gas, and increasing the mass and volumetric flow of the flue gas, resulting in a higher flue gas ID fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The two air heaters of F.B. Culley Unit 3 are regenerative Ljungström type air heaters with rotating baskets. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals that are misaligned or out of adjustment will result in increased air heater leakage rates. The F.B. Culley Unit 3 air heaters are regularly inspected by the OEM, including an assessment of the air heater seals and replacement if required during all planned outages. Prior to the SCR installation, the original design air leakage for the F.B. Culley Unit 3 air heaters was approximately 7 to 8 percent. The installation of the SCR units has resulted in a corresponding increase of the full load air-to-gas side differential pressure by several inches of water column (when combustion air and flue gas pressures are compared).

Air in-leakage testing (measuring the oxygen content rise in discrete sections of the F.B. Culley Unit 3 draft system) was performed in 2017. This testing indicated a 16 to 17 percent leakage across each of the F.B. Culley Unit 3 air heaters (with the unit at full load). The leakage data across the PJFF and SCR units indicated no significant air infiltration. These data are outlined in Table 3-11 and Figure 3-8.

Table 3-11 F.B. Culley Unit 3 Draft System and Air Heater Air In-Leakage Test Data (July 2017)

TESTING LOCATION	DESCRIPTION	F.B. CULLEY UNIT 3 DRAFT SYSTEM – WEST SIDE	F.B. CULLEY UNIT 3 DRAFT SYSTEM – EAST SIDE
SCR Inlet	SCR inlet after duct burner; duct burner out of service at during full load test	4.0	3.5
SCR Outlet	SCR outlet/AH inlet duct section	4.0	3.7
AH Outlet	AH outlet/PJFF inlet duct section	6.4	6.3
FF Outlet	PJFF outlet/ID fan inlet(s) duct section	6.5	6.2
Calculated AH Leakage (%)	Calculated from "SCR Out" and "AH Out" data provided above	16.9	17.8
AH - air heater			

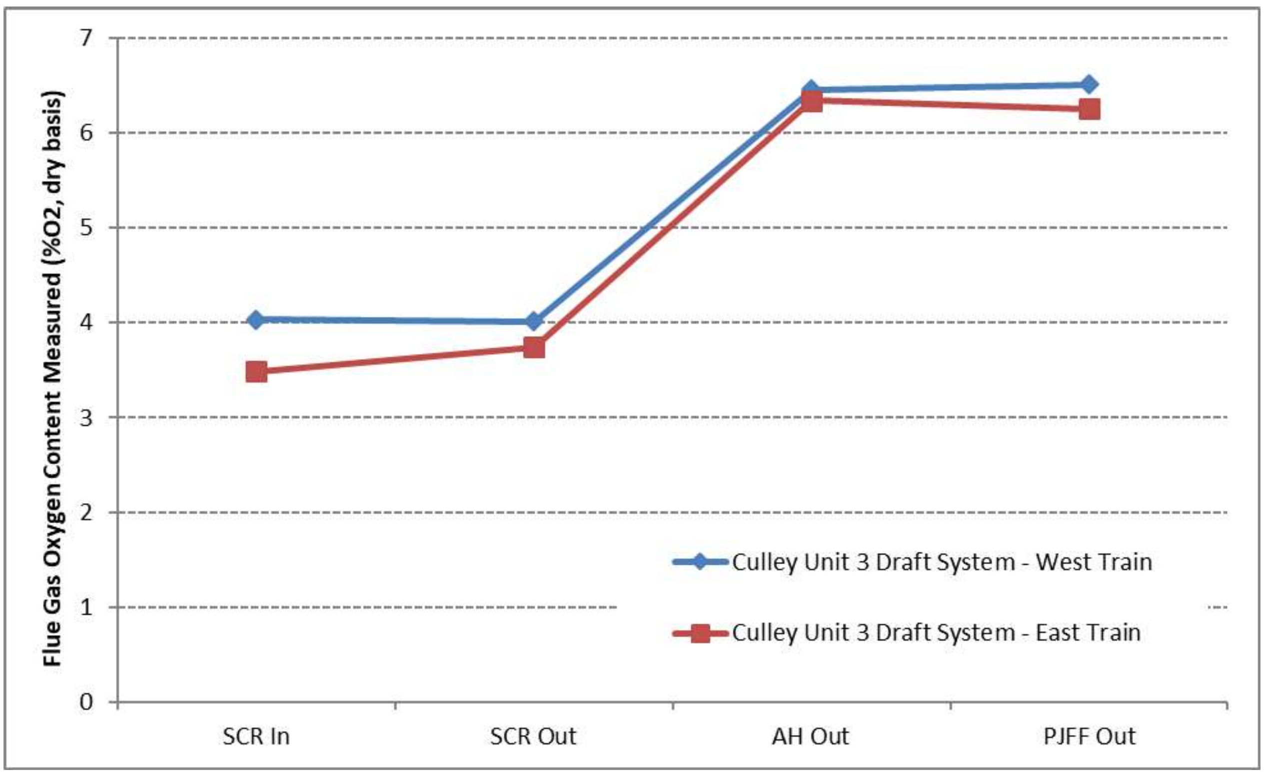


Figure 3-8 F.B. Culley Unit 3 Draft System Air Leakage Test Data (July 2017)

As a result of the air heater leakage test data, all sector plates and seals were replaced at the recommendation of the OEM during the recently completed 2019 planned outage for F.B. Culley Unit 3.

More frequent in situ monitoring or installation of permanent probes measuring flue gas oxygen content at the ID fan inlet would allow for more accurate trending of the air in-leakage over time. This information would assist with planned outage maintenance and would provide ancillary benefits such as reducing ID fan power consumption and improved heat rate due to dry gas loss reduction.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial because the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule, for every 40° F decrease in air heater gas outlet temperature, a 1.0 percent increase in boiler efficiency can be expected. The reduction in leakage previously discussed is expected to increase the measured average air heater gas outlet temperature. This increase would not be expected to negatively impact boiler efficiency as the air heater no-leak gas outlet temperature would remain the same. Black & Veatch expects that air heater upgrades that could lower the no-leak temperature by 20° F are attainable without an in-depth analysis of the air preheat system and acid gas dew points. This would increase boiler efficiency by about 0.5 percent.

However, if additional efficiency gains are desired, additional analyses of the air preheat system and acid gas dew points with the air heater performance would be required to ensure the average gas temperature does not encroach upon the acid gas dew point at all loads. It is expected that the air heater gas outlet temperature could be lowered by another 10 to 15° F, improving boiler efficiency by another 0.25 percent. The F.B. Culley Unit 3 air preheater (steam coils) are located in the FD fan room to maintain a minimum air inlet temperature setpoint, controlled by the FD fan outlet temperature. To achieve this, upgrades to the air preheat system and air-side and/or gas-side air heater bypasses would likely be required to maintain air heater gas outlet temperatures above the acid dew point at lower loads and during colder times of the year.

It should be noted that internal air heater condition should also be assessed to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR.

An additional area of opportunity for NPHR improvement related to the F.B. Culley Unit 3 air heaters is the potential reduction of the air heater cold-end setpoint temperature.

According to unit operating data provided by Vectren, F.B. Culley Unit 3 maintains a consistent air heater cold-end temperature near 325 to 330° F (measured at the ID fan inlet for F.B. Culley Unit 3). This temperature target is considered above the recommended setpoint, given the potential acid gas dew point temperature which is likely below 300° F. The gradual reduction of the air heater cold-end setpoint (e.g., reduction by 5 degrees every few months) would be a zero-cost (i.e., can be implemented via changes to set points within the existing control system) means of improving NPHR and not negatively impacting beneficial reuse of the fly ash. Changes to the condition of the draft system could be monitored during the regularly scheduled maintenance outages.

Air heater bypasses have been installed on the F.B. Culley Unit 3 draft system. This system provides a backup for the existing air preheating steam coil systems for cold-end temperature control for periods of extreme cold weather or a coil being taken out of service. Upgrades to the steam coil system would allow for fewer uses of the air heater (air-side) bypass during the year and fewer instances of the associated heat rate penalty during the intermittent use of the bypass.

In October 2018, Ljungström (F.B. Culley Unit 3 air heater OEM, a division of Arvos Group) provided information regarding a proposed air heater upgrade to improve heat rate as part of Vectren's ongoing heat rate improvement initiatives. According to a preliminary review of Ljungström's proposed air heater upgrade options, a 0.4 percent heat rate improvement was estimated. Black & Veatch recommends additional review of the proposed upgrades and potential balance-of-plant impacts (ID fan, ductwork, etc.). The basis of this improvement is relocating the DSI system upstream of the air heater, which would also need to be considered in the project costs.

3.3.4.2 Ductwork

The ductwork system can be divided between the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health.

The combustion air ductwork system operates at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakages will increase the duty of the combustion air fans and result in an increase in the combustion air fan auxiliary load, thus negatively impacting the unit's NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. For balanced draft units, the differential in flue gas ductwork internal pressure compared to ambient increases (i.e., becomes more negative) as the flue gas progresses from the furnace, through the draft system, and to the inlet of the ID fans. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans and result in an increase in the flue gas induced draft fan auxiliary load, thus negatively impacting the unit's NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion. Information provided to assess the flue gas duct work leakage is provided in Table 3-11 and Figure 3-8 above.

Ductwork inspection activities and the air heater upgrades discussed in the previous section would be expected to be incorporated during the regularly scheduled O&M outages. The F.B. Culley Unit 3 forecast for scheduled maintenance outages is outlined in Table 3-12.

Table 3-12 F.B. Culley Unit 3 O&M Scheduled Outage Intervals (2020-2039)

YEAR	F.B. CULLEY UNIT 3 O&M - SCHEDULED OUTAGE
2020	3 weeks
2021	--
2022	3 weeks
2023	3 weeks
2024	--
2025	3 weeks
2026	Major
2027	--
2028	3 weeks
2029	3 weeks
2030	--
2031	3 weeks
2032	3 weeks
2033	--
2034	3 weeks
2035	Major
2036	--
2037	3 weeks
2038	3 weeks
2039	--

To determine the overall cost associated with improving the ductwork leakage rates, field examinations and tests must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator (or similar system) to locate and catalog the leaks would be required. Leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e., areas closer to the discharge of the combustion air fans or areas closer to the inlet of the flue gas ID fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

Because the age of the previous leakage testing data and the subsequent air heater maintenance performed by Vectren, Black & Veatch has not assessed any NPHR impacts regarding reducing flue gas draft system leakage other than that discussed for the air heaters. The following activities described in this section can be implemented to continue to find draft system leakage points. With the availability of additional data, the following estimates could be further refined, and the following heat rate benefits would likely increase.

Air Heater Basket, Seal, and Sector Plate Replacement

Total Installed Capital Cost:	$750,000
Heat Rate (efficiency) Improvement:	0.5% (assumes 20° F air heater gas outlet temperature improvement)

Air Preheater (Steam Coil) System Repairs

Total Installed Capital Cost:	$350,000
Heat Rate (efficiency) Improvement:	0.1% (applicable to intermittent periods when steam coils would be used)

3.4 UNIT VARIABLE FREQUENCY DRIVE UPGRADES

Variable-frequency drives (VFDs) function by controlling electric motor speed by converting incoming constant frequency power to variable frequency, using pulse width modulation. VFD upgrades for main plant electric motors provide many co-benefits, the largest one of which is improved part-load efficiency and performance. The benefit is greatest at low load. The more part load and unit cycling that is done, the greater the benefit.

In addition to the reduced auxiliary power consumption, other benefits that are gained from the installation of VFDs on rotating equipment are as follows:

- Reduced noise levels around the equipment.
- Lower in-rush current during startups.
- Decreased wear on existing auxiliary power equipment.

Disadvantages of the installation of VFDs include the high capital cost plus a minimal amount of increased electrical equipment maintenance associated with the VFD system.

Output power signal quality and reliability of VFD equipment has increased significantly in the last 10 to 15 years. Part of this increased reliability comes from the development of technology to allow the VFD equipment to remain in operation if one or multiple insulated-gate bipolar transistor (IGBT) power cells fail by automatically bypassing the bad cell, or cells, until an outage when repairs can be made. Additionally, output power signals meet Institute of Electrical and Electronics Engineers (IEEE) 519 1992 requirements, eliminating the need for harmonic filters.

VFD installation typically requires about 2 months of total pre-outage work, with a 1-week outage (per device) for the final tie-in. To support installation of the VFDs, the following changes are necessary:

- Replacement of existing rotating equipment coupling with resilient elastomeric block shaft couplings to accommodate the shaft misalignment and absorb the high torque loads during rapid load changes. This means the existing equipment must be de-coupled from the motor and then realigned with the new coupling.
- Upgrades to lube oil system as necessary.
- New VFD enclosure foundations.
- New VFD enclosures and heat exchangers.
- Replace the power supply cables from existing switchgear to the new VFD cabinet. Install new cables from the VFD cabinet to the motor.
- For smaller units, the VFD control enclosure and cabinets will also be smaller with reduced pre-outage time requirements.

A high-level assessment of the technical and economic feasibility of VFD modifications that have been seen as beneficial in previous ACE studies were considered as part of this study. With financial benefits confirmed by integrated resource plan (IRP) modeling, specific modifications can then be reviewed in a detailed effort to confirm the performance and financial benefits of VFD modifications.

3.4.1 A.B. Brown Unit 1 Variable Frequency Drive Upgrades

The A.B. Brown Unit 1 rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, cooling tower fans, and the large draft fans for handling combustion air and flue gas.

After discussion with Vectren personnel, the best potential application for further VFD upgrades appears to be the ID fans.

3.4.1.1 Boiler Feed Pumps

The A.B. Brown Unit 1 boiler feed pump is a turbine driven feed pump that already provides high efficiency variable speed capability. The installation of a VFD system on the boiler feed pump will therefore not be evaluated further.

3.4.1.2 Circulating Water Pumps

The circulating water system includes two 50 percent capacity vertical turbine circulating water pumps driven by 1,750 horsepower motors. The impellers on the circulating water pumps were replaced with new impellers in 2008. According to the A.B. Brown Unit 1 operating data provided by Vectren, during the period of January 2017 through September of 2018, the unit was off-line at times and operated as high as 100 percent load. Excluding any hours when the unit was off-line or appeared to be ramping up to load, the operating data indicates that the unit operated between 40 percent load and 60 percent load for approximately 52 percent of the time, a significant period where Unit 1 was operating at a relatively significant part load. The operating data also indicate that the unit operated between 60 percent load and 80 percent load for approximately 15 percent of the time and between 80 percent load and 100 percent load for approximately 33 percent of the time. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow over the operating load ranges experienced during normal operation of the unit. However, variations in pump speed and circulating water flow can have a significant impact on condenser pressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser pressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e., circulating water pumps and cooling tower fans). These studies have shown that, for the majority of time, it is more advantageous to operate the circulating water pumps and cooling tower fans at full capacity to maintain the lowest temperature circulating water to the condenser with the resulting lowest condenser pressure possible. This operating scenario typically provides a better plant heat rate than lowering the auxiliary power requirements with a resulting increase in condenser back pressure.

As an example, for every 0.1 in. Hg increase in condenser pressure for A.B. Brown Unit 1, the turbine generator output is expected to decrease by about 0.3 to 0.8 MW, according to past experience. Decreasing circulating water flow by 5 percent will decrease the circulating water pump auxiliary load by about 0.3 to 0.4 MW, and the condenser pressure is expected to increase by more than 0.2 in. Hg for the vast majority of operating scenarios and unit loads, especially during the warmer months, creating a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and flow rates can be estimated utilizing the pump affinity laws. Table 3-13 summarizes the rated circulating water pump design conditions, as provided in the A.B. Brown Unit 1 documentation, and the reduced operating pump brake horsepower at a 1 percent and a 5 percent reduction in circulating water flow rate per pump. Estimations of pump speed have also been provided if these pumps were to be equipped with VFD systems.

Table 3-13 Predicted Circulating Water Pump Operating Conditions at Reduced Flows

	RATED OPERATING CONDITIONS	1% REDUCED FLOW OPERATING CONDITIONS	5% REDUCED FLOW OPERATING CONDITIONS
Flow, gpm	65,000	64,350	61,750
Total head, ft	84	82.3	75.8
Pump brake horsepower, hp	1,558	1,512	1,336
Pump speed, rpm	514	509	488
gpm – gallons per minute; ft – feet; hp – horsepower; rpm – revolutions per minute Note: The above operating data is for one of two (2x50%) circulating water pumps.			

This is not strictly true for systems with a high static head, and the savings could be somewhat less when the pump speed differences are fully accounted for. Detailed pump modeling should be conducted to improve the accuracy of these predictions as part of a next-phase effort.

The only scenarios that Black & Veatch has assessed where the installation of VFD systems on circulating water pumps has been beneficial is with once-through circulating water systems that use river or lake water that cools during winter months and there is no concern of freezing. Since the heat rejection system on A.B. Brown Unit 1 involves the use of a cooling tower, the installation of VFD systems on the circulating water pumps does not appear to be cost effective.

Lastly, the costs of adding VFDs to large motors is significant. The estimated costs for adding VFDs to the two Unit 1 circulating water pumps is $2,100,000.

3.4.1.3 Cooling Tower Fans

Cycle heat rejection is via a seven-cell mechanical draft cross-flow cooling tower with seven mechanical draft cooling tower fans. Each cooling tower fan is driven by a 200 hp motor equipped with a VFD system to control both de-icing and to control condenser backpressure. As the cooling tower fans are already equipped with VFDs, the fans will not be investigated further.

3.4.1.4 Large Draft Fans

According to available information and operating data, the A.B. Brown Unit 1 ID fan auxiliary power consumption benefit is estimated to be a total of 3.3 MW for both fans at full load and 4.1 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0473 pounds per cubic foot (lbm/ft^3) at 322° F.

The estimated furnish and erect price for a VFD system for the A.B. Brown Unit 1 ID fans includes the VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

VFD Deployment for ID Fans

Total Installed Capital Cost:	$2,900,000 for both fans
Auxiliary Power Reduction:	Full load: 3.3 MW Low Load: 4.1 MW
Heat Rate (efficiency) improvement:	Full Load: 1.4% Low Load: 3.0%

Estimated Additional Annual O&M Cost: $2,000 per unit

The A.B. Brown Unit 1 FD fan auxiliary power consumption benefit is estimated to be a total of 0.85 MW for both fans at full load and 0.7 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0726 pounds per cubic foot (lbm/ft^3) at 74° F.

The estimated furnish and erect price for a VFD system for the A.B. Brown Unit 1 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

VFD Deployment for FD Fans

Total Installed Capital Cost:	$2,000,000 for both fans
Auxiliary Power Reduction:	Full load: 0.85 MW Part load: 0.7 MW
Heat Rate (efficiency) Improvement:	Full Load: 0.37% Low Load: 0.54%

Estimated Additional Annual O&M Cost: $2,000 per unit

3.4.2 A.B. Brown Unit 2 Variable Frequency Drive Upgrades

The A.B. Brown Unit 2 rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, cooling tower fans, and the large draft fans for handling combustion air and flue gas.

After discussion with Vectren personnel, the best potential application for further VFD upgrades appears to be the ID fans.

3.4.2.1 Boiler Feed Pumps

The A.B. Brown Unit 2 boiler feed pump is a turbine driven feed pump that already provides high efficiency variable speed capability. The installation of a VFD system on the boiler feed pump will therefore not be evaluated further.

3.4.2.2 Circulating Water Pumps

The circulating water system includes two 50 percent capacity vertical turbine circulating water pumps driven by 1,750 hp motors. The impellers on the circulating water pumps were replaced with new impellers in 2008. According to A.B. Brown Unit 2 operating data provided by Vectren, during the period of January 2017 through September of 2018, the unit was off-line at times and operated as high as 100 percent load. Excluding any hours when the unit was off-line or appeared to be ramping up to load, the operating data indicate that the unit operated between 40 percent load and 60 percent load for approximately 44 percent of the time, a significant period where Unit 2 was operating at a relatively significant part load. The operating data also indicate that the unit operated between 60 percent load and 80 percent load for approximately 19 percent of the time and between 80 percent load and 100 percent load for approximately 37 percent of the time. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow over the operating load ranges experienced during normal operation of the unit. However, variations in pump speed and circulating water flow can have a significant impact on condenser back pressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser pressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e., circulating water pumps and cooling tower fans). These studies have shown that, for the majority of time, it is more advantageous to operate the circulating water pumps and cooling tower fans at full capacity to maintain the lowest temperature circulating water to the condenser with the resulting lowest condenser pressure possible. This operating scenario by and large provides a better plant heat rate than lowering the auxiliary power requirements with a resulting increase in condenser back pressure.

As an example, for every 0.1 in. Hg increase in condenser pressure for A.B. Brown Unit 2, the turbine generator output is expected to decrease by about 0.3 to 0.8 MW, according to past experience. Decreasing circulating water flow by 5 percent will decrease the circulating water pump auxiliary load by about 0.3 to 0.4 MW, and the condenser pressure is expected to increase by more than 0.2 in. Hg for the vast majority of operating scenarios and unit loads, especially during the warmer months, creating a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and flow rates can be estimated utilizing the pump affinity laws. Table 3-14 summarizes the rated circulating water pump design conditions, as provided in the A.B. Brown Unit 2 documentation, and the reduced operating pump brake horsepower at a 1 percent and a 5 percent reduction in circulating water flow rate per pump. Estimations of pump speed have also been provided if these pumps were to be equipped with VFD systems.

Table 3-14 Predicted Circulating Water Pump Operating Conditions at Reduced Flows

	RATED OPERATING CONDITIONS	1% REDUCED FLOW OPERATING CONDITIONS	5% REDUCED FLOW OPERATING CONDITIONS
Flow, gpm	65,000	64,350	61,750
Total head, ft	84	82.3	75.8
Pump brake horsepower, hp	1,558	1,512	1,336
Pump speed, rpm	514	509	488
Note: The above operating data is for one of two (2x50%) circulating water pumps.			

This is not strictly true for systems with a high static head, and the savings could be somewhat less when the pump speed differences are fully accounted for. Detailed pump modeling should be conducted to improve the accuracy of these predictions as part of a next-phase effort.

The only scenarios that Black & Veatch has assessed where the installation of VFD systems on circulating water pumps has been beneficial is with once-through circulating water systems that use river or lake water that cools during winter months and there is no concern of freezing. Since the heat rejection system on A.B. Brown Unit 2 involves the use of a cooling tower, the installation of VFD systems on the circulating water pumps does not appear to be cost effective.

Lastly, the costs of adding VFDs to large motors is significant. The estimated costs for adding VFDs to the two Unit 2 circulating water pumps is $2,100,000.

3.4.2.3 Cooling Tower Fans

Cycle heat rejection is via a seven-cell mechanical draft cross-flow cooling tower with seven mechanical draft cooling tower fans. Each cooling tower fan is driven by a 200 hp motor equipped with a VFD system. As the cooling tower fans are already equipped with VFDs, the fans will not be investigated further.

3.4.2.4 Large Draft Fans

According to available information and operating data, the A.B. Brown Unit 2 ID fan auxiliary power consumption benefit is estimated to be a total of 1.7 MW for both fans at full load and 2.3 MW on the basis of the density of the inlet air to the fans of 0.048 lbm/ft^3 at 321° F.

The evaluated impacts of this project are as follows:

VFD Deployment for ID Fans

Total Installed Capital Cost:	\$2,900,000 for both fans
Auxiliary Power Reduction:	Full load: 1.7 MW
	Part Load: 2.3 MW
Heat Rate (efficiency) improvement	Full Load: 0.73%
	Low Load: 1.7%

Estimated Additional Annual O&M Cost: \$2,000 per unit

The estimated furnish and erect price for a variable frequency drive system for the A.B. Brown Unit 2 ID fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The Brown Unit 2 FD fan auxiliary power consumption benefit is estimated to be a total of 0.3 MW for both fans at full load and 0.45 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0726 pounds per cubic foot (lbm/ft^3) at 74° F.

The estimated furnish and erect price for a VFD system for the Brown Unit 2 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

VFD Deployment for FD Fans

Total Installed Capital Cost:	\$2,000,000 for both fans
Auxiliary Power Reduction:	Full load: 0.3 MW
	Part load: 0.45 MW
Heat Rate (efficiency) improvement	Full Load: 0.13%
	Low Load: 0.34%

Estimated Additional Annual O&M Cost: \$2,000 per unit

3.4.3 F.B. Culley Unit 2 Variable Frequency Drive Upgrades

The F.B. Culley Unit 2 rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, and the large draft fans for handling combustion air and flue gas.

After discussion with Vectren personnel, the best potential application for further VFD upgrades appears to be the circulating water pumps.

3.4.3.1 Boiler Feed Pumps

F.B. Culley Unit 2 includes one 100 percent capacity motor driven boiler feed pumps. The pump is driven by a 2,500 hp single-speed electric motor, which indicates that this system is amenable to a VFD deployment. The boiler feed pump has a design capacity of 1,980 gpm. Feedwater flow at full load is 1,550 gpm and 960 gpm at low load.

Table 3-15 Boiler Feed Water Pump Operating Conditions

	RATED OPERATING CONDITIONS	FULL LOAD	LOW LOAD	FULL LOAD WITH VFD	LOW LOAD WITH VFD
Flow, gpm	1,980	1,550	960	1,550	960
Total head, ft	3,980	4,375	4,550	3,700	3,307
Pump brake horsepower, hp	2,388	2,146	1,690	1,771	1,133
Pump speed, rpm	3,750	3,750	3,750	3,310	3,050

The evaluated impacts of this project are as follows:

VFD Deployment for Boiler Feed Pump

Total Installed Capital Cost:	$600,000
Auxiliary Power Reduction:	Full load: 0.3 MW
	Part load: 0.4 MW
Heat Rate (efficiency) improvement	0.6%

Estimated Additional Annual O&M Cost: $2,000 per unit

3.4.3.2 Circulating Water Pumps

Unit cooling is provided via a once-through circulating water system utilizing river water as the cooling water supply. Circulating water pump installation is two 50 percent capacity vertical turbine wet pit circulating water pumps. The pumps are driven by 450 hp motors. The circulating water pumps take suction directly from the Ohio River. According to F.B. Culley Unit 2 operating data provided by Vectren, during the period of January 2017 through January of 2019, the unit was off-line at times and operated as high as 100 percent load. Excluding any hours when the unit was off-line or appeared to be ramping up to load, the operating data indicate that the unit operated between 40 percent load and 60 percent load for approximately 45 percent of the time, a significant period where Unit 2 was operating at a relatively significant part load. The operating data also indicate that the unit operated between 60 percent load and 80 percent load for approximately 23 percent of the time and between 80 percent load and 100 percent load for approximately 32 percent of the time. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow over the operating load ranges experienced during normal operation of the unit. However, variations in pump speed and circulating water flow can have a significant impact on condenser back pressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser back pressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e., circulating water pumps and cooling tower fans). However, Black & Veatch has assessed some coal fired plants where the installation of VFD systems on circulating water pumps has been beneficial when unit cooling was provided by once-through circulating water systems using river or lake water. The impact is particularly beneficial during winter months when the water supply is cold and there is no concern of freezing.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and flow rates can be estimated utilizing the pump affinity laws. Table 3-16 summarizes the rated circulating water pump design conditions, as provided in the F.B. Culley Unit 2 documentation, and the reduced operating pump brake horsepower at a 1 percent and a 5 percent reduction in circulating water flow rate per pump. Estimations of pump speed have also been provided if these pumps were to be equipped with VFD systems.

Table 3-16 Predicted Circulating Water Pump Operating Conditions at Reduced Flows

	RATED OPERATING CONDITIONS	1% REDUCED FLOW OPERATING CONDITIONS	5% REDUCED FLOW OPERATING CONDITIONS
Flow, gpm	34,920	33,947	32,576
Total head, ft	43.7	42.8	39.4
Pump brake horsepower, hp	443	430	380
Pump speed, rpm	505	500	480
Note: The above operating data is for one of two (2x50%) circulating water pumps.			

This is not strictly true for systems with a high static head, and the savings could be somewhat less when the pump speed differences are fully accounted for. Detailed pump modeling should be conducted to improve the accuracy of these predictions as part of a next-phase effort.

Variations in pump speed and circulating water flow can have a significant impact on condenser pressure, particularly when the reduced speed and corresponding decrease in flow result in an increased circulating water temperature to the unit. As an example, for every 0.1 in. Hg increase in condenser pressure for F.B. Culley Unit 2, the turbine generator output is expected to decrease by about 0.1 to 0.5 MW, according to past experience. Decreasing circulating water flow by 5 percent will decrease the circulating water pump auxiliary load by about 0.09 to 0.1 MW, and the condenser pressure is expected to increase by more than 0.2 in. Hg for the vast majority of operating scenarios and unit loads, especially during the warmer months, creating a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

However, when unit cooling is provided by once-through circulating water systems using river water, such as the F.B. Culley Unit 2, the water supply can be provided with little day-to-day variation in temperature. This is particularly beneficial during the winter months when the water supply is very cold and any reduction in circulating water pump speed, with the corresponding decrease in flow, can have little effect on the condenser pressure.

Evaluating the impact to condenser pressure and auxiliary load by the addition of VFDs to circulating water pumps on units with once-through cooling is an involved assessment. It is necessary to determine a temperature profile of the river water over at least one annual operating period since the cooling water temperature directly impacts condenser back pressure. Additionally, the circulating water flow rate impacts heat transfer, which also directly impacts condenser back pressure. The assessment basically requires creating condenser back pressure curves as a function of the two different variables but must also consider the river water temperature profile as a function of time. The assessment would then identify the auxiliary power savings on the basis of the operating profile of the VFD speed controlled circulating water pumps. Still another concern is that low water flow velocities can cause silting and drop-out of suspended particles in piping.

The costs of adding VFDs to large motors is significant, but in the case of once-through cooling water systems, the investment can prove beneficial. The estimated costs for adding VFDs to the two Unit 2 circulating water pumps is $900,000.

3.4.3.3 Large Draft Fans

Vectren personnel informed Black & Veatch that F.B. Culley Unit 2 has already installed VFDs on the ID fans, which are typically the motors that can gain the most HRI benefit.

The Culley Unit 2 FD fan auxiliary power consumption benefit is estimated to be a total of 0.3 MW for both fans at full load and 0.3 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0727 pounds per cubic foot (lbm/ft^3) at 74° F.

The estimated furnish and erect price for a VFD system for the Culley Unit 2 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

VFD Deployment for FD Fans

Total Installed Capital Cost:	$2,000,000 for both fans
Auxiliary Power Reduction:	Full load: 0.3 MW
	Low load: 0.3 MW
Heat Rate (efficiency) improvement:	Full Load: 0.34%
	Low Load: 0.57%

Estimated Additional Annual O&M Cost: $2,000 per unit

3.4.4 F.B. Culley Unit 3 Variable Frequency Drive Upgrades

The F.B. Culley Unit 3 rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, and the large draft fans for handling combustion air and flue gas.

After discussion with Vectren personnel, the best potential application for further VFD upgrades appears to be the circulating water pumps.

3.4.4.1 Boiler Feed Pumps

The F.B. Culley Unit 3 boiler feed pump is a turbine driven feed pump that already provides high efficiency variable speed capability. The installation of a VFD system on the boiler feed pump will therefore not be evaluated further.

3.4.4.2 Circulating Water Pumps

Unit cooling is provided via a once-through circulating water system utilizing river water as the cooling water supply. The circulating water system includes two 50 percent capacity vertical turbine circulating water pumps driven by electric motors. The circulating water pumps take suction directly from the Ohio River. According to F.B. Culley Unit 3 operating data provided by Vectren, during the period of January 2017 through June of 2018, the unit was off-line at times and operated as high as 100 percent load. Excluding any hours when the unit was off-line or appeared to be ramping up to load, the operating data indicate that the unit operated between 60 percent load and 80 percent load for approximately 14 percent of the time and between 80 percent load and 100 percent load for approximately 60 percent of the time. The operating data also indicate that the unit operated at less than 60 percent load for approximately 26 percent of the time. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow over the operating load ranges experienced during normal operation of the unit. However, variations in pump speed and circulating water flow can have a significant impact on condenser back pressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser back pressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e., circulating water pumps and cooling tower fans). However, Black & Veatch has assessed some coal fired plants where the installation of VFD systems on circulating water pumps has been beneficial when unit cooling was provided by once-through circulating water systems using river or lake water. The impact is particularly beneficial during winter months when the water supply is cold and there is no concern of freezing.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and flow rates can be estimated utilizing the pump affinity laws. Table 3-17 summarizes the rated circulating water pump design conditions, as provided in the Culley Unit 3 documentation, and the reduced operating pump brake horsepower at a 1 percent and a 5 percent reduction in circulating water flow rate per pump. Estimations of pump speed have also been provided if these pumps were to be equipped with VFD systems.

Table 3-17 Predicted Circulating Water Pump Operating Conditions at Reduced Flows

	RATED OPERATING CONDITIONS	1% REDUCED FLOW OPERATING CONDITIONS	5% REDUCED FLOW OPERATING CONDITIONS
Flow, gpm	69,000	68,310	65,550
Total head, ft	57	55.9	51.4
Pump brake horsepower, hp	1170	1135	1,003
Pump speed, rpm	300	297	285
Note: The above operating data is for one of two (2x50%) circulating water pumps.			

Variations in pump speed and circulating water flow can have a significant impact on condenser pressure, particularly when the reduced speed and corresponding decrease in flow result in an increased circulating water temperature to the unit. As an example, for every 0.1 in. Hg increase in condenser pressure for F.B. Culley Unit 3, the turbine generator output is expected to decrease by about 0.4 to 0.9 MW, according to past experience. Decreasing circulating water flow by 5 percent will decrease the circulating water pump auxiliary load by about 0.25 MW, and the condenser pressure is expected to increase by more than 0.2 in Hg for the vast majority of operating scenarios and unit loads, especially during the warmer months. This creates a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

However, when unit cooling is provided by once-through circulating water systems using river water, such as the F.B. Culley Unit 3, the water supply can be provided with little day-to-day variation in temperature. This is particularly beneficial during the winter months when the water supply is very cold and any reduction in circulating water pump speed, with the corresponding decrease in flow, can have little effect on the condenser pressure.

Evaluating the impact to condenser pressure and auxiliary load by the addition of VFDs to circulating water pumps on units with once-through cooling is an involved assessment. It is necessary to determine a temperature profile of the river water over at least one annual operating period since the cooling water temperature directly impacts condenser back pressure. Additionally, the circulating water flow rate impacts heat transfer, which also directly impacts condenser back pressure. The assessment basically requires creating condenser back pressure curves as a function of the two different variables but must also consider the river water temperature profile as a function time. The assessment would then identify the auxiliary power savings on the basis of the operating profile of the VFD speed controlled circulating water pumps. Moreover, plant personnel have expressed concerns about silting problems due to low water velocity, which is already a known issue at the plant, where, extended periods of operation at low flows have led to silting in the condenser tubes and associated corrosion.

The costs of adding VFDs to large motors is significant, but in the case of once-through cooling water systems, the investment can prove beneficial. The estimated costs for adding VFDs to the two Unit 3 circulating water pumps is $2,100,000.

3.4.4.3 Large Draft Fans

Vectren personnel informed Black & Veatch that F.B. Culley Unit 3 has already installed VFDs on the ID fans, which are typically the motors that can gain the most HRI benefit at a coal fired power plant.

The only other large rotating equipment identified for this F.B. Culley Unit 3 study that has the potential for significant HRI benefits from a VFD retrofit are the FD fans. The F.B. Culley Unit 3 FD fan auxiliary power consumption benefit is estimated to be a total of 0.6 MW for both fans at full load and 0.9 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0727 pounds per cubic foot (lbm/ft^3) at 74° F.

The estimated furnish and erect price for a VFD system for the Culley Unit 3 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

VFD Deployment for FD Fans

Total Installed Capital Cost:	$2,000,000 for both fans
Auxiliary Power Reduction:	Full load: 0.6 MW
	Low load: 0.9 MW
Heat Rate (efficiency) improvement:	Full load: 0.23%
	Low Load: 0.69%

Estimated Additional Annual O&M Cost: $2,000 per unit

3.5 BOILER FEED PUMP UPGRADES, REBUILDING, OR REPLACEMENT

The purpose of this project would be to reduce the energy consumed by the boiler feed pumps by exploring whether upgrades or repairs to the pump internal components, or replacement in kind with a new boiler feed pump would be warranted. As steam-driven boiler feed pumps are inherently much more efficient than any electric-driven boiler feed pumps, no analysis of a conversion to VFD use will be assessed on A.B. Brown Units 1 and 2, or Culley Unit 3.

3.5.1 A.B. Brown Unit 1 Boiler Feed Pumps

A.B. Brown 1 has one Pacific, 5 stage, Type BFIDS, Size 12” RHBK pump. The pump has a rated capacity of 4,400 gpm at 5,470 feet of head, 5,400 rpm, for 367 °F water. With the current data available, there is no indication that any significant improvement could be made to the overall unit heat rate by upgrading this pump. Discussions with one boiler feed pump retrofit vendor indicated that at best a 1-1.5% drive turbine efficiency could be realized, which would only translate to a very small efficiency improvement on a unit basis.

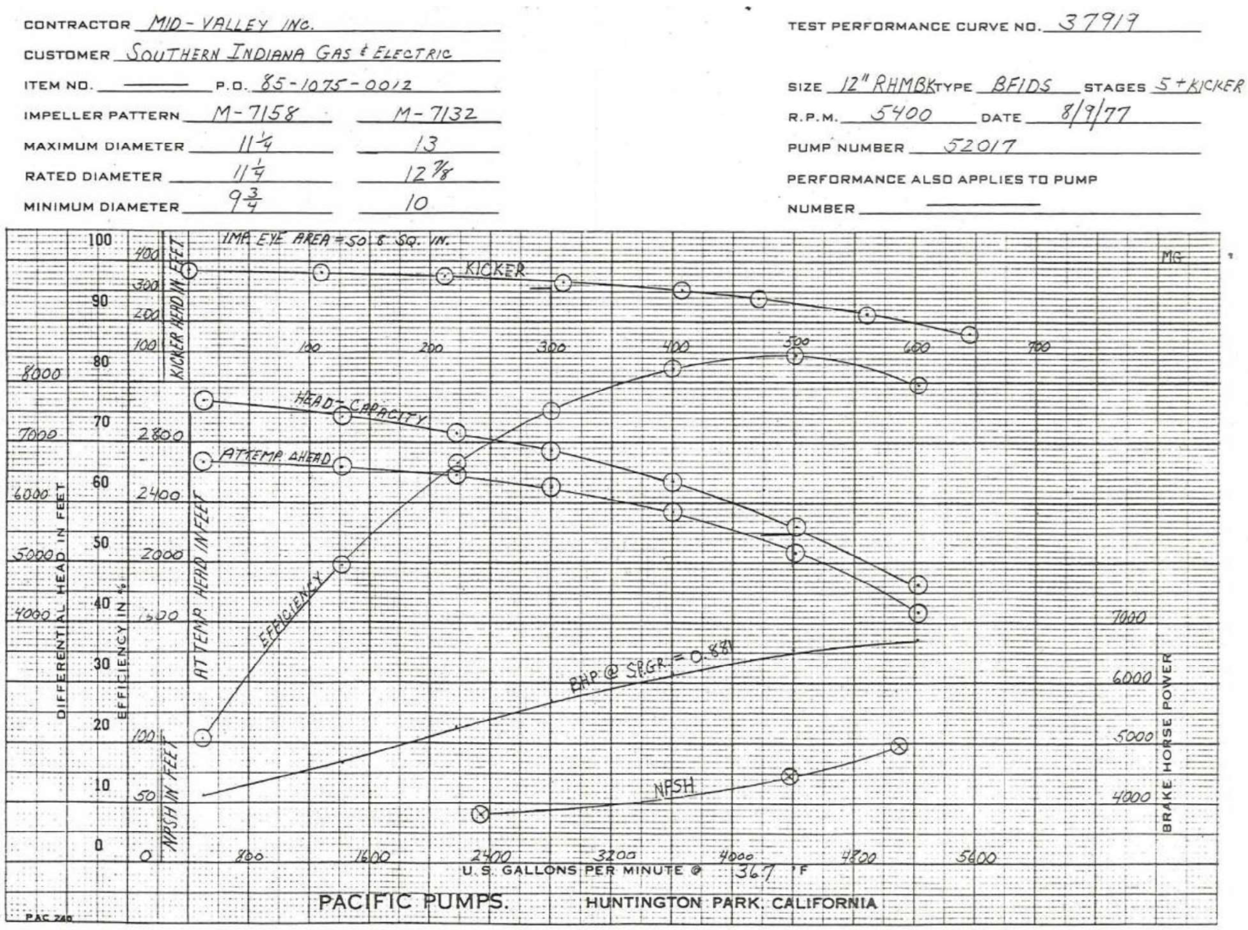


Figure 3-9 Brown 1, Brown 2, and Culley 3 Boiler Feed Pump Performance Curve

3.5.2 A.B. Brown Unit 2 Boiler Feed Pumps

A.B. Brown 2 has one Pacific, 5 stage, Type BFIDS, Size 12” RHBK pump. The pump has a rated capacity of 4,400 gpm at 5,470 feet of head, 5,400 rpm, for 367 °F water. As in the case of Unit 1, with the current data available, there is no indication that any significant improvement could be made to the overall unit heat rate by upgrading this pump. Discussions with one boiler feed pump retrofit vendor indicated that at best a 1-1.5% drive turbine efficiency could be realized, which would only translate to a very small efficiency improvement on a unit basis.

3.5.3 F.B. Culley Unit 2 Boiler Feed Pumps

F.B. Culley 2 has one Byron Jackson, double volute, 7 stage multiplex, Type DVMX, Size 6x8x11B pump. The pump has a rated capacity of 1,980 gpm at 3,980 feet of head, 3,750 rpm, and 220 °F water. The full load operating data set Black & Veatch was provided has the BFP operating with a discharge flow rate of 1,550 gpm and a total developed head of 3,980 ft. The pump curve shows that the pump should have a TDH of 4,380 ft. The actual developed head of the BFP is 9.2% less than that of the design curve. The pump no longer lies on the initial operating curve which suggest that degradation has occurred. Please see the section on VFD deployment for further information on upgrades that are possible for F.B. Culley Unit 2's boiler feed pump.

3.5.4 F.B. Culley Unit 3 Boiler Feed Pumps

F.B. Culley 3 has one Pacific, 5 stage, Type BFIDS, Size 12" RHBK pump**.** The pump has a rated capacity of 4,400 gpm at 5,470 feet of head, 5,400 rpm, for 367 °F water. With the current data available, there is no indication that any significant improvement could be made to the overall unit heat rate by upgrading this pump. Discussions with one boiler feed pump retrofit vendor indicated that at best a 1-1.5% drive turbine efficiency could be realized, which would only translate to a very small efficiency improvement on a unit basis.

3.6 UNIT NEURAL NETWORK DEPLOYMENT

The purpose of this project would be to tune the system to allow for the reduction of boiler outlet oxygen concentration without increasing NO_X or carbon monoxide (CO) emissions. Adaptive neural net systems have the greatest effect when controlling air flow and fuel mixtures down to a fine level. The full benefits are realized only if the plant has adequate feedback signals to allow the neural net to sense changes made to the available controls. For instance, individual fuel and air controls at each burner provide tremendous levers for a neural net system; however, the effect of the levers is reduced if the neural net does not receive feedback about the air/fuel mixture through a grid of CO measurements.

3.6.1 A.B. Brown Unit 1 Neural Network Deployment

The unit has the ability to bias individual mills as well as compartmented windboxes. Each burner row has an independent windbox with a damper for air control on each end, but there is only manual secondary air adjustment at each individual burner. CO measurement is located at the outlet of the reheat section, but this requires regular maintenance for reliable operation.

Reducing excess oxygen levels in the boiler increases the boiler efficiency by reducing sensible heat losses, although in some cases, unburned carbon losses can be increased (but almost never more than the sensible heat losses are reduced). In addition, reducing excess oxygen levels improves the NPHR by reducing both FD and ID fan flow requirements and can also benefit emissions control systems performance. Still another benefit would be the ability to better control the balance of O_2 across the furnace, which is known to be a current concern.

For A.B. Brown Unit 1, the excess oxygen varies roughly from between 2 percent to 4.5 percent at gross output levels above 250 MW, with an average level approximating 3.0 to 3.3 percent. No online correlation of NPHR or boiler efficiency from distributed control system (DCS) system calculations was readily available from which to draw a plant-specific correlation, but from examining the plant air heater temperature data, boiler temperature data, and other factors, it was estimated by utilizing representative plant models within the EPRI Vista fuel quality impact model that reducing the excess oxygen would result in the following improvements to boiler efficiency and heat rate:

- 0.25 percent reduction in excess O_2: 0.10 percent gain in boiler efficiency, 0.23 percent improvement in net plant heat rate.
- 0.50 percent reduction in excess O_2: 0.21 percent gain in boiler efficiency, 0.43 percent improvement in net plant heat rate.
- 0.75 percent reduction in excess O_2: 0.27 percent gain in boiler efficiency, 0.60 percent improvement in net plant heat rate.

Utilization of a specific Vista model of A.B. Brown Unit 1 would result in improved heat rate benefit estimates and should be considered as a next-phase effort. Hypothetically, it would be assumed that a modest reduction in boiler excess oxygen would be possible; therefore, if the unit could lower boiler outlet oxygen concentration by approximately 0.25 percent, then the NPHR improvement would be about 0.23 percent. The effects on NPHR were not linear because they varied as a function of auxiliary power changes, as well as changes in steam temperatures, which were affected by reduced excess O_2 levels.

Total Installed Capital Cost:	$500,000
Heat Rate (efficiency) Improvement:	0.23%

3.6.2 A.B. Brown Unit 2 Neural Network Deployment

The unit has the ability to bias individual mills as well as compartmented windboxes. Each burner row has an independent windbox with a damper for air control on each end, but there is only manual secondary air adjustment at each individual burner. There is no valid CO measurement [4]; thus, the unit must be restricted to an arbitrary O_2 lower limit to avoid typical low oxygen combustion issues such as slagging and tube wastage.

Reducing excess oxygen levels in the boiler increases the boiler efficiency by reducing sensible heat losses, although in some cases, unburned carbon losses can be increased (but almost never more than the sensible heat losses are reduced). In addition, reducing excess oxygen levels

[4] Lack of a valid CO measurement would significantly hamper the ability of a neural network system to affect positive change in unit operations.

improves the NPHR by reducing both FD and ID fan flow requirements and can also benefit emissions control systems performance.

For A.B. Brown Unit 2, the excess oxygen varies roughly from between 2 percent to 4.5 percent at gross output levels above 250 MW, with an average level approximating 3.1 to 3.3 percent. No online correlation of NPHR or boiler efficiency from DCS system calculations was readily available from which to draw a plant-specific correlation, but from examining the plant air heater temperature data, boiler temperature data, and other factors, it was estimated by utilizing representative plant models within the EPRI Vista fuel quality impact model that reducing the excess oxygen would result in the following improvements to boiler efficiency and heat rate (these are the same as A.B. Brown Unit 1):

- 0.25 percent reduction in excess O_2: 0.10 percent gain in boiler efficiency, 0.23 percent improvement in net plant heat rate.
- 0.50 percent reduction in excess O_2: 0.21 percent gain in boiler efficiency, 0.43 percent improvement in net plant heat rate.
- 0.75 percent reduction in excess O_2: 0.27 percent gain in boiler efficiency, 0.60 percent improvement in net plant heat rate.

Utilization of a specific Vista model of Brown 2 would result in improved heat rate benefit estimates and should be considered as a next-phase effort. Hypothetically, it could be assumed that a modest reduction in boiler excess oxygen would be possible; therefore, if the unit could lower boiler outlet oxygen concentration by approximately 0.25 percent then the NPHR improvement would be about 0.23 percent. The effects on NPHR were not linear because they varied as a function of auxiliary power changes, as well as changes in steam temperatures, which were affected by reduced excess O_2 levels.

Total Installed Capital Cost:	$500,000
Heat Rate (efficiency) Improvement:	0.23%

3.6.3 F.B. Culley Unit 2 Neural Network Deployment

The unit has the ability to bias individual mills, and each burner has an air shroud that can be biased; fuel biasing is available at each burner. Also, there is no valid CO measurement; thus, the unit must be restricted to an arbitrary O_2 lower limit to avoid typical low oxygen combustion issues such as slagging and tube wastage.

Reducing excess oxygen levels in the boiler increases the boiler efficiency by reducing sensible heat losses, although in some cases, unburned carbon losses can be increased (but almost never more than the sensible heat losses are reduced). In addition, reducing excess oxygen levels improves the NPHR by reducing both FD and ID fan flow requirements and can also benefit emissions control systems performance.

The excess oxygen varies roughly from between 3.5 percent to 5.2 percent at gross output levels above 80 MW, with an average level approximating 4.3 percent. No online correlation of

NPHR or boiler efficiency from DCS system calculations was readily available from which to draw a plant-specific correlation, but from examining the plant air heater temperature data, boiler temperature data, and other factors, it was estimated by utilizing representative plant models within the EPRI Vista fuel quality impact model that reducing the excess oxygen would result in the following improvements to boiler efficiency and heat rate:

- 0.25 percent reduction in excess O_2: 0.15 percent gain in boiler efficiency, 0.26 percent improvement in net plant heat rate.
- 0.50 percent reduction in excess O_2: 0.29 percent gain in boiler efficiency, 0.47 percent improvement in net plant heat rate.
- 0.75 percent reduction in excess O_2: 0.43 percent gain in boiler efficiency, 0.62 percent improvement in net plant heat rate.

Utilization of a specific Vista model of F.B. Culley 2 would result in improved heat rate benefit estimates and should be considered as a next-phase effort. Hypothetically, it could be assumed that a modest reduction in boiler excess oxygen would be possible; therefore, if the unit could lower boiler outlet oxygen concentration by approximately 0.25 percent, then the NPHR improvement would be approximately 0.26 percent. The effects on NPHR were not linear because they varied as a function of auxiliary power changes, as well as changes in steam temperatures, which were affected by reduced excess O_2 levels.

Total Installed Capital Cost:	$500,000
Heat Rate (efficiency) Improvement:	0.26%

3.6.4 F.B. Culley Unit 3 Neural Network Deployment

The unit has the ability to bias individual mills, and each burner has an air shroud that can be biased; there is no fuel biasing available at each burner. Also, there is no valid CO measurement[5]; thus, the unit must be restricted to an arbitrary O_2 lower limit to avoid typical low oxygen combustion issues such as slagging and tube wastage.

Reducing excess oxygen levels in the boiler increases the boiler efficiency by reducing sensible heat losses, although in some cases, unburned carbon losses can be increased (but almost never more than the sensible heat losses are reduced). In addition, reducing excess oxygen levels improves the NPHR by reducing both FD and ID fan flow requirements and can also benefit emissions control systems performance. Plant personnel have commented that this could also help to control the O_2 balance across the furnace, which would yield better combustion control and help reduce slagging.

For F.B. Culley Unit 3, the excess oxygen varies roughly from between 2.5 percent to 4.2 percent at gross output levels above 270 MW, with an average level approximating 3.5 percent. No online correlation of net plant heat rate NPHR or boiler efficiency from DCS system calculations was

[5] Lack of a valid CO measurement would significantly hamper the ability of a neural network system to affect positive change in unit operations.

readily available to draw a plant-specific correlation, but from examining the plant air heater temperature data, boiler temperature data, and other factors, it was estimated by utilizing representative plant models within the EPRI Vista fuel quality impact model that reducing the excess oxygen would result in the following improvements to boiler efficiency and heat rate:

- 0.25 percent reduction in excess O_2: 0.13 percent gain in boiler efficiency, 0.25 percent improvement in net plant heat rate.
- 0.50 percent reduction in excess O_2: 0.24 percent gain in boiler efficiency, 0.46 percent improvement in net plant heat rate.
- 0.75 percent reduction in excess O_2: 0.32 percent gain in boiler efficiency, 0.62 percent improvement in net plant heat rate.

Utilization of a specific Vista model of F.B. Culley 3 would result in improved heat rate benefit estimates and should be considered as a next-phase effort. Hypothetically, it could be assumed that a modest reduction in boiler excess oxygen would be possible; therefore, if the unit could lower boiler outlet oxygen concentration by about 0.25 percent, then the NPHR improvement would be about 0.25 percent. The effects on NPHR were not linear because they varied as a function of auxiliary power changes, as well as changes in steam temperatures, which were affected by reduced excess O_2 levels.

Total Installed Capital Cost:	$500,000
Heat Rate (efficiency) Improvement:	0.25%

3.7 UNIT INTELLIGENT SOOTBLOWING DEPLOYMENT

The purpose of this project would be to reduce the required sootblowing flow by installing an integrated intelligent sootblowing (ISB) control system. This system would utilize heat flux sensors, hanger strain gauges, and process data to determine the areas needing to be cleaned. By cleaning only "dirty" areas, sootblowing flow would be reduced and tube life potentially extended.

3.7.1 A.B. Brown Unit 1 Intelligent Sootblowing Deployment

An ISB system will not be investigated for this unit because A.B. Brown Unit 1 already has ISB installed.

3.7.2 A.B. Brown Unit 2 Intelligent Sootblowing Deployment

An ISB system will not be investigated for this unit because A.B. Brown Unit 2 already has ISB installed.

3.7.3 F.B. Culley Unit 2 Intelligent Sootblowing Deployment

The plant uses air as the sootblowing media, but currently, no heat flux sensors or hanger strain gauges are installed. Sootblowing is currently based on operator observation, attemperation, and control operator judgement. In addition to current sootblower O&M, it is estimated that an ISB could reduce sootblowing by approximately 10 percent or greater.

Total Installed Capital Cost:	$350,000
Heat Rate (efficiency) Improvement:	0.10%

3.7.4 F.B. Culley Unit 3 Intelligent Sootblowing Deployment

An ISB system will not be investigated for this unit because F.B. Culley Unit 3 already has ISB installed.

3.8 IMPROVED O&M PRACTICES

The purpose of this project would be to improve O&M practices as they pertain to three particular areas of focus: heat rate improvement training, on-site appraisals for identifying additional heat rate improvements, and improved condenser cleaning strategies.

3.8.1 Heat Rate Improvement Training

Black & Veatch conducts heat rate awareness training, which covers the fundamentals of determining unit performance, how to use these metrics, and the operating conditions and decisions that impact unit efficiency and heat rate. The course includes numerous real-life case studies identified through years of monitoring and diagnostic work. This on-site course is typically 2.5 days and is primarily geared toward operators and engineers.

Total Installed Capital Cost	$15,000/class (could cover multiple units and plants)
Heat Rate (efficiency) Improvement:	Unknown, although improved O&M practices at peer coal fired EGUs have claimed to result in net plant heat rate improvements of 0.1 to 0.5 percent in the first year of implementation

3.8.2 On-Site Heat Rate Appraisals

On-site heat rate appraisals, mentioned as a BSER in the EPA ACE proposal, is left open to interpretation; indeed, the EPA was not able to provide suitable guidance for estimated ranges of capital cost or HRI. On-site heat rate appraisals are often conducted via a detailed assessment of controllable losses, especially those that can be reduced or eliminated by low-impact operations changes and equipment repairs and upgrades. This assessment utilizes a combination of a review and analysis of historical operations data, interviews with plant O&M personnel, review of past test and capability reports, a detailed study of the current fuel sources and fuel-related impacts upon the plant, discussions with plant management to understand the plant generation goals and objectives, and a reliability and maintenance history analysis.

Real-world examples of heat rate improvement projects resulting from on-site heat rate appraisals and audits include the following:

- Diagnosis of a cracked feedwater heater partition plate via analysis of online performance data, which resulted in a $12,000 monthly heat rate savings and 0.4 MW capacity improvement.
- Discovery of a failed reheat stop valve by analyzing reheat pressure swings over time, resulting in a $65,000 monthly heat rate improvement and 4 MW capacity improvement.
- An audit of terminal temperature difference (TTD) and drain cooler approach (DCA) temperature trends across a feedwater heater train at one power plant found that the highest-pressure feedwater heater emergency drain valve was leaking, with 50 percent of its flow returning to the condenser, rather than cascading to the next feedwater heater. This failure resulted in a heat rate loss of 53 Btu/kWh (about 0.5 percent and a net capacity loss of 2.5 MW.
- Testing of mill dirty air flows and coal flow balances at one power plant found that by rebalancing the flows on four mills to bring the coal and air flow deviation to within ± 10% (compared to the ± 30 percent it formerly operated at), coal unburned carbon heat losses decreased by 0.5 percent, which directly translated to an HRI of 0.5 percent. Moreover, burner-zone slagging was nearly eliminated by this change, resulting in significantly less use of sootblowing steam in the furnace wall blowers, which resulted in an additional long-term heat rate benefit of 0.1 percent (and a corresponding improvement in furnace wall tube life).
- Long-term analysis of subtle deviations in feedwater heater extraction lines revealed an internal line had failed, resulting in not only a $15,000 heat rate loss, but the potential for an unplanned outage because of debris in the heater.
- An analysis of 19 different truck coals supplied to a power plant found that not only were 7 of the coals unprofitable to burn, burning the worst coal resulted in a heat rate loss of more than 2 percent Moreover, this coal was responsible, in whole or in part, for the majority of the plant de-rates because of high-temperature sodium-based fouling, which cost the unit an additional 1.2 percent in heat rate on an annual basis because of the increased number of starts and stops from fouling-related outages.
- A long-term analysis of plant continuous emissions monitoring system (CEMS) data and motor amperage data found that a malfunctioning VFD controller in the coal handling system was responsible for incorrect blending of two different coals to meet the plant SO_2 limit, resulting in not only excess use of low-sulfur coal, but a loss of heat rate equating 0.6 percent on an annual basis.

Heat rate assessment is an ever-moving target, so while there is substantial benefit from a focused heat rate auditing and improvement program, long-term use of some type of performance and O&M monitoring system will provide the best overall heat rate improvement.

3.8.3 Improved Condenser Cleanliness Strategies

3.8.3.1 A.B. Brown Unit 1 Improved Condenser Cleaning Strategies

Condenser performance problems can be caused by any combination of many factors: tube sheet fouling, tube fouling, high number of plugged tubes, circulating water flow issues, waterbox priming, air in-leakage, and poor steam cycle isolation to condenser. Generally, plant data can provide clear evidence of condenser performance problems, but the causes may be difficult to discern.

To determine condenser performance, an energy balance was calculated between the boiler and turbine cycle. Gross generation data allowed the calculation of a gross turbine cycle heat rate and condenser heat duty. The condenser design data and industry standard condenser performance calculations were used to determine the actual operating condenser performance and calculate the expected back pressure. This allowed a comparison between actual and expected condenser back pressure. The turbine OEM back pressure correction curve was employed to calculate a heat rate impact for the difference between actual and expected back pressure. For every hour of operation in the remaining data set, the heat rate impact in $/hour was calculated with an assumed fuel cost of $2.50/MBtu, actual generation, and assumed boiler efficiency.

Condenser performance was reviewed over 1.3 years of operating data. The timing covered two summers and one winter. Condenser performance was calculated across load and across seasons. The working data set began with 8,500 hours of data. Nearly 8,000 hours of data (93 percent) were considered good quality and used for analysis. The range of unit load for the data set spanned 120 MW to 270 MW gross load. Low load operation (less than 175 MW gross) comprised 56 percent of the generation while high loads (less than 240 MW gross) accounted for 31 percent operating data.

From summer 2017 to summer 2018, the hourly average heat rate impact for condenser back pressure showed a significant change across the 2018 spring outage. Condenser performance during 2017 showed very poor performance at low loads. The expected back pressure across load for A.B. Brown Unit 1 is shown by the red trace on Figure 3-10. Actual unit back pressure is shown by the blue trace on this figure. Actual back pressure never falls below 3.3 in. HgA when the unit drops load. This yielded a high heat rate impact on average of 84 Btu/kWh, with an associated fuel cost of $37.00/h.

Figure 3-10 shows a “floor” in actual back pressure (blue) around 3.5 in. HgA in 2017. As unit load goes down, the back pressure should follow the red trend.

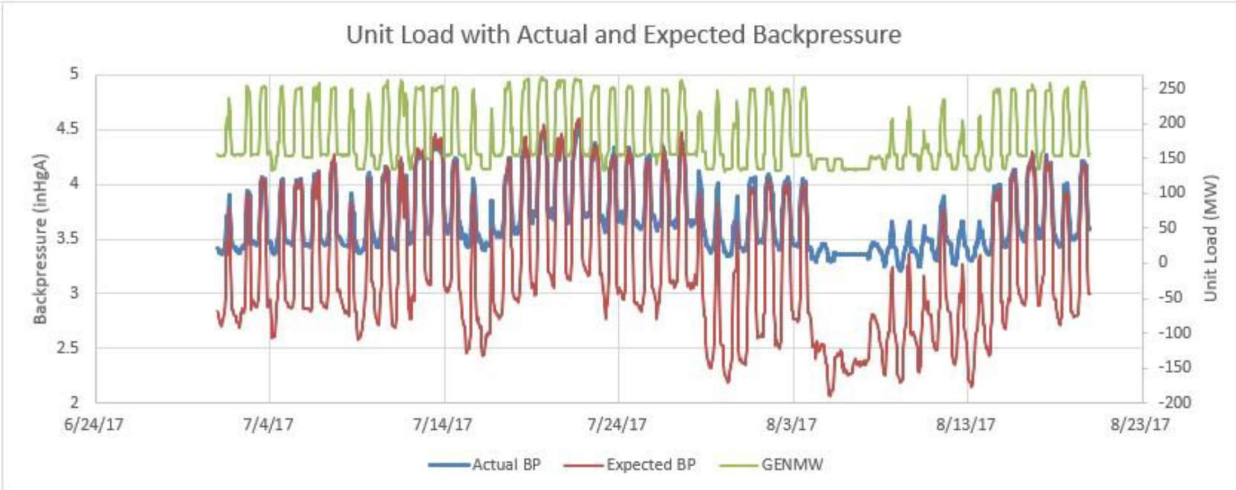


Figure 3-10 **Summer 2017 Backpressure vs Time (the actual is shown in red and blue is expected performance.)**

Figure 3-11 provides the perspective of actual and expected backpressure versus circulating water flow at low load. Back pressure deviations at low load for any unit can be significant.

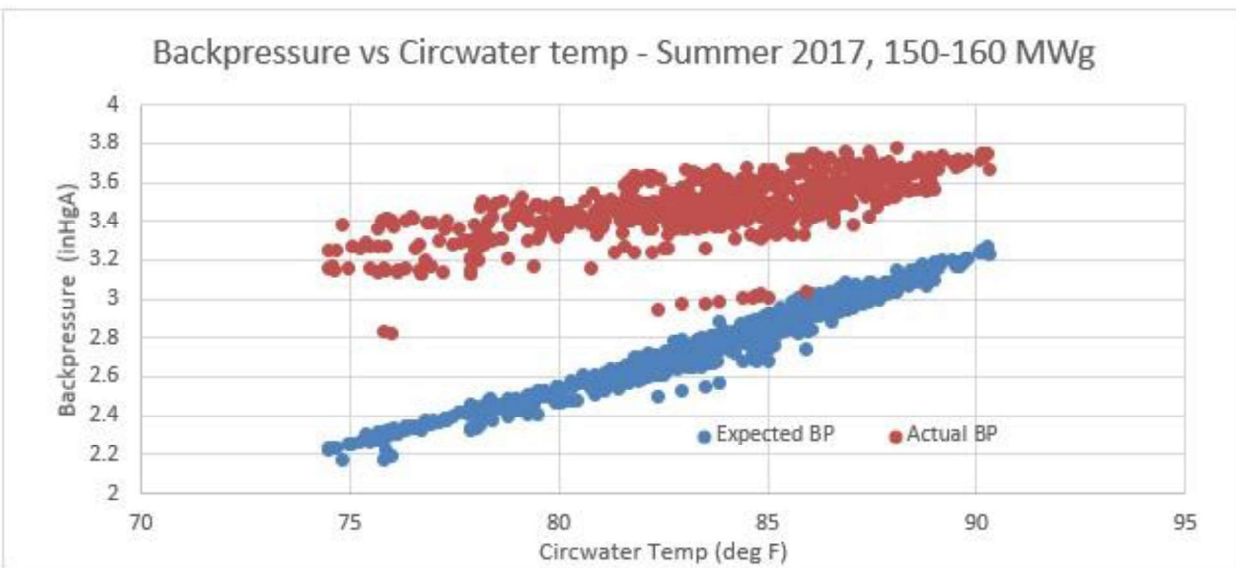


Figure 3-11 **Poor Condenser Performance at Low Load 2017**

When normal operation resumed in May of 2018, condenser performance looked good across load. The average heat rate impact from May to September of 2018 was estimated at 14 Btu/kWh, with a fuel-based heat rate cost of $5.7/h.

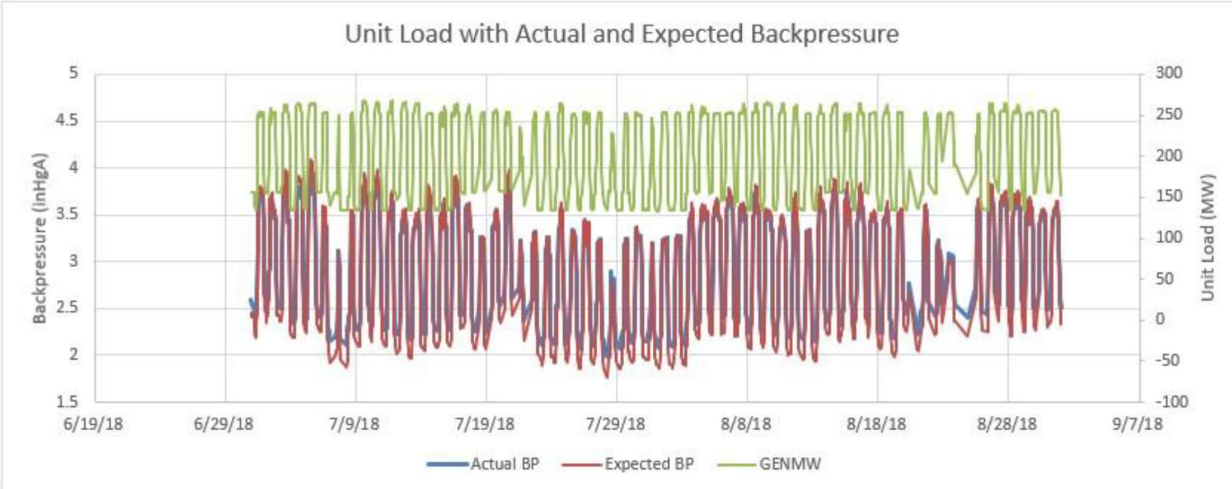


Figure 3-12 **2018 Post Outage Actual and Expected Backpressure Over Time**

On Figure 3-13 and 3-14, this actual back pressure is much closer to expected values in 2018. The remaining heat rate impact after the outage is likely to be due to the remaining gap in condenser performance at low load.

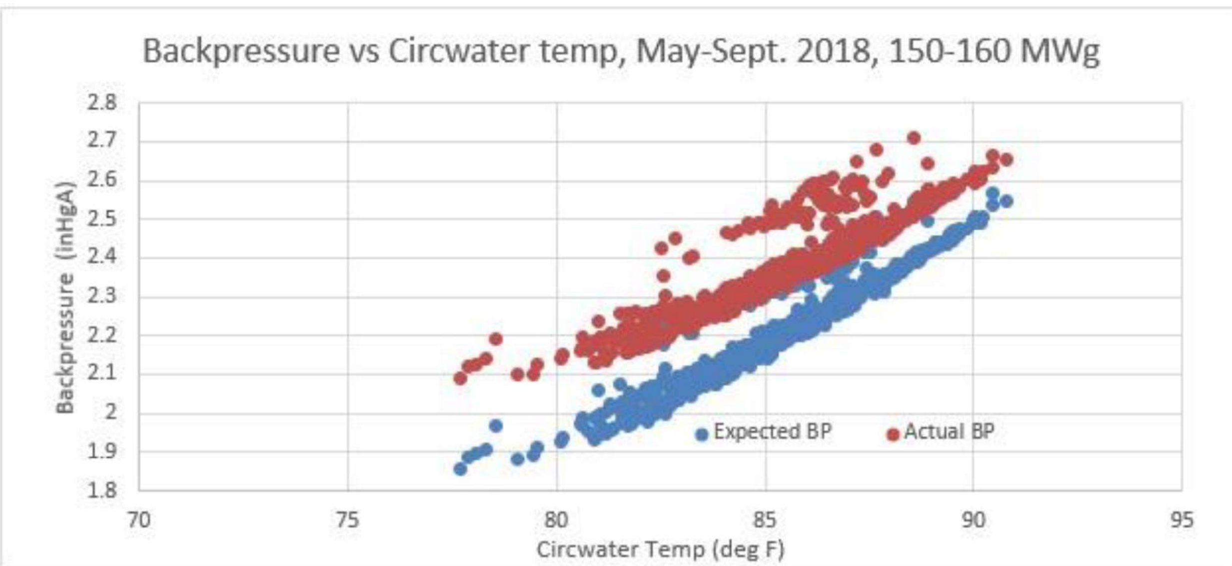


Figure 3-13 **2018 Post Outage Performance at Low Load vs Circulating Water Outlet Temperature**

Another noted change in condenser operation looking at both summers was calculated circulating water flow rate. Through the summer of 2017, average circulating water flow estimates were typically more than 25 percent below the design circulating water flow rate of 124,000 gpm. After the 2018 spring outage, estimated circulating water flow at full unit load was consistently 145,000 gpm, which is well above design. The estimated flow is sensitive to field measured circulating water temperatures and may need closer inspection.

The combination of these changes suggests significant air in-leakage or air removal improvements were made on the steam side, and water condenser cleaning yielded higher circulating water flows. According to plant personnel, they have repaired steam seal piping internal to the condenser neck. This issue has been appearing more regularly, and F.B. Culley 3 has had to perform similar repairs twice in the last two years. Across the span of the 15 months of operating data at full load, condenser performance was generally good, with cleanliness values at or above 70 percent as shown on Figure 3-14. However, because of low load performance problems, a fuel-based cost for 2017 operation is estimated to be $230,000 on an annual basis. Following the spring 2018 outage, the small deviation from expected condenser performance yields an estimated annual fuel cost of $35,000 on an annual basis. On the basis of the outage improvements seen in 2018, regularly scheduled maintenance and trending of performance should be sufficient to maintain good condenser performance.

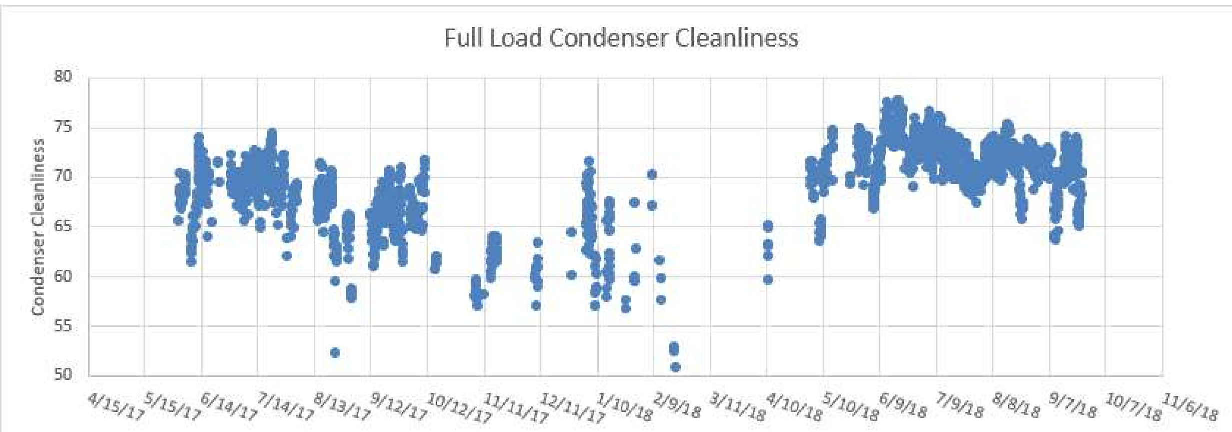


Figure 3-14 Full Load Cleanliness Results Over Time

3.8.3.2 A.B. Brown Unit 2 Improved Condenser Cleaning Strategies

Condenser performance was reviewed over 1.3 years of operating data. The timing covered two summers and one winter. Condenser performance was calculated across load and across seasons. In the process of reducing bad or suspicious data, 46 percent of the total data was removed. Nearly 6,000 hours of operating data ranging from 148 MW gross to full load was used for analysis.

Calculated results showed good performance for the condenser across load. It is suspected that measured back pressure readings may be biased low by approximately 0.2 to 0.3 in. HgA as actual back pressure consistently trended lower than expected and TTD at full load is unrealistically low (too good) at 3.5 to 5° F. The relationship between actual and expected back pressure versus circulating water temperature at constant load can be seen on Figure 3-15. As a result, condenser cleanliness values at full load consistently run greater than 90 percent and more than 100 percent at lower loads. Calculated circulating water flow rate is stable with estimated flows between

110,000 and 120,000 gpm. This is slightly below the design value of 124,000 gpm. Temperature rise across the condenser at full load runs 22° F versus design values of 20° F.

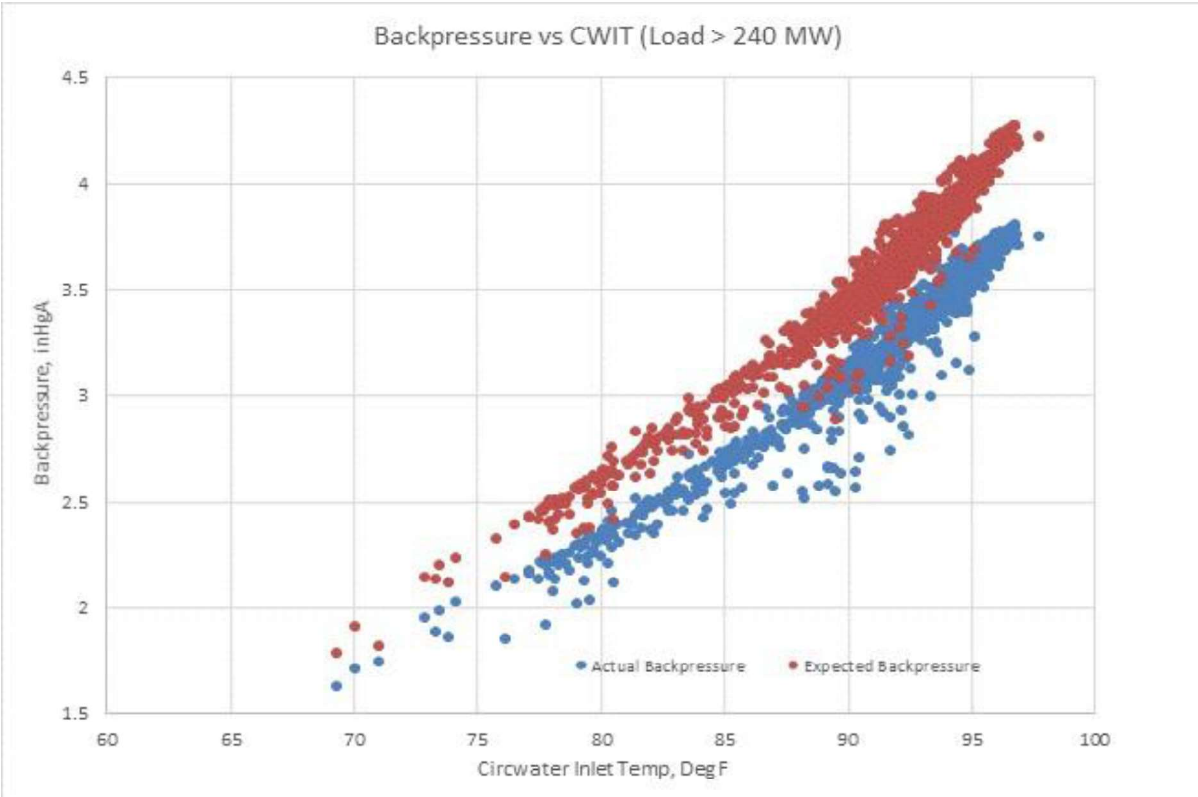


Figure 3-15 Condenser Back Pressure Versus Circulating Water Temperature at High Load

Generally, back pressure trended well across load during summer of 2017 and 2018. Separate trends of condenser performance behavior for summer 2017 and summer 2018 are provided on Figure 3-16 and Figure 3-17.

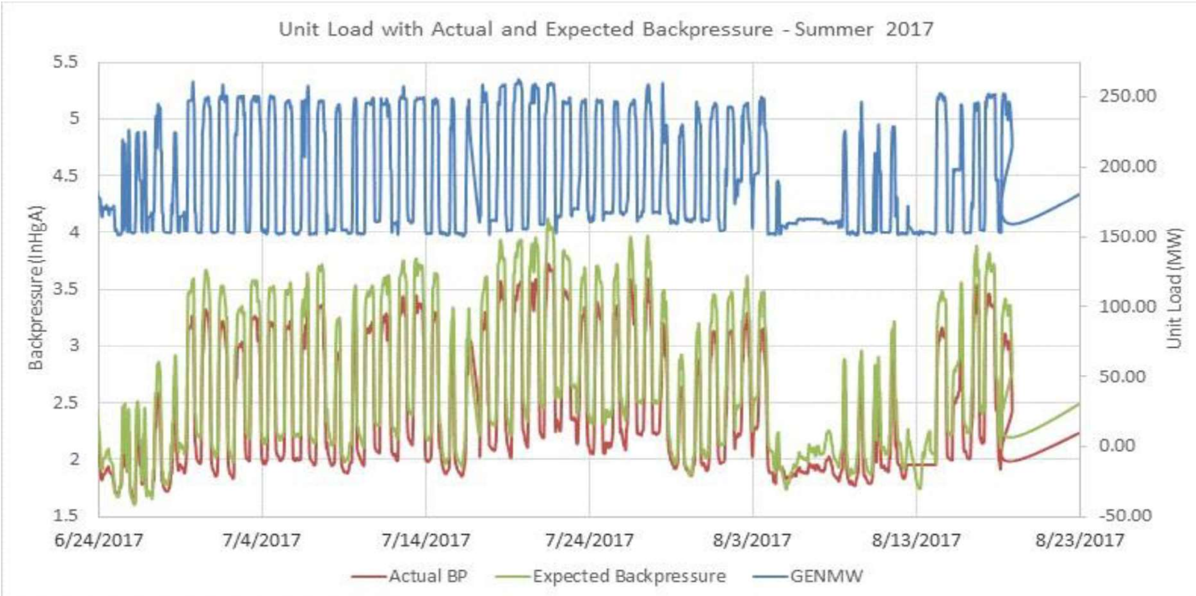


Figure 3-16 **Condenser Performance Summer 2017 Across Load**

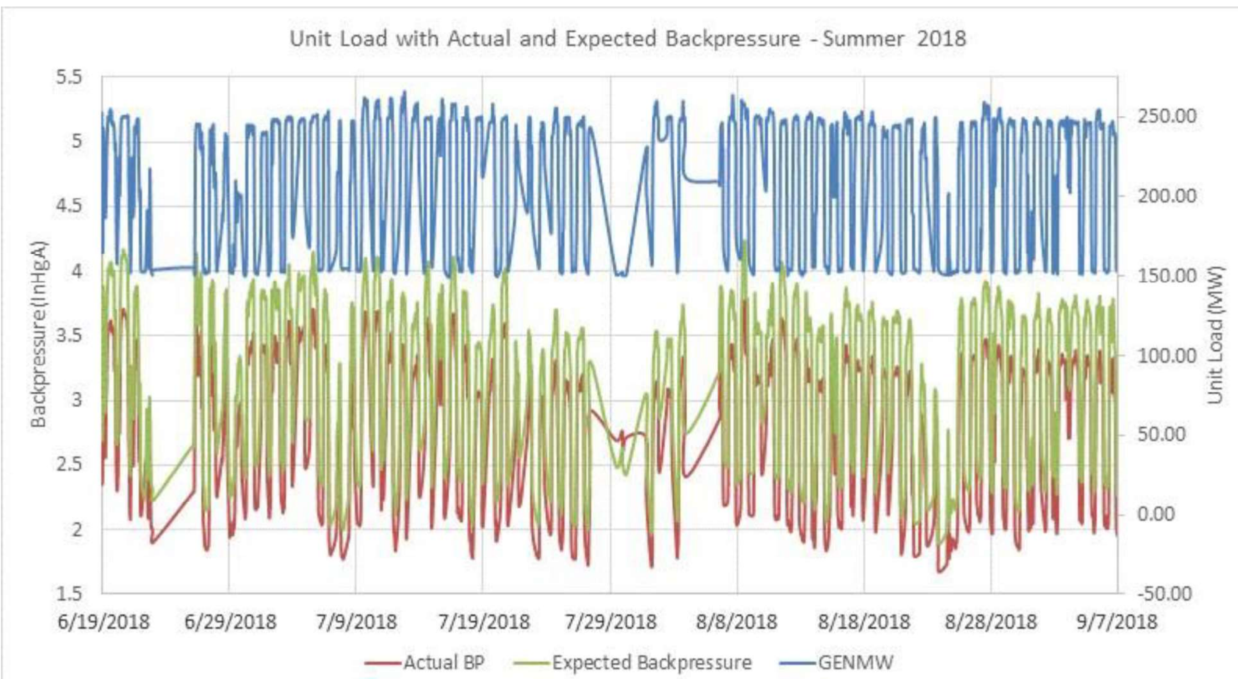


Figure 3-17 **Condenser Performance Summer 2018 Across Load**

Because the actual back pressure trends better than expected, no heat rate penalty is associated with normal unit operation for the data reviewed. Regularly scheduled maintenance and tracking of performance to highlight changes should be enough to maintain good condenser performance. For improved fidelity and confidence in performance metrics, the measured back pressure indication should be checked for accuracy and proper installation. The addition of more circulating water temperature measurements leaving the condenser would also improve accuracy of results by better capturing temperature stratification in the return piping.

3.8.3.3 F.B. Culley Unit 2 Improved Condenser Cleaning Strategies

For this study, 2 years of plant data were reviewed. Condenser performance was calculated across load and across seasons. Significant data reduction was necessary to eliminate offline or suspect data. This yielded more than 4,800 hours of operating data to characterize operation. In this data set, nearly 60 percent of the operating data were part load operation below 70 MW gross. Just over 30 percent of the data represented loads greater than 90 MW gross.

The hourly average heat rate impact of high condenser back pressure for Unit 2 is $42/h. Assuming the unit operates for 70 percent of a calendar year, this equates to a fuel cost of $257,000 per year. The average cleanliness value for Unit 2 is 28 percent. The highest achieved cleanliness values were in the low 50 percent range. The most significant observation with this analysis is shown on Figure 3-18 and is typical for the unit operation. Back pressure should have a strong load dependency. The Unit 2 back pressure data does not follow the expected pattern. The most likely cause of this behavior is significant air in-leakage or inadequate air removal system performance or limited capacity. Two additional factors are that Unit 2 relies upon steam jet air ejectors for air removal, and there is a suspected large air in-leakage around the turbine that has been present for years and has never been successfully resolved.

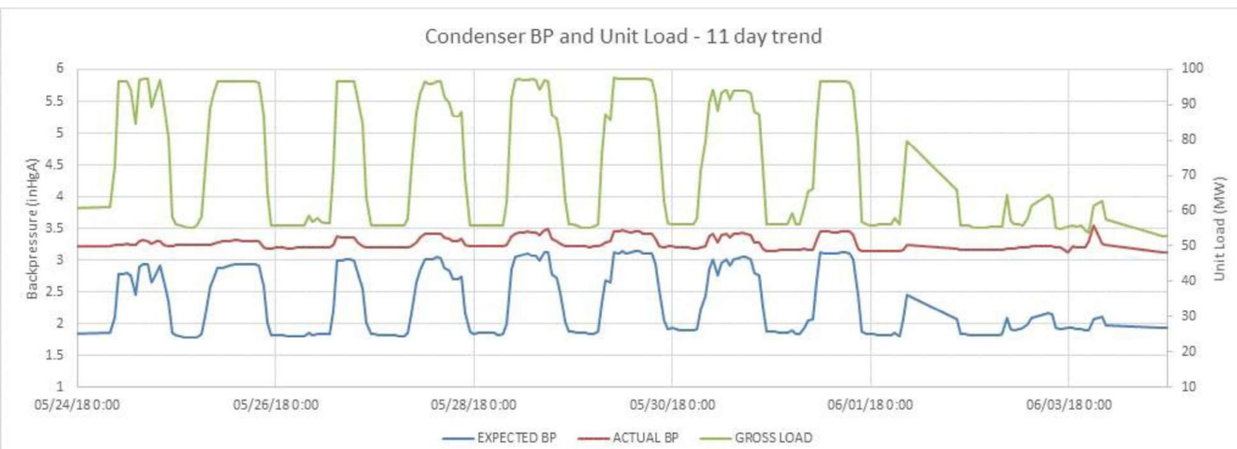


Figure 3-18 Condenser Back Pressure Versus Time (11 Day Trend)

The expected back pressure is calculated assuming no condenser tubes are plugged and cleanliness of 70 percent. Circulating water flow rate is calculated based on actual heat duty and circulating water temperature rise. Looking at full load operations across all season, there is a notable gap between actual and expected back pressure. This is shown on Figure 3-19, which illustrates back pressure versus circulating water temperature and versus time in Figure 3-20. The primary driver is expected to be the same issue of steam side air binding inhibiting lower backpressure at low circulating water temperatures.

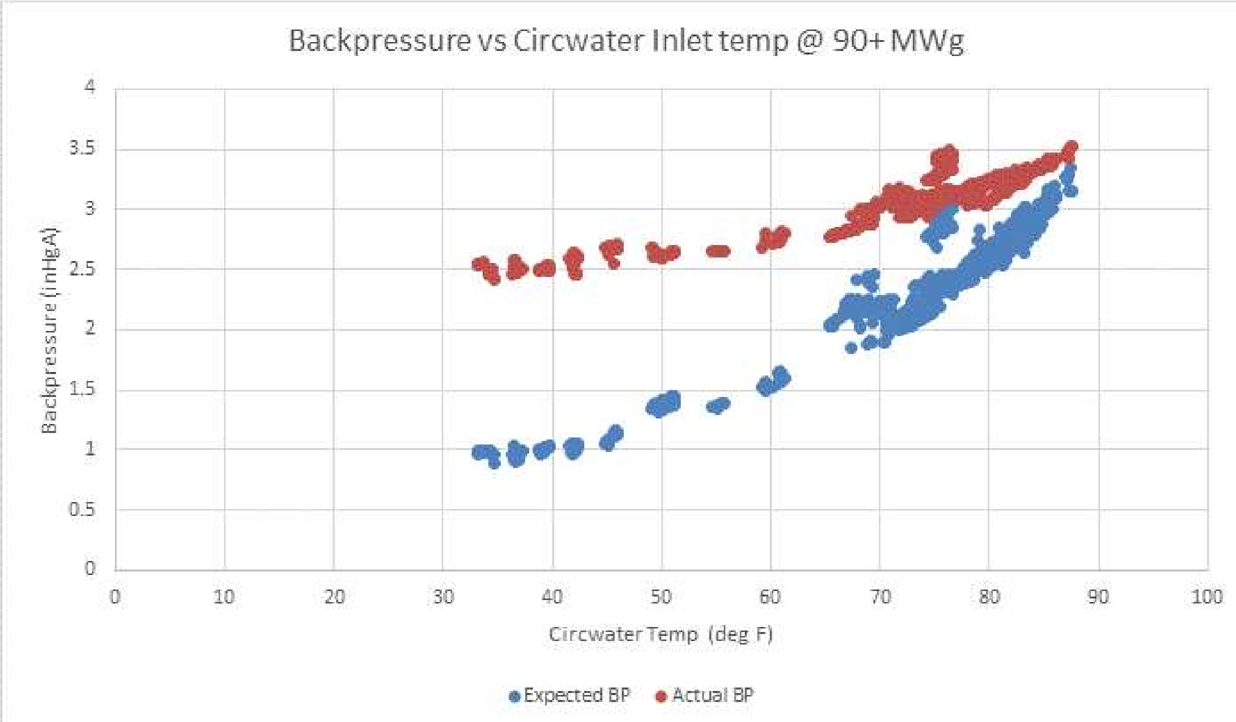


Figure 3-19 Condenser Back Pressure Versus Circulating Water Temperature

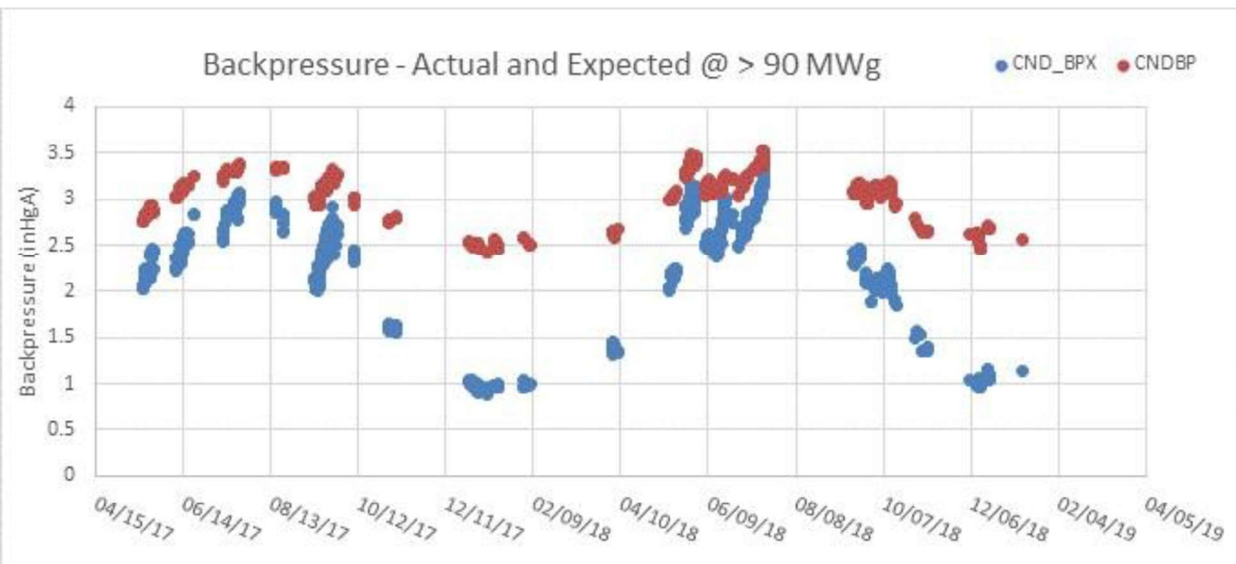


Figure 3-20 Back Pressure Versus Time (2-year trends)

3.8.3.4 F.B. Culley Unit 3 Improved Condenser Cleaning Strategies

The review of operating data for Unit 3 included 1.8 years of operational data. Data reduction to eliminate offline or suspect data eliminated 20 percent of the data, yielding more than 12,700 hours of data. The load used for analysis ranged from 135 MW gross up to 289 MW gross.

The hourly average heat rate impact of high condenser back pressure across all loads was 42 Btu/kWh and $24.8/h. Based on the data set for this analysis, the unit was in operation 90 percent of the time. Assuming this level of availability on an annual basis, the fuel cost associated with poor condenser performance is conservatively estimated at $196,000 per year. Load derates caused by high back pressure limits are probable for this unit, but highly variable, depending on the turbine design and manufacturer recommendation. Given the emphasis on efficiency opportunity in this report, an estimate for potential load impacts is not considered in this evaluation.

The highest sustained cleanliness value was slightly above 60 percent, with significant decay in performance lasting 9 of the 22 months, as seen on Figure 3-21.

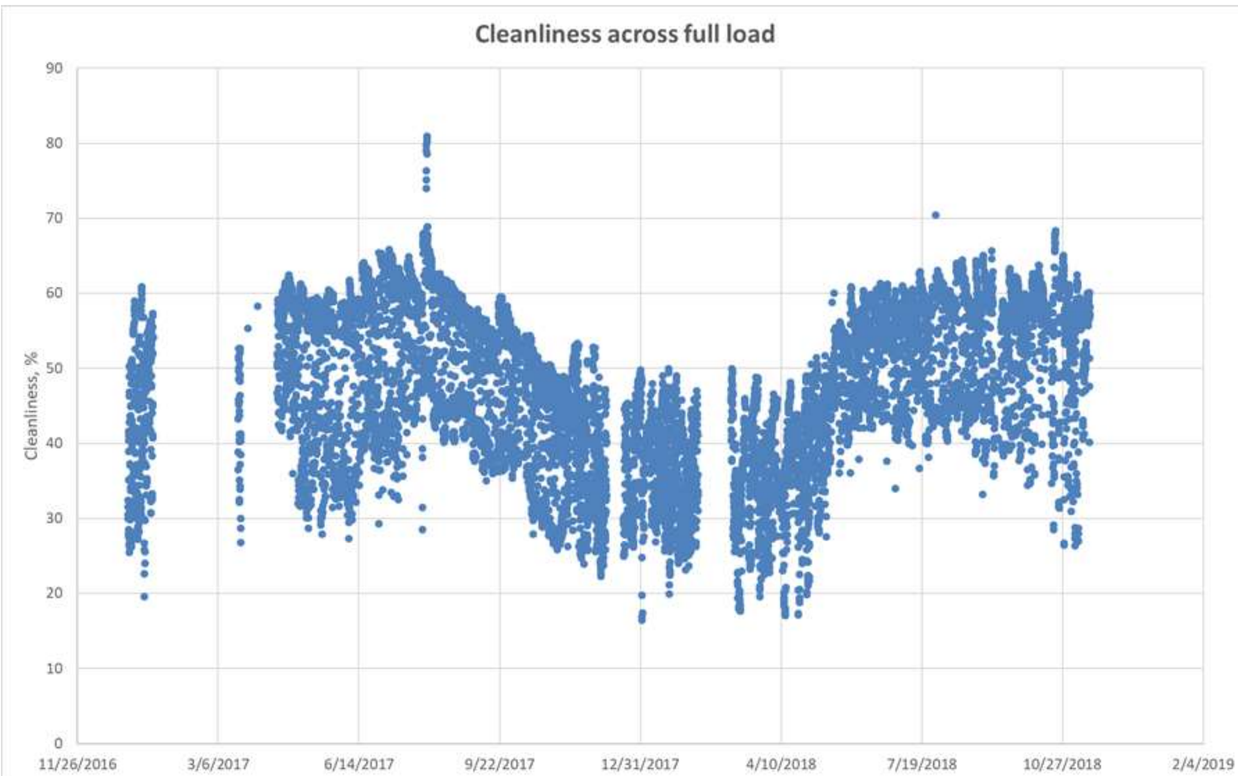


Figure 3-21 Condenser Cleanliness Across Time and Load

On closer look at the operating data, the repeated trend of increasing back pressure suggests significant tube sheet and or tube fouling issues on Figure 3-22.

Figure 3-22 Condenser Performance – 11 Day Trend

On Figure 3-23 and 3-24, a trend of back pressure versus circulating water inlet temperature at high load shows a mixture of good performance and very poor performance, especially at lower river temperatures.

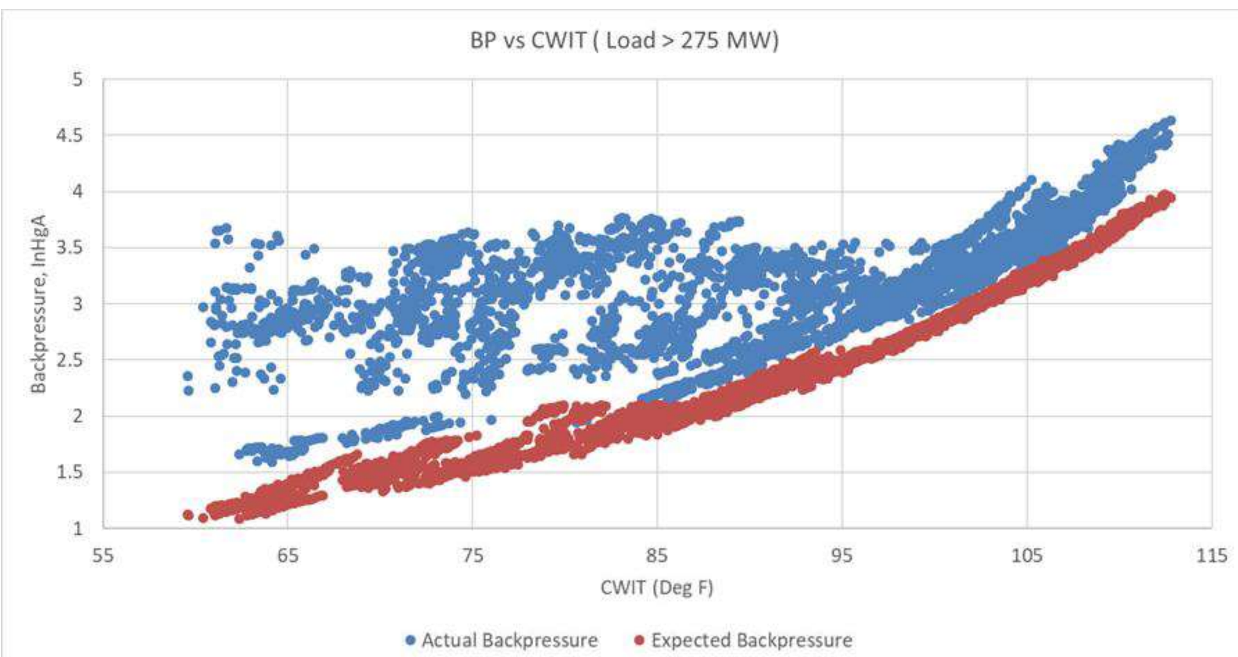


Figure 3-23 Condenser Back Pressure Versus Circulating Water Inlet Temperature

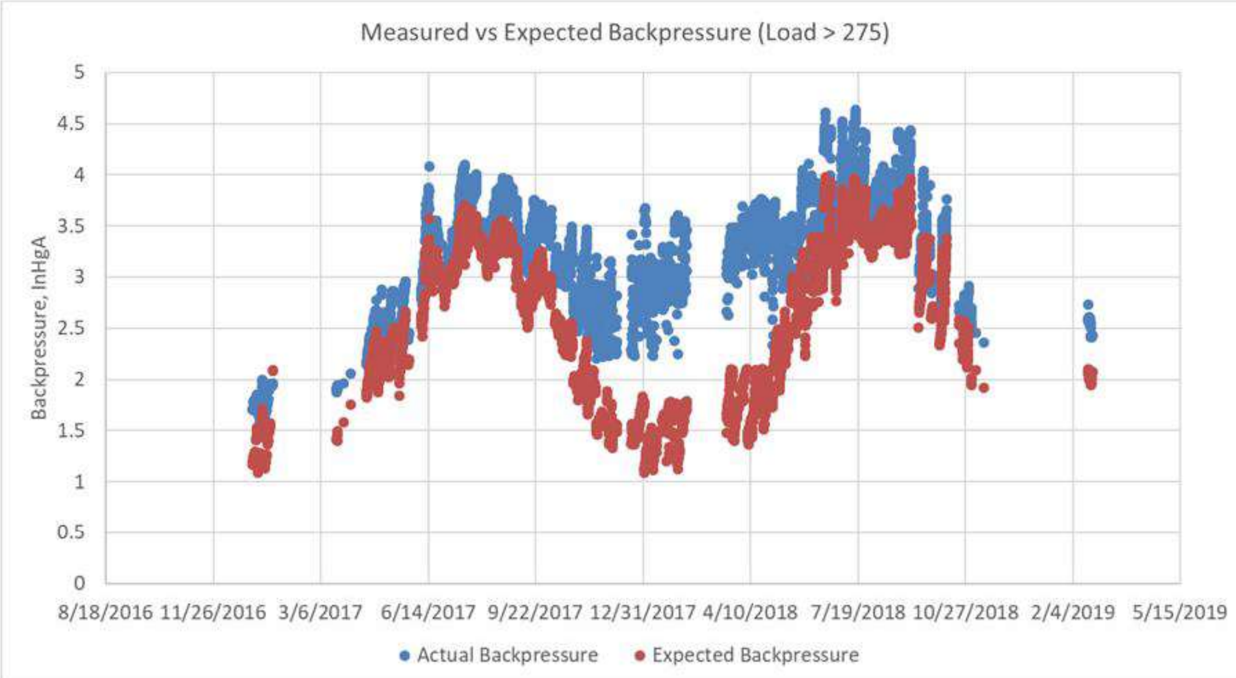


Figure 3-24 Condenser Back Pressure Versus Time at High Load

Condenser performance problems are unique to each unit and can be caused by a combination of factors. Considering the high availability, load capacity, and extent of condenser performance issues, this unit could be a candidate for added focus for improvement. If fouling the condenser is the primary concern felt by O&M personnel, payback on capital expenditure to rectify the situation may be too long, given this fuel cost. Adding backwash capability is likely to be cost prohibitive because of proximity of major piping work that would be required close to the turbine foundation. The addition of a debris filtering system would be beneficial and would be required before possible consideration of a ball cleaning system. The combined cost of these two capital improvements would likely be cost prohibitive.

4.0 Performance and CO_2 Production Estimates

High-level plant performance estimates were used to estimate the average annual CO_2 reduction. These performance benefits are summarized in Appendix B, Table B-1, Table B-2, Table B-3, and Table B-4, for A.B. Brown Unit 1, A.B. Brown Unit 2, F.B. Culley Unit 2, and F.B. Culley Unit 3, respectively. It should be noted that some projects will have overlapping performance impacts and benefits, so that the overall net benefit for a series of projects considered together will likely differ from the sum of the individual project benefits listed in each table.

The annual CO_2 production estimates shown in Tables 4-1 through 4-4 were based on the following plant performance basis. Net capacity, capacity factor, and the average annual net plant heat rate were provided by average annual values from the most recent full year data (2017) provided by SNL and Ventyx Velocity data.

Table 4-1 Basis for A.B. Brown Unit 1 CO_2 Reduction Estimates

GROSS/NET CAPACITY (MW)	NET CAPACITY FACTOR (%)	AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH)	FUEL HEAT INPUT (MBTU/Y)	LB CO_2/ MBTU (HHV)	ANNUAL CO_2 (TONS/Y)
265/248	43.7	11,575	11,427,186	205.2	1,172,428

Table 4-2 Basis for A.B. Brown Unit 2 CO_2 Reduction Estimates

GROSS/NET CAPACITY (MW)	NET CAPACITY FACTOR (%)	AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH)	FUEL HEAT INPUT (MBTU/Y)	LB CO_2/ MBTU (HHV)	ANNUAL CO_2 (TONS/Y)
265/248	45.7	11,007	11,554,139	205.2	1,185,450

Table 4-3 Basis for F.B. Culley Unit 2 CO_2 Reduction Estimates

GROSS/NET CAPACITY (MW)	NET CAPACITY FACTOR (%)	AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH)	FUEL HEAT INPUT (MBTU/Y)	LB CO_2/ MBTU (HHV)	ANNUAL CO_2 (TONS/Y)
104/90	22.2	12,639	2,395,298	205.0	245.523

Table 4-4 Basis for F.B. Culley Unit 3 CO_2 Reduction Estimates

GROSS/NET CAPACITY (MW)	NET CAPACITY FACTOR (%)	AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH)	FUEL HEAT INPUT (MBTU/Y)	LB CO_2/ MBTU (HHV)	ANNUAL CO_2 (TONS/Y)
287/270	70.5	10,552	20,885,900	205.1	2,141,818

Where:

Fuel Heat Input [MBtu/y] =

Net Capacity [MW] * 1,000 kW/MW * Capacity Factor [%] * 8,760 h/y * NPHR [Btu/kWh, HHV]/ (1,000,000 Btu/MBtu)

Annual CO_2 Production [tons/y] =

Fuel Heat Input [MBtu/y] * CO_2 Production Rate [CO_2 emissions, lbm/MBtu of Fuel Burned]/ (2,000 lbm/ ton)

5.0 Capital Cost Estimates

High-level capital cost estimates were developed for each alternative and are detailed with each HRI project in Section 3.0. These estimates are summarized in Appendix B, Tables B-1, B-2, B-3, and B-4 and are based on the information available and should be considered preliminary for comparative purposes. The estimates are on an overnight basis (exclusive of escalation). The estimates represent the total capital requirement for each project, assuming a turnkey EPC project execution strategy. Pricing was based on similar project pricing or Black & Veatch's internal database. Black & Veatch has not developed preliminary equipment sizing or layouts to determine the feasibility of adding the proposed equipment or performing the modifications that will be required to support their installation. More detailed evaluations will be required to verify, refine, and confirm the viability of any of the proposed projects that require equipment modification or additional area.

6.1 Project Risk Considerations

Factors that influence the ability to maintain power plant efficiency and corresponding CO_2 emissions reductions on an annual basis are discussed in this section.

6.2 EFFICIENCY DIFFERENCES DUE TO OPERATING PROFILE

Efficiency is significantly affected when plants operate under off-design conditions, particularly part-load operation or with frequent starts. The future operating characteristics of A.B. Brown Unit 1, A.B. Brown Unit 2, F.B. Culley Unit 2, and F.B. Culley Unit 3 can have a significant impact on the ability to achieve the expected efficiency gains and associated reduced CO_2 emissions.

6.2.1 Operating Load and Load Factor

Plants that operate with a low average output will have lower efficiency than their full-load design efficiency. Load or capacity factor describes the plant output over a period of time relative to the potential maximum; it depends on both running time at a given load and the operating load. Therefore, annual variation in both operating load and load factor can alter the CO_2 emissions as well as the benefit of capital projects intended to reduce plant emissions. Variation in the unit load factor can significantly impact the annual CO_2 emissions for a given generation rate.

Capital projects that may offer benefit in reducing outage duration or frequency may also see some benefit mitigated. For example, a plant may be able to extend the time between major overhauls and shorten the time required for a major overhaul of the steam turbine because of improved design. However, this could increase the hours the plant may run in a year and could increase the annual CO_2 emissions. Plant generation may be limited to avoid exceeding annual CO_2 emissions rates, negating some of the potential benefit of the upgrade.

6.2.2 Transient Operation

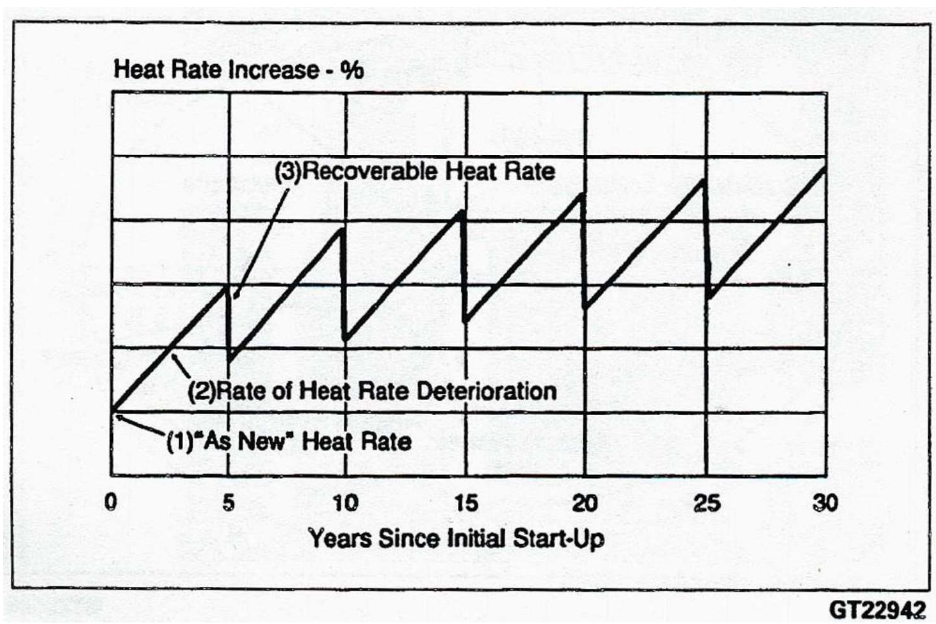
The greater the number of transients from steady state operating conditions that the plant experiences, the greater the impact to annual efficiency. During each of these transients, the plant will not be operating at peak performance. The influence of increasing renewable energy can affect the frequency of transient operation. Operation in frequency response mode, where steam flow and boiler firing fluctuate to regulate system frequency, can lead to more transients. Other situations may require frequent load changes, notably in response to power system constraints or power market pricing.

6.2.3 Plant Starts

Frequent shutdowns incur significant off-load energy losses, particularly during subsequent plant startup. Power plants operating in volatile or competitive markets, or operating as marginal providers of power, may be required to shut down frequently. This can also lead to deterioration in equipment condition, which will further affect annual plant efficiency and increase CO_2 emissions.

6.3 DETERIORATION

Figure 6-1 illustrates the characteristic performance deterioration that the steam turbine can be expected to experience between major overhauls. In addition, the ability of the steam turbine to economically recover from any deterioration in performance during a regularly scheduled maintenance overhaul is also illustrated. Any steam turbine retrofit is expected to experience a similar pattern of increasing deterioration, where increasingly, a portion of this deterioration is not viably recovered, even following a major overhaul. Turbine suppliers recognize the importance of sustained efficiency and work to incorporate features that result in superior sustained efficiency. The degree to which deterioration can be minimized by new designs is in large part dependent on the current design and feasible proven options. The ability of the steam turbine to sustain efficiency is a significant factor in achieving year after year CO_2 reduction.



Source: Steam Turbine Sustained Efficiency, GER-3750C

Figure 6-1 Steam Turbine Generator Heat Rate Change Over Time

Other plant equipment is also expected to see performance deterioration over the operating life after capital projects are implemented. The degree of deterioration and the rate at which it occurs is difficult to predict and presents a risk to the longer-term ability of the plants to sustain their efficiency gains.

6.4 PLANT MAINTENANCE

As well as ensuring plant availability, a key requirement of plant maintenance is to maintain peak operating efficiency. Improved maintenance and component replacement and upgrading can reduce energy losses.

Any poorly performing auxiliary equipment or individual components that affect performance will also contribute to the overall deterioration of plant performance over time, compounding the effects of deterioration in major components, such as the steam turbine. While not an intended outcome, plant upgrades can also result in increased maintenance if the expected improvements cannot be not achieved without increased or more complicated plant maintenance. Tables B-1, B-2, B-3, and B-4 (Appendix B) include an order-of-magnitude rating of comparative operating and maintenance cost impact associated with each of the given projects.

6.5 FUEL QUALITY IMPACTS

Variation in fuel quality can have a significant impact on the boiler efficiency. Reduced boiler efficiency will increase the required fuel heat input for a given generation which will increase CO_2 emissions. Variation in fuel composition can also have an effect on the pounds of CO_2 emission/MBtu of fuel burned.

6.6 AMBIENT CONDITIONS

Variation in ambient conditions can affect the condenser operating pressure and the resulting steam turbine output. In particular, higher wet bulb temperatures can have a significant impact on plant heat rate. Variation in annual average turbine back pressure because of wet bulb will affect the expected benefits of several of the heat rejection and steam turbine capital improvement projects.

Appendix A. Abbreviations and Acronyms

°F	Degrees Fahrenheit
ACE	Affordable Clean Energy (Plan)
ADSP	Advanced Design Steam Path
AH	Air Heater
AQCS	Air Quality Control System
BSER	Best System of Emission Reduction
Btu	British Thermal Unit
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPP	Clean Power Plan
DCA	Drain Cooler Approach
DCS	Distributed Control System
EGU	Electric Generating Unit
EPA	United States Environmental Protection Agency
EPRI	Electric Power Research Institute
FD	Forced Draft
Ft	Feet
GE	General Electric
GHG	Greenhouse Gas
gpm	Gallons per minute
h	Hour
HHV	Higher Heating Value
hp	Horsepower
HP	High Pressure
HRI	Heat Rate Improvement
ID	Induced Draft
IGBT	Insulated-Gate Bipolar Transistor
in. HgA	Inches of Mercury – Absolute
IP	Intermediate Pressure
IRP	Integrated Resource Plan
ISB	Intelligent Sootblowing
kW	Kilowatt
kWh	Kilowatt hour
lbm	Pound
LP	Low Pressure
MBtu	Million British Thermal Units

MW	Megawatt
NO_x	Nitrogen Oxide
NP	Normal Pressure
NPHR	Net Plant Heat Rate
NSR	New Source Review
OEM	Original Equipment Manufacturer
PA	Primary Air
PJFF	Pulse Jet Fabric Filter
rpm	Revolutions per Minute
SLR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
STG	Steam Turbine Generator
TTD	Terminal Temperature Difference
VFD	Variable Frequency Drive
VWO	Valve Wide Open
y	Year

Appendix B. Capital Cost and Performance Estimates

Table B-1 A.B. Brown Unit 1 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Steam Turbine	HP/IP Upgrades or Full Steam Path Upgrades	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Economizer	Redesign or Replacement	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Air Heater/Duct Leakage	Air Heater Basket, Seal, and Sector Plate Replacement	850	0.50	57.88	57,136	5,862	145.0	Low
Air Heater/Duct Leakage	Air Heater (Steam Coil) System Repairs	350	0.10	11.6	11,427	1,172	298.5	N/A
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Circulating Water Pumps	2,100	N/A	N/A	N/A	N/A	N/A	Low
Variable Frequency Drive (VFD) Upgrades	Cooling Tower Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	2,000	0.43	50.3	49,701	5,099	392.2	Low/Med
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	2,900	2.39	276.50	272,973	28,007	103.5	Low
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.25% reduction in excess O_2)	500	0.23	26.6	26,283	2,697	185.4	Low
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.50% reduction in excess O_2)	500	0.43	49.77	49,137	5,041	99.2	N/A

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.75% reduction in excess O_2)	500.0	0.60	69.5	68,563	7,035	71.1	Low
Intelligent Soot Blowing (ISB)	Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate.	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Improved O&M Practices	Heat rate improvement training.	15	0.30	34.7	34,282	3,517	4.3	Low
Improved O&M Practices	On-site heat rate appraisals.	Variable	Variable	N/A	N/A	N/A	N/A	Low
Improved O&M Practices	Improved Condenser Cleaning Strategies	N/A	0.15	17.4	17,141	1,759	N/A	Low

Table B-2 A.B. Brown Unit 2 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Steam Turbine	HP/IP Upgrades or Full Steam Path Upgrades	Not Recommended	N/A	N/A	N/A	N/A	N/A	No change
Economizer	Redesign or Replacement	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Air Heater/Duct Leakage	Air Heater Basket, Seal, and Sector Plate Replacement	850	0.50	55.0	57,771	5,927	143.4	Low
Air Heater/Duct Leakage	Air Heater (Steam Coil) System Repairs	350	0.10	11.0	11,554	1,185	295.2	Low
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	Not Recommended	N/A	N/A	N/A	N/A	N/A	Low
Variable Frequency Drive (VFD) Upgrades	Circulating Water Pumps	2,100	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Cooling Tower Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	2,000	0.26	28.6	30,015	3,080	649.4	N/A
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	2,900	1.33	146.3	153,608	15,760	184.0	Low
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.25% reduction in excess O_2)	500	0.23	25.3	26,575	2,727	183.4	Low/Med
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.50% reduction in excess O_2)	500	0.43	47.33	49,683	5,097	98.1	Low

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.75% reduction in excess O_2)	500	0.60	66.0	69,325	7,113	70.3	Low
Intelligent Soot Blowing (ISB)	Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate.	Not Recommended	N/A	N/A	N/A	N/A	N/A	Low
Improved O&M Practices	Heat rate improvement training.	15	0.30	33.0	34,662	3,556	4.2	Low
Improved O&M Practices	On-site heat rate appraisals.	Variable	Variable	N/A	N/A	N/A	N/A	Low
Improved O&M Practices	Improved Condenser Cleaning Strategies	N/A	N/A	N/A	N/A	N/A	N/A	Low

Table B-3 F.B. Culley Unit 2 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Steam Turbine	Full steam path upgrades.	10,400	1.4	176.9	33,534	3.44	3,025,611	No change
Economizer	Redesign or Replacement	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Air Heater/Duct Leakage	Air Heater Basket, Seal, and Sector Plate Replacement	476	0.50	63.2	11,976	1.23	387,744	Low
Air Heater/Duct Leakage	Air Heater (Steam Coil) System Repairs	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	600	0.60	75.8	14,372	1.47	407,294	N/A
Variable Frequency Drive (VFD) Upgrades	Circulating Water Pumps	900	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Cooling Tower Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	2,000	0.48	60.9	11,549	1.18	1,689,525	N/A
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.25% reduction in excess O_2)	500	0.26	32.9	6,228	0.64	783,257	Low/Med
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.50% reduction in excess O_2)	500	0.47	59.40	11,258	1.15	433,291	Low

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.75% reduction in excess O_2)	500	0.62	78.4	14,851	1.52	328,463	Low
Intelligent Soot Blowing (ISB)	Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate.	350	0.10	12.64	2,395	0.25	1,425,528	Low
Improved O&M Practices	Heat rate improvement training.	15	0.30	37.9	7,186	0.74	20,365	Low
Improved O&M Practices	On-site heat rate appraisals.	Variable	Variable	N/A	N/A	N/A	N/A	N/A
Improved O&M Practices	Improved Condenser Cleaning Strategies	N/A	0.42	53.1	10,060	1.03	N/A	Low

Table B-4 F.B. Culley Unit 3 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Steam Turbine	HP/IP upgrades	19,900	1.5	158.3	313,289	32,127	619.4	No change
Economizer	Major redesign with additional tube passes.	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Air Heater/Duct Leakage	Air Heater Basket, Seal, and Sector Plate Replacement	750	0.50	52.8	104,430	10,709	70.0	Low
Air Heater/Duct Leakage	Air Heater (Steam Coil) System Repairs	350	0.10	10.6	20,886	2,142	163	Low
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Circulating Water Pumps	2,100	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Cooling Tower Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	2,000	0.51	54.3	107,412	11,015	181.6	N/A
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.25% reduction in excess O_2)	500	0.25	26.4	52,215	5,355	93.4	Low/Med
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.50% reduction in excess O_2)	500	0.46	48.54	96,075	9,852	50.7	Low

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.75% reduction in excess O_2)	500	0.62	65.4	129,493	13,279	37.7	Low
Intelligent Soot Blowing (ISB)	Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate.	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Improved O&M Practices	Heat rate improvement training.	15	0.30	31.7	62,658	6,425	2.3	Low
Improved O&M Practices	On-site Heat Rate Appraisals	Variable	Variable	N/A	N/A	N/A	N/A	N/A
Improved O&M Practices	Improved Condenser Cleaning Strategies	N/A	0.44	46.4	91,898	9,424	#VALUE!	Low

Table B-5 Preliminary Fuel and O&M Cost Impacts Expansion, Including Useful Plant Life for all Units (Report – 5year)

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (5-year useful life)	Cost per ton of CO2 ($) (5-year useful Life)
ABB1	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	58	58,716	130.1	0	0	130.1	6.5	8.5	39.9	29.00
ABB1	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11.6	11,768	26.1	0	0	26.1	13.4	15.4	43.93310101	59.71
ABB1	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	420.0	N/A
ABB1	Induced Draft Fans	2021	2,900	2.2	254.65	258,330	572.2	-2	0	570.2	5.1	7.1	9.764152778	22.49
ABB1	Forced Draft Fans	2021	2,000	0.5	58	58,711	130.1	-2	0	128.1	15.6	17.6	271.9	68.23
ABB1	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.23	26.6	26,984	59.8	0	0	59.8	8.4	10.4	40.22590404	37.08
ABB1	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	50	50,489	111.8	0	0	111.8	4.5	6.5	-11.8	19.84
ABB1	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	69.5	70,504	156.2	0	0	156.2	3.2	5.2	-56.17667929	14.22
ABB1	Heat Rate Improvement Training.	2021	15	0.3	35	35,201	78.0	0	0	78.0	0.2	2.2	-75.0	0.85
ABB1	On-Site Heat Rate Appraisals.	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB1	Improved Condenser Cleaner Strategies	2021	N/A	0.2	17	17,651	39.1	0	0	39.1	N/A	N/A	N/A	N/A
ABB1	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-17,753	-39.3	0	N/A	-39.3	-19.1	-17.1	189.3	-75.26
ABB1	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-37,433	-82.9	0	N/A	-82.9	-13.0	-11.0	297.9	-50.94
ABB1	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-63,302	-140.2	0	N/A	-140.2	-10.0	-8.0	420.2	-39.15
ABB2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	55	58,348	129.2	0	0	129.2	6.6	8.6	40.8	29.00

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (5-year useful life)	Cost per ton of CO2 ($) (5-year useful Life)
ABB2	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11	11,670	25.8	0	0	25.8	13.5	15.5	44.15010234	59.71
ABB2	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	420.0	N/A
ABB2	Induced Draft Fans	2021	2,900	1.2	132.084	140,125	310.4	0	0	-2.0	-1,450.0	-1448.0	582	41.22
ABB2	Forced Draft Fans	2021	2,000	0.2	22	23,354	51.7	0	0	-2.0	-1,000.0	-998.0	402.0	170.59
ABB2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	3	25.3	26,840	59.5	0	0	59.5	8.4	10.4	40.54523538	2.84
ABB2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	47	50,211	111.2	0	0	111.2	4.5	6.5	-11.2	19.84
ABB2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	66	70,018	155.1	0	0	155.1	3.2	5.2	-55.09938596	14.22
ABB2	Heat Rate Improvement Training	2021	15	0.3	33	35,009	77.5	0	0	77.5	0.2	2.2	-74.5	0.85
ABB2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Improved Condenser Cleaner Strategies	2021	N/A	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-18,565	-41.1	0	N/A	-41.1	-18.2	-16.2	239.3250631	-100.34
ABB2	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-39,146	-86.7	0	N/A	-86.7	-12.4	-10.4	282.9	-47.39
ABB2	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-66,199	-146.6	0	N/A	-146.6	-9.5	-7.5	340.2219394	-27.96
FBC2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	476	0.5	63	12,782	28.3	0	0	28.3	16.8	18.8	66.9	16.24
FBC2	Circulating Water Pumps	2021	900	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	180	N/A
FBC2	Boiler Feed Pump	2021	600	0.6	76	15,337	34.0	-2	0	32.0	18.8	20.8	88.0	17.06
FBC2	Forced Draft Fans	2021	2,000	0.5	63.195	12,781	28.3	-2	0	26.3	76.0	78.0	373.6878337	68.23

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (5-year useful life)	Cost per ton of CO2 ($) (5-year useful Life)
FBC2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.3	33	6,654	14.7	0	0	14.7	33.9	35.9	85.3	32.81
FBC2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.47	59.4	12,014	26.6	0	0	26.6	18.8	20.8	73.38804211	18.15
FBC2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	78	15,856	35.1	0	0	35.1	14.2	16.2	64.9	13.76
FBC2	Synchronized Controlled Sootblowing System	2021	350	0.1	12.64	2,556	5.7	0	0	5.7	61.8	63.8	64.33711872	59.71
FBC2	Heat Rate Improvement Training	2021	15	0.3	38	7,665	17.0	0	0	17.0	0.9	2.9	-14.0	0.85
FBC2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC2	Improved Condenser Cleaner Strategies	2021	N/A	0.4	53	10,740	23.8	0	0	23.8	N/A	N/A	N/A	N/A
FBC3	HP/IP Upgrades	2022	19,900	1.5	158.3	280,580	621.5	0	0	621.5	32.0	35.0	3358.478728	226.31
FBC3	Air Heater Basket, Seal, and Sector Plate Replacement	2022	750	0.5	53	93,586	207.3	0	0	207.3	3.6	6.6	-57.3	25.59
FBC3	Air Heater (Steam Coil) System Repairs	2022	350	0.1	10.6	18,788	41.6	0	0	41.6	8.4	11.4	28.38202472	59.71
FBC3	Circulating Water Pumps	2022	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	420.0	N/A
FBC3	Forced Draft Fans	2022	2,000	0.46	48.5392	86,034	190.6	-2	0	188.6	10.6	13.6	211.424224	74.17
FBC3	Neural Network with 0.25% Reduction in Excess O_2	2022	500	0.3	26	46,793	103.7	0	0	103.7	4.8	7.8	-3.7	34.12
FBC3	Neural Network with 0.50% Reduction in Excess O_2	2022	500	0.46	48.54	86,035	190.6	0	0	190.6	2.6	5.6	-90.57891699	18.54

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (5-year useful life)	Cost per ton of CO2 ($) (5-year useful Life)
FBC3	Neural Network with 0.75% Reduction in Excess O_2	2022	500	0.6	65	115,919	256.8	0	0	256.8	1.9	4.9	-156.8	13.76
FBC3	Heat Rate Improvement Training	2022	15	0.3	31.7	56,187	124.5	0	0	124.5	0.1	3.1	-121.4613034	0.85
FBC3	On-Site Heat Rate Appraisals	2022	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC3	Improved Condenser Cleaner Strategies	2022	N/A	0.44	46.4	82,242	182.2	0	0	182.2	N/A	N/A	N/A	N/A
FBC3	Economizer (1 Tube Pass)	2022	750	-0.1	-14	-25,169	-55.8	0	195.0	139.2	5.4	8.4	10.8	70.12
FBC3	Economizer (2 Tube Pass)	2022	1,075	-0.28	-29.1	-51,578	-114.3	0	288.8	174.6	6.2	9.2	40.4	92.79
FBC3	Economizer (3 Tube Pass)	2022	1,400	-0.4	-45	-79,583	-176.3	0	382.6	206.3	6.8	9.8	73.7	117.78

Table B-6 Preliminary Fuel and O&M Cost Impacts Expansion, Including Useful Plant Life for all Units (Report –10 year)

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (10-year useful life)	Cost per ton of CO2 ($) (10-year useful Life)
ABB1	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	58	58,716	130.1	0	0	130.1	6.5	8.5	-45.1	14.50
ABB1	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11.6	11,768	26.1	0	0	26.1	13.4	15.4	8.9	29.85
ABB1	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	210.0	N/A
ABB1	Induced Draft Fans	2021	2,900	2.2	254.65	258,330	572.2	-2	0	570.2	5.1	7.1	-280.2	11.24
ABB1	Forced Draft Fans	2021	2,000	0.5	58	58,711	130.1	-2	0	128.1	15.6	17.6	71.9	34.12
ABB1	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.23	26.6	26,984	59.8	0	0	59.8	8.4	10.4	-9.8	18.54
ABB1	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	50	50,489	111.8	0	0	111.8	4.5	6.5	-61.8	9.92
ABB1	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	69.5	70,504	156.2	0	0	156.2	3.2	5.2	-106.2	7.11
ABB1	Heat Rate Improvement Training.	2021	15	0.3	35	35,201	78.0	0	0	78.0	0.2	2.2	-76.5	0.43
ABB1	On-Site Heat Rate Appraisals.	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB1	Improved Condenser Cleaner Strategies	2021	N/A	0.2	17	17,651	39.1	0	0	39.1	N/A	N/A	N/A	N/A
ABB1	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-17,753	-39.3	0	N/A	-39.3	-19.1	-17.1	114.3	-37.63
ABB1	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-37,433	-82.9	0	N/A	-82.9	-13.0	-11.0	190.4	-25.47
ABB1	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-63,302	-140.2	0	N/A	-140.2	-10.0	-8.0	280.2	-19.58

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (10-year useful life)	Cost per ton of CO2 ($) (10-year useful Life)
ABB2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	55	58,348	129.2	0	0	129.2	6.6	8.6	-44.2	14.50
ABB2	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11	11,670	25.8	0	0	25.8	13.5	15.5	9.2	29.85
ABB2	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	210.0	N/A
ABB2	Induced Draft Fans	2021	2,900	1.2	132.084	140,125	310.4	0	0	-2.0	-1,450.0	-1448.0	292.0	20.61
ABB2	Forced Draft Fans	2021	2,000	0.2	22	23,354	51.7	0	0	-2.0	-1,000.0	-998.0	202.0	85.29
ABB2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	3	25.3	26,840	59.5	0	0	59.5	8.4	10.4	-9.5	1.42
ABB2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	47	50,211	111.2	0	0	111.2	4.5	6.5	-61.2	9.92
ABB2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	66	70,018	155.1	0	0	155.1	3.2	5.2	-105.1	7.11
ABB2	Heat Rate Improvement Training	2021	15	0.3	33	35,009	77.5	0	0	77.5	0.2	2.2	-76.0	0.43
ABB2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Improved Condenser Cleaner Strategies	2021	N/A	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-18,565	-41.1	0	N/A	-41.1	-18.2	-16.2	139.3	-50.17
ABB2	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-39,146	-86.7	0	N/A	-86.7	-12.4	-10.4	182.9	-23.69
ABB2	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-66,199	-146.6	0	N/A	-146.6	-9.5	-7.5	240.2	-13.98

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (10-year useful life)	Cost per ton of CO2 ($) (10-year useful Life)
FBC2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	476	0.5	63	12,782	28.3	0	0	28.3	16.8	18.8	19.3	8.12
FBC2	Circulating Water Pumps	2021	900	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	90.0	N/A
FBC2	Boiler Feed Pump	2021	600	0.6	76	15,337	34.0	-2	0	32.0	18.8	20.8	28.0	8.53
FBC2	Forced Draft Fans	2021	2,000	0.5	63.195	12,781	28.3	-2	0	26.3	76.0	78.0	173.7	34.12
FBC2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.3	33	6,654	14.7	0	0	14.7	33.9	35.9	35.3	16.40
FBC2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.47	59.4	12,014	26.6	0	0	26.6	18.8	20.8	23.4	9.07
FBC2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	78	15,856	35.1	0	0	35.1	14.2	16.2	14.9	6.88
FBC2	Synchronized Controlled Sootblowing System	2021	350	0.1	12.64	2,556	5.7	0	0	5.7	61.8	63.8	29.3	29.85
FBC2	Heat Rate Improvement Training	2021	15	0.3	38	7,665	17.0	0	0	17.0	0.9	2.9	-15.5	0.43
FBC2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC2	Improved Condenser Cleaner Strategies	2021	N/A	0.4	53	10,740	23.8	0	0	23.8	N/A	N/A	N/A	N/A
FBC3	HP/IP Upgrades	2022	19,900	1.5	158.3	280,580	621.5	0	0	621.5	32.0	35.0	1,368.5	113.16
FBC3	Air Heater Basket, Seal, and Sector Plate Replacement	2022	750	0.5	53	93,586	207.3	0	0	207.3	3.6	6.6	-132.3	12.79
FBC3	Air Heater (Steam Coil) System Repairs	2022	350	0.1	10.6	18,788	41.6	0	0	41.6	8.4	11.4	-6.6	29.85

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (10-year useful life)	Cost per ton of CO2 ($) (10-year useful Life)
FBC3	Circulating Water Pumps	2022	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	210.0	N/A
FBC3	Forced Draft Fans	2022	2,000	0.46	48.5392	86,034	190.6	-2	0	188.6	10.6	13.6	11.4	37.08
FBC3	Neural Network with 0.25% Reduction in Excess O_2	2022	500	0.3	26	46,793	103.7	0	0	103.7	4.8	7.8	-53.7	17.06
FBC3	Neural Network with 0.50% Reduction in Excess O_2	2022	500	0.46	48.54	86,035	190.6	0	0	190.6	2.6	5.6	-140.6	9.27
FBC3	Neural Network with 0.75% Reduction in Excess O_2	2022	500	0.6	65	115,919	256.8	0	0	256.8	1.9	4.9	-206.8	6.88
FBC3	Heat Rate Improvement Training	2022	15	0.3	31.7	56,187	124.5	0	0	124.5	0.1	3.1	-123.0	0.43
FBC3	On-Site Heat Rate Appraisals	2022	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC3	Improved Condenser Cleaner Strategies	2022	N/A	0.44	46.4	82,242	182.2	0	0	182.2	N/A	N/A	N/A	N/A
FBC3	Economizer (1 Tube Pass)	2022	750	-0.1	-14	-25,169	-55.8	0	195.0	139.2	5.4	8.4	-64.2	35.06
FBC3	Economizer (2 Tube Pass)	2022	1,075	-0.28	-29.1	-51,578	-114.3	0	288.8	174.6	6.2	9.2	-67.1	46.40
FBC3	Economizer (3 Tube Pass)	2022	1,400	-0.4	-45	-79,583	-176.3	0	382.6	206.3	6.8	9.8	-66.3	58.89

Table B-7 Preliminary Fuel and O&M Cost Impacts Expansion, Including Useful Plant Life for all Units (Report –15 year)

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (15-year useful life)	Cost per ton of CO2 ($) (15-year useful Life)
ABB1	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	58	58,716	130.1	0	0	130.1	6.5	8.5	-73.4	9.67
ABB1	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11.6	11,768	26.1	0	0	26.1	13.4	15.4	-2.7	19.90
ABB1	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
ABB1	Induced Draft Fans	2021	2,900	2.2	254.65	258,330	572.2	-2	0	570.2	5.1	7.1	-376.9	7.50
ABB1	Forced Draft Fans	2021	2,000	0.5	58	58,711	130.1	-2	0	128.1	15.6	17.6	5.3	22.74
ABB1	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.23	26.6	26,984	59.8	0	0	59.8	8.4	10.4	-26.4	12.36
ABB1	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	50	50,489	111.8	0	0	111.8	4.5	6.5	-78.5	6.61
ABB1	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	69.5	70,504	156.2	0	0	156.2	3.2	5.2	-122.8	4.74
ABB1	Heat Rate Improvement Training.	2021	15	0.3	35	35,201	78.0	0	0	78.0	0.2	2.2	-77.0	0.28
ABB1	On-Site Heat Rate Appraisals.	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB1	Improved Condenser Cleaner Strategies	2021	N/A	0.2	17	17,651	39.1	0	0	39.1	N/A	N/A	N/A	N/A
ABB1	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-17,753	-39.3	0	N/A	-39.3	-19.1	-17.1	89.3	-25.09
ABB1	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-37,433	-82.9	0	N/A	-82.9	-13.0	-11.0	154.6	-16.98
ABB1	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-63,302	-140.2	0	N/A	-140.2	-10.0	-8.0	233.6	-13.05

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (15-year useful life)	Cost per ton of CO2 ($) (15-year useful Life)
ABB2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	55	58,348	129.2	0	0	129.2	6.6	8.6	-72.6	9.67
ABB2	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11	11,670	25.8	0	0	25.8	13.5	15.5	-2.5	19.90
ABB2	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
ABB2	Induced Draft Fans	2021	2,900	1.2	132.084	140,125	310.4	0	0	-2.0	-1,450.0	-1448.0	195.3	13.74
ABB2	Forced Draft Fans	2021	2,000	0.2	22	23,354	51.7	0	0	-2.0	-1,000.0	-998.0	135.3	56.86
ABB2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	3	25.3	26,840	59.5	0	0	59.5	8.4	10.4	-26.1	0.95
ABB2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	47	50,211	111.2	0	0	111.2	4.5	6.5	-77.9	6.61
ABB2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	66	70,018	155.1	0	0	155.1	3.2	5.2	-121.8	4.74
ABB2	Heat Rate Improvement Training	2021	15	0.3	33	35,009	77.5	0	0	77.5	0.2	2.2	-76.5	0.28
ABB2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Improved Condenser Cleaner Strategies	2021	N/A	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-18,565	-41.1	0	N/A	-41.1	-18.2	-16.2	106.0	-33.45
ABB2	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-39,146	-86.7	0	N/A	-86.7	-12.4	-10.4	149.6	-15.80
ABB2	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-66,199	-146.6	0	N/A	-146.6	-9.5	-7.5	206.9	-9.32

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (15-year useful life)	Cost per ton of CO2 ($) (15-year useful Life)
FBC2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	476	0.5	63	12,782	28.3	0	0	28.3	16.8	18.8	3.4	5.41
FBC2	Circulating Water Pumps	2021	900	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	60.0	N/A
FBC2	Boiler Feed Pump	2021	600	0.6	76	15,337	34.0	-2	0	32.0	18.8	20.8	8.0	5.69
FBC2	Forced Draft Fans	2021	2,000	0.5	63.195	12,781	28.3	-2	0	26.3	76.0	78.0	107.0	22.74
FBC2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.3	33	6,654	14.7	0	0	14.7	33.9	35.9	18.6	10.94
FBC2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.47	59.4	12,014	26.6	0	0	26.6	18.8	20.8	6.7	6.05
FBC2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	78	15,856	35.1	0	0	35.1	14.2	16.2	-1.8	4.59
FBC2	Synchronized Controlled Sootblowing System	2021	350	0.1	12.64	2,556	5.7	0	0	5.7	61.8	63.8	17.7	19.90
FBC2	Heat Rate Improvement Training	2021	15	0.3	38	7,665	17.0	0	0	17.0	0.9	2.9	-16.0	0.28
FBC2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC2	Improved Condenser Cleaner Strategies	2021	N/A	0.4	53	10,740	23.8	0	0	23.8	N/A	N/A	N/A	N/A
FBC3	HP/IP Upgrades	2022	19,900	1.5	158.3	280,580	621.5	0	0	621.5	32.0	35.0	705.1	75.44
FBC3	Air Heater Basket, Seal, and Sector Plate Replacement	2022	750	0.5	53	93,586	207.3	0	0	207.3	3.6	6.6	-157.3	8.53
FBC3	Air Heater (Steam Coil) System Repairs	2022	350	0.1	10.6	18,788	41.6	0	0	41.6	8.4	11.4	-18.3	19.90

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (15-year useful life)	Cost per ton of CO2 ($) (15-year useful Life)
FBC3	Circulating Water Pumps	2022	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
FBC3	Forced Draft Fans	2022	2,000	0.46	48.5392	86,034	190.6	-2	0	188.6	10.6	13.6	-55.2	24.72
FBC3	Neural Network with 0.25% Reduction in Excess O_2	2022	500	0.3	26	46,793	103.7	0	0	103.7	4.8	7.8	-70.3	11.37
FBC3	Neural Network with 0.50% Reduction in Excess O_2	2022	500	0.46	48.54	86,035	190.6	0	0	190.6	2.6	5.6	-157.2	6.18
FBC3	Neural Network with 0.75% Reduction in Excess O_2	2022	500	0.6	65	115,919	256.8	0	0	256.8	1.9	4.9	-223.4	4.59
FBC3	Heat Rate Improvement Training	2022	15	0.3	31.7	56,187	124.5	0	0	124.5	0.1	3.1	-123.5	0.28
FBC3	On-Site Heat Rate Appraisals	2022	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC3	Improved Condenser Cleaner Strategies	2022	N/A	0.44	46.4	82,242	182.2	0	0	182.2	N/A	N/A	N/A	N/A
FBC3	Economizer (1 Tube Pass)	2022	750	-0.1	-14	-25,169	-55.8	0	195.0	139.2	5.4	8.4	-89.2	23.37
FBC3	Economizer (2 Tube Pass)	2022	1,075	-0.28	-29.1	-51,578	-114.3	0	288.8	174.6	6.2	9.2	-102.9	30.93
FBC3	Economizer (3 Tube Pass)	2022	1,400	-0.4	-45	-79,583	-176.3	0	382.6	206.3	6.8	9.8	-113	39.26

Table B-8 Preliminary Fuel and O&M Cost Impacts Expansion, Including Useful Plant Life for all Units (Report –20 year)

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (20-year useful life)	Cost per ton of CO2 ($) (20-year useful Life)
ABB1	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	58	58,716	130.1	0	0	130.1	6.5	8.5	-73.4	9.67
ABB1	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11.6	11,768	26.1	0	0	26.1	13.4	15.4	-2.7	19.90
ABB1	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
ABB1	Induced Draft Fans	2021	2,900	2.2	254.65	258,330	572.2	-2	0	570.2	5.1	7.1	-376.9	7.50
ABB1	Forced Draft Fans	2021	2,000	0.5	58	58,711	130.1	-2	0	128.1	15.6	17.6	5.3	22.74
ABB1	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.23	26.6	26,984	59.8	0	0	59.8	8.4	10.4	-26.4	12.36
ABB1	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	50	50,489	111.8	0	0	111.8	4.5	6.5	-78.5	6.61
ABB1	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	69.5	70,504	156.2	0	0	156.2	3.2	5.2	-122.8	4.74
ABB1	Heat Rate Improvement Training.	2021	15	0.3	35	35,201	78.0	0	0	78.0	0.2	2.2	-77.0	0.28
ABB1	On-Site Heat Rate Appraisals.	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB1	Improved Condenser Cleaner Strategies	2021	N/A	0.2	17	17,651	39.1	0	0	39.1	N/A	N/A	N/A	N/A
ABB1	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-17,753	-39.3	0	N/A	-39.3	-19.1	-17.1	76.8	-18.81
ABB1	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-37,433	-82.9	0	N/A	-82.9	-13.0	-11.0	136.7	-12.73
ABB1	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-63,302	-140.2	0	N/A	-140.2	-10.0	-8.0	210.2	-9.79
ABB2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	55	58,348	129.2	0	0	129.2	6.6	8.6	-72.6	9.67

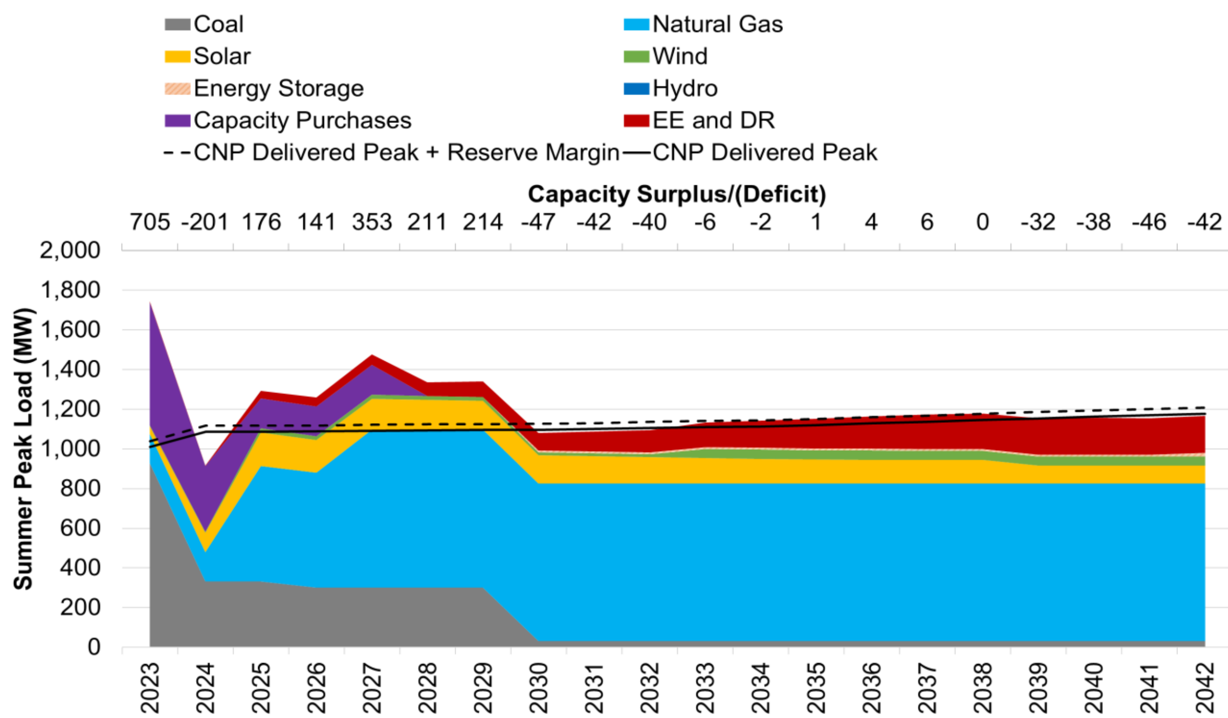
Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (20-year useful life)	Cost per ton of CO2 ($) (20-year useful Life)
ABB2	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11	11,670	25.8	0	0	25.8	13.5	15.5	-2.5	19.90
ABB2	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
ABB2	Induced Draft Fans	2021	2,900	1.2	132.084	140,125	310.4	0	0	-2.0	-1,450.0	-1448.0	195.3	13.74
ABB2	Forced Draft Fans	2021	2,000	0.2	22	23,354	51.7	0	0	-2.0	-1,000.0	-998.0	135.3	56.86
ABB2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	3	25.3	26,840	59.5	0	0	59.5	8.4	10.4	-26.1	0.95
ABB2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	47	50,211	111.2	0	0	111.2	4.5	6.5	-77.9	6.61
ABB2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	66	70,018	155.1	0	0	155.1	3.2	5.2	-121.8	4.74
ABB2	Heat Rate Improvement Training	2021	15	0.3	33	35,009	77.5	0	0	77.5	0.2	2.2	-76.5	0.28
ABB2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Improved Condenser Cleaner Strategies	2021	N/A	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-18,565	-41.1	0	N/A	-41.1	-18.2	-16.2	106.0	-33.45
ABB2	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-39,146	-86.7	0	N/A	-86.7	-12.4	-10.4	149.6	-15.80
ABB2	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-66,199	-146.6	0	N/A	-146.6	-9.5	-7.5	206.9	-9.32
FBC2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	476	0.5	63	12,782	28.3	0	0	28.3	16.8	18.8	3.4	5.41
FBC2	Circulating Water Pumps	2021	900	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	60.0	N/A
FBC2	Boiler Feed Pump	2021	600	0.6	76	15,337	34.0	-2	0	32.0	18.8	20.8	8.0	5.69
FBC2	Forced Draft Fans	2021	2,000	0.5	63.195	12,781	28.3	-2	0	26.3	76.0	78.0	107.0	22.74

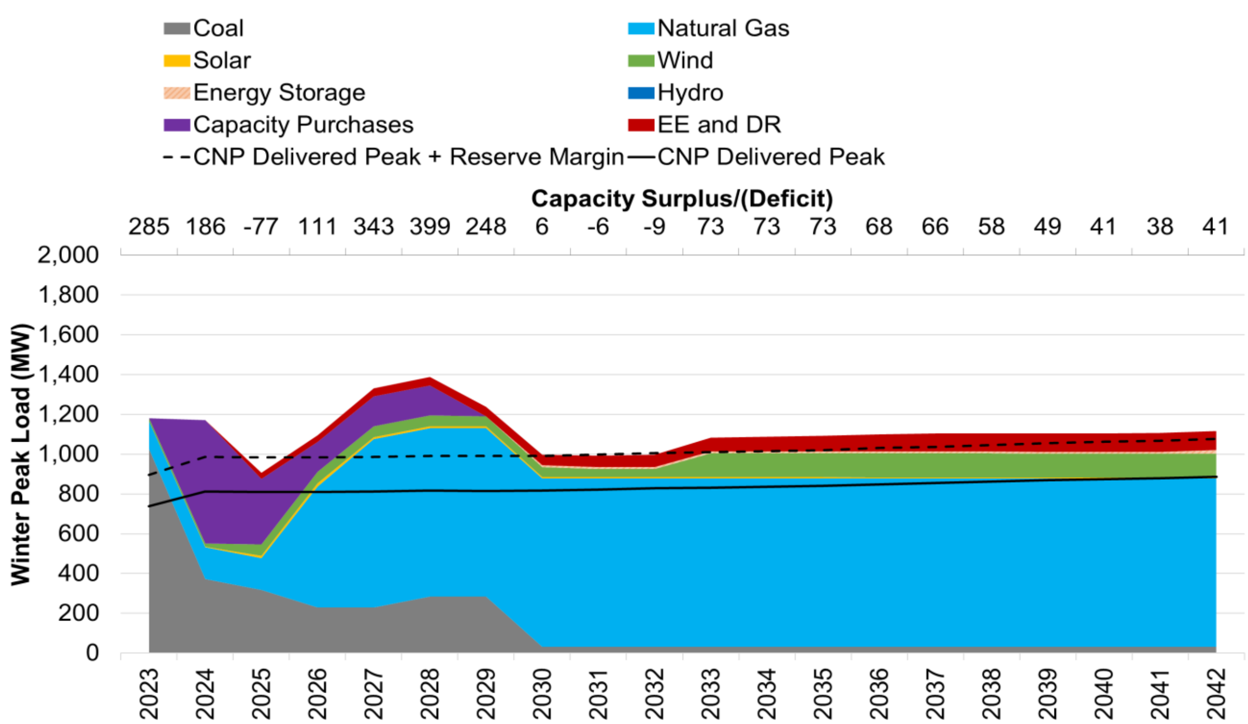
Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (20-year useful life)	Cost per ton of CO2 ($) (20-year useful Life)
FBC2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.3	33	6,654	14.7	0	0	14.7	33.9	35.9	18.6	10.94
FBC2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.47	59.4	12,014	26.6	0	0	26.6	18.8	20.8	6.7	6.05
FBC2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	78	15,856	35.1	0	0	35.1	14.2	16.2	-1.8	4.59
FBC2	Synchronized Controlled Sootblowing System	2021	350	0.1	12.64	2,556	5.7	0	0	5.7	61.8	63.8	17.7	19.90
FBC2	Heat Rate Improvement Training	2021	15	0.3	38	7,665	17.0	0	0	17.0	0.9	2.9	-16.0	0.28
FBC2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC2	Improved Condenser Cleaner Strategies	2021	N/A	0.4	53	10,740	23.8	0	0	23.8	N/A	N/A	N/A	N/A
FBC3	HP/IP Upgrades	2022	19,900	1.5	158.3	280,580	621.5	0	0	621.5	32.0	35.0	705.1	75.44
FBC3	Air Heater Basket, Seal, and Sector Plate Replacement	2022	750	0.5	53	93,586	207.3	0	0	207.3	3.6	6.6	-157.3	8.53
FBC3	Air Heater (Steam Coil) System Repairs	2022	350	0.1	10.6	18,788	41.6	0	0	41.6	8.4	11.4	-18.3	19.90
FBC3	Circulating Water Pumps	2022	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
FBC3	Forced Draft Fans	2022	2,000	0.46	48.5392	86,034	190.6	-2	0	188.6	10.6	13.6	-55.2	24.72
FBC3	Neural Network with 0.25% Reduction in Excess O_2	2022	500	0.3	26	46,793	103.7	0	0	103.7	4.8	7.8	-70.3	11.37
FBC3	Neural Network with 0.50% Reduction in Excess O_2	2022	500	0.46	48.54	86,035	190.6	0	0	190.6	2.6	5.6	-157.2	6.18

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (20-year useful life)	Cost per ton of CO2 ($) (20-year useful Life)
FBC3	Neural Network with 0.75% Reduction in Excess O_2	2022	500	0.6	65	115,919	256.8	0	0	256.8	1.9	4.9	-223.4	4.59
FBC3	Heat Rate Improvement Training	2022	15	0.3	31.7	56,187	124.5	0	0	124.5	0.1	3.1	-123.5	0.28
FBC3	On-Site Heat Rate Appraisals	2022	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC3	Improved Condenser Cleaner Strategies	2022	N/A	0.44	46.4	82,242	182.2	0	0	182.2	N/A	N/A	N/A	N/A
FBC3	Economizer (1 Tube Pass)	2022	750	-0.1	-14	-25,169	-55.8	0	195.0	139.2	5.4	8.4	-101.7	17.53
FBC3	Economizer (2 Tube Pass)	2022	1,075	-0.28	-29.1	-51,578	-114.3	0	288.8	174.6	6.2	9.2	-120.8	23.20
FBC3	Economizer (3 Tube Pass)	2022	1,400	-0.4	-45	-79,583	-176.3	0	382.6	206.3	6.8	9.8	-136.3	29.44

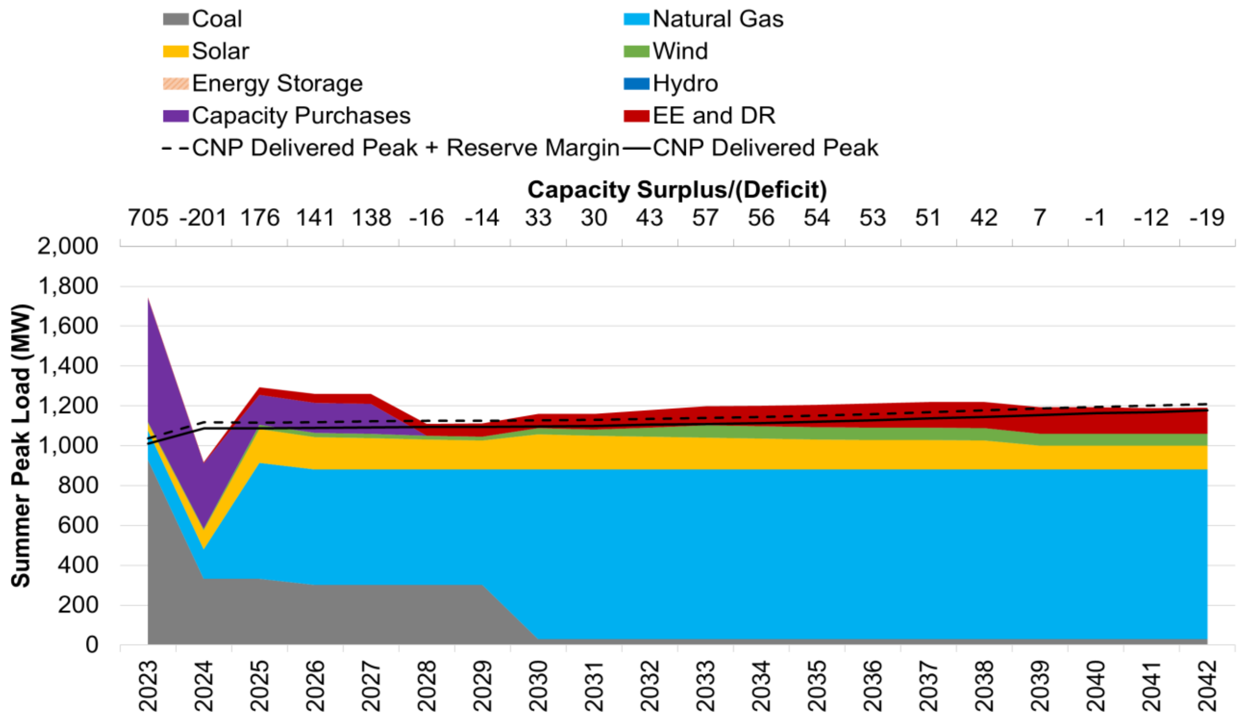
Attachment 8.1 Balance of Loads and Resources

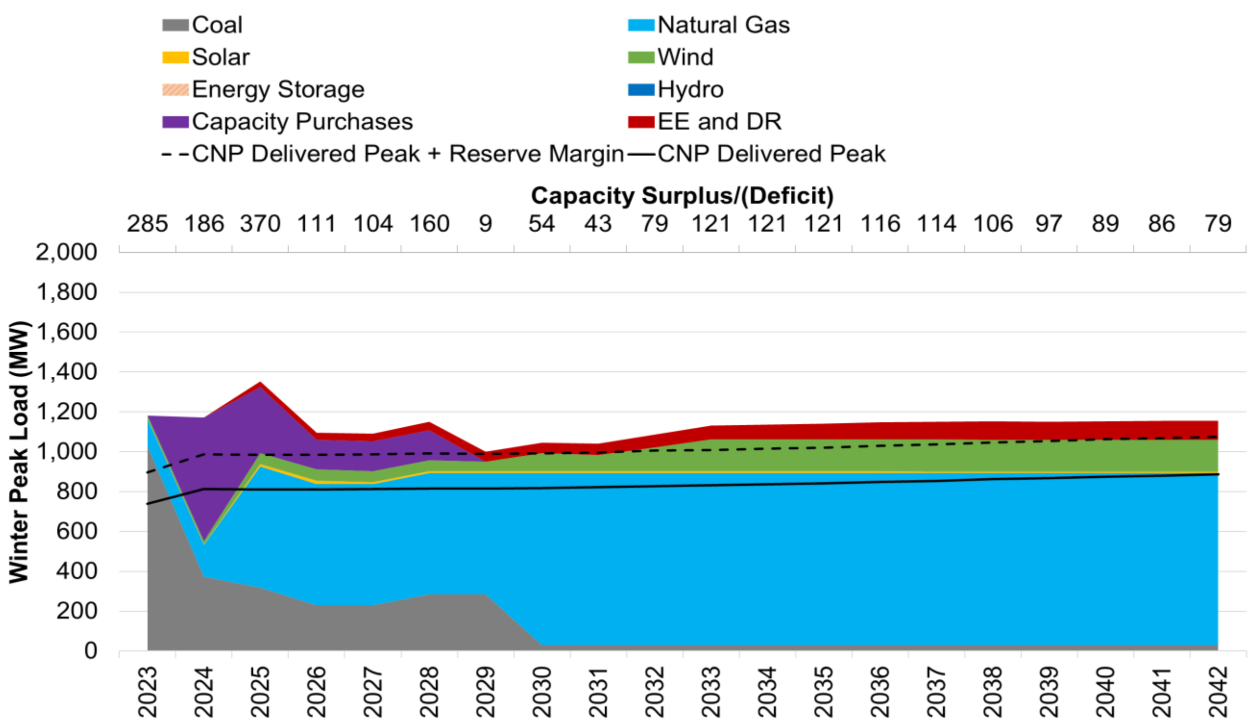
Portfolio 1: Reference Case



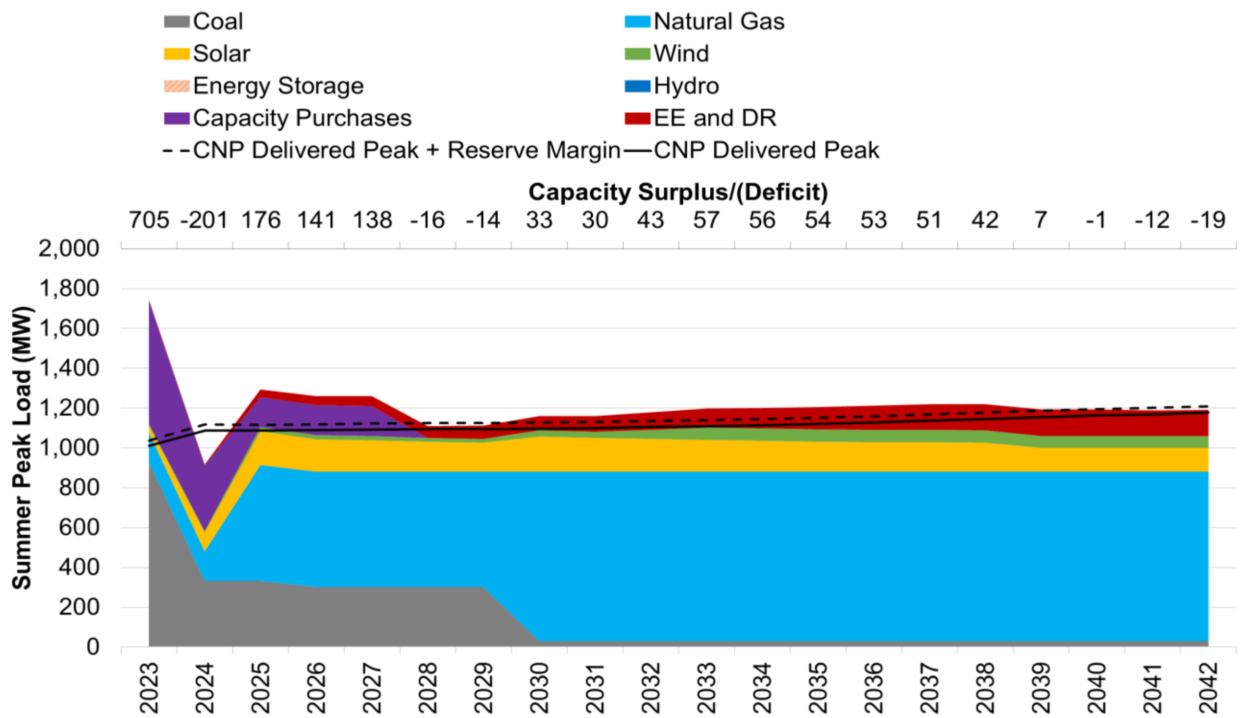


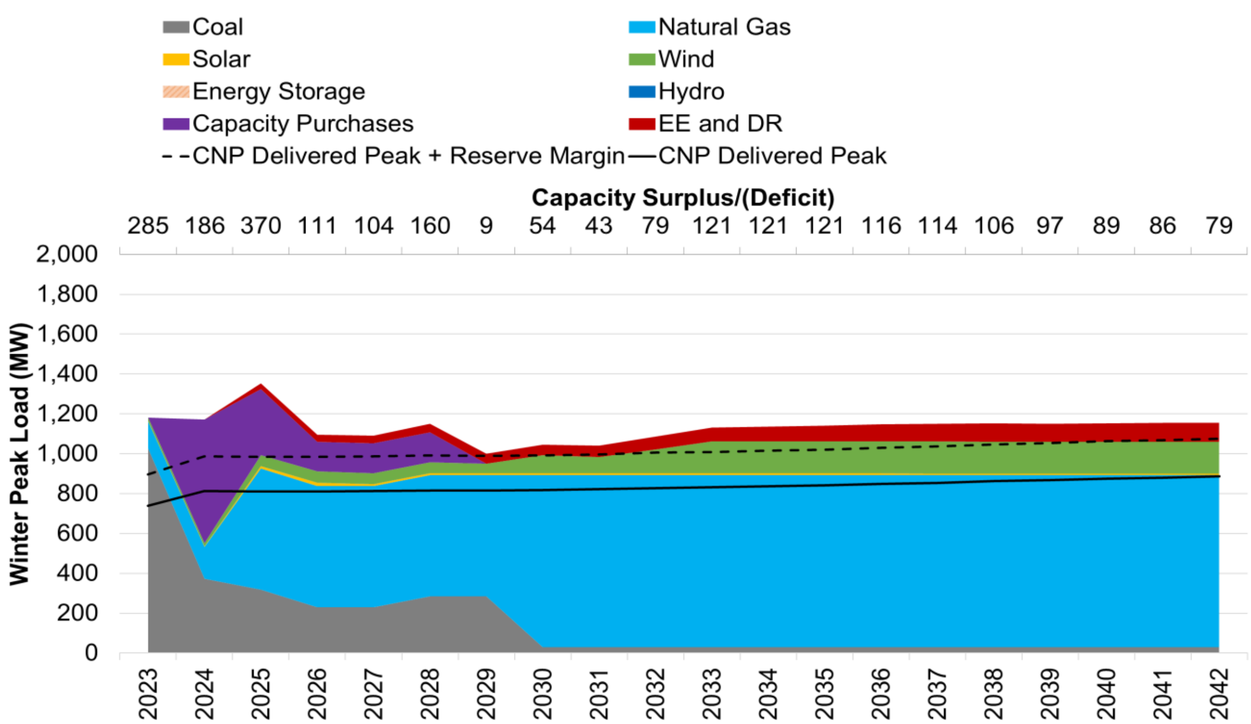
Portfolio 2: Business as Usual (BAU) Cont. FB Culley 3 on Coal



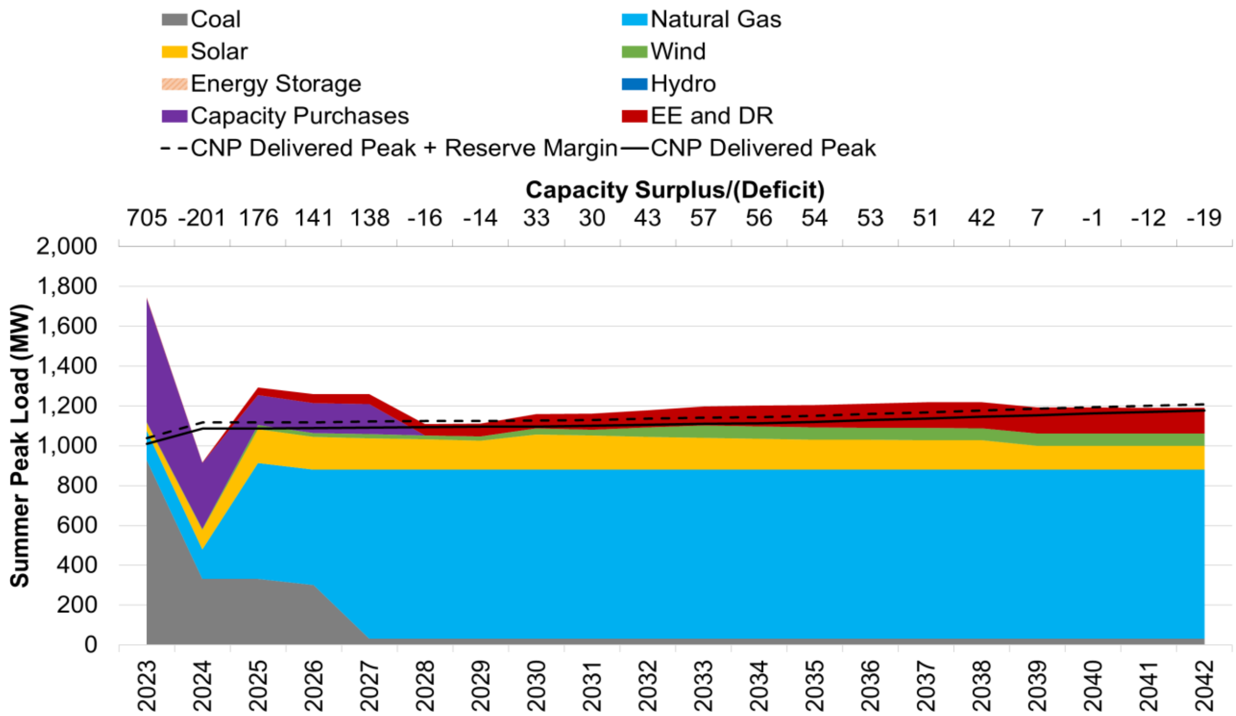


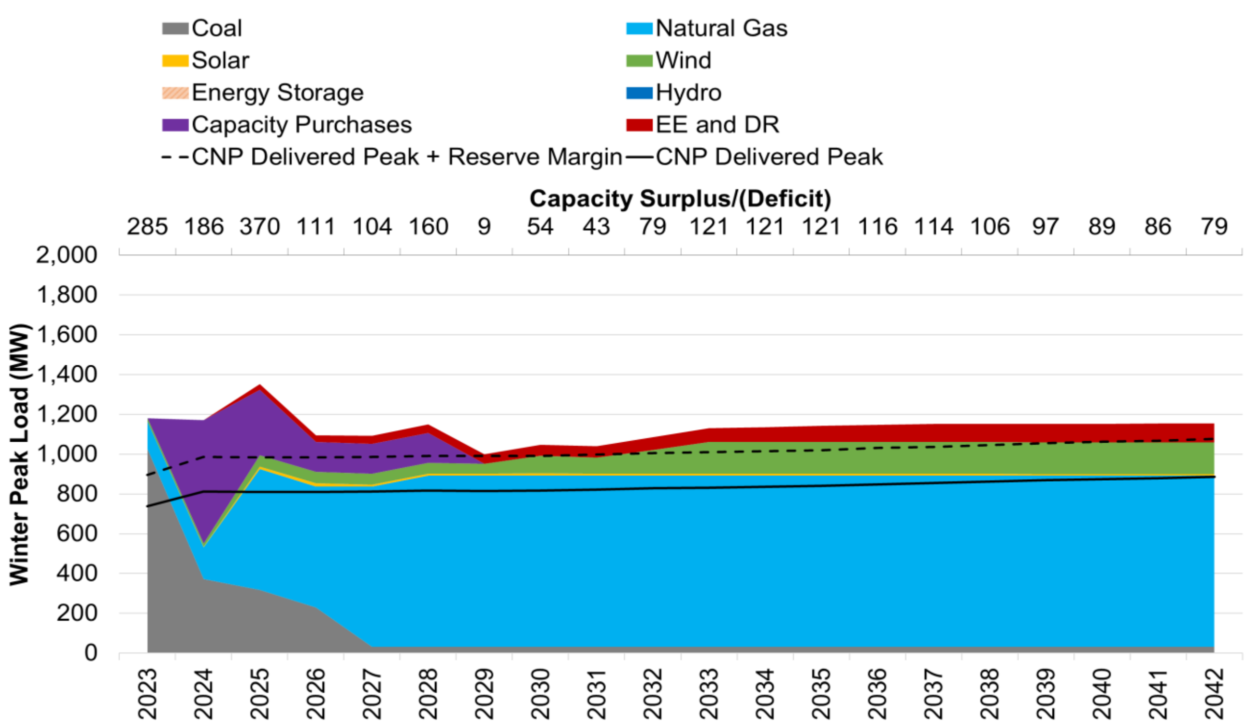
Portfolio 3: Convert F.B. Culley 3 to Natural Gas by 2030



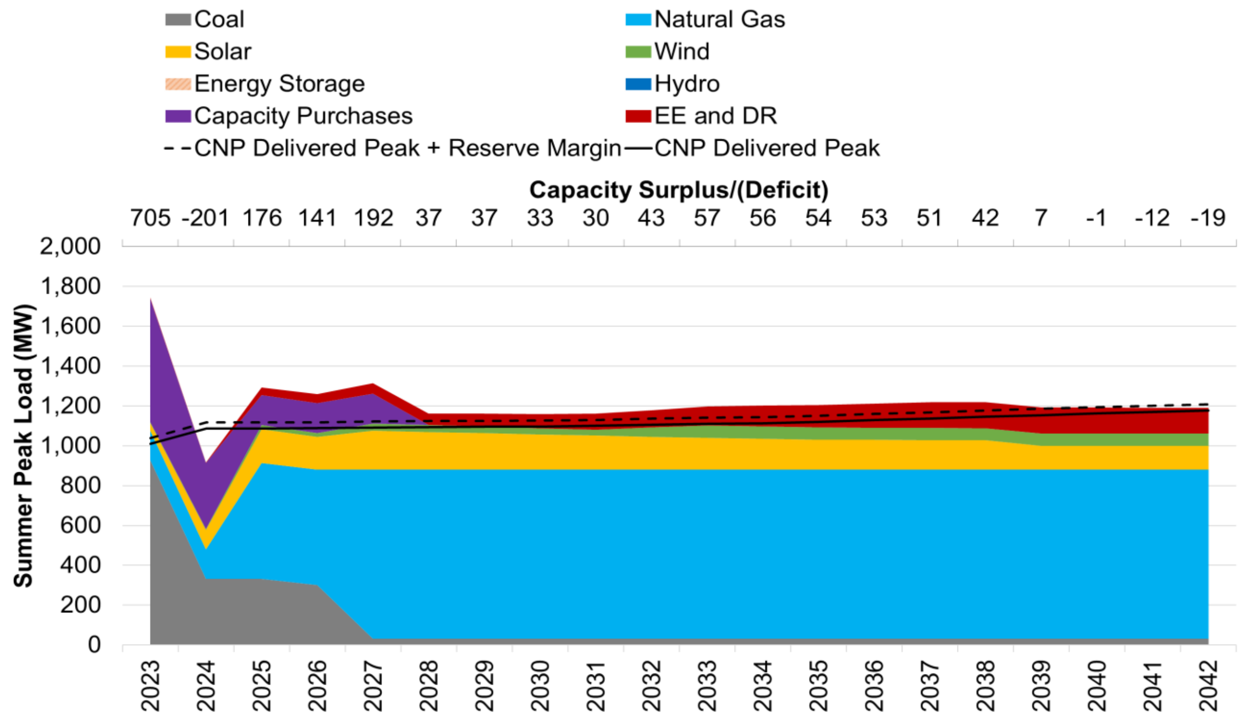


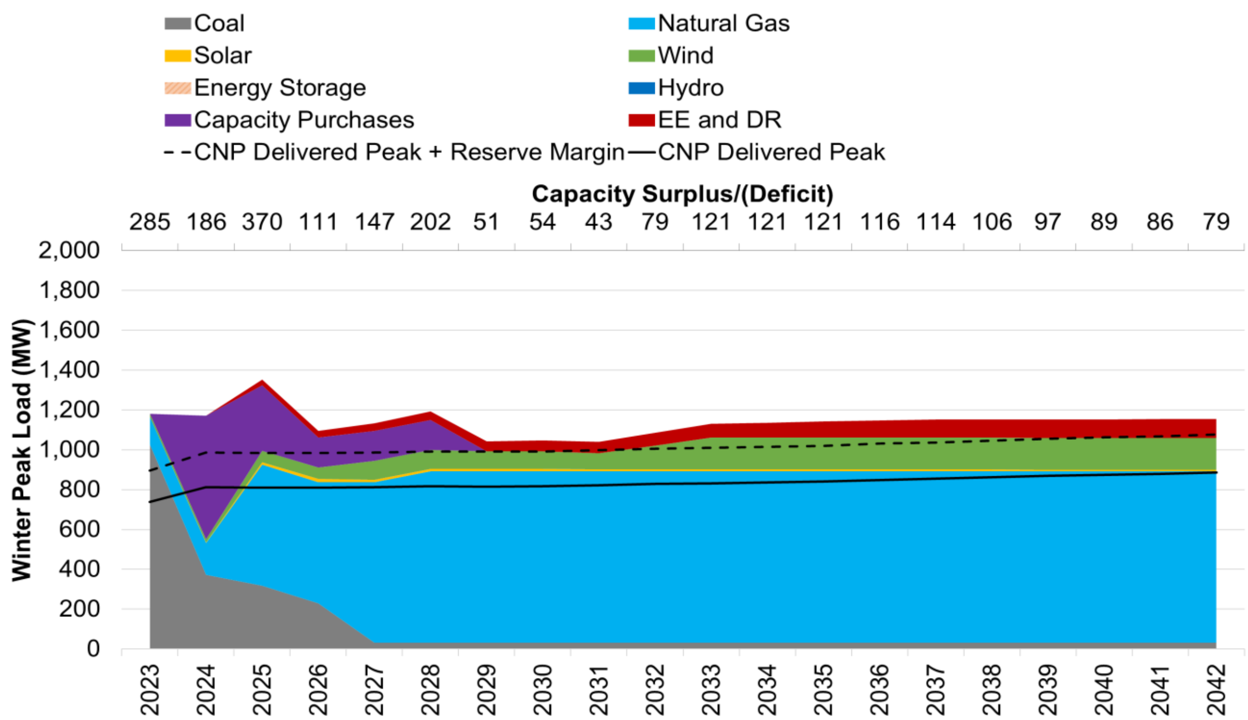
Portfolio 4: Convert F.B. Culley 3 to Natural Gas by 2027



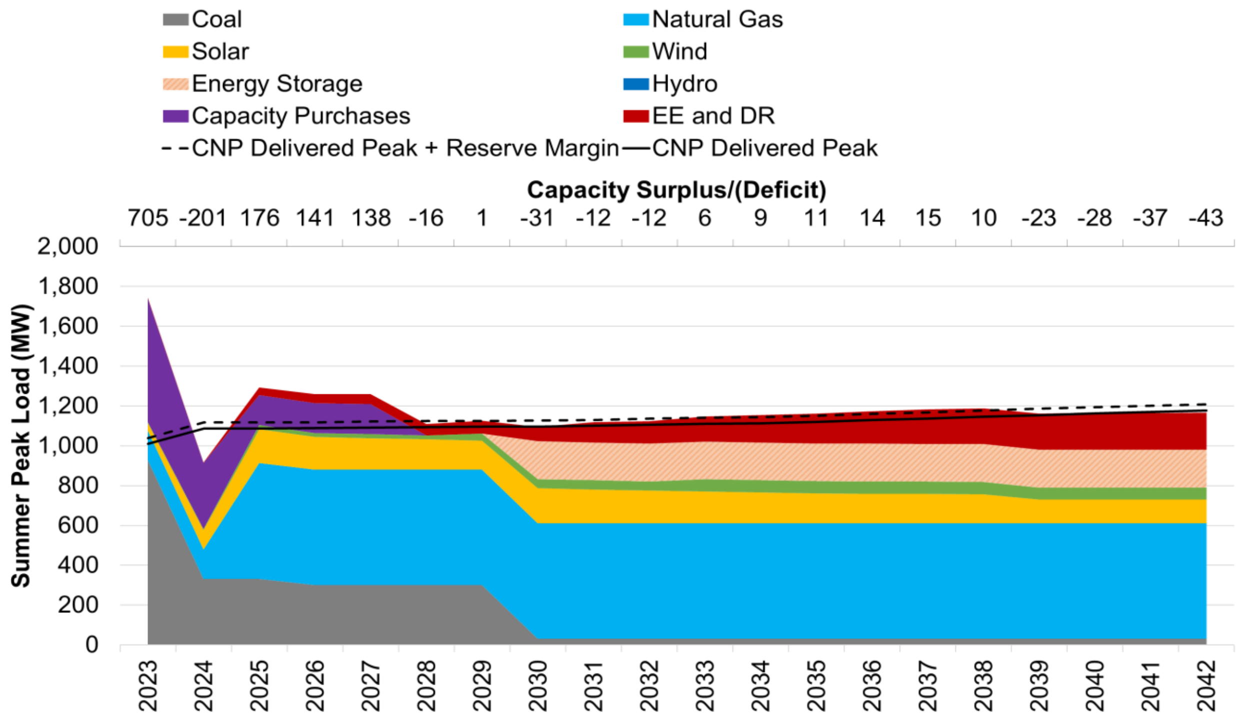


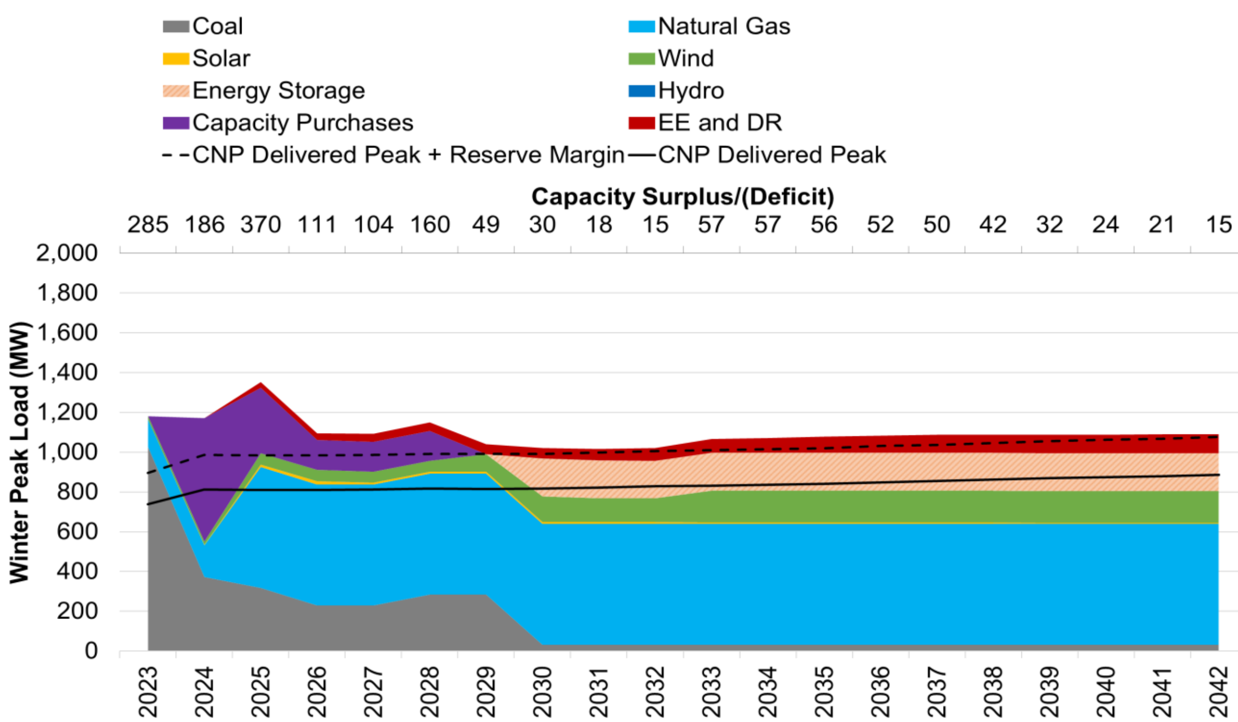
Portfolio 5: Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 Wind and Solar



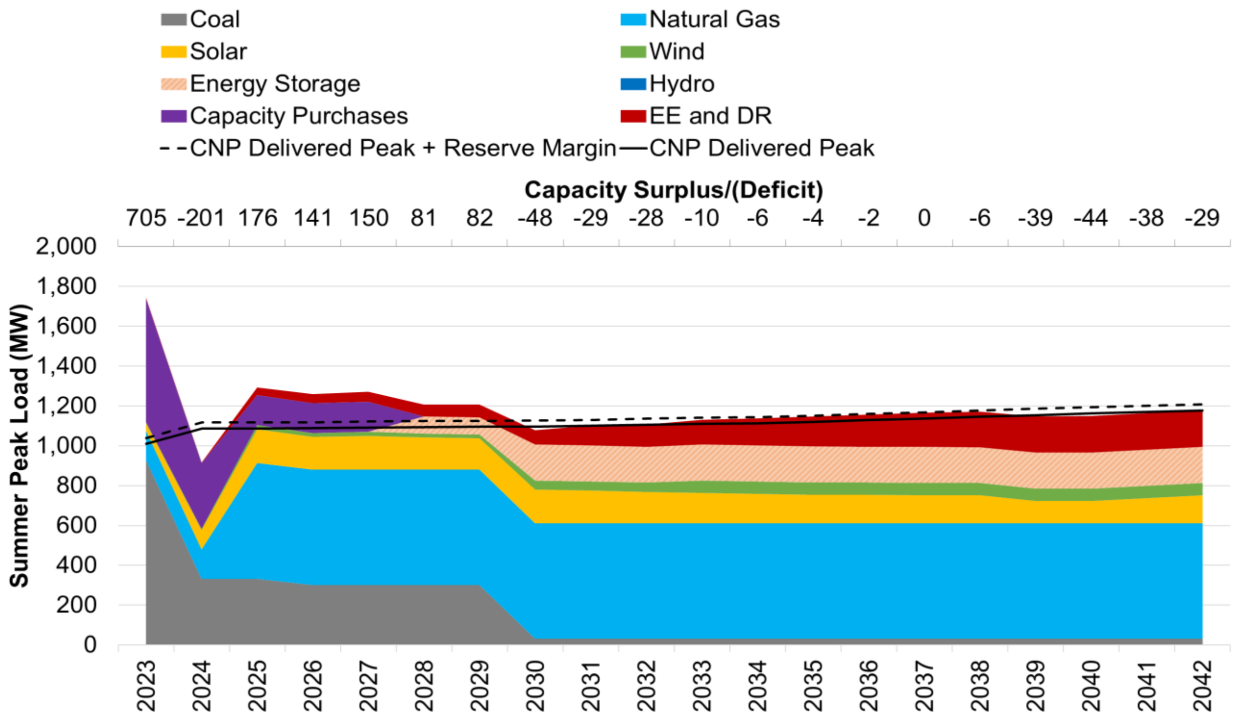


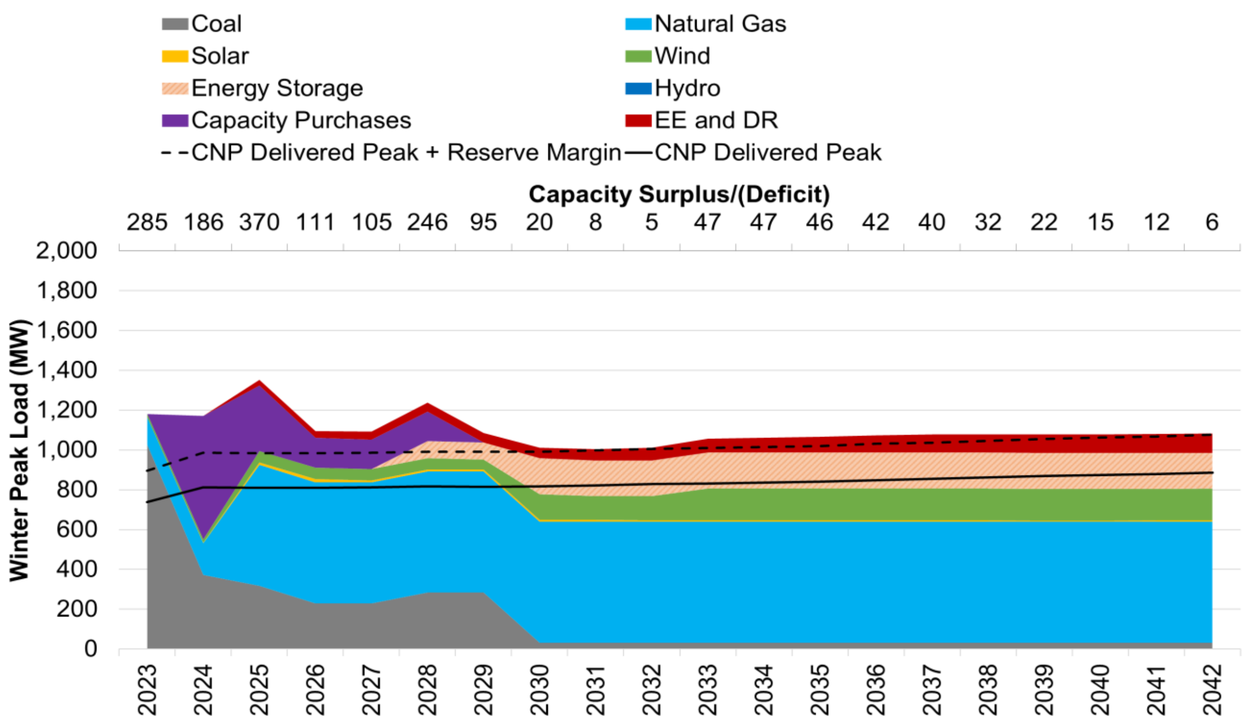
Portfolio 6: Diversified Renewables



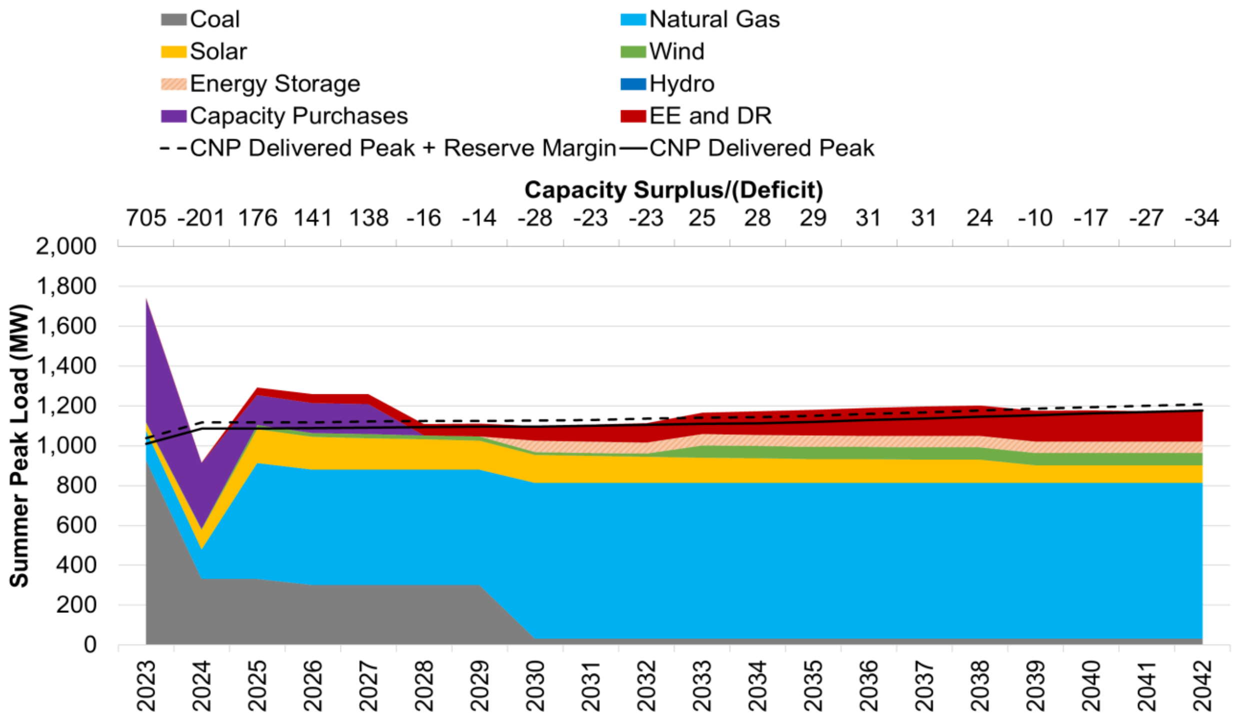


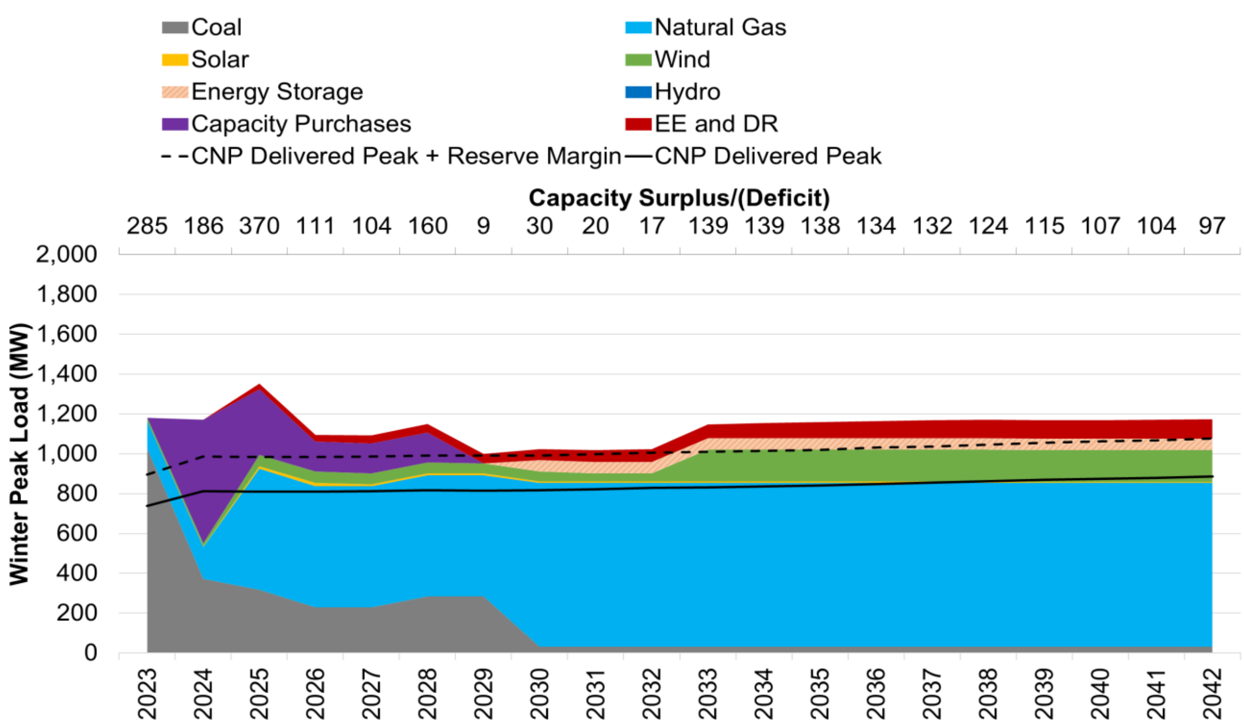
Portfolio 7: Diversified Renewables (Early Storage & DG Solar)



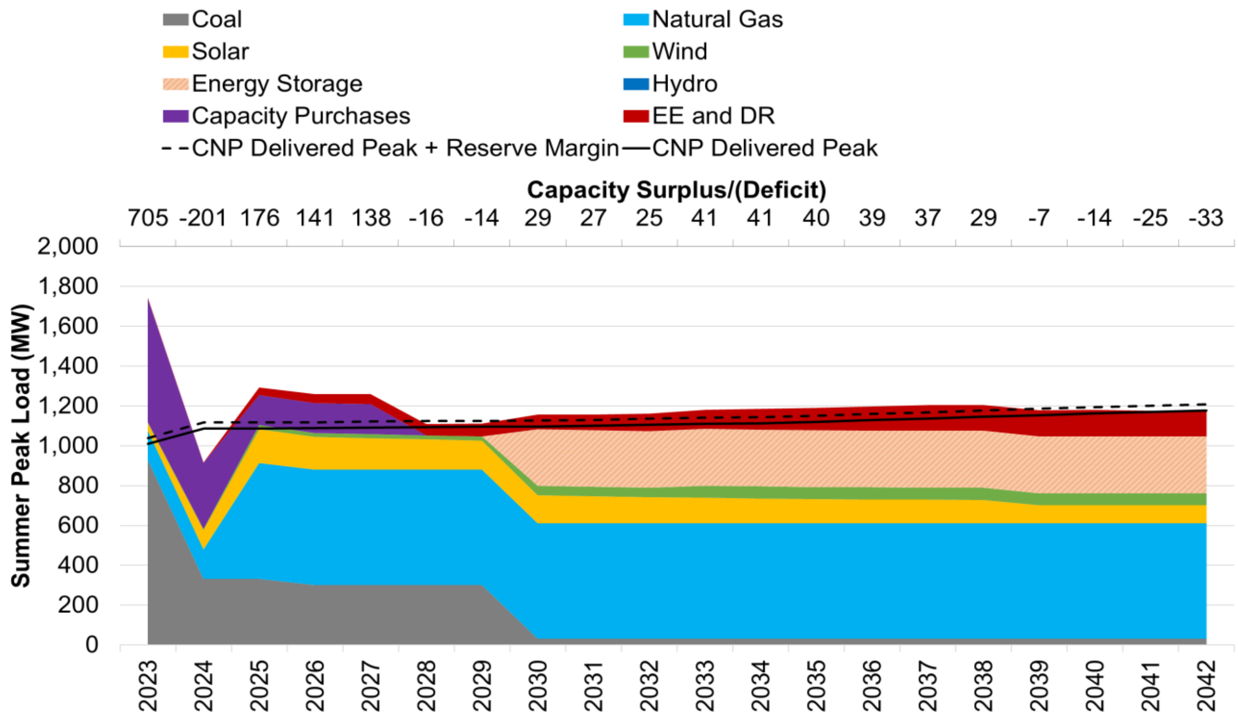


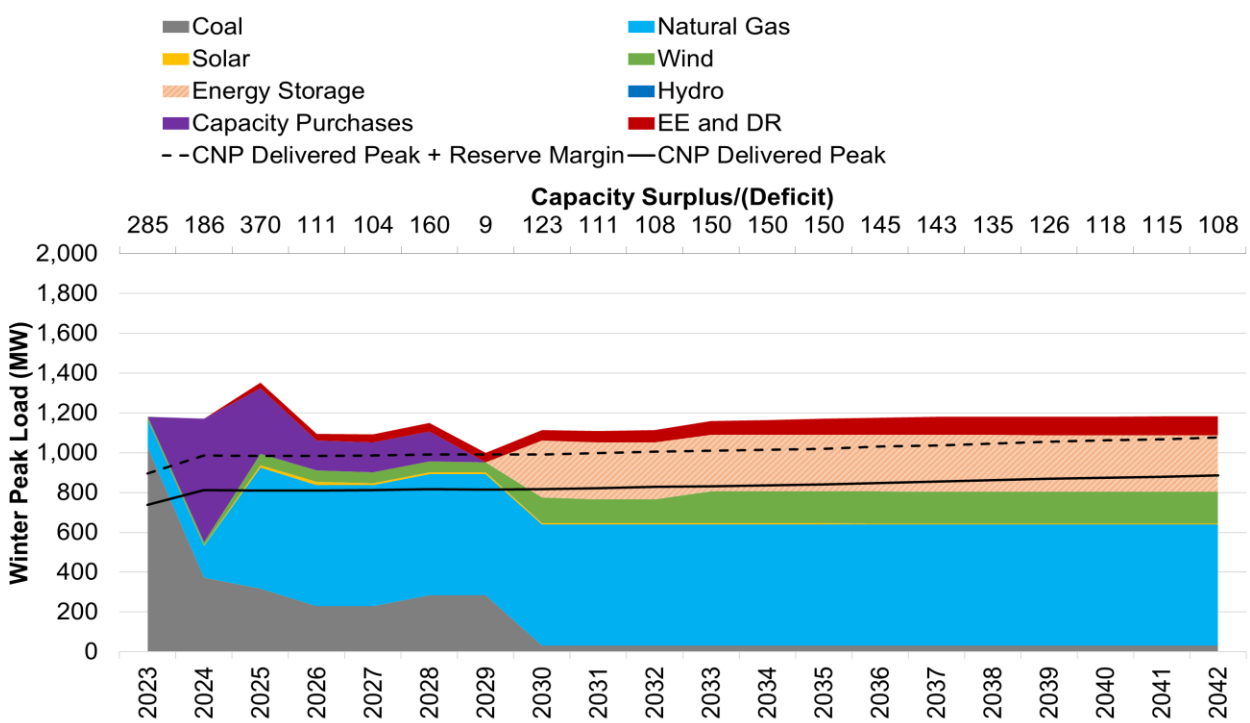
Portfolio 8: CT Portfolio (Replace FB Culley 3 with F Class CT)



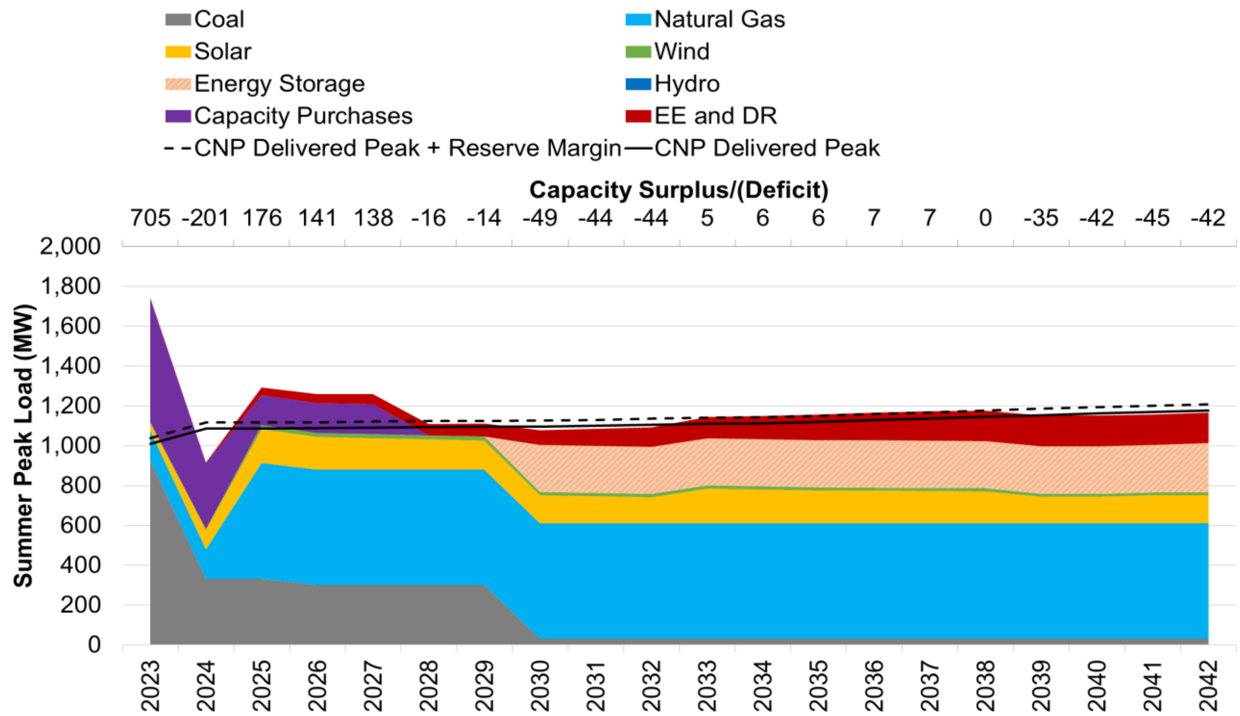


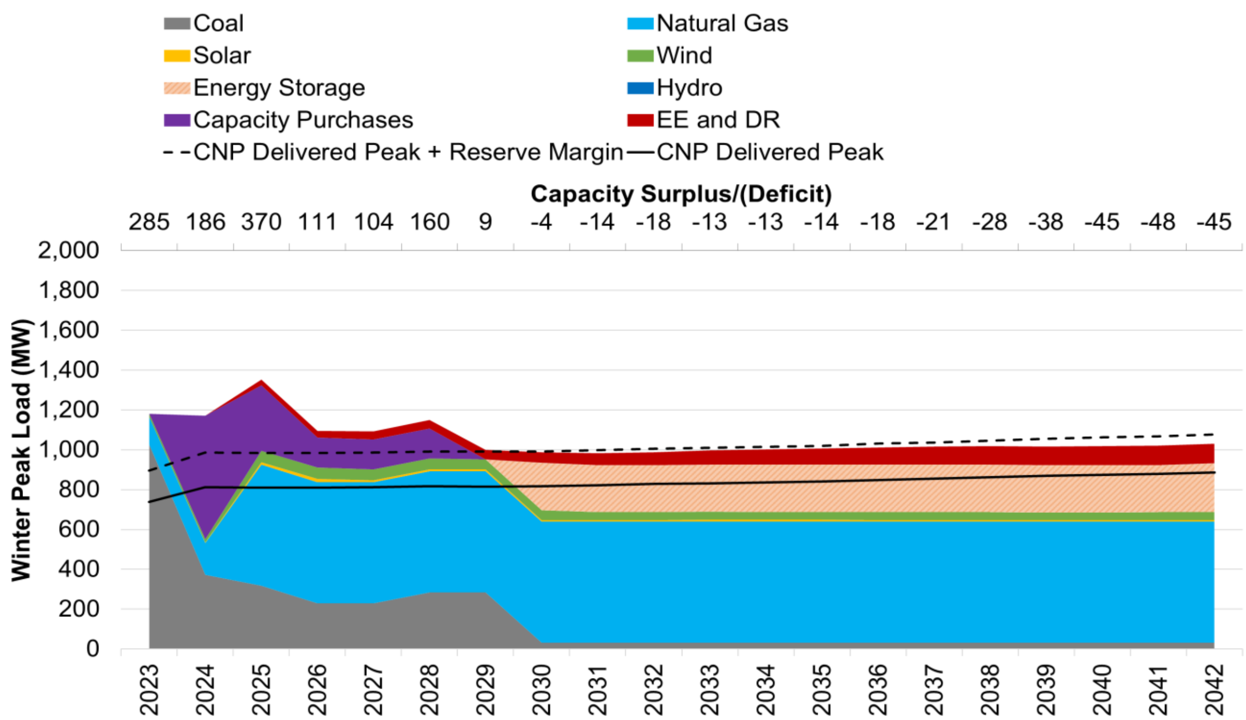
Portfolio 9: Replace FB Culley 3 with Storage and Wind





Portfolio 10: Replace FB Culley 3 with Storage and Solar





Attachment 8.2 Confidential EnCompass Input-Output Model Files

SEE ATTACHMENTS:CONFIDENTIAL - Optimized Model.zip
CONFIDENTIAL - Stochastic Model.zip