SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a CENTERPOINT ENERGY INDIANA SOUTH
(CENTERPOINT)

IURC CAUSE NO. 45501

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INDIANA UTILITY
REGULATORY COMMISSION

DIRECT TESTIMONY
OF
MATTHEW A. RICE
DIRECTOR OF INDIANA ELECTRIC REGULATORY AND RATES

ON

INTEGRATED RESOURCE PLAN, NECESSITY OF THE SOLAR PROJECTS AND RATEMAKING ISSUES

SPONSORING PETITIONER'S EXHIBIT NO. 4 (PUBLIC)
ATTACHMENTS MAR-1 THROUGH MAR-5

DIRECT TESTIMONY OF MATTHEW A. RICE

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Matthew Rice. My business address is 211 NW Riverside Drive, Evansville, Indiana 47708.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting testimony on behalf of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CenterPoint", "Petitioner", or "Company"), which is an indirect subsidiary of CenterPoint Energy, Inc.

Q. What is your role with respect to Petitioner?

A. I am Director of Indiana Electric Regulatory and Rates.

Q. Please describe your educational background.

A. I received a Bachelor of Science degree in Business Administration from the University of Southern Indiana in 1999. I also received a Master of Business Administration from the University of Southern Indiana in 2008.

Q. Please describe your professional experience.

A. Prior to working for CenterPoint, I worked as a Market Research Analyst for American General Finance for six years working primarily on customer segmentation, demographic analysis, and site location analysis. In 2007, I joined the Company as a Market Research Analyst, and have held various positions of increasing responsibility, including Senior Analyst, Manager of Market Research, and Director of Research and Energy Technologies. Since 2009, I have been responsible for long-term energy forecasting for the Company's IRPs, helping to manage the Company's 2011, 2014, 2016, and 2019/2020 IRPs. I have also managed its IRP stakeholder process since 2014. My duties have included conducting economic analysis, primary and secondary customer research (including surveying, focus groups, segmentation, and demographic analysis), customer satisfaction research, housing market research, and monitored industry research. In

February 2019, I became Manager of Resource Planning with responsibility for internal and external generation analysis and reporting. I was named to my current position of Director of Indiana Electric Regulatory and Rates in October 2020.

Q. What are your present duties and responsibilities as Director of Indiana Electric Regulatory and Rates?

A. I am responsible for electric regulatory and rate matters for CenterPoint in regulated proceedings before the Indiana Utility Regulatory Commission ("Commission"). I also have responsibility for resource planning and reporting for CenterPoint, including the IRP.

Q. Have you previously testified before the Commission?

A. Yes. I testified before the Commission in support of CenterPoint's Certificate of Public Convenience and Necessity ("CPCN") in Cause No. 45052, and Petitioner's request for approval of a tariff rate for Excess Distributed Generation in Cause No. 45378. Additionally, I recently provided written testimony in Cause No. 44910-TDSIC-8 and in Cause No. 44909-CECA 3.

II. <u>PURPOSE & SCOPE OF TESTIMONY</u>

Q. What is the purpose of your testimony in this proceeding?

A. My testimony describes the analysis and results of CenterPoint's 2019/2020 Integrated Resource Plan ("2019/2020 IRP") process. In addition, I describe and support CenterPoint's request for a CPCN to purchase and acquire the Posey County Solar Project through a Build Transfer Agreement ("BTA") pursuant to Ind. Code ch. 8-1-8.5. I also describe and support CenterPoint's proposal to enter into a Power Purchase Agreement ("PPA") with Clenera LLC's affiliate, Rustic Hills Solar II LLC, ("Clenera") to purchase energy and capacity from a 100 megawatts alternating current ("MWac") solar project in Warrick County, Indiana (the "Warrick County Solar Project"), over a 25-year term and finding the terms of the PPA reasonable and necessary. I also describe why the Posey County Solar Project qualifies as a "Clean Energy Project" under Ind. Code ch. 8-1-8.8. In addition, I will explain how the Levelized Rate for the Posey County Solar Project will be incorporated within CenterPoint's Clean Energy Cost Adjustment ("CECA"), which the Commission approved on August 16, 2017, in Cause No. 44909. I describe how the cost of the Warrick County Solar Project will be recovered through the fuel adjustment clause ("FAC") mechanism, including recovery of debt equivalency described in Witness Brett A. Jerasa's testimony. Finally, I describe how customer rates will be impacted by the two projects.

Q. Are you sponsoring any attachments to your direct testimony in this proceeding?

A. Yes. I am sponsoring the following attachments:

- Petitioner's Exhibit No. 4, **Attachment MAR-1**: CenterPoint's 2019/2020 Integrated Resource Plan Volume 1 of 2;
- Petitioner's Exhibit No. 4, **Attachment MAR-2**: 44909 CECA-3 Tariff Sheet[1];
- Petitioner's Exhibit No. 4, **Attachment MAR-3 (CONFIDENTIAL)**: Posey County Solar Project Residential Rate Impact;
- Petitioner's Exhibit No. 4, **Attachment MAR-4 (CONFIDENTIAL)**: Warrick County Solar Project Residential Rate Impact; and
- Petitioner's Exhibit No. 4, **Attachment MAR-5 (CONFIDENTIAL)**: Estimated Net Monthly Rate Impact by Customer Class.

Q. Were these attachments prepared by you or under your direction?

A. Yes, they were. The Company's 2019/2020 IRP process was managed under my direction or supervision, although it is important to recognize that other Company employees and consultants with specific areas of expertise engaged by the Company were involved in the process of developing the 2019/2020 IRP.

III. CENTERPOINT'S 2019/2020 IRP PROCESS

Q. Please describe how CenterPoint approached the 2019/2020 IRP.

A. The 2019/2020 IRP was CenterPoint's most detailed resource planning analysis process. The Company worked with several industry experts to conduct the technical analysis: Itron provided the long term energy and demand forecast; 1898 and Company, a Burns and

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[1] Currently pending before the Commission in CECA 3.

McDonnell company ("Burns and McDonnell"), worked with CenterPoint to conduct an All-Source Request For Proposals ("All-Source RFP") and provide modeling inputs for various generating resources; Black and Veatch assisted with several studies utilized to evaluate numerous alternatives for existing resources; GDS provided Energy Efficiency modeling inputs; and Siemens PTI, formerly Pace Global Energy Services ("Siemens PTI") provided scenario development, deterministic modeling, probabilistic modeling, and provided assistance with the risk analysis. A copy of Petitioner's 2019/2020 IRP is attached to my testimony as Petitioner's Exhibit No. 4, Attachment MAR-1 (Confidential).

Q. What process did Petitioner use in developing the 2019/2020 IRP?

A. Petitioner began the process by reviewing stakeholder comments from the 2016 IRP, including the Director's Report, and by carefully reviewing the Commission Orders issued in connection with Petitioner's requests for CPCNs in Cause Nos. 45052 (F.B. Culley 3 upgrades and CCGT) and 45086 (50 MW Troy solar). This feedback was used to formulate twelve continuous improvement commitments that were shared with CenterPoint IRP stakeholders in our first public stakeholder meeting on August 15, 2019, and fulfilled on June 30, 2020, with the submission of the 2019/2020 IRP. In the first stakeholder meeting, CenterPoint presented the analysis plan and laid out all topics to be discussed with stakeholders for each of CenterPoint's public stakeholder meetings. Figure 3.1 "2019/2020 Stakeholder Meetings" on page 108 of the IRP details the topics discussed in each meeting, which are summarized in Figure 1 below.

Figure 1: 2019/2020 Stakeholder Meetings

August 15, 2019
- 2019/2020 IRP Process
- Objectives and Measures
- All-Source RFP
- Environmental Update
- Draft Reference Case Market Inputs & Scenarios

October 10, 2019
- RFP Update
- Draft Resource Costs
- Sales and Demand Forecast
- DSM MPS/ Modeling Inputs
- Scenario Modeling Inputs
- Portfolio Development

December 13, 2019
- Draft Portfolios
- Draft Reference Case Modeling Results
- All-Source RFP Results and Final Modeling Inputs
- Scenario Testing and Probabilistic Modeling Approach and Assumptions

June 15, 2020
- Final Reference Case and Scenario Modeling Results
- Probabilistic Modeling Results
- Risk Analysis Results
- Preview the Preferred Portfolio

The general process involved presenting information and gathering feedback from stakeholders on key topics, including but not limited to the following: objectives, scorecard development, forecasts, modeling inputs, scenario development, portfolio development, technical modeling, and results. At the beginning of each stakeholder meeting, CenterPoint made a point to follow up with stakeholders on input provided in the prior meeting. Often stakeholder feedback was utilized, but in instances where it was not, CenterPoint discussed why it was not used. The planning analysis began with an All-Source RFP, which was conducted simultaneously with the IRP and was utilized as an input into modeling for resource selection/portfolio development. Objectives were presented at the first meeting. Scorecard development also began at this meeting and was refined throughout the process based on stakeholder feedback and evaluation of measures to ensure that each was a good representation of the risk factor it represented. Scenarios (potential future states) then were developed with stakeholder input for use in deterministic modeling. Portfolios (combinations of resource options to meet customer load over the evaluation period) were then developed with stakeholder input. Care was taken to ensure a wide range of scenarios and portfolios were utilized and evaluated within the IRP analysis, respectively. These portfolios then were modeled and evaluated within the deterministic futures and within probabilistic simulation of 200 potential futures (also referred to as stochastic modeling). CenterPoint utilized quantitative and qualitative information produced within this analysis to select a preferred portfolio.

Q. What forecasts did CenterPoint use in its 2019/2020 IRP?

A. Multiple forecasts were used as an input to the analysis to first develop a reference case. As described in Section 2.4.1 of the IRP, pages 89-91, CenterPoint relied on several industry experts for key inputs in the IRP analysis. For coal, gas, market capacity price forecasts, and long-term emerging resource costs, a consensus forecast was used. For natural gas and coal, CenterPoint created an average price using data from PIRA Energy Group, Wood Mackenzie, Siemens PTI, ABB, and Energy Ventures Analysis (EVA). For the MISO Zone 6 capacity value, CenterPoint created an average, utilizing Siemens PTI, ABB, and Wood Makenzie analyses.[2] The long-term capital price forecast (beyond 2024) for emerging supply side resources was based on the average of NREL, Burns and McDonnell, and Siemens PTI analyses. Siemens PTI developed the carbon price forecast. Itron developed the energy and demand forecast. GDS created a price forecast for demand side resources. Siemens PTI utilized both AURORAxmp power dispatch model with reference case inputs and expectations for the broader market to generate on-peak and off-peak power prices in the MISO region. In order to create varying inputs for scenarios, CenterPoint worked with stakeholders to determine how key inputs would vary by scenario in the short-, mid-, and long-term based on narrative-based futures. This process helped ensure multiple perspectives were captured and used to create a wide range of potential futures. Siemens PTI used probabilistic distributions and adjusted reference case forecasts for each scenario in conjunction with stakeholder guidance, where reasonable.

Q. In your opinion, were the forecasts used by CenterPoint reasonable?

A. Yes. Following the 2016 IRP, CenterPoint was praised in the Director's report for using consensus forecasts where possible to increase transparency for stakeholders and incorporate multiple views from credible sources. CenterPoint continued using consensus forecasts to develop the 2019/2020 IRP. Other inputs provided by expert third-party

[2] CenterPoint did not have access to a capacity forecast from PIRA or EVA.

sources were shared and discussed as part of the stakeholder process. Forecasts were also compared with publicly available forecasts, such as the Energy Information Administration's Annual Energy Outlook, for reasonableness.

Q. Did CenterPoint make an effort to consider stakeholder input received at the Company-specific meetings?

A. Yes. CenterPoint held three workshops as part of these meetings designed to solicit input from stakeholders that was incorporated into the IRP planning process. The fourth public meeting included a preview of the Preferred Portfolio. CenterPoint described how stakeholder input received at the prior stakeholder meeting was utilized in each meeting. Where feedback was not used, CenterPoint explained the reasoning. Feedback from stakeholders helped shape the analysis in significant ways, including but not limited to: scorecard development (identification and inclusion of key risks including considering full life cycle of CO_2e), scenario development, expected MISO accreditation of resources, fuel price forecasts, consideration of a wide range of portfolios, and use of an All-Source RFP.

Q. Did you incorporate stakeholder input into the portfolio development process?

A. Yes. CenterPoint incorporated stakeholder input prior to and during the 2019/2020 IRP analysis. Continuous improvement of the resource planning analysis was integral to CenterPoint's 2019/2020 IRP. CenterPoint learned from the last IRP that stakeholders were interested in utilizing least cost optimization to help ensure portfolio cost was as low as possible. In the third public stakeholder meeting held on December 13, 2019, CenterPoint discussed each strategy and described the relevant stakeholder input used to help develop portfolios. Examples of stakeholder input considered included, but were not limited to: explore options at AB Brown, make adjustments to various scenarios, explore conversion options, run AB Brown until 2039, do not run fossil fuel plants beyond 2030, consider smaller CCGT options, and consider flexible gas CTs and renewables.

Q. How did CenterPoint develop the portfolios modeled in the 2019/2020 IRP?

A. CenterPoint worked with stakeholders to consider and utilize strategies to develop a wide range of portfolios. Five portfolio development strategies were discussed with stakeholders: (i) Status Quo (i.e., continue running existing units), (ii) Scenario-Based (i.e., least cost optimization), (iii) Bridge (i.e., continued use of AB Brown assets), (iv) Diverse (i.e., diverse energy with renewables, gas, and coal), and (v) Renewables Focused (i.e., much less to no reliance on fossil fuel resources). Except for the Scenario-Based portfolio development strategy, various resource options were locked in, and deterministic modeling was utilized to select the most economical way to meet the remaining capacity and energy obligations. For example, under the Bridge portfolio development strategy, the Brown units would continue to run with the existing scrubber through 2029, and the model determined the replacement to meet MISO's planning reserve margin requirements and optimized for lowest net present value of revenue requirements ("NPVRR"). The Scenario-Based portfolio options were created for each of the five deterministic scenarios. In this process, existing coal units[3] were evaluated for economic retirement, which ultimately produced fifteen distinct portfolios, ranging from continuing most coal resources through the end of the forecast to an all-renewables portfolio by 2030.

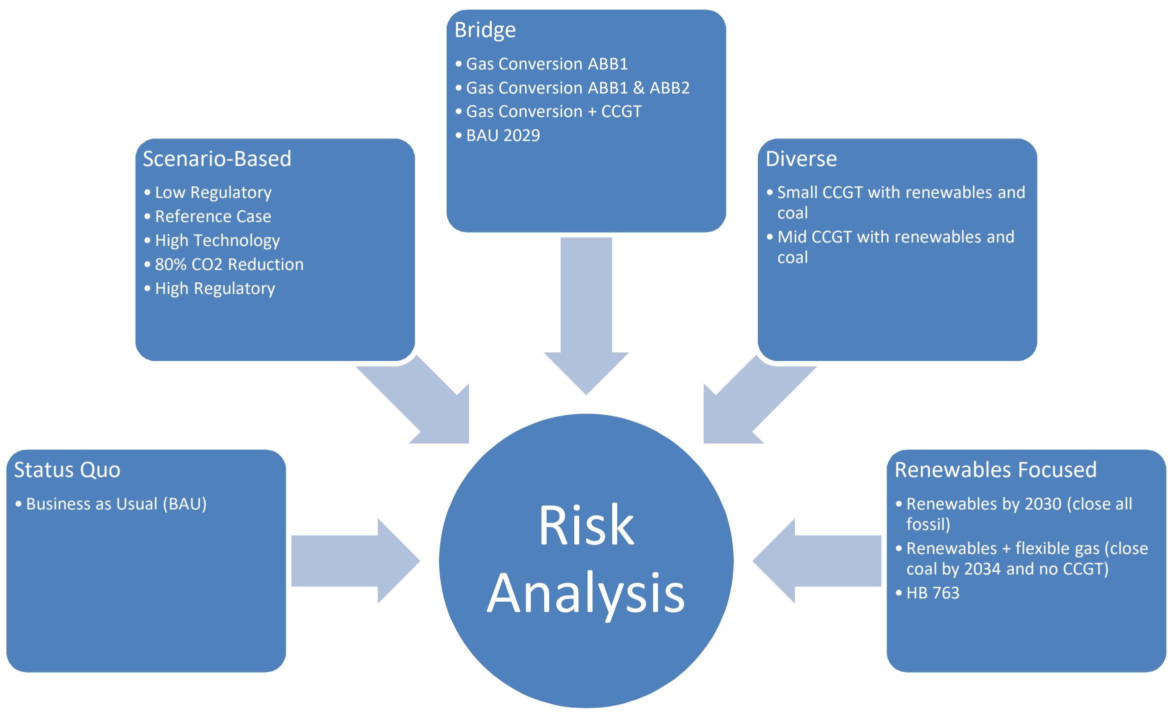
Q. Please summarize the fifteen optimized portfolios that CenterPoint examined.

A. Fifteen portfolios were created utilizing the process described above. Figure 2 below is a visual representation of the wide range of portfolios analyzed, bucketed by five portfolio development strategies: Status Quo, Scenario-Based, Bridge, Diverse, and Renewables Focused. A brief description of each strategy follows below. A Status Quo portfolio identified as Business as Usual ("BAU") through 2039 was included as a bookend. This portfolio included continuing to run all coal plants, except for Warrick Unit #4, through 2039. Five Scenario-Based portfolios were created (one per scenario) for the following scenarios: reference case, low regulatory, high technology, 80 percent reduction of CO_2 by 2050, and high regulatory. Each of these potential future states were optimized to produce a least cost portfolio in each future state. Four Bridge portfolios were created to explore options to continue to utilize existing equipment at the AB Brown plant. These portfolios included converting one unit to gas, converting two units to gas, converting one unit to gas with the addition of a small CCGT, and continuing to run both units with coal through 2029. Two Diverse energy portfolios were created: one with a small CCGT and the other with a mid-sized CCGT. These portfolios were included to explore options that

[3] AB Brown 1&2, F.B. Culley 2, and Warrick Unit #4. Warrick Unit #4 is a jointly operated plant with Alcoa. The current contract expires at the end of 2023, leaving a 150 MW capacity shortfall currently in all portfolios. CenterPoint modeled a potential 3-year extension of the contract; it was not selected based on economics.

produce a balanced mix of energy from coal, gas, and renewable resources. Finally, three Renewables Focused portfolios were created. The first was a renewables plus flexible gas portfolio, which involved closure of all coal units by 2034 and included gas CTs, renewables, and storage. The HB 763 portfolio was created with a very high CO_2 price per stakeholder input. The other bookend portfolio was to close all fossil fuel plants by 2030.

Figure 2: Portfolios by Strategy



All portfolios included demand side resources (i.e., Energy Efficiency and Demand Response). It should also be noted that the model selected a significant amount of wind and solar resources in all portfolios (300 MWs of wind and 1,150 MWs of solar before 2025), including the BAU portfolios, in part to replace Warrick Unit #4, but also because these resources lowered the NPVRR due to their production of low cost energy.

Q. What analyses did CenterPoint use to determine the Preferred Portfolio?

A. CenterPoint worked with Siemens PTI to conduct a multi-facetted risk analysis, which included evaluating portfolios on a quantitative and qualitative basis. After creation of the fifteen portfolios, each portfolio was evaluated utilizing simulated dispatch in the reference case. Several portfolios included fatal flaws and were excluded from further consideration. As described in more detail in Section 8.2 Evaluation of Portfolio Performance, on page 243 of the IRP, these included the HB 763, low regulatory, high regulatory, 80 percent reduction of CO_2, and the diverse energy mid-sized CCGT portfolio. Reasons for the exclusion of portfolios included high net sales, high market exposure, high cost, or redundancy. The remaining ten portfolios were then dispatched in each deterministic scenario to determine performance among a wide range of potential future states. Some portfolios performed very consistently in terms of cost across each scenario, including the reference case, preferred portfolio, and renewables plus flexible gas. Others, like the BAU portfolio or the all renewables portfolio had much greater cost variation across each potential future, relative to the reference case. Next, the remaining ten portfolios were dispatched 200 times under varying market conditions. Information gathered from this modeling was then utilized to populate the balanced scorecard, which was developed with stakeholder input. The balanced scorecard included quantitative measures to help CenterPoint understand tradeoffs among competing objectives of the IRP; these included stochastic mean 20-year NPVRR (cost), 95th Percentile Value of NPVRR (cost risk), Percent Reduction of CO_2e (life cycle emissions reduction including CO_2, methane and other emissions on a CO_2 equivalent basis), long-term percentage reliance on the energy market for sales or purchases, and long-term percentage reliance on the capacity market for sales and purchases. Table 1 below shows a summary of these measures.

Table 1: Quantitative IRP Scorecard Objectives and Metrics

Objective	Metric
Affordability	Mean value for the 20-Year Net Present Value of Revenue Requirements (NPVRR) (million$) across 200 dispatch iterations under varying market conditions
Cost Uncertainty Risk Minimization	95th percentile of NPVRR (million$) across 200 dispatch iterations under varying market conditions
Environmental Emissions	Reduction in tons of life-cycle greenhouse gas emissions (CO_2e) 2019-2039
Avoiding Overreliance on Market Risk	Annual Energy Sales and Purchases, divided by Annual Generation, average (%) and Annual Capacity Sales and Purchases, divided by Total Resources, average (%)

Six portfolios (five included continued use of AB Brown with coal or conversion options and the CCGT option), which were highest in cost and cost risk, were removed from consideration at this point based on their overall performance on scorecard measures and other qualitative considerations discussed at the last stakeholder meeting on June 15, 2020. Four competitive options remained for further analysis and consideration: (i) the reference case, (ii) renewables plus flexible gas, (iii) renewables by 2030, and (iv) the high technology portfolio. Table 2 below provides details regarding each portfolio.

Table 2: Portfolio Detail

Year	Reference Case	Renewables + Flexible Gas	Renewables by 2030	High Technology
2021-23	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency
2022	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)
2023	New Solar (731 MW), New Storage (126 MW)	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (278 MW)	New Solar (731 MW) New Storage (126 MW)
2023	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)
2024	New Combustion Turbine (236 MW)	New Combustion Turbine (236 MW)	-	New Combustion Turbine (236 MW)
2024	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response
2024-26	0.75% Energy Efficiency	0.75% Energy Efficiency	1.00% Energy Efficiency	0.75% Energy Efficiency
2025		-	-	New Combustion Turbine (236 MW)
2027-39	0.75% Energy Efficiency	0.75% Energy Efficiency	1.00% Energy Efficiency	0.75% Energy Efficiency
2029-32	-	-	Retire FBC3, ABB3, ABB4 (427 MW), New Storage (360 MW), Solar (700 MW)	-
2033-39	New Solar (250 MW)	Retire FBC3 (270 MW), New Combustion Turbine (236 MW)	New Solar (450 MW)	New Storage (50 MW)
2024-39	Average Annual Capacity Market Purchases (137 MW)	Average Annual Capacity Market Purchases (135 MW)	Average Annual Capacity Market Purchases (170 MW)	Average Annual Capacity Market Purchases (4 MW)

Q. What were the results of the scorecard process?

A. Of the four remaining portfolios, the high technology portfolio performed well across all risk factors. The cost is within 2.5 percent of the lowest cost portfolio (renewables plus flexible gas), primarily due to the early closure of F.B. Culley 3, as both options include about the same level of renewables and a second CT. This cost gap would close some because $50M in construction efficiency would be lost with building the second CT ten years later, which is not reflected within the NPVRR. The Preferred Portfolio performed well in terms of cost risk relative to other portfolios. While the percent reduction of CO_2e

was less than the renewables flexible gas and all renewables by 2030 portfolios, it was near the middle of all portfolios and driven primarily by the continued use of F.B. Culley 3, which provides resource diversity. Of the remaining portfolios, it relied least on energy purchases and was among the best in terms of reliance on energy sales to the market. The Preferred Portfolio was dramatically better, at 0.4 percent, in terms of less long-term reliance on the capacity purchases, while the other three portfolios average reliance ranged from 9.4 to 11.9 percent per year. The Preferred Portfolio relied on capacity sales of 4.6 percent, which was in the middle of all portfolios.

Q. Please describe further why the Preferred Portfolio was selected.

A. The Preferred Portfolio was selected because it was determined to be a very reliable and resilient portfolio that offers a transition to a clean energy future by complementing renewable energy resources with fast start and fast ramping capability. The portfolio is a good mix of traditional and emerging resources and has enough dispatchable capacity to cover CenterPoint's load in the winter when there is less solar output. The Preferred Portfolio is cost effective and expected to save CenterPoint's customers up to $320 million over the IRP's twenty-year planning period (2020-2039) compared to continuing to operate coal units. The Preferred Portfolio provides a physical hedge against high energy and capacity costs. As the future continues to be uncertain, this plan offers a diverse set of resources with multiple off-ramps, designed to hedge against risk of putting too much emphasis on a few large resources. While the flexible gas CTs are available to provide low cost capacity, their projected usage, largely limited to critical times, results in lower CO_2 emissions by 75 percent by 2035 over 2005 levels.

IV. THE PREFERRED PORTFOLIO

Q. What are the major components of the Preferred Portfolio?

A. The Preferred Portfolio includes energy efficiency at 1.25 percent between 2021-2023 and 0.75 percent[4] thereafter. The portfolio calls for 300 MW of wind resources to come online in 2022. It also calls for 1,150 MWs of new solar and solar plus storage in 2023-2024 to

[4] The level of EE for 2024 and beyond will be decided with future IRPs and DSM filings.

replace coal capacity, including Warrick Unit #4 which Petitioner jointly operates with Alcoa. Additionally, two CTs come online in 2024-2025. In 2039, 50 MW of storage was selected.

Q. What are the primary benefits of the Preferred Portfolio?

A. The Preferred Portfolio includes a diverse mix of resources. The risk analysis demonstrated that a diversified mix of generation resources, including renewables, gas, coal, and energy efficiency minimizes risk to customers if the future differs from the reference case scenario. As described in the final stakeholder meeting on June 15, 2020, and the 2019/2020 IRP, the Preferred Portfolio has the following characteristics: reliability, cost effectiveness, flexibility, diversity, risk mitigation and sustainability, and timeliness.

Q. Why did the Preferred Portfolio rank the best in the risk analysis?

A. Benefits of the Preferred Portfolio are spelled out in detail in Section 9 of the IRP and include affordability, cost uncertainty risk mitigation, environmental risk mitigation, market risk mitigation, future flexibility, reliability, operational flexibility, resource diversity, local resources, and economic development for the CenterPoint territory and the state of Indiana. As I mentioned earlier, the Preferred Portfolio performed well across multiple risk factors in the balanced scorecard. It avoids long term reliance on the capacity market or heavy reliance on battery energy storage, an emerging technology. The fast start and ramping capability of CTs allows for high penetration of low-cost renewable energy resources, which were consistently selected for all portfolios, regardless of potential future events. It also allows CenterPoint to incrementally pursue renewable build out with confidence that dispatchable resources will be available when needed, particularly in winter months where multi-day periods of cloud cover and no wind are possible.

Q. What factors support replacing the generation provided by F.B. Culley 2 and Warrick Unit #4?

A. As described in Petitioner's Witness Wayne D. Games' testimony, F.B. Culley 2 is CenterPoint's smallest and least efficient coal unit. It does not compete economically in the MISO market and needs costly upgrades to continue operation many years beyond 2023. Even the Indiana Coal Council ("ICC") acknowledged in their recent comments on

CenterPoint's 2019/2020 IRP, "There is no dispute over whether it should be retired. . . ."[5] Also, CenterPoint's contract with Warrick Unit #4 expires on December 31, 2023, and IRP modeling found extension of the contract was not economical. These two units currently provide 240 MW of installed capacity, 206 MW of which counts towards MISO's planning reserve margin ("PRM") requirement for the 2020-2021 planning year. While the Petitioner might be able to find economical ways to keep these plants running for a year or two longer to help meet its capacity needs, long term reliance on these plants is not the most economical answer for customers.

Q. What short-term steps does the Preferred Portfolio require CenterPoint to take?

A. The Preferred Portfolio calls for CenterPoint to pursue renewable projects within the next three years based on the retirement of F.B. Culley 2 and for the expiration of the contract for joint operation of Warrick Unit #4 in December 2023. Adding renewable projects during this time frame has the added benefit of allowing CenterPoint customers to take advantage of renewable tax incentives before they expire.[6]

Q. Has CenterPoint taken steps to begin implementing the Preferred Portfolio?

A. Yes. Consistent with the short-term action plan in the 2019/2020 IRP, CenterPoint selected two projects from the All-Source RFP conducted on June 12, 2019. As described in Petitioner's Witness Justin M. Joiner's testimony, CenterPoint, aided by Burns and McDonnell, evaluated and scored proposals. The projects scoring the highest were short-listed and proceeded to negotiation to ensure pricing was inclusive of all costs. The Posey County Solar Project and Warrick County Solar Project (collectively, the "Projects") were selected. Definitive agreements have been signed for the projects.

Q. Were the Posey County Solar Project and Warrick County Solar Project included within the IRP process?

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[5] ICC comments on CenterPoint's 2019/2020 IRP submitted to Director Brad Borum on October 28, 2020, bottom of page 6.

[6] The Posey County Solar Project is expected to qualify for the full 30 percent Investment Tax Credit ("ITC").

A. To a limited extent, yes. Both Tier 1[7] projects were included in the aggregate pricing utilized within the IRP.

V. POSEY COUNTY SOLAR PROJECT

Q. Please briefly describe the Posey County Solar Project.

A. Capital Dynamics is constructing the Posey County Solar Project through an affiliate on land west of the City of Evansville, Indiana, within Petitioner's assigned service territory. Once completed, the Posey County Solar Project will be a solar photovoltaic power plant with a nameplate capacity of approximately 300 MWac that will interconnect to Petitioner's A.B. Brown – Gibson 345 kV transmission line. The Posey County Solar Project is a clean energy project as defined in Ind. Code § 8-1-8.8-2(2). As discussed in Petitioner's Witness Joiner's testimony, CenterPoint and a Capital Dynamics' affiliate have entered into a BTA under which CenterPoint will purchase and acquire the Posey County Solar Project, subject to fulfillment of the conditions precedent to closing.

Q. In your opinion, is the Posey County Solar Project consistent with CenterPoint's 2019/2020 IRP?

A. Yes. The Posey County Solar Project was identified in the 2019 All-Source RFP, which was a major input into 2019/2020 IRP resource cost assumptions. As described above, solar resources were selected in all portfolios utilizing a wide range of potential future states. CenterPoint modeled solar projects on CenterPoint's system, which helps to minimize potential congestion cost risk. As described by Petitioner's Witness Brenda L. Musser, CenterPoint Energy, Inc. is able to monetize the tax benefit and pass on savings to our customers, which will provide reasonable and stable energy costs over the long-term.

Q. Does the Posey County Solar Project fulfill a capacity need identified in CenterPoint's 2019/2020 IRP?

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[7] Described in Witness Joiner's testimony, Tier 1 projects represent those that were located within the Company's service territory; or assumed congestion and delivery risk by pricing energy delivered to the Company's load node (SIGE.SIGW)

A. Yes. The Posey County Solar Project helps fill a portion of the capacity need identified in the 2019/2020 IRP. This project covers 300 MWac of the total 700-1,000 MWac of installed solar capacity identified as necessary in the IRP. In year one of operation, this resource is expected to cover 150 MWs towards CenterPoint's PRM requirement and 75-90 MWs in the long term due to expected penetration of solar on the MISO system.

Q. What are the benefits of adding solar resources generally?

A. Solar resources are an important part of the future of the electric industry, and utility scale solar energy ("Universal Solar") has emerged as an efficient, low-cost source of energy. As such, electric utilities are actively building and investing in solar infrastructure and expanding solar energy options for customers. As described by Petitioner's Witness Rina H. Harris, CenterPoint's customers are increasingly interested in the addition of more renewable resources to meet their energy needs. Solar energy helps CenterPoint and southwestern Indiana move towards a cleaner generation portfolio and helps the City of Evansville meet its Climate Action Plan by lowering the amount of CO_2 emitted from generating resources. A diversified portfolio also helps protect customers from risks in the marketplace, such as increases in fuel costs. While the capacity credit will diminish over time, solar generation generally aligns with CenterPoint's peak need for energy in the summer, shielding customers from high energy costs.

Q. Does CenterPoint also need to add more renewable resources to its portfolio in general?

A. In my opinion, yes. CenterPoint believes there is value in a balanced portfolio to reduce risk by having a balanced set of resources available to serve customer load (including wind, solar, energy efficiency, gas, and coal). The benefits of a balanced energy mix cannot be understated. One of the simplest and best ways to plan in an uncertain environment is to provide a diverse portfolio, which provides a hedge against unforeseen changes in regulations, technologies, and market.

Q. Is the Posey County Project a "clean energy project" under Indiana law?

A. Yes. Indiana Code § 8-1-8.8-2 defines a "clean energy project" as including "projects to develop alternative energy sources, including renewable energy projects." In addition, "solar energy" is specifically listed as one of the clean energy resources in Indiana Code

§ 8-1-37-4(a)(1) through -4(a)(16), thus making it a "renewable energy resource" under Ind. Code § 8-1-8.8-10. The proposed Posey County Solar Project also promotes a "robust and diverse portfolio of energy production or generating capacity, including . . . the use of renewable energy resources" which are imperative "if Indiana is to continue to be successful in attracting new businesses and jobs." Ind. Code § 8-1-8.8-1.

Q. Did CenterPoint consider demand side management ("DSM") as a resource in its 2019/2020 IRP?

A. Yes. CenterPoint considered DSM as a resource in its 2019/2020 IRP. CenterPoint considers DSM to be part of a balanced utility resource plan.

Q. In your opinion, are DSM initiatives a viable alternative to completing the Posey County Solar Project?

A. No. The 2019/2020 IRP demonstrates that DSM will be an important part of CenterPoint's resource options in the future. However, the IRP also recognizes that the addition of renewable resources, and in particular solar generation resources, is necessary to meet the needs of the system in the future and to diversify Petitioner's generation portfolio.

Q. In your opinion is the addition of the Posey County Solar Project to CenterPoint's generation portfolio in the public convenience and necessity?

A. Yes. The Posey County Solar Project is consistent with CenterPoint's 2019/2020 IRP and is an economic choice to help meet CenterPoint's retail electric load. The expected capacity attributable to the Project is necessary to meet CenterPoint's load and adequate reserve margins. In addition to providing necessary capacity, the Project is a reasonable addition to a portfolio of capacity resources that in the aggregate serve to mitigate risk through diversification. Commission approval of the Posey County Solar Project and associated relief sought herein is in the public interest, will enhance or maintain the reliability and efficiency of service provided by CenterPoint, and is otherwise consistent with Ind. Code § 8-1-8.8-11.

VI. <u>THE WARRICK COUNTY SOLAR PROJECT PPA</u>

Q. Please briefly describe the Warrick County Solar Project and PPA.

A. Clenera is constructing the Warrick County Solar Project in Warrick County, Indiana, south of the Town of Boonville. Upon completion, the Warrick County Solar Project will have an installed capacity of approximately 100 MWac. The Warrick County Solar Project is on CenterPoint's system. The terms and conditions of the PPA are further described in greater detail by Petitioner's Witness Joiner. In general, CenterPoint will pay a [redacted] price for capacity and energy, [redacted], and will only be obligated to pay for energy actually delivered to the energy delivery point. The PPA extends for a term of 25 years commencing on the commercial operation date of the facility.

Q. In your opinion, is the Warrick County Solar Project consistent with CenterPoint's 2019/2020 IRP?

A. Yes. Solar resources were selected as a part of the Preferred Portfolio, and this project was the least cost solar PPA offering from the All-Source RFP. It will provide low-cost energy with a [redacted]. This project provides an important off-ramp by adding flexibility to pivot should there be a better solution for customers in the future.

Q. Does the Warrick County Solar Project fulfill a capacity need identified in CenterPoint's 2019/2020 IRP?

A. Yes. The Warrick County Solar Project will fulfill 100 MWac of the initial 700 MWac of installed capacity identified in the 2019/2020 IRP. In year one of operation, this resource is expected to cover 50 MWac towards CenterPoint's PRM requirement and 25-30 MWac in the long term due to expected penetration of solar on the MISO system.

Q. Does the Warrick County Solar Project PPA represent prudent, valuable, and reasonably priced renewable energy resources for CenterPoint?

A. Yes. The Warrick County Solar Project PPA described herein will provide CenterPoint's customers with more affordable and cleaner energy resources. This is supported by the analysis performed in CenterPoint's 2019/2020 IRP.

Q. Is the Warrick County Solar Project a "clean energy project" under Indiana law?

A. Yes. For the same reasons that the Posey County Solar Project constitutes a clean energy project under Ind. Code § 8-1-8.8-2, the Warrick County Solar Project also qualifies as a clean energy project.

VII. <u>COST ISSUES</u>

Q. How do the cost assumptions associated with the new solar resource options modeled in the IRP compare with the cost of the Warrick County Solar Project PPA?

A. The model selected a 25-30 Year solar PPA at approximately $34 per MWh in 2024. The Warrick County Solar Project is a 25-year PPA [redacted] with a nominal value of $[redacted] per MWh.

Q. How much cost on a per MWh is added to the Warrick County project due to debt equivalency?

A. Per Petitioner's Witness Jerasa's testimony and included in <u>Petitioner's Exhibit No. 8</u>, Attachment BAJ-5 (CONFIDENTIAL), the rate for debt equivalency would be [redacted]

Q. How do the cost assumptions associated with the new solar resource options modeled in the IRP compare with the cost of the Posey County Solar Project BTA?

A. Ownership of solar resources was not modeled within the IRP because the strategy for monetizing the ITC had not been settled on. However, this option has a Levelized Cost of Energy[8] ("LCOE") of [redacted] per MWh, slightly lower than Warrick County, the lowest priced PPA CenterPoint received in the All-Source RFP, when future market replacement cost risk and debt equivalency are considered.

Q. Was any consideration given in the 2019/2020 IRP to the possibility that solar costs may decline in the future?

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[8] Levelized Cost of Energy measures lifetime costs divided by energy production. It calculates the present value of the total cost of building and operating a power plant over an assumed lifetime. In this case, it is 35 years.

A. Yes. The IRP included a declining cost curve for solar resources. The model selected solar in 2023 and 2024, taking advantage of near-term tax benefits and the need to replace capacity in the long term. This is in part due to the uncertainty of the Warrick Unit #4 contract and the expected retirement of F.B. Culley 2. While CenterPoint expects technology costs to continue to decline, the costs for land, labor, and interconnection to the system are not expected to decline. This, along with expiration of the ITC, help to flatten the decline over time. These projects offer customers low, stable prices for the long-term as compared to other offers, which included cost escalation of up to two percent per year over the life of the contract.

VIII. RATE ISSUES

Q. Please summarize CenterPoint's ratemaking proposals with respect to the Posey County Solar Project and the statutory support for these proposals?

Indiana Code ch. 8-1-8.8 provides for financial incentives including the timely recovery of costs and expenses incurred during the construction and operation of clean energy projects. In accordance with Ind. Code § 8-1-8.8-11 and utilizing the CECA mechanism approved in Cause No. 44909, CenterPoint requests the Commission authorize the necessary ratemaking treatment to permit CenterPoint to timely recover, through the CECA, the project costs it will incur during the construction and operation of qualifying projects (such as this Solar Project) through its rates. If the Commission approves the Posey County Solar Project, CenterPoint will include these costs in its annual CECA filing through the use of a "Levelized Rate." These annual CECA rate updates will be filed in Cause No. 44909, the proceeding in which the CECA was originally approved.

Q. What is the Levelized Rate for the Posey Solar Project?

A. As described by Petitioner's Witnesses Manzo and Joiner, the Levelized Rate is $0.0535 per kWh, subject to adjustment under specific limited circumstances.

Q. In your opinion, does the Levelized Rate have benefits over rates that might be included in a typical PPA?

A. Yes. The Levelized Rate will not be subject to an annual escalator like rates typically included in PPAs. There are very limited circumstances under which the Levelized Rate could be adjusted. CenterPoint is taking on operating cost risk to provide customers with a flat rate over the life of the asset. In addition, as described by Petitioner's Witness Games, the BTA offers long-term stability. CenterPoint will also maintain the land rights and options, zoning permits, and Generator Interconnection, shielding customers from potential future costs beyond the 35-year asset life.

Q. How will the Levelized Rate be applied to customer bills?

A. The Levelized Rate will be incorporated into the CECA mechanism, which the Commission approved on August 16, 2017, in Cause No. 44909 ("Order 44909") for renewable energy projects. Upon Commission approval of an Order in this proceeding, the CECA will be used to recover: (i) the approved revenue requirement associated with the three solar energy projects totaling approximately 4.1 MWac and one energy storage system[9] approved in Cause No. 44909 (the "44909 Projects"); (b) the Levelized Rate approved with respect to the 50 MW Solar Project in Cause No. 45086 ("45086 Project"); and (c) the Levelized Rate for the Posey County Solar Project. CenterPoint is not making any changes to the CECA mechanism as approved in Order 44909, except as necessary to support the incorporation of the Posey County Solar Project.

Q. How will the Posey County Solar Project component of the CECA be derived?

A. The Posey County Solar Project component of the CECA will be derived by multiplying the then effective Levelized Rate per kWh by the Production Baseline kWh produced by the Posey County Solar Project during the upcoming twelve-month period, grossed up for IURT. The Production Baseline will be set based on the final design of the solar facility, utilizing a 26.05 percent annual capacity factor in the first year of operation and 0.5 percent degradation factor for subsequent years. In the event that actual annual production from the Posey County Solar Project for a rolling three-year period is less than 90 percent of the Production Baseline for the same rolling three-year period and such deviation is not the result of a force majeure event (e.g., and without limitation, tornado, lightning damage,

[9] A battery storage scope at the Urban Living Research Facility (ULRC) was removed due to complications previously detailed in Petitioner's Witness Sears' testimony in Cause No. 44909-CECA 2.

fire, earth quake, acts of state or governmental action impending performance), CenterPoint shall credit the CECA in the next annual filing in the amount of the Levelized Rate multiplied by the difference between the rolling three-year period actual annual production and 90 percent of the Production Baseline, demonstrated Table 3 in the following calculation:

Table 3: Illustrative 90% Calculation:

		Actual Production	Baseline Production
2024		100,000,000	109,193,400
2025		97,000,000	108,647,433
2026		95,000,000	108,104,196
		97,333,333	108,648,343
Rolling 3-year Average Baseline Production Threshold (90%)			97,783,509
Actual Production Below Baseline Threshold		450,175	
Levelized Rate per kWh	$	0.0535	
CECA Production Credit	$	24,084	

In the event that actual annual production from the Posey Solar Project for a rolling three-year period is greater than 110 percent of the Production Baseline for the same rolling three-year period, CenterPoint shall include as a recoverable cost in the CECA in the next annual filing the amount of the Levelized Rate multiplied by the difference between the rolling three-year period actual annual production and 110 percent of the Production Baseline, demonstrated in Table 4 in the following calculation:

Table 4: Illustrative 110% Calculation:

		Actual Production	Baseline Production
2024		121,000,000	109,193,400
2025		120,000,000	108,647,433
2026		119,000,000	108,104,196
		120,000,000	108,648,343
Rolling 3-year Average Baseline Production Threshold (110%)			119,513,177
Actual Production Below Baseline Threshold		486,823	
Levelized Rate per kWh	$	0.0535	
CECA Production Charge	$	26,045	

Q. When will CenterPoint begin recovery on the Posey Solar Project?

A. To the extent it is feasible, Petitioner would propose to file two sets of rates for approval in the annual CECA filing prior to the projected in-service date of the Posey County Solar Project.:

(i) the first set of rates will recover the eligible revenue requirement associated with the 44909 Projects and 45086 Project; and

(ii) the second set of rates, effective on the date of in-service of the Posey Solar Project, will recover the eligible revenue requirement associated with the Posey County Solar Project.

Q. Please explain the basis for the allocation of CECA revenue requirements and to each rate schedule.

A. CenterPoint allocates the revenue requirements in the CECA to CenterPoint's various retail Rate Schedules based on the four coincident peak ("4CP") allocation percentages as approved by the Commission in Cause No. 43354-MCRA21 S1.

Q. Please describe the process for filing the CECA.

A. The CECA is filed annually in Cause No. 44909 and reconciled as a part of each annual CECA filing, with any over- or under-recovery collection variances returned to, or recovered from, customers in the Company's subsequent CECA filings as described in Cause No. 44909.

Q. To the extent future improvements are made to the Posey County Solar Project, will those improvements be accounted for in the CECA?

A. Not necessarily. In the event an investment is made at a later date to either expand the Posey County Solar Project to increase production or add technological improvements (e.g., battery storage or other investments to extend the life of the Solar Project), CenterPoint would seek approval for recovery in a future proceeding before the Commission.

Q. Please describe Petitioner's Exhibit No. 4, Attachment MAR-2.

A. Petitioner's Exhibit No. 4, Attachment MAR-2 is the proposed CECA tariff sheet, included in CECA 3, Sheet No. 67, Appendix C, CECA. The CECA mechanism and the associated tariff sheet originally were approved in Cause No. 44909.

Q. Please describe the bill impact of the Posey County Solar Project on a residential customer using 1,000 kWh per month.

A. Petitioner's Exhibit No. 4, Attachment MAR-3 shows that the estimated residential year-one bill impact for a residential customer that uses 1,000 kWh per month is approximately $11 per month. This impact does not reflect an offset for renewable energy credit ("REC") sales or O&M and fuel savings from exiting the Warrick Unit #4 agreement or closing F.B. Culley 2.

Q. How will the cost of the Warrick County Solar Project PPA be recovered?

A. CenterPoint is proposing to recover the Warrick County Solar Project PPA costs and associated debt equivalency cost throughout the full 25-year term of the agreements through the FAC (or successor mechanism) pursuant to Ind. Code §§ 8-1-2-42(a) and 8-1-8.8-11. CenterPoint is seeking a finding that power purchases pursuant to the Warrick County Solar Project PPA are reasonable throughout the entire term of the agreement. Therefore, CenterPoint is also seeking confirmation that the costs are recoverable through the FAC proceedings (or successor mechanism) without regard to the Ind. Code § 8-1-42(d)(1) test or any other FAC benchmarks.

Q. Please describe the bill impact of the Warrick County Solar Project on a residential customer using 1,000 kWh per month.

A. Petitioner's Exhibit No. 4, Attachment MAR-4 shows that the estimated residential bill impact for a residential customer that uses 1,000 kWh per month is approximately $2 per month.

Q. What is the combined rate impact of the Commission's approval of both the Posey County Solar Project and the Warrick County Solar Project?

A. CenterPoint believes the addition of the both projects will result in a net savings to residential customers of approximately $3.00 per month. While together, the projects add a cost of approximately $11 per month[10] to customer rates, these added costs are more

[10] Based on Average Use Per Customer of 860 kWh per month.

than offset by other expected savings. For instance, CenterPoint will sell the RECs created by both projects, which are anticipated to generate approximately $8 per MWh. In addition, Petitioner anticipates an approximately $19 million savings associated with retirement of F.B. Culley 2 and exiting the Joint Operating Agreement for Warrick Unit #4 for residential customers. Some of these cost savings will not be realized until Petitioner files a base rate case (i.e., operating and maintenance expense savings).[11] However, the reduced fuel costs will be realized immediately. Petitioner's Exhibit No. 4, Attachment MAR-5 shows estimated net monthly rate impact by customer class.

Q. In your opinion, are the rate proposals set forth herein reasonable and in the public interest?

A. Yes. The proposed ratemaking terms provide for reasonable cost recovery while providing related benefits and protections for customers. The projects will provide customers with affordable, stable energy for 25-35 years and are [redacted] or fuel cost. These projects are also timely, helping to provide a capacity benefit to help cover the loss of F.B. Culley 2 and Warrick Unit #4 and take advantage of the federal ITC.

Q. What reports will CenterPoint file with respect to the Posey County Solar Project?

A. CenterPoint will report on the Posey County Solar Project within the annual CECA filing.

IX. INDIANA CODE CH. 8-1-8.5 REQUIREMENTS

Q. Are you familiar with the factors set forth in Ind. Code ch. 8-1-8.5 that the Commission must consider before granting a CPCN?

A. Yes. While I am not an attorney, I am familiar with the factors set forth in Ind. Code § 8-1-8.5-5. Indiana Code provides that "[a] certificate shall be granted only if the commission has:

> (1) made a finding as to the best estimate of construction, purchase, or lease costs based on the evidence of record;
> (2) made a finding that either:

[11] CenterPoint is required to file by December 31, 2023, near the time when the Posey County and Warrick County Solar Projects are expected to go into service.

> (A) the construction, purchase, or lease will be consistent with the commission's analysis (or such part of the analysis as may then be developed, if any) for expansion of electric generating capacity; or
>
> (B) the construction, purchase, or lease is consistent with a utility specific proposal submitted under section 3(e)(1) of this chapter and approved under subsection (d). . . .;
>
> (3) made a finding that the public convenience and necessity require or will require the construction, purchase, or lease of the facility;
>
> (4) made a finding that the facility, if it is a coal-consuming facility, utilizes Indiana coal or is justified, because of economic considerations or governmental requirements, in using non-Indiana coal.

In addition, if a facility has a generating capacity of more than 80 megawatts, the Commission must find that the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable and also consider the following: "(A) Reliability" and "(B) Solicitation by the applicant of competitive bids to obtain purchased power capacity and energy from alternative suppliers."

Q. In your opinion, is the Posey County Solar Project consistent with the factors set forth in Ind. Code § 8-1-8.5-5?

A. Yes. Initially, the costs reflected in this proceeding represent "the best estimate of construction, purchase, or lease costs based on the evidence of record." As described in further detail by Petitioner's Witness Joiner, the cost of the Posey County Solar Project is fixed pursuant to the terms of the BTA. In addition, in accordance with Ind. Code § 8-1-8.5-5(b)(2), the construction of the Posey County Solar Project is consistent with CenterPoint's 2019/2020 IRP. The Posey County Solar Project fills a portion of the capacity need identified in the 2019/2020 IRP. This project covers 300 MWac of the total 700-1,000 MWac of installed solar capacity identified as necessary in the IRP.

Q. In your opinion, does the public convenience and necessity require construction of the Posey County Solar Project?

A. Yes, and the same is true for the Warrick County Solar Project. The Posey County Solar Project was included in Petitioner's Preferred Portfolio and adds diversity to Petitioner's generation portfolio thereby reducing risks. Fuel diversity and the addition of local renewable resources is important to protect electric utilities and their customers from contingencies such as fuel price fluctuations, and changes in regulatory practices that can drive up the cost of a particular fuel (e.g., environmental regulations). Moreover, as further described by Petitioner's Witnesses Games and Joiner, the Posey County Solar Project, in tandem with the Warrick County Solar Project, is necessary to meet capacity needs on Petitioner's system. Mr. Games notes that upon the retirement of F.B. Culley 2 and the exit of Warrick Unit #4, CenterPoint would need energy produced from the facilities at this issue in this proceeding or would need to turn to the market to purchase capacity.

Q. Was the Posey County Solar Project selected in accordance with the competitive bidding provisions of Ind. Code § 8-1-8.5-5(b)(2)?

A. Yes. As discussed by Petitioner's Witness Joiner, CenterPoint selected both the Posey County Solar Project and the Warrick County Solar Project based on the results of an All-Source RFP for 10 to 700 MWac of unforced capacity. Mr. Joiner notes that the responses to the RFP were robust and the All-Source RFP allowed CenterPoint to identify the best projects at the best available prices. The Posey County Solar Project and Warrick County Solar Project were identified as the top two projects to pursue based on their scoring among the top proposals.

Q. Did CenterPoint consider the reliability of the projects in comparison to obtaining purchased power capacity and energy from alternative suppliers?

A. Yes. As Mr. Joiner notes, the projects were compared to a variety of PPA options. The Warrick County Solar Project provides the lowest cost PPA pricing at a [redacted] for a period of 25 years. Both Mr. Joiner and Mr. Games explain how combining a PPA with ownership of solar assets enhances reliability. Both the solar BTA and PPA have unique benefits to customers, and the Company's plan to balance these risks will provide additional reliability for customers. For instance, the BTA will provide Petitioner with a resource that may be operated for beyond 35 years, after which the facility will continue to produce and provide low-cost power to the benefit of CenterPoint's customers. This long-term operation helps insulate customers from the risk that energy prices might rise in the future.

X. 21st CENTURY ENERGY POLICY DEVELOPMENT TASK FORCE PILLARS

Q. Have you reviewed the Final Report issued by the 21st Century Energy Policy Development Task Force dated November 19, 2020 (the "Final Report")?

A. Yes. I reviewed the five pillars that the Task Force recommended serve as a lens through which it would review future potential policy decisions.

Q. What are the five pillars?

A. The five pillars are reliability, resilience, stability, affordability, and environmental sustainability. Reliability consists of two fundamental concepts—adequacy and operating reliability. Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components. Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components.

Q. In your opinion, is the proposal in this proceeding consistent with those five pillars?

A. Yes. The addition of clean solar energy is consistent with the environmental sustainability pillar set forth in the Final Report. Moreover, as further supported by the IRP, both Projects promote reliability. Addition of energy from both Projects is needed to supply the aggregate power and energy requirements of electricity consumers at all times, particularly given the reduced generating capacity once F.B. Culley 2 is retired and the long-term uncertainty of the outlook for Warrick Unit #4 as further described by Petitioner's Witness Games. Moreover, while solar resources are intermittent in nature, they are no more impacted by short circuits or unanticipated loss of system components than other generation resources. Moreover, as Mr. Games notes, CenterPoint proposes to pair renewable generation with quick start and fast ramping dispatchable natural gas CT generation, which will further enhance the ability of the system to withstand sudden disturbances.

Q. In your opinion, will solar energy provided by the Projects be resilient and stable?

A. Yes. As to resiliency, the preferred portfolio, which includes solar energy, helps to minimize the risk of sustained disruption. Moreover, as further discussed by Petitioner's

Witness Holland, the IRP resulted in a Preferred Portfolio that significantly, but prudently, diversifies the resource mix for CenterPoint's generation portfolio to meet current and future load and reserve margin requirements. Reliability was an important consideration of selecting a holistic portfolio. Solar resources are a proven technology that will help ensure CenterPoint can continue to meet PRM requirements. Solar assets are also well suited to provide a stable source of energy in the summer, when usage is at its highest.

Q. Do you believe the Projects will result in an affordable generation mix?

A. Yes. As Mr. Games indicates, F.B. Culley 2 is Petitioner's oldest, smallest (90 MWs), and least efficient (12,500-13,000 BTU/kWh) coal unit. As a result, the unit only produces energy for CenterPoint's customers or the MISO market when energy prices spike to a level that justifies MISO dispatching the unit for a 24-hour period. Additionally, continued use of Warrick Unit #4 over the long-term is less economic than other sources of generation. To that end, CenterPoint conducted an All-Source RFP before selecting the projects. Mr. Joiner testifies that the Posey County Solar Project and the Warrick County Solar Project were the lowest cost projects on an LCOE basis. Petitioner's use of a Levelized Rate further reduces the cost of energy produced by the Posey County Solar Project by allowing CenterPoint customers to immediately realize the ITC as further discussed by Witnesses Manzo and Musser.

XI. <u>CONCLUSION</u>

Q. Does this conclude your direct testimony?

A. Yes, at the present time.

VERIFICATION

I, Matthew A. Rice, Director of Indiana Electric Regulatory and Rates for Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South, under the penalty of perjury, affirm that the answers in the foregoing Direct Testimony are true to the best of my knowledge, information and belief.

Matthew A. Rice
Director of Indiana Electric Regulatory and Rates

2019/2020
Integrated Resource Plan

VECTREN
A CenterPoint Energy Company

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IRP Rule Requirements Cross Reference Table

Rule		Section(s)
170 IAC 4-7-2 Integrated Resource Plan Submission Section 2		
(c) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents:		
(1) The IRP.		2019 IRP submitted on June 30, 2020
(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP. The technical appendix shall include at least the following: (A) The utility's energy and demand forecasts and input data used to develop the forecasts. (B) The characteristics and costs per unit of resources examined in the IRP; (C) Input and output files from capacity planning models, in electronic format. (D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file. If a utility does not provide the above information, it shall include a statement in the technical appendix specifying the nature of the information it is omitting and the reason necessitating its omission. The utility may request confidential treatment of the technical appendix under section 2.1 of this rule.		12 Technical Appendix Attachments 1.1-8.3
(3) An IRP summary that communicates core IRP concepts and results to nontechnical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) public advisory process; and (vi) additional details requested by the director. (B) A simplified discussion of the utility's resource types and load characteristics.		Executive Summary (non-technical summary document)
The utility shall make the IRP summary readily accessible on its website.		www.vectren.com/irp
170 IAC 4-7-2.6 Public advisory process Sec. 2.6		

(b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP within 15 business days of a written request or as otherwise agreed to by the utility and the interested party. If a utility is unable to provide the requested information within 15 business days or the agreed timeframe, it shall provide a statement to the director and the requestor as to the reason it is unable to provide the requested information.		3.4 Data Requests Summary
(c) The utility shall solicit, consider and timely respond to relevant input relating to the development of the utility's IRP provided by: (1) interested parties; (2) the OUCC; and (3) commission staff.		3 Public Participation Process
(d) The utility retains full responsibility for the content of its IRP.		n/a
(e) The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three (3) meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following:		3.1 Process Description
(A) An introduction to the IRP and public advisory process. (B) The utility's load forecast. (C) Evaluation of existing resources. (D) Evaluation of supply-side and demand-side resource alternatives, including: (i) associated costs; (ii) quantifiable benefits; and (iii) performance attributes. (E) Modeling methods. (F) Modeling inputs. (G) Treatment of risk and uncertainty. (H) Discussion seeking input on its candidate resource portfolios. (I) The utility's scenarios and sensitivities. (J) Discussion of the utility's preferred resource portfolio and the utility's rationale for its selection.		3 Public Participation Process; 12 Technical Appendix Attachment 3.1
(2) The utility may hold additional meetings.		3.1 Process Description
(3) The schedule for meetings shall: (A) be determined by the utility; (B) be consistent with its internal IRP development schedule; and		3 Public Participation Process

(C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.		
170 IAC 4-7-4 Integrated resource plan contents Sec. 4		
An IRP must include the following: (1) At least a twenty (20) year future period for predicted or forecasted analyses.		4.6 Base Energy And Demand Forecast
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.		11.1.3 Overview of Past Forecasts
(3) At least three (3) alternative forecasts of peak demand and energy usage in compliance with section 5(b) of this rule.		7.3. Alternate Scenarios; Figure 7.8 Vectren Peak Demand Forecast
(4) A description of the utility's existing resources in compliance with section 6(a) of this rule.		6.2 Current Resource Mix
(5) A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis, if performed.		6 Resource Options; 8 Portfolio Development and Evaluation
(6) A description of the possible alternative future resources for meeting future demand for electric service in compliance with section 6(b) of this rule.		6.3 Potential Future Options Modeling Assumptions; Figure 6-5 Tier 1 Cost Summary
(7) The resource screening analysis and resource summary table required by section 7 of this rule.		Figure 11.35 New Construction Alternatives; Figure 6-5 Tier 1 Cost Summary.
(8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with section 8(a) and 8(b) of this rule.		8.1 Portfolio Development
(9) A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.		8.2 Evaluation of Portfolio Performance; 9.1 Preferred Portfolio Recommendation
(10) A short term action plan for the next three (3) year period to implement the utility's preferred resource portfolio and its workable strategy, pursuant to section 9 of this rule.		10 Short Term Action Plan
(11) A discussion of the: (A) inputs; (B) methods; and (C) definitions; used by the utility in the IRP.		List of Acronyms/Abbreviations with Definitions; 2 Vectren's IRP Process; 3 Public Participation Process; 4 Customer Energy Needs; 6 Resource Options; 7 Model Inputs and Assumptions; 8 Portfolio Development and Evaluation
(12) Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this		12 Technical Appendix Attachments

rule. If the IRP references a third-party data source, the IRP must include for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of adjustments made to the data. The data must be submitted within two (2) weeks of submitting the IRP in an editable format, such as a comma separated value or excel spreadsheet file.		
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use. 14) The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.		6.2.4 Energy Efficiency; 11.1.1 Forecast Inputs; 12 Technical Appendix Attachment 4.1 2019 Long-Term Electric Energy and Demand Forecast Report
(15) A proposed schedule for industrial, commercial and residential customer surveys to obtain data on: (A) end-use penetration; (B) end-use saturation rates; and (C) end-use electricity consumption patterns.		11.1.4 Equipment Efficiencies and Market Share Data
(16) A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs and other aspects of planning.		1.3.3.1 Advanced Metering Infrastructure (AMI)
(17) A discussion of the designated contemporary issues designated, if required by section 2.7(e).		1.3.13 Contemporary Issues
(18) A discussion of distributed generation within the service territory and its potential effects on: (A) generation planning;		4.4 Customer Owned Distributed Energy Resources

(B) transmission planning; (C) distribution planning; and (D) load forecasting.		
(19) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.		4.3 Model Framework; 7.1 Resource Model
(20) A discussion of how the utility's fuel inventory and procurement planning practices-have been taken into account and influenced the IRP development.		9.1.7 Fuel Inventory and Procurement Planning
(21) A discussion of how the utility's emission allowance inventory and procurement practices for an air emission have been considered and influenced the IRP development.		11.2.1 Air Emissions
(22) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.		8.1 Portfolio Development
(23) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.		7.2. Reference Case Scenario; 7.3 Alternate Scenarios
(24) A discussion of how the utilities' resource planning objectives, such as: (A) cost effectiveness; (B) rate impacts; (C) risks; and (D) uncertainty; were balanced in selecting its preferred resource portfolio.		8.2 Evaluation of Portfolio Performance; 9.1 Preferred Portfolio Recommendation
(25) A description and analysis of the utility's Reference Case scenario, sometimes referred to a business as usual case or reference case. The Reference Case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include: (i) existing federal environmental laws; (ii) existing state laws, such as renewable energy requirements and energy efficiency laws; and (iii) existing policies, such as tax incentives for renewable resources. (C) Existing laws or policies continuing throughout at least some portion of the planning horizon with		7.2 Reference Case Scenario

a high probability of expiration or repeal must be eliminated or altered when applicable. (D) Not include future resources, laws, or policies unless: (i) a utility subject to section 2.6 of this rule solicits stakeholder input regarding the inclusion and describes the input received; (ii) future resources have obtained the necessary regulatory approvals; and (iii) future laws and policies have a high probability of being enacted. A Reference Case scenario need not align with the utility's preferred resource portfolio.		
(26) A description and analysis of alternative scenarios to the Reference Case scenario, including comparison of the alternative scenarios to the Reference Case scenario.		7.3 Alternate Scenarios
(27) A brief description of the models(s), focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC). (C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following: (i) The limits of the utility's transmission use. (ii) The utility's assessment practices developed through experience and study. (iii) Operating restrictions and limitations particular to the utility.		6.4 Transmission Considerations
(28) A list and description of the methods used by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast; (ii) forecasted impact from demand-side programs; (iii) cost estimates; and		4.3 Model Framework; 7.1 Resource Model; 6.3.2 DSM, 4.6 Energy and Demand Forecast (Reference Case); 6 Resource Options; 7 Model Inputs and Assumptions; 8.2 Evaluation of Portfolio Performance; 9.1 Preferred Portfolio

(iv) analysis of risk and uncertainty.		
(29) An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including: (i) fuel cost; (ii) plant operation and maintenance costs; (iii) spinning reserve; (iv) emission allowances; (v) environmental compliance costs; and (vi) transmission and distribution operation and maintenance costs.		11.3.5 Avoided Costs
(30) A summary of the utility's most recent public advisory process, including the following: (A) Key issues discussed. (B) How the utility responded to the issues. (C) A description of how stakeholder input was used in developing the IRP.		3 Public Participation Process
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.		6 Resource Options
170 IAC 4-7-5 Energy and demand forecasts Sec. 5.		
(a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following: (1) Historical load shapes, including the following: (A) Annual load shapes. (B) Seasonal load shapes. (C) Monthly load shapes. (D) Selected weekly load shapes. (E) Selected daily load shapes, which shall include summer and winter peak days and a typical weekday and weekend day.		11.1.3.2 Load Shapes; 12 Technical Appendix Attachments Attachment 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report; Attachment 4.2 Vectren Hourly Load Data
(2) Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) end-use; where information permits.		11.1.3 Overview of Past Forecasts; 12 Technical Appendix Attachments Attachment 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report

(3) Actual and weather normalized energy and demand levels.		11.1.3 Overview of Past Forecasts
(4) A discussion of methods and processes used to weather normalize.		11.1.3 Overview of Past Forecasts
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.		4.6 Energy and Demand Forecast (Reference Case)
(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system. (B) Customer classes or, rate classes, or both. (C) Firm wholesale power sales.		11.1.3 Overview of Past Forecasts
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.		12 Technical Appendix Attachments 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report
(8) Justification for the selected forecasting methodology.		12 Technical appendix attachments 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report
(9) A discussion of the potential changes under consideration to improve the credibility of the forecasted demand by improving the data quality, tools and analysis.		1.3.3.1 Advanced Metering Infrastructure; 11.1.2 Load Forecast Continuous Improvement
(10) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in section 4(14) of this rule.		n/a
(b) To establish plausible risk boundaries, the utility shall provide at least three (3) alternative forecasts of peak demand and energy usage including: (1) high; (2) low; and (3) most probable; peak demand and energy use forecasts.		7.3 Alternate Scenarios
(c) In determining the peak demand and energy usage forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices. (4) Price elasticity. (5) Penetration of new technology. (6) Demographic changes in population. (7) Customer usage. (8) Changes in technology. (9) Behavioral factors affecting customer consumption.		7.3 Alternate Scenarios; 12 Technical Appendix Attachments 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report

(10) State and federal energy policies. (11) State and federal environmental policies.		
170 IAC 4-7-6 Description of available resources		
Sec. 6. (a) In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the twenty (20) year planning period being evaluated: The net and gross dependable generating capacity of the system and each generating unit. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.		6.2 Current Resource Mix; 11.4.2 Approximate Net and Gross Dependable Capacity
(2) The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.		6.2 Current Resource Mix
(3) A fuel price forecast by generating unit. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.		12 Technical Appendix Attachments: Confidential Attachment 8.2 Aurora Input Model Files
(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and(D) subsequent disposal; and (E) water consumption and discharge; at existing fossil fueled generating units. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.		11.2 Environmental Appendix
(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce: (i) transmission losses;		11.8 Transmission Appendix

(ii) congestion; and (iii) energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network.		
(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy. (a)(6) shall be provided for each year of the future planning period.		6.2.4 Energy Efficiency; 6.2.5 Demand Response; 6.3.2 DSM; 11.3 DSM Appendix
The information listed in subdivision (a)(1) through (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.		Included in Sec. 6 (a)(1) through (a)(4) and in subdivision (a)(6)
(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Rate design as a resource in meeting future electric service requirements.		6.3.2.6 Other Innovative Rate Designs
(2) Demand-side resources. For potential demand-side resources, the utility shall include the following: (A) A description of the potential demand-side resource, including its costs, characteristics and parameters. (B) The method by which the costs, characteristics and other parameters of the demand-side resource are determined. (C) The customer class or end-use, or both, affected by the demand-side resource. (D) Estimated annual and lifetime energy (kWh) and demand (kW) savings. (E) The estimated impact of a demand-side resource on the utility's load, generating capacity and transmission and distribution requirements. (F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.		6.3.2 DSM, 12 Technical Appendix Attachments 6.2 2019 DSM Market Potential Study
(3) Supply-side resources. For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered, including the following: (i) Size in megawatts. (ii) Utilized technology and fuel type. (iii) Energy profile of nondispatchable resources. (iv) Additional transmission facilities necessitated by the resource.		6 Resource Options; 11.2 Environmental Appendix; 12 Technical Appendix Attachments: Attachment 1.2 Vectren Technology Assessment Summary Table; Confidential Attachment 8.2 Aurora Input Model Files

(B) A discussion of the utility's effort to coordinate planning, construction and operation of the supply-side resource with other utilities to reduce cost. (C) A description of significant environmental effects, including the following: (i) Air emissions. (ii) Solid waste disposal. (iii) Hazardous waste and subsequent disposal. (iv) Water consumption and discharge.		
(4) Transmission facilities as resources. In analyzing transmission resources, the utility shall include the following: (A) The type of the transmission resource, including whether the resource consists of one (1) of the following: (i) New projects. (ii) Upgrades to transmission facilities. (iii) Efficiency improvements. (iv) Smart grid technology. (B) A description of the timing, types of expansion and alternative options considered. (C) The approximate cost of expected expansion and alteration of the transmission network. (D) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources. (E) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.		6.4 Transmission Considerations
170 IAC 4-7-7 Selection of resources		
Sec. 7. (a) To eliminate nonviable alternatives, a utility shall perform an initial screening of the future resource alternatives listed in section 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.		6.6 Levelized Cost of Energy Resource Screening Analysis
170 IAC 4-7-8 Resource portfolios Sec. 8		

(a) The utility shall develop candidate resource portfolios from existing and future resources identified in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.		2.5 Portfolio Development; 8 Portfolio Development and Evaluation
(b) With regard to candidate resource portfolios, the IRP must include the following: (1) An analysis of how candidate resource portfolios performed across a wide range of potential future scenarios, including the alternative scenarios required under section 4(25) of this rule. (2) The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics. (3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.		8.2 Evaluation of Portfolio Performance; 9.1.2 Affordability; 11.6.8 Affordability Ranking
(c) Considering the analyses of the candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following: (1) A description of the utility's preferred resource portfolio. (2) Identification of the standards of reliability. (3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio. (4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of: (A) safety; (B) reliability; (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.		6 Resource Options; 8 Portfolio Development and Evaluation; 9.1 Preferred Portfolio Recommendation

(5) An analysis showing the preferred resource portfolio utilizes supply-side resources and demand-side resources that safely, reliably, efficiently and cost-effectively meets the electric system demand taking cost, risk and uncertainty into consideration.		9 IRP Preferred Portfolio Recommendation
(6) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system.		N/A
(7) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio. (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.		9. IRP Preferred Portfolio; 10.2.5 Ability to Finance the Preferred Portfolio, 11.3.5 Avoided Costs, 11.7.1 Affordability Ranking; 12 Technical Appendix Attachments, Confidential Attachment 8.2 Aurora Input Model Files
(8) A description of how the preferred resource portfolio balances cost effectiveness, reliability and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance; (ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (v) operating costs; (vi) construction costs; (vii) resource performance; (viii) load requirements; (ix) wholesale electricity and transmission prices; (x) RTO requirements; and (xi) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.		2 Vectren's IRP Process; 5 MISO Market; 7.2 Reference Case Scenario; 7.3 Alternate Scenarios; 8.2 Evaluation of Portfolio Performance; 9 Preferred Portfolio; Confidential Attachment 8.2 Aurora Input Model Files

(9) Utilities shall include a discussion of potential methods under consideration to improve the data quality, tools and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.		10.2 Discussion of Plans for the Next 3 years; 11.1.4 Advanced metering Infrastructure and Continuous Improvement
(10) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including changes in the following: (A) Demand for electric service. (B) Cost of new supply-side resources or demand-side resources. (C) Regulatory compliance requirements and costs. (D) Wholesale market conditions. (E) Fuel costs. (F) Environmental compliance costs. (G) Technology and associated costs and penetration. (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.		8.2 Evaluation of Portfolio Performance; 9 Preferred Portfolio
170 IAC 4-7-9 Short term action plan Sec. 9		
(a) A utility shall prepare a short term action plan as part of its IRP and shall cover a three (3) year period beginning with the first year of the IRP submitted pursuant to this rule.		10 Short Term Action Plan
(b) The short-term action plan shall summarize the utility's preferred resource portfolio and its workable strategy, as described in section 8(c)(9) of this rule, where the utility must act or incur expenses during the three (3) year period.		10 Short Term Action Plan
(c) The short term action plan must include, but is not limited to, the following: (1) A description of resources in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective.		10 Short Term Action Plan
(2) Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10, 170 IAC 4-8-1 *et seq.* and consistent with the utility's longer resource planning objectives.		10.2.2 DSM

(3) The implementation schedule for the preferred resource portfolio.		10.3 Implementation Schedule for the Preferred Resource Portfolio
(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.		10.2 Discussion of Plans for the Next 3 Years
(5) A description and explanation of differences between what was stated in the utility's last filed short-term action plan and what actually occurred.		10.1 Differences Between the Last Short Term Action Plan From What Transpired

List of Acronyms/Abbreviations

ABB	Power Consulting Company
ABB	A.B. Brown Generating Station
AC	Alternating Current
ACE	Affordable Clean Energy
AEO	Annual Energy Outlook
AMI	Advanced Metering Infrastructure
ATC	Around the Clock
AUPC	Average Use Per Customer
BAGS	Broadway Avenue Generating Station
BAU	Business as Usual
BES	Bulk Electric System
BEV	Battery Electric Vehicles
BPM	Business Practice Manual
BSER	Best System of Emission Reduction
Btu	British Thermal Unit
BYOT	Bring You Own Thermostat
C&I	Commercial and Industrial
CAC	Citizens Action Coalition
CAGR	Compound Annual Growth Rate
CAPP	Central Appalachian
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Day
CDS	Circulating Dry Scrubber
CHP	Combined Heat and Power
CNP	CenterPoint Energy
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide equivalent
Comm	Commercial
CONE	Cost of New Entry
COVID	Corona Virus Disease
CPCN	Certificate of Public Convenience and Necessity
CSA	Coordinated Seasonal Transmission Assessment
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
CVR	Conservation Voltage Reduction
CWIS	Cooling Water Intake Structures
C&I	Commercial and Industrial
DA-LSFO	Dual-Alkali FGD-Forced Oxidation
DA-LSIO	Dual-Alkali FGD-Inhibited Oxidation
DC	Direct Current
DG	Distributed Generation

List of Acronyms/Abbreviations (Cont.)

DGS	Demand General Service
DLC	Direct Load Control
DPP	Definitive Planning Phase
DR	Demand Response
DSI	Dry Sorbent Injection
DSM	Demand Side Management
DSMA	Demand Side Management Adjustment
EE	Energy Efficiency
EEFC	Energy Efficiency Funding Component
EGU	Electric Generation Units
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines
EM	Equipment Manufactures
EM&V	Evaluation, measurement and Verification
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitator
EV	Electric Vehicle
EVA	Energy Ventures Analysis, Inc.
FBC	F.B. Culley Generating Station
FBC3	F.B. Culley Unit 3
FDA	Flash Dryer Absorber
FDNS	Fixed Slope Decoupled Newton-Raphson
FERC	Federal Energy Regulatory Commission
FF	Fabric Filter
FGD	Flue Gas Desulfurization
GDP	Gross Domestic Product
GE	General Electric
GHG	Greenhouse Gas
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
GIR	Generator Interconnection Requests
GPS	Global Positioning System
GS	General Service
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt Hour
HB	House Bill
H_2SO_4	Sulfuric Acid
HDD	Heating Degree Days
Hg	Mercury
HHV	Higher Heating Value

List of Acronyms/Abbreviations (Cont.)

HLF	High Load Factor
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning
IC	Internal Combustion
ICAP	Installed Capacity
IDEM	Indiana Department of Environmental Management
ILB	Illinois Basin
IMPA	Indiana Municipal Power Agency
Ind	Industrial
IPL	Indianapolis Power and Light Company
IRP	Integrated Resource Plan
ISB	Intelligent Sootblowing
ISO	Independent System Operator
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
lb	Pound
LCOE	Levelized Cost of Energy
LCR	Local Clearing Requirement
LGE/KU	Louisville Gas and Electric/Kentucky Utilities
LIB	Lithium-ion Battery
Li-ion	Lithium-ion
LMP	Local Marginal Pricing
LMR	Load Modifying Resources
LMR	Load Management Receivers
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LP	Large Power
LRR	Local Reliability Requirement
LRZ	Local Resource Zone
LSE	Load Serving Entity
LSFO	Limestone FGD – Forced Oxidation
LTCE	Long-term Capacity Expansion
MATS	Mercury and Air Toxics Standards
MEEA	Midwest Energy Efficiency Alliance
MEP	Market Efficiency Project
MILP	Mixed Integer Linear Programming
MISO	Midcontinent Independent System Operator
MISO Tariff	Open Access Transmission, Energy and Operating Reserve Markets Tariff

List of Acronyms/Abbreviations (Cont.)

MLA	Municipal Levee Authority
MMBtu	One Million British Thermal Unit
MMWG	Multiregional Modeling Working Group
MPS	Market Potential Study
MSA	Metropolitan Statistical Area
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standard
NAEMA	North American Energy Markets Association
NAICS	North American Industry Classification System
NAPP	Northern Appalachia
NDA	Non-Disclose Agreement
NERC	North American Electric Reliability Council
NERC MOD	NERC Modeling, Data and Analysis
NH_3	Ammonia Scrubber
NIPSCO	Northern Indiana Public Service Company
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen Oxide
NOPR	Notice of Proposed Rulemaking
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NPVRR	Net Present Value Revenue Requirement
NREL	National Renewable Energy Lab
NRIS	Network Resource Integration Service
NTG	Net to Gross
NU	Network Upgrade
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
OMS	Organization of MISO States
ORSANCO	Ohio River Valley Sanitation Commission
OUCC	Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PC	Pulverized Coal
PHEV	Plug-in Hybrid Electric
PIRA	PIRA Energy Group
PJM	Pennsylvania New Jersey Maryland Interconnection LLC
PM	Particulate Matter
PPA	Purchase Power Agreement
PPT	Parts Per Trillion
PRA	Planning Resource Auction

List of Acronyms/Abbreviations (Cont.)

PRB	Powder River Basin
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PSEG	Public Service Electric and Gas
PTC	Production Tax Credit
PTI PSS/E	Power Technologies Incorporated's Power System Simulator Program for Engineers
PV	Photovoltaic
RAN	Resource Availability and Need
Res	Residential
RF	ReliabilityFirst
RFP	Request for Proposals
RGGI	Regional Greenhouse Gas Initiative
RIIA	Renewable Integration Impact Assessment
RIM	Ratepayer Impact Measure
RS	Rate Schedules
RTO	Regional Transmission Operator
SAE	Statistically Adjusted End-use
SBS	Sodium Based Sorbents
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SD	Standard Deviation
SDA	Spray Dryer Absorber
SEA	Senate Enrolled Act
SERC	Southeast Reliability Corporation
SGS	Small General Service
SIGECO	Southern Indiana Gas and Electric Company
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
STD Dev	Standard Deviation
TDSIC	Transmission, Distribution and Storage System Improvement Charge
T&D	Transmission and Distribution
TBtu	One Trillion British Thermal Unit
TRC	Total Resource Cost
UC	Utility Cost
UCAP	Unforced Capacity
UCT	Utility Cost Test
ULRC	Urban Living Research Center
UPC	Use Per Customer
V	Volt

List of Acronyms/Abbreviations (Cont.)

VAR	Volt-Amp Reactance
VER	Variable Energy Resources
VFD	Variable Frequency Drive
VOM	Variable Operation and Maintenance
VVC	Vectren Corporation
WLIO	Wet Lime FGD – Inhibited Oxidation
WN	Weather Normalized
WTE	Waste to Energy

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Executive Summary (Non-Technical Summary)

I. Introduction

Southern Indiana Gas and Electric Company d/b/a Vectren a CenterPoint Energy Company's ("Vectren") 2019/2020 Integrated Resource Plan is submitted in accordance with 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 Vectren's previous 2016 Integrated Resource Plan ("IRP"). The preferred portfolio in Vectren's previous 2016 IRP contemplated replacement of some of Vectren's coal fleet by the end of 2023 with a mix of renewable, energy efficiency and gas resources while retaining other coal resources. To implement this plan, Vectren filed two cases seeking Certificates of Public Convenience and Necessity ("CPCN") to (1) own and operate a 50 MW solar project located on its system (the "Troy Solar Project"), (2) install equipment designed to achieve compliance with environmental regulations in order to continue operation of its 270 MW Culley Unit 3 beyond 2023 and construct a 700-850 MW Combined Cycle Gas Turbine ("CCGT"). The Commission approved issuance of CPCNs authorizing the construction of the Troy Solar Project and Culley Unit 3 compliance projects. The Commission order denying a CPCN for the 700-850 MW CCGT urged Vectren to:

- Focus on outcomes that reasonably minimize the potential risk of an asset becoming uneconomic in an environment of rapid technological innovation;
- Fully consider options that provide a bridge to the future;
- Utilize a request for proposals ("RFP") to determine the price and availability of renewables; and
- Consider resource diversity and alternatives that provide off ramps that would allow Vectren to react to changing circumstances.

Vectren began its 2019/2020 IRP process in April 2019 with the objective of engaging in a generation planning process responsive to the Commission's guidance and seeking input from a variety of stakeholders. As part of its 2019/2020 IRP process, Vectren's evaluation has focused on exploring all new and existing supply-side and demand side resource options to reliably serve Vectren customers over the next 20 years. While the fundamentals of integrated resource planning were adhered to in developing the 2016 IRP, Vectren has enhanced its process and analysis in several ways. These enhancements include, but are not limited to the following:

- 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 and solar;
- An exhaustive review of reasonable options that leverage existing coal resources;
- increased participation and collaboration from stakeholders on all aspects of the analysis, inputs and resource evaluation criteria, with specific considerations and responses from Vectren;
- An encompassing analysis of wholesale market dynamics that accounts for MISO developments and market trends;
- The use of a more sophisticated IRP modeling tool, Aurora, which provided several benefits (simultaneous evaluation of many resources, evaluation of portfolios on an hourly basis and consistency in modeling, including least cost long-term capacity expansion planning optimization, simulated dispatch of resources and probabilistic modeling); and
- A more robust risk analysis, which encompasses a broad consideration of risks and an exploration of resource performance over a wide range of potential futures.

Based on this planning process and detailed analysis, Vectren has selected a preferred portfolio plan that significantly yet prudently diversifies the resource mix for its generation portfolio with the addition of significant solar and wind energy resources, the retirement or exit of four coal units, and continued investment in energy efficiency. These resources are complemented with dispatchable resources including continued operation of Culley Unit 3 and the addition of two flexible natural gas Combustion Turbines (CTs). The gas units represent a much smaller portion of Vectren's generation portfolio as compared to the 2016 IRP preferred portfolio while still providing reliable capacity and energy. The highly dispatchable and fast-ramping gas units are an important match with the significant renewable investment, enabling Vectren to maintain constant electric supply during potentially extended periods of low output from renewable energy sources. The units ramp quickly and provide load following capability, complimenting renewable energy production, which is expected to grow throughout the MISO footprint. Vectren's preferred portfolio reduces its cost of providing service to customers over the next 20 years by more than $320 million as compared to continuing with its existing generation fleet. Additionally, the preferred portfolio reduces carbon dioxide output by approximately 67% by 2025 and 75% by 2035 when compared to 2005 levels, which helps Vectren's parent company, CenterPoint Energy, achieve its commitments to environmental stewardship and sustainability, while meeting customer expectations for clean energy that is reliable and affordable.

Vectren's preferred resource plan reduces risk through diversification, reduces the cost to serve load over the next 20 years and provides the flexibility to continue to evaluate and respond to future needs through subsequent IRPs. The preferred portfolio has several advantages: including: 1) Energy supplied by this portfolio is generated primarily through a significant amount of near-term renewable solar and wind projects that take advantage of the Investment Tax Credit and the Production Tax Credit. This lowers portfolio costs and takes advantage of current tax-advantaged assets. 2) Two new, low-cost gas combustion turbines, continued use of Vectren's most efficient coal unit (Culley 3) and new battery storage resources, provide resilient, dispatchable power to Vectren's system that is complementary to significant investment in new intermittent renewable resources. This is very important, as coal plants, which have provided these attributes in the past, continue to retire in MISO Zone 6. 3) The portfolio provides flexibility to adapt to and perform well under a wide range of potential future legislative, regulatory, and market conditions. The preferred portfolio performed well under CO_2, methane constraints, and other related regulations such as a fracking ban. The cost position of this portfolio that is backed up by the two combustion turbine capacity resources does not change because the gas turbines predominantly run during peak load conditions. This provides a financial hedge against periodic instances of high market energy and capacity prices, 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 against purchases to remain poised to adapt to market shifts. 5) It includes new solar capacity when it is most economic to the portfolio. 6) Finally, it is timely. New combustion turbines can come online quickly to replace coal generation that retires by the end of 2023, minimizing in-service lag and reducing exposure to the market.

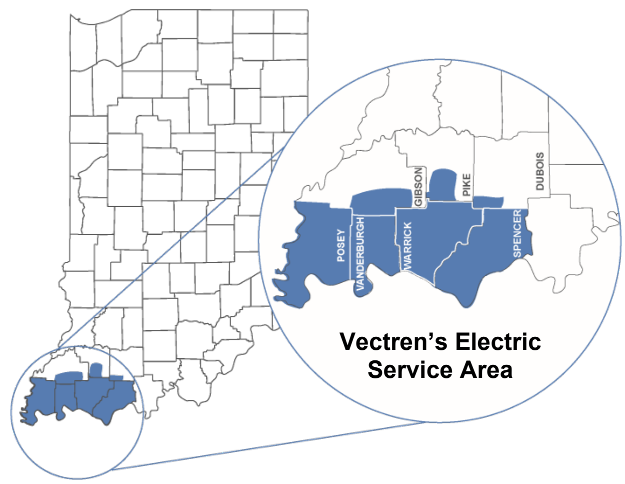
The resource options selected in this plan provide a bridge to the future. For example, CT's allow time for battery storage technology to continue to become more competitive in price and further develop longer duration storage capabilities. Further, should there be a need for new baseload generation in the future to accommodate a large load addition or to replace Warrick 4 and Culley 3, one or both CT's could be converted to a CCGT, a highly efficient gas energy resource. Even with the large commitment in the near term to renewable resources, additional renewable resources can be added over time.

The preferred portfolio also provides several off-ramps (future transitional inflection points) should they be needed. 1) Vectren continues to speak with Alcoa about a possible extension of Warrick 4 (W4) joint operations through 2026. This option could provide additional time and shield Vectren customers from capacity purchases at a time where the market is expected to be tight, causing much higher projected prices than today. Additionally, time may be needed to allow Vectren to secure the level of renewable resources identified in the preferred portfolio and to allow for contingency for permitting and construction of new combustion turbines. 2) While Culley 3 is not scheduled to be retired within the timeframe of this analysis, including thermal dispatchable generation in this portfolio will allow Vectren flexibility to evaluate this option in future IRPs. 3) Vectren will work to secure attractive renewables projects from the recent All-Source RFP but will likely require a second RFP to fully secure 700-1,000 MWs of solar on multiple sites and 300 MWs of wind constructed over a span of several years. Issuing a second RFP provides two main benefits. It allows more local renewable options to select from, as some offered proposals are no longer available. Second, it provides additional time to better understand how MISO intends to move forward with market adjustments, such as capacity accreditation and energy price formation. MISO's wholesale market is adapting to fleet transition that is moving toward intermittent renewable resources.

What follows is a summary of Vectren's process to identify this portfolio, focusing on Vectren's operations, an explanation of the planning process and a summary of the preferred portfolio.

II. Vectren Overview

Vectren provides energy delivery services to more than 146,000 electric customers located near Evansville in Southwestern Indiana. In 2018, approximately 44% of electric sales were made to large (primarily industrial) customers, 30% were made to residential customers and 26% were made to small commercial customers.



The table below shows Vectren generating units. Since the last IRP, Vectren has formally retired four, older small natural gas units[1] rather than investing significant capital dollars to ensure safety and reliability. Note that Vectren also offers customers energy efficiency programs to help lower customer energy usage and bills.

Unit	Installed Capacity ICAP (MW)	Primary Fuel	Year in Service	Unit Age	Coal Unit Environmental Controls[2]
A.B. Brown 1	245	Coal	1979	41	Yes
A.B. Brown 2	245	Coal	1986	34	Yes
F.B. Culley 2	90	Coal	1966	54	Yes
F.B. Culley 3	270	Coal	1973	47	Yes

[1] In 2018, Vectren retired BAGS 1 (50 MW). In 2019, Vectren retired Northeast 1&2 (20 MW) and BAGS2 (65 MW)

[2] 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 (H2S04) except F.B. Culley 2.

Unit	Installed Capacity ICAP (MW)	Primary Fuel	Year in Service	Unit Age	Coal Unit Environmental Controls[2]
Warrick 4	150	Coal	1970	50	Yes
A.B. Brown 3	80	Gas	1991	29	
A.B. Brown 4	80	Gas	2002	18	
Blackfoot[3]	3	Landfill Gas	2009	11	
Fowler Ridge	50	Wind PPA	2010	10	
Benton County	30	Wind PPA	2007	13	
Oak Hill[4]	2	Solar	2018	<2	
Volkman Rd[5]	2	Solar	2018	<2	
Troy	50	Solar	2021		

III. Integrated Resource Plan

Every three years Vectren 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, low cost, 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.

Vectren utilized direct feedback on analysis methodology, analysis inputs, and evaluation criteria from stakeholders, including but not limited to Vectren residential, commercial and industrial customers, regulators, elected officials, customer advocacy groups and environmental advocacy groups. Vectren continues to place an emphasis on reliability, customer cost, risk, resource diversity, and sustainability. The IRP process has become increasingly complex in nature as renewable resources have become more cost competitive, battery energy storage has become more viable, and existing coal resources are dispatched less and less.

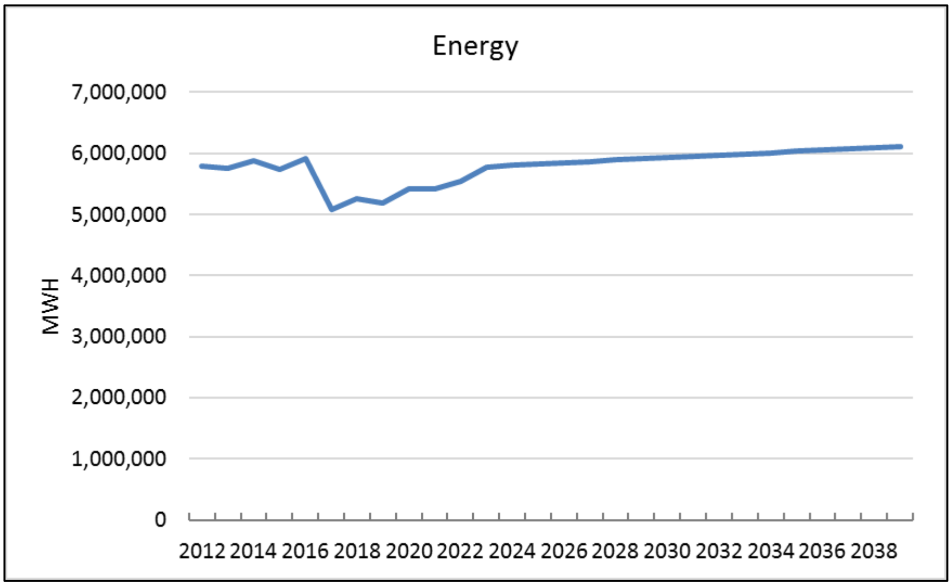
[3] The Blackfoot landfill gas generators are connected at the distribution level.
[4] Oak Hill Solar is connected at the distribution level.
[5] Volkman Rd. Solar is connected at the distribution level.

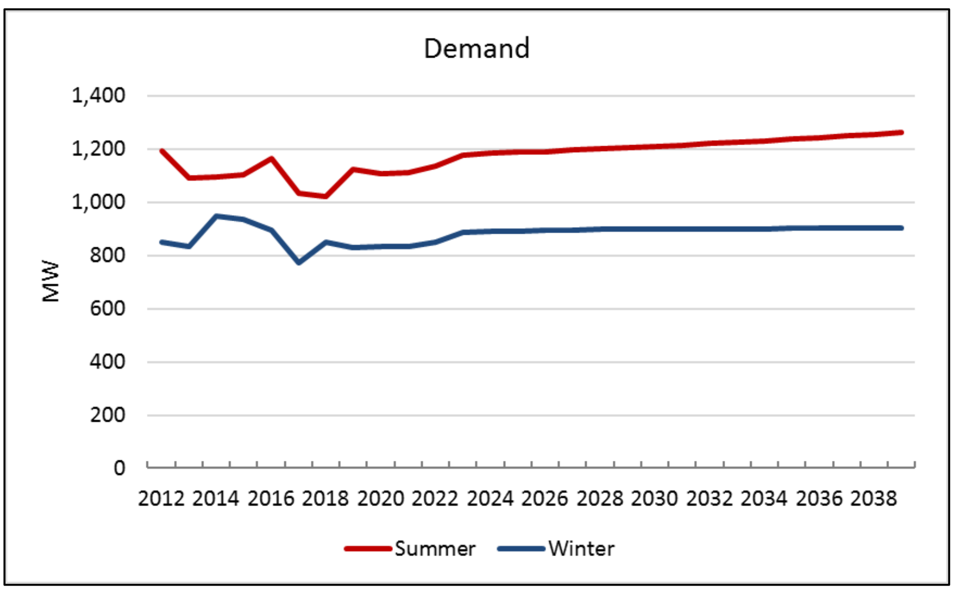
A. Customer Energy Needs

The IRP begins by evaluating customers' need for electricity over the 20-year planning horizon. Vectren 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 Vectren purchases some power from the market, Vectren is required to have enough generation and energy efficiency resources available to meet expected customers' annual 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 (Midcontinent Independent System Operator) member, Vectren must comply with MISO's evolving rules to maintain reliability.

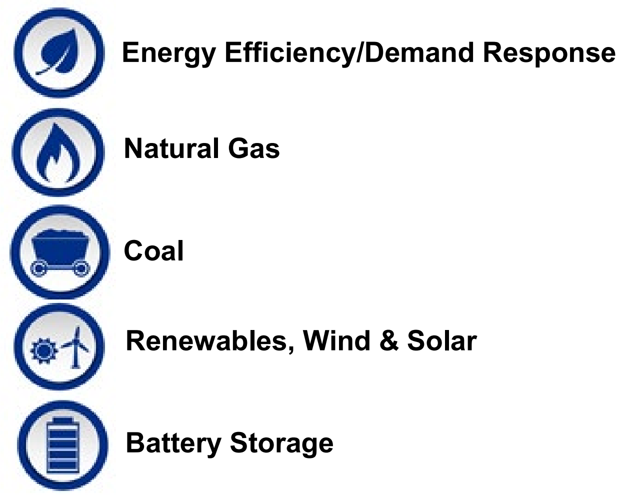
Historically, IRPs have focused on meeting customer demand in the summer, which is typically when reserve margins are at a minimum. As the regional resource mix changes towards intermittent (variable) renewable generation, it is important to ensure that resources are available to meet this demand in 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, Vectren ensured that its preferred portfolio would have adequate reserve margins for meeting both the winter and summer peak demand. Later in this document it is further explained how MISO is evaluating measures to help ensure year-round reliability.

Vectren 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 demand are expected to grow by 0.6% per year. Winter 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. Vectren considered both new and existing resource options. Burns and McDonnell, a well-respected engineering firm, conducted an All-Source RFP which generated 110 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 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, Vectren utilized other information sources for long term costs and operating characteristics for these resources and others over the entire 20-year period. Other options include continuation of existing coal units, conversion of coal units to natural gas, various natural gas resources, hydro, landfill gas, and long-duration batteries, as well as partnering with other load-serving entities. 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: projected low stable gas prices, low cost and projected high penetration of intermittent renewable resources, future of coal resources, new technology and projected changes in the MISO market to adapt and help ensure reliability.

i. Industry Transition

The cost of fuel used by generation facilities to produce electricity is also accounted for in evaluating the cost of various electric supply alternatives. Gas prices are near record low levels and are projected to remain stable over the long term. Shale gas has revolutionized the industry, driving these low gas prices and has fueled a surge in low-cost gas generation around the country. Vectren's IRP reflects the benefit low gas prices provide to the market, as gas units are on the margin and typically set market prices for energy.

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 26% of total generation in 2018[6]. Meanwhile, the cost of renewable energy has declined dramatically over this time period due to improvements in technology and helped by government incentives in the forms of the Production Tax Credit for wind and the Investment Tax Credit (ITC) for solar, both of which are set to expire or ratchet down significantly over the next few years.

MISO Energy Mix Transition (GWH) from 2005 to 2018 to 2030
(Based on Utility Announcements and State Integrated Resource Plans)*

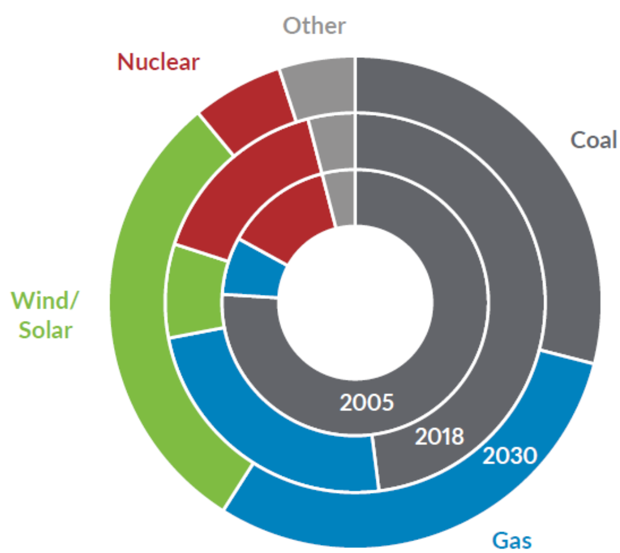


*Chart reflects ratios of generation.

The move toward low cost 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 compete on price with low cost 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

[6] MISO Forward Report, March 2019, page 10. https://cdn.misoenergy.org/MISO%20FORWARD324749.pdf

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. 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, MISO expects the generation mix in 2030 to be much more balanced than in the past with roughly one third renewables, one third gas and one third coal. Some large nuclear plants remain but have also found it challenging to compete on cost.

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, 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 is in the process of studying 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.

To deal with these challenges, MISO has been working through a series of studies and has put forth guidance for how they intend to evaluate resources moving forward. One significant development is the recognition that all hours matter. In the past, MISO resource adequacy requirements focused on only the peak hour each year. Recent MISO emergencies in all seasons have demonstrated that the system can experience potential energy shortfalls in any hour due to changing resource conditions. As such, MISO is planning for new requirements to ensure resources are available for reliability in each of the 8,760 hours of the year. Each resource has different operating characteristics and different output levels, depending on the season. Vectren has accounted for these changes by validating that portfolios in this analysis provide sufficient resources to meets its MISO obligations[7] in the two heaviest demand periods (summer/winter). MISO has initiatives underway that include new testing requirements to ensure that Demand Response (DR) resources are available when needed. MISO's annual Market Road Map process has prioritized the development of mechanisms to more accurately account for resource availability. This includes an evaluation of how to best incent resources with the right kinds of critical attributes needed to keep the system operating reliably. Incentives are contemplated for resources that are available (dispatchable), flexible (ability to start quickly and meet changing load conditions when needed) and visible (have a better understanding of customer owned generation in addition to larger utility assets). MISO expects that traditional dispatchable coal and gas resources will continue to provide resilience to the grid.

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 needed to move to more reliance on intermittent renewable resources. Lithium-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. Large scale batteries for utility applications have begun to emerge around the country, particularly where incentives

[7] Some portfolios have a heavy reliance on the market for both energy and capacity.

are available to lower the cost of this emerging technology or for special applications that improve the economics.

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 the reliability of the transmission system. Vectren has installed a 1 MW battery designed to capture energy from an adjacent solar project. This test project is providing 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. Currently, commercially feasible batteries are short duration, typically four hours. There are some commercially available longer-duration batteries that show promise, but these are still very expensive. 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. They can produce about 90-95 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 energy infrastructure, but they do not yet replace the need for other forms of dispatchable generation during extended periods without sun and wind. Vectren's All-Source RFP included bids for stand-alone batteries and batteries connected to solar resources.

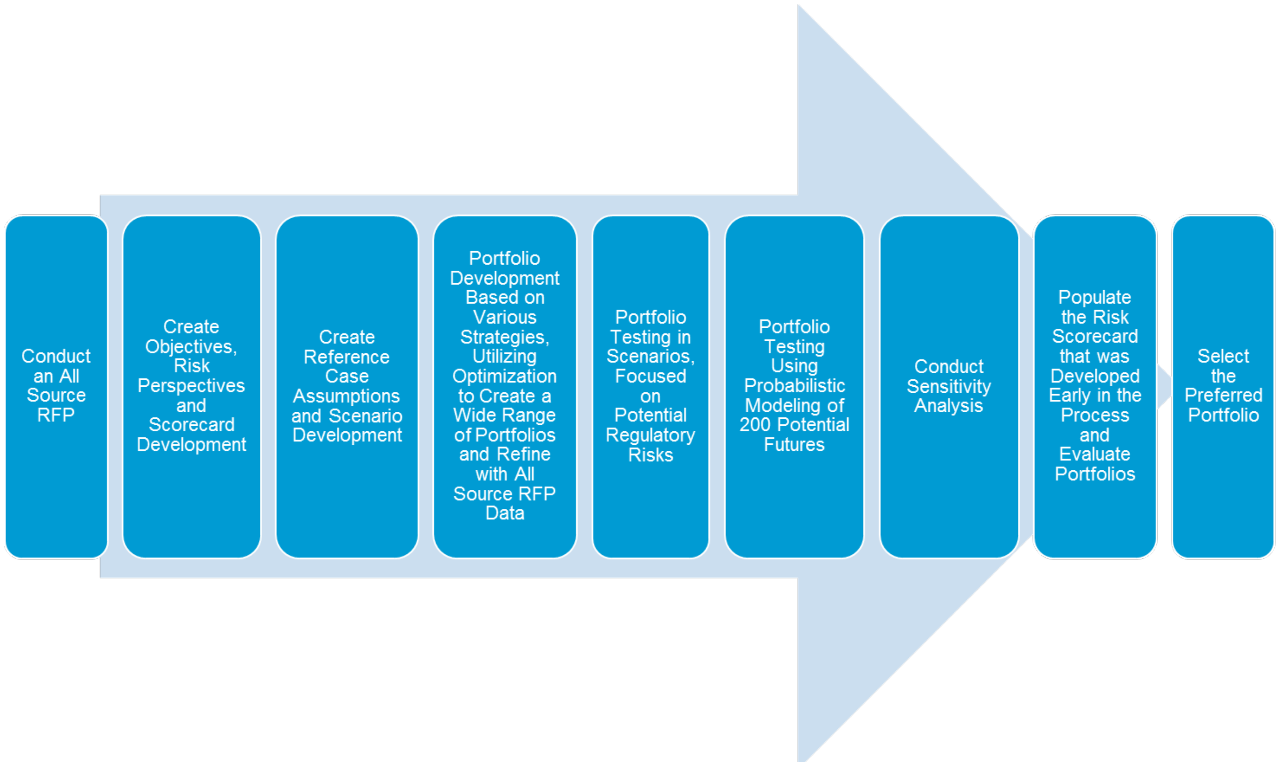
C. Uncertainty/Risk

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. Vectren'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. Vectren performed two sets of 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.

IV. Analysis

Vectren’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. Utilize the quantitative scorecard measures and judgement 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

Vectren reevaluated how to conduct the stakeholder process based on comments in the Director's report, stakeholder feedback and the Commission order in Cause number 45052. Careful consideration was taken to ensure that the time spent was mutually beneficial.

Each of the first three stakeholder meetings began with stakeholder feedback. Vectren would review requests since the last stakeholder meeting and provide feedback. Suggestions were taken and in instances where suggestions were not acted upon, Vectren made a point to further discuss and explain why not. Per stakeholder feedback, 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 phone calls/meetings in between each session per request.

Three of four public stakeholder meetings were held at Vectren in Evansville, IN. The final stakeholder meeting on June 15, 2020 was held via webinar due to the COVID-19 situation. Dates and topics covered are listed below:

August 15, 2019	October 10, 2019	December 13, 2019	June 15, 2020*
• 2019/2020 IRP Process • Objectives and Measures • All-Source RFP • Environmental Update • Draft Reference Case Market Inputs & Scenarios	• RFP Update • Draft Resource Costs • Sales and Demand Forecast • DSM MPS/ Modeling Inputs • Scenario Modeling Inputs • Portfolio Development	• Draft Portfolios • Draft Reference Case Modeling Results • All-Source RFP Results and Final Modeling Inputs • Scenario Testing and Probabilistic Modeling Approach and Assumptions	• Final Reference Case and Scenario Modeling Results • Probabilistic Modeling Results • Risk Analysis Results • Preview the Preferred Portfolio

- Moved final stakeholder meeting date per stakeholder request and the COVID-19 situation

Based on this stakeholder engagement, Vectren 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. Vectren utilized stakeholder information to create boundary conditions that were wide enough to produce plausible future conditions that would favor opposing resource portfolios (i.e. Indiana Coal Council (ICC) request to continue coal through 2029 or 2039 and environmental stakeholders' request to utilize all renewable resources by 2030). For example, the low regulatory future includes declining coal prices and higher gas prices, which was a request from the ICC. The High Regulatory scenario, which was heavily influenced by environmental stakeholders, is the other plausible future bookend with a natural gas fracking ban (sustained high price), a social cost of carbon fee starting at $50 per ton in 2022 and lower renewables cost trajectory than what is expected. Additionally, an evaluation measure was adjusted based on direct stakeholder input. Vectren included the life cycle of carbon emissions for all resources in response to the ICC and environmental stakeholders. The table below shows key stakeholder requests made during the process and Vectren's response.

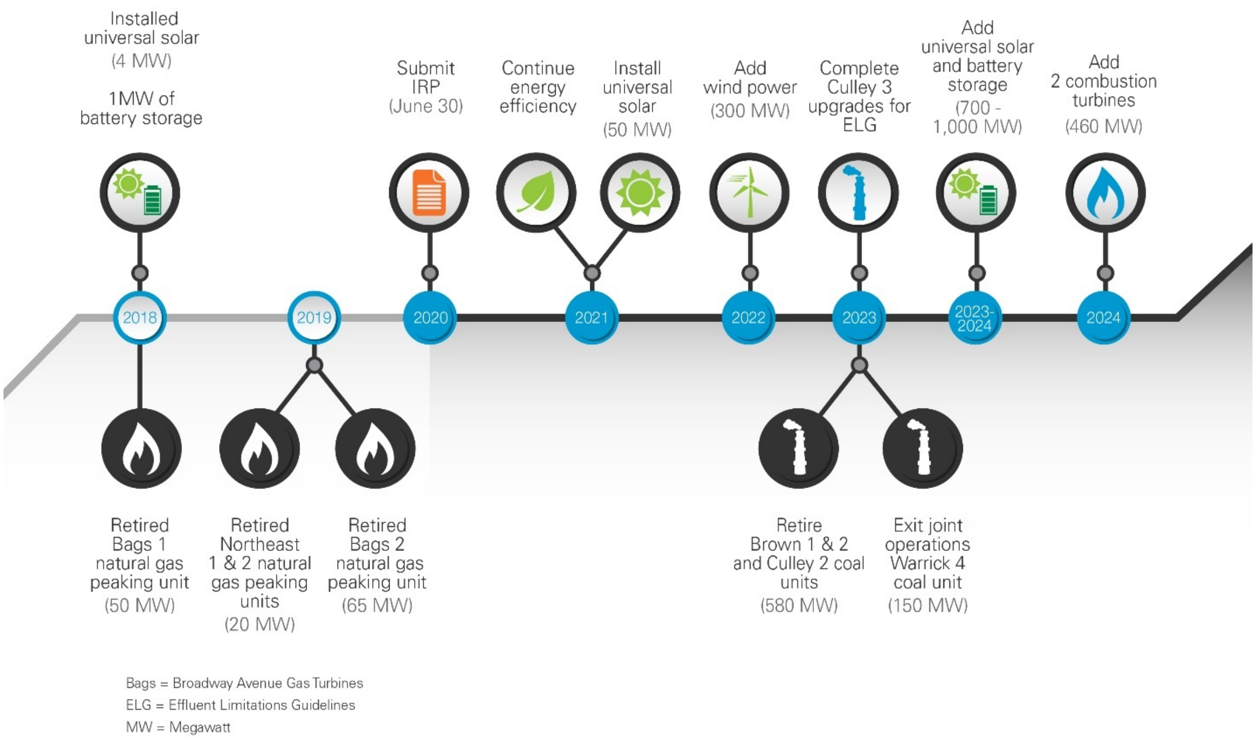
Request	Response
Update the High Regulatory scenario to include a carbon fee and dividend	Included a fee and dividend construct which assumed a balanced impact on the load (the economic drag from a carbon fee is neutralized by the economic stimulus of a dividend)
Lower renewables costs in the High Regulatory and 80% CO_2 Reduction scenarios	Updated scenario to include lower costs for renewables and storage than the Reference scenario
Consider life cycle emissions using CO_2 equivalent	Included a quantitative measure on the risk scorecard based on National Renewable Energy Lab (NREL) Life Cycle Greenhouse Gas Emissions (CO_2e) from Electricity Generation by Resource
Include a measure within the risk score card that considers the risk that assets become uneconomic	Included an uneconomic asset risk as a consideration in the overall evaluation. Not included in the scorecard.
Include a scenario with a carbon dividend modeled after HB 763 with a CO_2 price that was approximately $200 by the end of the forecast	Utilized a scenario with these prices to create an additional portfolio. Ultimately, this portfolio was not selected for the risk analysis, as the amount of generation built

Request	Response
	within modeling vastly exceeded Vectren's need and resulted in large energy sales
Reconsider the use of a seasonal construct for MISO resource accreditation	Reviewed calculation for solar accreditation in winter and utilized an alternate methodology, increasing accreditation in the winter
Include a CO_2 price in the reference case	Included mid-range CO_2 prices 8 years into the forecast. The Low Regulatory scenario did not include a CO_2 price, thus becoming a boundary condition

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

VI. The Preferred Portfolio

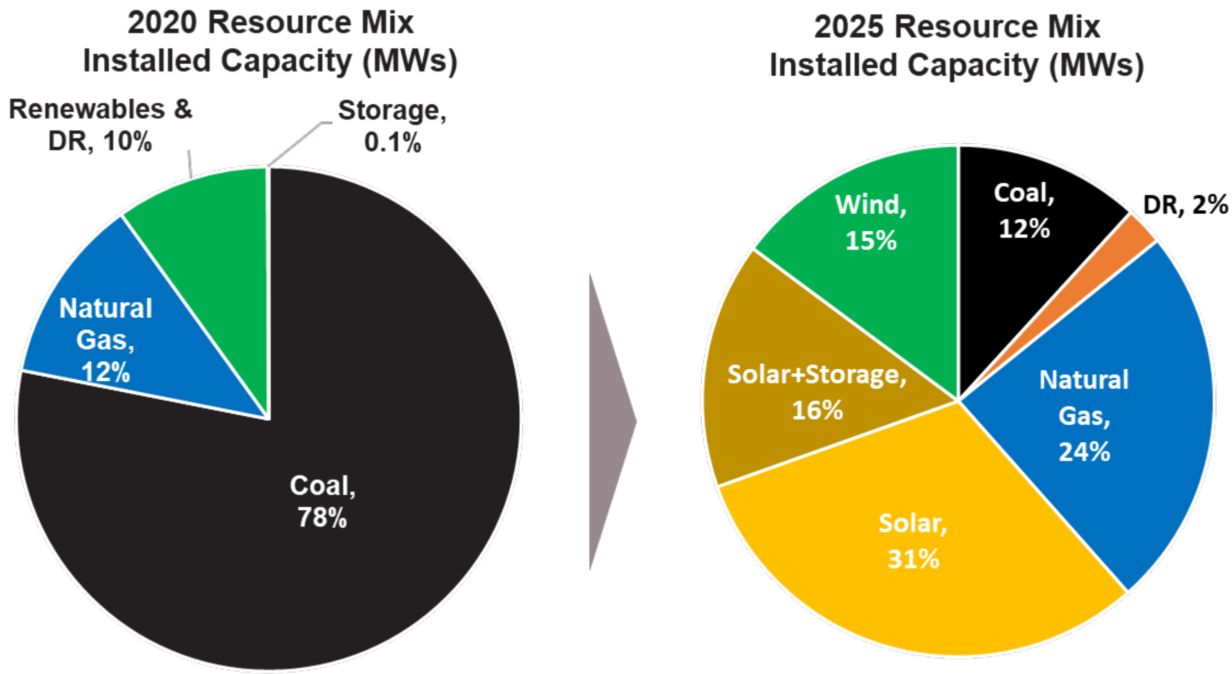
The Preferred Portfolio recommendation is to retire or exit 730 MWs of coal generation and replace with 700-1,000 MWs of solar generation (some connected to battery storage), add 300 MWs of wind backed by dispatchable generation that consists of 2 new Combustion Turbine (CT) gas units and maintaining Culley 3 (coal unit).



This preferred portfolio:

- Allows customers to enjoy the benefits of low-cost renewable energy, while ensuring continued reliable service as Vectren moves toward higher levels of intermittent renewable energy in the future.
- Saves customers over $320 million over the next 20 years when compared to continued operation of Vectren's coal fleet. The preferred portfolio is a low-cost portfolio in the near, mid and long term.
- Reduces lifecycle greenhouse gas emissions, which includes methane, by nearly 60% over the next 20 years. Direct carbon emissions are reduced 75% from 2005 levels by 2035.

- Includes a diverse mix of resources (renewables, gas and coal), 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 extend the contract with Alcoa for Warrick 4 for a few years and maintains the option to consider the replacement of Culley 3 in the future when appropriate based on continual evaluation of changing conditions. These options will be revaluated in future IRPs.
- 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.
- Adds some battery energy storage in the near term, paired with solar resources to provide clean renewable energy when solar is not available. Provides time for technological advances that will allow for high penetration of renewables across the system, further cost declines and further Vectren operational experience to meet Vectren's customers' energy needs.
- Continues Vectren's energy efficiency programs with near term energy savings of 1.25% of eligible sales and further long-term energy savings opportunities identified over the next 20 years. Vectren is committed to Energy Efficiency to help customers save money on their energy bills and will continue to evaluate this option in future IRPs.



VII. Next Steps

The preferred portfolio calls for Vectren to make changes to its generation fleet. Some of these changes require action in the near term. First, Vectren will finalize the selection process to secure renewable projects from the All-Source RFP and seek approval from the IURC for attractive projects. Second, the IRP calls for continuation of energy efficiency. Vectren filed a 2021-2023 plan with the IURC in June of 2020, consistent with the IRP. Third, Vectren intends to pursue two natural gas combustion turbines to provide dispatchable support to the large renewables based preferred portfolio. 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.

Vectren'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. Without incremental investment, the plant does not comply with the ELG and other water discharge control requirements. Vectren therefore continues to talk to Alcoa about its plans.

- The availability of attractive renewable projects is currently being evaluated. Negotiations for resources must take place to finalize availability and cost of projects. The Coronavirus has put pressure on supply chains and put in jeopardy the ability of full utilization of the Production Tax Credit and Investment Tax Credit for some projects. Competition for these projects is steep, with multiple, on-going RFP processes in the state of Indiana.
- Finally, MISO continues to evaluate the accreditation of resources. Vectren will continue to follow developments to determine the right amount of renewable resources to pursue in the near term.

SECTION 1
OVERVIEW

1.1 COMPANY BACKGROUND

Vectren is a wholly owned subsidiary of CenterPoint Energy, Inc. On February 1, 2019, CenterPoint Energy, Inc. (NYSE: CNP) and Vectren Corporation (NYSE: VVC) completed a merger. The combined company, which is named CenterPoint Energy and headquartered in Houston, has regulated electric and natural gas utility businesses in eight states that serve more than 7 million metered customers.

Operation of Vectren's electric transmission and distribution services, including its power generation and wholesale power operations now fall into CenterPoint's Indiana Electric business. Vectren serves approximately 146,000 customers in Southern Indiana.

1.2 INTEGRATED RESOURCE PLANNING

Vectren takes integrated resource planning very seriously. The IRP is used as a guide for how Vectren will serve existing and future customers over the next 20 years in a reliable and economic manner. The integrated resource plan can be thought of as a compass setting the direction for future generation and Demand Side Management (DSM) options. It is not a turn-by-turn GPS. Future analyses of changing conditions, filings and subsequent approvals from the IURC are needed to chart the specific course.

Vectren is required to submit its Integrated Resource Plan (IRP) to the Indiana Utility Regulatory Commission (IURC) every three years and last submitted it in 2016 with a plan to transition its generation fleet away from a majority reliance on coal. Vectren began this IRP process by gathering feedback from stakeholders on the last IRP, the Final Director's Report for 2016 Integrated Resource Plans and the Indiana Utility Regulatory Commission's Order in 45052 (Vectren's 2018 generation transition filing). Additionally, Vectren worked more closely with IRP stakeholders than ever before to listen, inform and consider updates to the process, as discussed in Chapter 3 Public Participation Process.

The future is uncertain; several factors have helped to set the stage for this analysis. Gas prices remain historically low and are projected to be stable over the long term. Shale gas has revolutionized the industry, driving these low gas prices. This has fueled a surge in gas generation investment, due to its low-cost energy and capacity value that it brings to the grid.

Renewable costs continue to decline and are producing competitively priced energy in the Midwest region, but still require backup for times when the wind is not blowing and the sun is not shining (on a daily and seasonal basis). Based on expectations of increasing penetration of renewables, particularly solar, MISO (Midcontinent Independent System Operator), Vectren's regional transmission operator, continues to evaluate rules and mechanisms that are needed now and in the future to maintain reliability. Vectren continues to monitor developments within MISO; the outcomes of two major studies are important for resource planning. 1) MISO is conducting a Renewable Integration Impact Assessment (RIIA) related to impacts of renewable energy growth in MISO over the long term. This study will assess implications to MISO's transmission needs and ability to effectively dispatch its members' generation fleet. 2) MISO is simultaneously conducting the Resource Availability and Need (RAN) initiative, which looks at more granular planning and accreditation of generation resources to account for a changing generation mix and resulting attributes, both of which are discussed in detail below.

In order to better evaluate renewable, energy storage and energy efficiency resources within the IRP analysis, Vectren chose to move to a more sophisticated IRP modeling tool than was used in the 2016 IRP, the Aurora modeling platform. It provided several benefits: 1) simultaneous evaluation of many resources, 2) evaluation of portfolios on an hourly basis and 3) consistency in modeling, including optimization, simulated dispatch of resources and probabilistic modeling. The output from this model provides quantitative data to help evaluate portfolios within a robust risk analysis, designed to understand performance over a wide range of futures.

1.2.1 IRP Objectives

Vectren's IRP strategy is designed to accommodate the ongoing changes and uncertainties in the competitive and regulated markets. The main objective is to select a preferred portfolio[8] of supply and demand resources to best meet customers' needs for reliable, reasonably priced, environmentally acceptable power over a wide range of future market and regulatory conditions, taking into account risk and uncertainty. Specifically, Vectren's objectives are as follows:

- Safe Reliable Service (a requirement for all portfolios)
- Affordability (reflected in the balanced scorecard)
- Environmental Risk Minimization (reflected in the balanced scorecard)
- Cost Uncertainty Risk Minimization (reflected in the balanced scorecard)
- Avoiding Overreliance on Market Risk for capacity and energy (reflected in the balanced scorecard)
- Future Flexibility (reflected in both offramps and "other considerations")
- Resource Diversity (reflected in "other considerations")
- System Flexibility (operational flexibility to back up renewable resources)

1.2.2 IRP Development

As mentioned above, Vectren incorporated feedback from IRP stakeholders, IURC staff and the Commission in developing the 2019/2020 IRP. Detailed feedback was provided to IRP stakeholders on August 15, 2019, in Vectren's first of four public stakeholder meetings in a presentation titled "2019/2020 IRP Process." This presentation provided the backdrop for several Vectren commitments to improve and strengthen the analysis, most notably with the addition of an All-Source RFP, but also other improvements, including but not limited to the following:

- Additional stakeholder input,
- More consistency in modeling,
- More comprehensive analysis and

[8] A portfolio is a mix of future supply and demand side resources to meet expected future demand for electricity.

- The evaluation of a wider mix of resources, including an exhaustive evaluation of existing resources.

Vectren worked closely with industry experts to develop a comprehensive analysis. Burns and McDonnell, now known as 1828 and Company, managed all aspects of the All-Source RFP. This analysis was utilized to provide current market pricing for resources and an opportunity for Vectren to pursue individual projects to help serve Vectren customers following the conclusion of the IRP. Pace Global, now known as Siemens Energy Business Advisory, worked with Vectren to conduct scenario development, modeling and a comprehensive risk analysis, which included both scenario based and probabilistic modeling.

1.3 CHANGES SINCE THE 2016 IRP

Several developments have occurred since the last IRP was submitted in 2016, which helps to illustrate the dynamic nature of integrated resource planning. The IRP analysis and subsequent write up represent the best available information at a point in time. The following sections discuss some of the major changes that have occurred over the last three years. Vectren realizes that conditions will change, and tis analysis was designed to test portfolios under a wide range of plausible futures.

1.3.1 Generation and Storage Filings

1.3.1.1 Generation Transition Plan

Following the conclusion of the 2016 IRP, Vectren began a generation transition plan to replace the majority of its coal fleet with a highly efficient, large, natural gas plant and a 50 MW universal solar plant. Vectren also proposed to continue operation of its most efficient coal unit by installing certain environmental compliance equipment. This was done through two separate filings in Cause numbers 45052 and 45086.

In April 2019, the IURC granted partial approval of Vectren's Smart Energy Future electric generation transition plan which included approval to retrofit F.B. Culley 3, Vectren's largest, most-efficient 270 MW coal-fired unit and to proceed with construction of a 50 MW universal solar array. The request to construct a 700-850 MW combined cycle natural gas power plant was not approved. The following concerns were raised in opposition to the proposal:

- Vectren selected a Combined Cycle Gas Turbine (CCGT) that was too large for a small utility
    - Did not adequately consider flexibility to change paths, adding stranded asset risks
    - Did not consider fuel or geographic diversity
- Risk analysis did not consider the full range of portfolios
    - Did not fully explore options at the Brown plant (conversion or scrubber alternatives)
    - Need to more fully consider customer-generator opportunities
    - Did not fully consider energy and capacity purchases
    - Did not consider smaller gas plant options in the risk analysis
- Vectren's analysis disadvantaged renewable resources
    - Vectren did not make a serious effort to determine the price and availability of renewables
    - The RFP was too restrictive
- Vectren did not fully respond to the Director's report critiques in updated CPCN analysis
    - Did not update the risk modeling
    - Did not consider the full range of gas prices (including methane regulation)

Each of these concerns is addressed in detail within this IRP analysis and selection of the preferred portfolio. All will be addressed in detail within this report.

1.3.1.2 Urban Living Research Center (ULRC)

Vectren has partnered with Scannell to develop the Urban Living Research Center (ULRC), a living laboratory facility which will serve as a leading-edge research vehicle for Vectren to better understand and partner with customers. The ULRC is part of a larger, mixed-use, multifamily development called the "Post House" which opened on June 1, 2020. The Post House/ ULRC originated as a partnership in response to the Regional Cities Initiative, which aims to retain and attract talent by enhancing the quality of Indiana communities. The ULRC will include a mix of natural gas and electric, efficient and smart energy-using devices, such as lighting, HVAC, water heating and instrumentation, that will help the Company research new products and services to help customers manage their energy use. The Company was awarded funding from the Department of Energy's Building Technologies Office to utilize toward the ULRC to advance research in grid-interactive buildings in partnership with Oak Ridge National Laboratory. Based on actual construction of the facility and the available rooftop space, Vectren plans to install rooftop solar. Lithium-ion battery storage in both front- and behind-the-meter configurations was also planned for the facility but was removed from the project due to concerns related to the placement of Lithium-ion batteries indoors in light of evolving safety standards and best practices. Lessons learned and data from this project could help future integrated resource planning efforts.

1.3.1.3 Volkman and Oak Hill Universal Solar and Battery Projects

In 2017, Vectren filed for and received approval to construct two 2-MW universal solar projects that are currently in operation; one near North High School in northern Vanderburgh County and the second near Oak Hill Cemetery near Morgan Ave., which is through a partnership with the City of Evansville. Both sites have been constructed and have been generating power since December 2018. The Volkman Road project also includes battery storage with the ability to discharge one megawatt of power per hour over a four-hour period.

1.3.2 Environmental Rules

1.3.2.1 Rules Update

1.3.2.1.1 Air

In March 2015, USEPA entered into a consent decree to resolve litigation concerning deadlines for completing 1-hour sulfur dioxide (SO2) National Ambient Air Quality Standard (NAAQS) designations. The agreement required USEPA to designate as nonattainment, attainment or unclassifiable, certain areas that included sources that emitted more than 16,000 tons of SO2 in 2012 or emitted more than 2,600 tons of SO2 with an average emission rate greater than 0.45 lbs./MMBtu. USEPA identified five sources in Indiana that exceeded this threshold, including the A. B. Brown plant. In order for Posey County to meet the attainment designation, Vectren had to agree to a lower SO2 emission rate for the A.B. Brown plant. Vectren worked with IDEM and accepted a Commissioner's Order to voluntarily lower the plant's SO2 emission limit, which went into effect April 19, 2016.

EPA finalized the Affordable Clean Energy rule (ACE) repealing and replacing the Clean Power Plan in June 2019. The ACE rule established carbon dioxide (CO_2) emission guidelines for states to use when developing plans to limit CO_2 at coal-fired electric generating units (EGUs) within the state. ACE established heat rate improvement, or efficiency improvement, as the Best System of Emissions Reductions (BSER) for CO_2 from coal-fired Electric Generating Units (EGUs). States were given six candidate technologies to be considered as BSER along with their calculated efficiency improvements and costs to implement and operate. States are to establish unit-specific standards of performance that reflect the emission limitation achievable through application of the BSER technologies with consideration of "the remaining useful life of the source" and other source-specific factors. State Implementation Plans are due July 2022 with compliance planned to begin within 24 months of submission.

In December 2015, Vectren agreed to a modified Consent Decree to resolve alleged air violations at the F. B. Culley and A. B. Brown plants. The negotiated settlement required Vectren to eliminate the scrubber bypass stack for F. B. Culley Unit 2 and install equipment to mitigate SO3 emissions from A. B. Brown Units 1 and 2 and F. B Culley Unit 3. Each unit is required to maintain a H2SO4 emission limit to demonstrate compliance.

The state of Indiana has developed a state implementation plan (SIP) to administer the three trading programs under the Cross-State Air Pollution Rule (CSAPR) and allocate allowances for affected electric generating unit starting in 2021. The SIP was published in the Federal Register on December 17, 2018. The intent of CSAPR is to address power plant emissions that cross state lines and contribute to ozone and fine particle pollution in other states.

1.3.2.1.2 Water

On September 30, 2015, EPA published the final Effluent Limitations Guidelines rule (ELG). The rule sets strict technology-based limits for waste waters generated from fossil fuel fired generating facilities and, will force significant operational and technological changes at coal fired power plants. EPA finalized the rule with a hybrid of the most stringent of the proposed options for fly ash transport water, bottom ash transport waters and FGD waste waters.

While the 2015 final rule includes reference to multiple waste waters, the key elements applicable to Vectren are FGD waste waters and ash transport waters. Specifically, FGD waste waters must meet new limits for arsenic, mercury, selenium and nitrate / nitrite at the end of the wastewater treatment system and prior to mixing with any other process waters. Water used to transport bottom ash or fly ash is prohibited from discharge in any quantity, which effectively forces the installation of dry or closed loop ash handling systems. In September 2017, the ELG Postponement Rule was published. The

Postponement Rule delayed the applicability date for the Bottom Ash Transport Waters from November 1, 2018 to November 1, 2020, but the no later than December 31, 2023 date for completion remained in place.

The A.B. Brown and F.B. Culley NPDES permits were renewed in 2017 and have since been modified as appropriate to allow for the BATW date extension allowed by the ELG Postponement Rule. As required by the ELG Rule and consequently the NPDES permits, FBC has ceased the discharge of FATW and will complete the conversion of bottom ash to a dry system in fall 2020. For FGD waste waters at F.B. Culley, alternate, but more restrictive limits can be voluntarily agreed to which would automatically extend the applicability date to December 31, 2023. Technology to meet the more restrictive limits could include the installation of zero liquid discharge equipment that would eliminate all discharge of FGD wastewater. The A.B. Brown permit was modified following publication of the ELG Postponement Rule. Currently, A.B. Brown is required to stop discharging both Fly Ash Transport Water and Bottom Ash Transport Water by November 2021. An additional ELG reconsideration rule, proposed in 2019, maintained the prohibition on the discharge of fly ash transport water and prohibits the discharge of bottom ash transport water, except in limited, specific circumstances, such as significant storm events.

1.3.2.1.3 Waste

The Coal Combustion Residuals Rule (CCR) was finalized on April 17, 2015. The rule regulates the final disposal of CCRs which include fly ash, bottom ash, boiler slag and flue gas desulfurization solids. The rule is applicable to all new and existing landfills and surface impoundments used to store or dispose of CCRs at a power plant that was generating electricity on the effective date of the rule (October 2015). The rule establishes operating criteria and assessments as well as closure and post closure care standards. The “Phase 1, Part 1” rule was published on July 30, 2018 and became effective on August 28, 2018. This rule delayed the deadline by which facilities must cease the placement of waste in a CCR surface impoundment in cases where the CCR unit fails to meet the aquifer location restriction and in cases where a CCR unit demonstrates an exceedance of a groundwater protection standard. The regulatory deadlines that currently present a scenario that could trigger the closure of Vectren surface impoundments include exceedance of ground water protection standards (triggering closure in October 2020), or failure to demonstrate compliance with location restrictions (triggering closure in October 2020). Environmental groups challenged the final "Phase 1, Part 1" rule in the D.C. Circuit Court. Additionally, in August 2018, the D. C. Circuit Court issued a decision in USWAG v. EPA, finding that the administrative record showed that all unlined impoundments pose a reasonable probability of adverse effects to human health and the environment and must be required to close. EPA filed a motion to remand the Phase 1, Part 1 rule and is currently working on rulemakings to implement the D.C. Circuit's decision. The "Disposal of Coal Combustion Residuals from Electric Utilities; A Holistic Approach to Closure Part A: Deadline to Initiate Closure" proposed rule provides an option for utilities to submit a demonstration (application) for surface impoundments to remain active beyond the current rule closure dates, however no longer than October 15, 2023.

1.3.2.2 Retrofitting Culley 3 to Comply with ELG

In accordance with the order of the IURC in Cause No. 45052 approving the planned activities necessary to continue to operate Culley 3 in compliance with the ELG and CCR rules, the bottom ash system at F.B. Culley Unit 3 is scheduled to be converted to a dry system in the Fall of 2020. Work is also taking place to convert the FGD system to zero liquid discharge technology. These two technologies will make Culley Unit 3 fully compliant with the Effluent Limitation Guidelines (ELG) rule and the NPDES permit requirements for Culley 3.

1.3.2.3 Closing Coal Ash Ponds

The West Ash Pond at F.B. Culley is currently undergoing closure, with those activities scheduled to be completed by December 2020. The closure design includes the construction of a lined contact storm water pond, which will receive contact storm water from various areas of the plant. The construction of this pond, along with the installation of the dry bottom ash and FGD ZLD technologies will enable the upcoming required closure of the F.B. Culley East Ash Pond.

The A.B. Brown Ash Pond is also facing forced closure soon. Plans are currently underway to prepare for the excavation of all material from the A.B. Brown ash pond, with a majority of the ash being sent for beneficial reuse.

1.3.3 Electric TDSIC

The IURC approved Vectren's seven-year infrastructure improvement plan for the period of 2018-2024 (Cause No. 44910). This plan helps to build/rebuild high–voltage transmission lines, replaces substation transformers, rebuilds electric circuits and includes distribution automation. These improvements will help Vectren to continue to reliably deliver power to its customers now and in the future. Additionally, these improvements, will allow more flexibility in resource planning by improving power flows across Vectren's system, particularly the addition of the East-West transmission line that will connect the F.B. Culley Plant site on the east side of the system with the A.B. Brown plant site on the west side.

1.3.3.1 Advanced Metering Infrastructure (AMI)

In 2017, Vectren began installation of AMI smart meters as a key part of Vectren's grid modernization plan. Vectren has since successfully installed meters across its territory. AMI provides access to much more granular customer load data and will help Vectren to better understand and anticipate changes in an evolving energy landscape. This improvement will have long-term benefits for load research and long-term load forecasting, as well as provide the opportunity to create innovative DSM programs for shaping customer load. Vectren customers have already received many benefits in the near term for billing, quicker service response time and quicker responses to power outages; however, the long-term benefits will take time and have not been fully realized by the compilation of this IRP.

1.3.4 IRP Rule Making Process

Revisions to Integrated Resource Planning were made via RM# 11-07, which began in 2010. Vectren voluntarily followed the draft rule in 2014 and 2016 IRPs, which included a public stakeholder process. In 2019 the rule was finalized and can be found in the IRP Rule Requirements Cross reference table of this document. Major updates to the rule included moving from a two year to three-year cycle and several updates to the stakeholder process, including the number of required stakeholder meetings, which is now three.

1.3.5 DSM Filing

On April 10, 2017, Vectren filed with the Indiana Utility Regulatory Commission (IURC) a Petition seeking approval of Vectren's 2018-2020 Energy Efficiency Plan (2018-2020 Plan or Plan). The Plan included proposed energy efficiency goals; program budgets and costs; and procedures for independent evaluation, measurement and verification (EM&V) of programs included in the Plan. The Plan has an estimated cost of $28.6 million, with $9.5 million in 2018, $9.6 million in 2019 and $9.5 million in 2020. The Plan includes a portfolio of programs designed to achieve 111 million kWh in energy savings and 26,000 KW in demand reduction during the three-year period.

On December 28, 2017, the IURC issued an Order approving Vectren's 2018-2020 Energy Efficiency Plan (2018-2020 EE Plan) pursuant to Section 10. Vectren carried out a lengthy analysis of the DSM resources included in its IRP process. The Commission found that the proposed energy savings goals appear reasonably achievable and consistent with historical savings that has been previously approved. A summary of the savings and budgets are listed in the table below.

Figure 1.1 – 2018-2020 Portfolio Summary of Participation, Impacts, & Budget

Portfolio Participation, Impacts & Budget								
Program Year	Participants /Measures	Annual Energy Savings kWh	Annual Demand Savings kW	Res & C&I Direct Program Budget	Indirect Portfolio Level Budget	Other Costs Budget	Portfolio Total Budget Including Indirect & Other	First Year Cost/kWh *
2018	334,626	36,656,341	7,430	$ 8,050,391	$ 937,436	$ 500,000	$ 9,487,827	$ 0.23
2019	354,120	38,069,188	7,607	$ 8,433,276	$ 960,110	$ 200,000	$ 9,593,386	$ 0.23
2020	225,065	36,347,642	7,750	$ 8,370,366	$ 960,225	$ 200,000	$ 9,530,591	$ 0.24

* Cost per kWh includes program and indirect costs for budget. First year costs are calculated by dividing total cost by total savings and do not include carryforward costs related to smart thermostats, BYOT and CVR program.

1.3.6 Alcoa Contract

Alcoa and Vectren have jointly owned and operated the 300 MW Warrick 4 unit since 1970. In 2016, Alcoa split into two separate public companies and Alcoa Inc., as owner of the Warrick site, closed the aluminum smelter and greatly reduced load at the Warrick site. Alcoa also issued notice to Vectren that it would terminate and exit the joint operations of Warrick 4. However, Alcoa later reopened the smelter. After filing the 2016 IRP, Vectren worked with Alcoa to extend joint operations of Warrick unit 4 until December 31, 2023. The Warrick power plant consists of four generating units: three 150 Megawatt (MW) industrial units wholly owned by Alcoa and one 300 MW electric generating unit (Warrick 4) that is jointly owned by 50% Alcoa and 50% Vectren. Alcoa's power plant provides most of its 600 MW electric generation, if not all, to meet the electric demand of the Warrick Operations facility with the smelter being most of that demand. Alcoa's interest in continuing to operate the jointly owned Warrick 4 is unclear. As Vectren sought to maintain flexibility in this IRP, the company approached Alcoa to see if there was any potential to continue jointly operating Warrick 4 beyond 2023. Alcoa commented that it would possibly consider jointly operating the unit for an additional three years. While there is no commitment to run past 2023, Vectren included a three-year Warrick 4 extension possibility within the IRP modeling analysis as an option to maintain flexibility. Part of Alcoa's evaluation of the future of Warrick 4 is the potential need to invest in environmental control upgrades to continue operating the unit beyond 2023.

1.3.7 Merger with CenterPoint Energy

On February 1, 2019, CenterPoint announced the successful completion of the merger between Vectren and CenterPoint. The combined company, which is named CenterPoint Energy and headquartered in Houston, has regulated electric and natural gas utility businesses in eight states that serve more than 7 million metered customers. These utilities consist of the following:

- Electric utility business – CenterPoint Energy maintains wires, poles and electric infrastructure serving 2.4 million metered customers in the greater Houston area and 146,000 customers in Indiana. The company also owns and operates approximately 1,200 megawatts of power generation capacity in Indiana. CenterPoint Energy's Texas electric utility business is headquartered in Houston and its Indiana electric utility business is headquartered in Evansville, Ind.
- Natural gas utility business – CenterPoint Energy sells and delivers natural gas to 4.5 million homes and businesses in eight states: Arkansas, Indiana, Louisiana, Minnesota, Mississippi, Ohio, Oklahoma and Texas, including the high-growth areas of Houston and Minneapolis. The company's natural gas utility business is headquartered in Evansville.

1.3.8 FERC Grid Resilience and MISO Initiatives

Grid resilience became a national topic of interest in 2017 when the Department of Energy issued a Notice of Proposed Rulemaking (NOPR) for the Federal Energy Regulatory Commission's (FERC) consideration. The basis of the NOPR was that due to the large amounts of retiring dispatchable generation, namely nuclear and coal, the nation's bulk electric system was susceptible to power interruptions during extreme events and that it would be ill-suited to recover from these events. In January of 2018, FERC terminated the NOPR and directed each regional transmission owner (RTO) to evaluate its own resiliency, defined as the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to and/or rapidly recover from such an event. MISO, the RTO that Vectren is a member of, filed comments to FERC stating its grid is resilient due to its robust electric and gas transmission infrastructure and its diverse generator makeup that spans a region from Ontario to the Gulf Coast. Furthermore, MISO stated footprint diversity is a staple of MISO's annual Value Proposition and is the cornerstone that MISO points to that ensures resiliency. MISO also noted several areas in which it would focus efforts to ensure continued resilience, namely through transmission planning, best in class technological tools and engagement with state and local regulators to assist in measurement and planning for local systems that may be vulnerable to high-impact events.

MISO's Resource Availability and Need (RAN) Initiative and its Renewable Integration Impact Assessment (RIIA) are the two current methods in which it is dealing with its evolving grid to help keep the system resilient and reliable. The RAN Initiative is aimed at better accrediting generation units while the RIIA is focused on understanding the impacts of renewable energy growth in MISO over the long term and assessing potential transmission solutions to mitigate them.

1.3.8.1 MISO Resource Availability and Need (RAN)

As a reaction to the increasing frequency, duration and ability for Max-Gen Events to occur within all periods of the year, in 2018 MISO implemented its Resource Availability and Need (RAN) initiative. The goal of this initiative is "ensure the processes in use appropriately assure the conversion of committed capacity resources into sufficient energy every hour of the Planning Year. A dramatically changing landscape has made this conversion process increasingly more uncertain. Therefore, an issue and solution development effort will help MISO and its stakeholders identify and meet the challenges posed by current and future portfolio and technology changes facing the region[9]."

[9] MISO Resource Availability and Need Issue Summary: page 1, January 12, 2018 https://www.misoenergy.org/api/documents/getbymediaId/96780

The RAN initiative has led to market mechanism reform that is currently underway. Such reform has included changes to the ability to interrupt customers enrolled as Load Modifying Resources/Interruptible Load. MISO currently has reform initiatives[10] that are high priority, including:

- Emergency Energy Pricing, which would allow higher cost energy resources to set pricing, thereby increasing energy pricing during emergency events,
- Increasing the Energy Offer Cap from $1,000/MWh to $2,000/MWh, thereby allowing generation to double its maximum offer price and allow prices to reach a higher threshold and
- a Seasonal Planning Resource Auction construct, which could break up the current annual capacity auction into seasons (winter and summer auctions) that would adjust the PRMR and capacity accreditation for resources during these periods. This initiative is in the primary phase of stakeholder vetting, with a possibility of tariff revisions submitted next year and could be in effect as early as the 2022-23 Planning Year.

1.3.8.2 MISO Renewable Integration Impact Assessment (RIIA)

With increased levels of intermittent renewable generation, operating the grid becomes increasingly more complex. To help understand what is needed in the long term to deal with this complexity, in 2017 MISO launched its Renewable Integration Impact Assessment (RIIA) study to find system integration inflection points. In other words, to find out where there may be potential issues as renewable penetration increases from 10%, 20%, 30% or beyond. MISO is focusing on a few key areas: Resource Adequacy, Energy Adequacy and Operating Reliability. As discussed further in this document, the resource adequacy portion of the analysis has already yielded actionable insights into integrated resource planning, which have been incorporated into Vectren's 2019/2020 analysis, particularly the amount of capacity that will likely be accredited to wind and solar resources over time based on penetration rate and expected output under peak

[10] MISO Market Roadmap, February 2019: https://cdn.misoenergy.org/MISO%20Market%20Roadmap194258.pdf

conditions. MISO calls this Effective Load Carrying Capability (ELCC). This study illustrates the need for dispatchable resources that support high renewable penetrations as the peak load, net of renewable generation, pushes farther into the evening after the sun goes down. Flexible, dispatchable resources are needed to meet this need quickly.

1.3.9 2016 IRP Director's Report

Each year, the Director to the IURC electric division issues a critique of IRPs. The 2016 IRP Director's report listed a balance of positive comments, coupled with improvement opportunities for Vectren. The table below shows the improvement opportunities with a brief description of how the comment was addressed within the 2019/2020 IRP:

Figure 1.2 – IRP Improvements Based on 2016 IRP Director's Report

Improvement Opportunities	Addressed
Include lower and higher boundary scenarios to create a wider range of portfolios	A wider range of forecasts were considered for key inputs within scenario development
Model a wide range of portfolios	Vectren modeled 10 portfolios in the risk analysis, utilizing feedback from multiple stakeholders to ensure many potential paths were covered, from continue most coal to all renewables by 2030
Strategist model did not consider enough options simultaneously	Utilized Aurora, which did consider all resources simultaneously
Update risk analysis methodology to be less qualitative and more encompassing of known risks. Clearly define risk analysis methodology	Included known risks within scenario development and the risk analysis, including, but not limited to CO_2 cost, potential methane regulations, possible

Improvement Opportunities	Addressed
	shale gas ban, uneconomic asset risk, etc.
Explore other options for modeling EE cost options and make greater use of a Market Potential Study (MPS) and Clearly define Energy Efficiency Methodology	Worked closely with stakeholders throughout the development process to develop EE modeling inputs using the latest MPS
More consideration given to Warrick unit 4 in scenario development	Warrick unit 4 extension (3 year) was considered within scenario optimizations. Discussions with Alcoa continue

1.3.10 Statewide Energy Policy Analysis

In 2019 the General Assembly created a task force to develop energy policy recommendations, and at this time, that work is ongoing.

The 21st Energy Policy Development Task Force was created by HEA 1278 (2019) to develop recommendations for the General Assembly and the Governor on the following:

1. Outcomes that must be achieved in order to overcome any identified challenges concerning Indiana's electric generation portfolios, along with a timeline for achieving those outcomes.
2. Whether existing state policy and statutes enable state regulators to properly consider the statewide impact of changing electric generation portfolios and, if not, the best approaches to enable state regulators to consider those impacts.
3. How to maintain reliable, resilient and affordable electric service for all electric utility consumers, while encouraging the adoption and deployment of advanced energy technologies.

In order to arrive at its recommendations, the task force will examine existing policies and how shifts in generation portfolios may impact system reliability, grid resiliency and affordability of electric service. The task force will issue its recommendations by December 1, 2020. Any outcomes that require statutory changes will likely be proposed in the 2021 legislative session.

Additionally, HEA 1278 passed in 2019 and required the IURC to conduct a statewide analysis of impacts of transitions in fuel sources and other electric generation resources, as well as the impacts of new and emerging technologies on electric generation and distribution infrastructure, electric generation capacity, system reliability, system resilience and the cost of electric utility service for consumers. IURC staff is working with Laurence Berkeley National Lab, Indiana University and the State Utility Forecasting Group. Results will be available this summer to help inform the 21st Energy Policy Development Taskforce.

Vectren stands ready to act as a resource to members of the 21st Energy Policy Development Task Force as progress is monitored. To this point, task force meetings have served as information-gathering sessions on various topics related to electric generation and delivery. Following the conclusion of the task force's work, Vectren will work collaboratively with policymakers and all stakeholders to help ensure a bright energy future for the State of Indiana.

1.3.11 HB 1414

The Indiana General Assembly passed legislation pertaining to electric generation during the 2020 legislation session. HEA 1414 Electric Generation was signed into law by Governor Holcomb on March 21, 2020 and provides the following:

- A public utility that owns and operates a reliable capacity electric generation resource must operate and maintain the unit using good utility practices and in a manner reasonably intended to support the availability of the unit for dispatch

- The bill sets parameters around a public utility's decision to retire, sell or transfer a reliable capacity resource with a capacity of at least 80 megawatts before May 1, 2021:
    - The utility must first provide written notice of its intent to do so to the IURC
    - The IURC must conduct a public hearing to receive information and issue analysis and conclusions, after which the utility may proceed, if doing so aligns with the preferred portfolio in its most recent IRP
    - If the planned retirement, sale or transfer was not included in the most recent IRP, the utility may not proceed for at least six months from the date of the commission's receipt of the written notice
    - If the utility cites a federal mandate as the basis for the planned retirement, sale, or transfer of the reliable capacity resource, the IURC may consider the status of the mandate in its analysis and conclusions.

Passage of HEA 1414 did not impact the selection of the preferred portfolio. The timing of Vectren's IRP is such that no retirements of electric generating stations could take place before the May 1, 2021 date in the legislation.

1.3.12 COVID-19

COVID-19, the disease caused by the coronavirus, has led to unprecedented changes in the energy industry as it has affected every aspect of life. The energy industry has seen demand drop since March of 2020, on average 6-10%, while commodity prices have decreased at a steep rate. This recent pandemic is still underway as of the writing of this document and the effects and duration are still largely unknown. The scenarios in this IRP account for a range of outcomes and the Low Load scenario is illustrative of the effects from a wholesale market pricing perspective. The following sections are independent of COVID-19 as the studies were performed prior to its onset and constitute resource planning for a 20-year period. The preferred portfolio includes multiple off-ramps, which help mitigate the risk that demand does not grow to pre-Covid-19 levels.

1.3.13 Contemporary Issues

Vectren participates in the Commission's IRP Contemporary Issues Technical Conference held each year. In 2019, the Conference was held on April 15, 2019. The Conference also covered topics such as database management, integration of DERs, incorporation of load shapes into planning, the changing availability and flexibility requirements of MISO Resource Availability and Need (RAN) initiative, long-term utility planning assumptions and procurement decisions, preliminary lessons learned from NIPSCO's all-source RFP, risk analysis and life cycle analysis of greenhouse gas emissions.

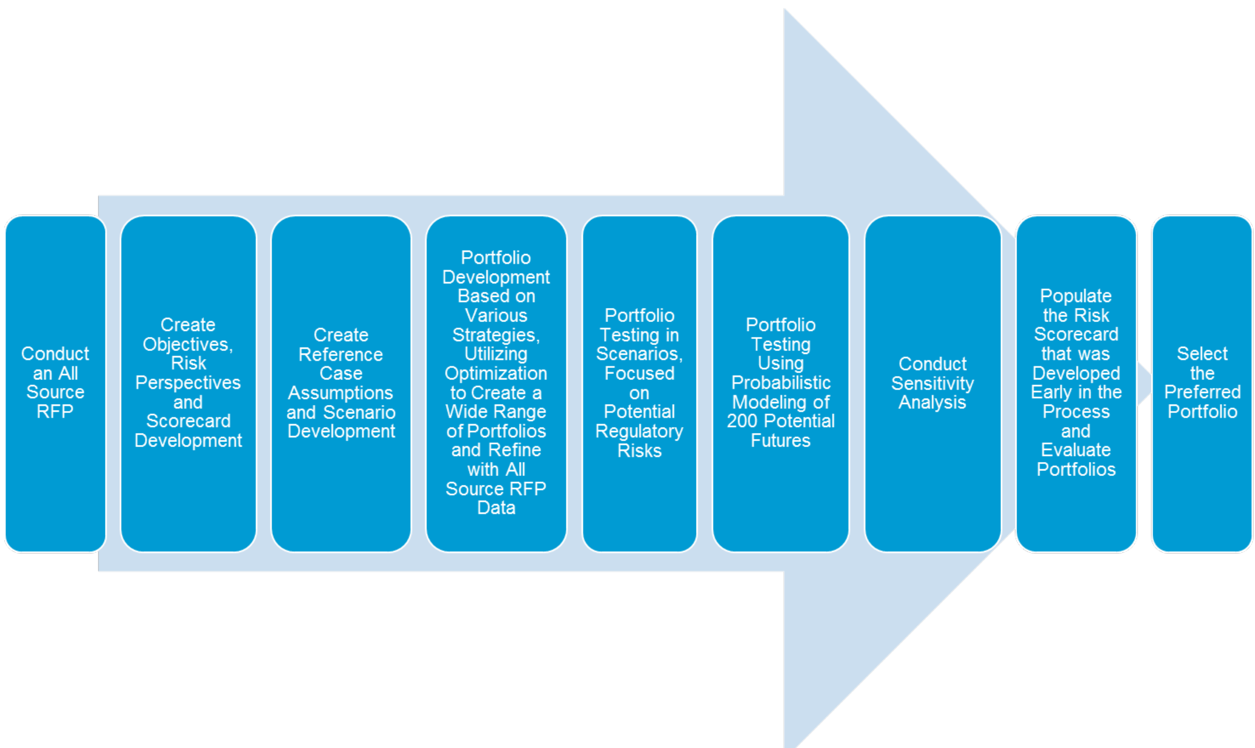
Several of these topics were timely and influential within Vectren's analysis. For example, the MISO RAN discussion, which included and expected focus on resource availability and flexibility to meet daily and variable energy needs, as well as a need for a holistic solution for seasonal resource adequacy. NIPSCO's discussion of All-Source RFP and lessons learned for the IRP was helpful as Vectren conducted its first All-Source RFP for this analysis. Finally, EVA's discussion on the need for Life Cycle Analysis (LCA) of carbon emissions analysis influenced Vectren's decision to include a life cycle greenhouse gas emissions variable within the risk scorecard.

SECTION 2
VECTREN'S IRP PROCESS

2.1 VECTREN'S IRP PROCESS

Vectren's 2019/2020 IRP followed a very structured, comprehensive process over a 14-month period with extensive risk-based analysis and included an All-Source RFP to include market-based pricing with the opportunity to secure available resources following the conclusion of the IRP. This process was designed to ensure that relevant technologies were evaluated and the resulting portfolio combinations were tested in a wide range of future market and regulatory conditions. The process followed is illustrated below.

Figure 2.1 – Vectren IRP Process



The following sections describe each step in the analysis.

2.2 Conduct an All-Source RFP

Vectren issued an 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. Long term resource planning requires addressing risks and uncertainties created by several factors including the costs associated with new resources. As part of ongoing resource planning, Vectren concluded that it was in the best interest of its customers to seek information regarding the potential to acquire, construct, or contract for additional capacity that qualifies as a MISO internal resource (i.e. not pseudo-tied into MISO) with physical deliverability utilizing Network Resource Integration Service (NRIS) to MISO LRZ 6. These requirements helped to provide price certainty, transparency and MISO Local Clearing Requirement (LCR) accreditation, that will be discussed in further detail.

Within the context of the 2019/2020 IRP process, Vectren used an All-Source RFP to solicit bids for supply-side and demand-side capacity resources. The purpose of the RFP was to identify viable resources available to Vectren in the marketplace to meet the needs of its customers. Dependent upon further evaluation of aging resources and prior to the 2019/2020 IRP, there was a potential capacity need of approximately 700 MW of accredited capacity beginning in the 2023/2024 planning year. Vectren sought flexibility when defining potential resource combinations and encouraged RFP respondents to offer available projects with less than, or more than, 700 MW. Vectren also considered alternative timelines related to the capacity acquisition to the extent Respondents were able to provide more competitive pricing and/or terms for delivery beginning prior to or after the 2023/2024 planning year. Vectren used aggregated data from the RFP responses as inputs into the IRP modeling. The RFP Proposal evaluation process was based upon the specific resource needs identified through this IRP modeling as well as the Proposal evaluation criteria. Through this RFP, Vectren sought to satisfy the identified capacity need through either a single resource or multiple resources including dispatchable generation, load modifying resources (LMRs)/demand response (DRs), renewables, stand-alone and paired storage and contractual arrangements.

In connection with this RFP, Vectren retained the services of an independent third-party consultant, Burns & McDonnell, to manage the entire RFP process and work with Vectren to perform the quantitative and qualitative evaluations of all Proposals.

All Respondents were directed to interface with Burns & McDonnell for all communications including questions, RFP clarification issues and RFP Proposal submittal until late in the evaluation process.

Proposals were initially reviewed for completeness by Burns & McDonnell. Respondents were contacted for additional data or clarifications by Burns & McDonnell via a designated Vectren RFP e-mail address, VectrenRFP@burnsmcd.com. Each complete Proposal was evaluated based on the Levelized Cost of Energy (LCOE), energy settlement location, interconnection/development status & local clearing requirement and project risk factors. The evaluation criteria were intended to relatively compare each Proposal to analogous submissions. This evaluation, in conjunction with the IRP, was used to determine which combination of resources are most capable of providing Vectren customers with a safe, reliable and affordable power supply.

2.3 OBJECTIVES, RISK PERSPECTIVES and SCORECARD DEVELOPMENT

Vectren's IRP process is designed to assure a systematic and comprehensive planning analysis to determine the "preferred portfolio" that best meets all its objectives over a wide range of market futures. This process results in a reliable and efficient approach to securing future resources to meet the energy needs for Vectren customers.

In addition, the IRP process complies with environmental regulations and reliability requirements, while reducing its vulnerability to market and regulatory risks, the risk of supply disruptions. In the IRP, Vectren also focused on increasing the diversification of its supply sources. As part of the IRP, Vectren considered maintaining flexibility to respond to market changes. The evaluation considered both existing and new resources, including renewable energy and battery storage options.

Economic modeling is an important part of the IRP process, as it allows Vectren to identify the portfolio of supply-side and demand-side resources on a competitive economic basis.

The resulting least cost portfolios reflect a combination of market, regulatory or technology specified conditions and market input parameters (for example, identify the least cost portfolio consisting of all renewables by 2030 using reference case market forecasts). While cost is an important objective, it is by no means the only objective. Vectren has several important objectives, each of which needs to be considered when evaluating the best portfolio for its stakeholders over time. Moreover, Vectren needs to account for operational and logistical considerations in the construction of alternative portfolios to ensure that they meet minimum reliability or resource adequacy considerations.

Vectren's IRP strategy is designed to accommodate ongoing changes and uncertainties in the market. Vectren's IRP objectives are based on the need for a resource strategy that provides long term value to its customers and communities. Therefore, as objectives are evaluated, tradeoffs must be considered. Specifically, Vectren's IRP objectives are as follows:

- Reliability: As new technologies proliferate and older baseload units retire, it is apparent that there will be increased reliance on intermittent, renewable energy resources. The ability to support local system stability and reliably provide power must be maintained by meeting MISO and NERC standards for reserve margins and resource adequacy.

Quantitative Metrics Directly Considered

- Affordability: Provide all customers with an affordable supply of energy
- Cost Uncertainty Risk Mitigation: Provide a predictable, balanced and diverse mix of energy resources designed to ensure costs do not vary greatly across alternative future market conditions or supply disruptions.
- Environmental Emission Risk Mitigation: Provide environmentally responsible power, leading to a low carbon future.
- Market Risk Minimization: Develop a flexible plan that can adapt to market conditions and regulatory and technological change to minimize risk to Vectren

customers and shareholders. The plan considers several alternative options for existing resources.

Other Considerations

- Future Flexibility: Mitigate the risk that assets in the portfolio may become uneconomic in the future through off ramps and optionality.
- Resource Diversity: Mitigate risk to customers of over-reliance on a single technology by providing a mix resources to minimize the dependence on any one resource type that could become operationally or economically eclipsed.
- System Flexibility: Operationally able to meet the current and future needs of the evolving grid

Reliability is Vectren's priority over all other objectives. While the IRP doesn't directly assess system stability issues, all portfolios must meet minimum reserve margin and resource adequacy requirements set by MISO. These are minimum requirements met in the modeling rather than a metric tracked for each portfolio. Vectren did a reliability assessment for portfolios that made it through the screening process. This is described in Section 6.4.3 Transmission Facilities as a Resource.

The next several objectives are given one or more defined and measurable metrics. By testing candidate portfolios against these metrics, Vectren illustrates tradeoffs among competing IRP objectives. This tool aided in the selection of the preferred portfolio. The last three objectives are more subjective in nature but relevant to the IRP process so are discussed under "other considerations". The following metrics were used to select the preferred portfolio:

Figure 2.2 – Vectren Scorecard for IRP Objectives and Risk Metrics

	Objective	Metric
Quantitative and Qualitative (considered outside of scorecard)	Reliability	• Reliability Assessment
Quantitative Scorecard Measure	Affordability	• Mean value for the 20-Year Net Present Value of Revenue Requirements (NPVRR) (million$) across 200 dispatch iterations under varying market conditions
	Cost Uncertainty Risk Minimization	• 95th percentile[11] of NPVRR (million$) across 200 dispatch iterations under varying market conditions
	Environmental Emissions	• Reduction in tons of life-cycle greenhouse gas emissions (CO_2e) 2019-2039
	Avoiding Overreliance on Market Risk	• Annual Energy Sales and Purchases, divided by Annual Generation, average (%) • Annual Capacity Sales and Purchases, divided by Total Resources, average (%)
Qualitative (considered outside of scorecard)	Resource Diversity	• Risk of overreliance on one type of resource
	System Flexibility	• Ability operationally to support the system to maintain stability and reliability
	Future Flexibility	• Risk that assets in a portfolio may become uneconomic

Defined metrics are used to evaluate different portfolios and planning strategies in the IRP process. These metrics provide objective assessments of critical factors of each portfolio under different market scenarios. There are natural trade-offs among these objectives; for example, the portfolio with low expected costs may increase exposure to market risk. The objective of the IRP is to find the right balance of these metrics across a wide variety of future conditions to ensure that the ultimate choice of a portfolio performs well, regardless of the circumstances. Portfolio selection is based on Vectren evaluating all qualitative and quantitative metrics and using well-informed judgement in selecting its preferred portfolio. A further description of each metric is provided below.

2.3.1 Objectives and Risk Perspectives

The IRP objectives were evaluated using the results of the scenario, sensitivity and probabilistic modeling, as well as other qualitative factors.

2.3.2 Scorecard Metrics

The Balanced Scorecard is a broad comparison of candidate portfolio attributes and risks. It was populated with metrics entirely derived from the probabilistic modeling. The probabilistic modeling subjected each portfolio to 200 iterations of the dispatch model under varying market conditions. Vectren then used the resulting performance data and the distributions from the 200 iterations to quantify the metrics that align with each IRP objective. The Balanced Scorecard metrics are the same as the risk metrics described in Figure 2.2.

2.3.2.1 Affordability

For the Affordability objective, the metric used is the mean value for the 20-Year Net Present Value of Revenue Requirements (NPVRR), expressed in millions of dollars. The NPVRR is a measure of all generation related costs (for each asset, the cost of generation – capital, O&M, fuel and related transmission costs to deliver power to Vectren customers, plus the cost of power and capacity purchases etc.) associated with the portfolio of assets over time. These costs are adjusted through a discount rate to ensure future costs are reflected in present year dollars, commonly known as a time value of money adjustment.

In this way, very different portfolios can be compared on a common metric or value over a long-time frame.

2.3.2.2 Cost Uncertainty Risk Mitigation

For the Cost Uncertainty Risk Mitigation objective, the metric used is the 95th percentile of NPVRR, also expressed in millions of dollars. After each portfolio was subjected to 200 dispatch model runs, a distribution is created of the NPVRR portfolio costs. The 95th percentile (approximately two standard deviations above the mean value) is a commonly used benchmark to demonstrate a reasonable upper threshold of cost risk under widely varying market circumstances.

2.3.2.3 Environmental Emission Risk Minimization

For the Environmental Emission Risk Minimization objective, the metric estimated life cycle greenhouse gas emissions of each generation type, measured in tons of carbon dioxide equivalent (CO_2e). The use of life cycle emissions rather than direct generation emissions was a result of feedback from the stakeholder process. Life cycle emissions account for "cradle to grave" emission impacts of generation and offer more consistent comparisons of environmental impact across generation technologies. The lifecycle emissions captures upstream emissions including raw material extraction, power generation facility construction and any upstream emissions associated with fuel extraction and transportation (if applicable). Life cycle emissions were estimated using the National Renewable Energy Laboratory's (NREL's) harmonized life cycle emissions factors for generation technologies considered in the analysis.[12] Life cycle emissions from existing and new resources are derived by multiplying the generation from each fuel type (including coal, gas combustion turbine, gas combined cycle, utility-scale solar and solar distributed generation and onshore wind) by the corresponding specific technology

[12] NREL conducted a systematic review of 2,100 life cycle greenhouse gas emissions studies for electricity generating technologies and screened down the list to about 300 credible references. From these, NREL published the median values which were shared with IRP stakeholders and used to calculate life cycle greenhouse gas emissions for each portfolio.

emission factor. Emission factors for life cycle greenhouse gas emissions are presented in Figure 2.3.

Figure 2.3 – Life Cycle Greenhouse Gas Emission Factors (grams CO_2e/kWh)[13]

	Specific Technology	Market[14]
All Coal		1,002
Sub Critical	1,062	
Super Critical	863	
All Gas		474
Gas CT	599	
Gas CC[3]	481	
All Nuclear		16
Onshore Wind	12	12
All PV		54
Thin Film	35	
Crystalline	57	
All hydropower	7	7
Bio Power	43	43

To account for life cycle emissions from energy purchases imported from the market, Vectren used the MISO 2033 Futures energy utilization mix corresponding to the Accelerated Fleet Change mix from the 2019 MISO Transmission Expansion Planning Report (MTEP19)[15]. This estimation provides a figure of 347.4 grams of CO_2e/kWh as shown below in Figure 2.3a.

[13] Source: https://www.nrel.gov/analysis/life-cycle-assessment.html - Values derived from graphs included for each resource type. Note that battery storage was not estimated.
[14] Utilized when specific technology breakouts were not available within the MTEP study
[15] 2019 MISO Transmission Expansion Planning Report (MTEP19) https://www.misoenergy.org/planning/planning/mtep-2019-/

Figure 2.4 – MTEP19 Accelerated Fleet Change Mix Used to Calculate CO_2e Emissions from Energy Imports

Resource	Given Percentage in MTEP19 Fig. 2.5-2	Normalized Percentage	Grams of CO2e per kWh (NREL)	Pro Rata Grams of CO2e per kWh
Coal	18%	15.7%	1,002	156.8
Nuclear	6%	5.2%	16	0.8
CC/ST Gas	23%	20.0%	481	96.2
CT	16%	13.9%	599	83.3
Wind	30%	26.1%	12	3.1
Utility Solar	10%	8.7%	54	4.7
DG Solar	5%	4.3%	54	2.3
DR	4%	3.5%	0	0.0
Other	3%	2.6%	0	0.0
Battery	0%	0.0%	0	0.0
Total	115%	100.0%		347.4

Outside of the scorecard, Vectren considered direct portfolio emissions reductions for each portfolio compared to a base year (2005) of power generation and resulting CO_2 emissions. The 2005 benchmark year saw 9,634,957 short tons of CO_2 emissions.

2.3.2.4 Market Overreliance Risk Minimization

For the Market Overreliance Risk Minimization objective, there were four metrics. There is the average annual energy sales and the average annual energy purchases, each divided by average annual generation and expressed as a percentage. There is also the average annual capacity sales and the average annual capacity purchases, divided by average total resources and expressed as a percentage.

Other Considerations

2.3.2.5 Uneconomic Asset Risk Mitigation

The recent generation order suggested that the consideration of future generation mix should include the risk that assets in the portfolio would become uneconomic due to technological advance. Vectren anticipated that the greatest risk would be imposed by capital intensive fossil plants as renewable assets became more economic with time.

To try to measure this risk, the probabilistic modeling provided an annual accounting of a plant's going-forward costs and revenues in each of the 200 iterations. In cases where the annual going-forward costs exceed the annual revenues for three consecutive years, the plant was deemed to be uneconomic[16] at that time. In the first year in which the plant was deemed uneconomic, the unamortized cost of the uneconomic asset and any additional losses in subsequent years was measured.

2.3.2.6 Resource Diversity Maximization

Vectren believes that resource diversity helps minimize risk to customers by providing a mix of resources to minimize the dependence on any one resource type that could become operationally or economically eclipsed. Vectren's coal units have served its customers well over the years, but continued pressure on this resource from environmental regulations, increasing use of intermittent renewable resources and low gas prices have resulted in several units having a low dispatch rate. The concentration of coal in Vectren's generation mix has become costly to Vectren customers over time. Additionally, the Indiana Commission reinforced this consideration in a recent Order that Vectren should consider resource diversity and alternatives that provide off ramps that allow Vectren to react to changing circumstances.

While very important, it is hard to create a measure that adequately captures this value. Instead, Vectren sought to develop a number of portfolios that included a wide range of resource types and fuel sources. To ensure this objective has been met, Vectren built portfolios that ensure diverse mixes. One way in which this has been done is that Vectren did not consider a large 2x1 Combined Cycle Gas Turbine (CCGT) in the 2019/2020 IRP. While potentially an economic solution for customers, moving from mostly coal to mostly gas was considered a risk in the long term due to the lack of

[16] Definition of an uneconomic asset: When going forward costs of the asset, which include annual variable costs (fuel + variable operations & maintenance or VOM + emissions) plus annual fixed operations & maintenance or FOM costs, are collectively greater than the total annual revenues (including both energy revenues and capacity revenues) in three successive years

flexibility to adjust to future conditions. Additionally, Vectren included an All-Source RFP to fully consider renewable resources within all portfolios.

2.3.2.7 System Flexibility

System flexibility was an important consideration in the 2019/2020 IRP. As intermittent renewable resources continue to grow on the transmission and distribution system, it is important to back these resources up for reliability and resilience. As such, Vectren considered performance of resources with the ability to start and ramp quickly and be available for sustained periods in times when the sun is not shining and the wind is not blowing. Vectren also considers the transmission system and the ability to rely on the market as an important consideration in IRP planning. While Vectren has considerable import capabilities with the addition of the Duff Coleman Market Efficiency transmission Project (MEP) and the upcoming East/West line, this capability is not unlimited and requires needed upgrades to maintain reliability for portfolios that rely less on dispatchable energy resources.

2.4 REFERENCE CASE ASSUMPTIONS AND BOUNDARY SCENARIOS

After selecting the objectives and metrics, the next step in the process was to define the Scenarios for consideration in the selection of alternative portfolios. In this case Vectren selected a Reference Case and four alternative scenarios for two purposes. The first purpose was to select a least cost portfolio for each of the five scenarios and the second was to test final portfolios against each of the market scenarios to determine how well they perform. Below is a brief discussion of each. Greater detail is provided in Section 7 which identifies the key inputs for each scenario.

2.4.1 Reference Case

The Reference Case scenario represents the most likely future conditions. Vectren surveyed and incorporated a wide array of third-party sources to develop its Reference Case assumptions, several of which reflect a current consensus view of key drivers in power and fuel markets. Reference Case assumptions include forecasts of the following key drivers:

- Vectren and MISO energy and demand (load)
- Henry Hub and delivered natural gas prices
- Illinois Basin mine and delivered coal prices
- National carbon (CO_2) prices
- Capital costs and associated cost curves for various supply side (generation) and demand side resource options

The long-term energy and demand forecast for the Vectren service territory was developed for Vectren by Itron, a leading forecasting consultant in the U.S. The forecast is based on historical residential, commercial and industrial usage and drivers such as appliance saturation and efficiency projections, electric price, long-term weather trends, customer-owned generation, electric vehicle adoption and several demographic and economic factors.

For natural gas, coal and capacity price, Vectren used a “consensus” Reference Case view of expected prices by averaging forecasts from several sources. This helps to ensure that multiple views are considered and allows Vectren to be transparent with modeling assumptions. For natural gas and coal, 2019 forecasts from PIRA, Wood Mackenzie, Pace Global, ABB, and EVA were averaged. Based on a stakeholder request to include CO_2 in future years, Vectren decided to include a CO_2 price in the Reference case but not in the low regulatory case. The CO_2 forecast was developed by Pace Global. The capacity price forecast was based on MISO Zone 6 forecasts from Wood Mackenzie, Pace Global and ABB.

All-source RFP bids were utilized for resource cost information between 2022 and 2024, where possible. Long term cost curve information was developed utilizing a consensus approach, using Burns and McDonnell, NREL ATB and Pace Global. Burns & McDonnell technology assessment helped fill in the gaps with operational data and for various traditional technologies like gas and coal resources.

Vectren worked with stakeholders and GDS to develop a Market Potential Study (MPS) for demand side resources. This study was used to create demand side inputs to be compared on a consistent and comparable basis with supply side resources.

Pace Global performed the production cost modeling used to create several key components of the IRP. Using the AURORAxmp power model, Pace Global developed an optimized, least-cost portfolio for the Reference Case, which was then run in chronological hourly dispatch mode. The deterministic dispatch run provided power price forecasts for MISO regions, as well as the least cost portfolios created utilizing the Reference Case. These key drivers constitute the Reference Case assumptions. More information on modeling inputs can be found in Section 7.2 Reference Case Scenario.

2.4.2 Alternative Scenarios

It is important to test technologies against a variety of future market conditions, not just the Reference Case. Hence, Vectren, with the support of Pace Global, selected four alternative scenarios (a Low Regulatory, a High Regulatory, an 80% Carbon Reduction and a High Technology) to provide boundary conditions for testing the technologies and developing portfolios that could be subjected to a full risk assessment (with hundreds of scenarios tested later in the process).

Vectren worked with Pace Global and received input from Vectren stakeholders on key inputs such as load forecasts, gas and coal prices, carbon emission prices and technology capital costs. With input from stakeholders, Vectren and Pace Global determined whether gas prices, coal prices, load, technology capital costs, retirements/ builds, carbon emission prices and power prices would move up or down relative to the Reference Case under each of those scenarios. This process was followed to illustrate what might happen under each of these scenarios in a consistent manner with the risk analysis. This wide range of scenarios is bounded on one end by a Low Regulatory future with no CO_2 price. Regulation of CO_2 and other regulations ratcheted up moving towards the outer boundary condition, the High Regulatory future. Below is an illustrative description of each scenario.

- Low Regulatory – The primary carbon regulation is assumed to be the ACE rule. Indiana implements a lenient interpretation of the rule. ELG is partially repealed with bottom ash conversions not required for some smaller units and is delayed for two years (this does not apply to F.B. Culley 3). The limited regulation promotes a stronger economy, higher load and higher natural gas prices relative to the Reference Case. Other drivers still support declining coal demand over the planning horizon and as a result coal prices remain at levels similar to the Reference Case. Similarly, technology costs retain the same outlook as the Reference Case. This case is consistent with the theme that the Indiana Coal Council has consistently requested.

- High Technology – This scenario assumes that technology costs decline faster than in the Reference Case, allowing renewables and battery storage to be more competitive without significant regulation. A low carbon tax is ultimately implemented. The economic outlook is better than in the Reference Case as lower technology costs and lower energy prices offset the impact of the carbon tax. Increased demand for natural gas is more than met with advances in key technologies that unlock more shale gas, increasing supply and lowering gas prices relative to the Reference Case. Less demand for coal results in lower coal prices. Utility-sponsored energy efficiency costs rise early in the forecast but ultimately fall back to below base levels due to technology advances, allowing for new and innovative ways to partner with customers to save energy. As technology costs fall, customers begin to move towards electrification, driving more electric vehicles and higher adoption of rooftop solar/energy storage and trend towards highly efficient electric heat pumps in new homes.

- 80% CO_2 Reduction by 2050 – This scenario assumes a carbon regulation mandating an ~80% reduction of CO_2 emissions from 2005 levels by 2050 is implemented. A gradually declining carbon cap drives carbon allowance costs up over time. Load decreases as the costs for energy and backup power increase and as the energy mix transitions. Natural gas prices remain at similar levels to the Reference Case as the impact of methane regulation is offset by lower demand and productivity increases that lower supply costs. Coal demand declines over time. Renewables and battery storage technologies are widely implemented to help meet the mandated CO_2 reductions. Despite this demand, costs are lower than the Reference Case due to subsidies or similar public support to address climate change concerns.

- High Regulatory – The High Regulatory scenario depicts a future of higher regulation resulting in higher costs of energy and some resulting economic slowdown. A high carbon fee set at the social cost of carbon is implemented early in the planning horizon (2022). Monthly rebate checks (dividend) redistribute revenues from the tax to American households based on number of people in the household. A fracking ban is imposed, driving up the cost of natural gas notably in the long-term as supply dramatically shrinks. Declining demand for coal results in coal prices lower relative to the Reference Case. With the higher costs, innovation occurs as renewables and battery storage are widely implemented to avoid paying high carbon prices, allowing costs to fall even as demand for these technologies increases. Utility-sponsored energy efficiency costs rise over time as the cost for regulatory compliance rises.

A summary of the relative outlooks for key market drivers across the scenarios considered is presented in Figure 2.5.

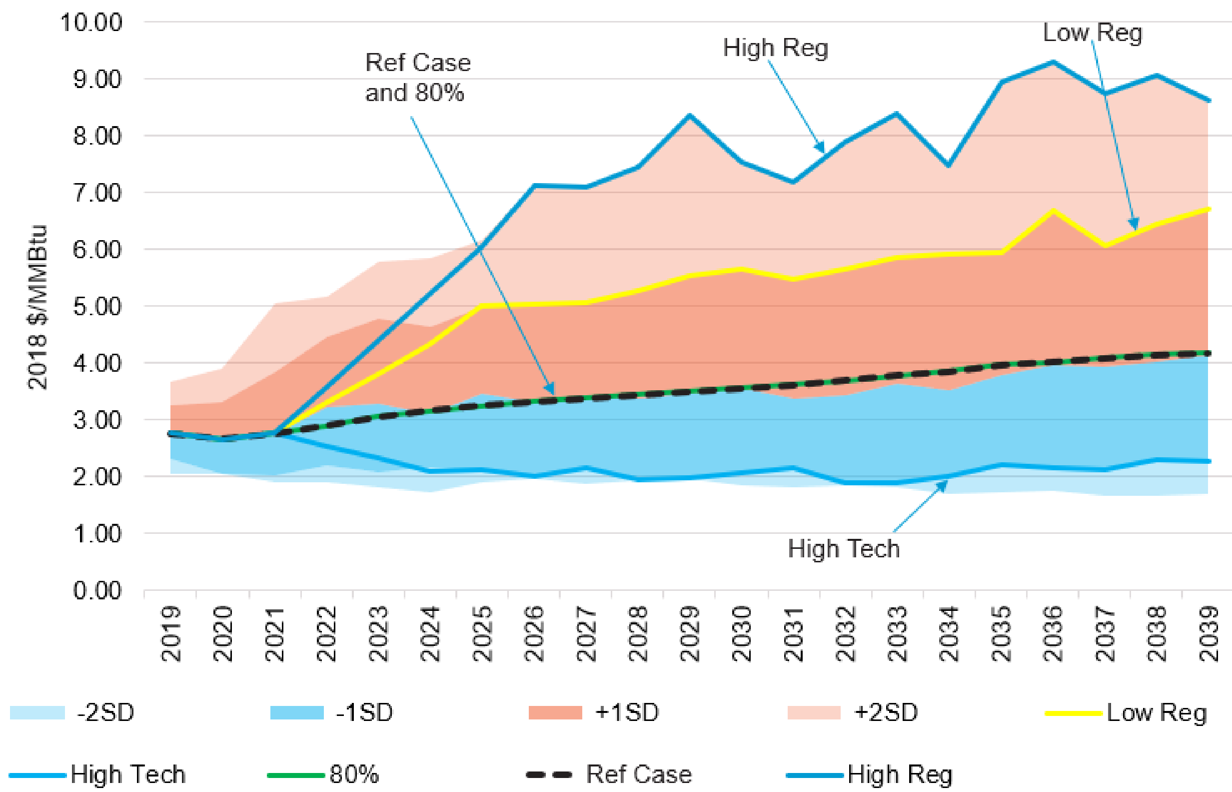
Figure 2.5 – Summary of Directional Relationships of Key Inputs Across Scenarios

	CO_2	Gas Reg.	Water Reg.	Economy	Load	Gas Price	Coal Price	Renewables and Storage Cost	EE Cost
Reference Case	ACE Replaced with CO_2 Tax	none	ELG	Base	Base	Base	Base	Base	Base
Low Regulatory	ACE	none	ELG Light*	Higher	Higher	Higher	Base	Base	Base
High Technology	Low CO_2 Tax	none	ELG	Higher	Higher	Lower	Lower	Lower	Lower
80% CO_2 Reduction by 2050	CO_2 Cap	Methane	ELG	Lower	Lower	Base	Lower	Lower	Higher
High Regulatory	High CO_2 Tax w/ Dividend	Fracking Ban	ELG	Base	Base	Highest (+2 SD)	Lower	Lower	Higher

*No bottom ash conversion required based on size of the unit and delay requirement for 2 years. Does not apply to Culley 3

Using the Reference Case as a consistent starting point, the boundary scenarios were developed. Key variables are assumed to remain the same as the Reference Case in the short-term (2019-2021). In the medium-term (2022-2028), key variables grow or decline to +/-1SD or (+/-2SD) by 2025 (midpoint of medium-term) as shown in the table above. After 2025, the variable stays at +/-1SD (or +/-2SD) into the long-term to 2039. Because this price path remains at the one (or two) standard deviation(s) path for the entire planning horizon, these levels have a low probability and are viewed as very wide. The five scenarios were designed to be consistent with the stochastic distributions (200 iterations) developed for the risk analysis, but on a much more limited scale (five scenarios). An illustration of this methodology for natural gas prices is presented in Figure 2.6

Figure 2.6 – Henry Hub Natural Gas Price Scenarios (2018$/MMBtu)



All gas prices begin at $2.77/MMBtu in 2019, dip slightly in 2020 and rise back to $2.76/MMBtu in 2021. After this time, the Reference Case gas prices gradually trend upward to $4.17/MMBtu in 2039. Gas prices in the other scenarios either follow the Reference Case or trend higher or lower, depending on the scenario's coordinated input direction. Gas prices in the High Regulatory scenario are designed to reach the +2 standard deviation level to replicate the price impact of a hydraulic fracturing ban, which would greatly limit domestic production, increase costs and put upward pressure on prices last seen prior to 2008 before the shale boom era began. The High-Tech scenario sees natural gas prices moving downward to -1 standard deviation below the Reference Case.

The convention of +/-1 standard deviation is used to maintain a consistent methodology and result when moving key market drivers up or down in each of the scenarios. It should be noted that the historical price distributions differ among the various market drivers are not necessarily symmetrical (i.e., normally distributed). For example, gas prices are positively skewed because they have no upper boundary and can reach many standard deviations above the historical average, whereas they typically cannot fall below zero (or approximately two standard deviations below the historical average).

Note that the selection of one standard deviation up in every year of the study means that the actual price in any one year may exceed that value 15.8% of the time, but over the entire 20 year planning horizon only about 5-7% of the time the price will exceed the price on the curve. Selecting a 2 standard deviation change, as was done for gas prices, means that only 2.2% of the time the price in any one year will exceed the value selected and over the 20-year planning horizon; the chances of a higher average price is less than 1 percent.

The graphical descriptions of values for each of the key metrics (e.g. load, gas prices, coal prices, technology costs, carbon prices and power prices) are shown in Section 7.3.2.2.

2.5 PORTFOLIO DEVELOPMENT

The portfolio development process was designed to test a wide range of technology options. An exhaustive list of technology options was developed and then refined. The viability of existing resources was considered as well as new resources including demand side measures of varying sizes and timeframes. The wide range of portfolio strategies was informed by stakeholder feedback as well as the All-Source RFP.

A Burns & McDonnell technology assessment defined the list of technologies and provided cost and performance information for resources. Where possible, technology costs from the All-Source RFP bids were utilized. Long-term cost projections were based on consensus estimates from three sources. These long-term cost estimates were averaged with outlooks from Pace Global and NREL to form the consensus technology cost projections over the planning horizon. A total of 30 resource options for power supply were included in the analysis. These included wind with and without storage, solar with and without storage, hydroelectric, landfill gas, several battery storage options, simple cycle and combined cycle natural gas and natural gas fired combined heat and power technologies. Note that Aeroderivative turbines and gas reciprocal engines were excluded based on the cost per KW and high gas pressure needed to run them. Two new coal-fired technologies were included, both of which were assumed to be equipped with carbon capture and storage.

An All-Source RFP was issued at the onset of the IRP process to obtain actual market information for near term indicative pricing for a wide range of technologies. The average delivered cost by resource informed the modeling and portfolio options. This included new builds, power purchase agreements, demand response and other supply options. The results of the All-Source RFP were vetted by Burns & McDonnell and ultimately converted into model inputs.

Long Term Capacity Expansion (LTCE) Assessments

The AURORAxmp power model (Aurora) was used as the central tool in the IRP to develop the 14 candidate portfolios in addition to the Reference Case portfolio. The long-term capacity expansion functionality within Aurora was used to develop least cost optimized portfolios based on the given sets of market input assumptions and portfolio requirements. This includes decisions to build, purchase, or retire plants.

Market transactions offer supply flexibility but also exposure to potential market risk to Vectren customers. In addition to the supply and demand side resource alternatives, portfolios were able to select market supply options as well. To reduce the risk that comes from exposure to the market, a limit of approximately ~15% of capacity needs, or 180 MW, was defined for annual capacity market purchases (except in a transitional year). This is much more than the 2016 IRP where a 10 MW cap was utilized and is responsive to the Commission Order 45052, which said Vectren did not fully consider energy or capacity purchases.

Portfolios were selected in a few different ways.

- Least cost portfolios were developed for the Reference Case and the other market and regulatory scenarios (5 Portfolios)
- Least cost portfolios with some modifications to existing units
- Stakeholder driven least cost portfolios

Portfolios were developed utilizing AURORA's LTCE modeling for the Reference Case and the four alternate scenarios. The model uses hourly chronological dispatch over a 20-year period, which means that outcomes are based on all 8,760 hours each year over a 20-year span. This helped to better evaluate intermittent renewable and storage resources.

In addition, alternative portfolios were developed by Vectren and based on stakeholder input to specifically test alternate resource strategies. These include the following additional 10 resource portfolios:

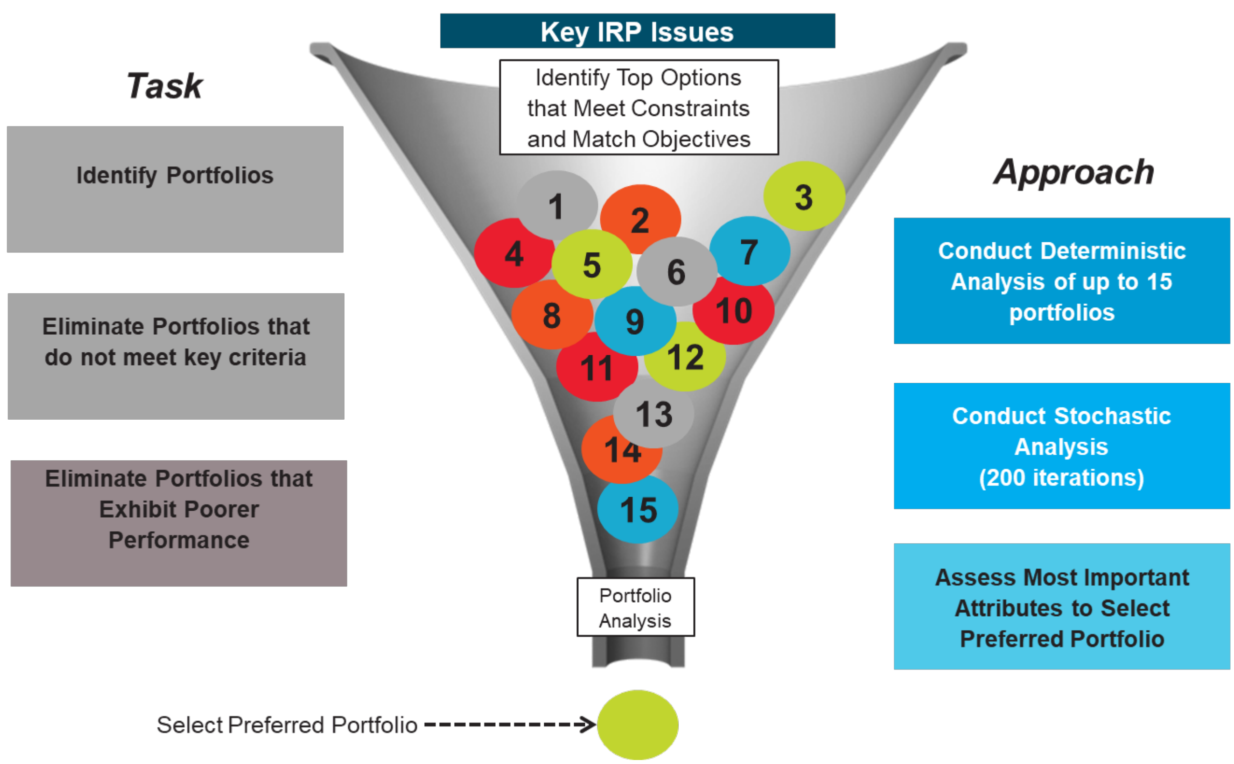
1. Business as usual to 2039 including the continued operation of all existing units (joint operations of Warrick 4 ends by 2024);
2. Bridge with business as usual to 2029, including the continued operation of A.B. Brown units 1 & 2 through 2029;
3. Bridge in which A.B. Brown 1 is converted to natural gas;
4. Bridge in which both A.B. Brown 1 and 2 are converted to natural gas;
5. Bridge in which A.B. Brown 1 is converted to natural gas and a CCGT is added;
6. Diverse energy portfolio including a new small (443 MW) natural gas CCGT;
7. Diverse energy portfolio including a new medium (511 MW) natural gas CCGT;
8. Renewables portfolio utilizing a combination of renewables, storage and peaking natural gas;

9. Renewables portfolio with no fossil technology options allowed in the portfolio by 2030; and
10. Portfolio based on HB 763 CO_2 price, which reaches $200/ton by the end of the study period.

In each of these LTCE assessments, the refinement for each portfolio, whether it be a modification to an existing unit or requiring the addition of a CCGT as a minimum requirement was required as part of a portfolio and then the model selected the remainder of the portfolio on a least cost basis.
Figure 2.7 – Structured Portfolio Selection Process illustrates the portfolio screening process applied in the analysis to select the preferred portfolio.

As described in Section 8, Vectren selected 10 of the 15 least cost portfolios for evaluation in the risk analysis. The selection criteria for eliminating the five portfolios are provided in that section.

Figure 2.7 – Structured Portfolio Selection Process



2.6 PORTFOLIO PERFORMANCE (SCENARIO BASED RISK ASSESSMENT)

The framework of the Indiana law mandating a triennial IRP[17] also requires the creation of alternative future scenarios with unique sets of inputs. Each candidate portfolio must be modeled in a dispatch run using these scenario-based inputs, which can provide a complementary view of portfolio strengths and weaknesses, separate from the probabilistic analysis that serves as the basis for scorecard measures. Four alternative scenarios were created (Low Regulatory, High Technology, 80% Reduction of CO_2 and High Regulatory), each with a unique set of inputs. All 10 candidate portfolios were modeled in a separate dispatch run for each of the four alternative scenarios.

AURORA is run in a market simulation mode holding each of the Vectren portfolios constant but allowing other MISO members to modify its decisions on the basis of the Scenario selected. The results of the scenario-based risk analysis are summarized in Section 8.2.1.

2.7 PORTFOLIO PERFORMANCE (PROBABILISTIC OR STOCHASTIC MODELING RISK ASSESSMENT)

Probabilistic modeling incorporates several market variables and probability distributions into the analysis, allowing for the evaluation of a portfolio's performance over a wide range of market conditions. Quantitative data is extracted from the results and is the foundation for the balanced scorecard and key drivers portion of the risk analysis. Probabilistic modeling begins with the development of 200 sets of future pathways for coal prices, natural gas prices, carbon prices, peak and average load (at the Vectren, MISO Local Resource Zone 6 (LRZ6) and MISO levels) and capital costs for a range of technologies. Each of these stochastic variables is propagated to the end of the study period, typically 1,000 to 3,000 times. A stratified sampling of the runs is taken, which allows the sample set to be reduced to 200 iterations. These 200 iterations of each stochastic variable are

[17] Indiana Code § 8-1-8.5

then loaded as inputs into the dispatch model. These inputs thus allow for the testing of each portfolio's performance across a wide range of market conditions.

Once again, all 10 portfolios were subjected to each of the 200 iterations (scenarios) using AURORA in dispatch mode where the Vectren portfolio is fixed but other MISO members can make decisions under each market scenario.

2.8 SENSITIVITY ANALYSIS

Vectren conducted several sensitivities in order to put brackets around resulting portfolios when one or more variables were adjusted. Sensitivities were also conducted to ensure seasonal Planning Reserve Margin (PRM) targets are met and that the candidate portfolio buildouts are calibrated to the greatest annual constraint, which occurs in the summer peak period.

- Vectren ran sensitivities to compare portfolio buildouts with winter solar/wind peak capacity credit on winter peak demand versus portfolio buildouts with summer solar/wind peak capacity credit on summer peak demand. Portfolios that are overly reliant on solar generation may risk not meeting MISO Planning Reserve Margin Requirements in the winter, as rules continue to evolve.
- Vectren performed sensitivities using a seasonal PRM target and seasonal peak capacity accreditation (solving to monthly peak hour). This sensitivity resulted in a solar peak capacity credit that approached zero as the Vectren system approached 2,000+ MW solar.
- Vectren performed a sensitivity in which the cost of a solar PPA resources increases 30%, based on more recent market information. The sensitivity demonstrated that even with increased costs, the solar PPA costs remain below the market clearing on-peak price of $42-45/MWh and continue to be selected as economic portfolio additions.
- Vectren conducted sensitivities to right-size several portfolios that had more capacity than needed in the early years of the transition from the point of view of the PRM target, but the model selects several early resources to capture the

benefits of the wind Production Tax Credit and solar Investment Tax Credit. Early solar and wind resources help to lower total cost of each portfolio.

- Sensitivities were run on the Reference Case and High Technology portfolios, swapping combustion turbine capacity for storage capacity. Portfolio costs rose as a result, but costs can vary widely depending on whether augmentation (replace dead battery cells) and other costs are fully incorporated into the bid price.
- A sensitivity was run on the Reference Case to assess 1.25% energy efficiency (EE) in the near-term as compared to the selected 0.75% EE in the near-term, which raised portfolio costs by 0.15%. As such, 1.25% was included in all portfolios for the first 3 years.

2.9 BALANCED SCORECARD

The Risk Analysis (based on the probabilistic modeling) of each of the portfolios was developed by Pace Global using the AURORAxmp dispatch model. There were several steps to this process:

- The first step was to develop the input distributions for each of the major market and regulatory drivers, including average and peak load growth and shape, natural gas prices, coal prices, carbon prices and technology capital costs. This was done by considering volatility of each factor in the short-term, medium-term and long-term.
- The second step was to run a probabilistic model (Monte Carlo) which selected 200 possible future states over the 20-year study planning period. This also formed the basis for the scenario inputs development.
- Each candidate portfolio was then run through simulated dispatch for the 200 possible future states using the AURORAxmp production cost model. AURORAxmp dispatches the candidate portfolio for each sampled hour over the

planning horizon. For this risk analysis procedure, AURORAxmp assumes that each Vectren candidate portfolio is constant but allows for builds and retirements to occur throughout the region based on economic criteria. Vectren generation, costs, emissions, revenues, etc. are tracked for each iteration over time.

- Next, values for each metric are tracked across all 200 iterations and presented as a distribution with a mean, standard deviation and other metrics as needed.
- These measures are used as the basis for evaluation in the balanced scorecard.

The results of risk analysis can be found in Section 8 Portfolio Development and Evaluation

2.10 SELECTION OF THE PREFERRED PORTFOLIO

The risk analysis includes scenario modeling, probabilistic modeling, sensitivity and other analyses to inform judgment in the selection of the preferred portfolio. In addition, a key part of selecting the preferred portfolio was based on how well each portfolio met multiple objectives as outlined in Section 2.3, under 200 iterations representing different, but internally consistent and plausible market condition scenarios. The selection process consisted of several comparisons illustrating each candidate portfolio's performance measured against competing objectives. The goal is to create the right balance between satisfying the competing objectives. The preferred portfolio delivered the best balance of performance across all competing metrics when viewed across the full range of 200 iterations, while also maintaining reliability and providing resource diversity/system flexibility. To help illustrate tradeoffs, Vectren used a Balanced Scorecard, as shown below in Figure 2.8 and further discussed in Section 8.

Figure 2.8 – Balanced Scorecard Illustration

Balanced Scorecard		Objective	Affordability	Price Risk Minimization	Environmental Risk Minimization	Market Risk Minimization		Market Risk Minimization	
		Metric	20-Year NPVRR ($million)	95th percentile NPVRR ($million)	Life Cycle GHG Emissions (million tons CO2e reduction 2019-2039)	Energy Market Purchases & Sales (% of generation)		Capacity Market Purchases & Sales (% of peak demand)	
No	Group	Candidate Portfolio							
						Purch	Sale	Purch	Sale
1	Reference	Reference Case							
2	BAU	BAU to 2039							
3		BAU to 2029							
4	Bridge	ABB1 gas conversion							
5		ABB1+ABB2 gas conversions							
6		ABB1 gas conversion + CCGT							
7	Diverse	Diverse Small CCGT							
8	Renewables	Renewables+ Flexible Gas							
9		Renewables 2030							
10	Scenario	High Technology							

The preferred portfolio represents Vectren's assessment, based on the analysis, of an appropriate balance between all identified objectives (See Figure 2.2) under a wide range of future conditions.

SECTION 3
PUBLIC PARTICIPATION PROCESS

3.1 PUBLIC PARTICIPATION PROCESS

Vectren reevaluated how to conduct the stakeholder process based on comments in the Director's report, stakeholder feedback and the Commission order in Cause number 45052. Careful consideration was given to improve the process. As a result, significant stakeholder input was directly included in key areas of the IRP, including but not limited to portfolio development, scenario development; scorecard development (metrics and measures), and modeling inputs such as energy efficiency inputs. While improvements have been made, Vectren's objectives for stakeholder engagement remain the same:

- **Listen**: Understand concerns and objectives
- **Inform**: Increase stakeholder understanding of the Integrated Resource Plan process, key assumptions and the challenges facing Vectren and the electric utility industry
- **Consider**: Provide a forum for relevant, timely stakeholder feedback at key points in the Integrated Resource Plan process to inform Vectren's decision making

IRP stakeholders include, but are not limited to, Vectren residential, commercial and industrial customers, regulators, customer advocacy groups, environmental advocacy groups, fuel suppliers and advocacy groups, shareholders and elected officials.

In the first public stakeholder meeting, Vectren publicly made 12 commitments and followed through with all throughout the process:

1. To strive to make every encounter meaningful for stakeholders and for us
2. To provide a data release schedule and provide modeling data ahead of filing for evaluation
3. That the IRP process informs the selection of the preferred portfolio
4. To utilize an All-Source RFP to gather market pricing & availability data
5. To use one model for consistency in optimization, simulated dispatch and probabilistic functions
6. To attempt to model more resources simultaneously

7. To include a balanced, less qualitative risk score card
8. To work with stakeholders on portfolio development
9. To test a wide range of portfolios in scenario modeling and ultimately in the risk analysis
10. To conduct a sensitivity analysis
11. To take an exhaustive look at existing resource options
12. That the IRP will include information presented for multiple audiences (technical and non-technical)

The first three stakeholder meetings began with stakeholder feedback. Vectren would review all requests since the last stakeholder meeting and provide feedback. Often suggestions were incorporated, but in instances where suggestions were not. Vectren made a point to discuss further and explain why not. Per stakeholder feedback, 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 phone calls/meetings in between each session per request. The final meeting was a preview of the preferred portfolio and a discussion of analysis. Due to COVID, this meeting was held via webinar.

The first three public stakeholder meetings were held at Vectren headquarters in Evansville, IN. Dates and topics covered are listed below:

Figure 3.1 – 2019/2020 Stakeholder Meetings

August 15, 2019

- 2019/2020 IRP Process
- Objectives and Measures
- All-Source RFP
- Environmental Update
- Draft Reference Case Market Inputs & Scenarios

October 10, 2019

- RFP Update
- Draft Resource Costs
- Sales and Demand Forecast
- DSM MPS/ Modeling Inputs
- Scenario Modeling Inputs
- Portfolio Development

December 13, 2019

- Draft Portfolios
- Draft Reference Case Modeling Results
- All-Source RFP Results and Final Modeling Inputs
- Scenario Testing and Probabilistic Modeling Approach and Assumptions

June 15, 2020

- Final Reference Case and Scenario Modeling Results
- Probabilistic Modeling Results
- Risk Analysis Results
- Preview the Preferred Portfolio

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

3.2 KEY ISSUES DISCUSSED

Throughout the process Vectren engaged stakeholders on all key inputs into the IRP, which helped shape the outcome of the analysis. In the first stakeholder meeting, Vectren presented a draft balanced scorecard which was used to evaluate key tradeoffs among portfolios. Adjustments were made and presented to stakeholders before modeling commenced. Vectren worked closely with stakeholders to develop scenario concepts and helped to refine various scenario inputs. Additionally, stakeholders provided input into portfolio development, which helped to provide a wide range of portfolios, included continuation of the Brown coal units through 2029 or 2039 and an all renewables portfolio by 2030.

3.3 STAKEHOLDER INPUT

During the 2019/2020 IRP, stakeholders provided their input in several ways: 1) verbal feedback through question/answer sessions during public stakeholder meetings; 2) through participation in Vectren stakeholder workshops; 3) via written feedback/requests; 4) telephone conversations; and 5) meetings between stakeholder sessions.

Vectren worked diligently to have an open forum for stakeholders to voice questions/concerns and make suggestions on the IRP analysis. Each Vectren stakeholder meeting was opened by Lynnae Wilson, Chief Business Officer for Indiana Electric. She and other senior management, Vectren subject matter experts and expert consultants actively participated in each meeting to help address stakeholder questions/concerns.

Below is a summary of key feedback during the 2019/2020 IRP that heavily influenced the analysis. For a full list, see the technical appendix Technical Appendix Attachment 3.1 Stakeholder Materials.

Figure 3.2 – Summary of Key Stakeholder Input

Request	Response
Update the High Regulatory scenario to include a carbon fee and dividend	Included a fee and dividend construct which assumed less impact on the economy/load
Lower renewables costs in the High Regulatory and 80% CO_2 Reduction scenarios	Updated scenario to include lower costs for renewables and storage than the Reference scenario
Consider life cycle emissions using CO_2 equivalent	Included a quantitative measure on the risk scorecard based on National Renewables Energy Laboratory (NREL) Life Cycle

Request	Response
	Greenhouse Gas Emissions (CO_2e) from Electricity Generation by Resource
Include a measure within the risk score card that considers sunk costs	Vectren worked with Pace Global to create an uneconomic asset risk measure. Ultimately, this measure was considered but not included within the scorecard, it did not fulfil the initial intention, to evaluate risk of resources with large initial capital investments
Include a scenario with a carbon dividend modeled after HB 763 with a CO_2 price curve that was approximately $200 by the end of the forecast	Ran a sensitivity to create a portfolio. Ultimately, this was not selected for the risk analysis, as the amount of generation built within modeling vastly exceeded Vectren's need
Reconsider the use of a seasonal construct for MISO resource accreditation	Reviewed calculation for solar accreditation in winter and utilized an alternate methodology, increasing accreditation in the winter
Include a CO_2 price in the reference case	Included a mid-range CO_2 price curve 8 years into the forecast. The low regulatory scenario did not include a CO_2 price, and remains a boundary condition

3.4 DATA REQUESTS SUMMARY

One of the key data requests made was to provide access to all-source RFP bids. While protecting confidentiality commitments to bidders' competitively sensitive information, Vectren provided two consumer groups (OUCC and CAC) who signed a NDA with electronic read-only access via a locked down SharePoint site. A data key was provided for convenience to show the difference between tier one and tier two bids and many attributes of each bid. Additionally, Vectren received a data request from the CAC on December 9, 2019. Per their request, Vectren provided wind and solar resource shape files, input files utilized in the load forecast for regression modeling along with documentation, probabilistic modeling distributions for natural gas, capital cost, carbon price and peak load and costs associated with the retirement of existing thermal units.

CAC also requested modeling files as a part of their review process, prior to filing the IRP. In order to accommodate this request, Vectren worked with them to provide files to the OUCC and CAC on May 15, 2020 in preparation for the final stakeholder meeting on June 15th. Vectren held a discussion with these stakeholders on May 26th to answer questions and walk them through the file formats. Vectren worked to answer questions leading into and after the final IRP stakeholder meeting.

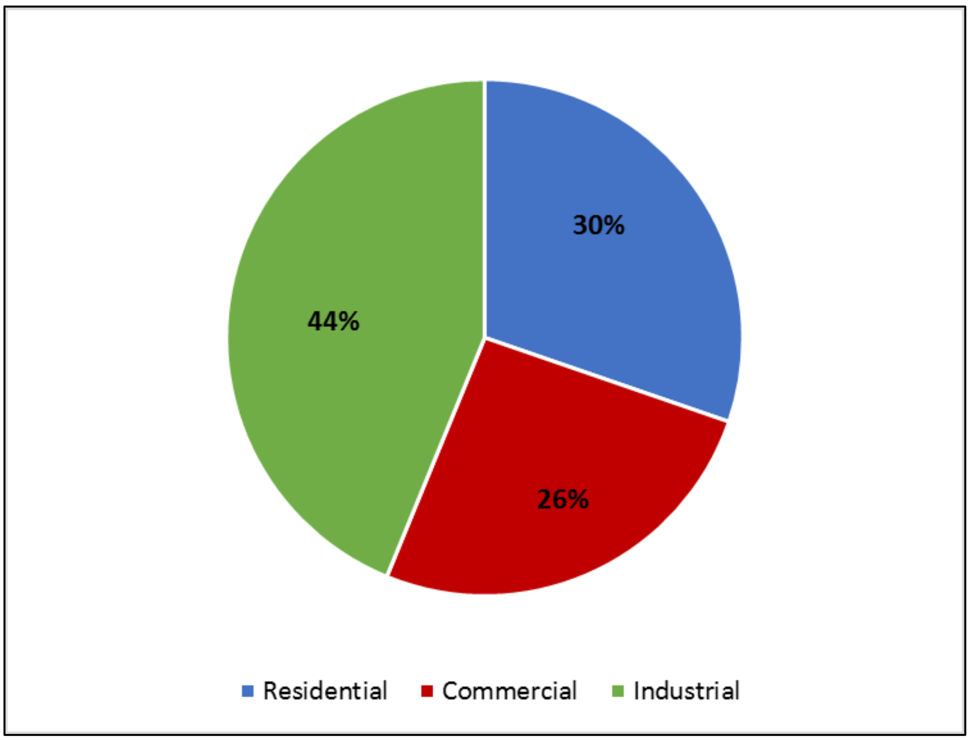
CAC also issued Data Request 2 on 6-5-20, Data Request 3 on 6-10-20 and Data Request 4 on 6-11-20. Vectren provided responses ahead of the required timeframe and before the filing of the IRP.

SECTION 4
CUSTOMER ENERGY NEEDS

4.1 CUSTOMER TYPES

Vectren serves more than 146,000 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 energy sales in 2018. The residential class accounts for 30% of sales with approximately 128,000 customers and the commercial class 26% of sales; there are approximately 18,000 nonresidential customers. System 2018 energy requirements were 5,308 GWh with non-weather normalized system peak reaching 1,039.2 MW. Figure 4.1 shows 2018 class-level sales distribution.

Figure 4.1 – 2018 Vectren Sales Breakdown



4.2 FORECAST DRIVERS AND DATA SOURCES

The main drivers of the energy and demand forecast include the following: historical energy and demand data, economic and demographic information, weather data, equipment efficiencies and equipment market share data.

Itron used over ten years of historical energy and demand data within the energy and demand forecasts. This data is maintained by Vectren in an internal database and was provided to Itron. Energy data is aggregated by rate class for the purposes of forecasting. There are two major rate classes for residential customers: the standard residential rate and the transitional electric heating rate (rate closed to new premises). Information for these rates is combined for the purposes of forecasting residential average use per customer. Similarly, small commercial (general service) rates are combined to produce the commercial forecast and large customer rates are combined to produce the industrial forecast. The demand forecast utilizes total system demand.

Economics and demographics are drivers of electricity consumption. Historically, there has been a positive relationship between economic performance and electricity consumption. As the economy improves, electricity consumption goes up and vice versa. Economic and demographic information was provided by Moody's Economy.com, which contains both historical results and projected data throughout the IRP forecast period. Examples of economic variables used include, but are not limited to, population, income, output and employment.

Weather is also a driver of electric consumption. Vectren's peak demand is typically in summer when temperatures are hottest. Air conditioning drives summer usage. Normal weather data is obtained from DTN, a provider of National Oceanic and Atmospheric Administration (NOAA) data. Vectren utilizes data over a 20-year period for the sales forecast and a 20-year period for the demand forecast in order to capture recent weather activity.

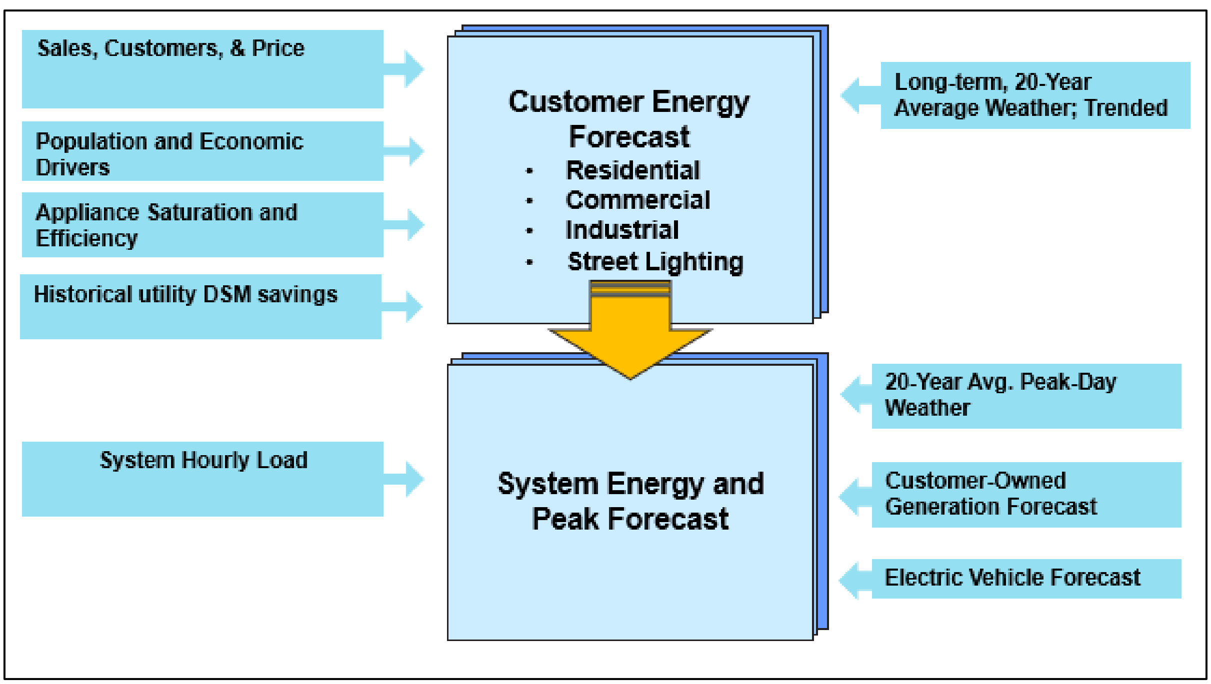
Itron, Inc. provides regional Energy Information Administration (EIA) historic and projected data for equipment efficiencies and market shares. This data captures projected changes in equipment efficiencies based on known codes and standards and market share projections over the forecast period, including but not limited to the following:

electric furnaces, heat pumps, geothermal, central air conditioning, room air conditioning, electric water heaters, refrigeration, dish washers, dryers, etc. Residential market share data was adjusted to Vectren's service territory based on the latest appliance saturation survey data.

4.3 MODEL FRAMEWORK

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 4.2 shows the general framework and model inputs.

Figure 4.2 – 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 changing appliance ownership trends, end-use efficiency changes, increasing housing square footage and thermal shell efficiency improvements. Changing structural components are captured in the residential and commercial sales forecast models through a specification that combines economic drivers with end-use energy intensity trends. 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 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.

4.4 CUSTOMER OWNED DISTRIBUTED ENERGY RESOURCES

Distributed generation (DG) is an electrical source interconnected to Vectren's transmission or distribution system at the customer's site. The power capacity is typically small when compared to the energy companies' centralized power plants. DG systems allow customers to produce some or all of the electricity they need. By generating a portion or all of the electricity a customer uses, the customer can effectively reduce their electric load. With respect to Vectren's electric service territory, DG will likely take these forms:

Small – 10 kW and under – roof-top photovoltaic (PV) systems, small wind turbine, etc. interconnected at distribution secondary voltage (120/240 V, etc.)

Medium – 10 kW to 10 MW – large scale PV systems, wind turbine(s), micro-turbine(s), etc. interconnected at distribution primary voltage (4 kV or 12 kV)

Large – 10 MW and over – heat recovery steam generator, combustion turbine, etc. interconnected at transmission voltage (69 kV and over)

Most renewable DG systems only produce power when their energy source, such as wind or sunlight, is available. Due to the intermittency of the power supply from DG systems, there will be times when the customer needs to receive electricity from Vectren. Conversely, when a DG system produces more power than the customer's load, excess power can be sent back to Vectren's electric system through a program called net metering. The customer is charged the retail rate for the net power that they consume.

4.4.1 Current DG

As of December 2019, Vectren had approximately 486 residential solar customers and 71 commercial solar customers, with an approximate installed capacity of 10.7 MW. Based on recent solar installation data, the residential average size is 10.5 KW, while the commercial average system size is 78.7 KW. Vectren has incorporated a forecast of customer owned photovoltaic systems into the sales and demand forecast.

Vectren monitors Combined Heat and Power (CHP) developments in its service area and adjusts the load forecast for any known, future customer owned CHP installations. A large CHP system went into service on Vectren's system in 2017.

4.4.2 Solar DG Forecast

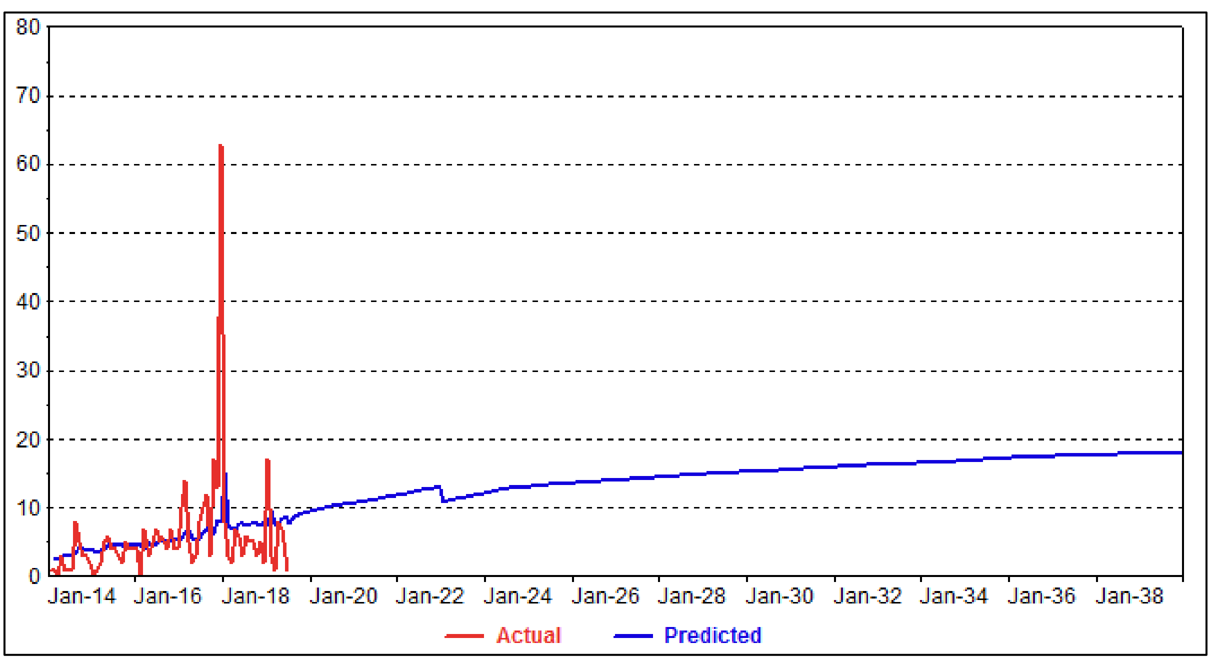
The energy and peak forecasts incorporate the impact of customer-owned photovoltaic systems. System adoption is expected to increase as solar system costs decline.

The primary factor driving system adoption is a customer's return-on-investment. Itron created a simple payback model, which was 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 generated from the system is considered "free." Solar investment payback is calculated as a function of system costs, tax credits, and incentive payments, retail electric rates and treatment of excess generation (solar generation returned to the grid). Currently, excess generation is credited at the customer's retail rate. While current net metering customers will be credited the retail rate, DG installed beyond 2021 will be credited at the wholesale cost plus 25%.

One of the most significant factors driving adoption is declining system costs, which have been declining rapidly over the last several years. In 2010, residential solar system cost was approximately $7.00 per watt. By 2017 costs had dropped to $3.70 per watt. For the forecast period, Itron assumed system costs will continue to decline 10% annually through 2024 and an additional 3% annually after 2024. Customer owned solar cost projections are consistent with the U.S. Dept. of Energy's Sun Shot Solar goals and national trends.

The solar adoption model relates monthly residential solar adoptions to simple payback. Figure 4.3 shows the resulting residential solar adoption forecast.

Figure 4.3 – Residential Solar Share 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. Some challenges to commercial adoption are 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, Itron assumed 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.

As shown in Figure 4.4, installed capacity of solar is expected to increase at a compound annual growth rate of 10.9% with 84.3 MWs by 2039.

Figure 4.4 – Solar Capacity and Generation

Year	Total Generation MWh	Installed Capacity (Aug) MW	Demand Impact MW
2019	20,144	9.3	2.7
2020	23,260	11.8	3.5
2021	26,856	14.6	4.3
2022	30,834	17.6	5.2
2023	34,842	20.7	6.1
2024	38,999	23.8	7.0
2025	43,290	27.1	8.0
2026	47,880	30.6	9.0
2027	52,577	34.2	10.1
2028	57,535	37.9	11.2
2029	62,462	41.7	12.3
2030	67,499	45.6	13.4
2031	72,742	49.6	14.6
2032	78,272	53.6	15.8
2033	83,492	57.7	17.0
2034	89,074	62.0	18.3
2035	94,787	66.3	19.5
2036	100,707	70.6	20.8
2037	106,394	75.1	22.1
2038	112,446	79.7	23.5
2039	118,499	84.3	24.8
CAGR 2020-2039	8.9%	10.9%	10.9%

4.4.3 Potential Effects of Distributed Generation on Transmission and Distribution

Distributed Generation customers currently affect a small amount of load on each respective distribution circuit, which has not caused significant operational issues for Vectren. At higher levels of DG penetration, Vectren would encounter more operational issues and would need to allocate more resources to mitigate these issues. Some examples of potential issues would include:

- **High voltage mitigation** – With a high penetration of DG, distribution feeder voltage profiles could become unacceptably high when light loading periods coincide with high DG output.

- **Protection system modifications** – Traditionally, electric distribution feeders have been designed as unidirectional from the energy company to the customer. Voltage regulation and feeder protection strategies are designed based on this premise. With high DG penetration under light load with high DG output, power flow could reverse from the customer to the energy company.
- **Power quality and harmonics mitigation** – Power quality issues are one of the major impacts of high photovoltaics penetration levels on distribution networks. Power inverters used to interface PV arrays to power grids increase the total harmonic distortion of both voltage and current, which can introduce heating issues in equipment like transformers, conductors, motors, etc.
- **Short term load forecast uncertainty** – At higher levels of DG penetration, short term load forecasting becomes more difficult. DG resources work to offset the customer's load, but their output can be variable depending upon weather conditions. A load forecasting technique would need to be implemented that is more granular and more responsive to short-term weather conditions.
- **Capacitor banks on the distribution feeders** – Capacitor banks are used to improve power factor and maintain acceptable voltages along the lines. These are strategically placed based on load/distance from the normal source (substation). Once additional sources (DG) are added to the circuits, capacitor bank placement will need to be reevaluated.
- **Electric Rates** – Vectren's electric rates are designed to recover the fixed costs of providing service (transmission, distribution, metering, etc.) via energy and (for large customers) demand charges, along with an associated fixed monthly customer facilities charge. The fixed monthly charge does not reflect the full amount of fixed costs that Vectren incurs to provide retail electric service. DG customers (who generate a portion of their own electricity but still rely on the electric grid) avoid paying towards the recovery of the fixed costs of the grid that are recovered through the energy charge, which leads to Vectren's under recovery of the cost of providing service. Over time, as base rates are updated periodically,

recovery of these costs shifts to non-net metering customers, resulting in a subsidy to net metering customers.

- **Transmission Power Flows –** High DG penetration impact power flow on transmission lines. Depending on the concentration and location of these resources, the transmission system may need to be reconfigured, with consideration given to the dependency of the resources on the weather (wind, solar, etc.). High DG penetration may also impact flows on transmission system tie lines to other entities and require additional mitigations, such as installation of reactors or phase shifters to control flows.
- **Generation Reserves** – With the output of DG being weather dependent, the remaining fleet of generators and the electric system must be capable of quickly reacting to the fast and potentially large generation changes on the system, as well as providing generation support during times when DG will not be available (such as nighttime for solar DG). The adoption of Electric Vehicles could also lead to increased load demand in the nighttime hours as they are charging. These issues will need to be evaluated and potentially require mitigations such as storage facilities, quick start generators, etc.
- **Additional Operational Challenges** – High DG penetration causes additional challenges to operate the electric system in a safe and reliable manner due to loss of inertia on the power system by replacing traditional rotating machine generators (high inertia) with inverter-based generators (no/low inertia). These challenges include maintaining spinning and quick start reserves, power system frequency fluctuations and increased system operations (tripping), among others. Each of these issues would need to be evaluated and potentially mitigated to maintain reliable and safe power system operation.

4.5 ELECTRIC VEHICLES

4.5.1 Current EVs

In 2019, Vectren estimated 238 registered electric vehicles were in the counties that Vectren 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. This estimate was based on Indiana BMV registration data for the counties that Vectren serves. Vectren purchases quarterly from the BMV a list of vehicle registrations for the counties that Vectren serves.

4.5.2 EV Forecast

As electric vehicles are gaining more traction in the vehicle market, Vectren decided to include an electric vehicle forecast in the 2019/2020 IRP. As described in the 2019 Long-Term Electric Energy and Demand Forecast Report in the Technical Appendix of this IRP, Itron created an electric vehicle forecast utilizing the Energy Information Administration (EIA) Annual Energy Outlook (AEO) transportation forecast to estimate the number of cars per household over time. This number is multiplied by the forecast of residential customers to create a projected number of vehicles per Vectren household. Itron then applied the EIA AEO projected saturation of battery electric vehicles and plug in hybrid electric vehicles.

Electric vehicles' impact on Vectren'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 Vectren'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 Vectren does not have incentivized BEV/PHEV off-peak charging rates, it is assumed that most of the charging will occur at home in the evening hours. Table 4.5 shows the electric vehicle forecast.

Figure 4.5 – Electric Vehicle Load Forecast

Year	BEV MWh	PHEV MWh	Total EV MWh	Demand Impact MW (Aug)	Demand Impact MW (Jan)
2019	432	305	737	0.1	0.1
2020	1,063	580	1,643	0.2	0.1
2021	2,667	1,110	3,777	0.4	0.3
2022	6,691	2,124	8,815	1.0	0.6
2023	14,769	3,732	18,501	2.1	1.4
2024	19,178	4,503	23,681	2.5	2.2
2025	22,770	5,106	27,876	2.9	2.7
2026	26,320	5,697	32,017	3.3	3.1
2027	29,838	6,275	36,113	3.8	3.5
2028	33,334	6,837	40,171	4.2	3.9
2029	36,869	7,392	44,261	4.6	4.3
2030	40,467	7,933	48,400	5.0	4.8
2031	44,164	8,455	52,619	5.5	5.2
2032	47,920	8,959	56,878	5.9	5.6
2033	51,735	9,438	61,173	6.3	6.1
2034	55,591	9,895	65,486	6.8	6.5
2035	59,461	10,327	69,788	7.2	7.0
2036	63,315	10,741	74,056	7.7	7.4
2037	67,111	11,137	78,248	8.1	7.8
2038	70,863	11,510	82,373	8.5	8.3
2039	74,607	11,872	86,479	8.9	8.7
CAGR 2020-2039	25.1%	17.2%	23.2%	22.7%	25.7%

4.5.3 Potential Effects on Generation, Transmission and Distribution

Electric Vehicles and their associated charging stations currently have a minimal impact on the Vectren electric system and therefore have not caused significant operational issues. As the level of EV charging stations increases, Vectren may encounter multiple operational issues that will need to be evaluated and potentially mitigated. Some examples of potential issues include:

- **Shifting Peak Load** – Increased use of EV will have an impact on the magnitude of daily load demand, as well as the timing of peak loading. If a large concentration of EV charging occurs in the late afternoon and early evening, the daily system peak could be shifted to later in the afternoon or a second (and most likely lesser) peak could occur in the evening.
- **Generation Reserves** – If EV charging largely occurs in the evening or overnight, the electric system would see higher than typical load demand values at times when DG and other solar generation installations would not be available. This would lead to a need for generation support during these hours, such as energy storage facilities, quick start generators, etc.
- **Peak Charging** – If a large portion of EV charging were to occur during peak loading times, the impact of the increased demand could lead to overloaded electrical infrastructure, unless some form of delayed or managed charging is available. These overloaded facilities would need to be upgraded or other system level upgrades would be needed to mitigate the overload conditions.
- **Transmission Planning Concerns** – MISO performs economic studies annually using a range of potential futures. The futures that they are currently evaluating include potential increases in electrification (including EV) at various growth levels. Due to the uncertainty around EV adoption and the differing values being analyzed, uncertainties as to when to complete transmission system upgrades to support a higher level of system peak load due to EV adoption may be introduced. A need for additional planning models and sensitivity analysis would be required to evaluate these uncertainties and determine the appropriate time to perform the needed transmission system upgrades.

- **Dynamic Behavior** – The dynamic behavior of these loads while in a charging state during fault conditions and during re-energization post fault condition is an additional issue that will need to be evaluated. Research is still needed to properly reflect how these types of loads respond from a dynamic behavior perspective and may require additional dynamic modeling for planning studies.

If there is a substantial increase in EV adoption within the next 10 years, it is anticipated that there would be a significant change in the system load profile. As an example, the system peak load hour could shift to later in the day. The load profile and generation expansion implications of the changing load shape suggest that EV adoption and resulting vehicle charging patterns should be monitored in the upcoming years.

4.6 ENERGY AND DEMAND FORECAST (REFERENCE CASE)

For the IRP filing, the long-term energy and demand forecast does not include energy savings from future DSM programs; DSM activity is considered a supply option and not a reduction to demand. Excluding DSM, total energy requirements and peak demand are expected to average 0.6% annual growth over the next 20 years. The table below shows Vectren's energy and demand forecast; the forecast includes the impact of customer owned distributed generation, electric vehicles, trended weather (warmer summers and winters), company owned distributed generation (solar and landfill gas) and customer EE outside of energy company sponsored programs but excludes future energy company sponsored DSM program savings. For more information on Vectren long-term energy and demand forecasts, including load shapes, see Technical Appendix Attachment 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report.

Figure 4.6 – Energy and Demand Forecast[18]

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2019	5,147,837		1,115		826	
2020	5,374,079	4.4%	1,100	-1.4%	831	0.6%
2021	5,380,877	0.1%	1,102	0.2%	828	-0.3%
2022	5,505,660	2.3%	1,126	2.2%	847	2.3%
2023	5,742,090	4.3%	1,168	3.7%	886	4.6%
2024	5,774,656	0.6%	1,173	0.5%	891	0.5%
2025	5,789,928	0.3%	1,176	0.3%	891	0.1%
2026	5,807,569	0.3%	1,179	0.3%	892	0.1%
2027	5,828,395	0.4%	1,183	0.3%	894	0.2%
2028	5,858,975	0.5%	1,189	0.5%	898	0.4%
2029	5,874,831	0.3%	1,192	0.3%	898	0.1%
2030	5,891,575	0.3%	1,196	0.3%	899	0.1%
2031	5,909,760	0.3%	1,200	0.3%	900	0.1%
2032	5,934,963	0.4%	1,205	0.4%	902	0.3%
2033	5,949,314	0.2%	1,209	0.3%	902	0.0%
2034	5,970,284	0.4%	1,214	0.4%	903	0.1%
2035	5,992,643	0.4%	1,219	0.4%	905	0.2%
2036	6,019,773	0.5%	1,225	0.5%	907	0.3%
2037	6,034,306	0.2%	1,229	0.4%	907	0.0%
2038	6,053,929	0.3%	1,234	0.4%	908	0.1%
2039	6,072,712	0.3%	1,239	0.4%	909	0.1%
CAGR 2020-2039		0.6%		0.6%		0.5%

4.7 DISCUSSION OF BASE LOAD, INTERMEDIATE LOAD and PEAK LOAD

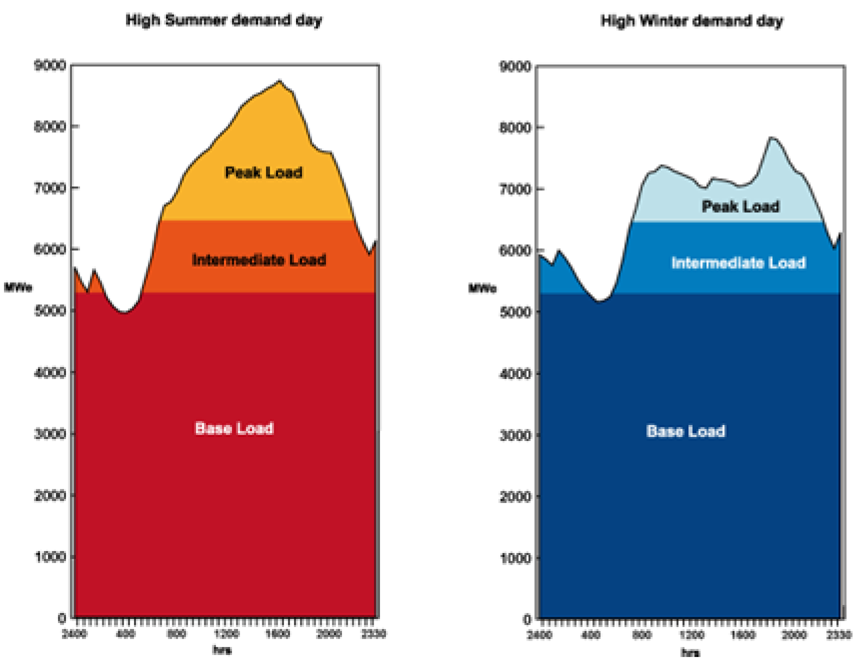
There are three levels of electric load: base load, intermediate load and peak load. Base load is the minimum level of demand on an electrical supply system over 24 hours. Base load is primarily served by power plants which can generate consistent and dependable power. Intermediate load is a medium level of demand. Plants can operate between extremes and generally have output increased in the morning and decreased in the evening. Peak load is the highest level of demand within a 24-hour period. The annual

[18] 2019/2020 IRP energy and demand forecast provided to MISO in Nov. 2019 differed slightly in order to match MISO's requirements which necessitated the following an adjustment. It incorporated the 2016 IRP's preferred level of DSM

peak hour is typically between June and September, when weather is hottest. For modeling purposes, Vectren uses August as the peak summer month and January as the peak winter month. Typically, peak demand is served by units that can be switched on quickly when additional power is needed.

The graphic below shows an illustrative example of summer and winter peak load.

Figure 4.7 – Typical Load Curve Illustrations (Summer and Winter)



This dynamic is evolving as more intermittent renewable resources, particularly solar, come online. MISO nets out energy produced from renewable resources from customer load. This is expected to shift the net peak into the evening hours where dispatchable resources will be needed to serve customer load.

4.8 STAKEHOLDER INPUT – Load Forecast

Vectren discussed the load forecast with stakeholders in the October 10th stakeholder meeting, providing an opportunity to provide input, question and comment on the draft load forecast before finalizing. There was a robust discussion on trended weather projections used in the load forecast. Some stakeholders believed that the trend utilized did not reflect the findings in a recent Purdue University climate study. Vectren reached out to Purdue University and they provided some clarification on the differences between their study and ours, including using different set points for heating and cooling degree days. Itron reviewed and estimated that the HDD trend was the same, while the CDD trend is nearly two times higher in the Purdue dataset. Utilizing the Purdue CDD trend would add approximately 40 MWs to Vectren's forecast over the next 20 years, which was well within Vectren's high bound forecast. Vectren did not update its load forecast, based on this analysis. This was discussed in the December 13, 2020 stakeholder meeting.

SECTION 5
The MISO Market

5.1 MISO

Midcontinent Independent System Operator (MISO), is the independent, not-for-profit Regional Transmission Operator (RTO) of which Vectren is a member. MISO oversees power delivery across 15 states and the Canadian province of Manitoba and is the largest energy and operating reserves market in the world. MISO is divided into 11 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 regarding energy and capacity and can rely on neighboring Zones to an extent, largely depending on transmission infrastructure. Based on MISO's Local Clearing Requirement (LCR), approximately 70% of Vectren's generation must be physically located within MISO Zone 6.

Figure 5-1 – MISO Local Resource Zones

MISO's two main roles are transmission planning and oversight of its energy, capacity and ancillary service markets. MISO has operational authority to control transmission facilities and coordinate security for its region to ensure reliability. MISO is responsible for dispatch of lowest cost generation units, ensuring the most cost-effective generation meets load needs.

5.2 MISO Planning Reserve Margin Requirement (PRMR)

MISO requires Vectren and its other member electric utilities to maintain a Planning Reserve Margin Requirement (PRMR). The PRMR is the amount of resources MISO requires in order to meet a NERC standard of one loss of load event in ten years and is designed to ensure there is enough power capacity throughout the MISO region to meet customer demands during peak periods, including peak periods where some equipment might fail. To further ensure the NERC standard of one loss of load event in ten years, the PRMR is further detailed by the Local Clearing Requirement (LCR) which mandates how much of a Local Resource Zone's (LRZ) PRMR must be met by generation resources physically located within that LRZ. In recent years the amount of available resources to meet load needs throughout MISO has tightened excess capacity that acts as a reliability safeguard. This trend appears to continue as some baseload units are projected to retire by 2023. As a result, long term dependence on the market for capacity and energy has considerable risk.

The illustration below shows the load on a typical day and load on the peak day with the reserve margin requirement.

Figure 5.2 –Illustration of Load Curve and Planning Reserve Margin

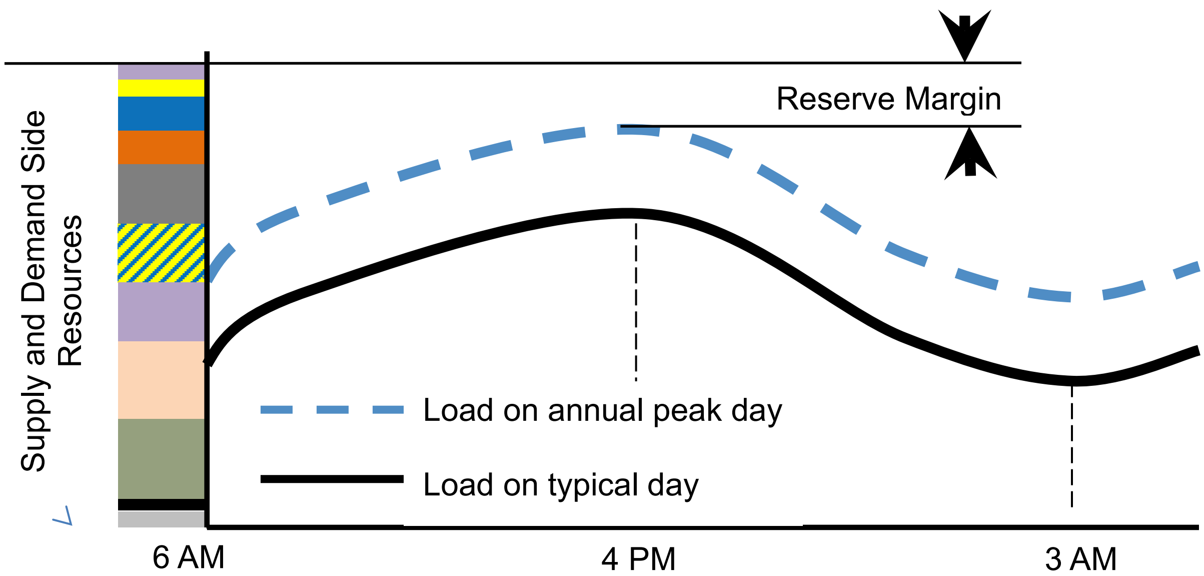


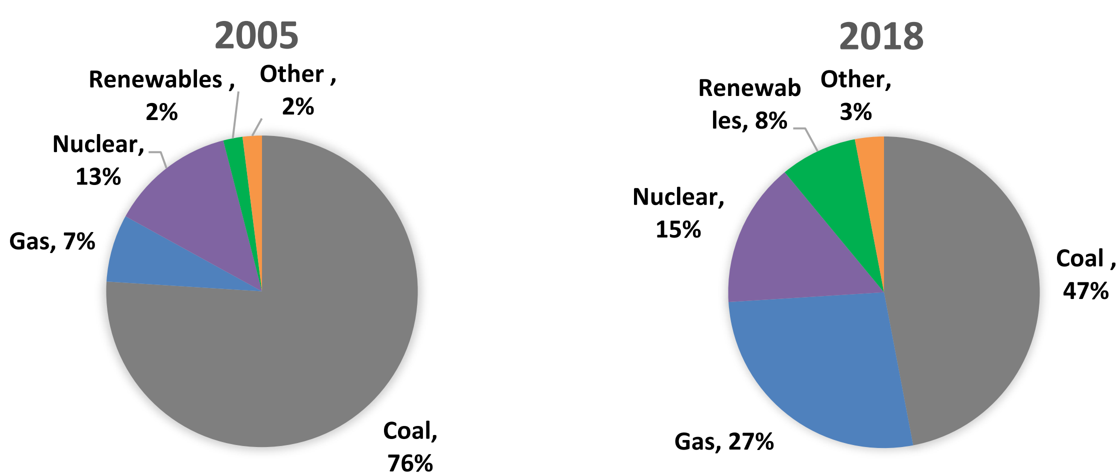
Figure 5.3 –Historic MISO PRMR

Planning Year	MISO PRMR (UCAP)-Required	MISO PRM (UCAP)-Excess Available: Offered/PRMR
2020-21	8.90%	142,082/135,960: 4.50%
2019-20	7.90%	142,082/134,743: 5.45%
2018-19	8.40%	141,781/135,179: 4.88%
2017-18	7.80%	142,146/134,753: 5.49%
2016-17	7.60%	141,524/135,483: 4.46%
2015-16	7.10%	145,861/136,359: 6.97%

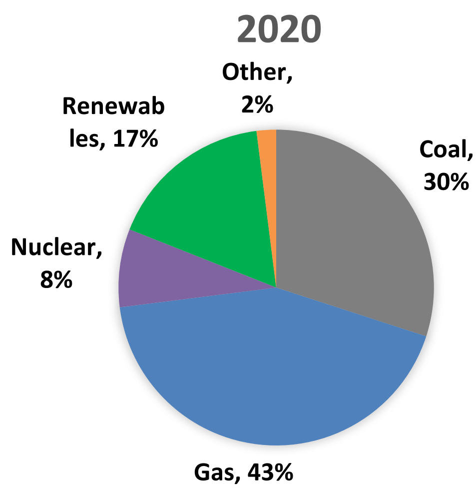
5.3 MISO Resource Mix – Past, Current and Future

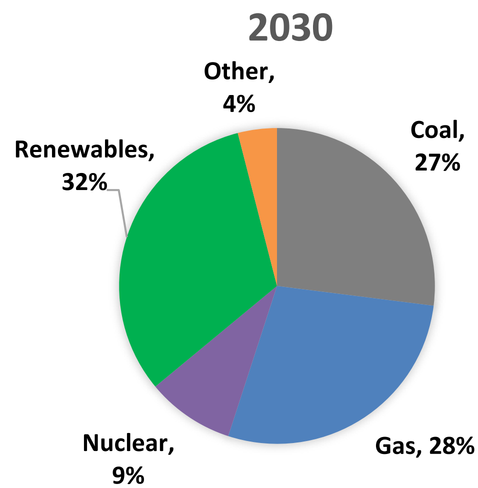
MISO's resource fuel mix has changed drastically since its market inception in 2005. In 2005, coal was the predominant fuel source, with MISO lacking diversity and nuclear as the closest competitor at 13%. In 2018, after the implementation of the Clean Power Plan and various other regulations and due to cost pressure from low gas price and declining renewable energy prices, MISO member companies began retiring aging coal units. As a result, its share of the MISO fuel mix dropped to 47%, with natural gas becoming the second leading fuel source and renewables quadrupling in size. This year natural gas (43%) is the leading fuel source in MISO, followed by coal (30%) and renewables (17%), while nuclear has decreased to only 8%. MISO now projects that by 2030 renewables will be the leading fuel source of MISO capacity at 32%, followed by gas at 28% and coal decreasing to 27%.

Figure 5-4 – MISO Fuel Mix[19]



[19] Sources: 2005 Mix: MISO Evolution of the Grid presentation on 11/07/17 https://ccaps.umn.edu/documents/CPE-Conferences/MIPSYCON-PowerPoints/2017/GenTheEvolutionoftheGridintheMidcontinentIndependentSystemOperator(MISO)Region.pdf
2018 Mix: MISO 2019 MTEP https://cdn.misoenergy.org/MTEP19%20Executive%20Summary%20and%20Report398565.pdf
2020 Mix: MISO Corporate Fact Sheet accessed 03/20 https://www.misoenergy.org/about/media-center/corporate-fact-sheet/
2030 Mix: MISO RASC Presentation 2020 Focus presented on March, 2020 https://cdn.misoenergy.org/20200304%20RASC%20Item%2002%20RAN%20Overview%20(RASC009%20RASC010%20RASC011%20RASC012)432103.pdf





5.4 Dispatchable vs. Intermittent

Dispatchable generation refers to sources of electricity that can be used or dispatched on demand at the request of the power grid operator. Intermittent generation is associated with renewable forms of electricity, mainly solar and wind, that cannot be dispatched at a moment's notice and without storage capabilities only generate electricity as available. Dispatchability of a generation resource allows for planning that is reflected in capacity accreditation, which provides a generator an annual value based on: expected generation output during peak-load conditions, generator characteristics and the past three years of operational performance. Lack of dispatchability creates planning challenges best illustrated through the recent increase in MISO Emergency Max-Gen Events that have occurred throughout the four seasons as the reliance on intermittent resources has increased. An intermittent resource that may be capable of 100% of nameplate generating capacity on a certain day may be reduced to 0% of capacity during another hour of that same day due to a weather pattern. This volatility of intermittent renewable resources has challenged grid planners as these resources have been added to the system. Dispatchable resources that are not on outage remain available as called upon during these severe conditions when intermittent resources do not meet planned output.

MISO has shifted from 96% dispatchable generation (all forms of generation except renewables) in 2005 to approximately 83% currently and is forecasted to be at 60% in

2030. In response to these conditions MISO commenced its Resource Availability and Need (RAN) Initiative and its Renewable Integration Impact Assessment (RIIA) to plan market rule changes to deal with the future resource mix. The RAN Initiative is aimed at better accrediting generation units while the RIIA is focused on understanding the impacts of renewable energy growth in MISO over the long term and assessing potential transmission solutions to mitigate them.

5.5 MISO Maximum-Generation Emergency Events

Maximum-Generation (Max-Gen) Events are the final step in MISO's emergency operating procedure before firm-load shed, otherwise known as blackouts. Max-Gen Events have historically been rare in nature, with MISO experiencing 3 events between 2009 to 2015 and they occurred only during peak load condition summer months. However, since 2016 there have been 10 events, spanning all four weather seasons. In January of 2019, MISO, for the first time in its existence, interrupted energy service to Industrial Customers enrolled as Load Modifying Resources (LMR). Going forward customers enrolled as LMRs must consider the increased possibility of future interruptions. It is likely that some LMRs will end their participation due to the heighted risk.

5.6 MISO Resource Adequacy Reform

As a reaction to the increasing frequency, duration and ability for Max-Gen Events to occur within all periods of the year, MISO implemented its RAN initiative. The goal of this initiative is to "ensure the processes in use appropriately assure the conversion of committed capacity resources into sufficient energy every hour of the Planning Year. A dramatically changing landscape has made this conversion process increasingly more uncertain. Therefore, an issue and solution development effort will help MISO and its stakeholders identify and meet the challenges posed by current and future portfolio and technology changes facing the region."

The RAN initiative has led to market mechanism reform that is currently underway. Such reform has included changes to the ability to interrupt customers enrolled as Load Modifying Resources/Interruptible Load. MISO currently has reform initiatives[20] that are high priority that include Emergency Energy Pricing, which would allow higher cost energy resources to set pricing, thereby increasing energy pricing during emergency events, increasing the Energy Offer Cap from $1,000/MWh to $2,000/MWh, thereby allowing generation to double its maximum offer price and allow prices to reach a higher threshold, instituting a Seasonal Planning Resource Auction construct, which would break up the current annual capacity auction to seasonal auctions that would adjust the PRMR and capacity accreditation for resources during these periods. Vectren considered the potential for winter and summer accreditation.

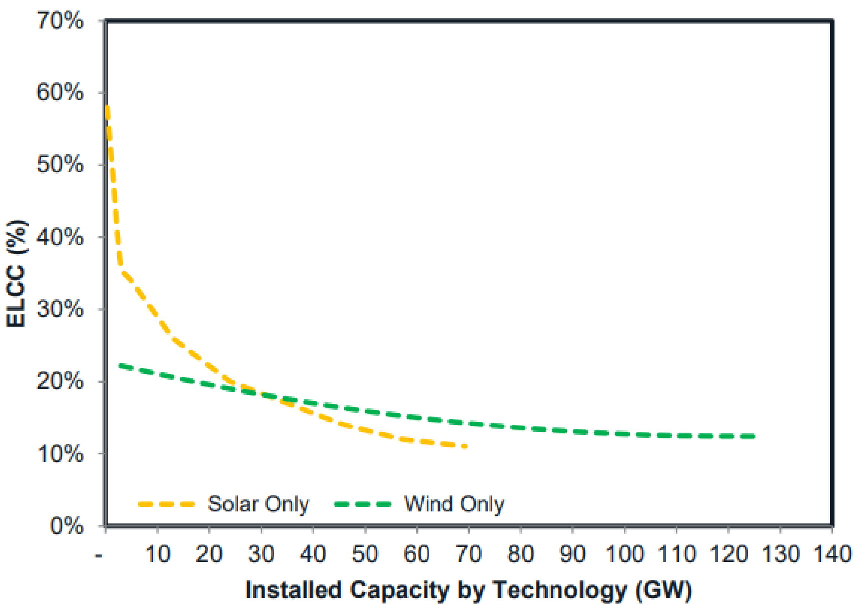
5.7 MISO CAPACITY CREDIT

Each resource option receives varying amounts of capacity credit towards MISO's resource adequacy requirement based on their ability to reliably contribute energy at the peak demand hour. Thermal generation, such as natural gas and coal-fired power plants, can produce an expected level of output when called upon. For this reason, utilities can count nearly the full installed capacity of thermal generation towards their resource adequacy requirement (less their historical outage rate). A new thermal generator can count ~96 MWs out of every 100 MWs of installed capacity towards meeting MISO's summer planning reserve margin requirement. This amount increases in the winter for gas resources due to air density in cold weather conditions. Renewable wind and solar resources are variable sources of power (available when the wind blows or the sun shines), which means they are not always available to meet peak demand. Because neither wind nor solar resources tend to reliably provide their full installed capacity at the peak demand hour, they receive less capacity credit.

[20] MISO 2019 Market Roadmap: https://cdn.misoenergy.org/MISO%20Market%20Roadmap194258.pdf

While renewable wind resources produce a lot of renewable energy over the course of the Planning Year, their capacity accreditation is typically a lot lower than dispatchable generation. MISO calculates the capacity which will be accredited for wind resources by calculating the resources' Effective Load Carrying Capability (ELCC). Wind resources located in MISO Zone 6 received a capacity credit of only 7.8% for MISO's 2019-2020 planning year, meaning for every 100 MWs of installed wind capacity, 7.8 MWs would count towards meeting MISO's planning reserve margin. As part of MISO's RIIA, MISO evaluated the ELCC of wind and solar resources as penetration levels increased. Renewable penetration is expected to increase as shown in Figure 5.4. Renewable penetration increasing results in the net peak load shifting. This shift results in lower renewable energy production coincidence with the net peak load and therefore a lower ELCC accreditation as seen in Figure 5-5.

Figure 5-5 Decreasing solar and wind ELCC as more is installed[21]



[21] Renewable Integration Impact Assessment (RIIA) Assumptions Document Version 6, December 2018, MISO, page 11, https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v7429759.pdf

The solar and wind accreditation used in the IRP modeling was calculated using MISO's ELCC accreditation formulas and adjusted based upon the level of renewable penetration expected on MISOs system. As additional renewable resources were included in the model the UCAP accreditation for these resources was revised. Over time, this results in a lower accreditation value as additional resources come online.

While MISO's current methodology for determining resource adequacy only considers the summer peak, they have begun to discuss the inclusion of other seasons. Wind and solar capacity factors and energy coincidence with the net peak load vary seasonally. A Solar PV production chart comparison for the winter and summer is shown in Figure 5-6. It shows solar output has a higher coincident with peak demand in the summer months than winter months, due to not only the lower winter solar production, but also the typical peak demand occurring later in the day. These combined effects result in lower solar winter capacity accreditation. Wind resources typically have higher capacity factors during winter months leading to a higher output during winter peak demand hours. Summer and winter wind production compared to load shape are shown in Figure 5-7 gas resource or other dispatchable generation, benefits from being able to turn on and off as needed with exception to unit outages and therefore have higher capacity accreditation than non-dispatchable intermittent resources. For reference, a typical gas resource seasonal capability difference is shown in Figure 5-8.

Figure 5-6 Average Solar PV energy production summer versus winter

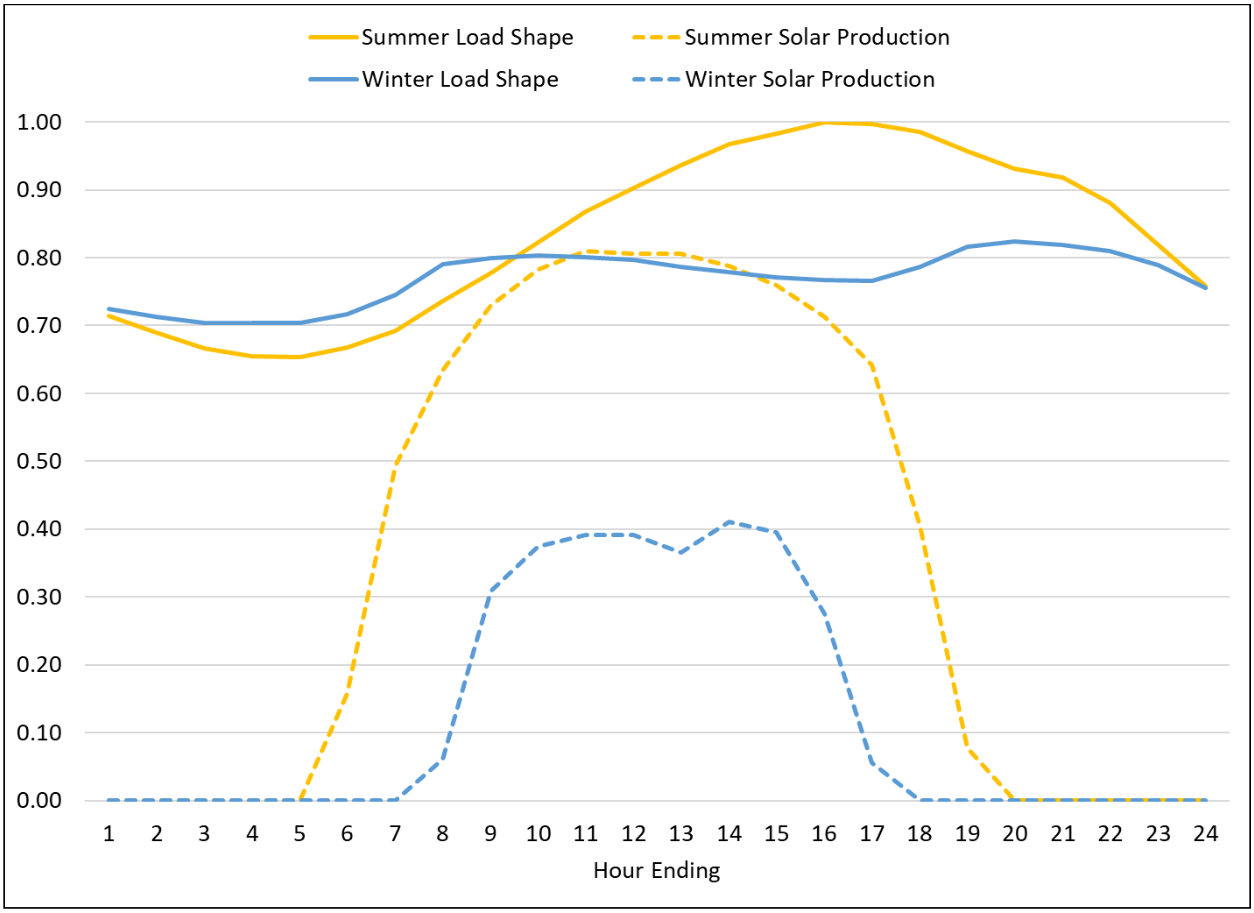


Figure 5-7 Average Wind energy production summer versus winter

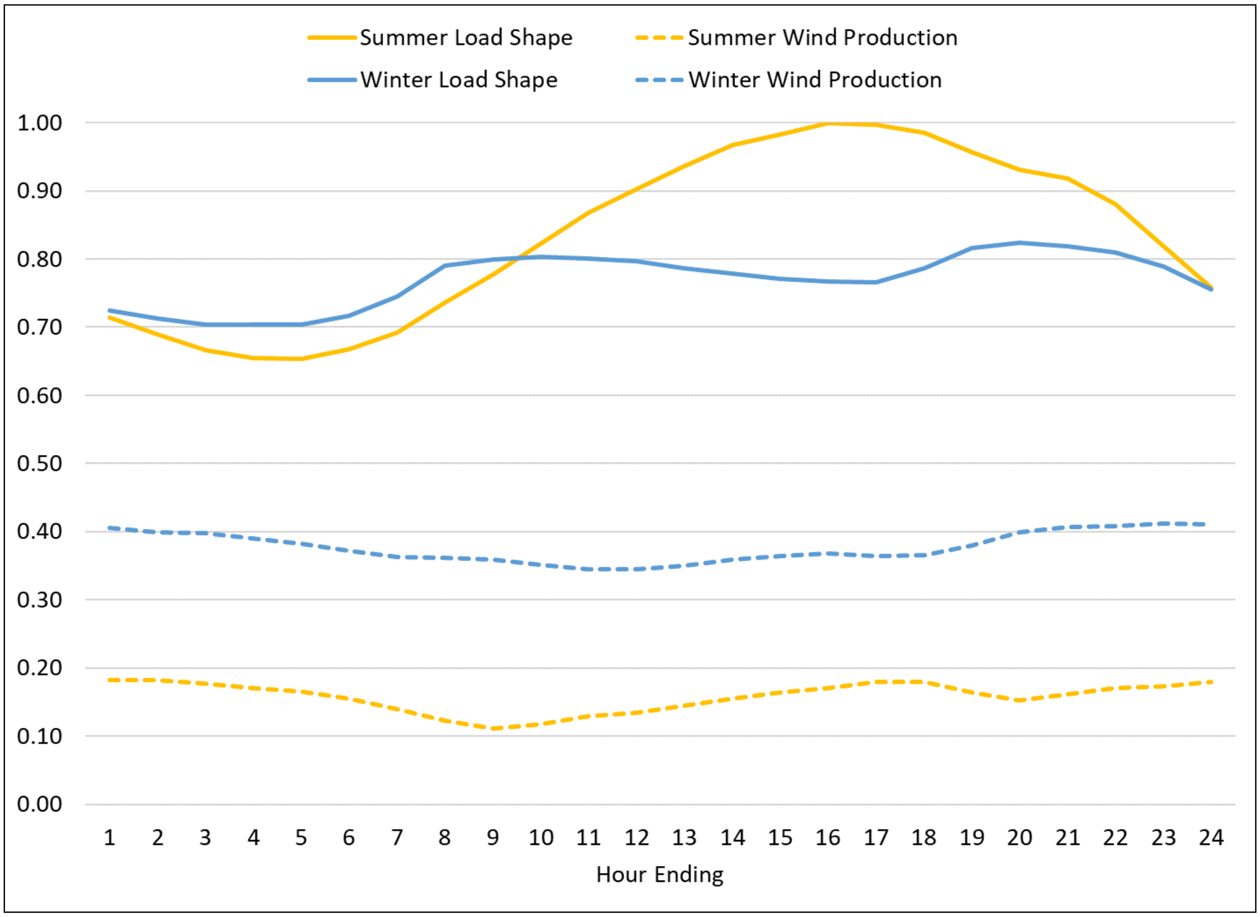
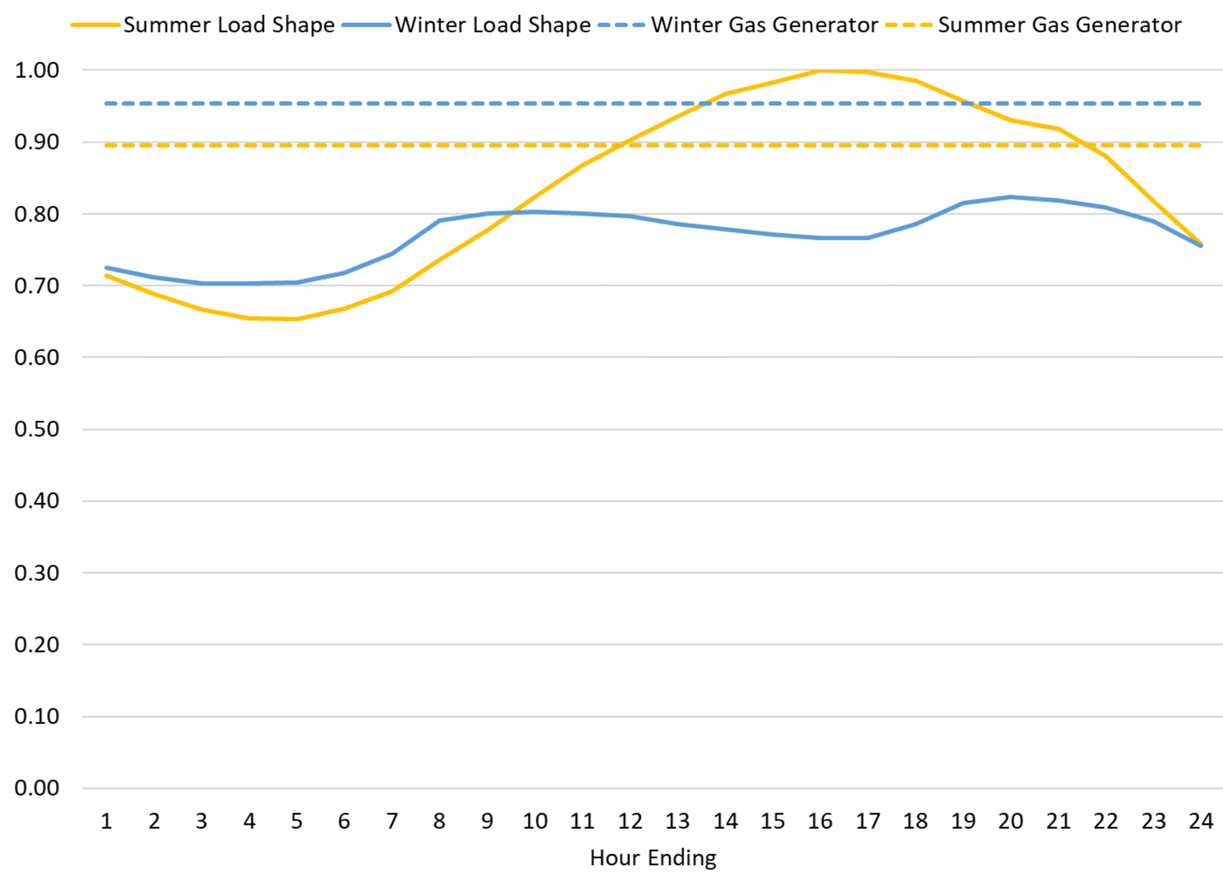


Figure 5-8 Average Gas Resource energy potential summer versus winter



MISO has already implemented seasonal coordinated maintenance schedule reporting. Additionally, MISO currently is considering implementing a seasonal construct to capacity accreditation. Based on recent MISO publications, discussions and input, this likely could be a four-season construct which is planned to be implemented as soon as 2022. Publicly posted feedback from MISO stakeholders and MISO indicated accreditation should vary by season and reflect expected availability of resources in each season. Vectren is a member of MISO and as such cannot ignore nor avoid updates to MISO's accreditation process. Vectren has utilized a conservative summer and winter capacity accreditation construct as part of this IRP as a means of preparing for this implementation.

5.8 MISO Capacity

Historically, the price for capacity in MISO's annual auction has been volatile. The Organization of MISO States (OMS), of which the IURC is a participant and MISO teamed together to better understand future resource needs. Since June of 2014, MISO and the OMS have compiled Resource Adequacy survey responses from MISO members that indicate the need for more supply and demand side resources to meet expected load. This survey has served as the main vehicle in communicating to the MISO stakeholder community the anticipated PRM for upcoming years and is a tool in determining whether additional action is needed.

Since its inaugural survey, MISO has warned that there may be inadequate capacity within the MISO footprint at some future date. OMS-MISO Resource Adequacy survey results have shown projected shortfalls for high certainty resources in the MISO region and Zone 6, which includes most of Indiana and a small portion of Kentucky. Figure 5.9 below illustrates Zone 6's increasing proportion of the entire MISO region shortfall projection and thus increased reliance on neighboring state generation resources. Over the years, the OMS and MISO have updated the methodology to project simply which resources are considered high certainty in hopes of increasing the accuracy of the projection. With these improvements in place since 2017, there is still a projected shortfall. This shortfall is concerning, especially from a zonal standpoint that shows certain zones relying heavily on other zones to meet the overall MISO capacity requirement. The latest OMS survey shows IN Zone 6 as one of the zones most at risk of a shortfall, with a deficit projected to surpass the entire MISO region's deficit. It is worth noting that since 2016 Indiana's Zone 6 has imported capacity to meet its PRMR needs. This means based on current MISO member plans and expectations, Zone 6 is expected to continue importing energy to meet a substantial amount of its needs through the year 2025, the last year of the survey period. This potential long-term reliance on the market makes Zone 6 and Vectren's customers susceptible to volatility in the auction clearing price and the resource adequacy policy and decisions of neighboring Zones. The table below demonstrates that since 2018 the MISO region has cut its projected shortfall in half, while Zone 6's shortfall has almost doubled.

Figure 5.9 – OMS-MISO Resource Adequacy Survey Results

OMS-MISO Resource Adequacy Survey Results by Year	Zone 6 Resource Adequacy Shortfall, 5-Year Projected	MISO-wide Resource Adequacy Shortfall, 5-Year Projected
2014	No 5-year projection provided	5.8 GW shortfall in 2019
2015	1.1 GW shortfall in 2020	2.3 GW shortfall in 2020
2016	800 MW shortfall in 2021	2.6 GW shortfall in 2021
2017	400 MW shortfall in 2022	No shortfall projected
2018	1.6 GW shortfall in 2023	4.5 GW shortfall in 2023
2019	2.4 GW shortfall in 2024	2.3 GW shortfall in 2024

5.8.1 Capacity Prices

The projected capacity shortfalls can result in volatile capacity prices. MISO's Planning Resource Auction (PRA) is held annually for each of the load zones within the MISO footprint to ensure sufficient capacity resources. The PRA has yielded a wide fluctuation in capacity pricing for Zone 6 since its inaugural year of 2013, as shown in Figure 5.10 below. These large swings in prices have made it difficult to forecast forward year prices. While the 2020-2021 capacity price was relatively low, neighboring Zone 7, which consists of the lower peninsula of Michigan reached the Cost-of-New-Entry (CONE) rate, which is approximately $257, or ~50 times higher than the $5.00 clearing price. Michigan very narrowly missed cone in the 2019-2020 planning year. Since then, MISO updated market rules to ensure only units that enter the auction will be available at the time of need, the likelihood of price increases intensifies.

Figure 5.10 – MISO Capacity Prices

Planning Year	Highest Clearing price for MISO-region	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/day[22]	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/year	Year-over-Year Price Change
2013-2014	$1.05	$1.05	$383.25	-
2014-2015	$16.75	$16.75	$6,113.75	1495% Increase
2015-2016	$150.00	$3.48	$1,270.20	79% Decrease
2016-2017	$72.00	$72.00	$26,280.00	1969% Increase
2017-2018	$1.50	$1.50	$547.50	98% Decrease
2018-2019	$10.00	$10.00	$3,650.00	567% Increase
2019-2020	$24.30	$2.99	$1,091.35	70% Decrease
2020-2021	$257.53	$5.00	$1,825.00	67% Increase

5.9 MISO Energy Prices

Energy prices in MISO have decreased in the last 18 months and are at all-time lows. The main driver of the price decrease is tied to the marginal generation units that set the energy price. Natural gas and renewables have shifted the marginal generation mix from coal to natural gas. Even prior to COVID-19, Natural gas prices were at historic lows, recently in the $2 range due to increased U.S. and global production and warmer than normal winter weather causing an oversupply, which has lowered the operating costs of natural gas generation. This has lowered the bids of generation in the MISO market and led to lower clearing prices as depicted below:

[22] MW/day is the amount customers are required to pay should they purchase capacity via the MISO Planning Resource Auction. For example, in the 2016-2017 planning year each MW cost $72 per day ($26,280 per MW annually).

Figure 5.11 – MISO Clearing Prices

Indiana Hub/Henry Hub Yearly Averages
2015 - YTD Apr. 2020

Year	Indiana Hub Real Time ATC Average	YoY% Change	Indiana Hub Day Ahead ATC Average	YoY% Change	Henry Hub Average	YoY% Change
YTD 2020	$21.02	-20.39%	$21.60	-19.81%	$1.83	-27.05%
2019	$26.41	-19.95%	$26.98	-18.72%	$2.51	-19.41%
2018	$32.99	12.59%	$33.19	12.97%	$3.12	5.36%
2017	$29.30	4.86%	$29.38	4.50%	$2.96	19.10%
2016	$27.94	-0.27%	$28.11	-1.94%	$2.49	-4.60%
2015	$28.02		$28.67		$2.61	

Over time, it is expected that natural gas prices will increase, but remain low and stable, keeping energy prices low.

5.10 MISO Interconnection of New Resources

Before a new generating facility can connect to the grid, the reliability impacts associated with interconnection must be studied. Issues uncovered during this process can be mitigated through electric transmission Network Upgrades (NU). The addition of upgrades to address system reliability have the potential to increase the costs associated with a new generating facility. Each of the All-Source RFP proposals were analyzed to determine its associated impacts to the transmission system as well as the associated Network Upgrade costs.

The MISO Generator Interconnection (GI) process is a three-phase study cycle that has been conducted twice annually (recent schedule is reduced to once per year) to study the impact and any associated transmission system upgrade costs as a result of new generation connecting to the MISO transmission system. Usually there is a study cycle in the 1st quarter and 3rd quarter of each year. Application and milestone payment requirements based on the size of the unit to be studied are required 45 days prior to the start of the study cycle. These two study cycles are the only two periods in which to enter the GI queue each year. Mid-year and mid-queue requests are not allowed. After all modeling details are finalized the study enters the Definitive Planning Phase (DPP). The DPP is broken into three phases that are restudies based on immaterial changes to generator attributes and the removal of projects that decide not to proceed to the next study phase. Upon completion of the third DPP, MISO and the GI requestor begin the GI Agreement (GIA) process. Upon satisfying all terms of the GIA, the GI requestor will receive a fully executed GIA that enables the generator to connect to the MISO transmission system and depending on the transmission service selected, participate and receive full accreditation in the MISO energy and capacity markets.

MISO estimates the process to take 505 days, start to finish. However, with the record amount of interconnection requests that MISO has seen in the last two years, the process is averaging over 2 and a half years per MISO's DPP schedule update posted 3/1/2020. As increased renewable development continues in order to qualify for tax incentives before expiration, the number of GI requests is not expected to subside and as a result, the timeline is likely to remain delayed.

GI costs are determined based on the MW impact from each project on identified constrained facilities. As such, cost allocation is assigned to the generator that causes or contributes to a constraint and therefore projects that are studied after prior cycles are more likely to have additional costs identified. More simply stated, the earlier a project gets in the queue, the more likely it is to utilize any available transmission capacity at lowest cost. Conversely, projects that request studying after prior cycles are more likely to be assigned higher costs as a result of prior projects connecting to and exhausting current transmission system topology. For this reason, existing interconnection rights at the Brown site are valuable. MISO allows for an expedited process for new generation with existing interconnection rights; this helps to shield customers from potential upgrade costs should Vectren enter the MISO queue at another site.

SECTION 6
RESOURCE OPTIONS

6.1 ALL SOURCE RFP

The All-Source RFP was conducted according to the schedule outlined in Figure 6-1. More details on the steps included in the RFP timeline are described below.

Figure 6-1 RFP Timeline

Step	Completed/Proposed Date
RFP Issued	Wednesday, June 12, 2019
Notice of Intent, RFP NDA and Respondent Pre-Qualification Application Due	5:00 p.m. CDT, Thursday, June 27, 2019
Respondents Notified of Results of Pre-Qualification Application Review	5:00 p.m. CDT, Wednesday, July 10, 2019
Proposal Submittal Due Date	5:00 p.m. CDT, Friday, August 9, 2019
Initial Proposal Review and Evaluation Period	Friday, August 9, 2019 – Wednesday, September 18, 2019
Proposal Evaluation Completion Target and Input to Vectren	2nd Quarter, 2020
Due Diligence and Negotiations Period	Mid 2020
Definitive agreement(s) Executed (subject to regulatory approvals) with Selected Respondent(s)	Late 2020
Petitions (if required) filed with the IURC, the Federal Energy Regulatory Commission (FERC), or any other required agency/commission	TBD

6.1.1 RFP Issued

Burns & McDonnell issued the All-Source RFP on behalf of Vectren on Wednesday, June 12, 2019 (http://vectrenrfp.rfpmanager.biz/default.aspx). Notice was sent to all known IRP stakeholders and posted on www.vectren.com/IRP. The RFP was advertised across multiple media outlets, including Megawatt Daily (~20,000 recipients), North American Energy Markets Association (NAEMA) (150 members) and Midwest Energy Efficiency Alliance (MEEA) Minute (161 members). It was also sent directly via e-mail to participants of Vectren's 2017 RFP, an internal Burns & McDonnell RFP contact list (>450 industry contacts) and Vectren industry contacts. While the RFP included general requirements and communicated that Proposals which do not meet the general requirements may be subject to disqualification, all were included for evaluation. For more details please refer to the submitted Vectren 2019 All-Source RFP in Technical Appendix Attachment 6.3.

6.1.2 Notice of Intent

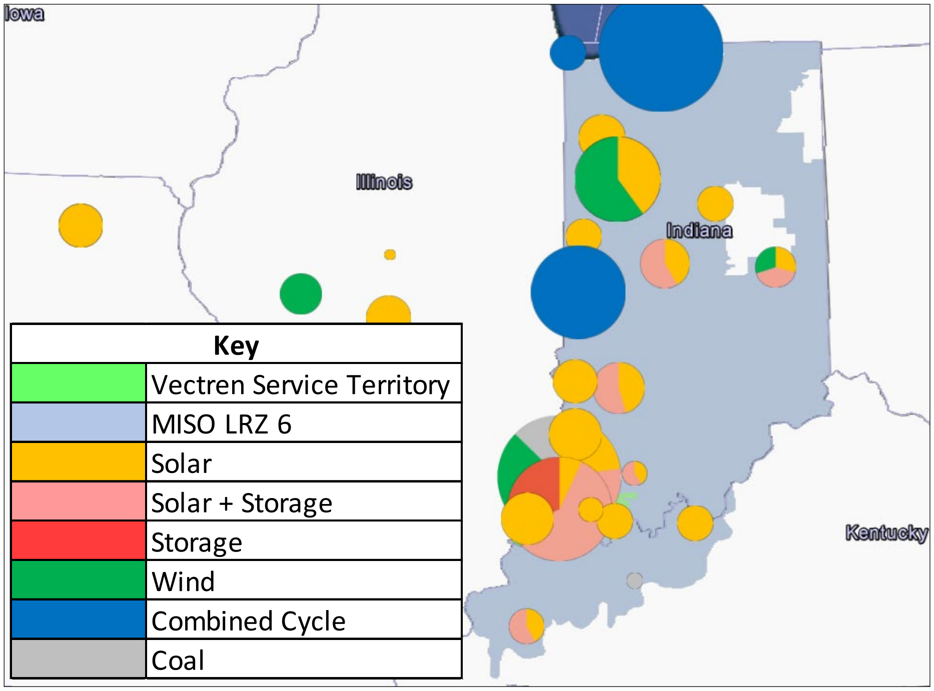
Respondents were given more than two weeks to submit a Notice of Intent to participate in the RFP process, sign the Non-Disclosure Agreement and complete the Pre-Qualification Application. The purpose of the Pre-Qualification Application is to verify that Respondents have adequate experience and financial capability to support their Proposal(s).

6.1.3 Proposal Review

The Proposal Submittal Due Date was Friday, August 9, 2019. After all Proposals had been received, Burns & McDonnell began the Initial Proposal Review. While Proposals were being reviewed, information was clarified with Respondents to confirm Proposals were interpreted as intended.

A total of 110 Proposals were received from 22 Respondents. The Proposals comprised eight battery storage, two coal, seven combined cycle gas, one LMR/DR, 57 solar, 19 solar plus storage, three system energy and 13 wind. Of the 110 Proposals, 91 were in Indiana. The Proposals contained approximately 21 GW of total installed capacity; however, many of the projects were included in multiple proposals. There was approximately 10 GW of unique project installed capacity after accounting for double counting. For example, a single 100 MW wind farm project could be offered as a purchase option or various PPA options. A graphical overview of all Proposals received is shown in Figure 6-2.

Figure 6-2 Map of Proposals Received



6.1.4 MISO Interconnection

The appropriate MISO DPP Generation Interconnection Study Group was identified for each of the respective Proposals. For the Proposals that reside in Study Groups with posted DPP reports, the identified NU and associated costs were used.

For the proposals that reside in Study Groups without posted DPP reports, Burns & McDonnell performed a steady state analysis using the appropriate DPP Study Group cases and auxiliary files. These selections were evaluated against the impact criteria defined in Section 6.1.1.1.8 of MISO's BPM-015 (Business Practices Manual), including the cumulative impact criteria.

Finally, for those selections that have not entered the queue or did not have a DPP Study Group case available, the most recent DPP Study Group case was used for the evaluation. The same impact criteria were applied with the exclusion of the cumulative impact criteria.

Figure 6-3 - RFP Project Definitive Planning Phase (DPP) Study Groups

Number of RFP Projects in DPP Study Group	Study Group	Network Upgrade (NU) Cost From:	Burns and McDonnell Action:
1	DPP-2016-FEB Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm Generator Interconnection Requests (GIRs) sharing allocations are active.
1	DPP-2016-AUG Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm GIRs sharing allocations are active.
4	DPP-2017-FEB Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm GIRs sharing allocations are active.
10	DPP-2017-AUG Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm GIRs sharing allocations are active.
5	DPP-2018-APR Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm GIRs sharing allocations are active.
1	DPP-2018-APR West	Project Group Analysis	1. Perform Project Group analysis to determine potential NU costs for ERIS analysis; 2. Allocate costs to GIRs based on full reconductor/replacement cost estimates.
18	DPP-2019-Cycle1 Central	Project Group Analysis	1. Perform Project Group analysis to determine potential NU costs for ERIS analysis; 2. Allocate costs to GIRs based on full reconductor/replacement cost estimates.

For any impacts reported, without any information on the limitation of the facility, Burns & McDonnell assumed a full rebuild scope and cost of the facility. NU costs for the reported impacts were developed using MISO's MTEP transmission cost estimation guide. These NU costs were considered for the evaluation of each proposal. Many Proposals included allowances for NU costs or indicated all NU were included in their Proposal and these nuances were accounted for during the analysis.

6.1.5 Grouping

Proposals were divided into groups based on characteristics such as technology type, ownership structure and contract duration. Aggregated cost and performance information from the RFP Proposals was provided to the IRP team to facilitate portfolio modeling. There are many benefits to modeling the RFP bids in Groups. These benefits include allowing the IRP modeling to help evaluate the technology, size, duration and mix of resources which would be included in the Preferred Portfolio. Given the volume of proposals received as part of the IRP, it may not have been possible and would not have been practical to model each individual project. Moreover, it would be difficult to maintain confidentiality of individual projects. IRP modeling of individual projects does not holistically evaluate all relevant factors, such as locational differences of wholesale market pricing and potential congestion impacts. Using a grouping method allows for IRP inputs to reflect anticipated project costs.

Proposals were divided into two tiers, based on factors that could add cost risk to Vectren customers. Tier 1 Proposals were those that included binding pricing and delivery of energy to SIGE.SIGW (Vectren's load node) or were physically located in Vectren's service territory. Tier 2 included the remaining Proposals that were not classified as Tier 1. Tier 2 Proposals generally did not provide a binding bid price and/or were located off Vectren's system, which increases cost risk due to congestion. Despite these risks, several were still analyzed and considered during the RFP evaluation process; however, Vectren wanted, to the extent possible, to include bids with more price certainty within the IRP modeling in order to protect customers from price volatility.

Seventeen (17) groups were formed. This resulted in data from 49 Tier 1 Proposals being used in IRP analysis. A summary of the Proposal grouping is shown in Figure 6-4. As seen in Figure 6-4, the energy-only Proposals were not put into a group because they did not meet the capacity requirement of the RFP. Due to a high quantity of bids in the group and to provide additional granularity in IRP modeling, groups 15 and 17 were split into high and low-cost groups.

Figure 6-4 Proposal Grouping

Grouping		RFP Count	Tier 1	Tier 2
1	Coal PPA	2	0	2
2	LMR/DR PPA	1	1	0
3	CCGT PPA	2	0	2
4	CCGT Purchase	5	0	5
5	Wind Purchase	2	0	2
6	12-15 Year Wind PPA	9	4	5
7	20 Year Wind PPA	2	1	1
8	Storage Purchase	4	4	0
9	Storage PPA	4	4	0
10	Solar + Storage PPA	6	5	1
11	Solar + Storage Purchase	9	5	4
12	Solar + Storage Purchase/PPA	4	1	3
13	Solar Purchase/PPA	6	1	5
14	12-15 Year Solar PPA	8	3	5
15	20 Year Solar PPA	16	10	6
16	25-30 Year Solar PPA	9	3	6
17	Solar Purchase	18	7	11
N/A	Energy Only	3	0	3
	Total	**110**	**49**	**61**

The costs for Tier 1 Proposals are outlined in Figure 6-5. Costs were not shown for groups that contained only one project to ensure confidentiality.

Figure 6-5 - Tier 1 Cost Summary[23]

	Group	# Proposals	# Projects	Proposal ICAP (MW)	Project ICAP (MW)	Capacity Weighted Average LCOE ($2019/MWh)	Capacity Weighted Purchase Price ($/kW)[2]
1	Coal PPA	0					
2	LMR/DR PPA	1	1	50	50		
3	CCGT PPA	0					
4	CCGT Purchase	0					
5	Wind Purchase	0					
6	12-15 Year Wind PPA	4	1	800	200		
7	20 Year Wind PPA	1	1	300	300		
8	Storage Purchase	4	2	305	152	$157	
9	Storage PPA	4	2	305	152	$135	
10	Solar + Storage PPA	5	3	902	526	$44	
11	Solar + Storage Purchase	5	3	862	486	TBD[1]	$1,417[3]
12	Solar + Storage Purchase/PPA	1	1	110	110		
13	Solar Purchase/PPA	1	1	80	80		
14	12-15 Year Solar PPA	3	2	350	225	$32	
15	20 Year Solar PPA	10	8	1,522	1,227	$35	
16	25-30 Year Solar PPA	3	2	400	275	$34	
17	Solar Purchase	7	6	902	732	TBD[1]	$1,262

1. The method for realizing tax incentives is being reviewed by Vectren
2. $/kW costs are in COD$, purchase option cost is the purchase price unsubsidized by applicable tax incentives and does not reflect ongoing operations and maintenance costs
3. Cost based on simultaneous MW injectable to the grid

6.1.6 Evaluation of Proposals

Burns & McDonnell quantitatively and qualitatively evaluated all conforming generation facility Proposals. Proposals were evaluated relative to others within the same grouping

[23] Note that proposals based on one project do not include capacity weighted Average LCOE or Capacity Weighted Purchase Price to maintain confidentiality of the bid.

using the scoring criteria set forth in the RFP. The scoring criteria included four major categories: LCOE, energy settlement location, interconnection/development status and local clearing requirement and project risk factors.

Scoring of the individual RFP Proposals was not part of the IRP process. Scoring criteria has been provided for transparency to respondents and to demonstrate that Vectren is serious about pursuing projects following the completion of the IRP analysis. Vectren does not believe that RFP's should be conducted just to obtain market data. The Proposals were scored to aid in the selection process after the preferred portfolio results were provided from the IRP. The Proposals were scored according to the criteria shown in Figure 6-6.

Figure 6-6 Scoring Summary

Scoring Criteria Name	Points	Scoring Method	Definition	Importance
LCOE Evaluation	150	Curve	$/MWh calculation within asset class	An LCOE evaluation comparing similar resource groups will help to show which Project(s) may provide lower cost energy to Vectren's customers.
Energy Settlement Location	100	Binary	Proposals that include all costs to have energy financially settled or directly delivered to Vectren's load node (SIGE.SIGW)	Having financial settlement or direct delivery to Vectren's load node provides Project's true resource cost to Vectren's customers, eliminating risks/costs associated with the delivery of energy.
Interconnection and Development Status	60	Binary	Executed a pro-forma MISO Service Agreement and Interconnection Construction Services Agreement (12 points) Completed a MISO Facilities Study (12 points) Completed a MISO System Impact Study (12 points) Achieved site control and completed zoning requirements (12 points) EPC Contract awarded (12 points)	These points are for completion of various critical milestones in the interconnection and development process. Projects which are further through the interconnection and development process will receive more points as cost certainty improves.
Local Clearing Area Requirement	30	Binary	Physically and electrically located in LRZ 6	Being located in LRZ 6 provides greater certainty that asset capacity can be deliverable to Vectren and fall within LCR requirements through entire life or contract term.
Credit and Financial Plan	20	Curve	Vectren will be reviewing the credit rating and financing capabilities in relation to a Bidder's Project.	Projects which lack the financial wherewithal to ensure development pose a significant risk to Vectren and their customers.
Development Experience	20	Curve	Scored based on 1,500 MW of relevant development experience	Relevant technology experience is important when looking at asset purchases or PPA's for facilities which are not in service. A Bidder's track record of project completion is a benefit to the Project's scoring.
Sole Ownership/Partial Owner	20	Binary	Being a sole owner would allow full site and dispatch rights/preferences	Being able to solely own, operate, and maintain a Project lowers risks for Vectren and their customers.
Ownership Structure (Purchase/PPA)	20	Binary	Vectren has a preference for ownership	Owning an asset and having control with regards to dispatch, maintenance, and operation of the facility lowers risks for Vectren and their customers.
Operational Control	20	Binary	Dispatch parameters used for the scheduling of energy into MISO and approval for maintenance outage periods	Operational control provides the ability to make prudent operational decisions when it makes economic sense for Vectren's customers.
Fuel Risk	20	Binary	Sites having firm and reliable fuel supply	Having fuel restrictions or a lack of reliable fuel could effect the operation of the Project and be a risk to the owner/off taker.
Delivery Date	20	Curve	For each year prior or after MISO PY 2023/2024, 25% of the points will be deducted	To the extent resources are brought on-line before potential Vectren unit retirements, Vectren customers could pay for duplicative capacity and/or energy; while there may be reasons to proceed with such projects, in recognition of their incremental costs, it is appropriate for such projects to not score as well in terms of timing.
Site Control	20	Binary	Proper rights to the site in which the facility will be located	Without proper permitting and permissions from the owner, there is a risk that the project may not move forward or could experience significant delays.

RFP bids were rank ordered consistent with the evaluation criteria and will be considered based on the RFP evaluation and the IRP determined need. Projects consistent with the

IRP have undergone further due diligence and have led to negotiations with bidders. As such, there is no assurance that the individual, highest-scoring qualified Proposal(s) will be selected. For further discussion of the evaluation criteria and results see Technical Appendix 6.9.

6.1.7 Challenges with Conducting an All-Source RFP within an IRP

While there are advantages to conducting an All-Source RFP as part of the IRP process, there are several challenges that must be considered, particularly the long lead time. Developers prefer certainty on project selection to minimize project development cost risk. Conducting an RFP as an input to the IRP necessitates a long process. Vectren believes that, at a minimum, a year is needed to conduct an IRP analysis. While Vectren asked bidders to keep bids open for a year after bid submittal, this does not mean that developers are able to wait until the process is complete.

As a result, some bids were withdrawn from Vectren's RFP during the IRP because the projects were acquired by other load serving entities. This delay has hurt the ability to act on proposals before they are acquired. During this IRP, at least one project, was purchased by another utility. Competition for projects in MISO zone 6 is steep with many utilities (NIPSCO, IPL, Hoosier Energy, IMPA and Vectren) currently all vying for announced projects that have more certainty of being developed.

Vectren has also had several attractive local wind and solar projects drop out of the MISO Generation Interconnection queue due to commitments/costs required from interconnection studies and they are no longer available at this time. Often projects are speculative. Developers apply with MISO to develop a project and are put in the MISO queue, as a series of studies is conducted. Each study requires more money from the developer in the form of milestone payments. Early studies put less money at risk for the developer. As interconnection costs for a project are identified the developer must make a choice to stay in the queue or drop out. Without certainty of an off taker, many projects drop. Long lead times increase this risk.

Additionally, some initial cost estimates have proved to be too low. As a project moves along, several issues can arise, including: updated engineering identifying new costs, environmental permitting, local pushback, local permitting, updated interconnection costs, updated risk assessments by the developers, etc.

6.2 CURRENT RESOURCE MIX

Generating units are often categorized as either base load, intermediate, or peaking units. This characterization has more to do with the economic dispatch of the units and how much service time they operate rather than unique design characteristics, outside of intermittent renewables, which do not have variable fuel costs. Base load units generally have the lowest energy costs per kWh and tend to operate most of the time, thereby providing the base of the generating supply stack after intermittent renewables, which operate as available and typically unrelated to market prices and conditions. The supply stack is the variable cost of production of power by each generating unit, stacked from least cost to most cost. In general, units that cost less to run are dispatched before units that cost more. Vectren's larger coal units have historically operated as base load units but with low natural gas prices and the introduction of more renewables into the market, capacity factors have decreased. Vectren's coal units more recently have operated more like intermediate units, particularly in shoulder months during Spring and Fall seasons. Intermediate units may cycle on and off frequently and may sit idle seasonally. Vectren's current peaking units have relatively high energy costs per kWh and are typically only started when energy demand exceeds 24/7 baseload capacity. Currently, Vectren's gas turbines are dispatched during these peak periods to assure reliability. These small peaking units may only run for a few hours and remain idle for long periods of time until called on.

Vectren's current generation mix consists of approximately 1,280 megawatts (MW) of installed capacity. This capacity consists of approximately 1,000 MW of coal-fired generation, 160 MW of gas fired peaking generation, 3 MW of renewable landfill gas generation, 4 MW of solar, Purchase Power Agreements (PPA's totaling 80 MW from wind) and a 1.5% ownership share of Ohio Valley Electric Corporation (OVEC) which equates to approximately 32 MW.

Figure 6.7 below references both Installed Capacity (ICAP) and Unforced Capacity (UCAP). Installed capacity is also referred to as nameplate capacity. This is the maximum output that can be expected from a resource. Unforced capacity is the amount of capacity that can be relied upon to meet peak load. MISO uses UCAP for planning purposes. The UCAP accreditation recognizes that all resources are not equally reliable or, in some cases, capable of achieving their design output. MISO uses a three-year reliability history and a weather normalized capability verification to determine the UCAP accreditation of each unit. Vectren used historical data and MISO's current methodology for thermal units to determine seasonal accreditation values along with the MISO UCAP planning reserve margin requirements (8.9% PRM[24]) in the current IRP. This information was utilized to help ensure that all portfolios met MISO obligations on a seasonal basis.

Figure 6.7 – Vectren Generating Units

Unit	Installed Capacity ICAP (MW)	Summer Unforced Capacity UCAP (MW)	Winter Unforced Capacity UCAP (MW)	Primary Fuel	Year Unit First In-Service
A.B. Brown 1	245	197	235	Coal	1979
A.B. Brown 2	245	232	221	Coal	1986
F.B. Culley 2	90	85	84	Coal	1966
F.B. Culley 3	270	261	263	Coal	1973
Warrick 4	150	133	137	Coal	1970
A.B. Brown 3	80	73	90*	Gas	1991

[24] Planning Year 2020-2021 Load of Load Expectations Report; MISO; https://cdn.misoenergy.org/2020%20LOLE%20Study%20Report397064.pdf; 11/01/2019; page 5

Unit	Installed Capacity ICAP (MW)	Summer Unforced Capacity UCAP (MW)	Winter Unforced Capacity UCAP (MW)	Primary Fuel	Year Unit First In-Service
A.B. Brown 4	80	72	82*	Gas	2002
Blackfoot	3	N/A[25]	N/A[26]	Landfill Gas	2009
Oak Hill Solar	2	N/A[22]	N/A[25]	Sun	2018
Volkman Road Solar	2	N/A[25]	N/A[25]	Sun	2018

*Installed capacity shown at 59°F, winter UCAP shown at 20°F

6.2.1 Coal

The A.B. Brown Generating Station (ABB), located in Mt. Vernon, IN, consists of two coal fired units, each with an installed capacity of 245 MW. ABB Unit 1 began commercial operation in 1979, while ABB Unit 2 became operational in 1986. Over the last three years these units have operated at an average capacity factor of 53%.

Both A.B. Brown units are scrubbed for sulfur dioxide (SO_2) emissions, utilizing a dual-alkali Flue Gas Desulfurization (FGD) process. The FGD systems were included as part of the original unit design and construction. Sulfur trioxide (SO_3) is removed via Sodium Based Sorbents (SBS) injection systems installed on both units in 2015. ABB is also scrubbed for nitrogen oxides (NO_x) with Selective Catalytic Reduction (SCR) systems having been installed on Unit 2 in 2004 and on Unit 1 in 2005. Mercury (Hg) removal is accomplished on both units as a co-benefit of SCR and FGD operations as well as through the addition of organosulfide injection systems installed in 2015. Particulate matter (PM) is captured via an electrostatic precipitator (ESP) on Unit 2. PM control at Unit 1 was upgraded to a fabric filter in 2004. The PM that is captured, also known as fly

[25] The Blackfoot landfill gas generator and 2 MW solar installations are connected at the distribution level and are not part of the transmission connected generation network managed by MISO. Therefore, they are not assigned a MISO UCAP value.

ash, is part of Vectren's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, MO where it is used in the manufacture of cement.

While the A.B. Brown units began commercial operation after the Culley units, the dual-alkali scrubbers on these units present several operational challenges. First, based on historical costs the variable production cost associated with the scrubbers is approximately six times greater than the limestone-based scrubber installed on the Culley units. Also, the dual-alkali process is corrosive which results in high maintenance costs to keep the FGD's and associated equipment operational. And finally, these FGD's are the last dual-alkali scrubbers in operation in the U.S. and are nearing the end of their useful life. This can lead to challenges obtaining operational support and replacement parts when needed.

A.B. Brown Units 1 and 2 burn Illinois basin bituminous coal, which is mined in Knox County, IN and is delivered via rail.

The A.B. Brown plant site also has two natural gas turbine generators which are discussed in Section 6.2.2, Natural Gas.

The F.B. Culley Generating Station (FBC), located near Newburgh, IN, is a two-unit, coal fired facility. FBC Unit 2 has an installed generating capacity of 90 MW and came online in 1966, while FBC Unit 3 has an installed capacity of 270 MW and became operational in 1973. Over the last three years Unit 2 has operated at an annual capacity factor of 23% while Unit 3 was 65%.

FBC is scrubbed for Sulfur Dioxide (SO_2) emissions, utilizing an FGD process which is shared by both units and was retrofitted in 1994. This standard technology is much more cost effective than A.B. Brown's scrubber. The captured SO_2 is converted into synthetic gypsum within the system and, as part of Vectren's beneficial reuse program, is shipped, via barge, to a facility near New Orleans, LA and is shipped via truck to a facility near

Shoals, IN where it is used in the manufacture of drywall. Sulfur trioxide (SO_3) is removed from FBC Unit 3 via a Dry Sorbent Injection (DSI) system installed in 2015. FBC Unit 3 is also scrubbed for NO_x with a Selective Catalytic Reduction (SCR) system that was installed in 2003. NO_x control on FBC Unit 2 is provided by low NO_x burners. Mercury removal is accomplished on both units as a co-benefit of SCR & FGD operation as well as through the addition of organosulfide injection systems installed in 2015. PM is captured via an ESP retrofitted on Unit 2 in 1972. Unit 3 was upgraded to a fabric filter for PM control in 2006. The PM that is captured, also known as fly ash, is part of Vectren's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, MO where it is used in the manufacture of cement.

The F.B. Culley units burn Illinois basin bituminous coal, which is mined in Knox County, IN and delivered via truck. F.B. Culley 3 is Vectren's most efficient coal unit with an industry standard scrubber, which has much lower variable costs than ABB1 and ABB2. As such F.B. Culley 3 is in the process of upgrades to comply with EPAs ELG rule.

Warrick Unit 4 (Warrick) located near Newburgh, IN is a coal fired unit operated and maintained by Alcoa Power Generating Inc. Vectren maintains 50% ownership of Warrick Unit 4. It has an installed capacity of 300 MW which began commercial operation in 1970. Vectren's 50% interest is equal to 150 MW. Over the last three years this unit has operated at a capacity factor of 62%.

Warrick Unit 4 is scrubbed for SO_2 emissions, utilizing a FGD process which was retrofitted in 2009. The captured SO_2 is converted into synthetic gypsum within the system and (as part of Vectren's beneficial reuse program) is shipped via truck to a facility near Shoals, IN where it is used in the manufacture of drywall. SO_3 is removed via a DSI system installed in 2010. Unit 4 is also scrubbed for NO_X with a SCR system which was retrofitted in 2004. Mercury removal is accomplished as a co-benefit of SCR and FGD operation as well as through the addition of organosulfide injection systems installed in 2015. PM is captured via an ESP. The PM that is captured, also known as fly ash, is part of Vectren's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, MO where it is used in the manufacture of cement.

Warrick Unit 4 burns Illinois basin bituminous coal. Vectren purchases coal for its share of Warrick Unit 4, which is mined in Knox County, IN and is delivered by rail.

6.2.2 Natural Gas

The A.B. Brown Generating Station has two natural gas fired Simple Cycle Gas Turbine (SCGT) peaking units. Each has an installed capacity of 80 MW. ABB Unit 3 began commercial operation in 1991, while ABB Unit 4 became operational in 2002. Over the last three years Unit 3 has operated at a capacity factor of 1% with Unit 4 at 2%.

6.2.3 Renewables

The Blackfoot Clean Energy Facility located in Winslow, IN is a base load facility consisting of two Internal Combustion (IC) landfill methane gas fired units. Blackfoot Units 1 & 2 became operational in 2009 and are capable of producing 1.5 MW each. Over the last three years these units have operated at a capacity factor of 42%.

The Oak Hill and Volkman Road universal solar projects in Evansville, IN became operational in 2018 with each location having an installed solar capacity of 2 MW. In addition to the solar capacity the Volkman Road site includes 1 MW of battery storage. These assets are located on the distribution system and are therefore netted out of Vectren load for this analysis. In 2019 the solar installations operated at an average annual capacity factor of 21%. The average annual capacity factor is affected by hours of daylight, cloud cover, temperature, etc. This installation was available over most hours in 2019.

A third solar facility is under development near Troy, IN and will have an installed capacity near 50 MW. It is expected to be operational in early 2021.

6.2.4 Energy Efficiency

Vectren utilizes a portfolio of Demand Side Management (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 Commission and implemented pursuant to various IURC orders over the years.

Since 1992, Vectren has operated a Direct Load Control (DLC) program called Summer Cycler that reduces residential and small commercial air-conditioning and water heating electricity loads during summer peak hours. A description of the program is included below. While this technology can still be reliably counted on to help lower demand for electricity at times of peak load, this aging technology will be phased out over time. Vectren's Summer Cycler program has served Vectren and its customers well for more than two decades, but emerging technology is now making the program obsolete. Between 2010 and 2018, Vectren's DSM programs reduced demand by approximately 69,000 kW and provided annual incremental gross energy savings of approximately 360,000,000 kWh.

The table below outlines the estimated program penetration on a yearly basis since Vectren programs began in 2010. Gross cumulative savings below, are shown as a percent of eligible retail sales. Note that historical DSM savings are implicitly included in the load forecast as these savings are embedded in the historical sales data.

Figure 6.8 Gross Cumulative Savings

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh) *	Gross Cumulative Savings (GW) *	Percent of Sales Achieved (Cumulative)
2010	5,616.87	2.53	.00051	0.04%
2011	5,594.84	19.40	.00331	0.35%
2012	5,464.75	66.95	.01212	1.23%
2013	5,459.11	128.64	.02271	2.36%

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh) *	Gross Cumulative Savings (GW) *	Percent of Sales Achieved (Cumulative)
2014**	3,498.69	175.98	.03053	5.03%
2015	3,223.81	202.82	.03552	6.29%
2016	3,256.3	236.40	.04336	7.26%
2017	3,280.7	268.86	.05005	8.20%
2018	3,490.7	309.28	.05759	8.86%

*Gross Cumulative Savings are adjusted for Residential Behavioral, which has a one-year program life therefore not cumulative in nature.

**Statewide DSM programs ended in 2013. The drop in eligible sales is attributed to industrial customers opting-out of DSM programs effective July 1, 2014.

6.2.4.1 2018-2020 Plan Overview

Consistent with the 2016 IRP, the framework for the 2018-2020 EE Plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 77% of eligible load. Below is a listing of residential and commercial & industrial programs offered in 2018-2020. For full program descriptions including the customer class, end use of each program and participant incentives provided by the programs, please refer to the 2018-2020 EE Plan detail found in the Technical Appendix Attachment 6.2 Vectren Electric 2018-2020 DSM Plan.

Residential Programs

- Residential Lighting
- Home Energy Assessments and Weatherization
- Income Qualified Weatherization
- Appliance Recycling
- Energy Efficient Schools
- Residential Prescriptive
- Residential New Construction
- Residential Behavior Savings
- Residential Smart Thermostat Demand Response (Incentives only)
- Bring Your Own Thermostat (BYOT)

- Food Bank – LED Bulb Distribution
- Conservation Voltage Reduction (CVR) Residential

Commercial & Industrial Programs

- Small Business Direct Install
- Commercial & Industrial Prescriptive
- Commercial & Industrial New Construction
- Commercial & Industrial Custom
- Building Tune-Up
- Multi-Family Retrofit
- Conservation Voltage Reduction - Commercial

The 2018-2020 plan was included an existing resource in the 2019/2020 IRP and has an assumed average measure life of 12 years. The table below shows the amount of net savings included in the IRP as a resource (gross savings can be found in Technical Appendix Attachment 6.2 Vectren Electric 2018-2020 DSM Plan).

Figure 6.9 2018-2020 Energy Efficiency Savings

	2018*		2019**		2020***	
Sector	Net MWh Energy Savings	Net MW Demand Savings	Net MWh Energy Savings	Net MW Demand Savings	Net MWh Energy Savings	Net MW Demand Savings
Residential	19,241	4.0	19,129	4.0	15,821	4.7
Commercial & Industrial	21,602	3.2	16,495	3.4	16,208	1.7
Total	40,843	8.5	35,624	7.4	32,029	6.4

* 2018 Evaluation Results used for 2018
** 2019 Operating Plan used for 2019 savings and Net to Gross (NTG) Factors
*** 2018-2020 Filed Plan used for 2020 Savings and NTG Factors

6.2.5 Demand Response

Vectren's tariff currently includes two active demand response programs: 1) the Direct Load Control and 2) interruptible options for larger customers. Demand response programs allow Vectren to curtail load for reliability purposes. Vectren's tariff also includes a MISO demand response tariff, in which no customers are currently enrolled given the absence of an active demand response program within the MISO market at this time.

6.2.5.1 Current DLC (Summer Cycler)

The DLC program provides remote dispatch control for residential and small commercial air conditioning, electric water heating and pool pumps through radio-controlled load management receivers. Under the program, Vectren compensates customers in exchange for the right to initiate events to reduce air-conditioning and water-heating electric loads during summer peak hours. Vectren can initiate a load control event for several reasons, including: to balance utility system supply and demand, to alleviate transmission or distribution constraints, or to respond to load curtailment requests from MISO.

Vectren manages the program internally and utilizes outside vendors for support services, including equipment installation and maintenance. Prospective goals for the program consist of maintaining load reduction capability and program participation while achieving high customer satisfaction. Vectren also utilizes an outside vendor, The Cadmus Group, to evaluate the DLC program and provide unbiased demand and energy savings estimates.

In 2020 Cadmus predicted that the DLC Program was capable of generating approximately 8.3 MWs of peak demand savings from residential air-conditioning load control and residential water heating load control. This is roughly half of prior predictions, which were used for IRP modeling.

Until recently, DLC switches have been the default choice for residential load control programs. Vectren has had a DLC program since the early 1990's and as of 2019 had approximately 21,000 residential customers with 27,000 switches participating in the program. However, with the advent of smart thermostats and the myriad of benefits they offer for both EE and DR, Vectren plans to begin replacing DLC switches with smart thermostats.

6.2.5.2 Current Interruptible Load

Vectren makes available a credit for qualified commercial and industrial customers to curtail demand under certain conditions. Vectren included three customers who were participating for a total demand reduction of 35 MW. New MISO testing requirements are currently being put into place to ensure these DR resources are available throughout the year. MISO is proposing interruptible resource accreditation based on the amount of interruptions and available hours to curtail. MISO has already implemented mandatory annual testing for the first time that will require load interruptions to meet the test requirements. Prior to January 31, 2019, Vectren had never been requested by MISO to deploy LMRs, thereby interrupting customer load. Because of these changes that will now require annual interruptions that are likely to increase in occurrence and duration, Vectren expects some, if not all, of its currently enrolled customers to drop out, as frequent interruptions in service can be very costly to industrial customers' operations. Since implemented, one customer (~7MWs) has left the program. While aggressive, Vectren maintained industrial interruptible load at the 35 MWs within the model throughout the analysis period. Given Vectren's mix of industrial customers, it is unlikely that new customers will sign up for this program. As such, Vectren did not allow the model to select additional interruptible DR.

6.2.5.3 Smart Thermostats

Vectren launched its pilot Smart Wi-Fi Thermostat program in 2016, by installing 2,000 smart Wi-Fi enabled thermostats in homes in its service territory. As an alternative to DLC switches, smart thermostats can optimize heating and cooling of a home to reduce energy usage and control load while learning from occupant behavior/preference, adjusting Heating, Ventilation and Air Conditioning ("HVAC") settings. Preliminary evaluation results are showing significantly more load reduction delivered by smart thermostats. The current DLC switch program is a well-established means for Vectren to shed load during peak demand; however, over time, this option is will become obsolete. As such, Vectren has designed a program to change out from switches to smart Wi-Fi thermostats, a strategic option for cost effective load control. The Smart DLC Change-out program will focus on residential single-family homes and apartment dwellers. By installing connected devices in customer homes rather than using one-way signal switches, Vectren will be able to provide its customer base deeper energy savings opportunities and shift future energy focus to customer engagement. This change out program is reflected in IRP modeling.

Additionally, Vectren also launched the Bring your Own Thermostat (BYOT) program as a demand response program. The BYOT program is a further expansion of the Residential Smart/Wi-Fi thermostat initiative. The 2018-2020 Plan provides for 240kW demand each year from the BYOT program based on 400 participants each year. BYOT allows customers who have or will purchase their own device from multiple potential vendors to participate in DR and other load curtailing programs managed through the utility. By taking advantage of two-way communicating smart Wi-Fi thermostats, BYOT programs can help utilities reduce acquisition costs for load curtailment programs and improve customer satisfaction. BYOT allows the utility to avoid the costs of hardware, installation and maintenance associated with transitioning to a smart thermostat. Through the use of smart/Wi-Fi enabled thermostats, the utility can remotely verify how many customers are connected to the network at any given time and determine which thermostats are participating in DR events. Smart thermostat DR programs provide approximately 0.6 kW - 1 kW per thermostat in load reductions during a DR event.

6.3 POTENTIAL FUTURE OPTIONS MODELING ASSUMPTIONS

Vectren utilized the All-Source RFP for modeling inputs through 2024 for wind, solar, solar + storage resources, (Tier 1 bids) as shown in Figure 6.5. The following supply side information was based on a technology assessment from Burns and McDonnell unless otherwise noted and was used to help provide needed information to model other resources where Vectren did not receive a Tier 1 bid and for resources in future years and utilizing the cost curve information in Figure 6.21.

6.3.1 Supply Side

Resources are typically divided into supply side and demand side resources. Supply side simply means resources that produce energy.

6.3.1.1 Coal Technologies

Coal power plants, also known as Pulverized Coal (PC) steam generators, are characterized by pulverizing coal, then burning the coal in a boiler to create heat. The heat from the boiler is then used to turn water into high pressure steam which is used to turn the turbine causing the generator to create electricity.

The power industry typically classifies conventional coal fired power plants as subcritical, supercritical and ultra-supercritical based on the steam operating pressure. Subcritical units operate below the critical point of water, which is 3208 psia and 705°F, supercritical units operate above the critical point of water. Ultra-supercritical units operate at even higher pressures or temperatures in order to increase efficiency. While efficiency is increased, higher grade and thicker materials must be used, which increase costs.

Proposed greenhouse gas (GHG) regulations for new construction will limit CO_2 emissions to 1,100 lbs./MWh, a level which would require carbon capture on PC plants. Carbon capture on PC plants has been demonstrated in the field and as the technologies mature, they will likely become more technically and financially feasible, especially if markets emerge for the captured gases. See Figure 6-10 for further details on the coal technologies evaluated.

Figure 6-10 – Coal Technologies

Coal		
Operating Characteristics and Estimated Costs	**Supercritical Pulverized Coal with Carbon Capture**	**Ultra-Supercritical Pulverized Coal with Carbon Capture**
Base Load Net Output (MW)	506	747
Base Load Net Heat Rate (HHV Btu/kWh)	11,290	10,480
Base Project Costs (2019$/kW)	$6,370	$5,760
Fixed O&M Costs (2019$/kW-year)	$29.10	$29.10

6.3.1.2 Natural Gas Technologies

6.3.1.2.1 Simple Cycle Gas Turbines (Combustion Turbines or CT)

SCGT utilize natural gas to produce power. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power or electricity. Typically, SCGTs are used for peaking power due to fast load ramp rates, higher heat rates compared to other technologies and relatively low capital costs. See Figure 6-11 for further details on the simple cycle gas turbine technologies evaluated.

To aid in the evaluation of SCGT, technology estimates were developed to represent the natural gas pipeline costs to supply firm gas service to the unit. Estimates were developed for firm gas supply (as opposed to interruptible) because MISO has signaled that while summer peak hours are important all hours of the year matter and a dispatchable resource needs to be available for service when needed by the system. The A.B. Brown site was used for this analysis. It is an existing brownfield site with interconnection rights through MISO. The cost estimates were developed in partnership with a potential service provider, Texas Gas.

Figure 6-11 – Simple Cycle Gas Turbine Technologies

Simple Cycle Gas Turbines					
Operating Characteristics and Estimated Costs	**1xLM 6000 SCGT**	**1xLMS 100 SCGT**	**1xE-Class SCGT**	**1xF-Class SCGT**	**1xG/H-Class SCGT**
Base Load Net Output (MW)	41.6	97.2	84.7	236.6	279.3
Base Load Net Heat Rate (HHV Btu/kWh)	9,280	8,895	11,527	9,928	9,311
Base Project Costs (2019$/kW)	$2,230	$1,660	$1,470	$730	$810
Fixed O&M Costs (2019$/kW-year)[27]	$36.28	$16.04	$21.46	$8.32	$8.02

6.3.1.2.2 Combined Cycle Gas Turbines

Combined Cycle Gas Turbines (CCGT) 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 the steam turbine and generator to produce electric power. Using both gas and steam turbine (Brayton and Rankine) cycles in a single plant results in high conversion efficiencies and low emissions. Additionally, natural gas can be fired in the Heat Recovery Steam Generator (HRSG) to produce additional steam and associated output for peaking load, a process commonly referred to as duct firing.

For this assessment, a 1x1 F class and G/H class, as shown in Figure 6-12, were evaluated with General Electric (GE) turbines as representative CCGT technologies. The F class is based on the GE 7F.05 turbine and the G/H class is based on the GE HA.01 turbine. A 1x1 CCGT is configured with one gas turbine and one steam turbine. Vectren did not model a large 2x1 CCGT. See Figure 6-12 for further details on the CCGT technologies evaluated.

[27] The cost for firm gas supply was included in this analysis but isn't included in the Fixed O&M Costs

Figure 6-12 – Combined Cycle Gas Turbine Technologies

Combined Cycle Gas Turbines		
Operating Characteristics and Estimated Costs[28]	**1x1 7F.05 CCGT (ABB)**	**1x1 7HA.01 CCGT (ABB)**
Duct-Firing	Fired	Fired
Base Load (24/7 Power) Net Output (MW)	365	420
Incremental Duct-Fired (Peaking) Net Output (MW)	72	79
Base Load Net Heat Rate (HHV Btu/kWh)	6,460	6,247
Incremental Duct-Fired Heat Rate (HHV Btu/kWh)	8,269	8,221
Base Project Costs (2019$/Fired kW)	$1,153	$1,087
Fixed O&M Costs (2019$/Base Load kW-year)[29]	$13.99	$15.94

6.3.1.3 Renewables Technologies

Four renewable technologies were evaluated in the IRP. Those technologies were wind energy, solar photovoltaic, hydroelectric and waste-to-energy.

6.3.1.3.1 Wind

Wind turbines convert the kinetic energy of wind into mechanical energy. Typically, wind turbines are used to pump water or generate electrical energy which is supplied to the grid. See Figure 6-13 for further details on the variety of wind technologies evaluated. Beyond the RFP bids, the following assumptions were based on the Burns and McDonnell tech assessment.

[28] Combined cycle gas turbines are shown as fired configuration at A.B. Brown site for this table.
Reference the Technology Assessment for additional details on duct-firing
Operational and cost estimates developed by Black & Veatch
[29] The cost for firm gas supply was included in this analysis but isn't included in the Fixed O&M Costs

Figure 6-13 – Wind Renewables

Operating Characteristics and Estimated Costs[30]	Wind (Southern Indiana)	Wind (Northern Indiana)	50 MW Wind (Indiana) & 10 MW / 40 MWh Storage
Base Load Net Output (MW)	200	200	50
Base Project Costs (2019$/kW) / ($/kWh for Storage)	$1,450	$1,450	$1,800 / $650
Fixed O&M Costs (2019$/kW-year)	$40.00	$40.00	$44.14
Variable O&M Costs (2019$/MWh)	Included in FOM	Included in FOM	$14.50 (Storage MWh Only)
Variable O&M Costs (2019$/MWh)	Included in FOM	Included in FOM	$14.50 (Storage MWh Only)
Annual Capacity Factor	28%	38%	

The Production Tax Credit (PTC) is a tax credit per-kilowatt-hour (kWh) for electricity generated by qualified energy resources. The duration of the credit is 10 years after the in-service date for all facilities placed in service after August 8, 2005. The tax credit is $0.015 per kWh in 1993 adjusted by inflation adjustment factor provided by the IRS and rounded to the nearest 0.1 cents. Vectren assumed 2.2% past 2019 IRS values, which was the general inflation used throughout the IRP. The tax credit is phased down by 20 percent per year for wind facilities commencing construction after December 31, 2016. The tax credit reduces from 100 percent for wind facilities commencing construction in 2016 and before, down to 60 percent for wind facilities commencing construction in 2019. See Figure 6-14 below for the percent of production tax credit. For purposes of the IRP, Vectren applied the PTC as if the commence construction was one year prior to the commercial operation date. Modeling assumed a safe harbor assumption of two years PTC extension for generic wind builds.

[30] Based on average of Burns and McDonnell, Pace, and NREL technology assessment information where available.

Figure 6-14 –Production Tax Credit by Year

Commence Construction (Prior to)	Production Tax Credit (%)
2017	100%
2018	80%
2019	60%
2020	40%
2021	60%*
2022	0%
2023	0%

*PTC Extended

6.3.1.3.2 Solar

The conversion of solar radiation to useful energy, in the form of electricity, is a mature concept with extensive commercial experience that is continually developing into a diverse mix of technological designs. Solar conversion technology is generally grouped into solar photovoltaic (PV) technology, which directly converts sunlight to electricity due to the electrical properties of the materials comprising the cell.

Photovoltaic (PV) cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively and negatively charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other. See Figure 6-15 for further details on the solar PV technologies evaluated.

Figure 6-15 – Solar Photovoltaic

Operating Characteristics and Estimated Costs[31]	10 MW Solar PV	50 MW Solar PV	100 MW Solar PV	50 MW Solar PV & 10 MW / 40 MWh Storage
Base Load Net Output (MW)	10	50	100	50
Base Project Costs (2019$/kW)	$1,961	$1,526	$1,414	$1,860
Fixed O&M Costs (2019$/kW-year)	$23.41	$22.91	$18.82	$22.33
Variable O&M Costs (2019$/MWh)	Included in FOM	Included in FOM	Included in FOM	$5.74 (Storage MWh Only)

The Investment Tax Credit (ITC) is a federal tax credit as a percent of basis invested in eligible solar generation. ITC percentage depends on the commencement of construction as shown below in Figure 6-16. For modeling purposes, Vectren assumed commercial operation date and commence construction to be the same year for solar projects. The eligible investment was assumed to be the total invested project costs to build. The ITC was normalized over the book life of the asset, which evenly distributes the tax credit out over the asset book life.

Figure 6-16 – Investment Tax Credit by Year

Commence Construction (Prior to)	Investment Tax Credit (%)
2017	30%
2018	30%
2019	30%
2020	30%
2021	26%
2022	22%
1/1/2022 & beyond	10%

[31] Based on average of Burns and McDonnell, Pace, and NREL technology assessment information where available.

For the purposes of the IRP, all modeled bids received safe harbor for full realization of the ITC. Modeling assumed a safe harbor assumption of two years ITC extension for generic solar builds.

6.3.1.3.2.1 Safe Harboring Methods

There are two options, often referred to as safe harboring methods, that developers can utilize to extend qualifications for the ITC and PTC. First, a project can prove that they have started and maintained construction of the project. Second, a project can purchase five percent of the total project cost. Once these safe harboring methods are initiated the developer has 4 years to complete the project. This allows developers to prolong the usefulness of the ITC and PTC.

6.3.1.3.3 Hydroelectric

Low-head hydroelectric power generation facilities are designed to produce electricity by utilizing water resources with low pressure differences, typically less than 5 feet head but up to 130 feet. This allows the technology to be implemented with a smaller impact to wildlife and environmental surroundings than conventional hydropower. However, power supply is dependent on water supply flow and quality, which are sensitive to adverse environmental conditions like dense vegetation or algae growth, sediment levels and drought. Additionally, low-head hydropower is relatively new and undeveloped, thus resulting in a high capital cost for the relatively small generation output. See Figure 6-17 for further details on the hydroelectric technology evaluated.

Data from a U.S. Army Corps of Engineers report was used to determine the economically feasible output from the Newburgh and John T. Myers dams located locally on the Ohio River. This report showed that when taking economics into consideration both dams had an average potential output near 50 MW which was consistent with tech assessment data used in the analysis. A separate publication from the U.S Army Corps of Engineers showed that the estimated construction cost of the Cannelton facility was very close to the assumptions used in the analysis.

Figure 6-17 – Hydroelectric

Operating Characteristics and Estimated Costs	50 MW Low-head Hydroelectric
Base Load Net Output (MW)	50
Base Project Costs (2019$/kW)	$6,050
Fixed O&M Costs (2019$/kW-year)	$92.40

6.3.1.3.4 Waste-to-Energy

Two waste-to-energy (WTE) technologies were included within the analysis. Waste fuel is combusted directly in the same way fossil fuels are consumed in other combustion technologies. The heat resulting from the burning of waste fuel converts water to steam, which then drives a steam turbine generator to produce electricity. It should be noted that these types of projects are very site specific and hard to have generic assumptions for use in an IRP. The two fuel types evaluated in the IRP were wood and landfill gas, which are represented in Figure 6-18.

Figure 6-18 – Waste to Energy Technologies

Operating Characteristics and Estimated Costs	Bubbling Fluidized Bed	Landfill Gas IC Engine
Base Load Net Output (MW)	50	5
Base Load Net Heat Rate (HHV Btu/kWh)	13,000	10,740
Base Project Costs (2019$/kW)	$5,640	$4,110
Fixed O&M Costs (2019$/kW-year)	$124.00	$111.78

6.3.1.3.5 Congestion Charges

Transmission congestion charges are the final element for consideration when analyzing the true cost of delivered resources and are the most difficult to estimate. Congestion charges are calculated by taking the difference in Locational Marginal Pricing (LMP's) where the energy is injected (source) and where the energy is withdrawn (sink). For Vectren to purchase energy outside of Zone 6 (Indiana) or even off Vectren's system in Indiana, Vectren would be responsible to pay the LMP at the sink and would receive payment from the source. Therefore, any price differential is an added risk and possible added cost to the delivery of energy. MISO does not provide estimates of congestion charges due to the volatility and immense variability that impacts the MISO transmission system and the congestion related charges. When taking into consideration the cost of a resource, the required transmission charges and estimated congestion charges based on historical data, the greater the distance, the greater the potential for higher costs.

Vectren's modeling accounted for congestion. As previously described, Vectren modeled tier 1 bid information, which included a "delivered price" (all in price from the developer), or projects on Vectren's system, which minimizes congestion risk. Outside of bid information, projects were generally assumed to be on Vectren's system. Any resource that is outside of Vectren's system must include an evaluation of potential congestion charges.

6.3.1.4 Energy Storage

Two types of energy storage technologies were evaluated in the IRP –lithium-ion batteries (typically short-duration) and flow batteries (long-duration). These are shown in Figure 6-19.

Batteries utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging and generating an electric current when discharged. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity and ease of installation and operation.

Lithium ion (Li-ion) batteries contain graphite and metal-oxide electrodes and lithium ions dissolved within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Li-ion technology has seen a resurgence of development in recent years due to its high energy density, low self-discharge and cycling tolerance.

Flow batteries utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane, in which the charge-inducing chemical reaction occurs and liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference.

Both Li-ion and flow batteries offer a way of storing low-priced, off-peak generation that can be discharged during higher-priced, peak demand hours (wholesale energy market arbitrage). These storage technologies can also function as transmission assets that can assist in maintaining the reliability of the grid, potentially displacing or deferring the need for more traditional transmission upgrades.

Figure 6-19 – Energy Storage Technologies

Operating Characteristics and Estimated Costs[32]	Lithium Ion 10 MW / 40 MWh	Lithium Ion 50 MW / 200 MWh	Flow Battery 10 MW / 60 MWh	Flow Battery 10 MW / 80 MWh	Flow Battery 50 MW / 300 MWh	Flow Battery 50 MW / 400 MWh
Base Load Net Output (MW)	10	50	10	10	50	50
Round-Trip Cycle Efficiency	85%	85%	68%	68%	68%	68%
Base Project Costs (2019$/kW)	$1,972	$1,562	$3,823	$4,305	$3,034	$3,478
Fixed O&M Costs (2019$/kW-year)	$22.36	$18.85	$110.10	$110.10	$35.06	$35.06
Variable O&M Costs (2019$/MWh)	$6.07	$6.07	$1.50	$1.50	$1.50	$1.50

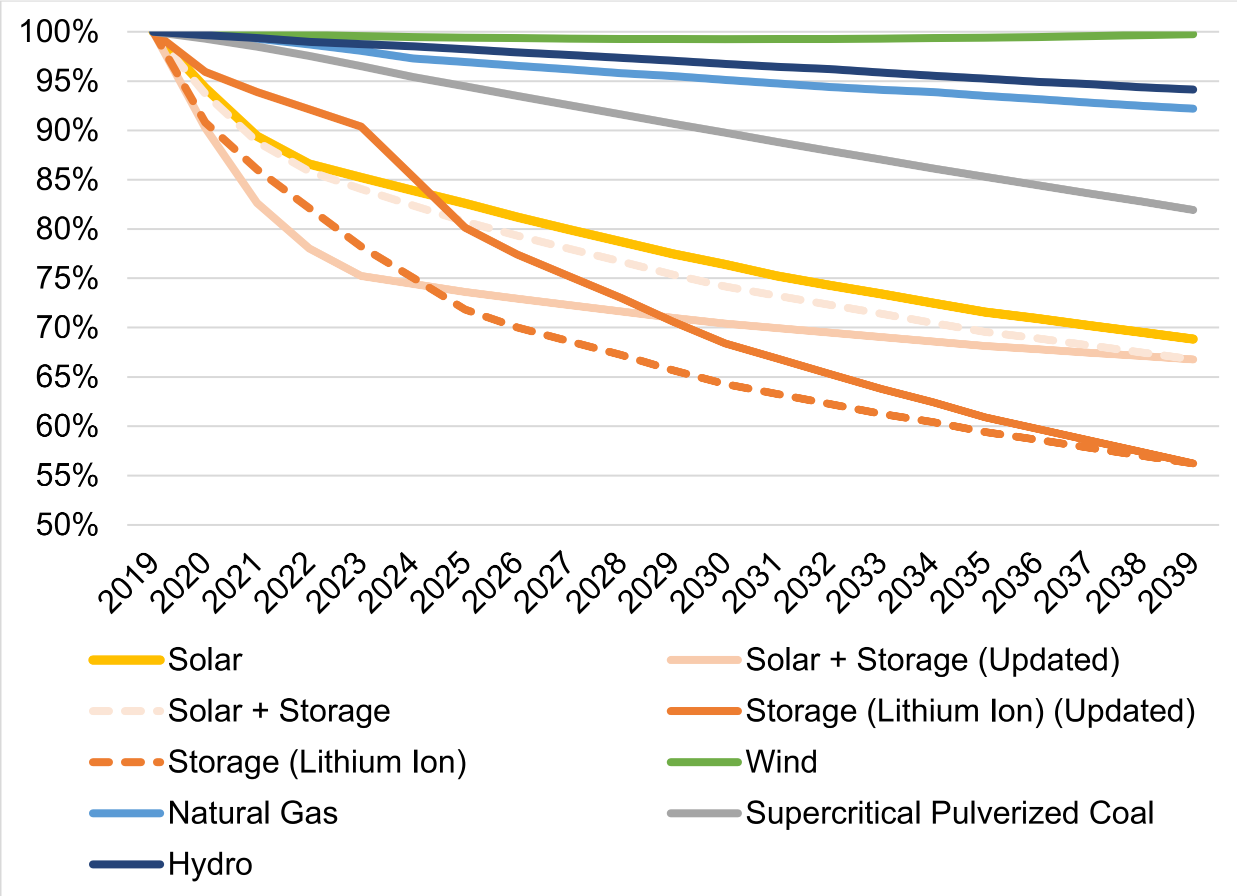
[32] Based on average of Burns and McDonnell, Pace, and NREL technology assessment information where available.

6.3.1.5 Cost Curve Discussion

Forward looking capital cost forecasts were developed and used as part of the 2019/2020 IRP process. Capital cost curves vary based on the generation technology, as shown in Figure 6-21.

Technologies whose capital costs do not decline significantly over the IRP time period such as wind, natural gas, coal and hydro are generally more mature, while technologies such as solar and storage are less mature and are expected to experience larger reductions in capital cost over the IRP time period. In the next 20 years, new technological developments and increasing efficiencies in solar and storage are expected to decrease capital costs by ~30% and ~40%, respectively. Due to uncertainty associated with these less mature technologies, Vectren relied upon multiple third-party sources to develop consensus capital cost forecasts. The capital cost forecast curves were adjusted for solar + storage and storage based on data received as part of the RFP process. Solar bids received in the RFP aligned very closely with the original consensus cost curve forecast (these curves are on top of each other in Figure 6-21, solar + storage bids resulted in lowering the near-term forecast, while the bids received for standalone storage resulted in a slight increase to the near term cost curve forecast. These updates help to align Vectren's forecasts with real market data for these less mature technologies. Figures 7.12-7.14 show modeled values by scenario.

Figure 6-20 - Forward Capital Cost Estimates



6.3.2 DSM

6.3.2.1 Energy Efficiency Background

In developing a resource plan that integrates demand side and supply side resources, it is incumbent for the energy company to provide the integrating process with a set of demand side (DSM) options that can be incorporated into the plan. This process aligns with IURC's Rule 170 IAC 4-7-6(b) which states:

> "An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service

requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers."

In addition, this process aligns with Senate Enrolled Act (SEA) 412 which requires that energy efficiency goals be consistent with an electricity supplier's IRP. Taken together, these jointly supportive requirements direct the energy company to study, similar to supply side resources, available DSM options that may be chosen by the IRP analytical process in arriving at a resource plan. In other words, the level of DSM to be pursued by the energy company should be determined through the IRP process.

6.3.2.2 DSM Market Potential Study

The first step in the process is a Market Potential Study (MPS). A key purpose of an energy efficiency MPS is to provide energy efficiency planners, decisionmakers and interested stakeholders with a roadmap to the best opportunities for energy efficiency savings opportunities in the residential, commercial and industrial customer classes. "Energy efficiency potential studies are an effective tool for building the policy case for energy efficiency, evaluating efficiency as an alternative to supply side resources and formulating detailed program design plans. They are typically the first step taken by entities interested in initiating or expanding a portfolio of efficiency programs and serve as the analytic basis for efforts to treat energy efficiency as a high-priority resource equivalent with supply-side options."[33] The results of a potential study pinpoint the energy efficiency measures having the greatest potential for energy savings and identifies the measures that are the most cost effective. Program administrators, regulators and stakeholders can use the results of potential studies to determine the types of programs that should be implemented and how much to invest in energy efficiency as a resource.

[33] "Guide for Conducting Energy Efficiency Potential Studies"; Prepared by Philip Mosenthal and Jeffrey Loiter, Optimal Energy, Inc.; https://www.epa.gov/sites/production/files/2015-08/documents/potential_guide_0.pdf; November 2017; page ES-1

Potential studies also provide useful information on the benefits and costs of energy efficiency measures and programs from various viewpoints: society as a whole, all ratepayers, the program administrator, program participants and utility rates.

Vectren's MPS completed in 2019 was both to inform the IRP and support the development of a DSM Action Plan for Vectren. The study included primary market research and a comprehensive review of current program, historical savings and projected energy savings opportunities to develop estimates of technical, economic and achievable potential. The study collected primary market research on up-to-date C&I data for the Vectren service area for the saturation of energy-using equipment, building characteristics and the percent of energy using equipment that is already high efficiency. Primary market research was also conducted to understand customer willingness to participate in energy efficiency programs at different incentives levels and targeted end-uses.

Technical potential is the maximum energy efficiency available, assuming that cost and market adoption of a technology are not a barrier. Economic potential is the subset of technical potential that is cost effective, meaning the economic benefit outweighs the cost. The economic potential is measured by the total resource cost test, which compares the lifetime energy and capacity benefits to the incremental cost of the energy efficiency measure. While some may contend that the full technical or economic potential should be provided as the level of DSM options available in the IRP process, this ignores the fact that 100% of the customers would have to participate. This is not realistic as historical evidence has shown that not all customers will adopt a given technology for reasons that range from aesthetic preferences, lack of information about energy efficiency measures, lack of access to capital to perceived comfort concerns. Rather, the potential modeled in the IRP should reflect some consideration of achievability.

To that end, 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. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:

1) **Maximum Achievable Potential** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
2) **Realistic Achievable Potential** estimates achievable potential with Vectren 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.

It is important to also note that the estimates of technical, economic and achievable potential considered in the MPS (and ultimately, in the IRP) exclude potential savings from customers who are eligible and have chosen to actively opt-out of participating in Vectren's energy efficiency programs. In the Vectren service area, approximately 75% of large C&I customers are eligible to opt-out and nearly 40% of eligible customers have chosen to do so. As a result, only 22% of total large C&I energy (MWh) sales have not presently opted out of funding Vectren's energy efficiency programs.[34]

6.3.2.3 Energy Efficiency – IRP Reference Case

For the DSM reference case of the IRP analysis, Vectren used the realistic achievable potential identified in the 2019 Market Potential Study as the starting point for developing bundles of energy efficiency to be modeled in .25% increments of eligible sales. However, two additional adjustments to the MPS' realistic achievable energy efficiency potential were necessary prior to inclusion in the IRP.

[34] These percentages are calculated based on 2019 Vectren large C&I customer data and 2018-2019 billing history.

The first adjustment converted the energy efficiency potential from gross savings to net savings. It is appropriate to model net energy efficiency impacts in order to remove MWh and MW impacts that would have occurred even in the absence of Vectren's programs. Net savings were calculated by applying Vectren's most recent (2017) program evaluation results and NTG ratios to the MPS estimates of gross realistic achievable savings. Due to annual differences in the mix of energy efficiency measures included in the realistic achievable potential, the weighted average NTG ratio adjustment ranged from 0.84 to 0.88 across the 20-year IRP analysis timeframe.

The second adjustment aligned the level of low-income potential identified in the realistic achievable potential with levels achieved historically by Vectren. The MPS assumes Vectren pays the full cost for all possible low-income potential savings, regardless of cost-effectiveness. However, this produces a low-income budget that significantly outpaces historical spending for the low-income sector and would create cross-subsidization concerns across customer segments. As a result of aligning the low-income sector spending in the IRP with recent historical levels, low-income achievable savings were also scaled accordingly.

The model included 2020 savings as a fixed resource as savings are currently approved by the Commission in Cause 44927. A total of 10 bundles were modeled for DSM, including one fixed low-income bundle, one fixed DR bundle (AC DLC as well as Smart Thermostat), one selectable DR BYOT (Bring Your Own Thermostat) and seven selectable energy efficiency bundles each representing 0.25% of annual load excluding opt-out sales.

Figure 6-22 shows the realistic achievable potential (as a % of annual forecast sales) identified in the MPS and the impacts after applying the two adjustments described above.

Figure 6-21 – MPS Realistic Achievable Potential (as a % of annual eligible sales) – Pre- & Post-Adjustments

	2020	2021	2022	2023	2024	2025
MPS Realistic Achievable	1.7%	2.1%	2.0%	2.0%	2.0%	2.0%
Adj#1: Gross to Net	1.4%	1.8%	1.7%	1.8%	1.8%	1.7%
Adj#2: Low Income Alignment	1.2%	1.5%	1.4%	1.5%	1.5%	1.5%

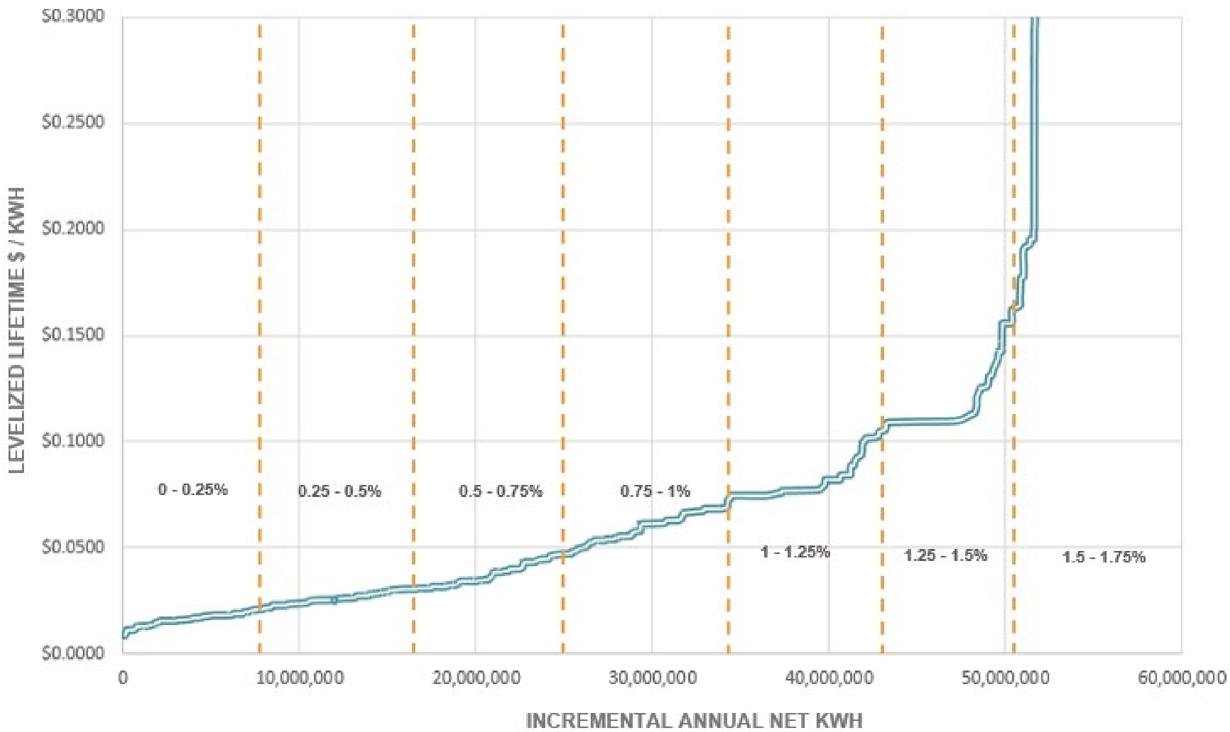
For the Vectren IRP process, energy efficiency is a selectable resource. Once the total energy efficiency savings to be included in the IRP Reference Case were calculated, a cost was assigned to each bundle of energy efficiency so that it can compete and be selected against supply-side resources. Again, the 2019 MPS and the annual supply curves were used to develop costs for each energy efficiency bundle. The costs from the MPS include incentive costs, program delivery costs and other cross-cutting program costs based on reported historical levels. Two modifications to the MPS cost estimates were created to further align the IRP Reference Case with empirical Vectren data. The first adjustment was to reduce incentive costs in the C&I sector from 2020 through 2027. This adjustment served to align modeled costs with Vectren recent historical and 2019 planned costs in the C&I sector. The second adjustment was to change the escalation rate for non-incentive program costs to 2.2% (in lieu of the 1.6% modeled in the MPS) to be consistent with other IRP planning assumptions.[35]

Following these savings and costs adjustments, a supply curve of the remaining electric energy efficiency potential was developed for each year of the MPS. A supply curve of energy efficiency potential is a device for demonstrating the total amount of energy efficiency savings available at specific price points, with the x-axis representing the cumulative annual energy savings available and the y-axis representing the cost of saved energy. The energy efficiency supply curve is useful in that it creates a logical order for pursuing energy efficiency measures based on least cost planning. Energy efficiency measures along the supply curve were then bundled into blocks of approximately 0.25%

[35] Incentive costs were not escalated in the MPS or IRP DSM inputs. Incentives (as a % of measure costs) were held constant in nominal dollars. Any fluctuation in incentives is a result of changes in annual participation.

net energy savings relative to forecast sales. The total number of energy efficiency bundles, each year, is dependent on the realistic achievable potential identified in that year. For example, the realistic achievable potential identified in 2024 allows for 6 complete bundles of 0.25% net efficiency savings and a partial 7th bundle (Figure 6-23).

Figure 6-22 – 2024 Supply Curve for Electric Energy Efficiency



As a final step in the IRP Reference Case energy efficiency bundle development, a single low-income bundle of energy efficiency was created. As noted earlier, this savings bundle is aligned so that total low-income spending in 2020-2039 is consistent with recent historical levels ($1.15 million annually). The cost per lifetime kWh-saved is expected to change over time as the associated mix of low-income measures in the realistic achievable potential changes. Annual savings associated with the LI Bundle range from 889 MWh in the early years of the IRP to a low of 457 MWh as the measure mix converts to higher $/kWh measures over time.

The following table (Figure 6-24) provides the estimated levelized costs, on a cumulative basis, used for each of the energy efficiency bundles included in the IRP Reference Case.

Except for the low-income bundle, no minimum level of energy efficiency impacts was locked in for the IRP optimization modeling for scenario analysis. Empty cells reflect a lack of net achievable potential (based on the MPS results) in that year.

Figure 6-23 – IRP Reference Case Cost of Energy Efficiency; Cost per Net Lifetime kWh[36]

CUM. BIN NET $/kWh	1	2	3	4	5	6	7	LI
2020	$ 0.0163	$ 0.0204	$ 0.0240	$ 0.0299	$ 0.0369			$ 0.1241
2021	$ 0.0154	$ 0.0201	$ 0.0232	$ 0.0268	$ 0.0314	$ 0.0380		$ 0.1448
2022	$ 0.0154	$ 0.0202	$ 0.0245	$ 0.0289	$ 0.0326	$ 0.0394		$ 0.1594
2023	$ 0.0158	$ 0.0206	$ 0.0246	$ 0.0292	$ 0.0342	$ 0.0397		$ 0.1754
2024	$ 0.0162	$ 0.0204	$ 0.0247	$ 0.0302	$ 0.0355	$ 0.0377	$ 0.0412	$ 0.1997
2025	$ 0.0168	$ 0.0217	$ 0.0263	$ 0.0321	$ 0.0375	$ 0.0410	$ 0.0427	$ 0.2134
2026	$ 0.0172	$ 0.0226	$ 0.0278	$ 0.0336	$ 0.0391	$ 0.0426	$ 0.0446	$ 0.2255
2027	$ 0.0179	$ 0.0237	$ 0.0291	$ 0.0357	$ 0.0409	$ 0.0442	$ 0.0462	$ 0.2429
2028	$ 0.0185	$ 0.0250	$ 0.0311	$ 0.0372	$ 0.0426	$ 0.0468	$ 0.0485	$ 0.2469
2029	$ 0.0194	$ 0.0262	$ 0.0330	$ 0.0399	$ 0.0443	$ 0.0499		$ 0.2481
2030	$ 0.0202	$ 0.0283	$ 0.0342	$ 0.0402	$ 0.0457	$ 0.0521		$ 0.2453
2031	$ 0.0210	$ 0.0294	$ 0.0350	$ 0.0423	$ 0.0470	$ 0.0531		$ 0.2517
2032	$ 0.0220	$ 0.0304	$ 0.0388	$ 0.0443	$ 0.0491	$ 0.0557		$ 0.2299
2033	$ 0.0233	$ 0.0317	$ 0.0409	$ 0.0478	$ 0.0505	$ 0.0574		$ 0.2345
2034	$ 0.0241	$ 0.0328	$ 0.0432	$ 0.0497	$ 0.0525	$ 0.0596		$ 0.2038
2035	$ 0.0203	$ 0.0262	$ 0.0323	$ 0.0405	$ 0.0462	$ 0.0480	$ 0.0545	$ 0.2285
2036	$ 0.0206	$ 0.0262	$ 0.0320	$ 0.0405	$ 0.0456	$ 0.0482	$ 0.0547	$ 0.2413
2037	$ 0.0208	$ 0.0264	$ 0.0322	$ 0.0399	$ 0.0457	$ 0.0485	$ 0.0547	$ 0.1969
2038	$ 0.0218	$ 0.0256	$ 0.0324	$ 0.0395	$ 0.0450	$ 0.0499	$ 0.0558	$ 0.2006
2039	$ 0.0231	$ 0.0262	$ 0.0333	$ 0.0398	$ 0.0458	$ 0.0506	$ 0.0564	$ 0.2068

6.3.2.4 Demand Response

Two bundles for demand response savings were included in the IRP Reference Case. The first bundle was included as a fixed adjustment to the total system load, similar to a "must-run" generation unit. This bundle includes demand response savings associated with Vectren's current demand response capabilities including the historical number of

[36] Savings bundles were based on net savings that were roughly equivalent to 0.25% of annual sales. Projected costs per kWh for each bundle are shown at the gross-level for easier comparison to prior IRP. Projected costs by bundle are cumulative (i.e. the projected cost in Bundle 4 represent the cost to achieve up to 1.0% of forecast sales).

direct load control switches on residential air conditioning units in the Vectren service area. Over the IRP time frame, Vectren anticipates replacing existing direct load control switches with smart thermostats that integrate demand response capabilities (via the Smart Cycle Program). The estimated annual impacts for the fixed bundle of DR is approximately 16 MW in 2020, increasing to 26 MW by 2039.

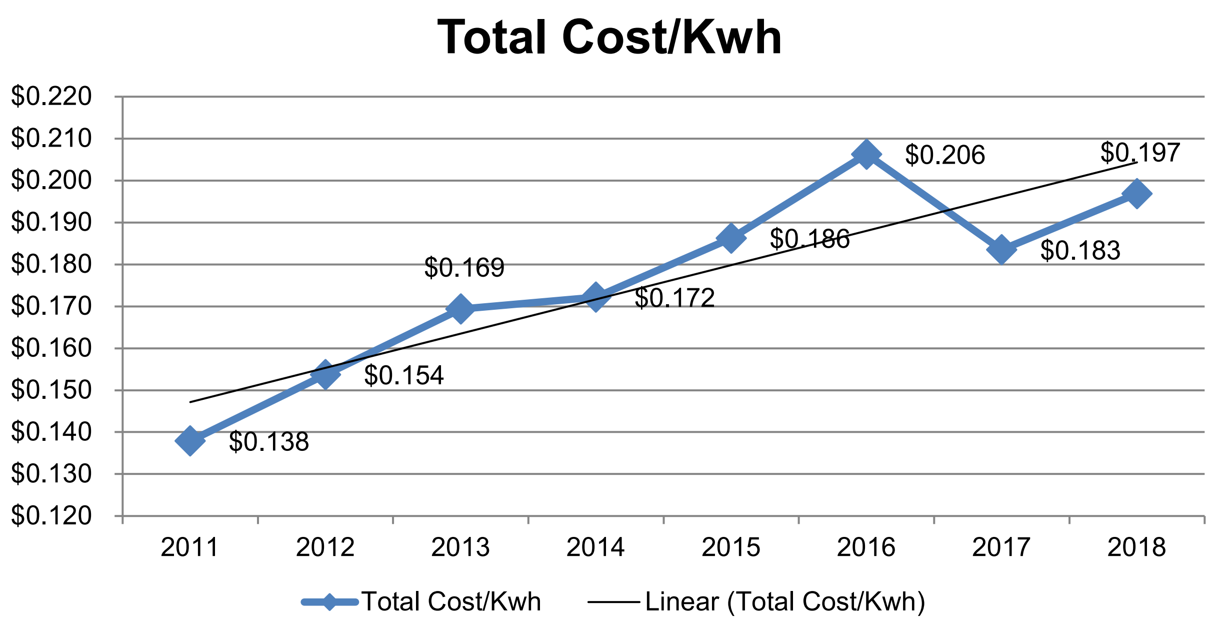
A second bundle, consisting of additional demand response enabled smart thermostats (BYOT Thermostats) above and beyond the current penetration of demand response devices, was included as a selectable resource. This bundle represents an additional 1.6 MW of peak reduction capabilities in 2020 increasing to 10 MW by 2039.

6.3.2.5 DSM Resources – IRP Sensitivities

The previous sections provided the Reference Case projection of DSM resource costs. DSM resource costs are a key component to the integration of DSM into the resource plan. Given the uncertainty around these costs, especially considering a 20-year implementation period, alternate views of the costs should be examined in the context of the scenario analyses. Only time and actual experience with increases in DSM market penetration will provide better guidance on these cost projections.

To that end, high and low DSM resource cost trajectories were developed by leveraging Vectren's 2011-2018 historical DSM spend per first-year kWh saved and calculating one standard deviation from the mean to develop high and low DSM spend scenarios. This approach uses the actual variation in Vectren's energy efficiency resource acquisition costs to define upper and lower bounds on future DSM costs per first-year kWh-saved. The result is an 11.9% increase or reduction in estimated annual DSM costs relative to the IRP Reference Case. Figure 6-25 shows the 2011-2018 average cost per first-year kWh-saved used to determine the IRP sensitivities on DSM costs.

Figure 6-24 – 2011-2018 Vectren Portfolio Cost per 1st-Year kWh Saved



Applying a range of expected costs produces the following high and low tables of projected DSM resource costs.

Figure 6-25 – High Case Cost per kWh: Plus One Standard Deviation

CUM. BIN NET $/kWh	1	2	3	4	5	6	7
2020	$ 0.0182	$ 0.0229	$ 0.0269	$ 0.0335	$ 0.0413		
2021	$ 0.0173	$ 0.0225	$ 0.0259	$ 0.0300	$ 0.0351	$ 0.0426	
2022	$ 0.0172	$ 0.0226	$ 0.0274	$ 0.0323	$ 0.0365	$ 0.0440	
2023	$ 0.0177	$ 0.0230	$ 0.0275	$ 0.0326	$ 0.0383	$ 0.0444	
2024	$ 0.0181	$ 0.0229	$ 0.0277	$ 0.0338	$ 0.0397	$ 0.0421	$ 0.0461
2025	$ 0.0188	$ 0.0242	$ 0.0294	$ 0.0359	$ 0.0419	$ 0.0458	$ 0.0478
2026	$ 0.0192	$ 0.0253	$ 0.0311	$ 0.0376	$ 0.0437	$ 0.0476	$ 0.0499
2027	$ 0.0200	$ 0.0265	$ 0.0325	$ 0.0399	$ 0.0457	$ 0.0495	$ 0.0517
2028	$ 0.0207	$ 0.0280	$ 0.0348	$ 0.0416	$ 0.0477	$ 0.0524	$ 0.0543
2029	$ 0.0217	$ 0.0293	$ 0.0369	$ 0.0446	$ 0.0496	$ 0.0559	
2030	$ 0.0226	$ 0.0317	$ 0.0382	$ 0.0450	$ 0.0511	$ 0.0582	
2031	$ 0.0235	$ 0.0329	$ 0.0391	$ 0.0473	$ 0.0526	$ 0.0594	
2032	$ 0.0246	$ 0.0341	$ 0.0434	$ 0.0496	$ 0.0550	$ 0.0624	
2033	$ 0.0260	$ 0.0355	$ 0.0458	$ 0.0535	$ 0.0565	$ 0.0642	
2034	$ 0.0269	$ 0.0367	$ 0.0483	$ 0.0556	$ 0.0587	$ 0.0667	
2035	$ 0.0227	$ 0.0293	$ 0.0361	$ 0.0453	$ 0.0517	$ 0.0537	$ 0.0610
2036	$ 0.0231	$ 0.0293	$ 0.0358	$ 0.0453	$ 0.0511	$ 0.0539	$ 0.0612

CUM. BIN NET $/kWh	1	2	3	4	5	6	7
2037	$ 0.0233	$ 0.0295	$ 0.0360	$ 0.0446	$ 0.0511	$ 0.0543	$ 0.0612
2038	$ 0.0244	$ 0.0287	$ 0.0363	$ 0.0442	$ 0.0503	$ 0.0558	$ 0.0624
2039	$ 0.0258	$ 0.0293	$ 0.0373	$ 0.0445	$ 0.0513	$ 0.0567	$ 0.0631

Figure 6-26 – Low Case Cost per kWh: Minus One Standard Deviation

CUM. BIN NET $/kWh	1	2	3	4	5	6	7
2020	$ 0.0143	$ 0.0180	$ 0.0212	$ 0.0264	$ 0.0325		
2021	$ 0.0136	$ 0.0177	$ 0.0204	$ 0.0236	$ 0.0276	$ 0.0335	
2022	$ 0.0135	$ 0.0178	$ 0.0216	$ 0.0254	$ 0.0287	$ 0.0347	
2023	$ 0.0139	$ 0.0181	$ 0.0216	$ 0.0257	$ 0.0302	$ 0.0350	
2024	$ 0.0143	$ 0.0180	$ 0.0218	$ 0.0266	$ 0.0313	$ 0.0332	$ 0.0363
2025	$ 0.0148	$ 0.0191	$ 0.0232	$ 0.0282	$ 0.0330	$ 0.0361	$ 0.0377
2026	$ 0.0151	$ 0.0199	$ 0.0245	$ 0.0296	$ 0.0344	$ 0.0375	$ 0.0393
2027	$ 0.0158	$ 0.0209	$ 0.0256	$ 0.0314	$ 0.0360	$ 0.0389	$ 0.0407
2028	$ 0.0163	$ 0.0220	$ 0.0274	$ 0.0328	$ 0.0375	$ 0.0412	$ 0.0427
2029	$ 0.0171	$ 0.0231	$ 0.0291	$ 0.0351	$ 0.0390	$ 0.0440	
2030	$ 0.0178	$ 0.0250	$ 0.0301	$ 0.0354	$ 0.0403	$ 0.0459	
2031	$ 0.0185	$ 0.0259	$ 0.0308	$ 0.0373	$ 0.0414	$ 0.0468	
2032	$ 0.0194	$ 0.0268	$ 0.0342	$ 0.0391	$ 0.0433	$ 0.0491	
2033	$ 0.0205	$ 0.0279	$ 0.0361	$ 0.0421	$ 0.0445	$ 0.0506	
2034	$ 0.0212	$ 0.0289	$ 0.0380	$ 0.0438	$ 0.0462	$ 0.0525	
2035	$ 0.0179	$ 0.0231	$ 0.0284	$ 0.0357	$ 0.0407	$ 0.0423	$ 0.0480
2036	$ 0.0181	$ 0.0231	$ 0.0282	$ 0.0356	$ 0.0402	$ 0.0425	$ 0.0482
2037	$ 0.0183	$ 0.0232	$ 0.0284	$ 0.0351	$ 0.0402	$ 0.0428	$ 0.0482
2038	$ 0.0192	$ 0.0226	$ 0.0286	$ 0.0348	$ 0.0396	$ 0.0439	$ 0.0492
2039	$ 0.0203	$ 0.0231	$ 0.0293	$ 0.0350	$ 0.0404	$ 0.0446	$ 0.0497

No IRP sensitivities for the low-income savings or demand response savings were included in the IRP as these bundles were modeled as fixed load impacts.

6.3.2.5.1 DSM Improvements Based on Stakeholder Feedback

Review of prior comments from stakeholders and robust stakeholder discussion led to several improvements to DSM modeling since the 2016 IRP. The model has been allowed to make multiple decisions over the 20-year period. The model selects DSM for two three-year periods beginning in 2021 and 2024 and then evaluates the remaining years beginning in 2027 as one collective group. This allows the model to select the appropriate level of DSM based on cost-effectiveness differences between the short, mid and long run. Another improvement is the addition of bin specific load shapes which improved accuracy versus utilizing the same average load shape for each bin. Further, DR bundles have been added to the model. The modeled savings were aligned to the latest MPS and conducted price sensitivities mentioned in section "DSM Resources – IRP Sensitivities". The addition of price sensitivities guides Vectren's understanding of energy savings potential as costs might vary.

6.3.2.6 Other Innovative Rate Design

Vectren periodically evaluates alternative rate design and its ability to implement new options as the energy marketplace continues to evolve. Proposals that provide variable energy pricing based on how electric prices change throughout the day (Time of Use rates) and other pricing alternatives will be considered now that the required technology upgrades are being finalized, including technology to improve access to multitudes of data provided by installation of AMI. This information was not available for the 2019/2020 IRP.

6.4 TRANSMISSION CONSIDERATIONS

6.4.1 Description of Existing Transmission System

Vectren's transmission system is comprised of 64 miles of 345 kV lines, 377 miles of 138 kV lines and 570 miles of 69 kV lines. It has interconnections with Duke Energy (345 kV-138 kV-69 kV), Hoosier Energy (161 kV-69 kV), Indianapolis Power and Light Co. (138 kV), Big Rivers Electric Company (138 kV) and LGE/KU (138 kV). Key interconnection points include three 345 kV interconnections to Duke Energy's system in the area of Duke's Gibson Generation Station, a 345 kV interconnection to Big Rivers' Reid EHV Substation, a 138 kV interconnection at IPL's Petersburg Generation Station and 161 kV and 138 kV interconnections to Hoosier Energy, LGE/KU and Big Rivers at Vectren's Newtonville Substation.

6.4.2 Discussion on Resources Outside of Area

As mentioned above, Vectren's transmission system interconnects with neighboring systems, which provides wholesale import and export capability. Transmission planning studies indicate the existing transmission system provides a maximum import capability of approximately 750 MWs (or approximately 65% of peak demand). Although Vectren has the capability to offset internal generation with imported capacity, this is not a long-term solution; several factors would influence that capability, including:

- MISO resource adequacy requirements
- Availability of firm capacity
- Transmission path availability
- Operating concerns (post-contingent voltage and line flow)
- Anticipated congestion costs
- Real-time binding constraints

6.4.3 Transmission Facilities as a Resource

As part of this year's IRP, Vectren performed a multitude of transmission planning analysis to study a wide range of potential futures. These included studying the replacement of various levels of coal generation with a Combined Cycle Gas Turbine (CCGT), Combustion Turbines (CTs) and import from the MISO market. Each of these cases also included the addition of various levels of renewable resources, primarily solar and wind. The models utilized were from the latest cycle of the MISO generation interconnection process in order to have the latest modeling data for generation resources in Vectren's area. The renewable resources used for Vectren's analysis were projects already in the MISO queue and existing in the MISO models, while the CCGT and CT's were modeled at Vectren's A.B. Brown power plant for ease of modeling.

The CCGT case was modeled at a similar MW output as the coal generation it was replacing and therefore the results of the transmission planning study analysis showed very few differences from the study case with the system as it is today, or Base Case.

As the level of power imported from the MISO market increased due to the coal generation retirements, network upgrades were identified to increase the Vectren system import capability to suitable levels. These projects included the replacement of three transformers at an estimated total cost of $11 million and were needed for all non-CCGT cases, including the CT cases. In addition to these identified import capability issues, voltage issues also arose due to insufficient reactive power reserves as the level of imported power increased. These issues were minimal in the CT cases due to the reactive capability of the CT's and could be resolved with existing facilities, but the issues became substantial in the all renewables by 2030 portfolio and all import cases and would require additional upgrades of $20-$30 million beyond the $11 million described above. These upgrades for reactive support would need to be studied in more depth to determine the placement of new facilities and to determine the type of devices needed.

6.5 Partnering with Other Utilities

As a part of the 2019/2020 IRP process, Vectren contacted utilities in the region to discuss opportunities to partner together on generation projects to lower costs. Partnership opportunities with other Indiana utilities did not materialize due to a variety of factors including a lack of alignment in timing, needs, or other factors.

SECTION 7
MODEL INPUTS AND ASSUMPTIONS

7.1 RESOURCE MODEL (AURORA)

AURORAxmp was the primary tool for conducting Vectren's analysis. AURORAxmp is an industry standard chronological unit commitment and dispatch model with extensive presence throughout the electric power industry. The model uses a mixed integer linear programming approach (MILP) to capture details of power plant and transmission network operations while observing real world constraints, such as emission reduction targets, transmission and plant operation limitations, renewable energy availability and mandatory portfolio targets.

The model can be run in several modes; two were utilized for this study. The Long-Term Capacity Expansion mode (LTCE), the model was utilized to determine the least cost mix of existing and new generating assets that meets demand (electric load) over time and also meets regulatory and reliability requirements. In dispatch mode, the model was utilized to assess how a portfolio of assets will perform under a fixed set of market conditions.

AURORAxmp is widely used by electric utilities, consulting agencies and other stakeholders to forecast generator performance and economics, develop IRPs, forecast power market prices and assess detailed impact of regulations and market changes affecting the electric power industry. Key inputs to the model include load forecasts, power plant costs and operating characteristics (e.g. heat rates), fuel costs, fixed and variable operating costs, outage rates, emission rates as well as capital costs. The model assesses the potential performance, fixed and variable O&M costs and capital costs of prospective and existing generation technologies and resources and makes resource addition and retirement decisions for economic, system reliability and policy compliance reasons on a utility system, regional and nationwide scale. Outputs of the model include plant generation, gross margin, emissions, power prices, capacity additions, retirements and a variety of other metrics.

Pace Global has used Aurora for well over 15 years as its primary model for asset valuation, power market forecast and IRPs. The model is equipped to determine least cost portfolios and it can analyze portfolio risks by assessing portfolio performance across 200 different future market outlooks. Pace Global has developed a sophisticated stochastic framework to ensure that these future market outlooks reflect both relevant historic uncertainty in key market drivers and cross relationships between different market drivers. Pace Global has also developed modules to simulate the different operating characteristics of ISO/RTO regions across the country. For this reason, it is one of the most comprehensive, reliable and flexible tools in the market for conducting IRPs. Pace Global has successfully conducted numerous IRPs for many utilities across the country. Aurora has gained wide acceptance among electric utility executives, stakeholder groups and regulatory commissions.

In order to perform both the required deterministic (scenario based) and probabilistic (stochastic) modeling, Pace Global developed five scenarios and a set of probability distributions for key market driver variables. These include both forecasts of each variable under the five conditions and probabilistic distributions for demand growth (load), fuel costs (natural gas and coal), environmental compliance costs (carbon) and capital costs. In the sections below is a description of how these forecasts and distributions were developed.

7.2 REFERENCE CASE SCENARIO

Vectren developed a Reference Case forecast of key market drivers that collectively represent the expected or most likely to occur path forward for each input variable. For key assumptions, including natural gas prices, coal prices and capacity prices, a range of views from four vendors were incorporated into a consensus forecast.

The Reference Case scenario is based upon consensus forecasts from several consultants. Hence, it is impossible to describe specifics regarding the assumptions driving each forecast. However, the Reference Case can be described in more general terms based upon consistency in general trends among the individual forecasts that comprise the consensus forecast. Generally, the forecast is characterized by reasonable and balanced levels of growth, best guess forecasts of market conditions, regulatory requirements and technological change. Typically, market participants under Reference Case conditions can adapt and adjust in a timely manner to changing market forces.

Short Term: In the short-term (2020-2021), the Reference Case assumes an overall positive sales growth as Vectren adds general service and large customer growth. Residential customer annual consumption is expected to decline slightly to 2021 before rising again in the medium-term and long-term. Large commercial and industrial (C&I) customers are expected to increase both in numbers and consumption, also with a partial offset of this growth by increasing efficiency. As a result, average energy sales grow at 2.2% for 2019-2021.

Natural gas prices are expected to decline in 2020 compared to 2019, as the oversupply situation from shale gas and associated gas production continues to dominate gas market dynamics. In the short-term, natural gas prices are expected to remain below $2.80/MMBtu.

Meanwhile, coal prices decline in the near-term as domestic markets remain soft. Exports of coal provide a small amount of upward pressure demand, but mine prices are expected to continue to decline in the short-term from the 2019 price of $1.78/MMBtu in the Illinois Coal Basin.

Coal plant retirements were high in 2015 driven by regulation including MATS and again in 2018 for economic reasons. Capacity additions in the form of efficient combined cycle gas turbine plants or fast-ramping simple cycle gas turbines grew rapidly over the past few years as merchant plants and utilities took advantage of low gas prices. The EIA in its AEO 2020 report anticipates a continued pace of capacity additions over the next few years, balanced between gas plants and renewables.[37]

Medium Term: In the medium-term (2022-2028), the Reference Case reflects the assumption that a carbon price will be implemented on the national level and will begin in 2027 at approximately $4/short ton of CO_2 (in real 2018$). CO_2 prices in California and in Northeast states participating in RGGI are expected to harmonize with the broader U.S. market at this time. In this IRP, Vectren is accounting for both direct CO_2 emissions and CO_2-equivalent (CO_2e) emissions for the life cycle of assets.

In the medium-term as in the short-term, energy efficiency standards and energy company sponsored DSM programs mostly offset the growth in energy sales from a growing residential customer base. However, overall load growth continues, driven by new C&I customers locating in the Midwest to take advantage of access to low-cost shale gas.

Natural gas prices at the Henry Hub in the medium-term will continue to be low but will rise over time, with the consensus forecast anticipating prices in the $3.00-$3.50/MMBtu range. Low prices tend to be self-correcting, resulting in restricted production and reduced gas supply. Coupled with LNG export capacity growing through 2023 and increased industrial consumption in many parts of the country, overall demand is expected to rise and gas markets to tighten. This is especially true in the premium Gulf Coast market, where much of the demand is materializing, increasing prices beginning in 2021.

Coal prices in the Illinois Basin are expected to continue to decline gently in the medium-term, as the modest export market is unable to compensate for declining domestic demand. Consensus Illinois Basin prices at the mine are low, averaging $1.60/MMBtu over the study period, with a slight decline over time.

[37] https://www.eia.gov/outlooks/aeo/

Power prices, which are an output of the AURORA model for MISO Zone 6, continue to move upward moderately as natural gas prices increase from the currently low levels. As the customer base continues to grow, energy company operating costs continue to rise. Commodity markets recover in the medium-term, pushing up material costs and consequently capital costs. In addition, as the overall economy continues to improve and the unemployment rate remains near historically low levels, capital costs rise as competitive upward pressure remains on labor costs.

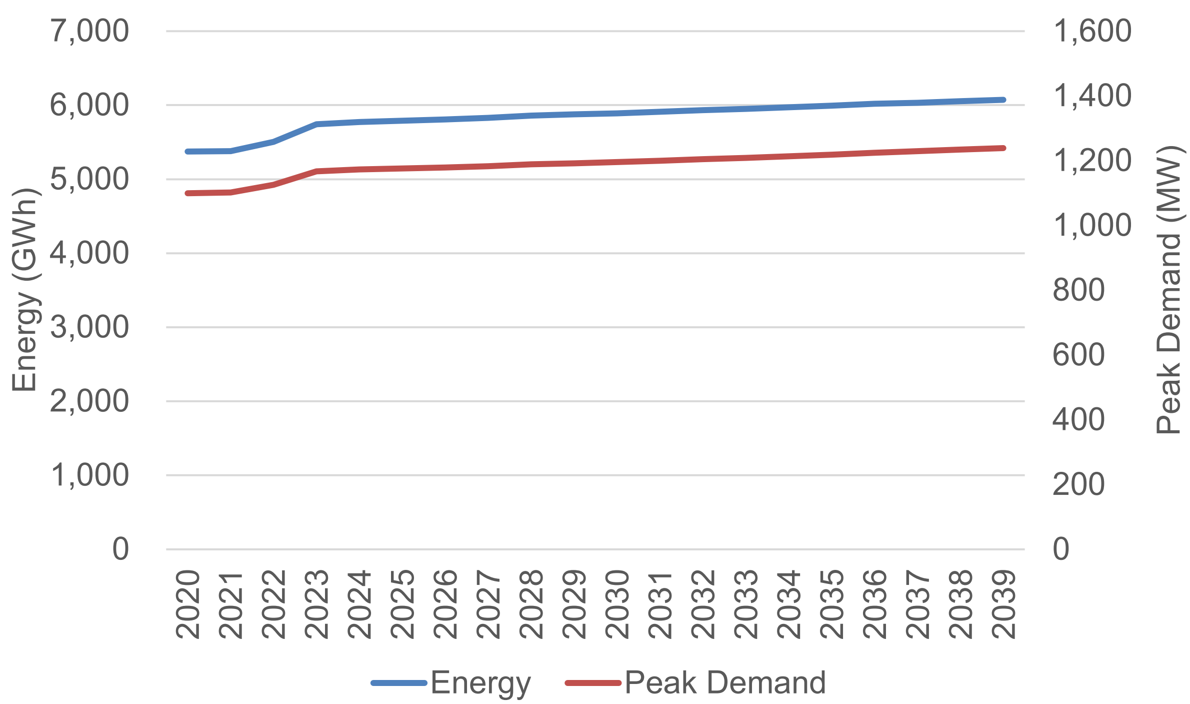
Coal retirements in the Reference Case mean no emissions from retired units, which contribute to lowering total CO_2 (and CO_2e) emissions. Coal plant retirements will continue to be driven by plant-specific going-forward economics, which rise as a national CO_2 price is assumed to begin in 2027. Meanwhile, capacity additions in the medium-term are expected to come from natural gas combined cycle plants as well as solar and wind facilities.

Long Term: In the long-term (2029-2039), the suite of market outcomes and drivers in the Reference Case settles into a pattern of moderate growth based on a well-balanced market. Energy sales grow at a moderate pace (0.6% CAGR for 2020-2039). The consensus forecast for Henry Hub has prices reaching $4/MMBtu by 2036 (in real 2018$), while ILB coal prices at the mine decline to $1.58/MMBtu by 2039 (in real 2018$). Market participants have enough time to adapt and adjust as regulatory compliance costs increase, helping to keep CO_2 prices moderate albeit rising to approximately $15/short ton by 2039 (in real 2018$). Energy demand grows as electric vehicle sales take hold and as residential and commercial customers electrify their energy use, but this is partially offset by continued gains in distributed solar generation, demand side management and energy efficiency measures. Domestic shale gas resources help to keep fuel cost growth to a low level. Capital costs increase at a measured pace as the GDP growth rate averages two percent or more and as higher borrowing costs come from long-term rising interest rates. Capacity additions and retirements continue at a reasonable rate as the fleet of power plants maintains a healthy rate of turnover.

7.2.1 Input Forecasts

The long-term energy and demand forecast for the Vectren service territory was developed for Vectren by Itron. The long-term energy and demand forecast for the MISO market comes from the System Forecasting for Energy Planning section of MISO's website.[38] For more information, please see Section 4 Customer Energy Needs. The forecast is based on a combination of historical usage trends and a bottom-up approach to drivers such as residential and commercial demand, industrial load, appliance saturation, energy efficiency, long-term weather trends, customer-owned generation, electric vehicle adoption and an outlook for economic factors.

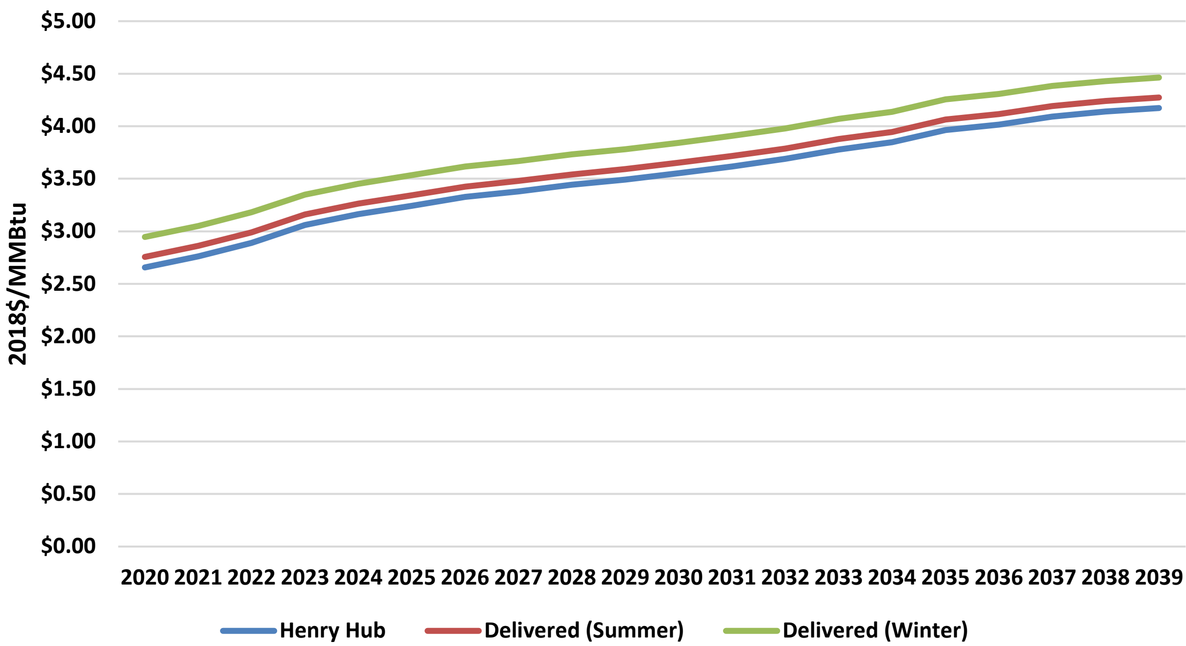
Figure 7.1 – Reference Case Vectren Load Forecast (MWh and MW)



[38] https://www.misoenergy.org/planning/policy-studies/system-forecasting-for-energy-planning/#nt=%2Freport-study-analysistype%3ALoad%20Forecast&t=10&p=0&s=FileName&sd=desc

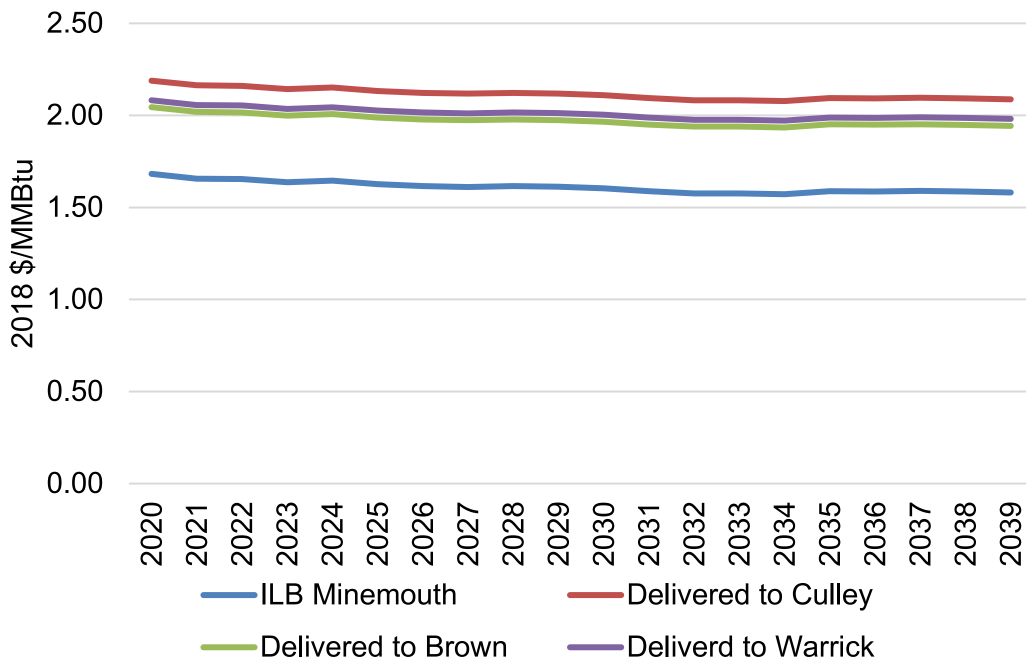
For both natural gas and coal Vectren used a "consensus" Reference Case view of expected prices by averaging forecasts from several sources. For natural gas and coal, forecasts from PIRA, Wood Mackenzie, Pace Global, ABB, & EVA were averaged. For capacity, Vectren used a consensus forecast, using Pace Global, ABB and Wood Mackenzie[39]. This helps to capture views from several experts and allows Vectren to be more transparent in the planning process. Delivered natural gas prices are \$0.10-\$0.29 higher than Henry Hub due to seasonal transportation tariffs.

Figure 7.2 – Reference Case Natural Gas Price Forecast (2018$/MMBtu)



[39] Vectren did not have access to a capacity forecast from PIRA or EVA

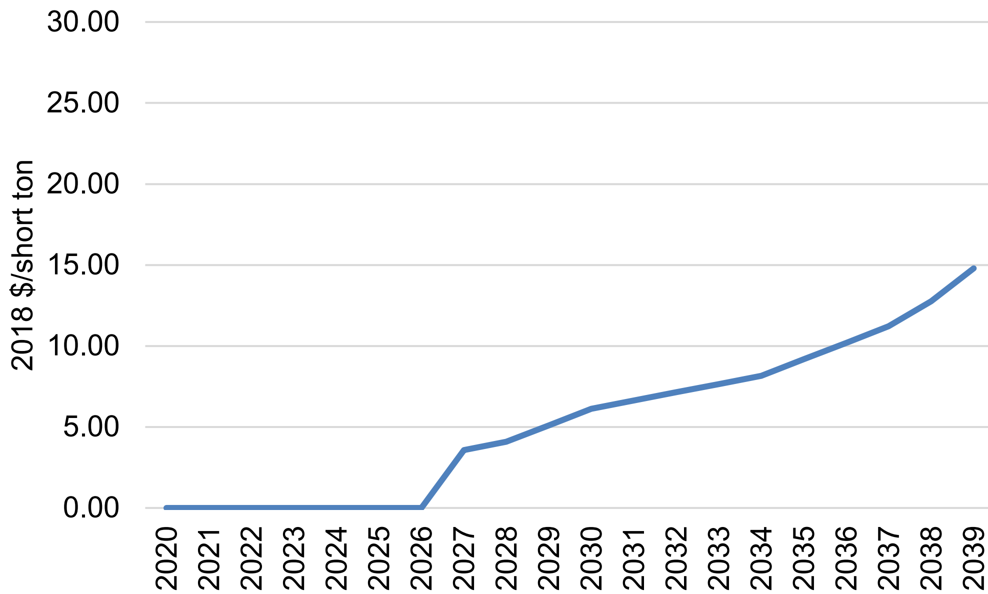
Figure 7.3 – Reference Case Coal Price Forecast (2018$/MMBtu)



No comprehensive national legislation of carbon emissions exists in the United States currently. Efforts to enact federal policy covering carbon emissions from major sources have occurred over the years. This included efforts by the U.S. Congress to pass a national cap-and trade regime, the EPA's regulation of GHG emissions from new and existing power generators which culminated in the current ACE rule, and more recently proposals in the U.S. Congress for carbon taxes and comprehensive clean energy targets.

Action to limit carbon emissions has increased in recent years with states taking the lead in defining low and no-carbon generation requirements. Indiana does not have a state policy limiting or otherwise placing a price on carbon emissions from power generation. However, the potential remains for enactment of such a policy at the national level over the study period. To account for this uncertainty and per stakeholder request, a moderate price on CO_2 emissions from fossil generators is assumed in the Reference Case. This outlook includes a national carbon price to become effective in 2027, covering emissions from electric generating units in the United States. Pace's EBA's CO_2 price projections in the Reference Case are presented in the figure below.

Figure 7.4 – Reference Case CO_2 Price Forecast (2018$/short ton)



Capital costs in the near to midterm (through 2024) were based on Tier 1 bids, as described in Section 6.1.5 Grouping. As described in Section 6, non-renewable capital costs were developed by Burns & McDonnell, while long term solar, wind and battery storage costs were developed using a consensus forecast from Burns & McDonnell, Pace Global and the NREL ATB 2018. Long-term capital costs for storage and solar + storage were adjusted to reflect bid pricing in the near term and then the capital cost indexes were used to adjust prices beyond the bid period. The long-term cost for solar was in line with the consensus forecast and therefore was not adjusted. Forward capital cost estimates can be found in Figure 6-21.

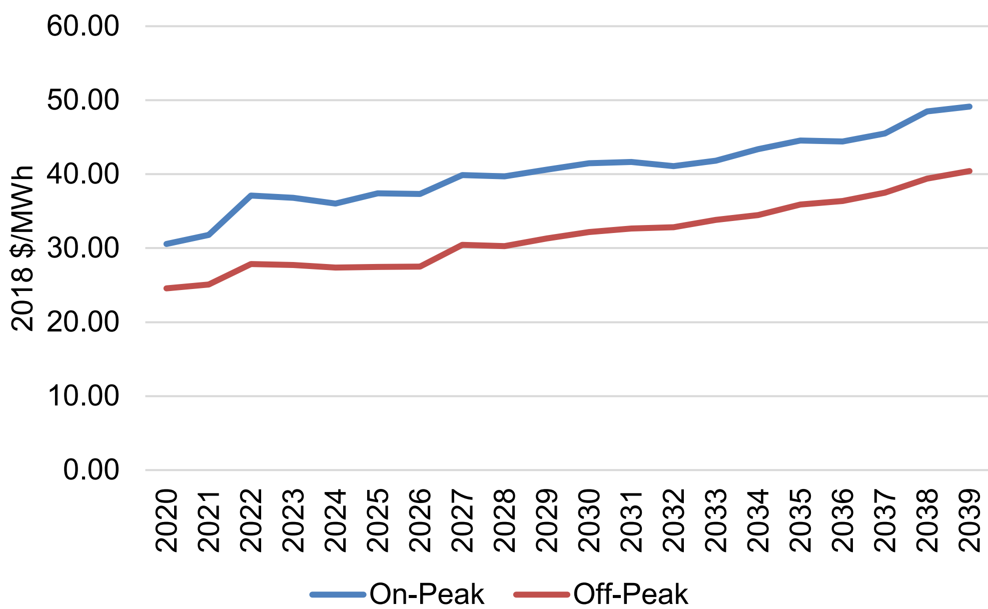
7.2.2 Energy Prices

On- and off-peak (day ahead) power price forecasts were a modeling output developed by Pace Global using the Reference Case assumptions described above, together with

Pace Global' s view of the greater MISO market, in the AURORAxmp power dispatch model.

Vectren's modeling does assume curtailment of resources when more energy is produced than is needed to meet customer load and Vectren's All-Source RFP sought operational control of resources.

Figure 7.5 – Reference Case Power Price Forecast (2018$/MWh)



Levelized DSM costs were developed by utilizing the 2019 MPS and the annual supply curves to develop costs for each energy efficiency bundle, as described in Section 6-32 Energy Efficiency Reference Case.

7.2.3 Environmental Regulations

The current modeling analysis primarily focused on evaluation of alternatives to comply with the CCR, ELG, 316(b) and ACE rule requirements. For CCR and ELG compliance, conversion to dry or closed loop bottom ash handling, wastewater treatment and landfill construction options were evaluated. For 316(b) compliance, based on site-specific considerations, standard mesh and fish friendly screens and fish return systems were assumed. All costs presented below are preliminary screening level estimates used for modeling purposes only. Individual elements of the estimate may go up or down depending on final design specifications and vendor bids.

7.2.3.1 Effluent Limitations Guidelines (ELG)

A. B. Brown: ELG related changes include conversion to dry bottom ash, upgrades to the dry fly ash system, a new landfill that can handle scrubber product and ash and a new system to handle process waters. ($138M)

F. B. Culley: Required plant upgrades include conversion to dry bottom ash, FGD wastewater treatment and access to a landfill that can handle dry ash. ($62M)

For Warrick Unit 4, Vectren modeled its share of the total capital spend.

7.2.3.2 Coal Combustion Residuals (CCR)

For A. B. Brown and F. B. Culley, it was assumed that ash ponds would be closed at the end of their useful life. The timing of the closures are based on forced closure (i.e. exceedance of GWPS and failure of aquifer location restriction) and whether alternative disposal capacity is available. The base cost for the closures does not change regardless of future generation. In order to continue operating coal-fired units, the A.B. Brown facility will potentially need to construct a new CCR rule compliant landfill capacity and a new CCR rule compliant pond, both of which depend on the scrubber technology utilized in the future. Vectren has not historically utilized the ponds at the Warrick power plant for its share of the CCR generated by WPP4 and therefore is not liable for pond closure costs.

7.2.3.3 Affordable Clean Energy (ACE)

As described earlier, In June 2019 EPA finalized the ACE, which replaces the Clean Power Plan from 2015 (a cap and trade program which sought to lower CO_2 emissions from existing power plants by 30% from 2005 levels). Vectren assumed that ACE compliance would begin in 2024.

Figure 7.6 – ACE Cost

Unit	Total ACE Upgrade Cost (2019$)
A.B. Brown 1	$10 Million
A.B. Brown 2	$10 Million
F.B. Culley 2	$26 Million
F.B. Culley 3	$30 Million
Warrick 4	N\A[40]

7.2.3.4 316(b)

EPA issued its final rule regarding Section 316(b) of the Clean Water Act. The rule establishes requirements for cooling water intake structures (CWISs) at existing facilities.

This requirement applies to both F. B. Culley and Warrick. At this time, based on available information for A. B. Brown, IDEM has made a Best Technology Available determination that the existing cooling water intake structures represent best technology available to minimize adverse environmental impact. This determination will be reassessed at the next NPDES permit reissuance. Standard fine mesh and fish friendly screens and fish return systems were estimated to be $21M at F. B. Culley. Warrick is required to install modified travelling screens and a fish handling and return system at Warrick. Vectren is responsible for its share of total capital.

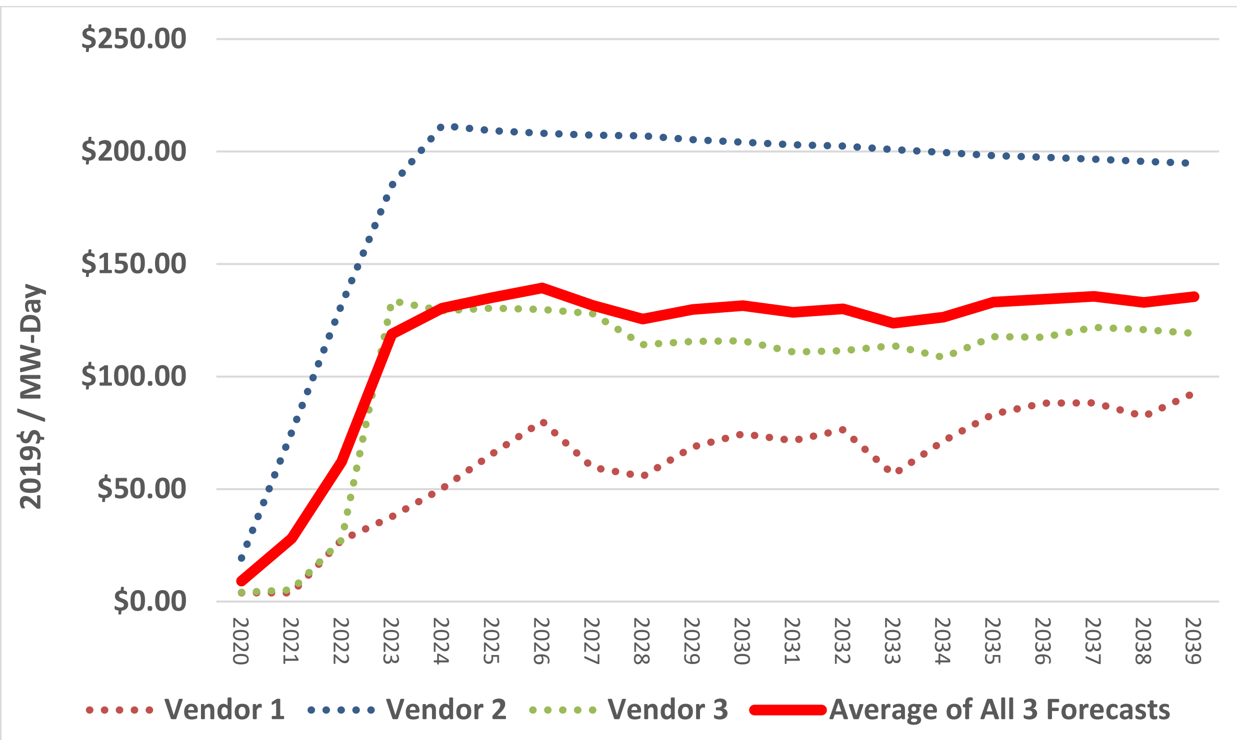
7.2.3.5 Market Capacity Price

The MISO capacity price has been difficult to predict as indicated by the volatile price history shown. This is especially true when analyzing the clearing price for the entire MISO-region. The clearing price in neighboring zones can be drastically different than

[40] In this analysis it is assumed joint operations of Warrick 4 ends in 2023 or 2026; In the 2026 scenario there is a cost of ~$1 million

Zone 6's and becomes an important consideration as Zone 6 imports capacity to meet its planning reserve margin requirement. Nonetheless, it is necessary for analysis purposes to have a capacity market price assumption to be included in the IRP modeling process. For illustrative purposes only, for every $1 per MW-day increase in the auction clearing price, there is an approximate $438,000 ($1 x 1,200 MW x 365 days) annual cost of capacity impact to Vectren customers. Some capacity will be bought or sold nearly every year since load and planning reserve margin requirements vary while most supply side resources, such as generating units, come in large blocks with 30+ year expected lifetimes. Vectren used a consensus forecast, utilizing Pace Global, ABB and Wood Makenzie for Reference Case MISO Indiana capacity prices for modeling purposes.

Figure 7.7 – Capacity Market Value Forecast (2019$/MW-Day)



For reference, MISO has set the Cost of New Entry (CONE) for Zone 6 in the 2020-2021 planning year at $255/MW-Day which sets the maximum offer and clearing price in the annual capacity auction. While the forecast used in this analysis is significantly lower than CONE it is necessary to consider that capacity prices could reach this level making long term reliance on the capacity market a risk that should be avoided. This consideration is even more relevant due to Zone 7, the lower peninsula of Michigan, clearing at CONE during this year's PRA.

It is a combination of the MISO warnings, the widely varying Consultant forecasts and the risks associated with an illiquid market that suggests to Vectren that the best way to mitigate the capacity market risk is through building Combustion Turbines for capacity rather than rely heavily on the market.

7.2.4 Additional Modeling Considerations

Vectren received approval in 2019 from the Commission to upgrade F.B. Culley 3, Vectren's most efficient coal unit, for continued operations. As such, the unit was modeled with continued operations throughout the planning period. As stated in that case, there is a premium for resilience and diversity with continuing to run the Culley unit. Based on updated reference case modeling in this IRP, that premium is estimated to be about ~0.5% in total NPV for continuing to run the plant through 2034. Vectren has chosen to continue operating this unit for the resiliency that it provides. All other coal units could retire economically within the model beginning December 31, 2023.

Modeling also included other fixed considerations. All candidate portfolios were designed to include the first five selectable energy efficiency bins, corresponding to 1.25% of energy efficiency, in the near-term years of 2021-2023. The model also included one fixed low-income bundle and one fixed demand response bundle (an air conditioning direct load control measure to a smart thermostat measure). Vectren's coal units were modeled to dispatch to LRZ6 on the basis of full variable costs (fuel, emissions, VOM) in the years 2019-2023, while dispatching to serve native load on the basis of fuel only in these same years. All coal units (whether selected to continue or not) were modeled to dispatch to full variable costs to LRZ6 and Vectren from 2024 through the end of the forecast period (2039). Long term annual capacity market purchases were limited to ~180 MW.

While a dynamic peak capacity credit (automatically adapting to the penetration level of solar and wind resources in MISO) proved to be challenging to implement in Aurora, Vectren's modeling efforts did include a seasonal, declining peak capacity credit for both solar and wind resources. Summer solar peak capacity credit began at 29% in 2023 (the first year in which new solar resources are available) and declined to 17% by 2039, while winter solar peak capacity credit began at 7% in 2023 and declined to 4% in 2039. Summer wind peak capacity credit began at 7.23% in 2022 (the first year in which new wind resources are available) and declined to 6.62% by 2039, while winter wind peak capacity credit began at 16.1% in 2022 and declined to 14.74% in 2039. Battery storage was modeled with a 95% peak capacity credit. Non-bid solar and Non-bid wind resources were not permitted until 2025 after short-term renewable and storage PPAs were no longer available.

Additional modeling parameters were included to account for logistical, commercial and operational limitations. These included limiting wind energy resources to 400 MW per year, wind plus storage resources to 150 MW per year, solar photovoltaic resources to 500 MW per year, solar plus storage resources to 150 MW per year, lithium-ion battery storage resources to 300 MW per year and flow battery storage to 400 MW per year. Combined cycle gas resources were limited to one unit per year, while simple cycle gas turbine resources were limited to a total of three units. Combined heat and power (CHP), reciprocating engines and aeroderivative gas turbines were excluded as resource options on the basis of lack of a dedicated facility for steam in the case of CHP and for technical considerations (for example, gas pipeline pressure requirements and cost) in the case of aeroderivatives.

7.3 ALTERNATE SCENARIOS

In order to develop several alternative scenarios for its IRP process, Vectren used a construct that allowed for increasing regulatory restrictions across four alternative scenarios. As previously mentioned, there were two purposes for these scenarios. First, each alternative market scenario was used to develop a least cost portfolio. Second, the final list of portfolios was evaluated against each alternative market scenario.

The alternate scenarios were created with increasing order of regulatory restriction included the Low Regulatory scenario, the High Technology scenario, the 80% Reduction in CO_2 scenario and the High Regulatory scenario. Pace Global provided the qualitative descriptions and quantitative inputs for each of these scenarios, which were based on collaboration between Vectren, Pace and stakeholders.

Each of the four alternative scenarios provided a framework of market inputs in which a least cost portfolio solution was developed. Of the four scenario based portfolios that were developed, only the High Technology portfolio was selected for further analysis.

The High Technology portfolio provided a useful boundary condition on the Reference Case, relying on a second combustion turbine unit, 1,146 MW of solar, 300 MW of wind and 176 MW of storage. The other three alternative scenario based portfolios included significantly greater renewable resources in their respective market scenario conditions than needed to serve Vectren customers under reference case conditions. In these three scenarios that were not selected for further analysis, the portfolios selected as least cost assumed large quantities of off-system sales in order to reduce portfolio costs. The high level of sales associated with these portfolios precluded them from further consideration as that was a significant issue raised in several of the portfolios in the 2016 study in the Director’s report.

For example, the Low Regulatory portfolio included higher load and higher gas prices than in the Reference Case. However, the portfolio (optimized to those different market conditions) included 2,146 MW of solar, 2,700 MW of wind, 126 MW of battery storage and a relatively heavy reliance on capacity market purchases, in addition to F.B. Culley 3 and one new CT.

The least cost 80% Reduction of CO_2 portfolio included 1,946 MW of solar, 3,050 MW of wind and 392 MW of battery storage. Due to the significant increase in late-term renewables buildout, this portfolio saw annual net energy sales climb from 2,500,000 MWhs in 2033 to over 9,300,000 MWhs by 2039.

The least cost High Regulatory portfolio included 2,956 MW of solar, 3,600 MW of wind and 618 MW of battery storage. Due to the heavy buildout of renewables, this portfolio reached 10,000,000 MWh of annual net energy sales by 2029 and stayed above this level for the remainder of the study period.

7.3.1 Description of Alternate Scenarios

As described in Section 2.4, the second purpose of developing these “boundary” scenarios was to test a relevant range for each of the key market drivers (gas, coal, CO_2, load and capital costs) on how various technologies perform under boundary conditions.

7.3.1.1 Low Regulatory

The Low Regulatory scenario is meant to be a lower boundary scenario in which there is a general laissez-faire attitude toward regulations. In the Low Regulatory scenario, only the ACE rule is included for CO_2 regulation and remains in place throughout the forecast. Indiana implements a lenient interpretation of the rule. ELG is partially repealed with bottom ash conversions not required for some smaller units and is delayed for two years (this does not apply to F.B. Culley 3).

In this scenario, fewer regulations are expected to result in a better economy and higher load. Gas prices are expected to move upward with increased demand, while coal prices continue to remain at Reference Case levels as demand for coal continues to decline nationally due to investor pressure and demand for cleaner alternatives. Technology capitals costs are expected to continue to decline at Reference Case levels.

Energy efficiency costs are expected to net to the Reference Case level. There is downward pressure with fewer codes and standards being implemented, leaving some low hanging fruit, but upward pressure with increasing load, netting to no change from the Reference Case level.

7.3.1.2 High Technology

The High Technology scenario was constructed to be indicative of significant advances in energy storage technology, renewable energy deployment, emissions reduction and CO_2 removal technology, high efficiency gas-fired generation and natural gas extraction productivity. Overall, there are significant developments in technologies that improve energy efficiency, which helps to mitigate the load growth that might otherwise be expected in a high technology scenario with robust economic growth.

The High Technology scenario assumes that technology costs decline faster than in the Reference Case, allowing renewables and battery storage to become more competitive. A relatively low CO_2 tax is implemented in this scenario. The economic outlook is better than in the Reference Case as lower technology costs and lower energy prices offset the impact of the CO_2 tax. The increased demand for natural gas is more than met with advances in key technologies that unlock more shale gas, increasing supply and lowering gas prices relative to the Reference Case. There is less demand for coal, which results in lower prices relative to the Reference Case. In addition, utility-sponsored energy efficiency costs rise early in the forecast but ultimately fall back to below Reference Case levels due to technology advances, allowing for new and innovative ways to partner with customers to save energy.

As technology costs fall, customers begin to move towards electrification, driving increased electric vehicle sales and higher adoption of rooftop distributed solar and battery storage, which trend towards highly efficient electric heat pumps in new homes.

7.3.1.3 80% CO_2 Reduction by 2050

The 80% CO_2 Reduction by 2050 scenario assumes that a carbon cap regulation is implemented, which mandates an 80% reduction of CO_2 by 2050 from 2005 levels. A glide path is then set based on a gradual ratcheting-down of CO_2 emissions and an increasing CO_2 allowance cost.

In this scenario, load decreases as the costs for energy and backup power increase and as the energy mix transitions into areas such as increased electrification. In this scenario, regulations on methane emissions initially drive up gas prices, but are partially offset by increased supply. The price of natural gas remains on par with the Reference Case. However, there is less demand for coal, which drives prices lower than the Reference Case. Some large and efficient coal plants remain as large fleets can comply with the regulation on a fleet wide basis.

Renewable energy and battery storage technologies are widely implemented to help meet the mandated CO_2 reductions. Despite this demand, costs are lower than the Reference Case due to subsidies or similar public support to address climate change concerns. Market-based solutions are implemented to lower CO_2. Innovation continues to occur but is offset by more codes and standards with no incentives. As a result, energy efficiency costs rise.

7.3.1.4 High Regulatory

The High Regulatory scenario is characterized by a more heavily regulated path. The High Regulatory path is indicative of the following plausible circumstances relative to the Reference Case:

- A much higher cost for compliance with emissions controls, which begins virtually immediately in 2022 at $50/short ton of CO_2;
- More renewable adoption pushed through via mandates;
- Additional regulations on carbon on the horizon after 2030 that are higher than in the Reference Case, including a potential expansion of carbon costs not only at

the upstream level (which is relatively efficient to administer across a few thousand producers) but also on the downstream level (which is much less efficient to administer across millions of consumers, a policy that is adopted to force through more rapid change);

- Greater adoption of distributed generation in the form of solar and combined heat and power; and
- Restrictions on fracking and fugitive methane emissions that limit gas supply growth, drive up gas prices and result in an additional push and economic case for renewable energy.

The social cost of carbon is implemented via a high CO_2 tax early in the scenario. Monthly rebate checks (dividends) help to redistribute the revenues from the tax to American households based on number of people in the household. Furthermore, a fracking ban is imposed, driving up the cost of natural gas to historical levels last seen in the pre-shale boom era (pre-2008) in the long-term as supply dramatically shrinks (quantitatively, the price path is +2 standard deviations above current levels). For coal, a strong decline in demand puts downward pressure on coal prices.

The economic outlook remains at the Reference Case level as any potential benefit of the CO_2 dividend is offset by the drag on the economy imposed by additional regulations, including the fracking ban. Innovation occurs as renewables and battery storage are widely implemented to avoid paying high CO_2 prices, allowing costs to fall even as demand for these technologies increases. Utility-sponsored energy efficiency costs rise over time as the cost for regulatory compliance rises.

7.3.2 Coordinated Forecasts for Alternate Scenarios

The qualitative description of alternate scenarios described in Section 7.3.1 were next translated into quantitative inputs for use as modeling inputs. The steps in this process were described in Section 2.

- Stochastic distributions were developed for each input variable

- A table was developed that determined whether the variable would be above or below the Reference Case in the short, mid and long term.
- Values in specific years were developed by moving up or down one standard deviation (for gas sometimes two standard deviations) from the mean or reference forecast.
- Smoothing occurred to reach interim year values.

This was done using a probabilistic modeling framework, described below, which allowed the development of higher and lower forecasts, relative to the Reference Case for natural gas prices, CO_2 prices, coal prices, average and peak load for Vectren as well as surrounding markets (MISO, PJM and SERC) and capital costs for renewables, storage and fossil technologies.

7.3.2.1 Stochastic Distributions

In order to perform the probabilistic modeling, also known as stochastic analysis, a set of probability distributions were required for the key market driver variables described above (fuel, emissions, load and capital costs). These probability distributions were developed from a simulation that creates 200 future paths for each stochastic variable. The following sections describe the methodologies for developing these stochastic variables, with additional detail explained in the Technical Appendix 11.6.

7.3.2.1.1 Load Stochastics

To account for electricity demand variability that derives from economic growth, weather, energy efficiency and demand side management measures, Pace Global developed stochastics around the load growth expectations for the Vectren control area and the neighboring ISO zones, including MISO, PJM and SERC. Pace Global’ s long-term load forecasting process is a two-step process that captures both the impact of historical load drivers such as economic growth and variability of weather and the possible disruptive impacts of energy efficiency penetration in constructing the average and peak demand outlook. Pace Global benchmarked the projections against MISO-sponsored load forecasting studies that are conducted by independent consultants, institutions and market monitors and then released into the public domain.

7.3.2.1.2 Gas Stochastics

Pace Global developed natural gas price stochastic distributions for the benchmark Henry Hub market point. These stochastic distributions are first based on the consensus Reference Case view of natural gas prices with probability bands developed then based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility. For the period 2019-2022, volatility calculated from the past three years of price data is used. For 2023-2025, volatility calculated from the past five years is used. For 2026-2039, volatility calculated from the past 10 years is used. This allows gas price volatility to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility. The 95th percentile probability bands are driven by increased gas demand (e.g., coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization relatively low as well as few to no new environmental regulation around power plant emissions.

7.3.2.1.3 Coal Stochastics

Pace Global developed coal price stochastic distributions for the CAPP, NAPP, ILB and PRB basins. These stochastic distributions are first based on a consensus Reference Case view of coal prices with probability bands developed then based on a combination of historical volatility and mean reversion parameters. It should be noted that most coal contracts in the U.S. are bilateral and only approximately 20% are traded on the NYMEX. The historical data set that is used to calculate the parameters is comprised of the weekly traded data reported in NYMEX.

7.3.2.1.4 Emissions Stochastics

Pace Global developed uncertainty distributions around carbon compliance costs, which were used in Aurora to capture the inherent risk associated with regulatory compliance requirements. The technique to develop carbon costs distributions, unlike the previous variables, is based on projections largely derived from expert judgment, as there are no national historical data sets (only regional markets in California and the Northeast) to estimate the parameters for developing carbon costs distributions.

7.3.2.1.5 Capital Cost Stochastics

Pace Global developed the uncertainty distributions for the cost of new entry units by technology type, which was used in Aurora for determining the economic new builds based on market signals. These technologies included gas peaking units, gas combined cycles, solar, wind and battery storage resources. The methodology of developing the capital cost distributions is a two-step process: (1) a parametric distribution based on a Reference Case view of future all-in capital costs, historical costs and volatilities and a sampling of results to develop probability bands around the Reference Case; and (2) a quantum distribution that captures the additional uncertainty with each technology that factors in learning curve effects, improvements in technology over time and other uncertain events such as leaps in technological innovation.

7.3.2.1.6 Cross-Commodity Stochastics

Pace Global captured the cross-commodity correlations in the stochastic process, which is a separate stochastic process from those for gas, coal and CO_2 prices. The feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators. Pace Global conducted a fundamental analysis to define the relationship between gas and coal dispatch costs and demand. The dispatch costs of gas and coal were calculated from the gas and coal stochastics and CO_2 stochastics, along with generic assumptions for variable operation and maintenance costs. Where the gas-coal dispatch differential changes significantly enough to affect demand, gas demand from the previous year was adjusted to reflect the corresponding change in demand. A gas price delta was then calculated based on the defined gas demand. This gas price delta was then added to the gas stochastic path developed from historic volatility to calculate an integrated set of CO_2 and natural gas stochastic price forecasts.

7.3.2.2 Model Inputs

The following graphs illustrate the key market driver inputs across all the alternate scenarios.

Figure 7.8 – Vectren Peak Load (MW) Alternate Scenarios

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,115	1,115	1,115	1,115	1,115
2020	1,100	1,100	1,100	1,100	1,100
2021	1,102	1,102	1,102	1,102	1,102
2022	1,126	1,146	1,146	1,084	1,126
2023	1,168	1,191	1,191	1,066	1,168
2024	1,173	1,235	1,235	1,049	1,173
2025	1,176	1,303	1,303	1,055	1,176
2026	1,179	1,325	1,325	1,045	1,179
2027	1,183	1,322	1,322	1,036	1,183
2028	1,189	1,348	1,348	1,028	1,189
2029	1,192	1,338	1,338	1,035	1,192
2030	1,196	1,337	1,337	1,059	1,196
2031	1,200	1,356	1,356	1,055	1,200
2032	1,205	1,371	1,371	1,055	1,205
2033	1,209	1,386	1,386	1,056	1,209
2034	1,214	1,356	1,356	1,051	1,214
2035	1,219	1,379	1,379	1,051	1,219
2036	1,225	1,379	1,379	1,065	1,225
2037	1,229	1,383	1,383	1,060	1,229
2038	1,234	1,386	1,386	1,076	1,234
2039	1,239	1,391	1,391	1,062	1,239

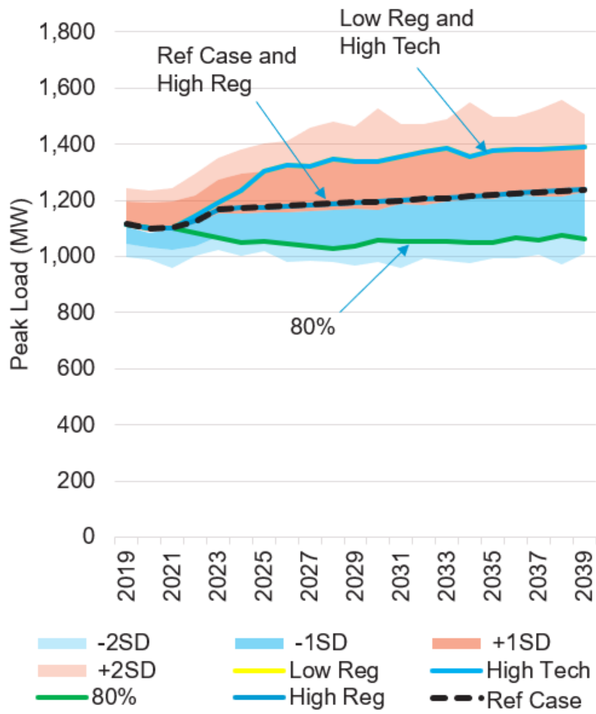


Figure 7.9 – Coal (Illinois Basin) Alternate Scenarios (2018$/MMBtu)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1.78	1.78	1.78	1.78	1.78
2020	1.68	1.68	1.68	1.68	1.68
2021	1.66	1.66	1.66	1.66	1.66
2022	1.65	1.65	1.57	1.57	1.57
2023	1.64	1.64	1.49	1.49	1.49
2024	1.64	1.64	1.41	1.41	1.41
2025	1.63	1.63	1.27	1.27	1.27
2026	1.62	1.62	1.29	1.29	1.29
2027	1.61	1.61	1.25	1.25	1.25
2028	1.62	1.62	1.25	1.25	1.25
2029	1.61	1.61	1.25	1.25	1.25
2030	1.60	1.60	1.25	1.25	1.25
2031	1.59	1.59	1.25	1.25	1.25
2032	1.58	1.58	1.25	1.25	1.25
2033	1.58	1.58	1.25	1.25	1.25
2034	1.57	1.57	1.25	1.25	1.25
2035	1.59	1.59	1.25	1.25	1.25
2036	1.59	1.59	1.25	1.25	1.25
2037	1.59	1.59	1.25	1.25	1.25
2038	1.59	1.59	1.25	1.25	1.25
2039	1.58	1.58	1.25	1.25	1.25

A price floor is set at $1.25/MMBtu

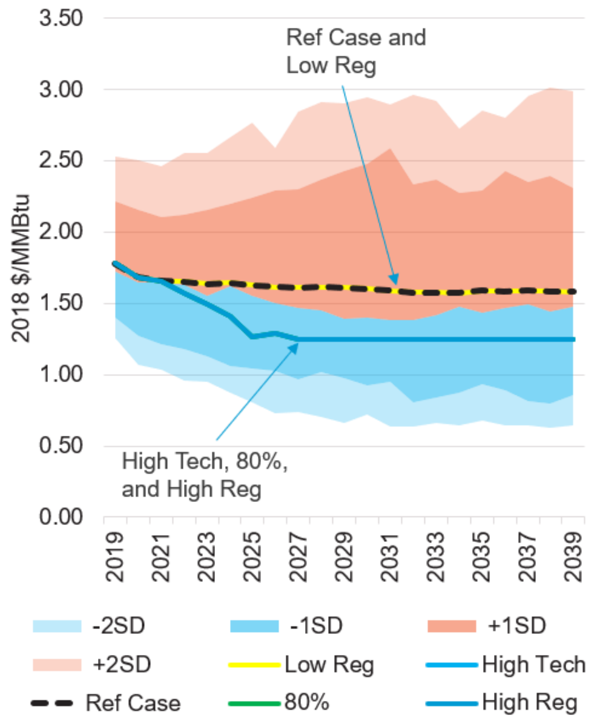


Figure 7.10 – C0₂ Alternate Scenarios (2018$/ton)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	0	0	0	0	0
2022	0	0	0	0	49.46
2023	0	0	0	0	50.40
2024	0	0	0	0	51.34
2025	0	0	1.20	3.57	52.28
2026	0	0	1.44	4.08	53.23
2027	3.57	0	2.06	5.10	54.17
2028	4.08	0	2.28	6.12	55.11
2029	5.10	0	2.38	6.63	56.05
2030	6.12	0	2.68	7.14	56.99
2031	6.63	0	2.94	7.65	57.94
2032	7.14	0	3.17	8.16	58.88
2033	7.65	0	3.89	9.18	60.06
2034	8.16	0	4.49	10.20	61.23
2035	9.18	0	5.46	11.22	62.41
2036	10.20	0	6.01	12.75	63.59
2037	11.22	0	6.85	14.79	64.77
2038	12.75	0	7.52	17.34	65.94
2039	14.79	0	8.50	19.89	67.12

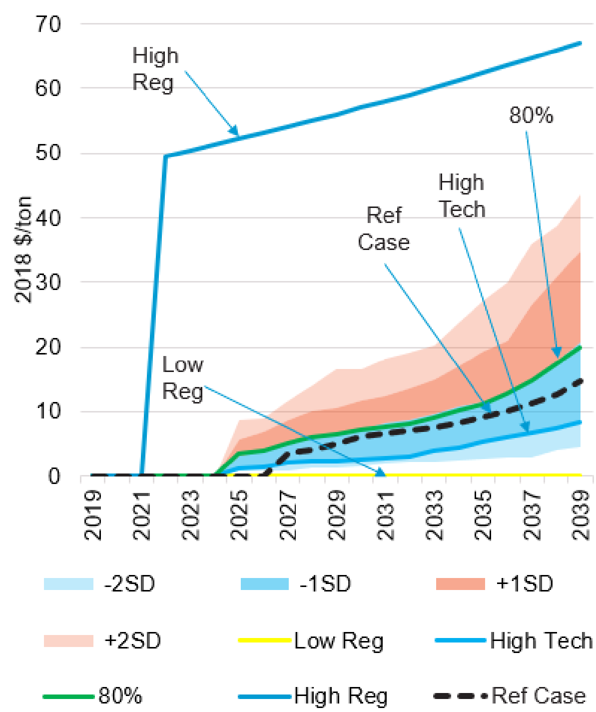


Figure 7.11 – Natural Gas (Henry Hub) Alternate Scenarios (2018$/MMBtu)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	2.77	2.77	2.77	2.77	2.77
2020	2.66	2.66	2.66	2.66	2.66
2021	2.76	2.76	2.76	2.76	2.76
2022	2.89	3.46	3.01	2.89	3.58
2023	3.06	4.10	2.82	3.06	4.39
2024	3.16	4.75	2.64	3.16	5.21
2025	3.24	5.12	2.33	3.24	6.03
2026	3.33	5.27	2.08	3.33	7.14
2027	3.38	5.20	2.13	3.38	7.10
2028	3.44	5.45	2.06	3.44	7.43
2029	3.49	5.62	2.04	3.49	8.37
2030	3.55	5.77	2.12	3.55	7.53
2031	3.62	5.60	2.13	3.62	7.17
2032	3.69	5.76	1.97	3.69	7.89
2033	3.78	5.95	2.02	3.78	8.40
2034	3.85	6.02	1.95	3.85	7.49
2035	3.96	6.12	2.12	3.96	8.95
2036	4.02	6.64	2.12	4.02	9.29
2037	4.09	6.23	2.07	4.09	8.75
2038	4.14	6.77	2.19	4.14	9.07
2039	4.17	6.85	2.20	4.17	8.63

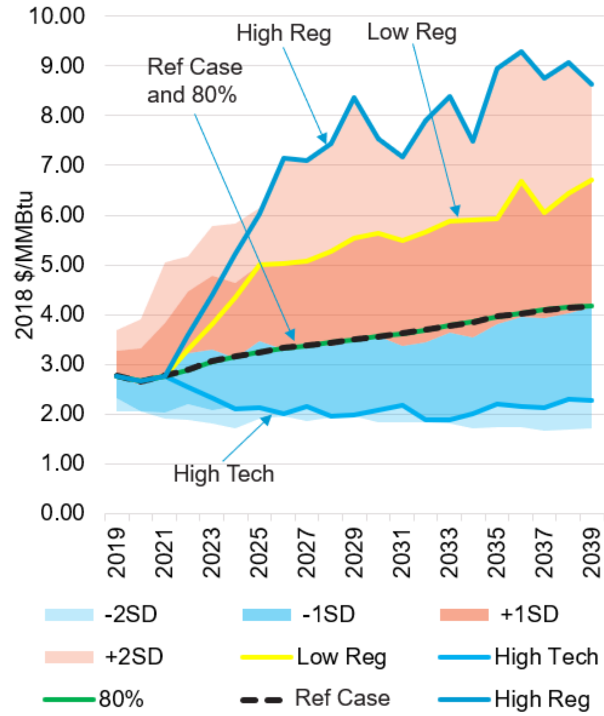


Figure 7.12 – Solar Capital Costs Alternate Scenarios(100 MW) (2018 $/kW)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,384	1,384	1,255	1,255	1,255
2020	1,305	1,305	1,160	1,160	1,160
2021	1,237	1,237	1,093	1,093	1,093
2022	1,198	1,198	1,043	1,043	1,043
2023	1,179	1,179	1,008	1,008	1,008
2024	1,161	1,161	996	996	996
2025	1,143	1,143	954	954	954
2026	1,124	1,124	956	956	956
2027	1,106	1,106	943	943	943
2028	1,089	1,089	949	949	949
2029	1,072	1,072	921	921	921
2030	1,057	1,057	887	887	887
2031	1,041	1,041	878	878	878
2032	1,028	1,028	871	871	871
2033	1,016	1,016	858	858	858
2034	1,003	1,003	817	817	817
2035	990	990	801	801	801
2036	981	981	790	790	790
2037	972	972	792	792	792
2038	962	962	789	789	789
2039	952	952	800	800	800

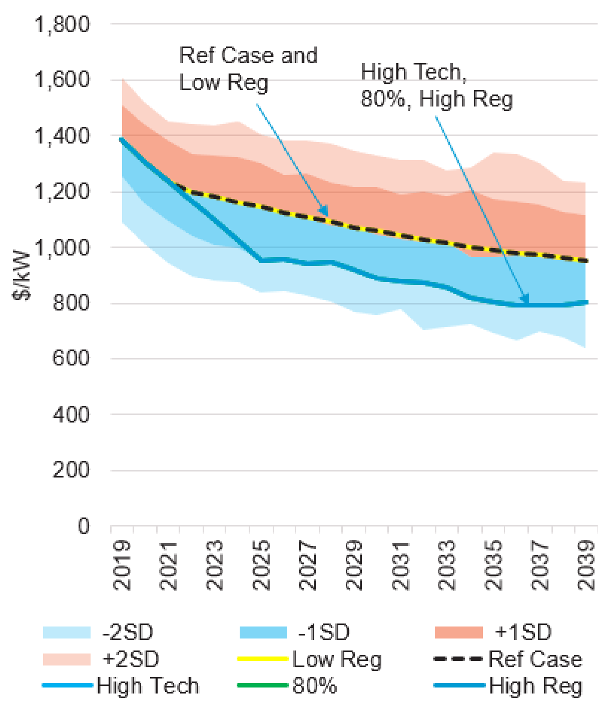


Figure 7.13 – Wind Capital Costs Alternate Scenarios (200 MW) (2018 $/kW)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,334	1,334	1,334	1,334	1,334
2020	1,332	1,332	1,332	1,332	1,332
2021	1,330	1,330	1,330	1,330	1,330
2022	1,329	1,329	1,289	1,289	1,289
2023	1,328	1,328	1,249	1,249	1,249
2024	1,327	1,327	1,208	1,208	1,208
2025	1,326	1,326	1,167	1,167	1,167
2026	1,325	1,325	1,163	1,163	1,163
2027	1,324	1,324	1,123	1,123	1,123
2028	1,324	1,324	1,157	1,157	1,157
2029	1,324	1,324	1,160	1,160	1,160
2030	1,324	1,324	1,182	1,182	1,182
2031	1,324	1,324	1,152	1,152	1,152
2032	1,324	1,324	1,152	1,152	1,152
2033	1,324	1,324	1,166	1,166	1,166
2034	1,325	1,325	1,161	1,161	1,161
2035	1,326	1,326	1,139	1,139	1,139
2036	1,327	1,327	1,129	1,129	1,129
2037	1,328	1,328	1,142	1,142	1,142
2038	1,329	1,329	1,142	1,142	1,142
2039	1,330	1,330	1,143	1,143	1,143

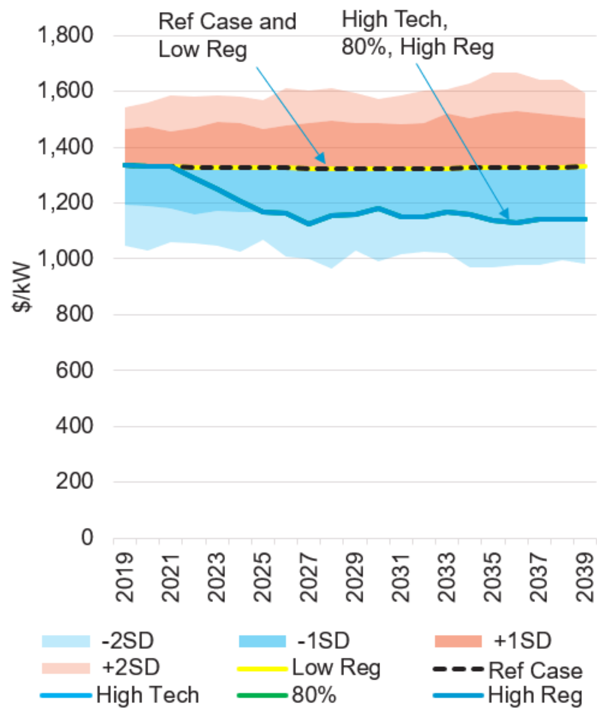
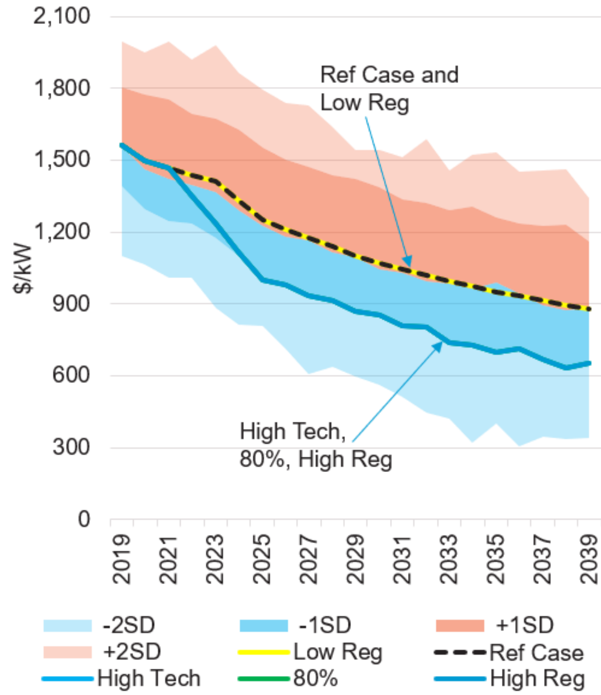


Figure 7.14 – Lithium-Ion 50 MW / 200 MWh Battery Storage Capital Costs Alternate Scenarios (2018$/kW)[41]

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,562	1,562	1,390	1,390	1,390
2020	1,498	1,498	1,299	1,299	1,299
2021	1,467	1,467	1,247	1,247	1,247
2022	1,439	1,439	1,236	1,236	1,236
2023	1,412	1,412	1,178	1,178	1,178
2024	1,332	1,332	1,100	1,100	1,100
2025	1,252	1,252	1,001	1,001	1,001
2026	1,209	1,209	982	982	982
2027	1,175	1,175	936	936	936
2028	1,140	1,140	916	916	916
2029	1,103	1,103	869	869	869
2030	1,068	1,068	852	852	852
2031	1,044	1,044	811	811	811
2032	1,020	1,020	806	806	806
2033	996	996	739	739	739
2034	975	975	727	727	727
2035	951	951	699	699	699
2036	933	933	714	714	714
2037	915	915	669	669	669
2038	897	897	631	631	631
2039	878	878	654	654	654



[41] Note that storage costs were updated since the October 10th stakeholder meeting and are lower

SECTION 8
PORTFOLIO DEVELOPMENT AND EVALUATION

8.1 PORTFOLIO DEVELOPMENT

Vectren developed a wide range of portfolios for scenario modeling in the dispatch module of Aurora and ultimately for the probabilistic modeling portion of this IRP process. Working with external stakeholders and building upon feedback from the IURC Director's Report from the 2016 IRP, Vectren developed 15 "least cost" portfolios for evaluation that included the continuing use of coal plants (status quo) for comparative cost and performance benchmarking purposes, scenario-based portfolios optimized under widely varying market conditions, bridge portfolios designed to take advantage of existing resources during the transition to a generation fleet with many new resources, diversified portfolios with a balanced mix of generation technology types and renewables-focused portfolios designed with directed input from stakeholders. Each least cost portfolio was constructed with the option to include near-term solar, wind and battery storage options, from the All-Source RFP solicitation, while medium-term and long-term resource options were available for selection from a comprehensive technology assessment performed by Burns & McDonnell (with capital costs developed from a consensus view of prices from Burns & McDonnell, Pace Global and NREL for renewable and storage options). These resource portfolios were then selected on a least-cost basis using the LTCE module of the Aurora model. DSM resource options were also available for selection

8.1.1 Portfolio Strategies with Stakeholder Input

Vectren strived to take into consideration the many diverse interests of a broad range of stakeholders. Accordingly, several of the 15 candidate portfolios were developed with direct and indirect input from stakeholders. Three portfolios were designed to be focused on renewables, including a Renewables 2030 portfolio in which all fossil generation is retired at the end of 2029; a Renewables plus Flexible Gas portfolio, that includes closing F.B. Culley 3 by December 31, 2033 and excludes any new gas combined cycle plants; and an HB 763 portfolio modeled after a bill in the U.S. Congress that includes a CO_2 price in 2022 of $15, increasing by $10 per short ton each year (approximately $200 by 2039). Other portfolios, including the Business as Usual and Bridge portfolios, were designed to consider the interests of a separate set of stakeholders.

8.1.2 Least Cost Portfolio Construction

Each of the 15 strategies were utilized to construct portfolios in the Aurora model using a Least Cost Capacity Expansion module in AURORA with a cost minimization objective function. The scenario-based portfolios (Low Regulatory, High Technology, 80% Reduction of CO_2 and High Regulatory) each selected the lowest cost combination of assets assuming their respective market inputs. In Section 7 it is noted that three of those portfolios were eliminated from consideration because they employ greater capacity than needed in the form of renewable resources and rely on extensive off-system sales to reduce costs.

Other portfolios were determined by forcing certain design considerations for specific generating stations, including bridge options that include converting existing coal units into gas peaking units or extending the life of A.B. Brown coal units and then the model selected the least cost portfolio of remaining assets. Vectren also constructed in diverse energy portfolios with two sizes of gas combined cycle technologies and portfolios focused primarily on renewable and battery storage technologies. Utilizing this strategy allowed for a wide range of portfolios that were least cost portfolios using available resources, subject to initial design parameters in each strategy. All portfolios were also designed to include five (5) blocks of near-term (2021-2023) energy efficiency, which is equivalent to approximately 1.25% of eligible retail sales. Each portfolio description below details the optimized amount of EE selected.

8.1.3 Portfolio Descriptions

The following sections describe in detail designed portfolios (including bridge, diverse and renewables-focused portfolios). Figure 8.1 Portfolio Details shows a summary table of the build outs for each of the selected set of portfolios for consideration in the Risk Analysis. Note that the last line of each table shows long-term capacity market exposure under reference case conditions. Also, based on a sensitivity described in Section 8.2.2 near-term energy efficiency of 1.25% included in all portfolios.

Figure 8-1 – Portfolio Details

Year	Reference Case	Business as Usual to 2039	Business as Usual to 2029	Gas Conversion ABB1	Gas Conversion ABB1 + ABB2
2021-23	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency
2022	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)
2023	New Solar (731 MW), New Storage (126 MW)	New Solar (731 MW), New Storage (126 MW)	New Solar (731 MW), New Storage (126 MW)	New Solar (731 MW), New Storage (126 MW)	New Solar (731 MW), New Storage (126 MW)
2023	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Scrubber control on ABB1 and ABB2, Exit Warrick (150 MW)	Exit Warrick (150 MW)	Retire ABB2, FBC2, Exit Warrick (485 MW)	Retire FBC2, Exit Warrick (240 MW)
2024	New Combustion Turbine (236 MW)	-	-	ABB1 Conversion (245 MW)	ABB1+ABB2 Conversions (490 MW)
2024	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response
2024-26	0.75% Energy Efficiency	0.75% Energy Efficiency	0.75% Energy Efficiency	0.75% Energy Efficiency	0.75% Energy Efficiency
2027-39	0.75% Energy Efficiency	0.25% Energy Efficiency	0.50% Energy Efficiency	0.75% Energy Efficiency	0.50% Energy Efficiency
2029-30	-	-	Retire ABB1, ABB2, FBC2 (580 MW), New Combustion Turbine (236 MW)	-	-
2033-34	-	-	-	Retire ABB1, New Combustion Turbine (279 MW)	Retire ABB1+ABB2, New Combustion Turbine (279 MW)
2037-39	New Solar (250 MW)	-	-	-	-
2024-39	Avg Annual Capacity Mkt Purchases (137 MW)	No Capacity Market Purchases	Avg Annual Capacity Mkt Purchases (101 MW)	Avg Annual Capacity Mkt Purchases (133 MW)	Avg Annual Capacity Mkt Purchases (56 MW)

Year	Gas Conversion ABB1 + CCGT	Diverse Small CCGT	Diverse Medium CCGT	Renewables + Flexible Gas	Renewables 2030
2021-23	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency
2022	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)
2023	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (278 MW)
2023	Retire ABB2, FBC2, Exit Warrick (485 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)
2024	ABB1 Conversion (245 MW)	-	-	New Combustion Turbine (236 MW)	-
2024	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response
2024-26	0.75% Energy Efficiency	0.75% Energy Efficiency	0.75% Energy Efficiency	1.00% Energy Efficiency	0.75% Energy Efficiency
2025	-	New Small CCGT (433 MW)	New Medium CCGT (497 MW)	-	-
2026	New Small CCGT (433 MW)	-	-	-	-
2024-26	0.50% Energy Efficiency	0.50% Energy Efficiency	0.25% Energy Efficiency	1.00% Energy Efficiency	0.75% Energy Efficiency
2029-32	-	-	-	-	Retire FBC3, ABB3, ABB4 (427 MW), New Storage (360 MW), Solar (700 MW)
2033-34	-	-	-	Retire FBC3 (270 MW), New Combustion Turbine (236 MW)	New Solar (450 MW)
2024-39	Avg Annual Capacity Mkt Purchases (16 MW)	Avg Annual Capacity Mkt Purchases (23 MW)	Avg Annual Capacity Mkt Purchases (18 MW)	Avg Annual Capacity Mkt Purchases (135 MW)	Avg Annual Capacity Mkt Purchases (170 MW)

Year	HB 763	Low Regulatory	High Technology	80% Reduction of CO2 by 2050	High Regulatory
2021-23	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency
2022	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)
2023	New Solar (731 MW) New Storage (278 MW)	New Solar (731 MW) New Storage (278 MW)	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (202 MW)	New Solar (731 MW) New Storage (278 MW)
2023	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)
2024	New Landfill Gas (27 MW)	New Combustion Turbine (279 MW)	New Combustion Turbine (236 MW)	-	-
2024	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response
2024-26	1.50% Energy Efficiency	1.25% Energy Efficiency	0.75% Energy Efficiency	0.75% Energy Efficiency	1.25% Energy Efficiency
2025	New Solar (550 MW) New Wind (650 MW) New Storage (50 MW)	-	New Combustion Turbine (236 MW)	-	New Solar (550 MW) New Wind (650 MW) New Storage (50 MW)
2026-39	New Solar (1,100 MW) New Wind (2,500 MW) New Storage (220 MW)	New Solar (1,000 MW) New Wind (2,400 MW)	-	-	New Solar (1,260 MW) New Wind (2,650 MW) New Storage (290 MW)
2027-39	1.25% Energy Efficiency	1.00% Energy Efficiency	0.75% Energy Efficiency	0.5% Energy Efficiency	0.50% Energy Efficiency
2033-39	-	-	New Storage (50 MW)	New Solar (800 MW) New Wind (2,750 MW) New Storage (190 MW)	-
2024-39	Avg Annual Capacity Mkt Purchases (10 MW)	Avg Annual Capacity Mkt Purchases (12 MW)	Avg Annual Capacity Mkt Purchases (4 MW)	Avg Annual Capacity Mkt Purchases (203 MW)	Avg Annual Capacity Mkt Purchases (11 MW)

8.1.3.1 Reference Case

The Reference Case is considered to be the “most likely” case, built with commodity forecasts based on a consensus outlook from industry experts as described in Section 7.2 Reference Case Scenario.

The least cost Reference Case portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new 236.6 MW CT selected in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) while the optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 137.5 MW during the period 2024-2039. Finally, 250 MW of solar is selected in the final three years of the forecast (2037-2039).

8.1.3.2 Status Quo

The BAU to 2039 status quo portfolio was designed, by definition, to provide a business as usual outlook through the forecast period. In this portfolio, each of the four Vectren-owned coal generation units are kept in operation to 2039, subject to various upgrades to keep them in compliance with existing environmental regulatory requirements. The Warrick 4 unit was given the option to extend for an additional three years of operation before exiting the joint agreement, but ultimately was not selected by the optimization routine for continuation based on purely economic considerations. This portfolio provides a useful, status quo benchmark for financial and operational performance to compare against all the other candidate portfolios. Vectren exits Warrick 4 joint operations with Alcoa. This 150 MWs is replaced with renewables. The optimized (least costs) BAU to 2039 portfolio includes 300 MW of wind resources selected in 2022, approximately 746

MW of solar selected in 2023 and 2024 and the selection in 2023 of paired "solar plus storage" resources (400 MW solar; 126 MW storage). Approximately 0.50% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) while an additional block of EE (0.25%) is selected in the time period 2024-2026. This portfolio is capacity-rich, so no capacity market purchases are required during the period 2024-2039.

8.1.3.3 Four Scenario Based Portfolios

Four scenario-based portfolios (Low Regulatory, High Technology, 80% Reduction of CO_2 and High Regulatory) were developed to evaluate various regulatory constructs, economic and market conditions and technological progress. In general, the scenario-based portfolios move from low to high regulation, with intermediate levels of regulation characterized by the High Technology and 80% Reduction of CO_2 portfolios.

While the Reference Case is considered the most likely future, the alternative scenario-based portfolios were developed to bookend the Reference Case with higher than, lower than, or similar inputs to the Reference Case. The following sections describe the qualitative and quantitative development of the scenario-based portfolios.

8.1.3.3.1 Low Regulatory

The Low Regulatory portfolio (optimized under high load conditions) includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new 279.3 MW CT is selected in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 1,000 MW of solar is selected beginning in 2026, while an additional 2,600 MW of wind is selected beginning in 2032. Approximately 1.00% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039), an additional block (0.25%) of energy efficiency is selected in the time period 2024-2026 and the optional demand response bin is selected in the time periods 2024-2026 and 2027-

2039. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 18.4 MW during the period 2024-2033. Because the Low Regulatory portfolio was significantly overbuilt relative to the Reference Case load outlook, this optimized portfolio was not selected for further analysis.

8.1.3.3.2 High Technology

The High Technology portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and two new 236.6 MW gas CT is selected in 2024 and 2025, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 50 MW of storage is selected in the final year of the forecast. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) with the exception of the third block of energy efficiency, which is not selected in the time period 2027-2039. The optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. F B Culley 3 operations continue through the forecast period. The only shortfall in capacity occurs in 2024 and is met through 70.9 MW of capacity market purchases. Because the optimized High Technology portfolio buildout had less reliance on the capacity market than the Reference Case portfolio, it offered a useful comparison of cost and performance. It was selected for further analysis and was eventually selected as the preferred portfolio.

8.1.3.3.3 80% CO_2 Reduction

The 80% Reduction of CO_2 by 2050 portfolio (least cost under reference case load conditions) includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024 and the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 800 MW of solar is selected beginning in

2035, an additional 2,750 MW of wind is selected beginning in 2033 and an additional 266 MW of battery storage is selected beginning in 2036. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) with the exception of the third block of energy efficiency, which is not selected in the time period 2027-2039. The optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. F B Culley 3 operations continue through the forecast period. The only shortfall in capacity occurs in 2024 and is met through 70.9 MW of capacity market purchases. Because the optimized 80% Reduction of CO_2 by 2050 portfolio buildout was significantly overbuilt relative to the Reference Case load outlook, this optimized portfolio was not selected for further analysis.

8.1.3.3.4 High Regulatory

The least cost High Regulatory portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, approximately 152 MW of storage in 2023 and 2024 and the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 1,810 MW of solar is selected beginning in 2025, an additional 3,300 MW of wind is selected beginning in 2025 and an additional 340 MW of battery storage (which is paired with wind) is selected beginning in 2025. Approximately 1.25% of energy efficiency blocks are selected in the first two time periods (near-term 2021-2023 and mid-term 2024-2026), while 0.50% of energy efficiency is selected in the time period 2027-2039. No optional demand response is selected. F B Culley 3 operations continue through the forecast period. The only shortfall in capacity occurs in 2024 and is met through 165.6 MW of capacity market purchases. Because the optimized High Regulatory portfolio buildout was significantly overbuilt relative to the Reference Case load outlook, this optimized portfolio was not selected for further analysis.

8.1.3.4 Bridges

The following portfolios were designed to serve as bridge portfolios, offering short-term and long-term transition pathways toward a fleet with greater renewable resources while utilizing existing resources.

8.1.3.4.1 Gas Conversion ABB1

This portfolio was designed to include the conversion of the older, less efficient unit at the A B Brown plant from a baseload coal-fired to natural gas peaking, which helps to preserve and repurpose much of the existing asset base. The unit would be converted for operation beginning in 2024 and expected to operate for 10 years before retirement. Conversions utilize some old equipment and require on-going capital investments to keep the units running. Since conversion of a unit offers less flexibility with slow start time (8-24 hrs.) and slow ramp rate (2MW/Min) it does not complement renewables well. The one conversion unit and the near-term (2021-2023) energy efficiency blocks are the only design parameters included in this candidate portfolio. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Gas Conversion ABB1 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), in addition to the conversion in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. One new 279.3 MW CT is selected in 2034 once the conversion unit is retired. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039). The optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 133.3 MW during the period 2024-2033.

8.1.3.4.2 Gas Conversion ABB1 & ABB2

Similar to the Gas Conversion ABB1 portfolio, this portfolio was designed to include the conversion of both units at the A B Brown plant from baseload coal-fired units to natural gas peaking units. These conversions also help to preserve and repurpose much of the existing asset base at this facility. As described above, gas conversion units do not start or ramp quickly. Both units would be converted for operation beginning in 2024 and expected to operate for 10 years before retirement. The two conversion units and the near-term (2021-2023) energy efficiency blocks are the only design parameters included in this candidate portfolio. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Gas Conversion ABB1 & ABB2 portfolio retired F B Culley 2 and exited joint operations at Warrick 4. and includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), in addition to the two conversions in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. One new 279.3 MW CT is selected in 2034 once the conversion unit is retired. Approximately 0.50% of energy efficiency blocks are selected in the near-term (2021-2023), while 0.75% is selected in the mid-term (2024-2026) and long-term (2027-2039). The optional demand response bin is selected in the 2027-2039 time period. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 150.1 MW during the period 2034-2039.

8.1.3.4.3 Gas Conversion ABB1 + CCGT

This portfolio was designed to include conversion of one unit at the A B Brown plant from a baseload coal-fired unit to a natural gas peaking unit, which helps to preserve and repurpose much of the existing asset base at this facility. It retired A B Brown unit 2, F B Culley 2 and exited joint operations at Warrick 4. In addition, this portfolio includes a small CCGT unit with duct-firing capability (total 442.5 MW) in 2026. The conversion unit is be converted for operation beginning in 2024 and is expected to operate for 10 years before retirement. The conversion and CCGT units are the only design parameters included in this candidate portfolio beyond near term EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Gas Conversion ABB1 + CCGT portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and the conversion unit in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. One new 432.6 MW combined cycle unit is designed to begin operations in 2026. Approximately 0.50% of energy efficiency blocks are selected in the near-term (2021-2023), while 0.75% is selected in the mid-term (2024-2026) and long-term (2027-2039). The optional demand response bin is selected in the 2024-2026 time period. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 16.4 MW during the period 2024-2039.

8.1.3.4.4 BAU 2029

The BAU 2029 portfolio was designed to bridge half of the study period (2019-2029) using existing baseload coal resources at A B Brown plant. Culley 2 (90 MW) is retired in 2023 and Vectren exits joint operations of Warrick 4 (150 MW) in 2023. The two coal units at A B Brown are extended through 2029 using existing FGD scrubber technology and retired by 2030. This portfolio strategy helps to preserve the existing asset base while providing a transition pathway to a generation fleet with greater renewable resources. The two coal unit extensions through 2029 is the only design parameters included in this candidate portfolio beyond near term EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost BAU 2029 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new 236.6 MW gas

CT is selected in 2030. The coal unit F B Culley 2 and Warrick 4 are selected for retirement or exit of joint operations beginning in 2024. Approximately 0.50% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039), an additional 0.25% is selected in the time period 2024-2026 and 2027-2039. The optional demand response bin is selected in the time period 2027-2039. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 162.4 MW during the period 2030-2039.

8.1.3.5 Diverse

The following portfolios were designed to serve as portfolios that offer a diverse mix of baseload, peaking and intermittent technologies as well as a diversity of fuel sources including coal, natural gas and renewables.

8.1.3.5.1 Small CCGT with Renewables and Coal

The Small CCGT with Renewables and Coal portfolio was designed to provide a diversified mix of generation and fuel technologies, including a small-sized CCGT with duct-firing capability (total 442.5 MW). This portfolio strategy provides a transition pathway to a generation fleet, while maintaining and adding a diverse fuel mix of baseload generation technology. This portfolio retired A B Brown units 1 and 2, F B Culley 2 and exited joint operations at Warrick 4. The CCGT unit and the near-term (2021-2023), keeping Culley 3, and the selection of renewables, storage and DSM options were the only design parameter included in this candidate portfolio beyond near term EE. Also, additional CCGTs or CT's were not allowed to be selected. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Small CCGT with Renewables and Coal portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new small-sized CCGT with duct-firing capability (total 442.5 MW) that begins in

2025. Approximately 0.50% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039), an additional 0.25% is selected in the time periods 2024-2026 and 2027-2039. No optional demand response is selected. F B Culley 3 operations continue through the forecast period. There is a capacity shortfall in 2024 equal to 285.7 MW before the CCGT becomes operations, but thereafter any capacity shortfall is minimal and met through capacity market purchases, which average 21.5 MW during the period 2036-2039.

8.1.3.5.2 Mid CCGT with Renewables and Coal

The Mid CCGT with Renewables and Coal portfolio was designed to provide a diversified mix of generation and fuel technologies, including a medium-sized CCGT with duct-firing capability (total 510.7 MW). This portfolio strategy provides a transition pathway to a generation fleet with greater renewable resources while maintaining and adding a diverse mix of fuels and a diverse mix of baseload, peaking and intermittent generation technologies. This portfolio retired A B Brown units 1 and 2, F B Culley 2 and exited joint operations of Warrick 4. The CCGT unit, keeping Culley 3 and the selection of renewables and storage were the only design parameter included in this candidate portfolio beyond near term EE. Also, additional CCGTs or CT's were not allowed to be selected. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Mid CCGT with Renewables and Coal portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new medium-sized CCGT with duct-firing capability (total 510.7 MW) that begins in 2025. Approximately 0.50% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039), an additional 0.25% is selected in the time period 2024-2026. No optional demand response is selected. F B Culley 3 operations continue through the forecast period. There is a capacity shortfall in 2024 equal to 285.7 MW before the CCGT becomes operational, but thereafter any capacity shortfall is minimal and met through capacity market purchases, which occur only in 2039 and equal 3 MW. Because this portfolio did not produce a meaningful distinction with the optimized least cost Small CCGT with Renewables and Coal portfolio other than increased cost, with limited performance benefits, this portfolio was not selected for further analysis.

8.1.3.6 Renewables Focused

The following portfolios were designed to include a primary focus on renewable and battery storage resources, using three strategies: (1) closing all fossil by 2030 and backfilling only with renewables and battery storage resource, (2) closing all coal units by 2034 and backfilling with flexible units (CTs) and renewables and (3) optimizing a renewables-focused portfolio using a very high CO_2 price (modeled after the HB 763 bill introduced before the U.S. Congress) that begins in 2022 at \$15 and increases by \$10 per short ton each year, reaching ~\$200 by 2039. The third portfolio strategy (HB 763) was included for initial analysis based on direct feedback from stakeholders through the public stakeholder process.

8.1.3.6.1 Close All Fossil by 2030

The close All Fossil by 2030 portfolio was designed to transition Vectren's generation fleet to 100% renewables and battery storage beginning in 2030, which requires closing all coal and natural gas peaking units by the end of 2029. This portfolio strategy provides a rapid transition pathway to a generation fleet with 100% renewable and battery storage resources. The requirement that all fossil retire by the end of 2029 was the only design parameter included in this candidate portfolio beyond near term EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Close All Fossil by 2030 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and approximately 152 MW of battery storage are selected in 2023 and 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. F B Culley 3 and the two gas peaking units at A B Brown continue operating through 2029 before retiring in 2030. An additional 1,150 MW of solar resources are selected beginning in 2027, while an additional 360 MW of battery storage are selected beginning in 2027. Approximately 1.00% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) while the optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. Any shortfall in capacity is met through capacity market purchases, which average 169.7 MW during the period 2024-2039.

8.1.3.6.2 Renewables + Flexible Gas (CTs), Close Coal by 2034

The Renewables + Flexible Gas (CTs), Close Coal by 2034 portfolio was designed to transition Vectren’s generation fleet to renewables and battery storage while also maintaining the flexibility afforded by gas CTs. This portfolio strategy provides a transition pathway to a generation fleet focused on renewable and battery storage resources while maintaining the resource adequacy provided by flexible gas CTs. The requirement that all coal units retire by the end of 2033 was the only design parameter included in this candidate portfolio beyond near term EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Renewables + Flexible Gas (CTs), Close Coal by 2034 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024 and the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 600 MW of solar resources are selected beginning in 2034. F B Culley 3 operations continue through 2033 before retiring in 2034. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) while the optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. Any shortfall in capacity is met through capacity market purchases, which average 134.7 MW during the period 2024-2039.

8.1.3.6.3 HB 763

The HB 763 portfolio was designed to incentivize a rapid transition to renewables and battery storage through a very high CO_2 tax (modeled after the HB 763 bill introduced before the U.S. Congress) that begins in 2022 at $15 and increases by $10 per short ton each year, reaching $200 by 2039. This portfolio strategy provides a rapid and aggressive transition pathway to a generation fleet focused on renewable and battery storage resources. The CO_2 price and was the only design parameter included in this candidate portfolio beyond EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost HB 763 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024 and the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 1,650 MW of solar resources are selected beginning in 2025 and an additional 3,150 MW of wind resources are selected beginning in 2025. F B Culley 3 operations as well as the two gas peaking units at A B Brown plant continue through the forecast period. Approximately 1.25% of energy efficiency blocks are selected in the near-term (2021-2023), approximately 1.50% of energy efficiency blocks are selected in the medium-term (2024-2026) and approximately 1.00% of energy efficiency blocks are selected in the long-term (2027-2039). No optional demand response is selected. A one-year shortfall in capacity in 2024 is met through capacity market purchases, which equal 164.2 MW. Because the optimized HB 763 portfolio buildout was significantly overbuilt relative to the Reference Case load outlook, because this portfolio was the only portfolio that showed significant amounts of wind and solar curtailments (reaching as high as 11.8% annually and 21.4% annually, respectively) and because this portfolio had very high annual net energy sales, this optimized portfolio was not selected for further analysis.

8.2 EVALUATION OF PORTFOLIO PERFORMANCE

A total of 15 portfolios were developed in this IRP process, as described above. After an initial process in which a least cost portfolio was selected, 10 of the portfolios were selected as candidate portfolios for further analysis.

Five were screened out. These included three scenario-based portfolios (80% Reduction of CO_2 by 2050, High Regulatory and Low Regulatory) and two additional portfolios optimized around a key feature (Diverse Medium CCGT and HB 763). The scenario-based portfolios were optimized using the long-term capacity expansion module of Aurora within the wide-ranging market inputs described in Section 7, then simulated in the chronological hourly dispatch module of Aurora. However, each of three scenario-based portfolios were shown to be heavily reliant on energy market sales to reduce total portfolio costs (43.3%, 229.1% and 62.9% higher than the Reference Case, respectively, for the 80% Reduction by 2050, High Regulatory and Low Regulatory portfolios). In addition, around-the-clock (ATC) market clearing prices were as much as 77.3% higher than the Reference Case (specifically in the High Regulatory portfolio). Similarly, the Diverse Medium CCGT portfolio produced comparable results to the Diverse Small CCGT portfolio but at additional cost with little to no additional benefit. The HB 763 portfolio new unit capital costs were 382% higher than the Reference Case, which sold $5.3 billion in energy market sales in a market with average ATC power prices 55% higher than the Reference Case. In effect, the very high energy market sales in the High Regulatory and HB 763 would create a merchant utility, while the other portfolios were not expected to offer additional insights beyond the 10 candidate portfolios shown in the Balanced Scorecard. Furthermore, the HB 763 portfolio showed relatively high levels of renewable energy curtailments that were not seen in any other portfolio in the deterministic modeling (and very rarely in the subsequent stochastic modeling, for those candidate portfolios that underwent risk analysis). For these reasons, these five scenarios were not selected for further analysis in the stochastic framework.

Each of the remaining candidate portfolios was then subjected to two different forms of a risk analysis. One was scenario-based and one was based on probabilistic modeling (200 iterations), which serves as the basis for the balanced scorecard.

8.2.1 Scenario Risk Analysis

The IRP requires scenario-based modeling be performed as a part of the risk analysis be performed. In the Scenario Based risk analysis, the remaining ten candidate portfolios that were selected for further analysis were each modeled under each of the four scenarios with their respective market inputs. The following provides a summary of the results of this scenario risk analysis. The results of the deterministic scenario-based Risk Analysis are shown in Figures 8-2 – 8.5 below

Figure 8-2 – Portfolio NPVRR (million $)

	Scenarios				
	Reference	**Low Regulation**	**High Technology**	**80% Reduction of CO_2 by 2050**	**High Regulation**
Reference Case	100.0%	100.0%	100.0%	100.0%	100.0%
Business as Usual to 2039	119.7%	101.2%	120.7%	117.1%	112.5%
Business as Usual to 2029	108.0%	100.9%	108.5%	106.4%	104.8%
ABB1 Conversion + CCGT	112.6%	112.6%	111.5%	111.2%	107.4%
ABB1 Conversion	103.9%	104.5%	104.5%	103.9%	102.0%
ABB1 + ABB2 Conversions	110.0%	110.0%	110.1%	109.9%	105.5%
Diverse Small CCGT	105.3%	105.3%	104.2%	103.5%	102.7%
Renewables + Flexible Gas	98.4%	101.4%	98.2%	98.1%	97.7%
All Renewables by 2030	101.4%	108.2%	105.0%	100.5%	94.3%
High Technology	102.3%	102.6%	101.3%	102.1%	102.2%

Figure 8-3 – Portfolio CO2 Emissions Reductions by 2039 from 2019 Levels (thousand Tons)

	Scenarios				
	Reference	**Low Regulation**	**High Technology**	**80% Reduction of CO_2 by 2050**	**High Regulation**
Reference Case	78.2%	52.0%	87.9%	77.3%	76.4%
Business as Usual to 2039	60.3%	-22.5%	72.6%	54.3%	49.2%
Business as Usual to 2029	74.6%	53.6%	85.9%	74.0%	73.4%
ABB1 Conversion + CCGT	61.5%	40.0%	69.6%	61.8%	62.7%
ABB1 Conversion	74.0%	53.5%	85.6%	73.5%	72.9%
ABB1 + ABB2 Conversions	74.1%	53.5%	85.5%	73.5%	73.0%
Diverse Small CCGT	61.8%	39.8%	69.7%	61.9%	62.7%
Renewables + Flexible Gas	95.2%	90.2%	95.7%	94.9%	91.5%
All Renewables by 2030	95.8%	95.8%	96.0%	95.8%	95.8%
High Technology	77.8%	51.9%	88.2%	77.1%	76.1%

Figure 8-4 – Portfolio Average Market Purchase Amount (thousand MWh) from 2019-2039

	Scenarios				
	Reference	**Low Regulation**	**High Technology**	**80% Reduction of CO_2 by 2050**	**High Regulation**
Reference Case	100.0%	100.0%	100.0%	100.0%	100.0%
Business as Usual to 2039	79.6%	58.1%	97.7%	71.3%	17.1%
Business as Usual to 2029	84.1%	74.5%	90.1%	78.8%	73.5%
ABB1 Conversion + CCGT	38.9%	30.1%	46.0%	42.0%	38.7%
ABB1 Conversion	93.7%	90.9%	103.7%	82.6%	106.1%
ABB1 + ABB2 Conversions	93.2%	89.2%	101.2%	78.1%	104.2%
Diverse Small CCGT	36.2%	26.5%	42.2%	42.2%	35.7%
Renewables + Flexible Gas	108.5%	125.8%	98.9%	106.4%	139.7%
All Renewables by 2030	124.5%	166.1%	134.6%	117.9%	186.1%
High Technology	101.6%	94.0%	89.8%	102.1%	100.9%

Figure 8-5 – Portfolio Average Market Sale Amount (thousand MWh) from 2019-2039

	Scenarios				
	Reference	Low Regulation	High Technology	80% Reduction of CO_2 by 2050	High Regulation
Reference Case	100.0%	100.0%	100.0%	100.0%	100.0%
Business as Usual to 2039	141.9%	170.4%	114.9%	170.5%	222.1%
Business as Usual to 2029	129.8%	138.1%	121.3%	139.5%	140.3%
ABB1 Conversion + CCGT	160.4%	161.3%	139.4%	182.1%	136.0%
ABB1 Conversion	104.2%	102.2%	94.2%	113.2%	98.0%
ABB1 + ABB2 Conversions	107.6%	108.5%	99.9%	130.7%	102.0%
Diverse Small CCGT	160.2%	159.7%	139.1%	170.3%	138.9%
Renewables + Flexible Gas	104.7%	99.8%	108.2%	119.0%	97.3%
All Renewables by 2030	128.4%	116.3%	107.4%	143.9%	107.9%
High Technology	96.3%	99.0%	113.8%	94.0%	96.4%

Four portfolios performed very well across all the alternative scenarios and relative to the remaining six candidate portfolios in terms of low cost, low energy sales and purchases and greater CO_2 emissions reductions. These four portfolios included the Reference Case Renewables + Flexible Gas, All Renewables by 2030 and High Technology portfolios. Each of these portfolios ranked in the top four of 10 portfolios in terms of lowest cost, lowest energy purchases and greatest CO_2 emissions reductions. Similarly, three of these same four portfolios ranked in the top four of 10 portfolios in terms of lowest energy sales (the All Renewables by 2030 portfolio ranked 6th). Accordingly, these four portfolios performed well consistently across the metrics in the Balanced Scorecard[42] and were put forward as final candidates for consideration as the preferred portfolio.

By contrast, the remaining six of 10 portfolios performed relatively less well across these key metrics of portfolio cost, energy sales and purchases and CO_2 emissions reductions. In terms of cost, the BAU to 2039, ABB1 Conversion + CCGT, ABB1 + ABB2 Conversions and BAU to 2029 portfolios were the worst performers, with the notable exception of the two BAU portfolios under Low Regulatory scenario conditions (i.e., no CO_2 price). In terms

[42] Note: The scenario-based risk analysis measured CO_2 emissions reductions rather than CO_2-equivalent emissions reductions.

of CO_2 emissions reductions, the BAU to 2039, ABB1 Conversion + CCGT, Diverse Small CCGT and ABB1 + ABB2 Conversions portfolios showed the worst performance due to increased emissions from coal, CCGT, or coal-to-gas conversion unit operations. Finally, the BAU to 2039, ABB1 Conversion + CCGT, Diverse Small CCGT and ABB1 + ABB2 Conversions portfolios demonstrated the greatest exposure to market risk in terms of energy sales and purchases. The remaining two portfolios with one or both conversion of the A B Brown coal units performed relatively neither well nor poorly in each of these metrics. While the scenario based risk analysis was not the determinative factor for excluding portfolios or promoting them to final consideration, these results did help to inform the final decision-making process. In the end, all but the Reference Case Renewables + Flexible Gas, All Renewables by 2030 and High Technology portfolios were eliminated from final consideration.

8.2.2 Sensitivity Analysis

Several sensitivities were conducted on the candidate portfolios to test and refine the design of the portfolios and whether and how results might change if isolated variables might change. The following section describe these sensitivities and the conclusions drawn from this analysis, as well as any impact on the candidate portfolios.

The All-Source RFP resulted in a number of solar, wind and battery storage resources that were included as near-term resources in the optimization module of the Aurora model. A sensitivity was performed in which solar costs were increased by 30% to determine if this would impact their selection in 2022-2024, the timeframe during which they were offered and allowed to be selected in the model. The sensitivity showed that even with an increase of 30% in cost, the portfolio cost increased by 3.99% but the offerings remained below the market-clearing on-peak locational marginal price for Indiana and thus continued to be selected by the model as beneficial low-cost resources.

A sensitivity was conducted on the near-term (2021-2023) selectable energy efficiency blocks. The optimization module in the Aurora model selected between 0.50% and 1.50%

energy efficiency, based on the modeling inputs and the scenario being optimized. A sensitivity analysis was performed to compare 1.25% of energy efficiency to the 0.75% energy efficiency selected in the Reference Case. The sensitivity showed that increasing the near-term energy efficiency to 1.25% from 0.75% only increased the 20-year portfolio cost (NPVRR) by 0.15%.

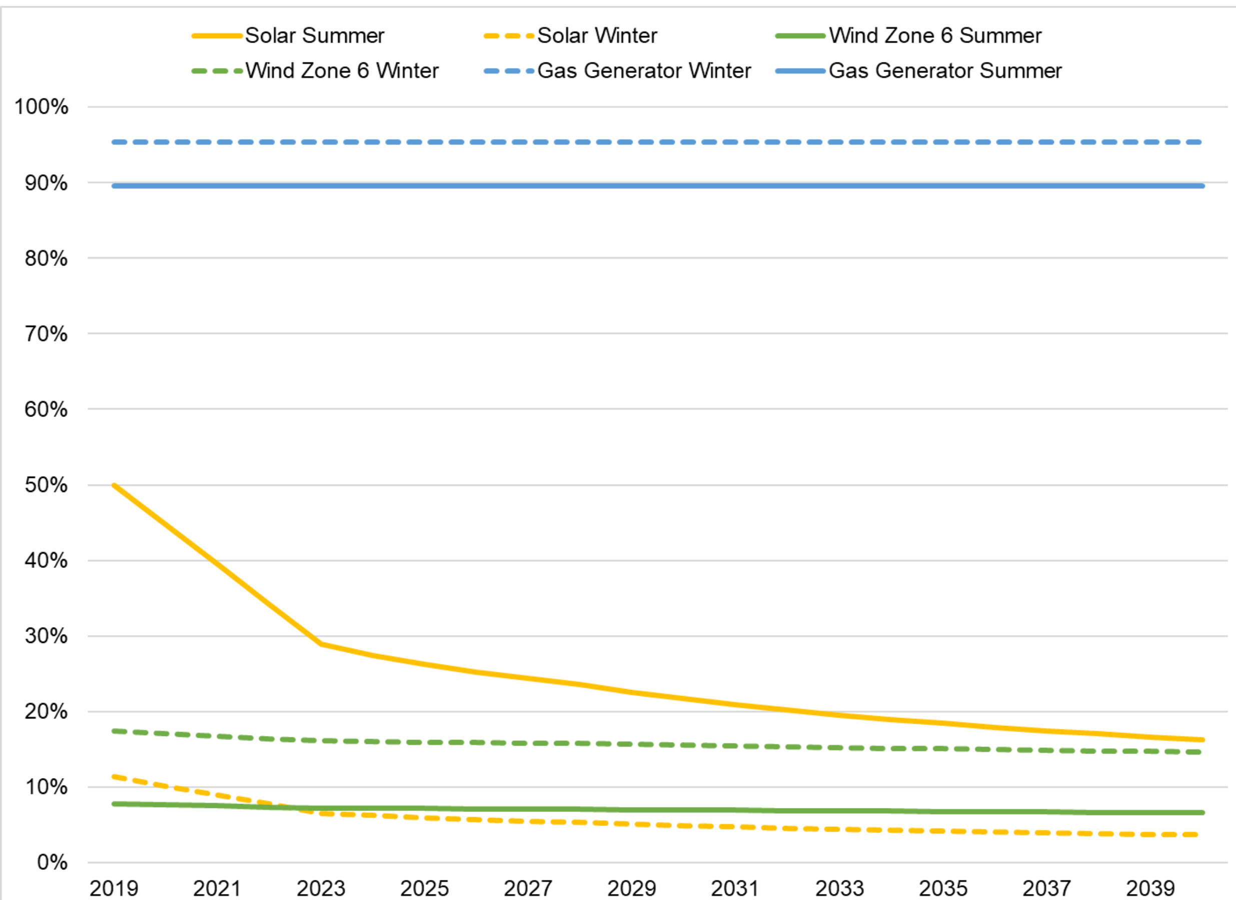
MISO is considering moving to a seasonal planning requirement. Accordingly, a sensitivity was conducted to determine the implications to the Reference Case portfolio of building to a summer peak vs. a winter peak and the resulting impact this would have on seasonal planning reserve margin requirements. Modeling a dynamic seasonal planning reserve margin requirement proved to be challenging and ultimately was not pursued, so the sensitivity focused on comparing a summer peak construct to a winter peak construct. Summer peak load is higher than winter peak load, but this difference in peak load is partially offset by a difference in seasonal unit capacity rating. The optimization routine in the Aurora model consistently selected for the maximum amount of solar available in the early years. However, the analysis showed that a constraint was necessary to prevent an overbuild of solar in this early timeframe. This is because the lower peak capacity accreditation for solar during the winter season meant that the winter peak demand was not met with solar that exceeded 1,150 MW. Accordingly, this required a limitation on the availability of solar to this level. The amount of solar in the early years was also limited by practical considerations around logistics and operational feasibility.

For this sensitivity, Vectren evaluated portfolios utilizing a reasonable summer and winter capacity accreditation construct as part of this IRP as a means of preparing for this implementation. All portfolios were required to meet both summer and winter peaks utilizing winter and summer accreditation. These forecasts were determined using MISO's ELCC accreditation formulas and MISO MTEP models for estimating renewable penetration levels. Applying similar methodology to MISO's current accreditation calculations, seasonal resource generation dispatching capabilities were accounted for. While using similar methodology to MISO's current solar would result in a 0% summer accreditation, Vectren utilized a conservative assumption based on Stakeholder feedback of 11% UCAP accreditation (year 1). 11% was derived by providing some benefit to output at 9 am, which is one of the three non-consecutive highest winter load hours.

Figure 8-6 - Year 1 Seasonal Accreditation

Seasonal Capacity Accreditation	Year 1 (2019)	
	Summer	Winter
Solar	50%	11%
Wind MISO Zone 6	8%	17%
Gas Generator	~90%	~95%

Figure 8-7 - Seasonal UCAP Accreditation Forecast



The sensitivity demonstrated that Vectren should continue to plan for meeting its summer peak as the greater of the two seasonal constraints. When planning for and building to a winter peak, the Vectren system is built to meet the winter peak in all hours but is overbuilt to meet the summer peak in all hours. Based on this sensitivity analysis, each portfolio was designed and built to meet summer peak load and resulting planning reserve margin requirements.

8.2.3 STOCHASTIC (PROBABILISTIC) RISK ASSESSMENT

After selecting the 10 portfolios for further consideration and completion of the deterministic (Scenario based) risk assessment and sensitivities, the remaining step is to conduct the 200 iteration or scenario risk assessment and complete the balanced scorecard, consider "other" relevant factors and select the preferred portfolio given all of that information.

A more comprehensive risk analysis, using 200 iterations or scenarios, was utilized to provide a more comprehensive assessment of how the 10 portfolios performed under a range of conditions. As with any analysis, the risk analysis and the balanced scorecard that is developed from it, does not provide Vectren with an answer, but rather it is intended to provide insights into tradeoffs associated with a variety of portfolios over a range of future conditions.

The relevant information is provided in many of the metrics in the balanced scorecard. The benefit of conducting the stochastic risk assessment is that Vectren can get a clearer picture of the tradeoffs between least cost , the cost uncertainty (measured by the 95th percentile of cost outcomes over the planning horizon), the carbon equivalent profile of the portfolios and the percentage dependence on energy and capacity purchases and sales of the portfolios based on the probabilistic range of potential outcomes. After this comparison there is also a discussion of other factors that must be considered, like diversity, flexibility and optionality to adapt to conditions that might cause uneconomic assets.

A summary of how the ten candidate portfolios performed against each of the above metrics is provided in the table below:

Figure 8-8 - IRP Portfolio Balanced Scorecard Color-Coded Comparison (NPVRR in millions of dollars)

	Stochastic Mean 20-Year NPVRR	95th Percentile Value of NPVRR	% Reduction of CO2e (2019-2039)	Purchases as a % of Generation	Sales as a % of Generation	Purchases as a % of Peak Demand	Sales as a % of Peak Demand
Reference Case	$2,538	$2,921	58.1%	16.8%	26.8%	9.7%	1.2%
BAU to 2039	$2,914	$3,308	35.2%	12.0%	36.5%	0.1%	11.1%
Bridge BAU 2029	$2,691	$3,094	61.9%	15.2%	31.4%	7.1%	4.3%
Bridge ABB1 Conversion+CCGT	$2,875	$3,269	47.9%	6.6%	31.8%	1.3%	10.1%
Bridge ABB1 Conversion	$2,677	$3,048	61.5%	19.2%	26.4%	1.2%	9.3%
Bridge ABB1+ABB2 Conversion	$2,836	$3,215	61.5%	18.5%	27.6%	4.0%	5.6%
Diverse Small CCGT	$2,681	$3,072	47.9%	6.4%	31.1%	1.7%	3.7%
Renewables Peak Gas	$2,528	$2,927	77.4%	21.5%	27.7%	9.4%	1.2%
Renewables 2030	$2,614	$3,003	79.3%	26.1%	31.9%	11.9%	1.7%
High Technology	$2,592	$2,978	59.8%	16.7%	26.9%	0.4%	4.6%

A color-coded comparison (conducted automatically by the spreadsheet) of the balanced scorecard is shown above in Figure 8-8. Green indicates scoring well relative to its peers in a metric and red indicates scoring poorly relative to its peers. The color scheme is purely for illustrative purposes to show where differences between the best performing portfolio and the worst performing for that attribute is displayed.

The Mean of the Net Present Value is clearly one of the most important attributes, as it was the basis on which each of the portfolios were selected in the first place. Under both reference case conditions and also considering the mean of the distribution, the Renewables Peak Gas Portfolio, which retired Culley 3 early, was the lowest cost Portfolio but by less than half of one percent relative to the reference portfolio. Since Culley provides greater reliability, resilience and diversity to the portfolio and the flexibility to retire the plant early, Vectren did not consider this to be a significant difference.

The next two lowest cost portfolios were the Reference portfolio and the High Technology portfolios whose NPVRRs were within two percent of each other. Once again, Vectren did not consider portfolios within two percentage points on both the mean of the distribution and the 95th percentile (representing cost uncertainty risk) to be significant enough to differentiate these two options on the basis of cost.

The Costs and 95th percentile of the Business As Usual Portfolio and two of the Bridge solutions (the Bridge ABB1 and ABB2 and the Bridge ABB1 plus CC) were well above 10 percent higher than the Reference Mean and 95th percentile solutions, so they were eliminated from further consideration on the basis of cost.

SECTION 9
IRP PREFERRED PORTFOLIO

9.1 PREFERRED PORTFOLIO RECOMMENDATION

Based upon several factors, Vectren's preferred portfolio is the High Technology Portfolio.

9.1.1 Description of the Preferred Portfolio

The new and existing supply and demand resources in the preferred portfolio (High Technology) include 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage[43]) and two new 236.6 MW CT units selected in 2024 and 2025, all of which replace the A B Brown 1 and 2, F B Culley 2 and Warrick 4 coal units when they retire or exit at the end of 2023. An additional 50 MW of storage is selected in the final year of the forecast for reserve margin purposes. Approximately 1.25% of energy efficiency blocks are included in the near-term time period (2021-2023), approximately 0.75% of energy efficiency blocks are selected in the mid-term (2024-2026) and approximately 0.50% of energy efficiency blocks are selected in the long-term (2027-2039). In addition, low Income energy efficiency is included in all periods. The optional demand response bin is selected in the time periods 2024-2026 and 2027-2039, while a Direct Load Control (DLC) program called Summer Cycler is transitioned to Wi-Fi thermostats over time. F B Culley 3 operations continue throughout the forecast period. The only shortfall in capacity occurs in 2024 and is met through 70.9 MW of capacity market purchases.

The preferred portfolio (High Technology) performs well across a range of metrics, both in absolute terms and relative to the other candidate portfolios. The preferred portfolio (High Technology) was within 2.5 percent of the lowest cost portfolio and ranked 2 out of 10 (second best) in the 95th percentile cost risk metric. It did not over-rely on either purchases or sales of energy or capacity.

[43] Modeled as 3-hour battery. Equates to a ~90MWs for 4-hours

Importantly it provides the flexibility and optionality to move quickly to a more renewable future as the reliability of the MISO system adapts to higher levels of renewables across the system. By having the option to retire Culley, Vectren can move when needed to a portfolio more like the Renewable + Flexible Gas portfolio.

Another distinguishing factor in this portfolio is the selection of two CTs. The two CT's provide the following benefits:

- They eliminate the reliance on for capacity in the near term at a time when MISO suggests that there could be shortages
- They provide the capability to convert to a combined cycle if needed for reliability in the future
- They are primarily used for peaking and fast ramping, which provides more room for renewables in the future
- They are relatively inexpensive to build and save customers ~$50M in design and construction costs by building two units at the same time vs. waiting to build the 2nd
- Maintains interconnection rights should units be built at the Brown site, shielding customers from future transmission upgrade costs

The High Technology portfolio provides a number of additional benefits to Vectren customers and other stakeholders, including that it:

- Is among the best performing portfolios across multiple measures on the balanced scorecard
- Is a low cost portfolio (within 2.5% of the lowest cost portfolio and 2.2% of the Reference Case (the latter of which is the more appropriate comparison due to the same assumption that F B Culley 3 is operational through the forecast period)
- Leads to a lower carbon future – Achieves almost 60 percent reduction in life cycle carbon emissions (CO_2e) during the period 2019-2039 and achieves a nearly 75%

reduction in CO_2 (base year 2005) by 2035 with the flexibility to achieve even more if needed

- Brings a significant volume of renewables into the portfolio beginning in 2022. Renewable resources and ongoing energy efficiency account for more than 72% of total installed capacity by 2024 (more than 42% in terms of UCAP)
- Provides dispatchable generation that enhances opportunities for economic development and wholesale sales without overexposure to market risk relative to other candidate portfolios, which lowers customer bills
- Provides fast ramping generation to help manage the intermittency of renewables, including extended periods of complete cloud cover that can reduce solar generation by up to 75%[44]
- Avoids reliance on a single fuel and provides a balanced and diversified mix of renewables, DSM, gas and coal.
- Provides the optionality of converting to a combined cycle unit in the future if market, regulatory, technological and/or economic conditions necessitate
- Reduces dependence on coal-fired generation in a prompt timeframe yet provides the flexibility to adapt to changes in technology in the future
- Takes advantage of tax incentives for new solar power plants and for new wind resources

9.1.2 Affordability

Affordability is a key objective in the balanced scorecard and that is measured as part of the stochastic analysis. The measure for affordability is the 20-year Net Present Value of Revenue Requirements (NPVRR), which comes from the stochastic mean (average) of 200 iterations of a portfolio as it is run in the dispatch model under varying market

[44] NASA, Cloud Cover and Solar Irradiation, (source: https://scool.larc.nasa.gov/lesson_plans/CloudCoverSolarRadiation.pdf) using the formula shown below:

$$P = 990\,(1-0.75F^3) \quad \text{watts/m}^2$$

where F is the fraction of sky cloud cover on a scale from 0.0 (0% no clouds) to 1.0 (100% complete coverage).

conditions. Each iteration provides the total annual cost of each component of total portfolio cost, including fuel costs, emissions costs, variable operations and maintenance costs, fixed operations and maintenance costs, energy export revenues (sales), energy import costs (purchases), capacity market sales revenue and capacity market purchases costs. Each annual cost category is then summed into a total portfolio cost and discounted by Vectren's weighted average cost of capital of 7.71% to arrive at the NPVRR. The lower the NPVRR is for a portfolio, the lower the rates can be in order to recuperate the cost to serve load over the next 20 years. The stochastic methodology allows for a rigorous analytical framework to determine the affordability of a portfolio.

The preferred portfolio (High Technology) was determined to be a cost portfolio across the 10 candidate portfolios, with a 20-year NPVRR of $2,592 million. This NPVRR is only 2.16% higher than the Reference Portfolio, a difference of less than $55 million over 20 years on a net present value basis. The preferred portfolio (High Technology) is 11% less expensive than the Business as Usual to 2039 portfolio (the most expensive portfolio in this objective category), which provides a savings of nearly $322 million over 20 years on a net present value basis.

9.1.3 Cost Uncertainty Risk Minimization

The Cost Uncertainty Minimization objective is measured in a similar way to the Affordability objective, using the 20-year NPVRR values from the stochastic analysis. However, this objective provides a measure of the 95th percentile of the NPVRR to determine an upper boundary (or worst-case perspective) of portfolio costs across the 200 stochastic iterations. The Price Risk Minimization objective can be interpreted as follows: There is a 95% chance that total portfolio costs as measured by the 20-year NPVRR will be at or below this measure. In this way, the risk that total portfolio costs over 20 years can be measured, allowing for the selection of a portfolio that minimizes this risk. This in turn minimizes the risk that rates (prices) will be higher than the expected, where expected rates (costs) come from the Affordability objective.

The preferred portfolio (High Technology) performed well in the Price Risk Minimization category. The 95th percentile of the 20-year NPVRR was determined to be $2,978 million, which is only 1.95% higher ($57 million) as compared to the Reference Portfolio 95th percentile of the 20-year NPVRR. For this same objective, the preferred portfolio (High Technology) was found to be $330 million less than the Business as Usual to 2039 portfolio, which is also the most expensive portfolio in this objective category. Accordingly, the preferred portfolio (High Technology) is shown to have a low level of price risk relative to its own expected NPVRR as well as relative to the least cost portfolio, the most expensive portfolio and all other candidate portfolios.

9.1.4 Environmental Emission Minimization

The Environmental Emission Minimization objective is determined from the stochastic analysis and is measured as the life cycle greenhouse gas emissions reductions during the study period of 2019-2039. Life cycle greenhouse gas emissions are also known as CO_2-equivalent or CO_2e emissions. The development of this measure is described in detail in Section 2.3.2.3 and takes into account the CO_2e emissions associated with the annual MWh of generation over 20 years from each technology type in the candidate portfolio. CO_2e emissions are also calculated for any energy imports from MISO, using a representative future capacity mix by resource that is associated with the 2033 Accelerated Fleet Change mix from MISO's MTEP 2019 document.

The preferred portfolio (High Technology) performed relatively well in the Environmental Risk Minimization objective, reducing annual CO_2e emissions by more than 4 million tons over the 2019-2039 study period (where 2019 CO_2e emissions are more than 6.7 million). This represents a nearly 60% decrease over 20 years and a larger decrease than is shown in the Reference Case, which is determined to have a 58% decrease. Relative to the other candidate portfolios, the preferred portfolio (High Technology) shows a CO_2e emissions reduction figure that is in the middle of the pack, with a smaller reduction than the renewables focused portfolios but a greater reduction than the Business as Usual to 2039 portfolio, which only reduces CO_2e emissions by 35% over the 20 year study period.

However, there is flexibility built into this portfolio to achieve further reductions if coal is no longer needed for reliability and resilience purposes and if the economics of renewables becomes even more compelling.

While not part of the balanced scorecard, the preferred portfolio (High Technology) was found to reduce (actual not life cycle) CO_2 emissions by 74.5% compared to the baseline year of 2005. This represents an annual reduction of nearly 7.2 million tons of CO_2 from the baseline of 9.6 million tons of CO_2. This figure is more than twice the reduction of CO_2 emissions that is shown in the Business as Usual to 2039 portfolio and slightly greater than the Reference Case CO_2 emissions reduction.

9.1.5 Market Risk Minimization

The Market Risk Minimization objective is applicable to both energy market risk and capacity market risk. The greater the energy market purchases that are required by a candidate portfolio, the greater the exposure to the risk that energy prices will be higher than the short-run marginal cost of energy production from the Vectren fleet. Similarly, the greater the capacity market purchases that are required by a candidate portfolio, the greater the exposure to the risk that capacity market purchase prices will be higher than the cost of adding capacity to the Vectren fleet. Conversely, the greater the energy market sales by a candidate portfolio, the greater the exposure to the risk that energy prices will be lower than the short-run marginal cost of energy production from the Vectren fleet. Similarly, the greater the capacity market sales by a candidate portfolio, the greater the exposure to the risk that capacity market purchase prices will be lower than the cost of capacity in the Vectren fleet, meaning the portfolio is overbuilt. In either case, heavy reliance on market sales could lead to inflated valuation of a portfolio.

The preferred portfolio (High Technology) performed relatively well in terms of energy market risk minimization, averaging 16.7% energy purchases as a percentage of generation. This figure is in the middle of the 10 candidate portfolios, slightly less than the Reference Case (16.8%) and much less than the Renewables 2030 portfolio (26.1%) but greater than the Diverse Small CCGT portfolio (6.4%). The preferred portfolio (High Technology) ranked third best in terms of energy sales with a figure of 26.9% as a percentage of generation, only slightly more than the best performing portfolio in this category (the Bridge ABB1 Conversion portfolio at 26.4%) and much less than the Business as Usual to 2039 portfolio at 36.5%. When looking at net energy sales, the preferred portfolio (High Technology) demonstrates a figure of 10.2%, which is within the threshold criteria of 15% that was discussed during a stakeholder meeting. The 15% level is based on a reasonable level of net sales that would not overexpose Vectren to energy market risks, in the estimation of Vectren's market consultants. Accordingly, the preferred portfolio (High Technology) was shown to have a reasonably minimal level of energy market risk, both in terms of its own measure and relative to the measures of other candidate portfolios.

The preferred portfolio (High Technology) performed relatively well in terms of capacity market risk minimization, demonstrating a figure of only 0.4% capacity market purchases as a percentage of peak load. This figure is the second lowest of the 10 candidate portfolios, only slightly more than the Business as Usual to 2039 portfolio with 0.1% capacity market purchases. The selection of two CT's reduces the need for significant levels of capacity purchases throughout the planning horizon, which is important since MISO is still evaluating the issues of reliability and resilience of the grid as renewables become a larger share of the region's portfolio. The preferred portfolio (High Technology) was determined to have capacity market sales of 4.6% as a percentage of peak load, which is in the middle of the 10 candidate portfolios and much less than the 11.1% capacity market sales in the Business as Usual to 2039 portfolio but greater than the Reference Case portfolio with 1.2% capacity market sales. Accordingly, the preferred portfolio (High Technology) was shown to have a reasonably minimal level of capacity market risk, both in terms of its own measure and relative to the measures of other candidate portfolios.

9.1.6 Other Considerations

9.1.6.1 Future Flexibility

The preferred portfolio (High Technology) was originally selected using a least-cost capacity expansion under the market conditions for the High Technology alternative scenario, but was then dispatched under the same Reference Case market conditions in the deterministic analysis and then evaluated using the same range of market conditions as all other candidate portfolios in the stochastic analysis.

These alternative market conditions for the optimization included lower CO_2 costs, higher load, lower fuel prices and lower renewable and EE costs, all relative to the Reference Case. Each of the market conditions are plausible alternatives to the most expected path in the Reference Case. For example, there is not yet a political consensus on whether and how to implement a national tax on carbon, which provides some justification for a lower CO_2 price relative to the Reference Case. The load growth from electric vehicles and the electrification of several sectors (buildings, industry, heavy transport) represent substantially more upside potential than the savings and downside potential that could come from demand side management and energy efficiency, which provides some justification for a higher load outlook. Coal markets experienced a downturn in 2020 due to COVID-19-induced demand reduction, from which (together with many other downward market pressures) it will be difficult to recover in the long-term. Gas prices have come down significantly in the last decade due to technology improvements and an expanding list of reserves from new discoveries, which could continue over the next two decades, while a more aggressive move to renewables could undercut demand for natural gas in the power sector, all of which would put increased downward pressure on gas prices. Finally, an aggressive expansion of renewables relative to the Reference Case could put downward pressure on capital costs, in much the same way that the broad deployment of personal computers led to lower prices due to economies of scale.

The preferred portfolio (High Technology) performed well across the various metrics in the balanced scorecard in both the Reference Case (expected) market conditions and (by definition) the High Technology market conditions, which are only slightly less probable than the Reference Case market conditions (in the estimation of Vectren's market consultants). It also performed well relative to the other candidate portfolios when dispatched in the 80% Reduction by 2050, High Regulation and Low Regulation alternative market conditions. In all of the scenario-based alternative market conditions as well as the stochastic analysis with 200 iterations of varying market conditions, the preferred portfolio (High Technology) did not show any solar energy curtailments and only showed an expected average value of 0.02% wind energy curtailment in five years during the 2019-2039 study period. Thus, the preferred portfolio (High Technology) demonstrated the flexibility to adapt to a wide range of changing market conditions.

9.1.6.2 Uneconomic Asset Risk

One of the factors that Vectren considered was the potential for assets becoming uneconomic over the planning horizon. This was a concern raised by stakeholders about the 2016 IRP when Vectren recommended building a large combined cycle plant which benefited from a significant reliance on projected energy sales to support its economics. One of the concerns expressed was whether the plant could become uneconomic if renewables and storage were to achieve rapid cost declines such that the combined cycle dispatch would be adversely impacted and thus unable to cover its costs.

An analysis was performed to determine whether this was a significant risk with the mix of assets proposed. A metric was created to assess the risk. An asset was determined to be uneconomic during one of the iterations of the risk analysis if for three years in succession, revenues would not recover costs. The analysis performed determined that the assets most at risk were the assets that were selected to provide capacity to support the renewable resources, mainly the CT's and storage. The reason is that especially early in the planning horizon, capacity has often been priced below CONE. While MISO has indicated a concern that shortages could well occur in MISO over the next several years, this was not reflected in many of the iterations. Ultimately the value of this metric is questionable. Portfolios with plants with large energy revenues (coal and combined cycle) performed better than combustion turbines, even though they require a larger capital spend than CTs.

If Vectren were to mitigate this conclusion it would rely heavily on purchases in the capacity market rather than build CT's and storage. Vectren did not believe this was appropriate in this uncertain environment and chose a path with CT's and storage rather than relying heavily on the capacity market.

9.1.6.3 Reliability

Reliability can be measured in different ways, but one common metric is whether the portfolio experiences any unserved energy. The preferred portfolio (High Technology) was dispatched in the Aurora model using Reference Case inputs as well as the inputs from the four alternative scenarios, each of which had widely varying market assumptions for fuel prices, emissions prices, load and capital costs. In each of these deterministic dispatch runs, the preferred portfolio (High Technology) was not found to have any hours of unserved energy. Accordingly, although Reliability is not an explicit objective in the balanced scorecard, the preferred portfolio (High Technology) was found to provide reliable service in meeting Vectren's expected load requirements over the 20-year study period.

Two highly dispatchable combustion turbines (460 MW) support a high penetration of renewables, ensuring reliability and provide a hedge against both the energy and capacity markets. They help provide customers assurance of reliable service in many ways.

- Thermal resources are still needed to maintain reliable service in multiday periods of cloud cover and no wind
- Two CT's provide better support than one. Better coverage should a unit go down to provide a hedge against high energy prices and provide system support when issues arise

- Two CT's keeps existing interconnection rights, which shields customers from potential transmission upgrade costs in the future should Vectren have to re-enter the MISO Queue (a three-year process).
- Two CT's provide fast start (10 min) & more fast ramping capability (80 MW/minute vs 40 MW/minute) to help support for intermittent solar and allows for a smooth transition into a renewables future locally and regionally as the MISO system adapts to higher levels of renewables across the system
- Two CT's provide a high degree of flexibility in the future

9.1.6.4 Operational Flexibility

The preferred portfolio (High Technology) includes a significant amount of new variable energy resources (VER) (wind and solar) balanced by 176 MW of battery storage (50 MW of which enters late in the forecast) and two 236.6 MW natural gas peaking units. The battery storage and CT units can help to smooth out the intermittency of the VERs. The fast-ramping requirements of a system increase as the balance shifts toward increased VERs, particularly solar resources. The phenomenon known colloquially as the "duck curve" demonstrates the need for fast-ramping capability, a role that CT's and battery storage perform well, to handle the onset of evening peak demand concurrent with rapidly declining solar output. Given the level of VER in the preferred portfolio (High Technology) (approximately 1,500 MW) together with the fast-ramping capabilities of the CT's and battery storage, this portfolio is expected to meet all operational flexibility requirements.

Natural gas peaking combustion turbines (CT) respond quickly to changing operational requirements, since there is no water to heat on a percentage of capacity per minute basis (as compared to a combined cycle unit). CT's are simple to operate, requiring few staff and resources to run properly and to maintain (typically under a long-term service agreement or LTSA) and often they can be started remotely. CT's can also be black started, offering an additional degree of increased resiliency and operational flexibility.

Given the high volume of intermittent renewable generation in the preferred portfolio Vectren feels it's critical to have an adequate amount of dispatchable generation to meet its obligation to ensure reliable service is provided to Vectren customers throughout the different seasons of the year as well as all 24 hours of the day. Vectren's experience shows that renewable generation can be unpredictable, therefore, a portion of generation should (a) provide a dispatchable (controllable) output (b) be able to start and stop more than once daily and be placed in service quickly and (c) respond to rapid changes in renewable output.

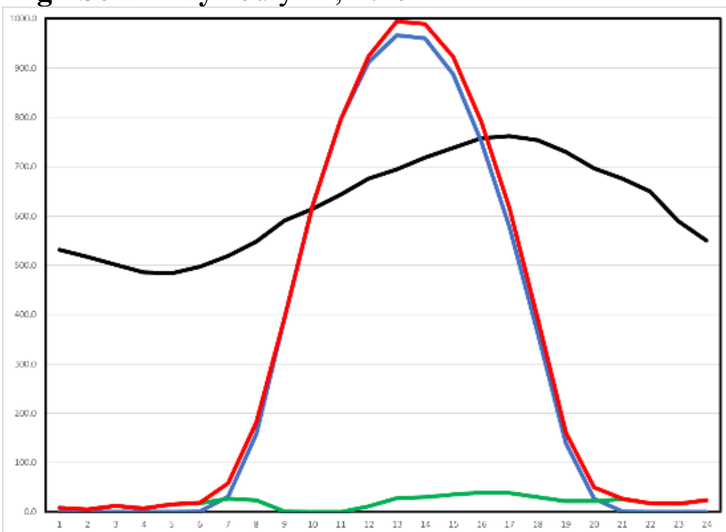
9.1.6.4.1 Vectren Seasonal and Daily Experience with Solar and Wind Production

The figures 9.1-9.4[45] below are actual seasonal days during 2019 and 2020 that show hour by hour customer demand and how 1,000 MW's of solar capacity and 380 MW's of wind capacity would have met customer demand if the solar and wind capacity factors were the same as what was realized from Vectren's current solar fields and wind purchase power agreements. High, typical and low solar production days were chosen for each season to show the large variation in levels that can be experienced daily during each season. Also, note the large drop off in production in the evening hours after the sun goes down. The additional energy required to serve Vectren customer demand would need to be purchased from the market or supplied by Vectren owned dispatchable generation sources. Local generation ensures more reliable energy and capacity with less risk of additional congestion charges associated with importing energy.

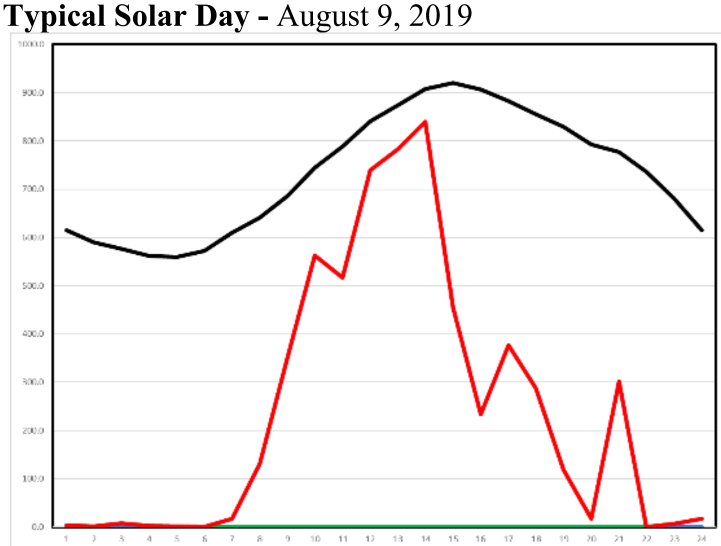
[45] **Black – System Load, Green – Wind, Blue – Solar, Red – Wind + Solar Used 1000 MW solar (scaled up from existing solar), 380MW wind (scaled up from existing 80MW). All data in 1-hour average increments, charts range from 0 to 1,000 MW except on high solar days in December (1,200MW) and March (1,400MW)**

Figure 9-1 - Summer Production and Vectren Demand:

High Solar Day - July 24, 2019



Typical Solar Day - August 9, 2019



Low Solar Day - July 15, 2019

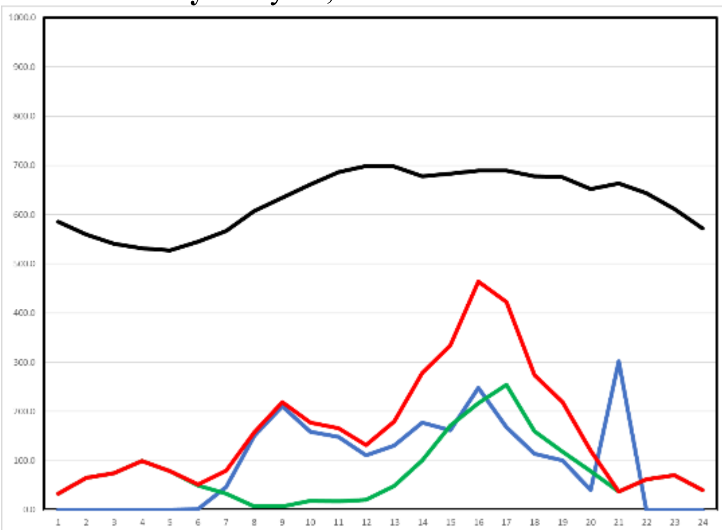
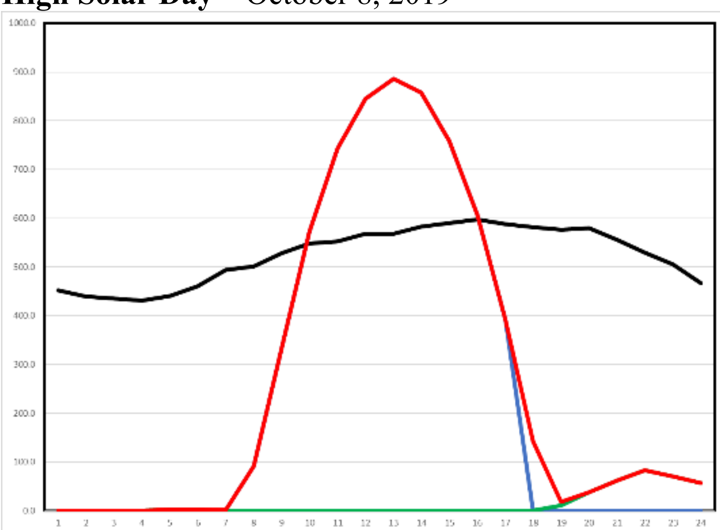
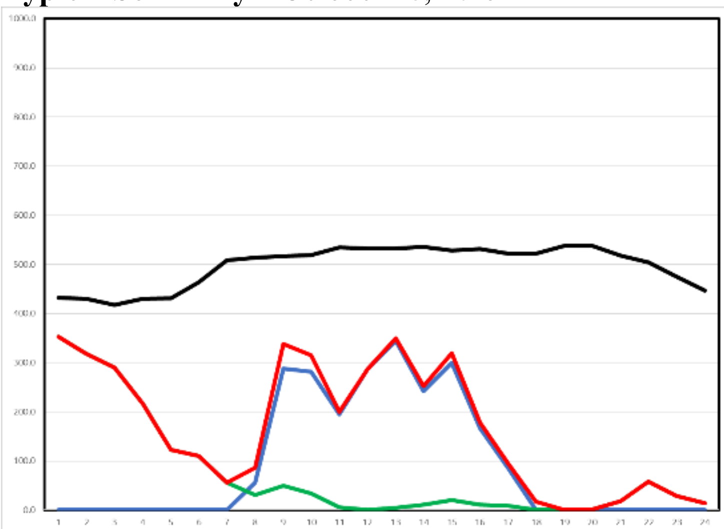


Figure 9-2 – Fall Production and Vectren Demand:

High Solar Day – October 8, 2019



Typical Solar Day – October 18, 2019



Low Solar Day – October 25, 2019

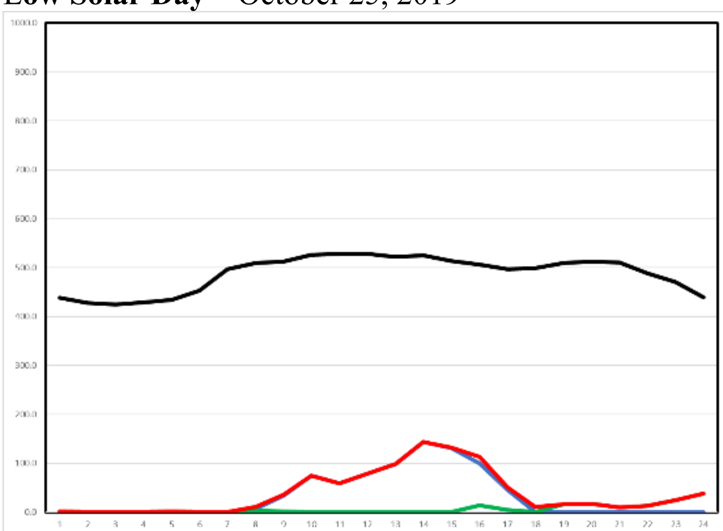
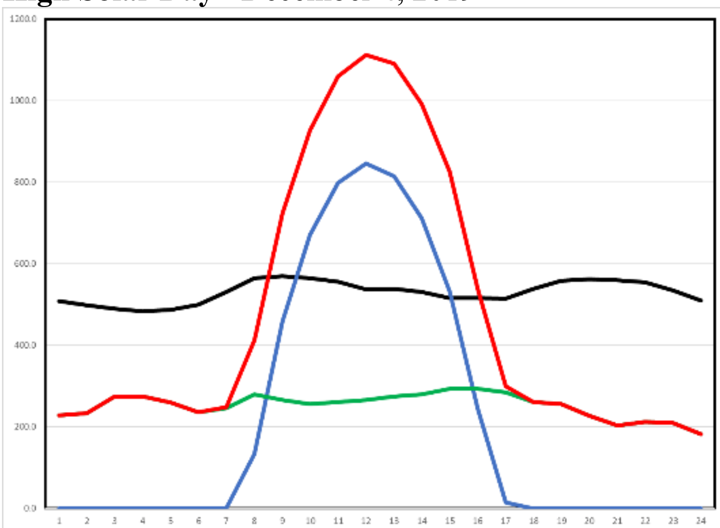
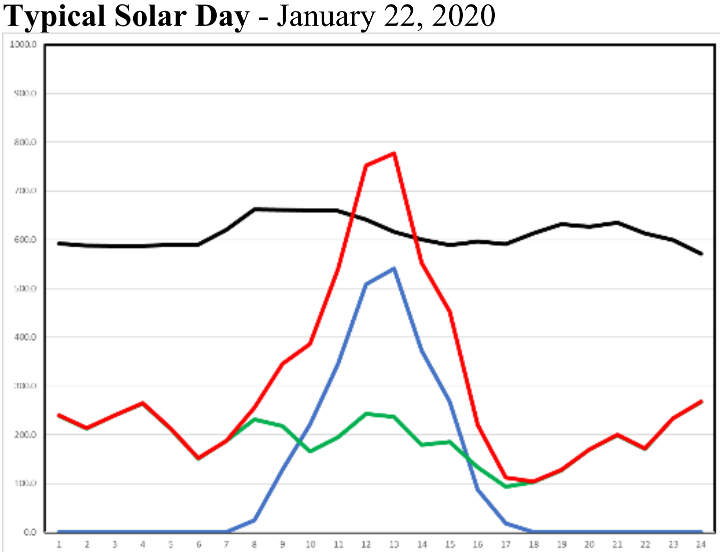


Figure 9-3 - Winter Production and Vectren Demand:

High Solar Day - December 4, 2019



Typical Solar Day - January 22, 2020



Low Solar Day - December 16, 2019

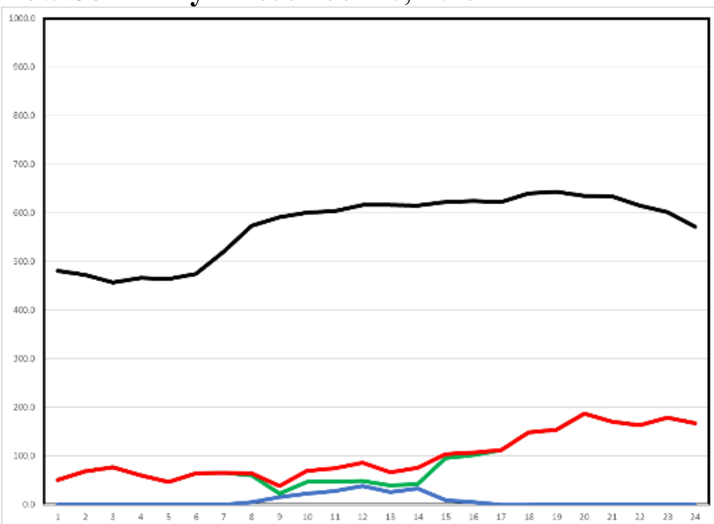
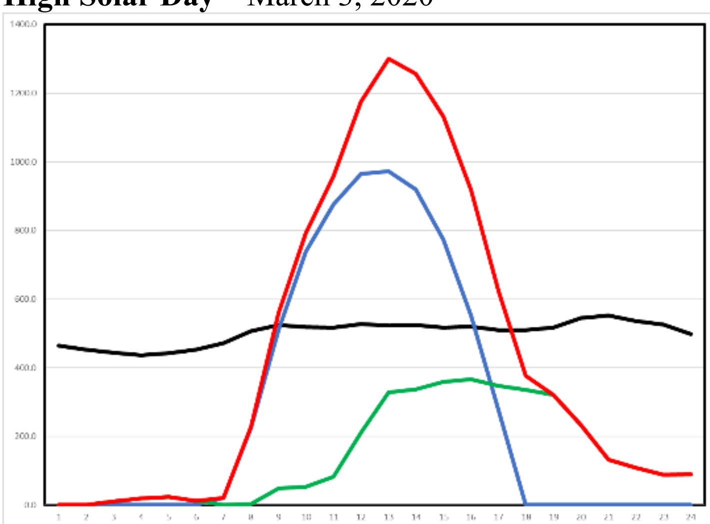
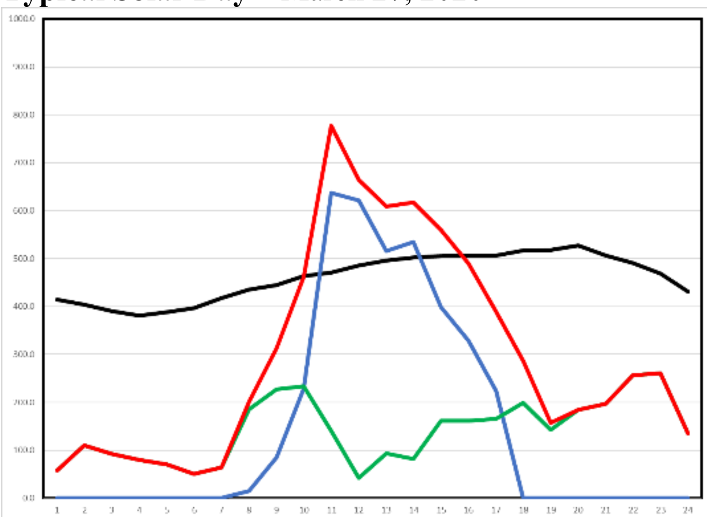


Figure 9-4 - Spring Production and Vectren Demand:

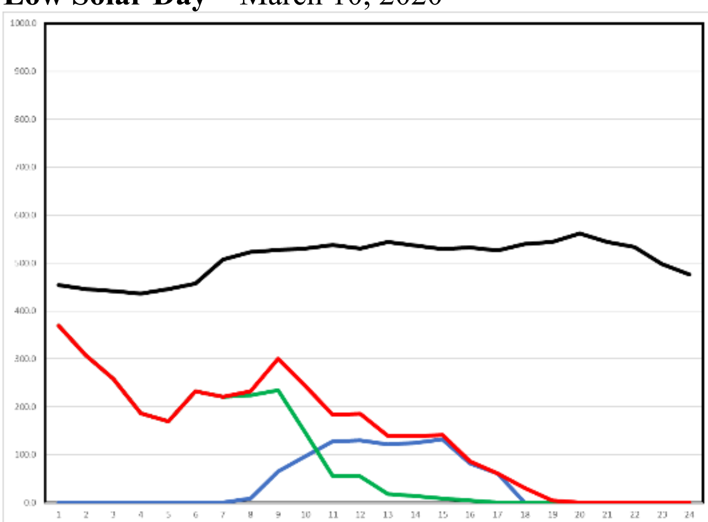
High Solar Day – March 3, 2020



Typical Solar Day – March 27, 2020



Low Solar Day – March 10, 2020



9.1.6.4.2 Vectren Experience with Solar Hourly and Daily Intermittency

The Figures above (9.1-9.4) represent an average hourly output or artificial smoothing of production across each hour of the day. There are days when there are large fluctuations in output over short periods of time due to changes in cloud cover or periodic gusts of wind. The figures below (9.5 and 9.6) show actual variation in output over a twenty-four-hour period and a one-hour period. These rapid fluctuations in output while working to meet constantly changing customer demand require a robust transmission and distribution system to import large amount of power quickly as well as dispatchable resources that can ramp output up and down quickly. It should be noted that as other utilities retire coal resources and install more intermittent generation it will become more important to have locally placed fast reacting dispatchable resources to ensure reliable service is delivered to industrial, commercial and residential customers.

Figure 9-5 – 24 Hour Solar Chart

Sept. 2, 2019 - 12:00 to 13:00

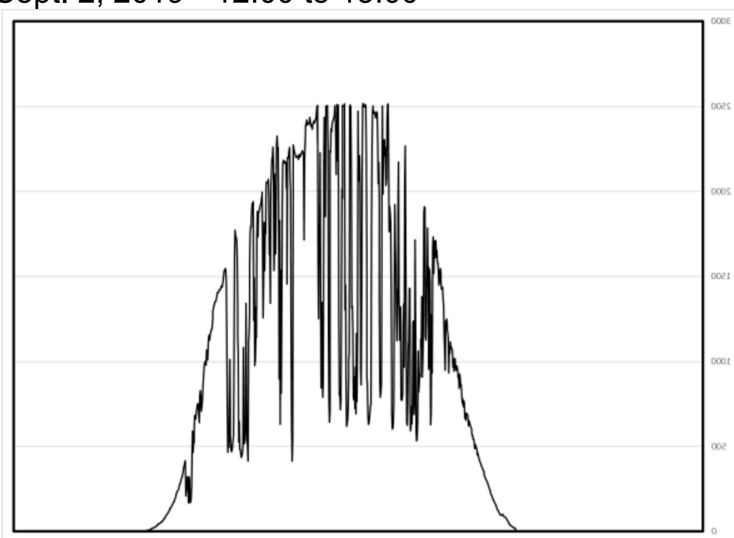
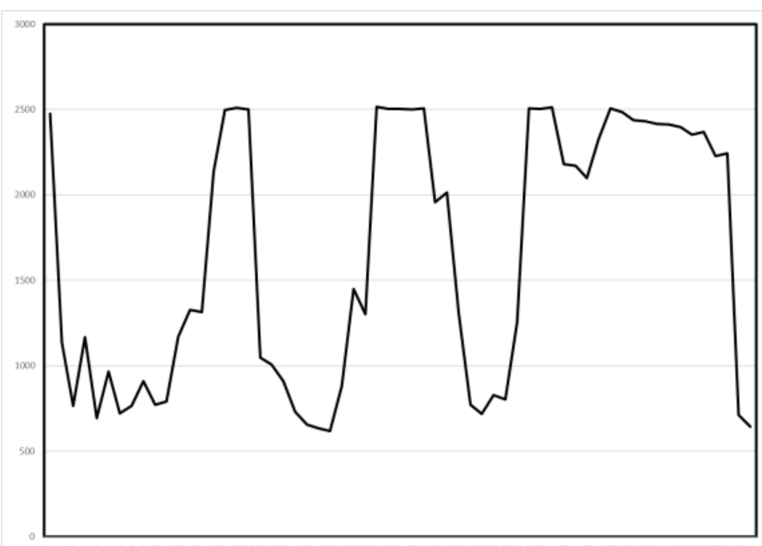


Figure 9-6 – 1-Hour Solar Production – September 2, 2019



Figures 9.5-9.6 aren't representative of every day throughout the year as there will be days when solar and wind production are more consistent; however, Vectren has an obligation to ensure customer demand is met by supplying reliable energy throughout every minute of every day of the year. Local fast start and fast reacting dispatchable resources will still be required to meet customer demand on days like Vectren experienced on September 2, 2019 as well as the evening hours after the sun goes down. Battery storage systems can meet a portion of this need; however, they are limited by discharge times as well as charge/discharge cycles, whereas CT's provide more long duration support.

Each unit will have the ability to start and be synchronized to the grid producing energy in approximately 10 minutes. This is important when relying on a large portfolio of renewable capacity. The CT's may be required to start and provide reliable energy for customers several times throughout the year when renewable energy is operating at reduced capacity due to cloud cover or a lack of wind. It's likely there may be times when the CT's are started and stopped more than one time daily.

Once placed in service, the quick ramping ability of a CT, at approximately 40MW/minute, will help meet customer needs when demand changes or renewable energy supplies quickly dip then return as cloud cover rolls over various solar arrays and wind fluctuates in areas where wind farms are built. Having two new CT's will provide the ability to ramp or adjust output by up to 80MW/minute to help supplement the import capability of the grid. In addition, having two CT's will provide flexibility as only one or both can be started as needed. Due to environmental restrictions, each CT will have a minimum output of approximately 80MW's. With one in service, the output can range from 80-220MW's. With both units in service, the output can range from 160-440MW's providing the operational flexibility to meet the needs of customers.

Of the gas fired generation options explored, the CT's were chosen due to the balance of low capital cost, efficiency and operational flexibility. Given the quantitative objectives in the balanced scorecard that includes; (a) minimizing the cost to the customer, (b) reducing emissions and (c) not relying heavily on the energy or capacity market as well as the qualitative objective such as diversity and properly supporting a large portfolio of renewable resources the CT's were chosen as an important resource in the preferred portfolio.

Lastly, the preferred portfolio with two CT's provides future flexibility to increase capacity and provide lower cost energy to Vectren customers by adding a steam cycle to one or both CT's. A steam cycle could be placed on one or both CT's to create a Combined Cycle Gas Turbine (CCGT) to capture waste heat to be turned into energy. This would lower the cost/MWh by increasing the efficiency of a CT by 30-35%. This could be accomplished if the need arises as a result of load growth due to new industrial customers, if it were determined in a future IRP that Culley Unit 3 should be retired, or the need for more low cost energy arises due to higher than expected market energy prices.

9.1.6.5 Resource Diversity

Resource Diversity is not an explicit objective in the balanced scorecard but is nevertheless an important criterion for a well-balanced portfolio. Resource Diversity allows a portfolio to avoid being dependent on one type of fuel or technology, which can expose the fleet to risks such as an extended cloudy period (reducing solar generation) or a fuel disruption that can come from a force majeure event on a gas pipeline. Resource Diversity also contributes indirectly to the other objectives discussed here, including operational flexibility, future flexibility and reliability. From this point of view, the preferred portfolio (High Technology) is reasonably diverse and well-balanced in terms of resources, with a mix of natural gas CTs, solar and wind resources, battery storage resources and a baseload coal unit.

9.1.6.6 Local Resources

Vectren prefers local resources for both capacity and energy needs. Local resources benefit Vectren customers by reducing cost risk and providing tax base, jobs and grid support for reliability. The All-Source RFP provided many attractive renewable resources in Vanderburgh, Posey, Warrick, Gibson and Spencer Counties, which Vectren is evaluating for procurement.

Local generation also helps to minimize the risks of differences in cost between where power is produced and where it is consumed. When power is produced on system, customers minimize the likelihood of congestion charges, which can occur when delivering power via the transmission system. The chances of incurring these charges increases the further away energy must be delivered. Local generation also reduces the need to construct new high voltage power lines to bring clean renewable power to our area. These transmission projects take years to complete, often require eminent domain and ultimately cost customers money.

Investing in local projects help produce tax base and jobs, which directly benefit the communities Vectren serves. Currently, Vectren generates tax revenues for primarily two counties, Posey and Warrick. The preferred portfolio will provide opportunities for continued investment in these counties with the potential to also provide tax base from generating resources in Vanderburgh, Gibson and Spencer counties. Communities where Vectren customers live can utilize this money to support school systems, police, parks and recreation and other critical support services. Additionally, these projects will continue to be operated by local employees that contribute to the local economy.

Local projects also help keep the system reliable. Vectren's preferred portfolio maintains a good balance between intermittent renewable generation and local, dispatchable generation that provides the system with voltage support and a physical hedge against instances of high market prices. This is particularly important for large, industrial customers that make up nearly half of Vectren load.

9.1.6.7 Transmission/Distribution

The preferred portfolio required the lowest number of transmission system network upgrades of all cases studied, except for the CCGT case. Although the number of network upgrades were lower than other cases, upgrades to the Vectren system import capability were identified. The upgrades identified are the replacement of three transformers for a total estimated cost of $11 million and were also required for the other non-CCGT cases studied.

The reliance on imports from the MISO market into Vectren's area led to voltage concerns for post contingent conditions due to insufficient reactive reserves. CT's provide mitigation to these issues and can be used for reactive (VAR) support in the MISO market. The all imports and all renewables cases studied presented voltage issues that could not be mitigated with existing facilities. These issues would require additional network upgrade projects to add reactive power support and could also potentially lead to the need for Vectren to make Reactive Power Payments to the MISO market to receive off-network support to maintain proper reactive power and voltage levels. These upgrades for reactive support would need to be studied in more depth to determine the placement of new facilities and to determine the type of devices needed. However, initial estimates for needed upgrades are estimated to be between $20 and $30 million to maintain reliability. This amount was not included in the NPVRR of this portfolio.

Studies were performed using the latest MISO generation interconnection system models and all renewable resources studied were assumed to be the projects already in the MISO queue and existing in the model. Additional study will be required on the preferred portfolio once specific renewable projects are identified and sited to determine any further impacts on the Vectren transmission and distribution electric system.

9.1.6.8 Economic Development

The preferred portfolio allows Vectren to provide solutions to assist with manufacturers' renewable and sustainable energy goals. Companies are setting these goals leading to a reduction in fossil fuels consistent with their sustainability strategies. If these companies cannot find a solution with their local utility partners, they may procure energy from other sources or make strategic decisions to relocate manufacturing load.

Renewable energy investments are important steps in facilitating the ability to provide Vectren customers with a portion of their energy requirements via renewable energy. With proper oversight and investment strategy renewable energy can be more efficient and cost-effective for many customers as compared to securing their own sources of energy which requires land and/or capital investments.

The communities in Vectren's service territory will benefit to the extent the addition of renewable energy supports growth among Vectren South's large customers or attracts new customers. The creation of additional jobs in the communities Vectren serves has a ripple effect on the local economy. Moreover, renewable energy projects will create construction jobs in the community and provides additional income for landowners, which also will benefit the local economy. Ultimately, renewable energy projects support the attraction and retention of large customers.

Although Vectren supports cost effective and reliable renewable energy projects, Vectren must maintain strategic planning in the event large industrial customers locate to SW Indiana and require baseload generation for production. Site selectors and large industrial power users are typically sophisticated and fully understand the requirements to apply, receive approval and execute generation buildout. Comprehensive generation planning inclusive of renewable energy and base load assets must be properly balanced to continue economic growth for our region.

For industrial customers to maintain their required voltage level, the Vectren system must be able to supply an adequate amount of reactive power (VARs). Transmission planning studies have shown that this cannot be accomplished without on-network reactive power supplying facilities, such as local synchronous generation. The CT's in the preferred portfolio provide this needed reactive power support. Even when they are not dispatched normally, CT's are able to be started and brought online quickly if needed for Vectren system reliability. CT's also prevent Vectren from entering into Reactive Power Payments through the MISO market, which would impact Vectren customers' bills.

Importantly, the current plan offers flexibility and a hedge assurance, reducing market risk for customers. Specifically, Vectren must remain nimble and dynamic for prospective industrial customers and to be able to adapt to the potential need for CCGT build out. Vectren aggressively pursues manufacturing opportunities which has direct, indirect and induced economic benefits for the region and state of Indiana. Vectren's ability to attract and retain these types of customers is vital to the region's economic wellbeing. Job growth leads to increased earning opportunity for local residents at the same time raising state revenue and tax base. Additionally, large power users assist all Vectren customers with lower utility rates by spreading the fixed cost recovery requirements for the rate base.

In addition, large customers and site selectors understand the comprehensive risks of market rate pricing and the corresponding volatility. The current IRP plan and the opportunity for future baseload generation allows for customers to remain confident in Vectren's ability to provide safe, reliable and cost-effective service. Vectren's generation strategy is an essential service for customers and the region's economic growth capability.

9.1.7 Fuel Inventory and Procurement Planning

It is impossible to perfectly predict price fluctuations in commodity prices such as coal and natural gas. Vectren uses coal contract strategies intended to even out short-term price fluctuations, such as locking in prices for various overlapping time horizons.

Normally these contract renewals are staggered in time in order to even out short-term price fluctuations. Coal suppliers and transportation providers generally require firm commitments on quantities; however, Vectren coal contracts include optionality to adjust tonnage up or down to help manage operational variability which impacts inventory levels. Currently Vectren utilizes non-firm pipeline delivery and gas storage for the existing peaking units. It is planned that the future flexible combustion turbines will utilize firm pipeline supply contracts.

SECTION 10
SHORT TERM ACTION PLAN

10.1 DIFFERENCES BETWEEN THE LAST SHORT-TERM ACTION PLAN FROM WHAT TRANSPIRED

Vectren pursued all the items listed in the 2016 IRP short-term action plan.

10.1.1 Generation Transition

Following the conclusion of the 2016 IRP, Vectren began a generation transition plan to replace the majority of its coal fleet with a highly efficient large natural gas plant and a 50 MW universal solar plant. Vectren also proposed to continue operation of its most efficient coal unit by installing certain environmental compliance equipment. Vectren pursued this plan through two separate filings in Cause numbers 45052 and 45086.

In April 2019, the IURC granted partial approval of Vectren's Smart Energy Future electric generation transition plan which included approval to retrofit F.B. Culley 3, Vectren's largest, most-efficient 270 MW coal-fired unit and to proceed with construction of a 50 MW universal solar array. The request to construct a 700-850 MW combined cycle natural gas power plant was not approved.

10.1.2 DSM

The 2016 IRP did support continued energy efficiency programs designed to save 1% of eligible retail sales. Vectren proposed the 2018-2020 Electric DSM Plan to obtain approval of programs to achieve this level of savings. The Commission approved this plan on December 28, 2017 in Cause No. 44927. Consistent with the 2016 IRP, the framework for the 2018-2020 filed plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 80% eligible load.

10.1.3 Solar Projects

In 2017, Vectren filed for and received approval to construct two 2-MW universal solar projects that are currently in operation; one near North High School in northern Vanderburgh County and the second near Oak Hill Cemetery near Morgan Ave., which is through a partnership with the City of Evansville. Both sites have been constructed and have been generating power since December of 2018. The Volkman Road project also includes battery storage with the ability to discharge one megawatt of power per hour over a four-hour period.

10.1.4 Environmental Permits for ELG/CCR

The bottom ash system at F.B. Culley Unit 3 is scheduled to be converted to a dry system in the Fall of 2020. Work is also taking place to convert the FGD system to zero liquid discharge technology. These two technologies will make Culley Unit 3 fully compliant with the Effluent Limitation Guidelines (ELG) rule and the NPDES permit requirements for Culley 3.

The West Ash Pond at F.B. Culley is currently undergoing closure, with those activities scheduled to be completed by December 2020. The closure design includes the construction of a lined contact storm water pond, which will receive contact storm water from various areas of the plant. The construction of this pond, along with the installation of the dry bottom ash and FGD ZLD technologies will enable the upcoming required closure of the F.B. Culley East Ash Pond.

The A.B. Brown Ash Pond is also facing forced closure soon. Plans are currently underway to prepare for the excavation of all material from the A.B. Brown ash pond, with a majority of the ash being sent for beneficial reuse.

10.2 DISCUSSION OF PLANS FOR NEXT 3 YEARS

The short-term action plan describes the early steps to pursue the preferred portfolio, consistent with the objectives and risk perspectives listed in Section 2.3. Progress on the items listed below will be tracked and reported on in the next IRP. IRP estimates of each piece of the plan listed below can be found in Confidential Attachment 8.2 Aurora Input Model Files. Individual cost estimates can also be found in Section 6 Resource Options.

10.2.1 Procurement of Supply Side Resources

As described above, the preferred portfolio included 300 MWs of wind, 700-1,000 MWs of solar and two combustion turbines (~460 MWs) to replace approximately 730 MWs of coal fired generation. Vectren will continue to monitor developments with the State of Indiana's Energy Policy Task Force and the wholesale energy market for potential changes that could alter Vectren's plan. Regardless of the outcome, Vectren must continue to plan, as some portions are more certain than others.

Vectren plans to close its smallest, most inefficient coal unit, Culley 2 (90 MWs) and Vectren's contract for joint operations of Warrick unit 4 (150 MWs) expires by the end of 2023. In order to replace this generation, Vectren plans to acquire renewable generation in the next three years in order for Vectren's customers to benefit from expiring renewables tax incentives and, at a minimum, replace this portion of Vectren's coal fleet. This equates to approximately 700-1,000 MWs of capacity from solar generation towards the 2023/2024 and the 2024/2025 MISO planning years, partially dependent on expected solar penetration levels within MISO at that time and MISO resource accreditation.

To fill this need, Vectren plans to pursue attractive projects from its 2019 All-Source RFP consistent with the findings in the 2019/2020 IRP. The All Source RFP bids remain open until August 2020 and Vectren is in active discussions with short listed bidders for various renewables projects. Upon completion of expected negotiations Vectren plans to file a CPCN in 2020 so that its customers can receive low-cost solar energy from these projects before tax incentives are reduced. The remainder of Vectren's renewable need, including wind, solar and storage, could be filled through a second RFP. Affordable pricing will be important.

Vectren's plan allows for flexibility while awaiting clarity from the outcome of the Energy Policy Task Force and resource accreditation decisions from MISO; however, preliminary planning must begin for the potential replacement of the A.B. Brown coal plants with two combustion turbines most likely as it offers many benefits at the Brown site.

In order to accommodate the need for capacity by the end of 2023 for the 2024/2025 planning season, Vectren will begin design work and obtain updated cost estimates for equipment. Additionally, permits would need to be filed with FERC to bring gas to the Brown site, a continuation of work done in support of the 2016 plan. Vectren currently has approximately 500 MWs of interconnection rights for the Brown units at this brownfield site, which will allow Vectren to bypass the MISO Generation Interconnection Queue. Utilization of the Brown site helps to mitigate risk for Vectren customers, including reliance on the capacity market and risk of future transmission upgrades at different sites or later at the Brown site. A decision on CPCN timing will be made later this year.

10.2.2 DSM

Vectren has filed its 2021-2023 electric demand side management (DSM) plan in June of 2020. The 2021-2023 energy efficiency savings were guided by the 2019/2020 IRP process. Once approved by the Commission, the Vectren Oversight Board, including the Office of Consumers Counselor (OUCC), Citizens Action Coalition (CAC) and Vectren, will oversee the implementation of energy efficiency programs.

10.2.3 Solar Projects

Based on the Commission's 2019 approval, Vectren is currently constructing a 50 MW universal solar plant, interconnecting at transmission voltage (161kV) and is expected to be in service in the first quarter of 2021.

10.2.4 Culley 3

Based on the Commission's 2019 approval, Vectren is proceeding with the installation of the F.B. Culley Unit 3 mandated environmental compliance projects. The new pollution control equipment installations are in various stages of engineering and planning with the expected in-service dates meeting the defined timelines.

10.2.5 Ability to Finance the Preferred Portfolio

The Company and its parent corporations expect to have sufficient funds to finance the preferred portfolio, through a combination of internally generated cash flow from operations and external capital markets activity.

10.2.6 Continuous Improvement

Vectren takes continuous improvement seriously and works to ensure that improvement opportunities are evaluated and where appropriate implemented. This is done in several ways. First, Vectren participates in the Director's report process and listens to critiques of its IRPs from multiple stakeholders. Second, Vectren always conducts post IRP discussions with internal team members, as well as outside consultants to determine what can be done better in the next IRP. Third, Vectren participates in stakeholder meetings of other Indiana utilities and follows stakeholder feedback in those processes. Fourth, Vectren collects information on IRPs through news articles, conferences and Indiana's annual Contemporary Issues meeting. Finally, improvement opportunities come directly through the stakeholder process with formal and informal meetings, as they did throughout this IRP.

10.3 Implementation Schedule for the Preferred Resource Portfolio

Below is a general timeline for the Preferred Resource Portfolio, subject to change pending outcome of the Energy Policy Task Force.

Figure 10-1 – Implementation Schedule

Year	Quarter	Activity
2020	Q2	File for 2021-2023 DSM Plan File IRP
	Q3	Select Attractive Renewable Projects from All-Source RFP
	Q4	File CPCN for Renewable Projects Second RFP
2021	Q1	File CPCN for Combustion Turbines Results of 2nd RFP in
	Q2	
	Q3	Renewables CPCN Order
	Q4	Begin 2022 IRP Combustion Turbines CPCN Order
2022	Q1	
	Q2	
	Q3	
	Q4	File 2022 IRP

SECTION 11
TECHNICAL APPENDIX

11.1 CUSTOMER ENERGY NEEDS APPENDIX

11.1.1 Forecast Inputs

11.1.1.1 Energy Data

Historical Vectren sales and revenues data were obtained through an internal database. The internal database contains detailed customer information including rate, service, North American Industrial Classification System (NAICS) codes (if applicable), usage and billing records for all customer classes (more than 15 different rate and customer classes). These consumption records were exported out of the database and compiled in a spreadsheet on a monthly basis. The data was then organized by rate code and imported into the load forecasting software.

11.1.1.2 Economic and Demographic Data

Economic and demographic data was provided by Moody's Economy.com for the nation, the state of Indiana and the Evansville Metropolitan Statistical Area (MSA). Moody's Economy.com, a division of Moody's Analytics, is a trusted source for economic data that is commonly utilized by utilities for forecasting electric sales. The monthly data provided to Vectren contains both historical results and projected data throughout the IRP forecast period. This information is input into the load forecasting software and used to project residential, commercial (GS) and industrial (large) sales.

11.1.1.3 Weather Data

Historical and normal HDD and CDD are derived from daily temperature data for the Evansville airport, obtained from DTN, a provider of National Oceanic and Atmospheric Administration (NOAA) data. HDDs are defined as the number of degrees below a base temperature for a given day. CDDs are defined as the number of degrees above s base temperature for a given day. Normal degree-days are calculated by averaging the historical daily HDD and CDD over the last twenty years. Historical weather data is imported into the load forecasting software and is used to normalize the past usage of residential and GS customers. Similarly, the projected normal weather data is used to help forecast the future weather normalized loads of these customers.

In reviewing historical weather data, Itron found a statistically significant positive, but slow, increase in average temperature. This translated into fewer HDD and more CDD over time. Itron's analysis showed HDD are decreasing 0.2% per year while CDD are increasing 0.5% per year. These trends were incorporated into the forecast. Starting normal HDD were allowed to decrease 0.2% over the forecast period while CDD increased 0.5% per year through 2039. Figure 11.1 and Figure 11.2 show historical and forecasted monthly HDD and CDD.

Figure 11.1 – Heating Degree Days

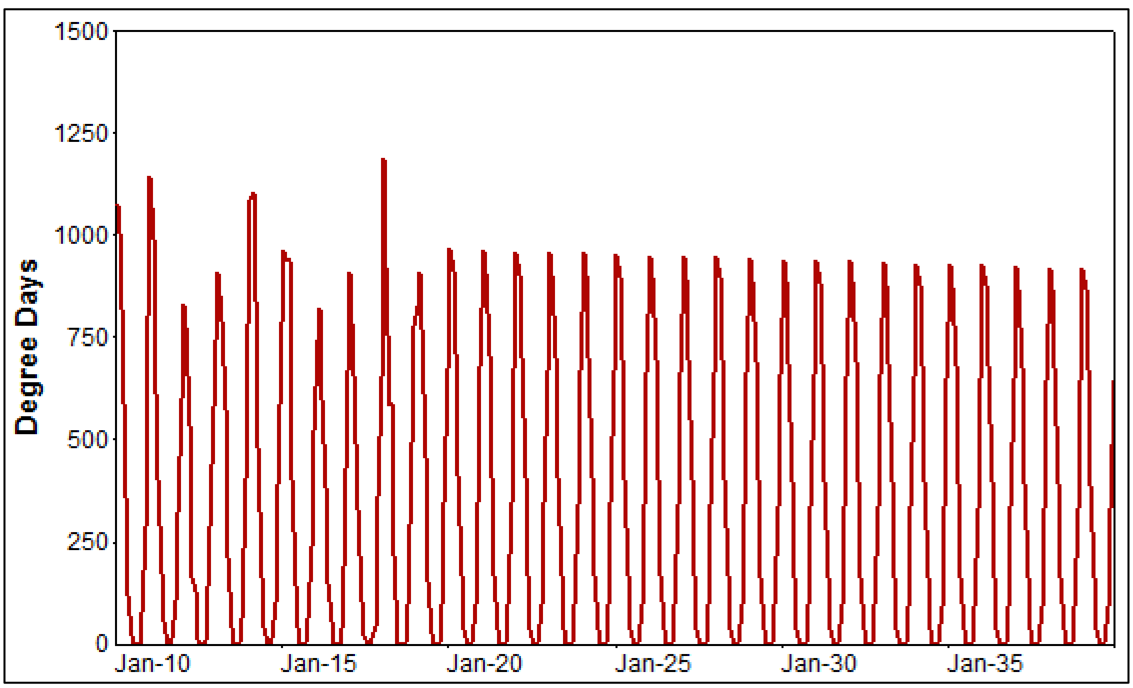
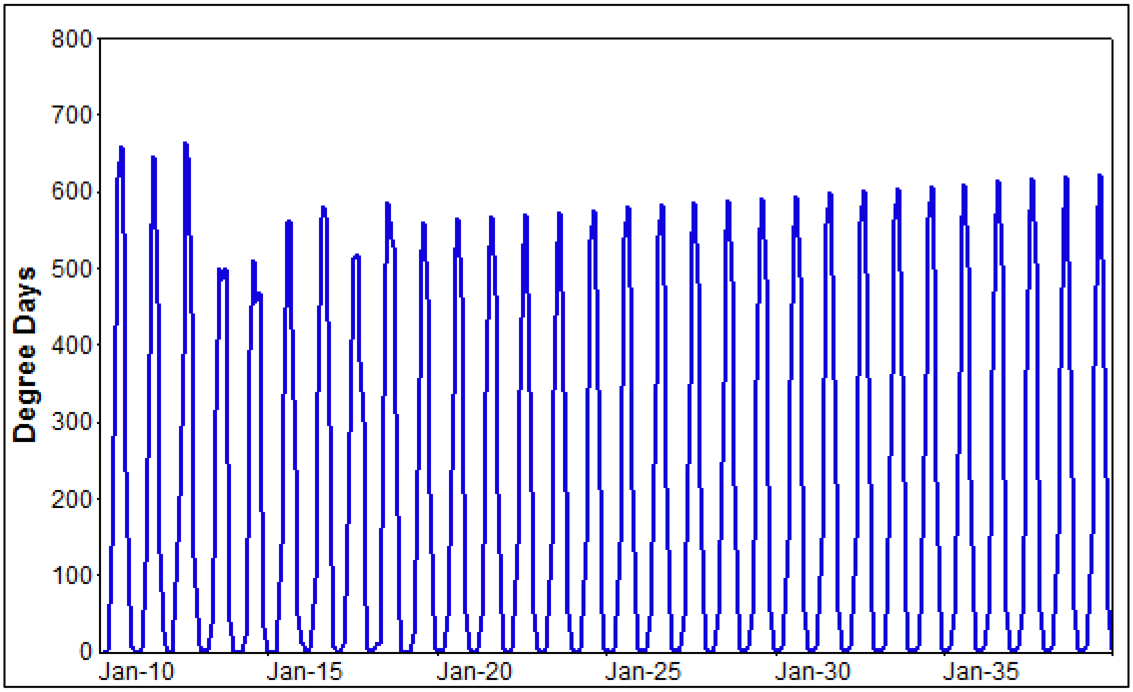


Figure 11.2 – Cooling Degree Days



11.1.1.4 Equipment Efficiencies and Market Shares Data

Itron Inc. provides regional Energy Information Administration (EIA) historic and projected data for equipment efficiencies and market shares. This information is used in the residential average use model and GS sales model. Vectren conducted an Electric Baseline survey in the third quarter of 2016 of Vectren's residential customers. This data was utilized to compare its territory market share data with the regional EIA data. In order to increase the accuracy of the residential average use model, regional equipment market shares were altered to reflect those of Vectren's actual territory. Appliance saturation surveys are conducted every 2-4 years, depending on need.

11.1.2 Load Forecast Continuous Improvement

Itron continues to improve and evolve the SAE (Statistically Adjusted End-Use) modeling framework. In addition to annually updating efficiency and saturations projections with the latest estimates from the EIA (Energy Information Administration) the framework has evolved to include utility specific DSM program activity data. The inclusion of a utility specific DSM variable in the modeling specification greatly improves model fit and enables the model to produce a baseline forecast excluding the impact of future DSM program activity. Additionally, Itron built a framework for the inclusion and use of trended normal weather where historical weather patterns show this to be appropriate.

The Vectren forecast now also takes into account emerging technologies: customer distributed generation and electric vehicles. Customer owned photo-voltaic (PV) adoption is modeled as a function of simple payback. The model explains historic adoption well and provides a framework that considers projected PV installation costs, electric prices and incentives. The adoption of electric vehicles is based on the EIA's forecast of vehicle adoption. The EIA uses a robust transportation model that includes a vehicle manufacturer component and a consumer choice component to estimate the mix of vehicles by powertrain type; gasoline, diesel, electric, plug-in hybrid electric, etc. The model accounts for projected fuel prices, electric prices, the decline in battery costs and federal incentives for electric vehicles.

Additionally, Vectren continually stays up to date with load forecasting topics in a variety of ways. First, Vectren is a member of Itron's Energy Forecasting Group. The Energy Forecasting Group contains a vast network of forecasters from around the country that share ideas and study results on various forecasting topics. Vectren forecasters attend an annual meeting that includes relevant topic discussions along with keynote speakers from the EIA and other energy forecasting professionals. The meeting is an excellent source for end-use forecasting directions and initiatives, as well as a networking opportunity. Vectren forecasters periodically attend continuing education workshops and webinars on various forecasting topics to help improve skills and learn new techniques. Additionally, Vectren discusses forecasts with the State Utility Forecasting Group and other Indiana utilities to better understand their forecasts. Vectren compares Vectren model assumptions and results to these groups to gain a better understanding of how they interpret and use model inputs.

11.1.3 Overview of Past Forecasts

The following tables outline the performance of Vectren's energy and demand forecasts over the last several IRPs by comparing Weather Normalized (WN) sales and demand figurers to IRP forecasts from 2009-2018.

Weather-normalization is performed each month by importing customer count, meter read schedule, billing month sales and daily temperature into Vectren's Electric AUPC Estimation system. Underlying the Electric AUPC Estimation System is a set of MetrixND (Itron's statistical modeling software) average use models. Separate models have been estimated for residential and general service customer classes. These models have been estimated from historical billed sales and customer data and daily system delivery data. On execution, the Use per Customer (UPC) project files read actual weather data from the Access weather database and generate daily use per customer estimates for the revenue classes. The results are exported back to the AUPC system database where the predicted daily use estimates are used to allocate billed monthly sales to the calendar-month period. The models are also executed using normal daily temperatures. Results are written back to the AUPC system database. Weather-normalized sales are then exported from the Electric AUPC Estimation system.

The following tables show the WN[46] and forecasted values for:

- Total Peak Demand
- Total Energy
- Residential Energy
- GS Energy
- Large Energy

[46] Note that large sales are not weather normalized.

Figure 11.3 – Total Peak Demand Requirements (MW), Including Losses and Street Lighting

Year	2007 Total Demand Forecast (MW)	2009 Total Demand Forecast (MW)	2011 Total Demand Forecast (MW)	2014 Total Demand Forecast (MW)	2016 Total Demand Forecast (MW)	WN Total Demand (MW)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	1,216					1,069	-13.7%				
2010	1,237	1,153				1,136	-8.9%	-1.5%			
2011	1,252	1,179				1,159	-8.0%	-1.7%			
2012	1,258	1,118	1,156			1,136	-10.7%	1.6%	-1.7%		
2013	1,265	1,115	1,156			1,144	-10.5%	2.6%	-1.0%		
2014	1,272	1,107	1,165			1,133	-12.3%	2.3%	-2.8%		
2015	1,281	1,100	1,164	1,155		1,113	-15.1%	1.1%	-4.6%	-3.8%	
2016	1,290	1,092	1,160	1,156		1,087	-18.7%	-0.5%	-6.7%	-6.3%	
2017	1,299	1,094	1,151	1,113	1,082	1,038	-25.2%	-5.4%	-11.0%	-7.2%	-4.3%
2018	1,308	1,093	1,145	1,109	1,086	1,006	-30.0%	-8.6%	-13.8%	-10.2%	-7.9%
Mean Absolute Error							15.3%	2.8%	5.9%	6.9%	6.1%

Figure 11.4 – Total Energy Requirements (GWh), Including Losses and Street Lighting

Year	2007 Total Energy IRP Forecast (GWh)	2009 Total Energy IRP Forecast (GWh)	2011 Total Energy IRP Forecast (GWh)	2014 Total Energy IRP Forecast (GWh)	2016 Total Energy IRP Forecast (GWh)	WN Total Energy Results (GWh)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	6,090					5,365	-13.5%				
2010	6,230	5,306				5,701	-9.3%	6.9%			
2011	6,329	5,460				5,819	-8.8%	6.2%			
2012	6,369	5,456	5,837			5,718	-11.4%	4.6%	-2.1%		
2013	6,422	5,434	5,807			5,743	-11.8%	5.4%	-1.1%		
2014	6,476	5,403	5,803			5,797	-11.7%	6.8%	-0.1%		
2015	6,527	5,365	5,772	5,914		5,773	-13.1%	7.1%	0.0%	-2.4%	
2016	6,580	5,336	5,725	5,936		5,725	-14.9%	6.8%	0.0%	-3.7%	
2017	6,629	5,315	5,657	5,514	5,257	5,073	-30.7%	-4.8%	-11.5%	-8.7%	-3.6%
2018	6,680	5,292	5,590	5,503	5,290	5,139	-30.0%	-3.0%	-8.8%	-7.1%	-2.9%
Mean Absolute Error							15.5%	5.7%	3.4%	5.5%	3.3%

Figure 11.5 – Residential Energy (GWh)

Year	2007 Res. IRP Forecast (GWh)	2009 Res. IRP Forecast (GWh)	2011 Res. IRP Forecast (GWh)	2014 Res. IRP Forecast (GWh)	2016 Res. IRP Forecast (GWh)	WN Res. Results (GWh)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	1,595					1,512	-5.5%				
2010	1,620	1,467				1,483	-9.2%	1.1%			
2011	1,645	1,440				1,460	-12.7%	1.3%			
2012	1,663	1,421	1,462			1,437	-15.7%	1.1%	-1.7%		
2013	1,683	1,391	1,419			1,421	-18.4%	2.1%	0.1%		
2014	1,703	1,365	1,399			1,412	-20.6%	3.3%	0.9%		
2015	1,722	1,332	1,371	1,404		1,444	-19.2%	7.8%	5.1%	2.8%	
2016	1,742	1,304	1,340	1,394		1,416	-23.0%	7.9%	5.4%	1.5%	
2017	1,759	1,282	1,305	1,383	1,407	1,398	-25.8%	8.3%	6.7%	1.1%	-0.6%
2018	1,777	1,264	1,271	1,377	1,395	1,375	-29.2%	8.1%	7.6%	-0.2%	-1.5%
Mean Absolute Error							17.9%	4.6%	3.9%	1.4%	1.1%

Figure 11.6 – Commercial (GS) Energy (GWh)

Year	2007 Comm. (GS) IRP Forecast (GWh)	2009 Comm. (GS) IRP Forecast (GWh)	2011 Comm. (GS) IRP Forecast (GWh)	2014 Comm. (GS) IRP Forecast (GWh)	2016 Comm. IRP Forecast (GWh)	WN Comm. (GS) Results (GWh)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	1,384					1,319	-4.9%				
2010	1,404	1,275				1,314	-6.8%	3.0%			
2011	1,426	1,284				1,307	-9.1%	1.8%			
2012	1,438	1,296	1,375			1,283	-12.1%	-1.0%	-7.2%		
2013	1,455	1,304	1,383			1,294	-12.4%	-0.7%	-6.9%		
2014	1,472	1,307	1,399			1,312	-12.2%	0.4%	-6.6%		
2015	1,490	1,306	1,402	1,304		1,321	-12.8%	1.1%	-6.2%	1.3%	
2016	1,507	1,306	1,398	1,320		1,281	-17.7%	-1.9%	-9.1%	-3.0%	
2017	1,525	1,309	1,384	1,315	1,315	1,278	-19.3%	-2.4%	-8.3%	-2.9%	-2.9%
2018	1,544	1,311	1,373	1,311	1,324	1,235	-25.0%	-6.1%	-11.1%	-6.1%	-7.2%
Mean Absolute Error							13.2%	2.0%	7.9%	3.3%	5.1%

Figure 11.7 – Industrial (Large) Energy (GWh)

Year	2007 Ind. (Large) IRP Forecast (GWh)	2009 Ind. (Large) IRP Forecast (GWh)	2011 Ind. (Large) IRP Forecast (GWh)	2014 Ind. (Large) IRP Forecast (GWh)	2016 (Large) IRP Forecast (GWh)	WN Ind. (Large) Results (GWh)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	2,820					2,251	-25.3%				
2010	2,921	2,281				2,601	-12.3%	12.3%			
2011	2,980	2,445				2,744	-8.6%	10.9%			
2012	2,999	2,449	2,687			2,714	-10.5%	9.8%	1.0%		
2013	3,014	2,449	2,693			2,744	-9.8%	10.7%	1.9%		
2014	3,028	2,446	2,693			2,786	-8.7%	12.2%	3.3%		
2015	3,040	2,445	2,688	2,916		2,722	-11.7%	10.1%	1.2%	-7.1%	
2016	2,718	2,447	2,679	2,932		2,722	0.2%	10.1%	1.6%	-7.7%	
2017	2,730	2,446	2,664	2,546	2,211	2,097	-30.2%	-16.7%	-27.1%	-21.4%	-5.5%
2018	2,742	2,440	2,646	2,547	2,252	2,182	-25.7%	-11.9%	-21.3%	-16.7%	-3.2%
Mean Absolute Error							14.3%	11.6%	8.2%	13.3%	4.3%

11.1.3.1 Actual and Weather Normalized Energy and Demand Levels

Figure 11.8 – Historic Peak Demand

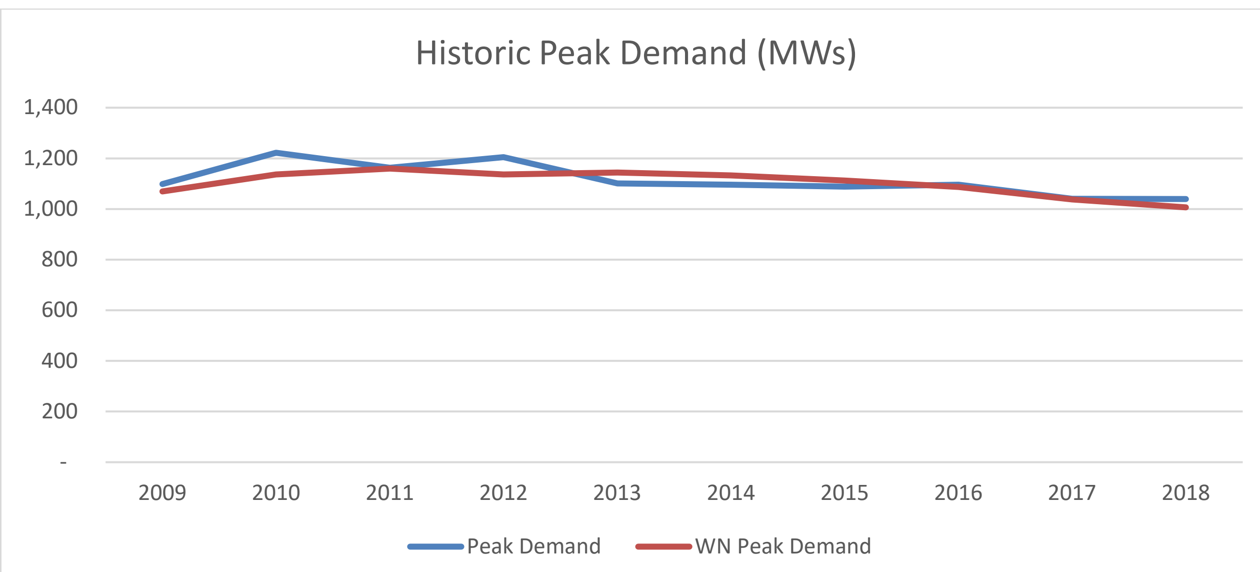
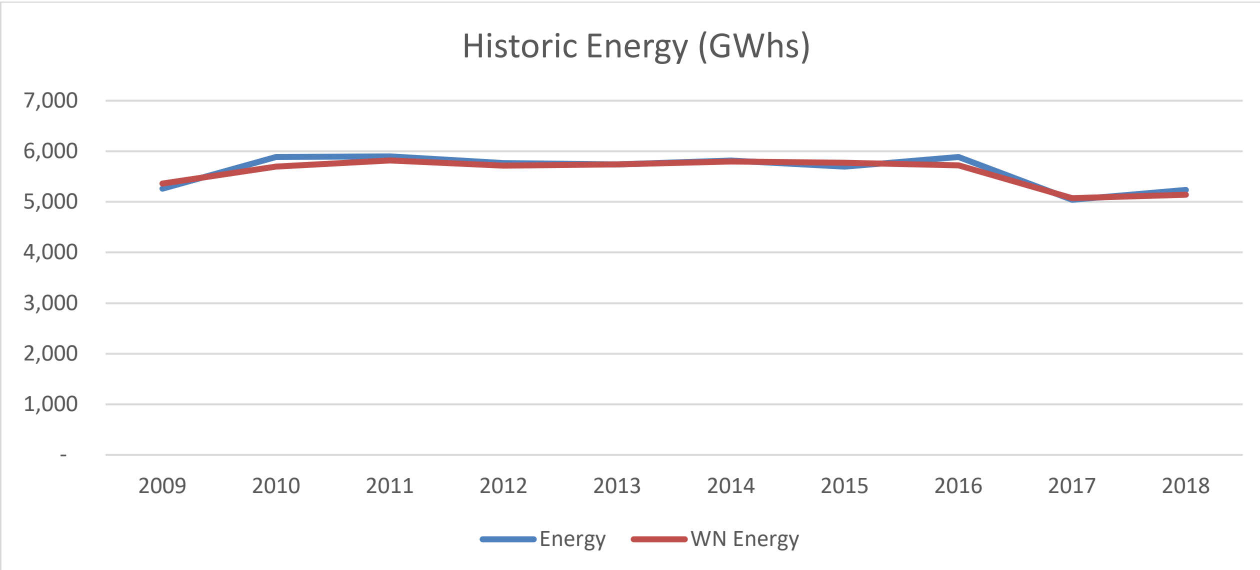


Figure 11.9 – Historic Energy



11.1.3.2 Load Shapes

Figure 11.10 – Historic Annual Load Shape

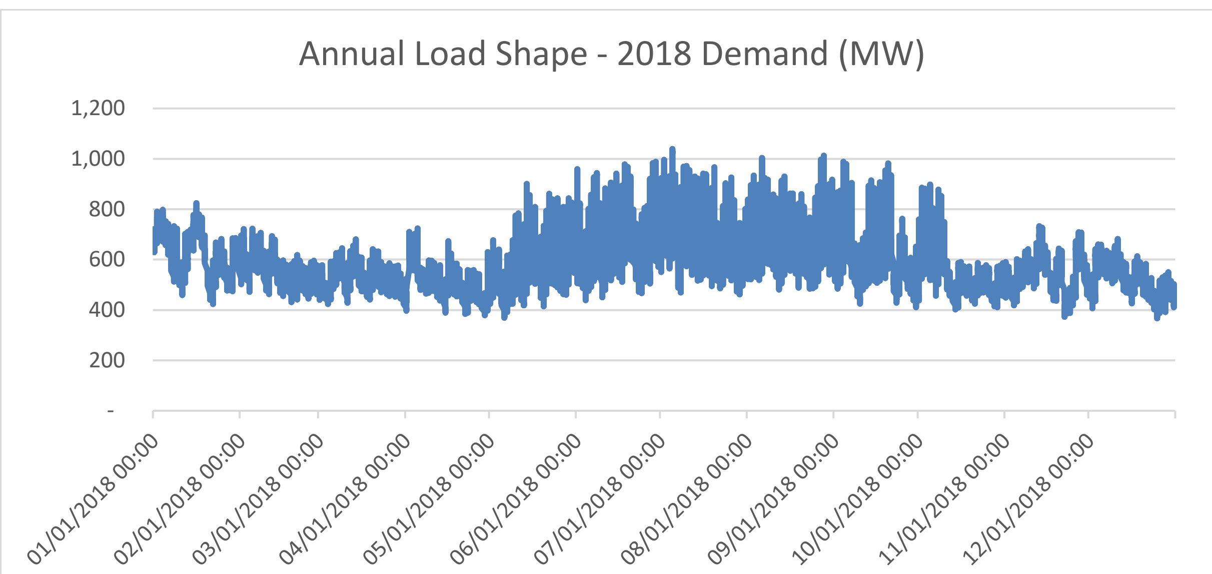


Figure 11.11 – Winter Peak Day

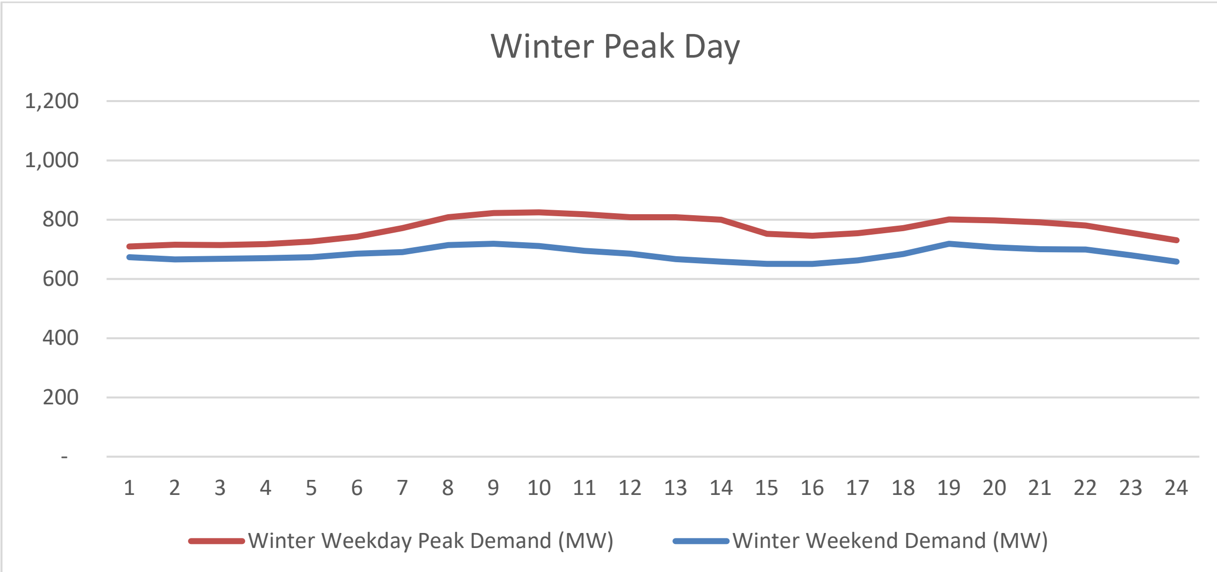


Figure 11.12 – Typical Spring Day

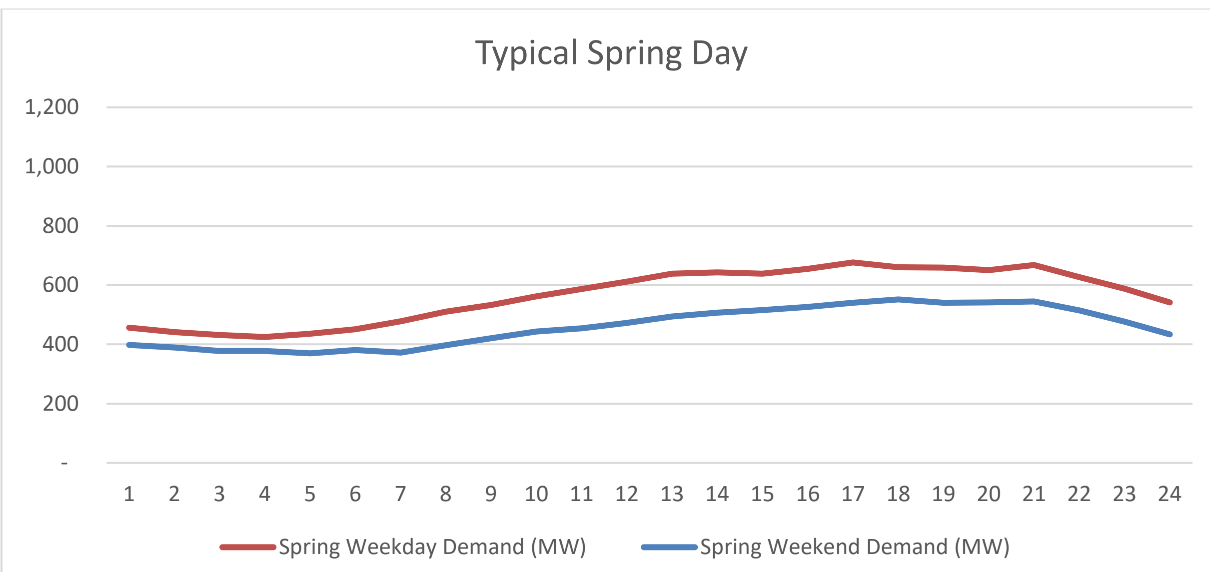


Figure 11.13 – Summer Peak Day

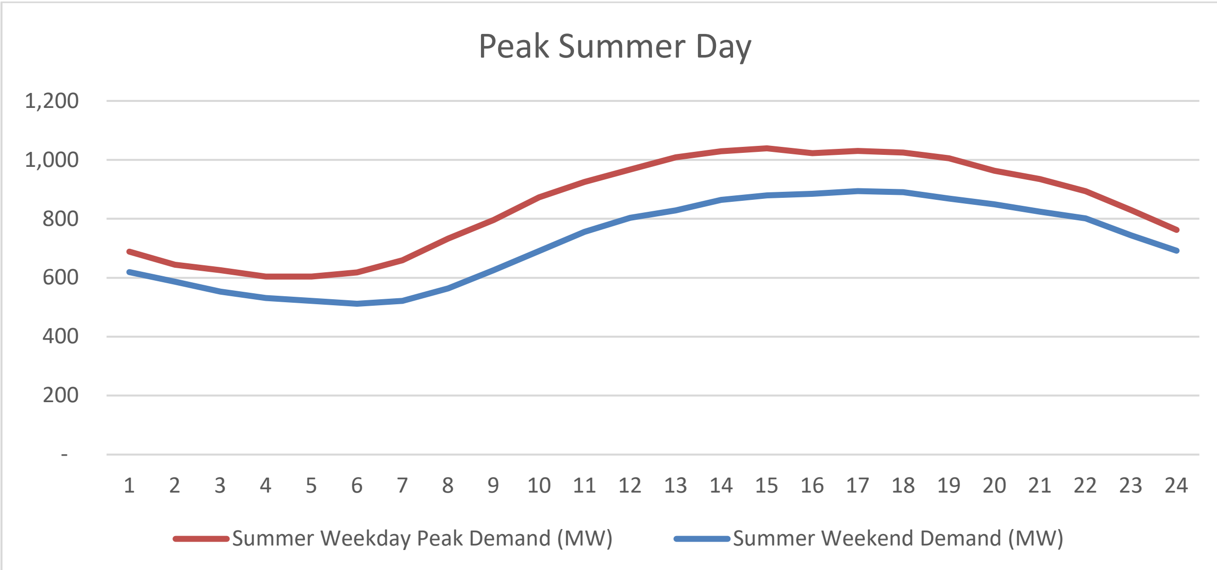


Figure 11.14 – Typical Fall Day

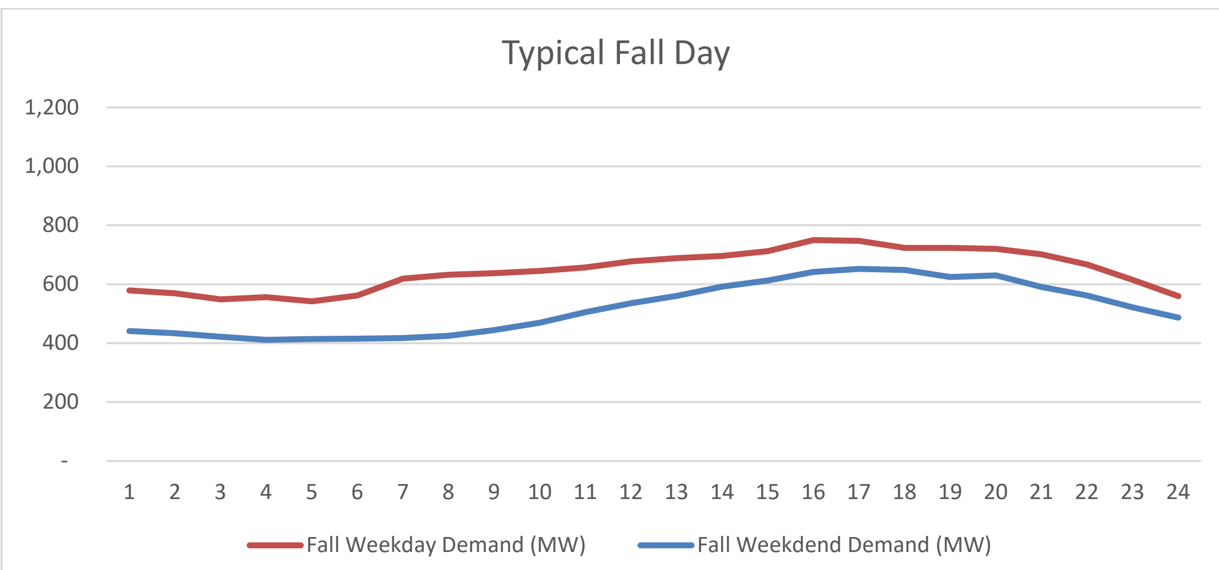


Figure 11.15 – January Load

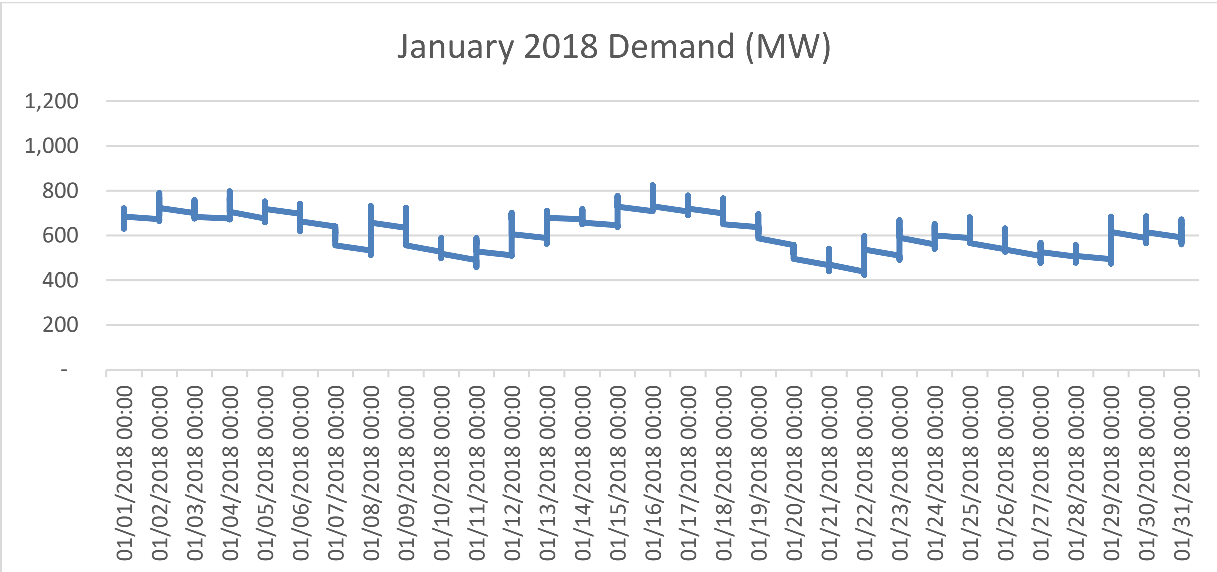


Figure 11.16 – February Load

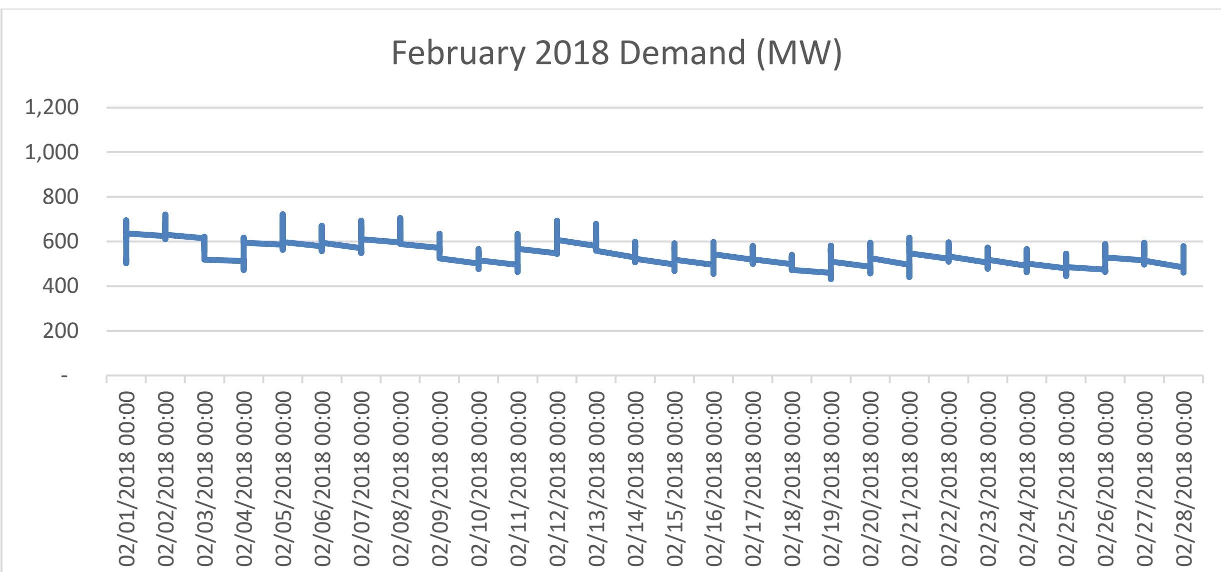


Figure 11.17 – March Load

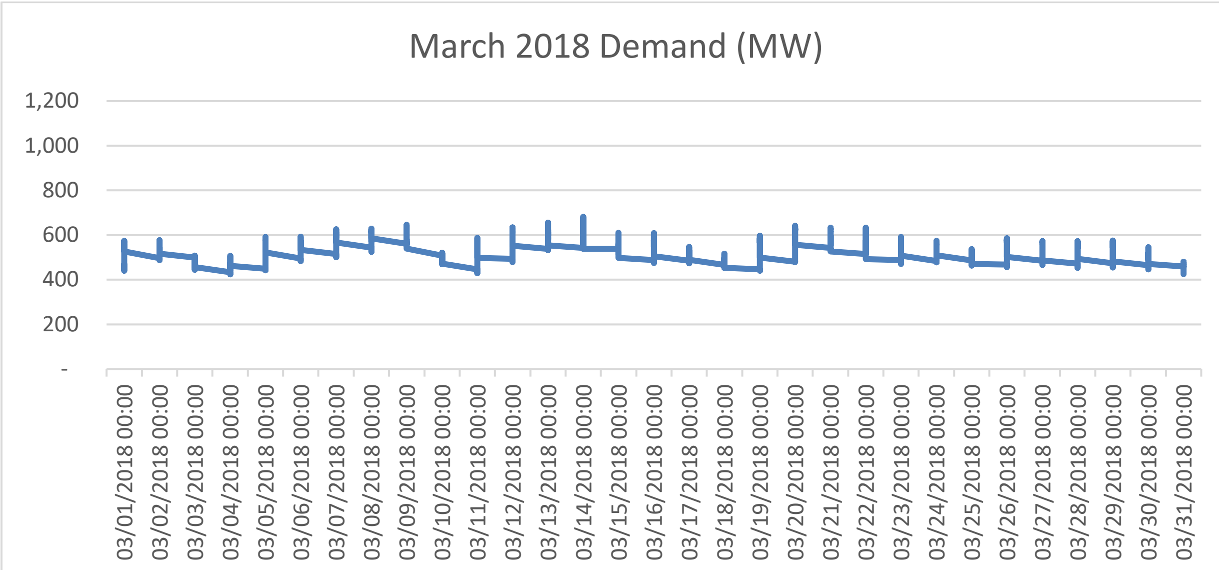


Figure 11.18 – April Load

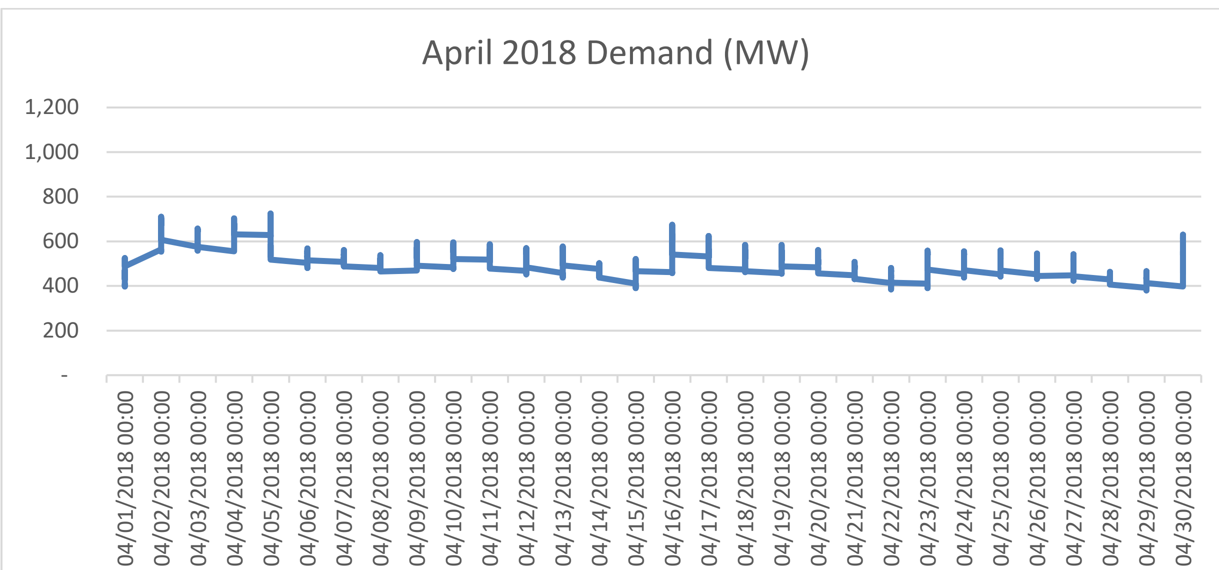


Figure 11.19 – May Load

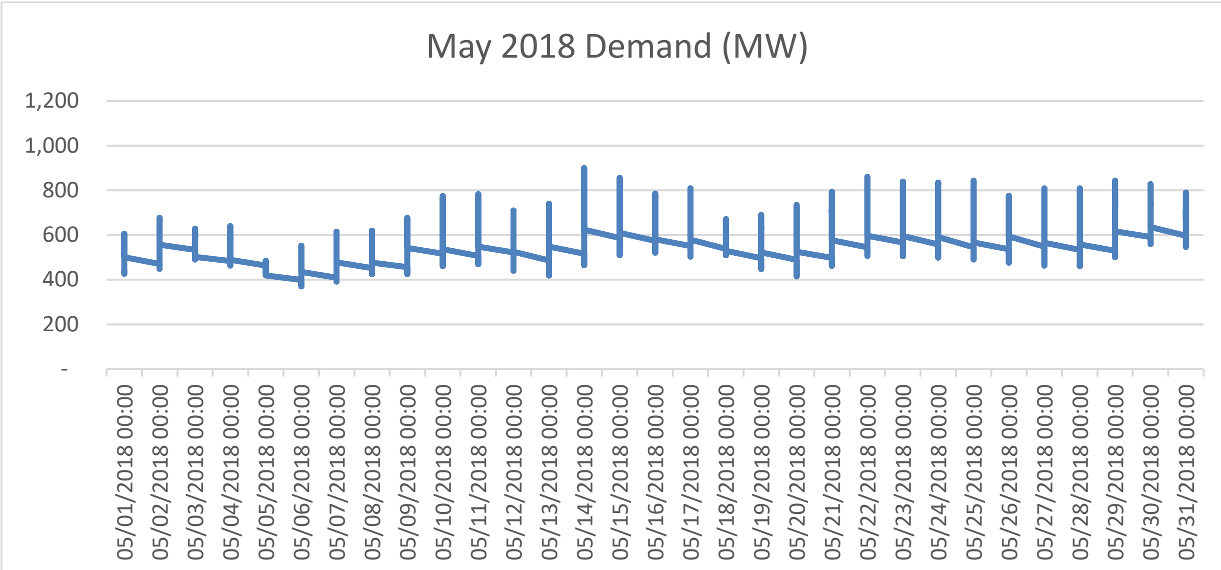


Figure 11.20 – June Load

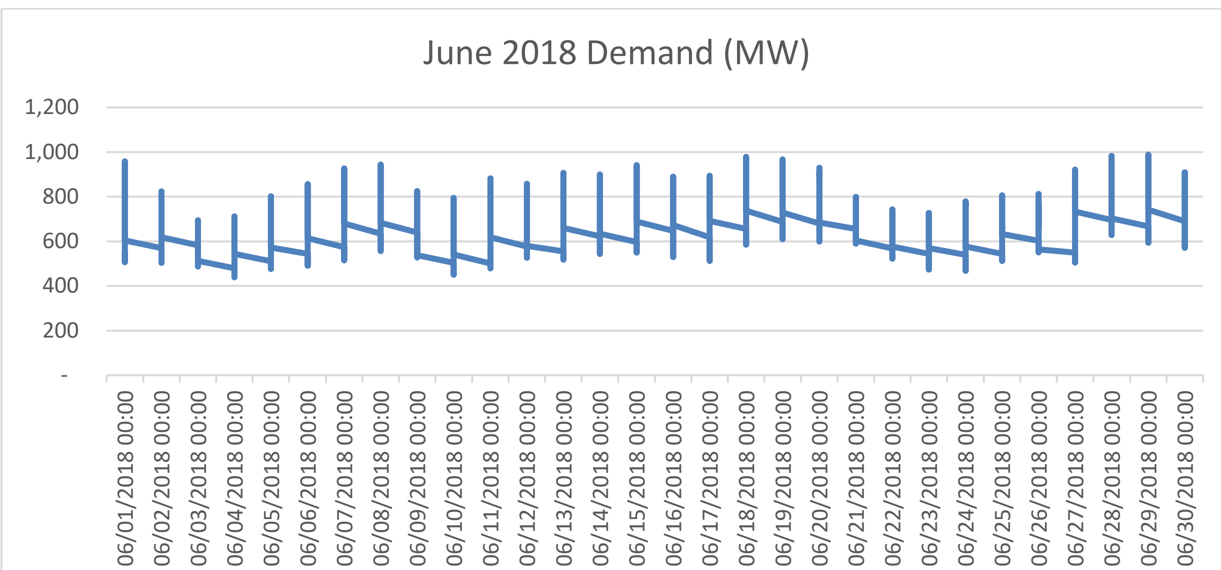


Figure 11.21 – July Load

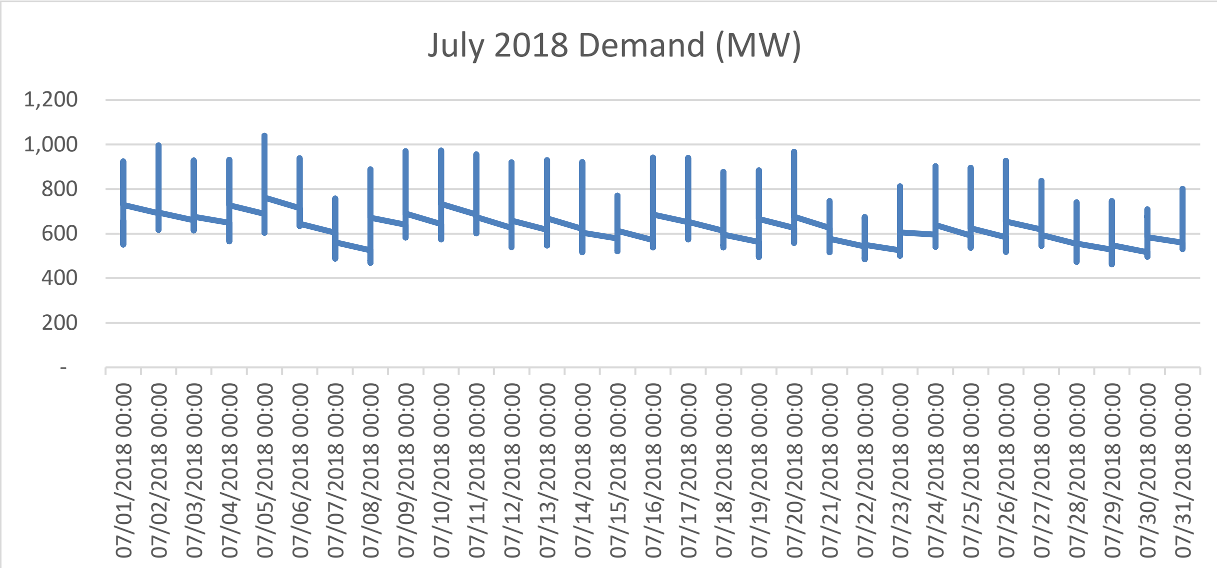


Figure 11.22 – August Load

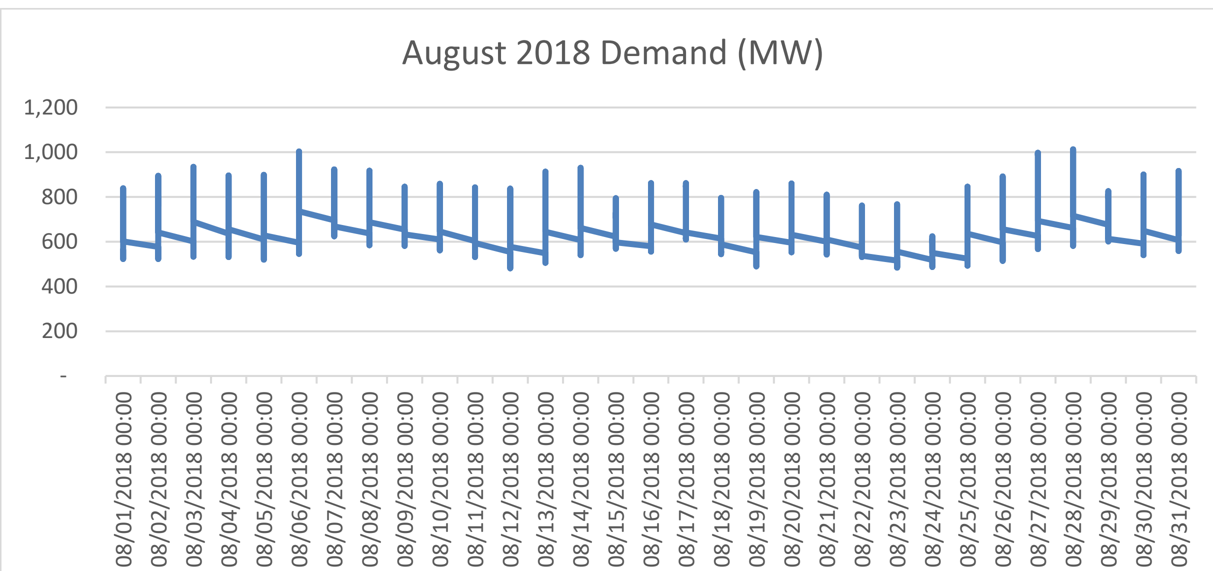


Figure 11.23 – September Load

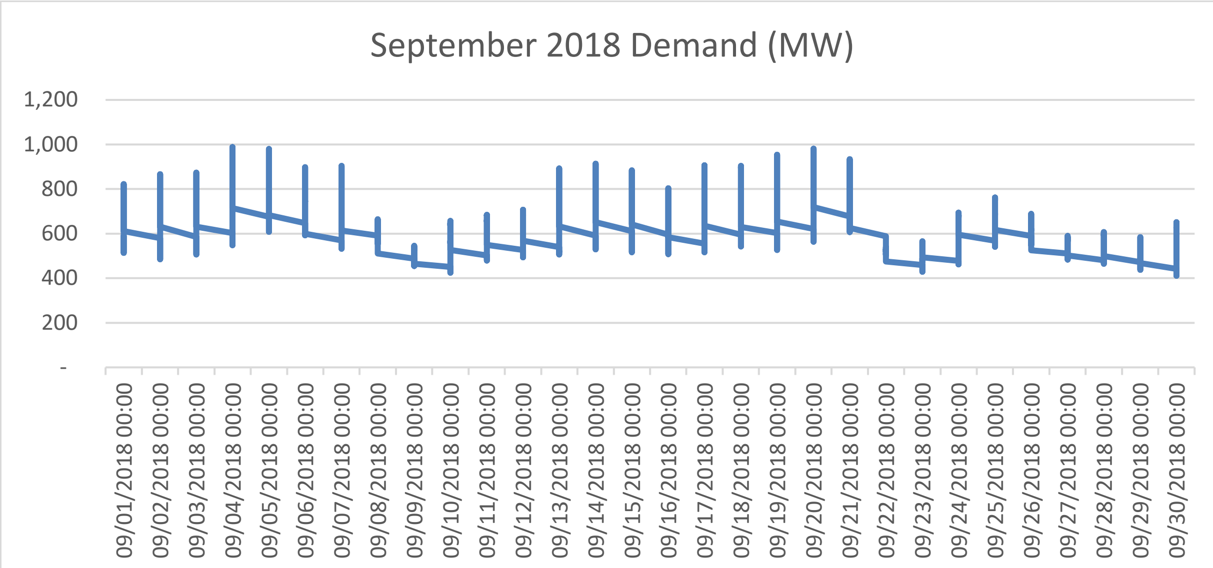


Figure 11.24 – October Load

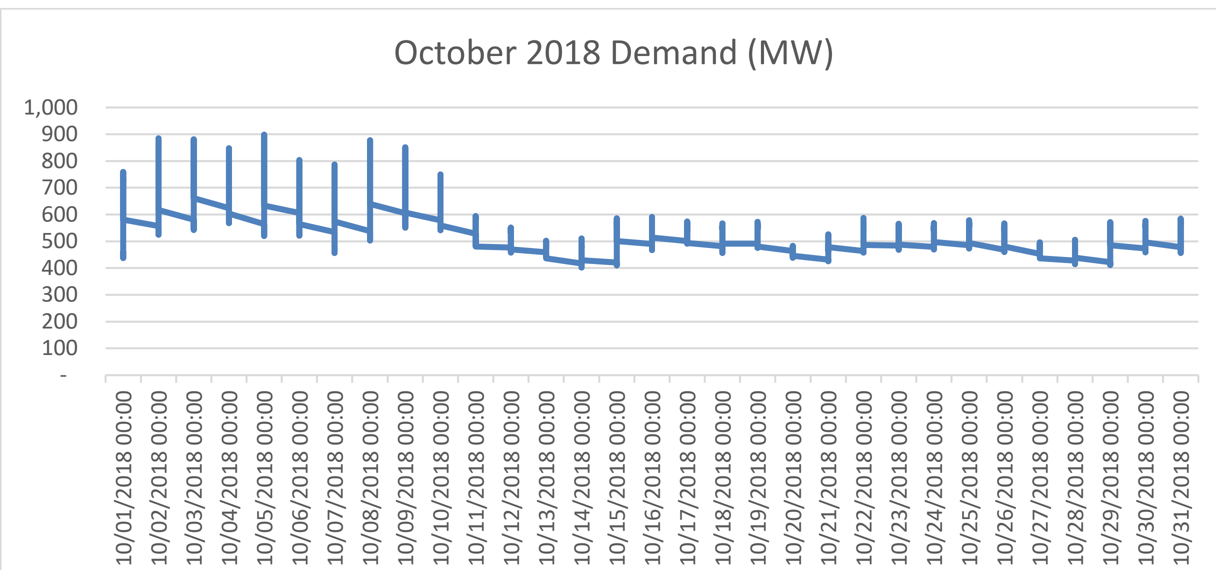


Figure 11.25 – November Load

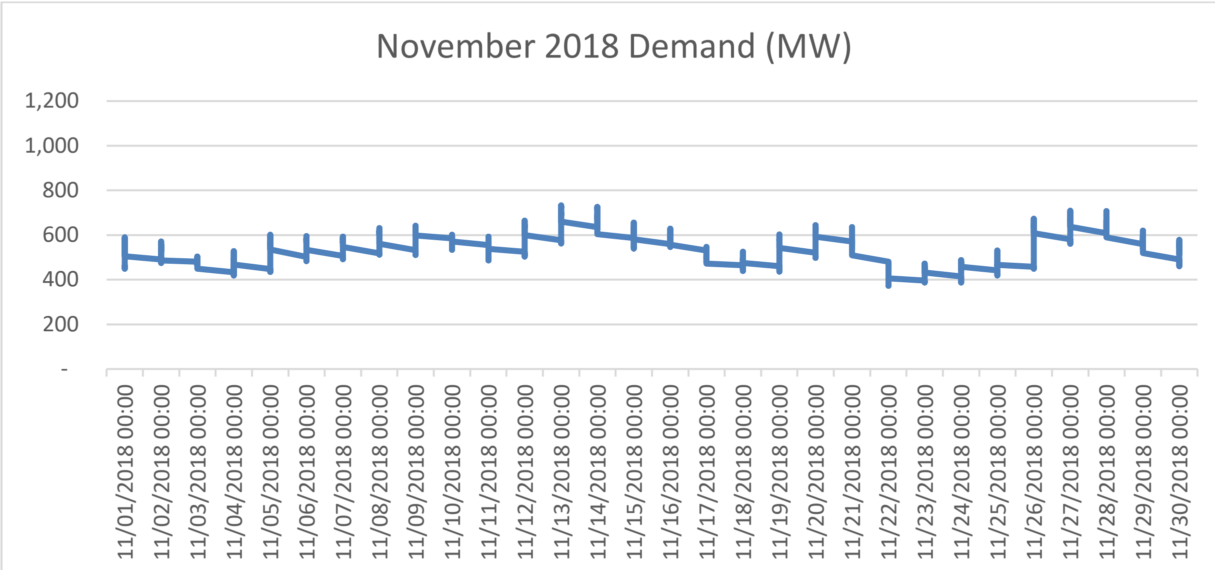
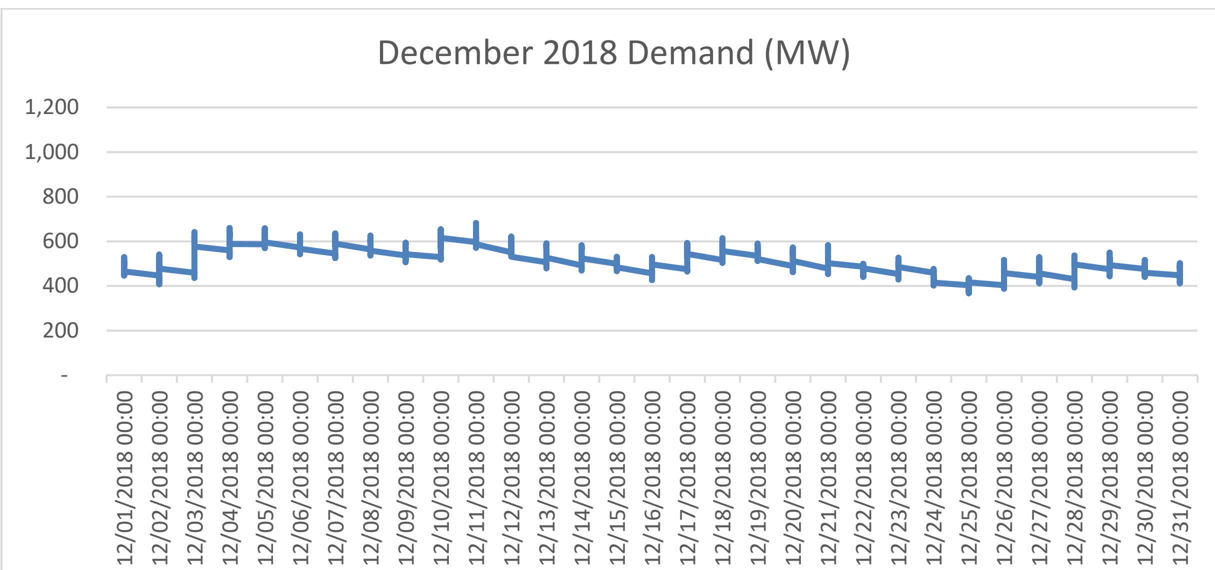


Figure 11.26 – December Load



11.2 ENVIRONMENTAL APPENDIX

11.2.1 Air Emissions

It was assumed that current or future generation resources would not exceed Vectren's allocated SO_2 and NOx emission allowances. Vectren's fleet of existing power generation facilities meet all rules and regulations related to SO_2 and NOx emissions while the cost of emission control equipment for SO_2 and NOx is factored into any new facilities that would be selected as part of a portfolio. Air emissions allowance costs are accounted for within IRP modeling.

Figure 11.27 – Air Pollution Control Devices Installed

	F.B. Culley 2	F.B. Culley 3	Warrick 4	A.B. Brown 1	A.B. Brown 2
Vintage	1966	1973	1970	1979	1986
MW (net)	90	270	150	245	245
NO_X	Low NO_X Burner	SCR	SCR	SCR	SCR
SO_2	FGD	FGD	FGD	FGD	FGD
PM	ESP	FF	ESP	FF	ESP
MATs	Shared w/ U3	Injection	Injection	Injection	Injection
SO_3		Injection	Injection	Injection	injection

Figure 11.28 – CSAPR SO_2 Allowances

SO_2				
	A.B. Brown	F.B. Culley	SIGECO W4	Total
2016	7,894	4,411	2,892	15,197
2017	4,423	3,890	1,620	9,933
2018	4,423	3,890	1,620	9,933
2019	4,423	3,890	1,620	9,933

NOx					
	A.B. Brown	BAGS[47]	F.B. Culley	SIGECO W4	Total
2016	1,214	21	1,060	445	2,740
2017	1,195	21	1,044	437	2,697
2018	1,195	21	1,044		2,698
2019	1,195	21	1,044	437	2,697

[47] Retired

Figure 11.29 – CSAPR Seasonal NOx Allowances

	A.B. Brown	BAGS[48]	F.B. Culley	SIGECO W4	Total
2016	1,214	21	1,060	445	2,740
2017	658	6	465	227	1,356
2018	658	6	465	227	1,356
2019	658	6	465	227	1,356

11.2.2 Solid Waste Disposal

Scrubber by-products from A.B. Brown are sent to an on-site landfill permitted by Indiana Department of Environmental Management (IDEM). During the fall of 2009, Vectren finalized construction of a dry fly ash silo and barge loading facility that would allow for the beneficial reuse of Vectren-generated fly ash. Since February 2010, the majority of A.B. Brown fly ash is diverted to the new dry ash handling system and sent for beneficial reuse to a cement processing plant in St. Genevieve, Missouri via a river barge loader and conveyor system. This major sustainability project serves to mitigate negative impacts from the imposition of a more stringent regulatory scheme for ash disposal, as the majority of Vectren's coal combustion materials are now being diverted from the existing ash pond structures and surface coal mine backfill operations and instead transported offsite for recycling into a cement application.

Fly ash from the F.B. Culley facility is similarly transported off-site for beneficial reuse in cement. In May 2009, Culley began trucking fly ash to the St. Genevieve cement plant. Upon completion of the barge loading facility at the A.B. Brown facility in late 2009, F.B. Culley's fly ash is now transported to the A.B. Brown loading facility and shipped to the cement plant via river barge. The F.B. Culley facility sends its bottom ash to the East ash pond via wet sluicing. The pond is approximately 10 acres in size. By the end of 2020, the East pond will no longer receive bottom ash as a result of the conversion to a dry system. The West pond (32 acres) no longer receives bottom ash but has continued to accept coal pile run-off and general storm water from the west side of the plant, including the plant entrance road. By the end of 2020, the West pond will be closed. The closure

[48] Retired

project includes the construction of a new geosynthetic lined contact storm water pond that will receive the coal pile run-off and other storm water that contacts industrial activity. Scrubber by-product generated by the F.B. Culley facility is also used for beneficial reuse and shipped by river barge from F.B. Culley to a wallboard manufacturer. In summary, the majority of Vectren's coal combustion material is no longer handled on site but is being recycled and shipped off-site for beneficial reuse.

11.2.3 Hazardous Waste Disposal

Vectren's A.B. Brown and F.B. Culley plants are episodic producers of hazardous waste that may include paints, parts washer fluids, or other excess or outdated chemicals. Both facilities are typically classified as Small Quantity Generators. All hazardous waste is disposed of in accordance with Federal and state regulations.

11.2.4 Water Consumption and Discharge

A.B. Brown and F.B. Culley currently discharge process and cooling water to the Ohio River under National Pollutant Discharge Elimination System (NPDES) water discharge permits issued by the Indiana Department of Environmental Management (IDEM). A.B. Brown utilizes cooling towers while F.B. Culley has a once through cooling water system. In fall 2014, both plants installed chemical precipitation water treatment systems to meet Ohio River Valley Sanitation Commission (ORSANCO) regional water quality standards mercury limit of 12 ppt monthly average.

11.3 DSM APPENDIX

11.3.1.1 DSM Planning Process

One of the key objectives of the IRP is to "provide all customers with a reliable supply of energy at the lowest reasonable cost." The level and costs of DSM to be offered in Vectren's service territory are important outcomes of the IRP process. The IRP will determine the appropriate level of DSM to include in the preferred resource plan. However, for Vectren, the IRP is not the appropriate tool to determine which specific programs to include in a DSM plan. Instead, every 2-3 years Vectren engages in a multi-step planning process designed to select programs that meet the level of savings established in the preferred resource portfolio. Once the level of DSM to be offered has been established by the IRP and a portfolio of programs to meet the savings levels has been designed, the last step in the planning process is to re-affirm the cost effectiveness of the proposed programs.

11.3.1.2 Cost Benefit Analysis

Utilizing the DSMore cost/benefit model, the measures and programs were analyzed for cost effectiveness. The model includes a full range of economic perspectives typically used in EE and DSM analytics. Inputs into the model include the following: participation rates, incentives paid, energy and demand savings of the measure, life of the measure, avoided costs, implementation costs, administrative costs, incremental costs to the participant of the high efficiency measure and escalation rates and discount rates. Vectren considers the results of each test and ensures that the portfolio passes the Total Resource Cost (TRC) test as it includes the total costs and benefits to both the energy company (program administrator) and the consumer. The outputs include all the California Standard Practice Manual results:

- Participant Cost Test
- Ratepayer Impact Measure Test
- Utility Cost Test ("UCT")
- Total Resource Cost Test ("TRC")

The cost effectiveness analysis produces two types of resulting metrics:

- Net Benefits (dollars) = NPV ∑ benefits – NPV ∑ costs
- Benefit Cost Ratio = NPV ∑ benefits ÷ NPV ∑ costs

The Participant Cost Test shows the value of the program from the perspective of the energy company's customer participating in the program. The test compares the participant's bill savings over the life of the DSM program to the participant's cost of participation.

The Utility Cost Test shows the value of the program to the utility considering only avoided utility supply costs (based on the next unit of generation) in comparison to the utility program costs.

The Ratepayer Impact Measure (RIM) Test shows the impact of a program on all utility customers through impacts on 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 Total Resource Cost (TRC) Test shows the combined perspective of the energy company and the participating customers. This test compares (1) the level of benefits associated with the reduced energy supply costs to (2) the costs incurred by the energy company and by program participants. In completing the tests listed above, Vectren used 6.19% as the weighted average cost of capital, which is the weighted cost of capital that was approved by the IURC on May 29, 2019 in Cause No. 44910.

Figure 5.3.2.8.1 – Vectren 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
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
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
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)

11.3.2 Gross Savings 2018-2020 Plan

Figure 11.30 – 2018-2020 Plan Gross kWh Energy Savings

	2018		2019		2020	
Sector	Gross kWh Energy Savings	kW Demand Savings	Gross kWh Energy Savings	kW Demand Savings	Gross kWh Energy Savings	kW Demand Savings
Residential	23,302,096	6,417	23,337,912	4,846	19,294,127	5,977
Commercial & Industrial	24,931,097	3,656	20,500,000	4,321	17,053,515	1,773
Total	48,233,193	10,073	43,837,912	9,167	36,347,642	7,750

* 2018 Evaluated Savings used for 2018
** 2019 Operating Plan used for 2019
*** 2020 Filed Plan used for 2020

11.3.3 DSM Programs

Vectren has offered tariff-based DSM resource options to customers for several years. Consistent with a settlement approved in 2007 in Cause No. 43111, the Demand Side Management Adjustment ("DSMA") was created to specifically recover all Vectren's Commission approved DSM costs, including (at that time) a DLC Component. The Commission, in its order in Cause No. 43427, authorized Vectren to include both Core and Core-Plus DSM Program Costs and related incentives in an Energy Efficiency Funding Component ("EEFC") of the DSMA. The EEFC supports the Company's efforts to help customers reduce their consumption of electricity and related impacts on peak demand. It is designed to recover the costs of Commission-approved DSM programs from all customers receiving the benefit of these programs. In Cause Nos. 43427, 43938 and 44318, the Commission approved recovery of the cost of Conservation Programs via the EEFC. This rider is applicable to customers receiving service pursuant to Rate Schedules RS, B, SGS, DGS, MLA, OSS, LP and HLF.

11.3.4 Impacts

The table below demonstrates estimated energy (kWh) and demand (kW) savings per participant for each program.

Figure 11.31 – 2018 Evaluated Electric DSM Program Savings

Program	Residential/ Commercial	Participants *	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross kW/ Participant	Net KW
Residential Lighting	Residential	235,192	58%	8,136,654	35	4,706,664	1,121	0.005	649.0
Residential Prescriptive	Residential	6,900	68%	3,326,588	482	2,277,461	1,667	0.242	1,098.0
Residential New Construction	Residential	145	54%	162,407	1,120	87,700	62	0.428	34.0
Home Energy Assessments	Residential	350	75%	341,133	975	256,938	31	0.089	23.0
Income Qualified Weatherization	Residential	2,043	100%	931,314	456	931,314	100	0.049	100.0
Energy Efficient Schools	Residential	2,401	100%	712,638	297	712,638	76	0.032	76.0
Residential Behavioral Savings	Residential	41,400	100%	7,063,475	171	7,063,475	1,839	0.044	1,838.7
Appliance Recycling	Residential	1,300	67%	1,326,520	1,020	891,359	169	0.130	114.0
BYOT (Bring Your Own Thermostat)	Residential	400	100%				358	0.895	358.0
SmartDLC - Wifi DR/DLC Changeout	Residential	1,043	100%	379,779	364	379,779	866	0.831	866.4
Community Based - LED Lighting	Residential	44,189	100%	921,588	21	921,588	127	0.003	127.0
Evaluated Nonparticipant Spillover	Residential					1,012,564			
Commercial & Industrial Prescriptive	Commercial	37,200	84%	18,605,544	500	15,628,657	2,713	0.073	2,278.7
Commercial & Industrial Custom	Commercial	40	85%	2,512,038	62,801	2,135,232	324	8.100	276.0
Small Business Direct Install	Commercial	138	101%	3,813,515	27,634	3,837,960	619	4.486	623.0
Portfolio Total		372,741	85%	48,233,193	129	40,843,329	10,073	0.027	8,461.8

* Participants are the Verified installations

Figure 11.32 – 2019 Electric DSM Operating Plan Program Savings

Program	Residential/ Commercial	Participants	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross kW/ Participant	Net KW
Residential Lighting	Residential	241,418	72%	8,340,633	35	6,005,256	939	0.004	675.7
Residential Prescriptive	Residential	4,314	53%	2,318,054	537	1,228,569	957	0.222	507.2
Residential New Construction	Residential	171	50%	157,033	918	78,517	90	0.526	45.0
Home Energy Assessments	Residential	400	99%	403,067	1,008	399,036	42	0.105	41.6
Income Qualified Weatherization	Residential	851	100%	546,248	642	546,248	95	0.112	95.0
Energy Efficient Schools	Residential	2,500	100%	962,750	385	962,750	108	0.043	108.0
Residential Behavioral Savings	Residential	41,400	100%	7,370,000	178	7,370,000	961	0.023	961.0
Appliance Recycling	Residential	1,500	53%	1,491,900	995	790,707	198	0.132	104.9
BYOT (Bring Your Own Thermostat)	Residential	400	100%				240	0.600	240.0
SmartDLC - Wifi DR/DLC Changeout	Residential	1,000	100%	198,000	198	198,000	1,015	1.015	1,014.5
Community Based - LED Lighting	Residential	50,496	100%	1,550,227	31	1,550,227	202	0.004	202.0
Commercial & Industrial Prescriptive	Commercial	40,179	75%	13,500,000	336	10,125,000	3,612	0.090	2,709.0
Commercial & Industrial Custom	Commercial	44	96%	3,500,000	79,545	3,360,000	450	10.227	432.0
Small Business Direct Install	Commercial	78	86%	3,500,000	44,872	3,010,000	259	3.321	222.7
Portfolio Total		384,751	81%	43,837,912	114	35,624,309	9,167	0.024	7,358.7

Figure 11.333 – 2020 Electric DSM Filed Plan Program Savings

Program	Residential/ Commercial	Participants	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross kW/ Participant	Net KW
Residential Lighting	Residential	163,416	67%	6,075,005	37	4,070,253	791	0.005	530.0
Residential Prescriptive	Residential	6,595	52%	1,979,280	300	1,029,226	1,910	0.290	993.3
Residential New Construction	Residential	139	50%	187,038	1,346	93,519	118	0.849	59.0
Home Energy Assessments	Residential	1,210	98%	863,991	714	846,711	192	0.159	188.2
Income Qualified Weatherization	Residential	525	100%	1,130,945	2,154	1,130,945	540	1.029	540.2
Energy Efficient Schools	Residential	2,600	100%	645,216	248	645,216	53	0.020	52.8
Residential Behavioral Savings	Residential	35,298	100%	5,600,000	159	5,600,000	1,153	0.033	1,153.0
Appliance Recycling	Residential	920	54%	884,915	962	477,854	117	0.127	63.1
Conservation Voltage Reduction	Residential	5,324	100%	1,461,047	274	1,461,047	263	0.049	263.1
BYOT (Bring Your Own Thermostat)	Residential	400	100%				240	0.600	240.0
SmartDLC - Wifi DR/DLC Changeout	Residential	1,000	100%	466,690	467	466,690	600	0.600	600.0
Community Based - LED Lighting	Residential								
Commercial & Industrial Prescriptive	Commercial	6,856	87%	5,002,621	730	4,352,280	369	0.054	321.0
Commercial & Industrial Custom	Commercial	93	100%	7,002,080	75,291	7,002,080	633	6.806	633.0
Small Business Direct Install	Commercial	131	95%	4,016,159	30,658	3,821,144	585	4.466	556.7
Conservation Voltage Reduction	Commercial	558	100%	1,032,655	1,851	1,032,655	186	0.333	185.9
Portfolio Total		225,065	88%	36,347,642	161	32,029,620	7,750	0.034	6,379.2

11.3.5 Avoided Costs

The avoided power capacity costs are reflective of the estimated replacement capital and fixed operations and maintenance (O&M) cost. For this avoided cost analysis, a 236 MW 1x F-class simple cycle gas turbine was used as the comparison due to the low capital and fixed O&M costs. The operating and capital costs are assumed to escalate with inflation throughout the study period. Transmission and distribution capacity are accounted for within the transmission and distribution avoided cost.

The marginal operating energy costs were based off the modeled Vectren system marginal energy cost from the base optimized scenario under base assumptions. This included emission cost for CO_2 starting in 2027, estimated capital, variable operation and maintenance and fuel costs. The marginal system cost reflects the modeled spinning reserve requirement and adjusted sales forecasts accounting for transmission and distribution losses.

The table below shows avoided costs when energy efficiency is selected through the IRP modeling process. As energy efficiency competes against other supply side resources and is selected, then the cost of a 236 MW 1x F-class simple cycle gas turbine is avoided.

Figure 11.34 – Avoided Costs

Year	Avoided Capital/O&M Cost $/kW*	Transmission & Distribution Avoided Capital Cost $/kW	Total Capacity Avoided Cost $/kW	Natural Gas Forecast $/MMBtu **	CO2 Forecast $/Ton	System Marginal Cost $/MWh***
2020	$148.60	$6.36	**$154.96**	$2.98	$0.00	$28.63
2021	$151.87	$6.43	**$158.30**	$3.16	$0.00	$30.06
2022	$155.21	$6.55	**$161.76**	$3.37	$0.00	$34.99
2023	$158.63	$6.73	**$165.35**	$3.63	$0.00	$35.77
2024	$162.12	$6.71	**$168.82**	$3.83	$0.00	$36.81
2025	$165.68	$6.83	**$172.51**	$4.00	$0.00	$38.82
2026	$169.33	$6.99	**$176.31**	$4.19	$0.00	$39.80
2027	$173.05	$7.15	**$180.20**	$4.35	$4.34	$44.04
2028	$176.86	$7.32	**$184.18**	$4.52	$5.07	$46.36
2029	$180.75	$7.50	**$188.25**	$4.68	$6.48	$48.37
2030	$184.73	$7.63	**$192.36**	$4.87	$7.95	$50.18
2031	$188.79	$7.81	**$196.60**	$5.06	$8.80	$51.76
2032	$192.94	$7.98	**$200.93**	$5.27	$9.68	$52.59
2033	$197.19	$8.16	**$205.35**	$5.51	$10.60	$54.94
2034	$201.53	$8.34	**$209.87**	$5.73	$11.56	$56.60

Year	Avoided Capital/O&M Cost $/kW*	Transmission & Distribution Avoided Capital Cost $/kW	Total Capacity Avoided Cost $/kW	Natural Gas Forecast $/MMBtu **	CO2 Forecast $/Ton	System Marginal Cost $/MWh***
2035	$205.96	$8.52	**$214.48**	$6.02	$13.29	$59.93
2036	$210.49	$8.71	**$219.20**	$6.23	$15.09	$61.52
2037	$215.12	$8.90	**$224.02**	$6.48	$16.97	$64.69
2038	$219.86	$9.10	**$228.95**	$6.70	$19.71	$69.00
2039	$224.69	$9.30	**$233.99**	$6.90	$23.36	$72.04

***Transmission costs derived from switchyard upgrade on brownfield A.B. Brown site**

***Distribution costs derived from average investment per lot**

****Assumes average of winter/summer delivered to S. Indiana**

*****Based on Vectren Reference Case (Around-the-Clock prices shown)**

11.3.6 Estimated Impact on Historical and Forecasted Peak Demand and Energy

11.4 RESOURCE OPTIONS APPENDIX

11.4.1 Existing Resource Studies

11.4.1.1 Existing Brown Scrubber Assessment

Both A.B. Brown units are scrubbed for sulfur dioxide (SO2) emissions, utilizing a dual-alkali flue gas desulfurization (FGD) process. The FGD systems were included as part of the original unit design and construction. A.B. Brown Unit 1 FGD has reached 40 years of service life and Unit 2 FGD has reached 33 years of service life as of 2019. The operating life of these scrubbers has been impacted by a combination of the acidic and caustic dual-alkali conditions, which are both very damaging to structural steel and concrete. Continual maintenance and repairs have been completed throughout the many years of service. Despite these continuous repair and maintenance efforts, many steel elements and foundations exhibit severe corrosion. Structural assessment studies have been completed by a local engineering firm, Three i Design. Major replacements and repairs have been identified to further the existing FGD operation another 10 years to

2029. Three i Design provided costs for upgrading and refurbishing the existing FGD system to extend the life through the 10-year period.

11.4.1.2 Replacement Scrubber Options at Brown

New replacement FGD technologies at A.B. Brown, identified in Table 10-1 have been evaluated for availability and applicability. Technically feasible options that are both available and applicable to A.B. Brown had high level AACE Class 5 installation cost estimates developed.

Table 10-1 Identify Available and Applicable Technologies

Technology Alternative	Technically Feasible (Yes/No)	
	Available	Applicable
Wet FGD		
Limestone Conversion of Existing Dual-Alkali FGD - Forced Oxidation (DA-LSFO)	Yes	No –Existing equipment capacity inadequate for conversion. New technology required to meet emissions criteria.
Limestone Conversion of Existing Dual-Alkali FGD - Inhibited Oxidation (DA-LSIO)	Yes	No –Existing equipment capacity inadequate for conversion. New technology required to meet emissions criteria.
Wet Limestone FGD - Forced Oxidation(1) (LSFO)	Yes	Yes – New installations are capable of meeting performance standards.
Wet Lime FGD - Inhibited Oxidation (1) (WLIO)	Yes	Yes– New installations are capable of meeting performance standards.
Spray Dryer Absorber (SDA)	Yes	No – SDA has limited SO_2 removal efficiency over the project range of fuels, which are higher sulfur contents.
Circulating Dry Scrubber (CDS) or Turbosorp	Yes	Yes – Installations comparable in size are in operation. However, no full-scale operational experience is available in the United States over the high sulfur range of the coals used at A.B. Brown.
Flash Dryer Absorber (FDA)	Yes	No – FDA has limited SO_2 removal efficiency over the high range of sulfur in the fuels.

Technology Alternative	Technically Feasible (Yes/No)	
	Available	Applicable
Ammonia Scrubber (NH_3)	Yes	Yes – However, only one small US industrial application in operation and current interest limited to one Chinese supplier with no US experience.
Powerspan ECO Process	No	No – Only pilot size experience
(1) Alternate absorber designs in wet lime or limestone FGD (spray tower, double contact spray tower, trays, etc.) are equal for comparison purposes.		

Analysis was inclusive of FGD options necessary to keep the A.B. Brown Units 1 and 2 in compliance with current SO2 emissions limits and maintaining compliance with existing Hg and H2SO4 emissions requirements. Based on these requirements the DA-LSIO and DA-LSFO conversion options will not meet emissions performance criteria. High level capital installation estimates were developed by Black & Veatch for the Wet Lime FGD Inhibited Oxidation (WLIO), Circulating Dry Scrubber (CDS) and Ammonia Scrubber (NH3). Burns & McDonnell developed an estimate for the Wet Limestone FGD Forced Oxidation (LSFO), building on their previous experience with this technology assessment at A.B. Brown. Capital and O&M estimates for these remaining four technologies were evaluated by PACE Global screening using analysis consistent with the IRP evaluation Reference Case. The least cost option was selected and included in the BAU portfolio. Note that there are risks such as byproduct market availability, byproduct disposal requirements and reagent supply availability. These risks were qualitatively assessed independent of the screening analysis.

For the BAU to 2039 portfolio, an analysis of the most economic FGD scrubber option was conducted. Each of the four scrubber technologies was evaluated in the Aurora model with identical model runs except for the difference of the scrubber technology costs and performance metrics. The analysis demonstrated that the DA-LSIO was the least cost FGD scrubber technology among the four options. The DS-LSFO option was shown to increase portfolio costs by 1.51% all other things being equal, the NH3 option was shown to be 1.66% more costly and the CDS option was shown to be 2.95% more costly.

Accordingly, the DA-LSIO option was selected for modeling purposes in the BAU to 2039 portfolio.

11.4.1.3 Coal to Gas Conversion

The conversion of A.B. Brown Unit 1 and 2 existing coal fired boilers to burn natural gas instead of coal was studied. Conceptual design studies were developed by engineering firms and OEM suppliers to determine natural gas conversion MW output, heat rate performance, emissions and balance of plant equipment. Engineering and construction estimates were developed to determine high level AACE Class 4 installation costs. The converted plant is expected to be operated as a peaking facility on 100% natural gas. Daily on/off cycling of the plant may be required. These units were originally designed as base load coal units. The boiler metallurgy and turbine were not designed for cycling operation. The impacts of cycling will require increased maintenance of this equipment compared to previous coal operations. Startup durations remain the same as coal fired operations continuing to limit the response time in a cycling environment. Natural gas conversion of the units reduces boiler efficiency compared to the coal fired design and increase net plant heat rate.

11.4.1.4 ACE Rule Compliance

The Affordable Clean Energy (ACE) rule, finalized by the United States Environmental Protection Agency (EPA) June 19, 2019, establishes new standards for reducing greenhouse gas emissions for coal fired electric utility generating units. ACE details specific heat rate improvement techniques, called Best System of Emission Reduction (BSER), that are meant to be the best technology options or other measures that have been known to reduce plant heat rate.

The specific candidate technology options are as follows:

- 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 Upgrades.
- Equipment & facilities improvements to enhance operations and maintenance (O&M) practices.

The potential alternatives for improvements at the four coal fired units A.B. Brown Units 1 & 2 and F.B. Culley Units 2 & 3 were assessed to meet the goals of the ACE rule. Applicability of candidate technologies for the four existing coal fired units is found in the "ACE Heat Rate Improvement Study" located in technical appendix 6.8. The characteristics of the four plants were reviewed and each plant was examined according to applicable BSER alternatives. Estimates of heat rate improvement, annual carbon dioxide reduction, O&M and a rough order of magnitude capital cost estimate were developed for each applicable alternative.

11.4.2 Approximate Net and Gross Dependable Generating Capacity

Figure 11.35 – Approximate Net and Gross Dependable Generating Capacity

	Gross Dependable Capacity (MW)	Net Dependable Capacity (MW)
A.B. Brown 1	265	245
A.B. Brown 2	265	245
A.B. Brown 3	74	74
A.B. Brown 4	74	74
F.B. Culley 2	100	90
F.B. Culley 3	287	270
Warrick 4	162	150

11.4.3 New Construction Alternatives

Figure 11.36 – New Construction Alternatives

Technology	Fuel	Capacity (kW)
Biomass	Biomass	50,000
Energy Efficiency Bins 1-7 (2021-23)	Energy Efficiency	Varies
Energy Efficiency Bins 1-7 (2024-26)	Energy Efficiency	Varies
Energy Efficiency Bins 1-7 (2027-39)	Energy Efficiency	Varies
Hydroelectric	Hydro	50,000
Landfill Gas	Landfill Gas	4,500
F-Class CT	Natural Gas	236,635
E-Class CT	Natural Gas	84,721
GH-Class CT	Natural Gas	279,319
F-Class CCGT	Natural Gas	442,400
GH-Class CCGT	Natural Gas	510,700
Generic Solar PV	Solar	10,000
Generic Solar PV	Solar	50,000
Generic Solar PV	Solar	100,000
12to15 Year Solar PPA	Solar	112,500
20 Year Solar PPA	Solar	200,000
20 Year Solar PPA	Solar	165,460
25to30 Year Solar PPA	Solar	137,500
Li-Ion Battery Storage (4 hour)	Storage	10,000
Li-Ion Battery Storage (4 hour)	Storage	50,000
Flow Battery Storage (6 hour)	Storage	10,000
Flow Battery Storage (6 hour)	Storage	50,000
Flow Battery Storage (8 hour)	Storage	10,000
Flow Battery Storage (8 hour)	Storage	50,000
Li-Ion Battery Storage (paired with Generic Solar PV) (4 hour)	Storage	10,000
Li-Ion Battery Storage (paired with Generic Wind) (4 hour)	Storage	10,000
Annual MISO Capacity Market Purchase	Capacity	Up to 180,000
Li-Ion Battery Storage PPA (4 hour)	Storage	76,200
Solar PV (paired with Storage) PPA	Solar	133,333
Li-Ion Battery Storage (paired with Solar) PPA (4 hour)	Storage	42,000
Demand Response Bin 1 (2021-23)	Storage	Varies

Technology	Fuel	Capacity (kW)
Demand Response Bin 2 (2024-26)	Storage	Varies
Demand Response Bin 3 (2027-39)	Storage	Varies
Generic Wind	Wind	200,000
Generic Wind	Wind	50,000
12to15 Year Wind PPA	Wind	200,000
20 Year Wind PPA	Wind	300,000

11.5 RISK APPENDIX

Probabilistic modeling incorporates five key market variables and probability distributions into the analysis, allowing for the evaluation of a portfolio's performance over a wide range of future market conditions. Quantitative data are extracted from the results and is the foundation for the balanced scorecard. Probabilistic modeling begins with the development of 200 sets of future pathways for coal prices, natural gas prices, carbon prices, peak and average load (for Vectren, MISO Local Resource Zone 6 and all of MISO) and capital costs for a range of technologies. Each of these stochastic variables is propagated to the end of the study period, typically 1,000 to 3,000 times. A stratified sampling of the runs is taken, which allows the sample set to be reduced to 200 iterations. The 200 iterations of each stochastic variable are then inputted into the Aurora model. This allows for the testing of each candidate portfolio's performance across a wide range of market conditions.

All portfolios were subjected to each of the 200 iterations (scenarios) using the dispatch module in the Aurora model where the Vectren portfolios are fixed but other market participants can make decisions under each market scenario. The entire Eastern Interconnection except FRCC and ISO-NE was run stochastically in each scenario. The risk analysis (based on the probabilistic modeling) of each of the portfolios was developed by Pace Global using the Aurora model. There were several steps to this process:

- The first step was to develop the input distributions for each of the major market and regulatory drivers, including average and peak load growth and shape, natural gas prices, coal prices, carbon prices and technology capital costs. This was done by considering volatility of each factor in the short-term, medium-term and long-term.

- The second step was to run a probabilistic model (Monte Carlo) which selected 200 possible future states over the 20-year study planning period. This also formed the basis for the scenario inputs development.
- Each candidate portfolio was then run through simulated dispatch for the 200 possible future states using the Aurora production cost model. Aurora dispatches the candidate portfolio for each sampled hour over the planning horizon. For this risk analysis procedure, Aurora assumes that each candidate portfolio is constant but allows for builds and retirements to occur throughout the region based on economic criteria. Vectren generation, costs, emissions, revenues, etc. are tracked for each iteration over time.
- Next, values for each metric are tracked across all 200 iterations and presented as a distribution with a mean, standard deviation and other metrics as needed.
- These measures are used as the basis for evaluation in the risk analysis.

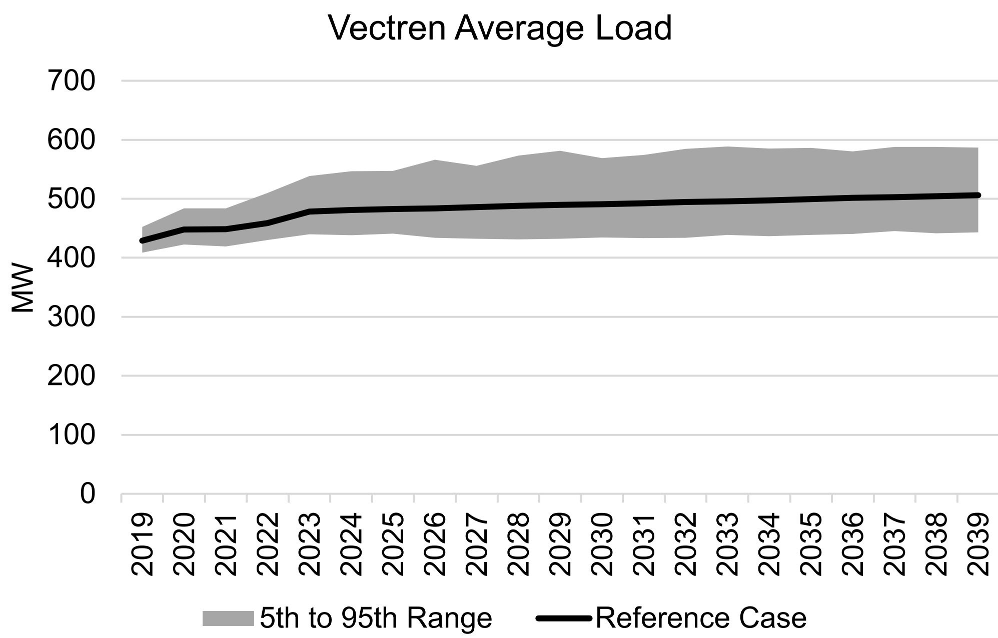
11.6 Stochastic Distributions

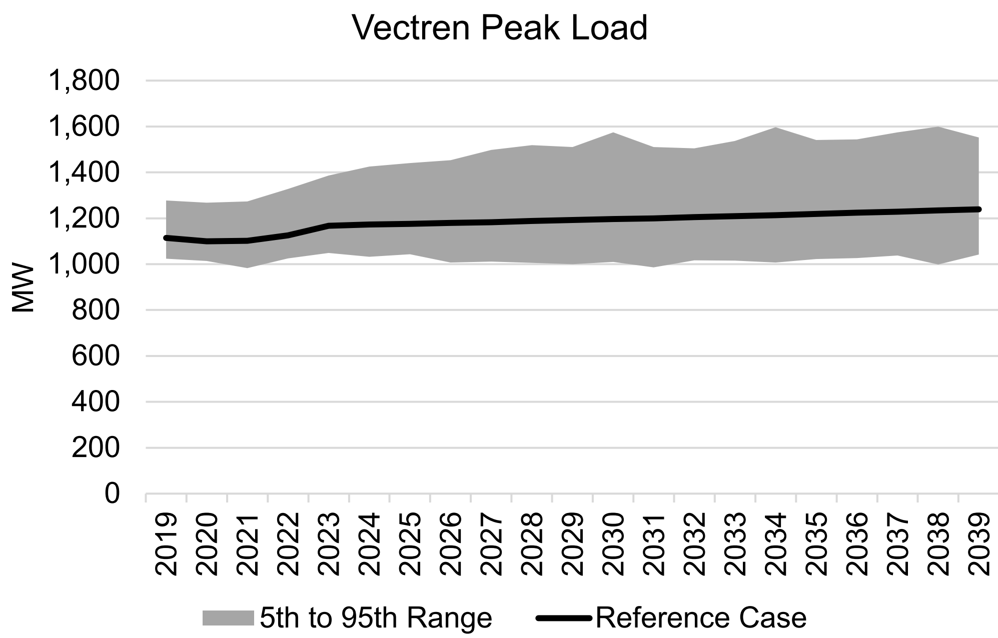
In order to perform the probabilistic modeling (stochastics), a set of probability distributions was required for each of the key market driver variables described above (fuel, emissions, load and capital costs). These probability distributions were developed from a simulation that creates 200 future paths for each stochastic variable. The following sections describe the methodologies for developing these stochastic variables.

11.6.1 Load Stochastics

To account for electricity demand variability that derives from economic growth, weather, energy efficiency and demand side management measures, Pace Global developed stochastics around the average and peak load growth expectations for the Vectren control area and the neighboring ISO zones, including MISO, PJM and utilities not served by an ISO in SERC. Pace Global benchmarked the MISO-wide projections against MISO-sponsored load forecasting studies that are conducted by independent consultants, institutions and market monitors and then released into the public domain. In addition, solar distributed generation (a decrement to Vectren load) and electric vehicles demand (an increment to Vectren load) were developed independently and incorporated into the Vectren load stochastics.

Exhibit 1: Vectren Load Distribution (Megawatts)



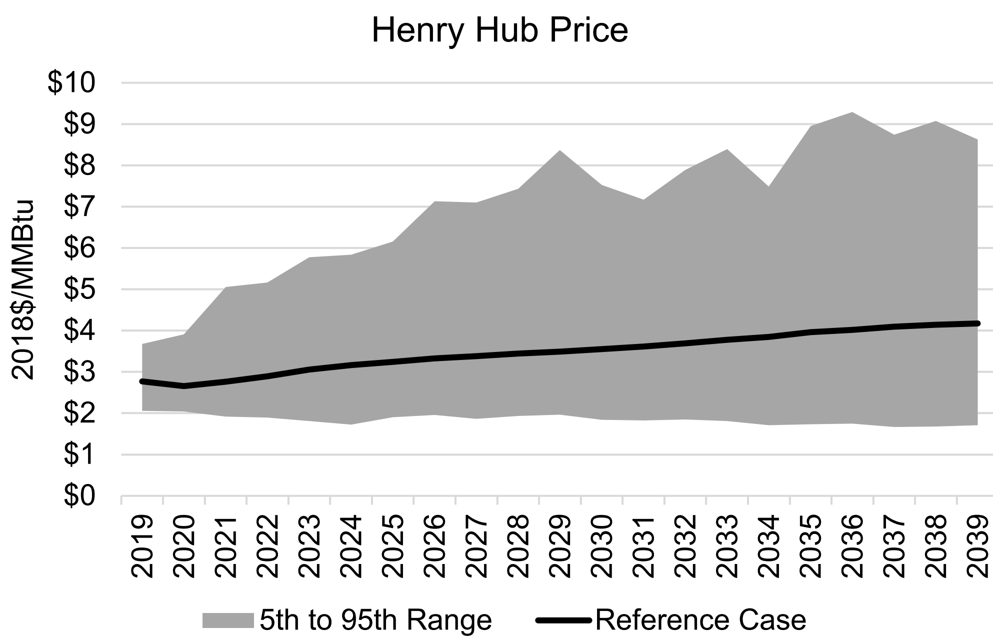


Source: Pace Global

11.6.2 Natural Gas Price Stochastics

Pace Global developed natural gas price stochastic distributions for the benchmark Henry Hub market point. These stochastic distributions are first based on the consensus Reference Case view of natural gas prices with probability bands developed then based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility. For the period 2019-2022, volatility calculated from the past three years of price data is used. For 2023-2025, volatility calculated from the past five years is used. For 2026-2039, volatility calculated from the past 10 years is used. This allows gas price volatility to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility. The 95th percentile probability bands are driven by increased gas demand (e.g., coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization relatively low as well as few to no new environmental regulation around power plant emissions.

Exhibit 2: Natural Gas (Henry Hub) Price Distribution (2018$/MMBtu)

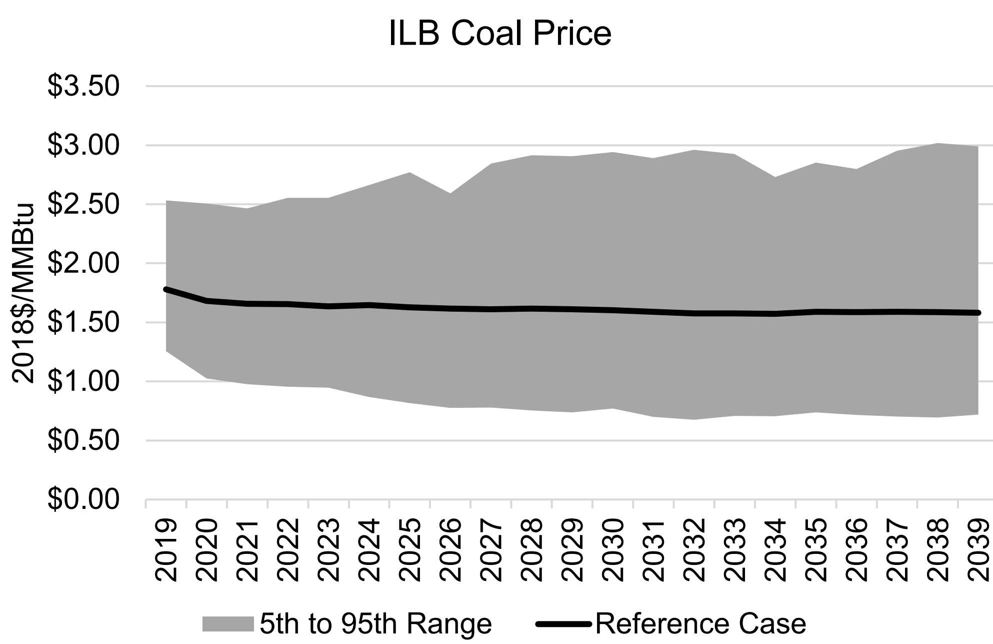


Source: Pace Global

11.6.3 Coal Price Stochastics

Pace Global developed coal price stochastic distributions for the CAPP, NAPP, ILB and PRB basins. These stochastic distributions are first based on the consensus Reference Case view of coal prices with probability bands developed, then based on a combination of historical volatility and mean reversion parameters. It should be noted that most coal contracts in the U.S. are bilateral and only approximately 20% are traded on the New York Mercantile Exchange (NYMEX). The historical data set that is used to calculate the parameters is comprised of the weekly traded data reported in NYMEX.

Exhibit 3: Coal Price Distribution (2018$/MMBtu)

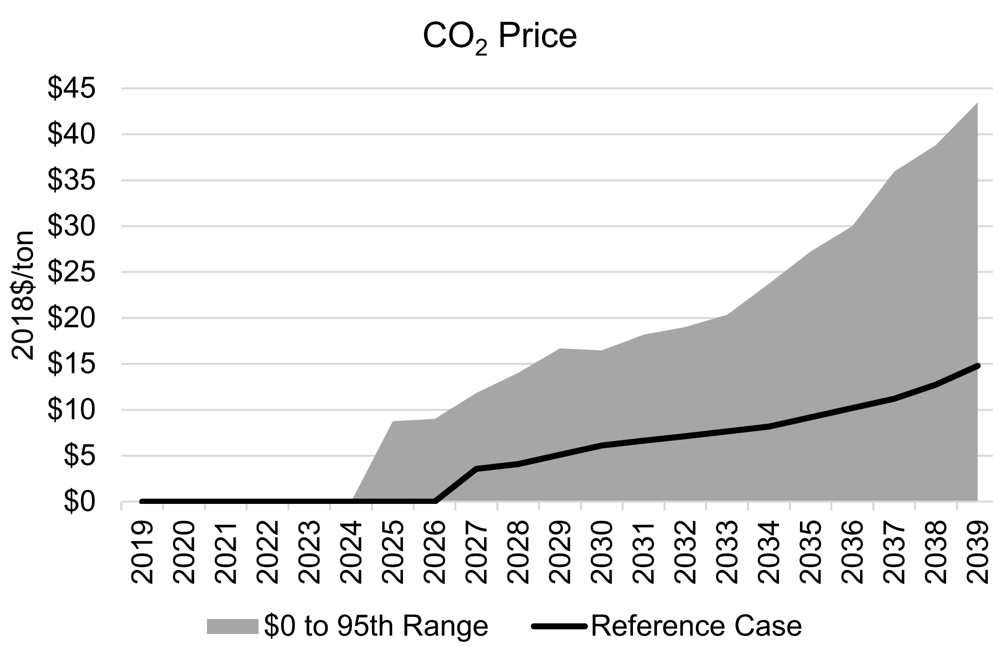


Source: Pace Global

11.6.4 CO_2 Emissions Price Stochastics

Pace Global developed uncertainty distributions around carbon compliance costs, which were used in Aurora to capture the inherent risk associated with regulatory compliance requirements. The technique to develop carbon costs distributions, unlike the previous variables, is based on projections largely derived from expert judgment, as there are no national historical data sets (only regional markets in California and the northeast U.S.) to estimate the parameters for developing carbon costs distributions. The consensus Reference Case CO_2 price outlook reflects a view that some type of legislation will likely occur in the mid-2020s to provide incentives for faster shifts from fossil to renewable generation. Previous studies of a proposed trading mechanism showed prices rising to about $15/ton. The bottom end of the distribution assumes no future regulation. The top end reflects the social cost of a carbon emission program. Two portfolios (HB 763 and High Regulatory) were optimized using CO_2 prices that exceeded the 95th percentile shown below.

Exhibit 4: CO_2 Price Distribution (2018$/ton)



Source: Pace Global

11.6.5 Capital Cost Stochastics

Pace Global developed the uncertainty distributions for the cost of new entry units by technology type, which was used in Aurora for determining the economic new builds based on market signals. These technologies included gas peaking units, gas combined cycles units, solar, wind and battery storage resources. The methodology of developing the capital cost distributions is a two-step process: (1) a parametric distribution based on a consensus Reference Case view of future all-in capital costs, historical costs and volatilities and a sampling of results to develop probability bands around the consensus Reference Case; and (2) a quantum distribution that captures the additional uncertainty with each technology that factors in learning curve effects, improvements in technology over time and other uncertain events such as leaps in technological innovation.

Exhibit 5: Solar Capital Costs Distribution (2018$/kW)

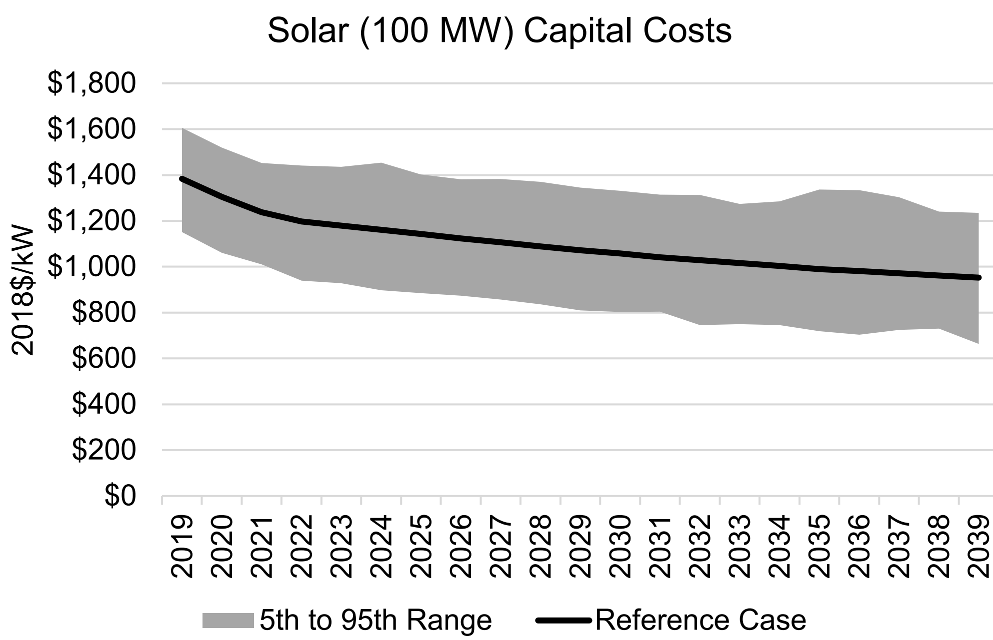
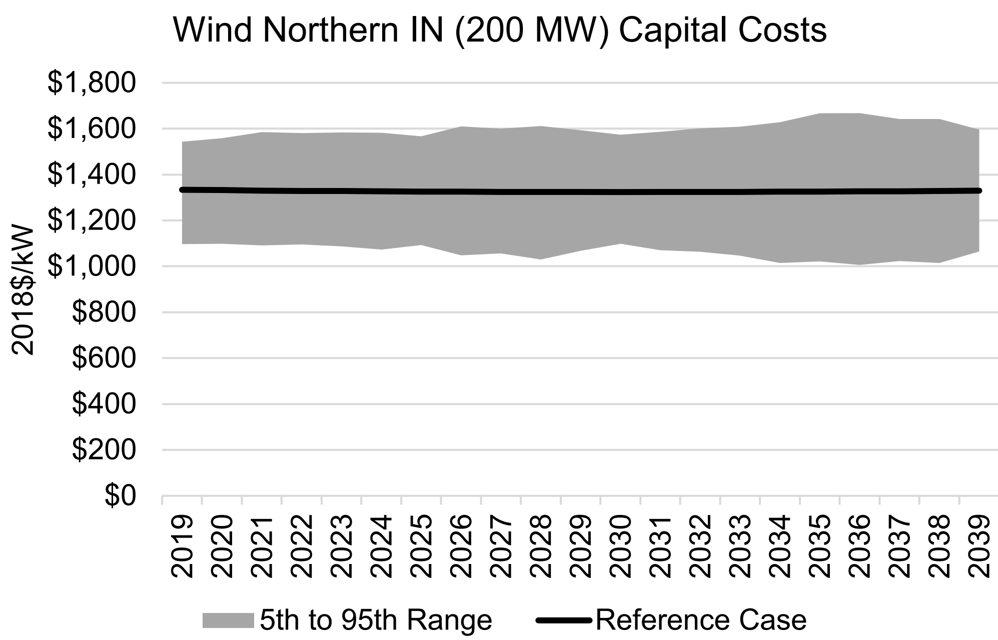


Exhibit 6: Wind Capital Costs Distribution (2018$/kW)



Source: Pace Global

Exhibit 7: Battery Storage Capital Costs Distribution (2018$/kW)

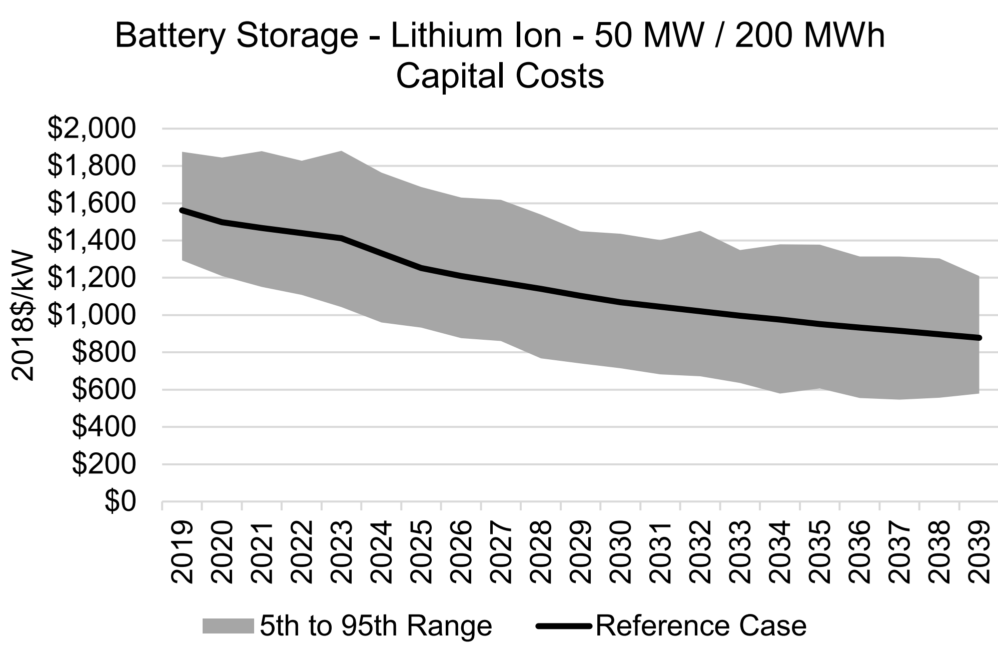
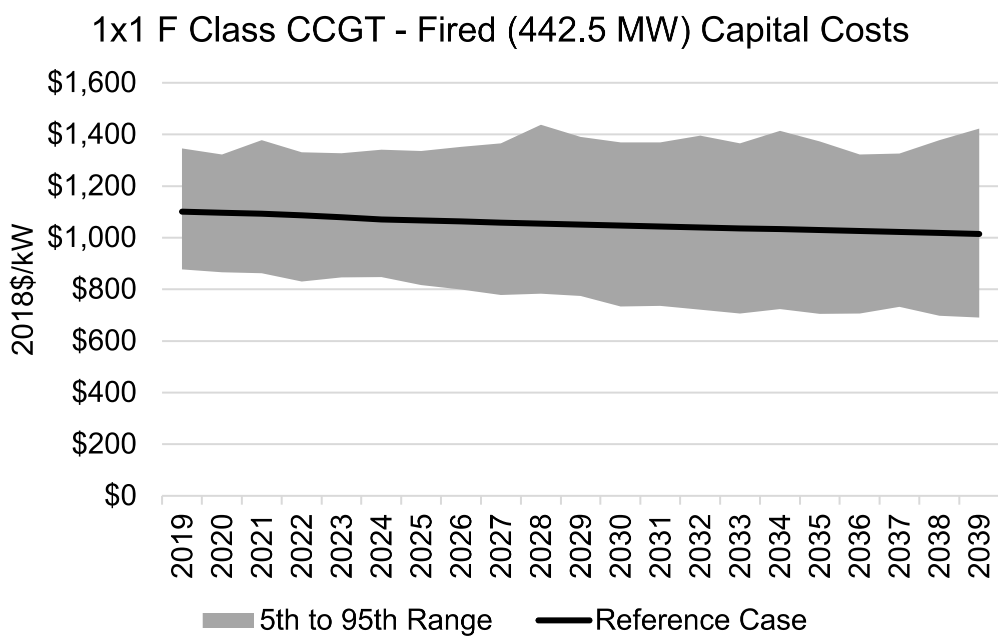
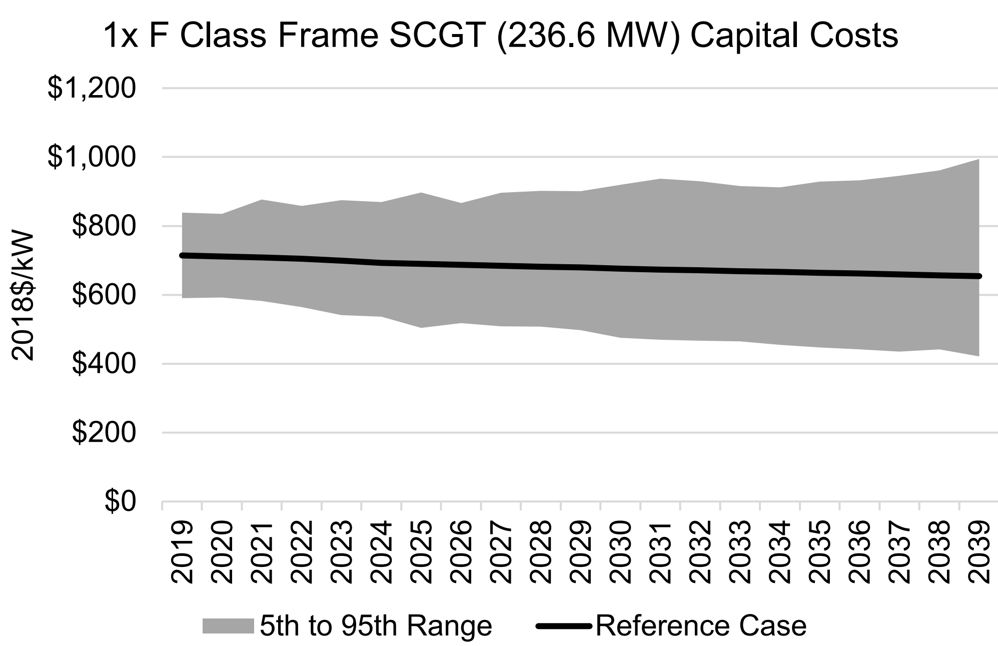


Exhibit 8: Advanced Combined Cycle Capital Costs Distribution (2018$/kW)



Source: Pace Global

Exhibit 9: Advanced Combustion Turbine Capital Costs Distribution (2018$/kW)



Source: Pace Global

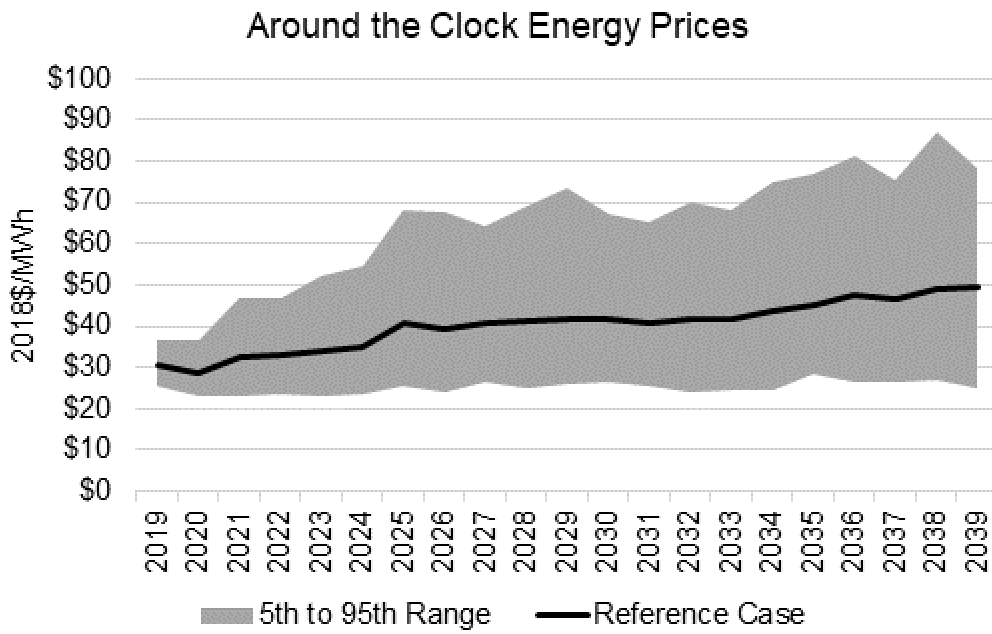
11.6.6 Cross-Commodity Stochastics

Pace Global captured the cross-commodity correlations in the stochastic process, which is a separate stochastic process from those for gas, coal and CO_2 prices. The feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators. Pace Global conducted a fundamental analysis to define the relationship between gas and coal dispatch costs and demand. The dispatch costs of gas and coal were calculated from the gas and coal stochastics and CO_2 stochastics, along with generic assumptions for variable operation and maintenance costs. Where the gas-coal dispatch differential changes significantly enough to affect demand, gas demand from the previous year was adjusted to reflect the corresponding change in demand. A gas price delta was then calculated based on the defined gas demand. This gas price delta was then added to the gas stochastic path developed from historic volatility to calculate an integrated set of CO_2 and natural gas stochastic price forecasts.

11.6.7 Energy Price Distribution

Pace Global produces a stochastic distribution of energy prices as a result of running the input distributions through Aurora (200 times). Aurora not only determines the build decisions for the region but also the resulting prices. The exhibit below displays these prices.

Exhibit 1: Stochastic Inputs – Energy Prices – Market Forecast



11.6.8 Affordability Ranking

Figure 11.37 – Probabilistic 20-Year Mean NPV $ Billion

Portfolio	20 Year NPV[49]	% above lowest cost
Renewables + Flexible Gas	$2,526	99.6%
Reference Case	$2,536	100.0%
High Technology (Preferred Portfolio)	$2,590	102.2%
All Renewables by 2030	$2,613	103.0%
Bridge ABB1 Conversion	$2,675	105.5%
Diverse Small CCGT	$2,680	105.7%
Business as Usual to 2029	$2,689	106.0%
ABB1+ABB2 Conversions	$2,834	111.8%
ABB1 Conversion + CCGT	$2,872	113.3%
Business as Usual to 2039	$2,912	114.8%

[49] The NPV of energy procurement is an indicative component of rates

11.7 TRANSMISSION APPENDIX

11.7.1 Transmission and Distribution Planning Criteria

Vectren continually assesses the performance of its electric transmission and distribution systems to ensure safe and reliable service for its customers. The primary goals of Vectren's planning process can be summarized as follows:

a) Developing a transmission system capable of delivering voltage of constant magnitude, duration and frequency at levels which meet Vectren customers' needs during normal conditions and during a system contingency or set of contingencies;
b) Minimizing thermal loadings on transmission facilities to be within operating limits during normal conditions and to be within emergency limits during contingency conditions;
c) Analyzing the dynamic stability of the transmission system under various contingency conditions;
d) Ensuring the fault current duty imposed on circuit breakers does not exceed the interrupting capability established by the equipment manufacturer;
e) Optimizing the system configuration such that costs (capital and operating) are minimized while maintaining reliability and providing a plan for system upgrades to meet performance requirements;
f) Coordinating transmission planning activities in broader regional evaluations with the Midcontinent Independent System Operator (MISO), ReliabilityFirst (RF) and neighboring transmission owners;
g) Performing an annual assessment of the electric transmission system over a ten-year planning horizon;
h) Performing analysis of reactive power resources to ensure adequate reserves exist and are available to meet system performance criteria;
i) Analyzing the performance of its distribution system to ensure reliability, adequacy to meet future load growth and to address age and condition of existing facilities; and

j) Ensuring compliance with Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC) and RF Reliability Standards for transmission planning.

11.7.2 MISO Regional Transmission Planning

The Midcontinent Independent System Operator (MISO) performs the North American Electric Reliability Corporation (NERC) functional role of Planning Coordinator on behalf of Vectren. In its NERC functional role of Transmission Planner, Vectren supports MISO's regional transmission planning processes.

MISO develops regional transmission models that are used for a variety of near-term and long-term planning studies. On an annual basis, MISO builds models to represent a 10-year planning horizon. The modeling process begins in September and concludes the following August. Vectren is responsible for submitting the required modeling data to MISO pursuant to NERC MOD-032.

Vectren participates in MISO coordinated seasonal transmission assessments (CSAs) for spring, summer, fall and winter peak loads as applicable. MISO's Seasonal Assessments review projected demand and resources for the MISO footprint and assess adequacies and risks for upcoming seasons. The CSAs consider planned and unplanned generation and transmission outages. Vectren also participates in MISO Generator Interconnection and Transmission Service Requests planning processes as required.

Vectren participates in MISO's regional Transmission Expansion Plan (MTEP). The system expansion plans produced through the MTEP process ensure the reliable operation of the transmission system, support achievement of state and federal energy policy requirements and enable a competitive electricity market to benefit all customers. The planning process, in conjunction with an inclusive, transparent stakeholder process, identifies and supports development of transmission infrastructure that is sufficiently robust to meet local and regional reliability standards, enables competition among wholesale capacity and energy suppliers in the MISO markets and allows for competition among transmission developers in the assignment of transmission projects.

MISO approved a 345kV Market Efficiency Project between Vectren's Duff substation and Big Rivers Electric Corporation's Coleman EHV substation during the MTEP 2015 planning cycle. The project is expected to be in-service by the beginning of 2021. Pursuant to FERC Order 1000, MISO solicited competitive bids to construct the 345kV line. Vectren partnered with PSEG in submitting a proposal to MISO to construct the line; however, the project was awarded to Republic Transmission, LLC. Vectren, as the incumbent transmission owner, will be responsible for the Duff substation modifications required for the project. The overall project cost is shared according to MISO's Tariff. The project not only provides regional economic benefits, but also enhances grid reliability in the area of Vectren's Newtonville substation.

11.7.3 Annual Transmission Assessment

Vectren's most recent transmission assessment was completed in 2019. The study used the final Multiregional Modeling Working Group (MMWG) 2018 Series Models, which includes the Vectren full detailed model. The MMWG is responsible for developing a library of solved power flow models and associated dynamics simulation models of the Eastern Interconnection. The models are used by the NERC Regions and their member systems in planning future performance and evaluating current operating conditions of the interconnected bulk electric systems. Siemens PTI PSS/E version 33.11 software was used to conduct the assessment.

Vectren's internal planning procedures direct the specific tasks and methods for conducting this study. The internal procedures also define the ratings methodology used for the existing and proposed facilities. All simulations were performed using Steady State Power Flow models using AC analysis. Models were solved using the Fixed Slope Decoupled Newton-Raphson (FDNS) solution method with stepping transformer tap adjustments, switched shunts enabled, area interchange control enabled for tie lines and loads, DC taps disabled and VAR limits applied automatically. Dynamic simulations were not completed in 2019, as previous dynamic studies were still deemed valid. Dynamic simulations were completed with MTEP-19.

The Vectren Bulk Electrical System (100kV and above) is expected to be stable and perform well over the next 10 years. Normal system conditions do not result in any voltage problems or thermally overloaded facilities. Some facility outage contingencies create thermal overloads and voltage violations. When these violations cannot be effectively mitigated by operational guides, Vectren plans projects to mitigate the violations.

The loss of the two 138kV lines into Toyota substation results in the loss of service to the facility. A new 138kV line from Toyota substation to Scott Township substation is proposed. This line will also provide a second line into Scott Township substation, which is on a radial 138kV line. Scott Township substation provides voltage support for most of the load along the Highway 41 North corridor. This proposed line will also become a parallel path to the Francisco to Elliott 138kV line and increases post-contingent import capability.

The only mentionable extreme contingency is for the complete loss of the A.B. Brown 138kV substation. This substation loss has the potential to cause voltage loss to the Mt. Vernon area and numerous large industrial customers. NERC requirements do not require that Vectren prevent this event. The standards only require that extreme contingencies not cause cascading outage and impair the Bulk Electric System (BES). The electric transmission system outside of Mt. Vernon is not affected; however, an outage of this magnitude would require a notification to NERC.

Several 69kV lines are proposed as alternate feeds to reduce outage times.

- A new 69kV line to be installed between Boonville and Boonville Pioneer Substation (scheduled in-service date of 12/31/2021).

- Extend an existing 69kV line to provide a third source into the Jasper area from Dubois substation (scheduled in-service date of 12/31/2024).

These are not NERC reliability driven projects, but should reduce outage durations to customers caused by transmission outages in these areas and should improve reliability indices and metrics.

Toyota South and Tepe Park are new distribution substations recently installed to meet load growth. The Tepe Park substation project also facilitates 4kV to 12kV conversion projects.

SECTION 12
TECHNICAL APPENDIX ATTACHMENTS

Attachment 1.1 Non-Technical Summary

Attachment 1.2 Vectren Technology Assessment Summary Table

Attachment 3.1 Stakeholder Materials

Attachment 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report

Attachment 4.2 Vectren Hourly System Load Data

Attachment 4.3 2019 MISO LOLE Study Report

Attachment 6.1 Vectren Electric 2018-2020 DSM Plan

Attachment 6.2 2019 DSM Market Potential Study

Attachment 6.3 All-Source RFP

Confidential Attachment 6.4 1x1 CCGT Study

Attachment 6.5 Coal to Gas Conversion Study

Attachment 6.6 Brown Scrubber Assessment Study

Attachment 6.7 Environmental Compliance Options Study

Attachment 6.8 ACE Rule Heat Rate Study

Attachment 8.1 Balance of Loads and Resources

Attachment 8.2 Confidential Aurora Input Model Files

Attachment 8.3 Aurora Output Model Files (submitted via DVD)

APPENDIX C
CLEAN ENERGY COST ADJUSTMENT[1]

APPLICABILITY

The Clean Energy Cost Adjustment (CECA) shall be applicable to all Rate Schedules as reflected in the CECA Rates section below.

DESCRIPTION

The CECA shall recover Clean Energy Investments, as approved by the Commission, as follows:

(1) Company's costs and expenses incurred during the construction and operation of clean energy projects pursuant to Ind. Code Ch. 8-1-8.8.

The CECA shall be calculated annually for each Rate Schedule as follows:

$$CECA = \frac{[(RR1 + RR2 + V) x \ Rate \ Schedule \ Allocation \ Percentage]}{Rate \ Schedule \ Sales \ Quantities}$$

Where:

RR1 is the Revenue Requirement on eligible Public Utility Property[2] Clean Energy Investments as follows:

(a) The Annualized Return on the Net Plant Balance of eligible Clean Energy Investments, inclusive of deferred Post In-Service Carrying Costs (PISCC); plus
(b) Incremental Depreciation Expense on in-service qualified CECA Investments; plus
(c) Incremental Operation & Maintenance expenses associated with Clean Energy Investments; plus
(d) Amortization of Deferred Operation & Maintenance expenses associated with Clean Energy Investments; plus
(e) Amortization of Deferred Depreciation Expense on in-service qualified CECA Investments; plus
(f) Amortization of Deferred PISCC on qualified CECA Investments; plus
(g) Associated Taxes including Property Taxes; less
(h) Investment Tax Credit (ITC) Amortization Credits; less
(i) Proceeds from the sale of Renewable Energy Credits associated with qualified Clean Energy Investments.

RR2 is the Revenue Requirement on eligible Non-Public Utility Property[3] Clean Energy Investments ("qualifying projects"), calculated as follows:

Effective:

[1] Currently pending before the Commission in CECA 3

[2] Public Utility Property – Under internal revenue code investment tax credit normalization rule definitions, a facility must meet three requirements to be considered public utility property. (1) It must be used predominantly in the trade or business of the furnishing or sale of inter alia, electric energy; (2) The rates for such furnishing or sale must be established or approved by a State or political subdivision thereof, any agency or instrumentality of the United States, or by a public service or public utility commission or similar body of any State or political subdivision thereof; and (3) The rates so established or approved must be determined on a rate-of return- basis.

[3] Non-Public Utility Property – Any property not meeting the definition of public utility property as outlined herein is non-public utility property.

APPENDIX C
CLEAN ENERGY COST ADJUSTMENT
(Continued)

(a) Approved levelized rate is multiplied by the approved production baseline for a qualifying project beginning on its in-service date.

(b) In the event that actual annual production from the qualifying project for a three-year period is less than 90% of the established annual production baseline (not the result of a force majeure event – e.g. and without limitation, tornado, lightning damage, fire, earthquake, acts of state or governmental action impeding performance), the Company shall credit the CECA in the next annual filing in the amount of the approved levelized rate multiplied by the difference between the rolling three-year period actual annual production and the established annual production baseline threshold at 90%.

In the event that actual annual production from a qualifying project for a rolling three-year period is greater than 110% of the production baseline for a rolling three year-period, the Company shall include as a recoverable cost in the CECA in the next annual filing the amount of the levelized rate multiplied by the difference between the rolling three-year period actual annual production and production baseline threshold at 110%.

V is the variance from the applicable prior period reconciliation, with any differences being reflected as a charge or credit in a subsequent CECA.

Rate Schedule Allocation Percentage is the proportion of the CECA applicable to each Rate Schedule. The percentage for each Rate Schedule is shown in the CECA Rates section below.

Rate Schedule Quantities are the estimated billing determinant quantities for each Rate Schedule for the projection period.

The calculated CECA rates shall be further modified to include the impact of the Indiana Utility Receipts Tax and other similar revenue-based tax charges.

CECA RATES

Rate Schedule	Modified 4CP Allocation Percentage[4]	Charge Adjusted	CECA Rate ($ per kWh)
RS	40.6160%	Energy	$0.002991
B	0.1307%	Energy	$0.001664
SGS	1.8234%	Energy	$0.002891
DGS/MLA	27.9043%	Energy	$0.002676
OSS	2.1556%	Energy	$0.002453
LP	24.6258%	Energy	$0.001215
BAMP	1.8495%	Energy	$0.001057
HLF	0.8947%	Energy	$0.000803

Effective:

[4] Pursuant to Cause No. 43354-MCRA 21 S1 Settlement Agreement.

Attachment MAR-3 (CONFIDENTIAL) provided separately

Attachment MAR-4 (CONFIDENTIAL) provided separately

Attachment MAR-5 (CONFIDENTIAL) provided separately