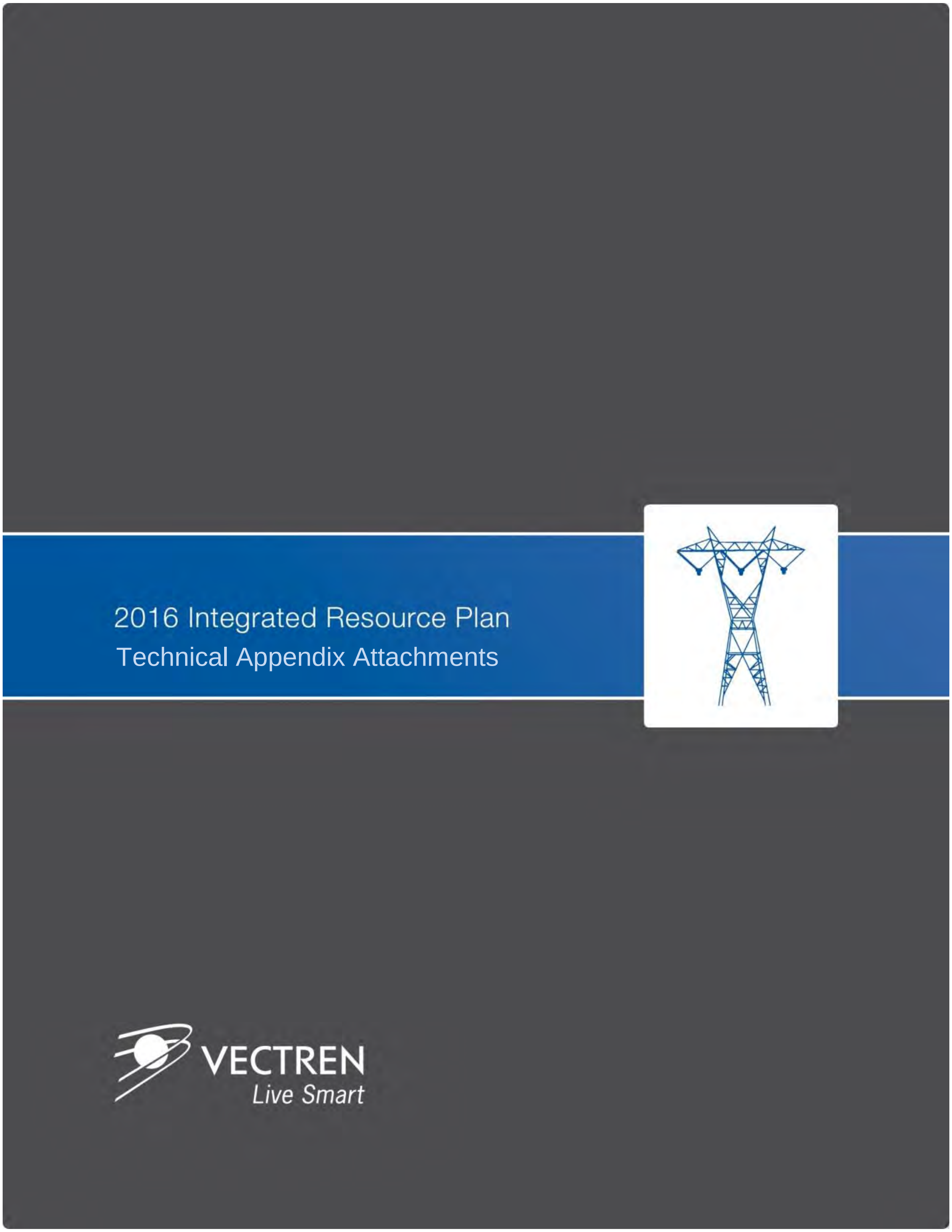

December 2016

VECTREN
Live Smart

Attachment 1.1 Non-Technical Summary

2016 Integrated Resource Plan

Non-Technical Summary

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I. Introduction

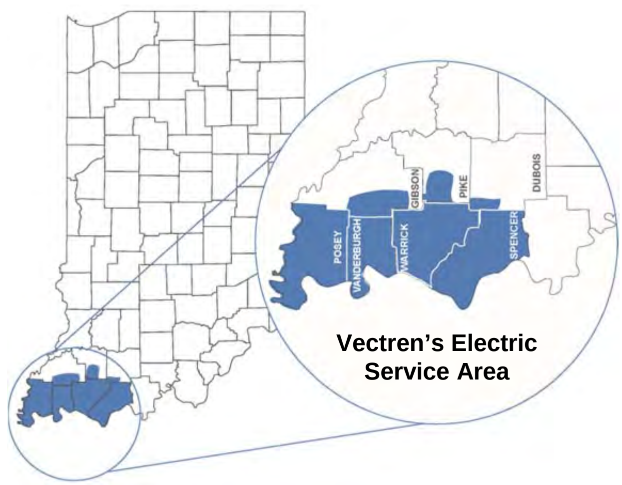
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren") engaged in a planning exercise during 2016 to evaluate its electric supply needs over a 20-year planning horizon. That exercise culminated in this 2016 Integrated Resource Plan ("IRP"). This planning exercise evaluated anticipated customer demand for electric supply in Vectren's electric service territory and identified resources to satisfy that demand. It included public meetings designed to solicit input from stakeholders about modeling assumptions. The evaluation then sought to use the inputs to estimate the total 20-year net present value cost, in 2016 dollars, of the various resource plan options to satisfy that demand. The analysis factored in the risk with heavy emphasis on evaluating the plan in the face of multiple possible future states. The future could bring various government regulations, varying fuel prices, varying resource costs, etc. This analysis was used to identify the portfolio of electric supply and demand side resources that best balances reliability, cost, risk, and sustainability.

Based on this planning process, Vectren has selected a preferred portfolio plan that balances the energy mix for its generation portfolio with the addition of a new combined cycle gas turbine facility and solar power plants and significantly reduces its reliance on coal-fired electric generation. Vectren's preferred portfolio reduces its cost of providing service to customers over the next 20 years by approximately $60 million as compared to continuing with its existing generation fleet. Additionally, the preferred portfolio reduces carbon dioxide output by approximately 46% by 2024 from 2012 levels, exceeding the Clean Power Plan (CPP) regulation, which requires a 32% reduction by 2030. When considering 2005 levels, this would be a reduction of almost 60%. Importantly, from a risk perspective, Vectren will continue to evaluate its preferred portfolio plan in future IRPs to ensure it remains the best option to meet customer needs.

What follows is a summary of the process Vectren engaged in 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 over 144,000 electric customers and approximately 110,000 gas customers located near Evansville in southwestern Indiana. In 2015, approximately 50% of electric sales were made to large (primarily industrial) customers, 26% were made to residential customers and 24% were made to small commercial customers.



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

Unit	Installed Capacity ICAP (MW)	Primary Fuel	Unit Age	Coal Unit Environmental Controls[1]
AB Brown 1	245	Coal	1979	Yes
AB Brown 2	245	Coal	1986	Yes
FB Culley 2	90	Coal	1966	Yes
FB Culley 3	270	Coal	1973	Yes
Warrick 4	150	Coal	1970	Yes
AB Brown 3	80	Gas	1991	
AB Brown 4	80	Gas	2002	
BAGS 2	65	Gas	1981	
Northeast 1&2	20	Gas	1963 / 1964	
Blackfoot[2]	3	Landfill Gas	2009	
Fowler Ridge	50	Wind PPA	2010	
Benton County	30	Wind PPA	2007	

[1] All coal units are controlled for Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_X), Particulate Matter (dust), and Mercury. All coal units are controlled for Sulfur Trioxide (SO_3) except FB Culley 2.
[2] The Blackfoot landfill gas generator is connected at the distribution level.

III. Integrated Resource Plan

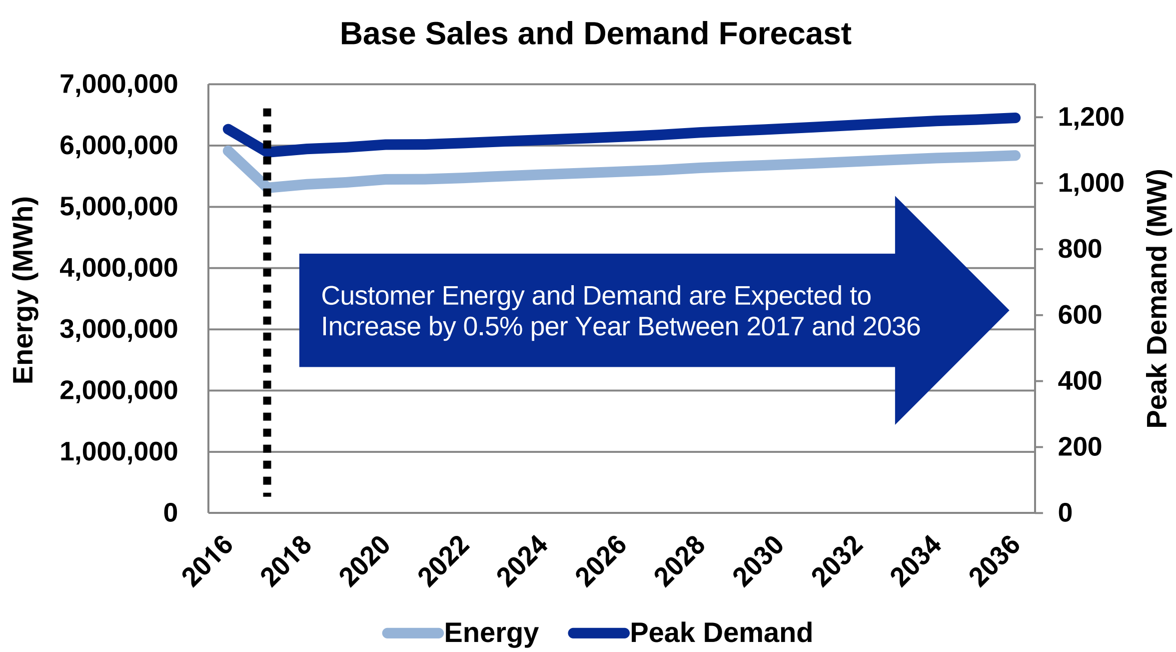
Vectren periodically submits IRPs to the Indiana Utility Regulatory Commission (IURC or Commission) as required by IURC rules. The IRP describes the analysis process used to determine the best mix of generation and energy efficiency resources (resource portfolio) to meet customers' needs for reliable, low cost, environmentally acceptable 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 finalize the detailed course.

Vectren considered input/perspectives from stakeholders, including but not limited to Vectren residential, commercial and industrial customers, regulators, elected officials, customer advocacy groups, environmental advocacy groups, and Vectren shareholders. Throughout the IRP analysis, Vectren placed an emphasis on reliability, customer cost, risk, and sustainability.

A. Customer Energy Needs

An 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. 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 help maintain 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 established reserve requirements.

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, and weather. In 2017, a large customer is expected to commence generating a large portion of its energy needs with its own generation, which will decrease Vectren's overall energy and demand forecast between 2016 and 2017. Beyond 2017, these forecasts, which do not include future energy company sponsored energy efficiency, indicate that overall customer energy and demand are expected to grow by 0.5% per year.



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, provided Vectren with detailed information on each of the generating resources, including but not limited to, capital costs, operating costs, operating characteristics, how much generation to expect under various conditions, plant emissions, etc. These costs provide a complete picture of the cost of various resource options over the entire 20-year period. Numerous costs impact supply resources, but the following that had a particularly significant impact on the IRP were EPA regulations, low natural gas prices, and renewable costs.

Energy Efficiency/Demand Response

Natural Gas, including CHP

Coal

Renewables, Wind & Solar

Battery Storage

Through investments in emissions control equipment over the past 15 years, Vectren's power system became one of the best controlled for emissions in the Midwest.

i. Environmental Protection Agency (EPA) Regulations

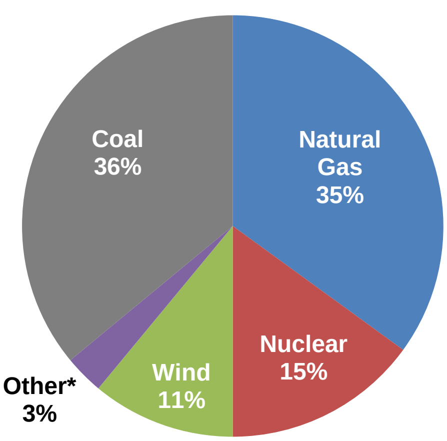
While Vectren's coal plants are controlled to meet or exceed current regulations for Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_x), mercury, and particulate matter (dust), new EPA regulations require Vectren, and other utilities around the country, to make incremental investments in coal-fired generation plants if they are to continue operating them. The EPA regulation adoption process begins with a notice of proposed rulemaking, accepts comments from the public, and then finalizes rules for announcement. The EPA issued final rules for Effluent Limitations Guidelines (ELG) in 2015 (regulates water discharge) and Coal Combustion Residuals (CCR) in 2015 (regulates coal ash ponds) that were more stringent than first proposed. The Clean Power Plan (CPP), which regulates carbon dioxide emissions, would also impact the ability to cost-effectively operate coal-fired generation if it moves forward and is also more stringent than first proposed.

Each new regulation increases the cost of operating existing coal-fired plants over the 20-year horizon. Investment in Vectren's existing coal-fired generation to achieve compliance with ELG regulations would be significant. As currently written, ELG compliance would require investments by 2023.

ii. Low Gas Prices

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 low and projected to be stable over the long term. Shale gas has revolutionized the industry, driving these low gas prices, and is fueling a surge in low-cost gas generation around the country. Vectren's IRP reflects the benefit low gas prices provide to gas-fired generation.

Projected 2030 MISO Energy Mix



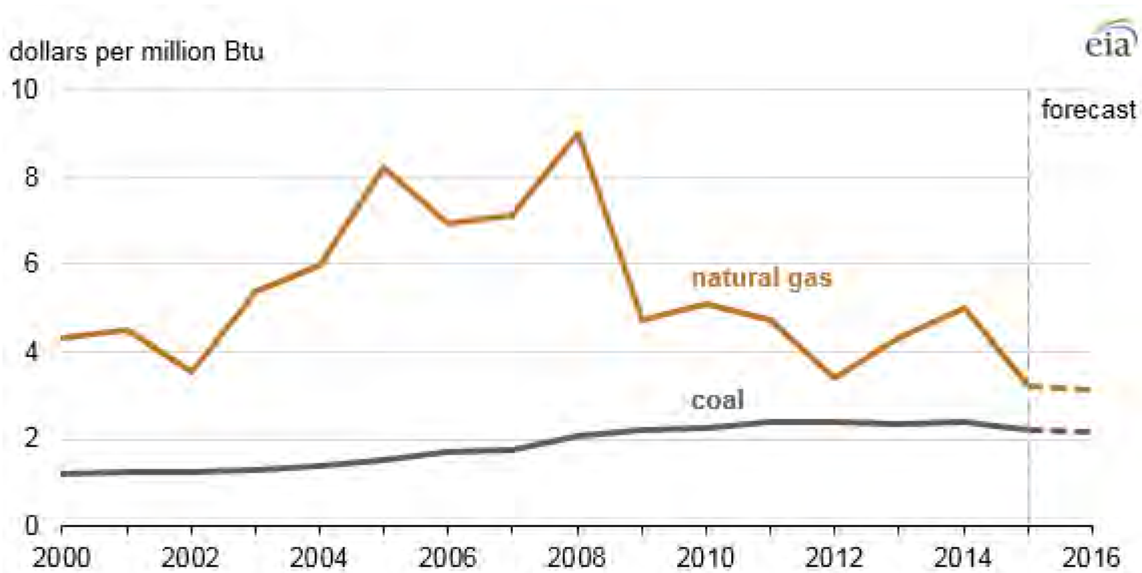
*Other includes hydro, pumped hydro, oil, solar and others.

Vectren is a member of MISO, an independent transmission operator, which functions as the regional transmission operator for 15 Midwestern and Southern states, including Indiana (also parts of Canada). Within the MISO footprint, energy from gas generation has increased from 17% of total electric generation in 2014 to

28% in 2016. Energy from gas generation is projected to grow to 35% by 2030[3].

While the cost advantage of natural gas makes switching to natural gas-fired generation appear to be preferable from a cost perspective, Vectren also factored in the risk of particular supply side resources to its IRP. Reliance on an all natural gas generation portfolio would eliminate any resources that could mitigate the impacts of high gas prices or environmental regulations impacting natural gas facilities that might occur in the future. Vectren's risk modeling identified the risks with an unbalanced portfolio.

The table below shows average gas and coal fuel receipt costs at electric generating units between 2000 and 2016[4]. Note that shale gas has driven low gas costs since 2009.

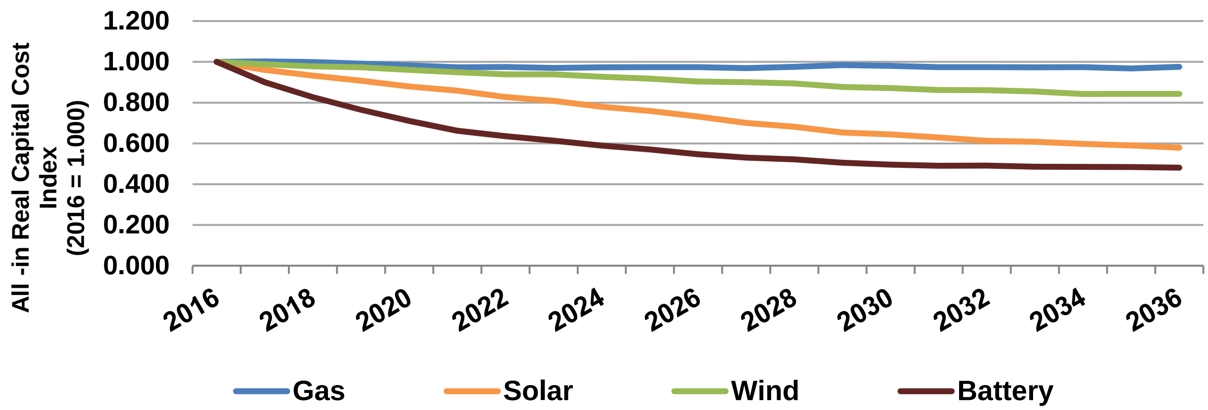


iii. Cost of Renewables

[3] MISO, 2016 Winter Readiness Workshop, presented on October 31st 2016, https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2016/20161031%20Winter%20Readiness%20Workshop/20161031%20Winter%20Readiness%20Workshop%20Presentation.pdf, Slide 64

[4] U.S. Energy Information Administration, *Electric Power Monthly*, and *Short-Term Energy Outlook* (March 2016); http://www.eia.gov/todayinenergy/detail.cfm?id=25392

Another factor in Vectren's resource evaluation is the timing of the reduction in renewable energy costs. Vectren must either invest in its coal-fired generation to comply with ELG requirements, as currently written, or construct replacement generation by 2023. Renewable costs continue to decline, but they are still expected to be more expensive in the Midwest region than other alternatives in the next several years. Vectren needs to learn more about integrating solar resources in its territory, but the price decline and cost effectiveness of large renewable investments does not support a larger investment by Vectren based upon the timing for resource decisions. Advancements in technology should drive renewable and battery storage costs down over the next several years, making them more competitive with other generation resources. Pace Global, an industry expert consultant, helped develop cost curves based on industry projections as well as their expert judgment. The cost curves below were included in Vectren's IRP analysis.



C. Uncertainty/Risk

The future is far from certain. Uncertainty creates a risk that a generation portfolio that was reasonable under an anticipated future fails to perform as expected if the future turns out differently. Vectren's integrated resource plan 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. To help better understand the wide range of possibilities for regulations, technology 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 varying resource mixes.

IV. Analysis

Having identified its need for electricity and the potential resources to satisfy that need, Vectren conducted an analysis to identify a 20-year preferred resource plan. Vectren's 2016 IRP analysis was more robust than ever before. A methodical, step-by-step analysis was used to determine the preferred portfolio. Analysis steps are listed below.

1) Determined objectives in developing a preferred resource plan, including:
    a) Maintain reliability
    b) Minimize cost to customers
    c) Mitigate risk to customers and Vectren
    d) Provide environmentally acceptable power leading to a lower carbon future
    e) Include a balanced mix of energy resources
2) Worked with consultants and IRP stakeholders to anticipate future uncertainties and incorporate them into several possible future states of the world. The future could bring economic development, economic stagnation, increased pace of technological development, more regulations, or fewer regulations. Multiple possibilities were explored.
3) Utilized computer modeling to consider various resource combinations to meet customer energy needs in each of these possible futures. The model is a deterministic, optimization model. It considered thousands of possible resource combinations to satisfy customer demand and energy needs for each pre-determined future. The model optimizes on cost to the customer. Seven portfolios were created; one for each pre-determined future. While creating these computer-generated resource portfolios are an important step in resource planning, it is also important to use judgment to consider other possibilities in creating portfolios with a balanced mix of resources to meet customer energy needs.

4) Worked with external stakeholders that participated in Vectren's IRP public stakeholder meetings to develop two balanced portfolios. Vectren also worked with expert consultants to develop five additional balanced portfolios. Additionally, Vectren included a portfolio very similar to the current mix of resources, which is heavily reliant on the five existing coal units. In all, 15 portfolios were created for analysis.
5) Utilized probabilistic modeling to simulate operating each of the 15 portfolios under 200 possible computer-generated futures. The model captured portfolio performance to determine likely portfolio operating costs, emissions of carbon dioxide and regulated pollutants, exposure to the energy markets, risk, etc. In essence, this resulted in 3,000 model runs.
6) Used a balanced scorecard approach to evaluate the potential impact of multiple risk factors on each portfolio, including but not limited to, customer cost, environmental impact, flexibility, balance of resources, and economic impact to the communities that Vectren serves. No single portfolio performed best in all categories; however, the preferred portfolio performed well in all measured risk contingencies.

V. Stakeholder Process

Vectren believes in the importance of stakeholder engagement. Vectren's objectives for stakeholder engagement are as follows:

- **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

Vectren worked hard 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 Carl Chapman, Chairman, President, and Chief Executive Officer of Vectren. He and other senior management, Vectren subject matter experts, and expert consultants actively participated in each meeting to help address stakeholder questions/concerns. Additionally, Vectren addressed stakeholder questions outside of public meetings via irp@vectren.com in a timely manner.

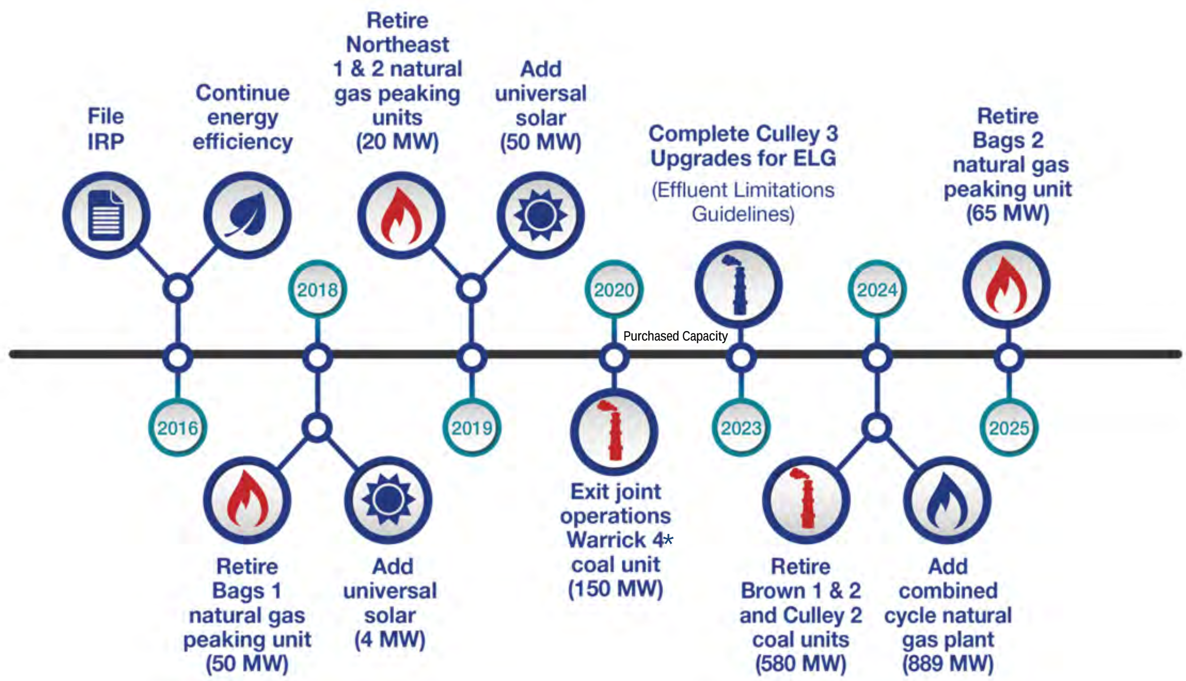
On February 3, 2016 Vectren participated in the Joint Utilities Stakeholder Education Session with other Indiana investor-owned utilities. After that, Vectren hosted three public stakeholder meetings at its headquarters in Evansville, IN. Dates and topics covered are listed below:

- April 7, 2016 – Vectren Public IRP Stakeholder Meeting
    - Vectren IRP Process Overview
    - Gathered Stakeholder Input on Uncertainties
    - Long-term Energy and Demand Forecast
    - Customer-Owned Distributed Generation
    - 2016 IRP Technology Assessment Generation Resource Alternatives
    - Generation Retrofit Alternatives
    - Energy Efficiency Modeling Discussion
- July 22, 2016 – Vectren Public IRP Stakeholder Meeting
    - Environmental Compliance
    - Base Case/Modeling Inputs
    - Resource Screening Analysis and Optimization Modeling
    - Scenario Development
    - Gathered Stakeholder Input to Portfolio Selection
- November 29, 2016 – Vectren Public IRP Stakeholder Meeting
    - Recap of Vectren IRP analysis
    - Presentation of the Preferred Portfolio

- Existing EPA Regulations
- Optimization Modeling Results and Portfolio Development
- Risk Analysis Results

In addition to these public meetings, Vectren met with the Vectren Oversight Board and staff from the Indiana Utility Regulatory Commission to discuss energy efficiency modeling for the 2016 IRP on October 14, 2016. All Vectren stakeholders were invited to participate via webinar.

VI. The Preferred Portfolio

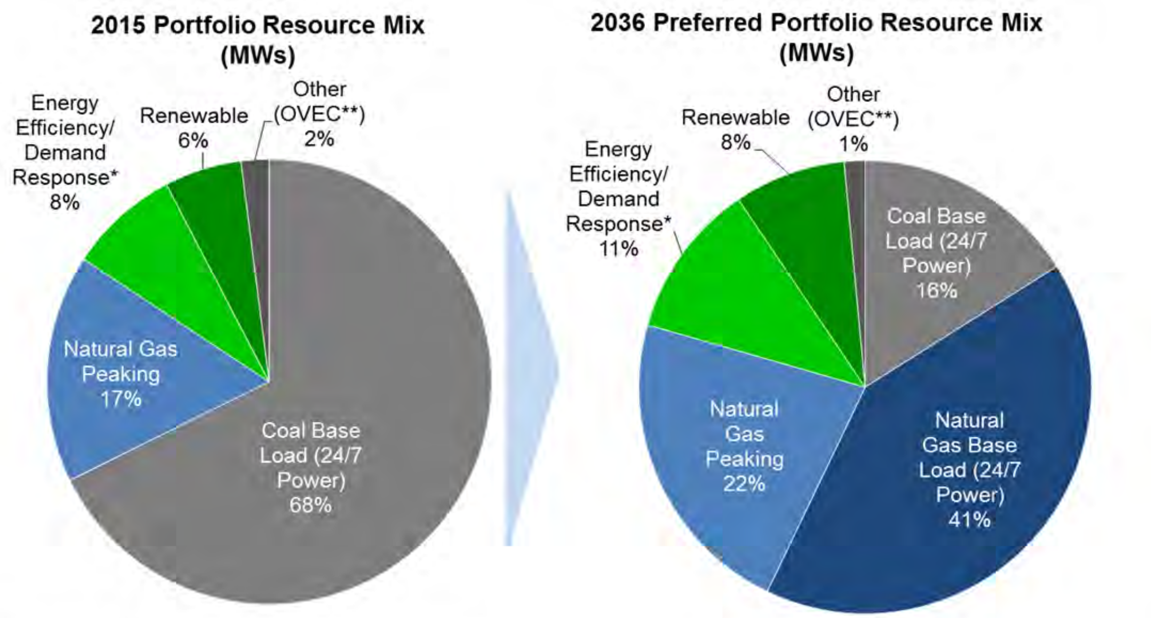


* Warrick 4 jointly owned with Alcoa, which is in the midst of transition. Vectren continues to discuss the future of Warrick 4 with Alcoa.

Based on the analysis Vectren conducted, Vectren has identified a preferred portfolio that consists of continued energy efficiency, retirement of existing coal and some gas units (Bags Units 1 and 2, Brown Units 1 and 2, FB Culley Unit 2, and Northeast Units 1 and 2), exiting joint operations of Warrick Unit 4, and construction of a combined cycle natural gas plant and solar generation. This preferred portfolio:

- Is among the best performing portfolios across multiple measures on the balanced scorecard.
- Is among the lower cost portfolios (within 4% of the lowest cost portfolio).
- Leads to a lower carbon future – Achieves almost 50% reduction in carbon (base year 2012) by 2024, which exceeds the Clean Power Plan (CPP) requirements – carbon emissions reduction from 2005 levels would be almost 60%.
- Brings renewables into the portfolio by 2019. Renewables and ongoing Energy Efficiency account for approximately 20% of total capacity by 2036.
- Provides low-cost peaking generation through duct-firing[5] that enhances opportunities for economic development and wholesale sales, which lowers customer bills.
- Avoids reliance on a single fuel and provides a balanced mix of coal, gas, and renewables. While reliance on gas is significant, a duct-fired plant would allow for back up of further variable renewable resources in the long term.
- Is among the best portfolios in terms of limiting negative economic impact from job loss and local tax base. University of Evansville professors concluded that the economic ripple effect of losing 82 FB Culley jobs equates to 189 additional job losses in the community. Total state and local tax impact would be approximately 7 million dollars annually. Moreover, to the extent a new gas unit is built at the AB Brown site, over 100 total jobs are expected to be retained in the community. Total state and local tax impact would be approximately 4 million dollars annually.
- Reduces dependence on coal-fired generation over time and provides flexibility to adapt to changes in technology.
- Takes advantage of tax incentives for solar power plants.

[5] Depending on set up, Duct-firing can provide approximately 200 MWs (Installed Capacity) of efficient peaking capacity capability through gas burners located within the heat recovery steam generator. These burners can be fired to generate more power when needed.



*Cumulative Demand Response & Net Energy Efficiency
**Vectren's 1.5% ownership of Ohio Valley Electric Corporation (OVEC) coal units. Per contractual obligations, all portfolios include OVEC.

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, the IRP calls for continuation of energy efficiency. Vectren's current authority related to energy efficiency initiatives expires on December 31, 2017. Vectren will file for authority necessary to facilitate continuation of energy efficiency early in 2017 so that programs continue to be available. Second, Vectren must comply with ELG requirements, as currently written, by the end of 2023. As such, Vectren plans plant upgrades for FB Culley 3 for conversion of dry bottom ash and flue gas desulfurization waste treatment. The preferred portfolio calls for construction of a new combined cycle gas turbine in lieu of further investments in Brown Units 1 and 2, FB Culley Unit 2, and Warrick Unit 4 to ensure compliance. IURC approvals will need to be sought in the near future. Third, Vectren intends to pursue solar projects in 2017 and 2019. 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, and other assumptions could warrant deviations from the preferred plan.

Following the outcome of the recent presidential election, there is potential for industry change over the next several years. For example, the EPA's Clean Power Plan may be rescinded or modified. Additionally, Clean-Energy Tax incentives may be at risk. Even in the midst of possible industry change, other rules like ELG/CCR, which are the main drivers of closing Vectren coal plants, will be much more difficult to change.

Vectren is confident in the need for new gas generation in 2024. Under all scenario modeling, a natural gas-fired plant was selected, including the low regulatory scenario. While future carbon regulations are less certain than prior to the election, it is likely that new administrations will continue to pursue a long term lower carbon future. Vectren's preferred portfolio positions the company to meet that expectation.

Other aspects of the preferred portfolio are less certain. For example, the timing of exiting joint operations of the Warrick 4 coal plant could change. The plant is jointly owned with Alcoa, which recently went through a corporate reorganization and remains in the midst of transition. Given the plant, absent incremental investment, does not comply with the CCR and ELG requirement, Vectren continues to talk to Alcoa about the timing of possible closure. Additionally, Vectren plans to add 50 MW of solar in 2019, which corresponds with clean energy tax incentives. Timing of this solar plant may change should these incentives not be available.

Confidential Attachment 1.2 2016 Vectren Technology Assessment Summary Table
(Not Included in Public Document)

Attachment 3.1 Stakeholder Materials

Vectren Integrated Resource Plan (IRP) Stakeholder Meeting

Gary Vicinus – Meeting Facilitator
Vice President and Managing Director, Pace Global
April 7, 2016

Agenda

1:00 p.m.	Sign-in/ refreshments	
1:30 p.m.	Welcome	Carl Chapman, Vectren President and CEO
1:35 p.m.	Take attendance in person and on phone (give name and organization) Meeting Format and Ground Rules	Gary Vicinus, Pace Global – Managing Director of Consulting Practice
1:45 p.m.	Vectren IRP Process Overview and Discussion of Uncertainties	Gary Vicinus, Pace Global – Managing Director of Consulting Practice
2:45 p.m.	Break	
2:55 p.m.	Sales and Demand Forecast Update	Matt Rice, Manager Market Research & Analysis
3:05 p.m.	Customer-Owned Distributed Generation Forecast	Mike Russo, Itron – Forecast Analyst
3:20 p.m.	Resource Options – Generation Resource Alternatives	Mike Borgstadt, Burns & McDonnell –Project Manager
3:35 p.m.	Resource Options – Generation Retrofit Alternatives	Scott Brown, Manager Generation Planning
3:45 p.m.	Resource Options – Energy Efficiency	Shawn Kelly, Director Energy Efficiency
4:00 p.m.	Stakeholder Questions, Feedback and Comments	
4:30 p.m.	Adjourn	

Meeting Guidelines

1. Please hold most questions until the end of the presentation (Clarifying questions about the slides are fine throughout). You may write questions on these topics or others using the cards at your table. We will collect them as we go and use to facilitate discussion.
2. For those on the webinar, we will open the (currently muted) phone lines for questions within the allotted time frame. You may also type in questions via the chat feature.
3. At the end of the presentation, we will open up the floor for "clarifying questions," thoughts, ideas and suggestions.
4. There will be a parking lot for items to be addressed at a later time.
5. Additional questions and suggestions may be sent to IRP@vectren.com for a period of two weeks after this meeting.
6. We will address most verbal questions here. Please allow a few weeks for responses to written questions submitted to IRP@vectren.com or follow-up questions from this meeting.

Vectren's IRP Process

- Vectren's IRP process is designed to determine a preferred portfolio that best meets all objectives over a wide range of market futures to meet our customers' future energy needs:
    - Objectives and Overview of Planning Process
    - Metrics
    - Key Inputs
    - Screening Process
    - Selection of Portfolios
    - Risk Assessment
    - Findings and Recommendations

Purpose and Guidelines for Vectren's 2016 IRP

Vectren is seeking to develop its 2016 IRP to test what future portfolio best meets customers' needs for reliable, low cost, environmentally acceptable power over a wide range of future market and regulatory conditions.

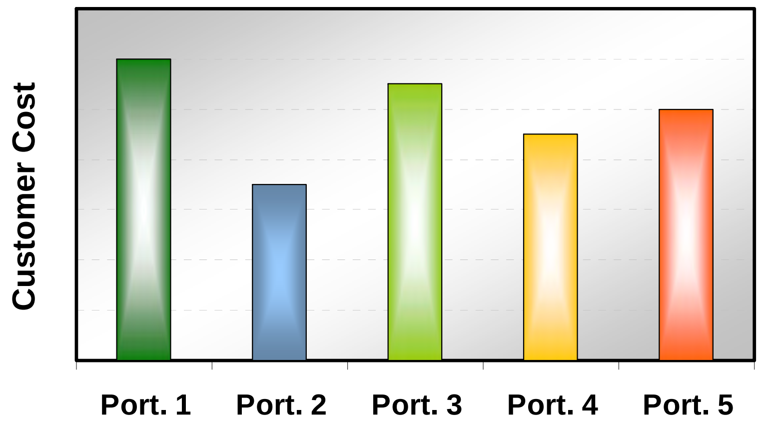
- The 2016 IRP will follow the IURC's directive to assess options against a wide range of future market conditions and to perform a comprehensive risk assessment to ensure its recommended portfolio performs well against a wide range of futures

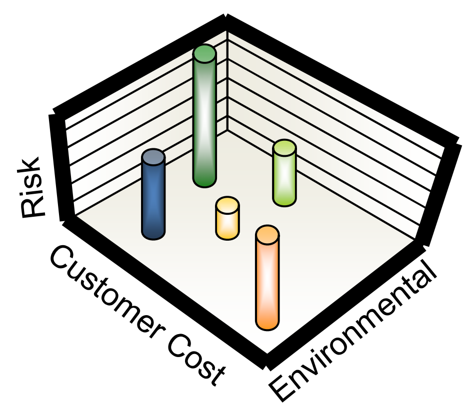
- Vectren will conduct a thorough stakeholder process beginning today, to ensure it receives feedback from its stakeholders throughout the process
  - There will be at least three stakeholder meetings: today, late July and late fall

IURC = Indiana Utility Regulatory Commission

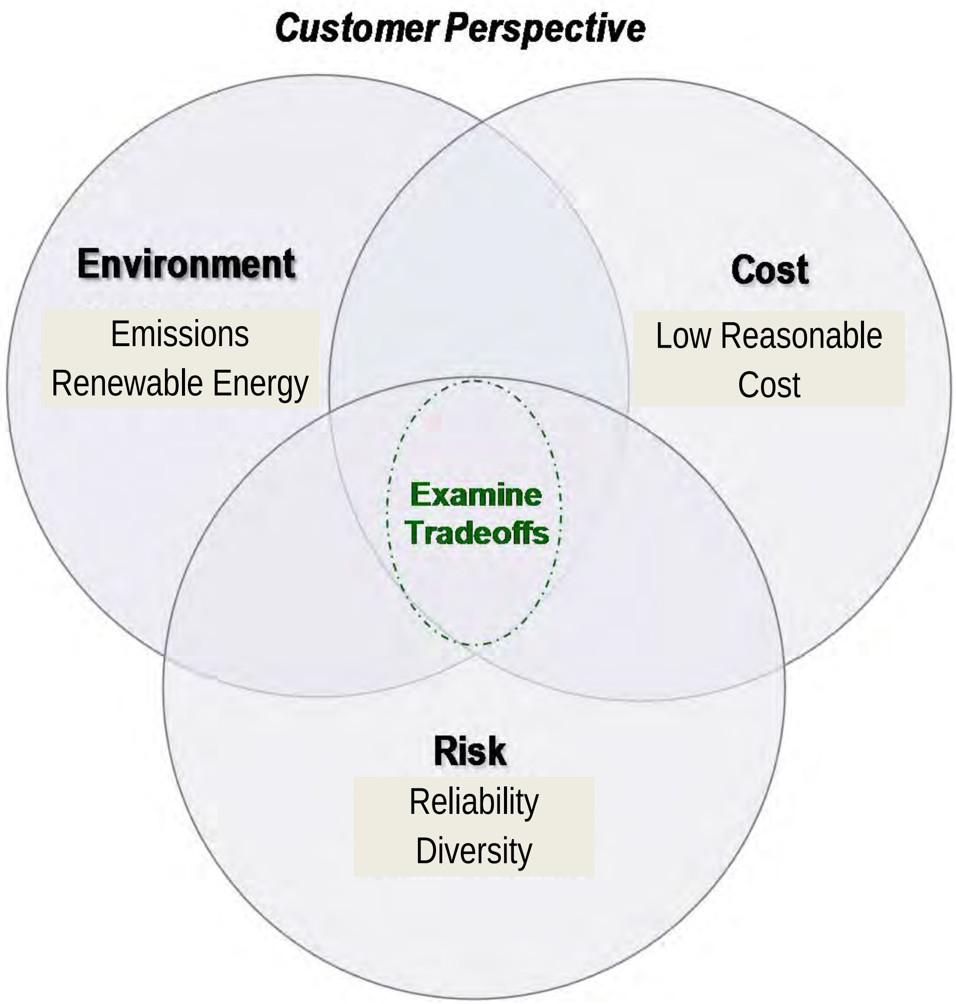
Vectren's Approach Will Build on Traditional Approaches, Considering Multiple Objectives

Traditional Approach	Vectren Approach
▪ Focuses on minimizing customer costs ▪ Portfolio evaluation is one-dimensional	▪ Focuses on the simultaneous evaluation of multiple objectives and tradeoffs - Risk Mitigation - Customer Cost - Environmental Stewardship

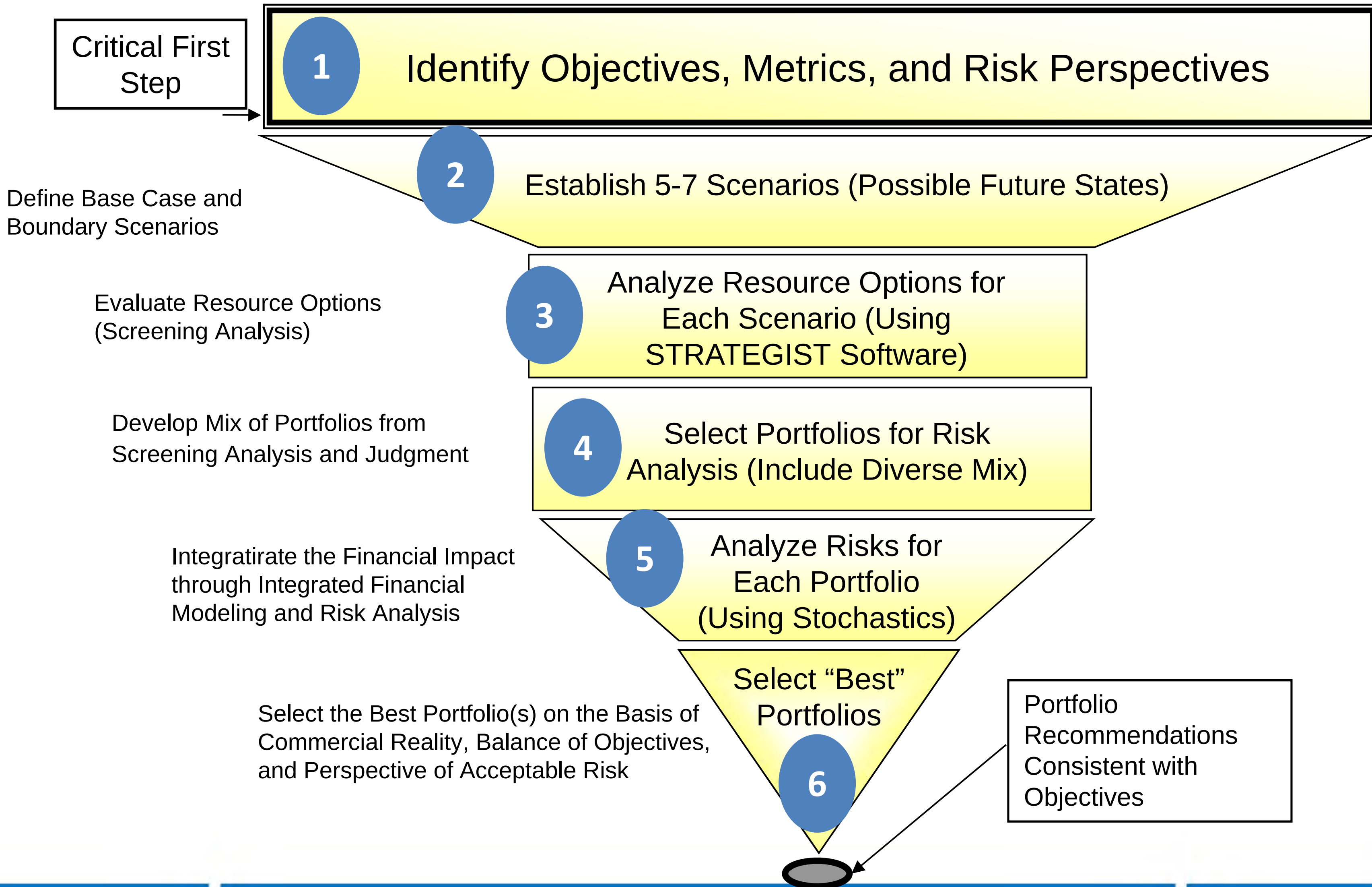




The Selected Portfolio Will Identify and Evaluate Tradeoffs on Key Metrics



Vectren Will Follow a Structured Approach



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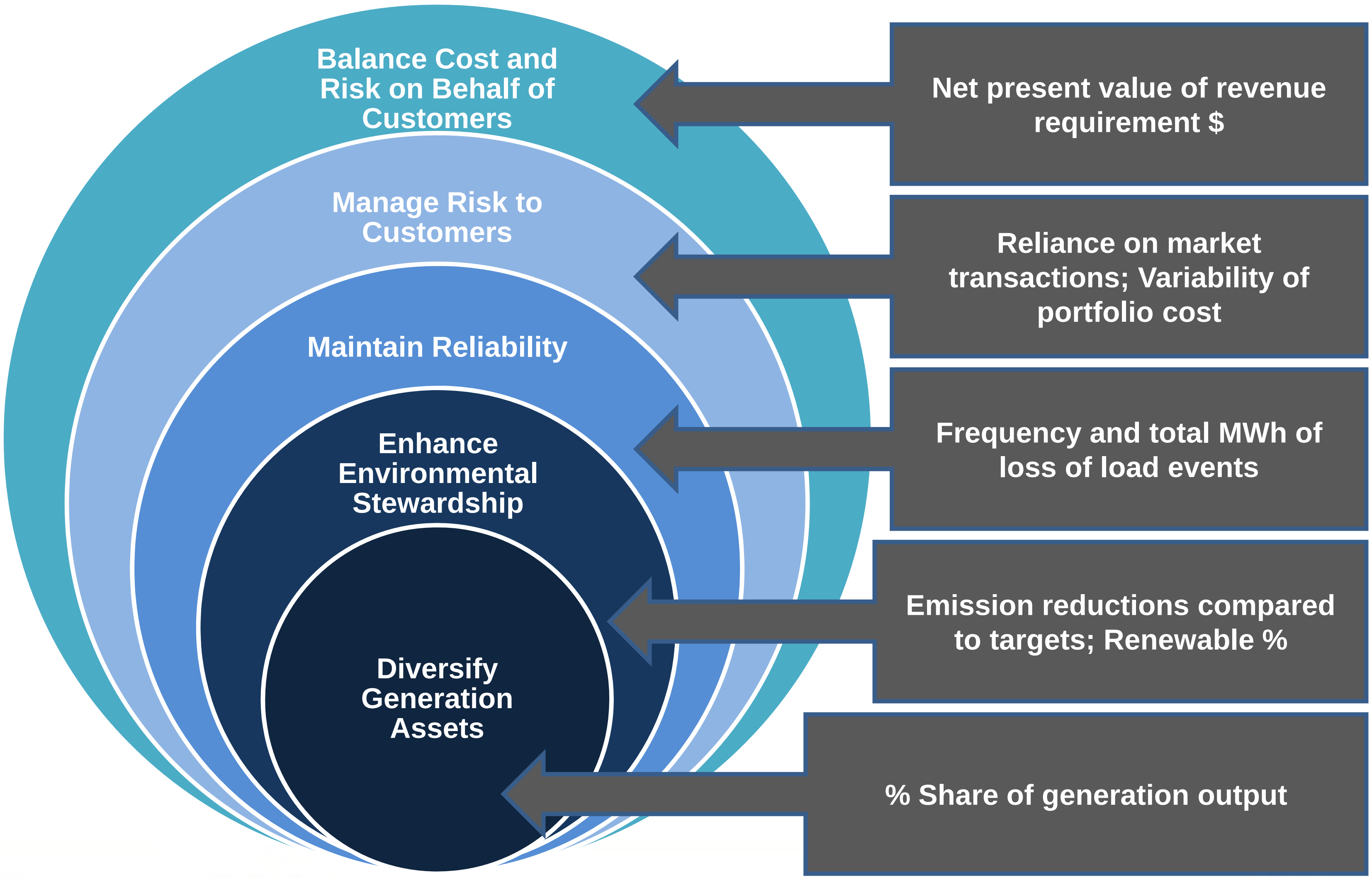
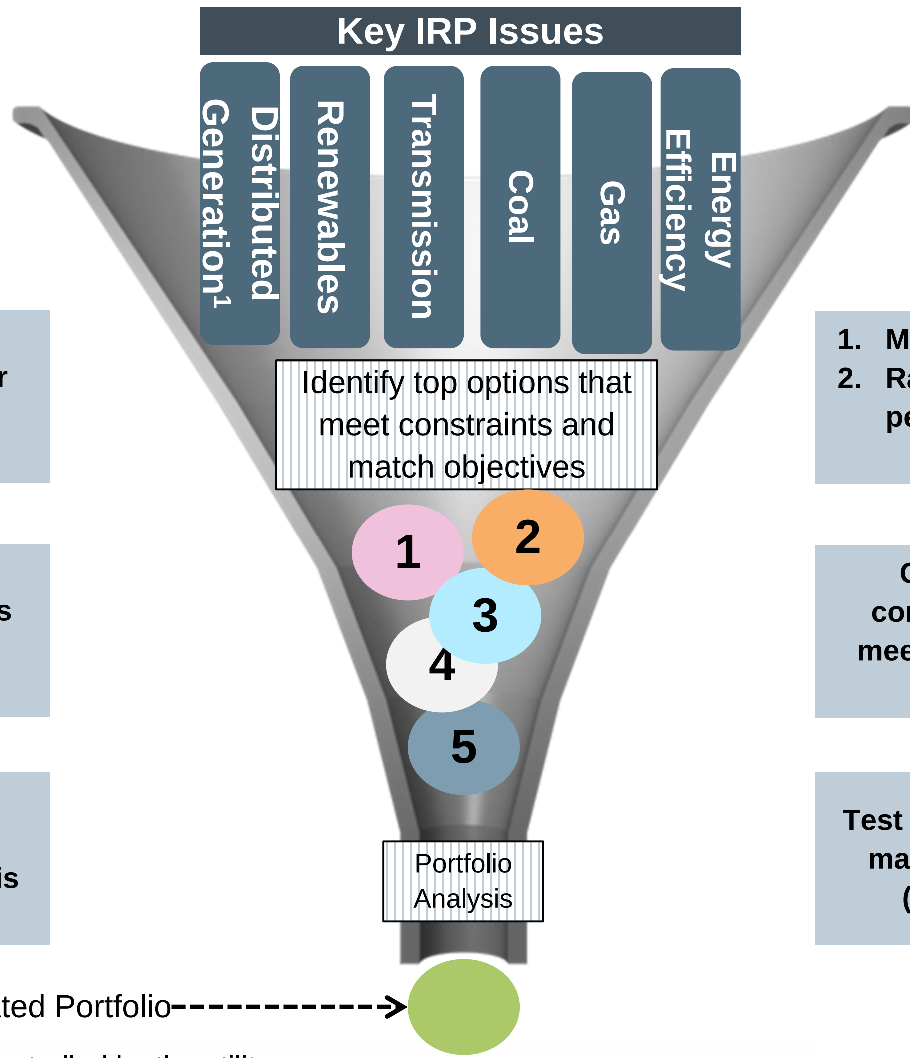
Objectives and Metrics



MWh = Mega Watt Hour

2-4

Structured Screening Process to Address Issues Efficiently and Select Portfolios



Task

Screen feasible options for each "issue category"

Combine individual options into integrated portfolios

Perform quantitative scenario-based risk analysis

Approach

1. Meet planning constraints;
2. Rank by cost and environmental performance

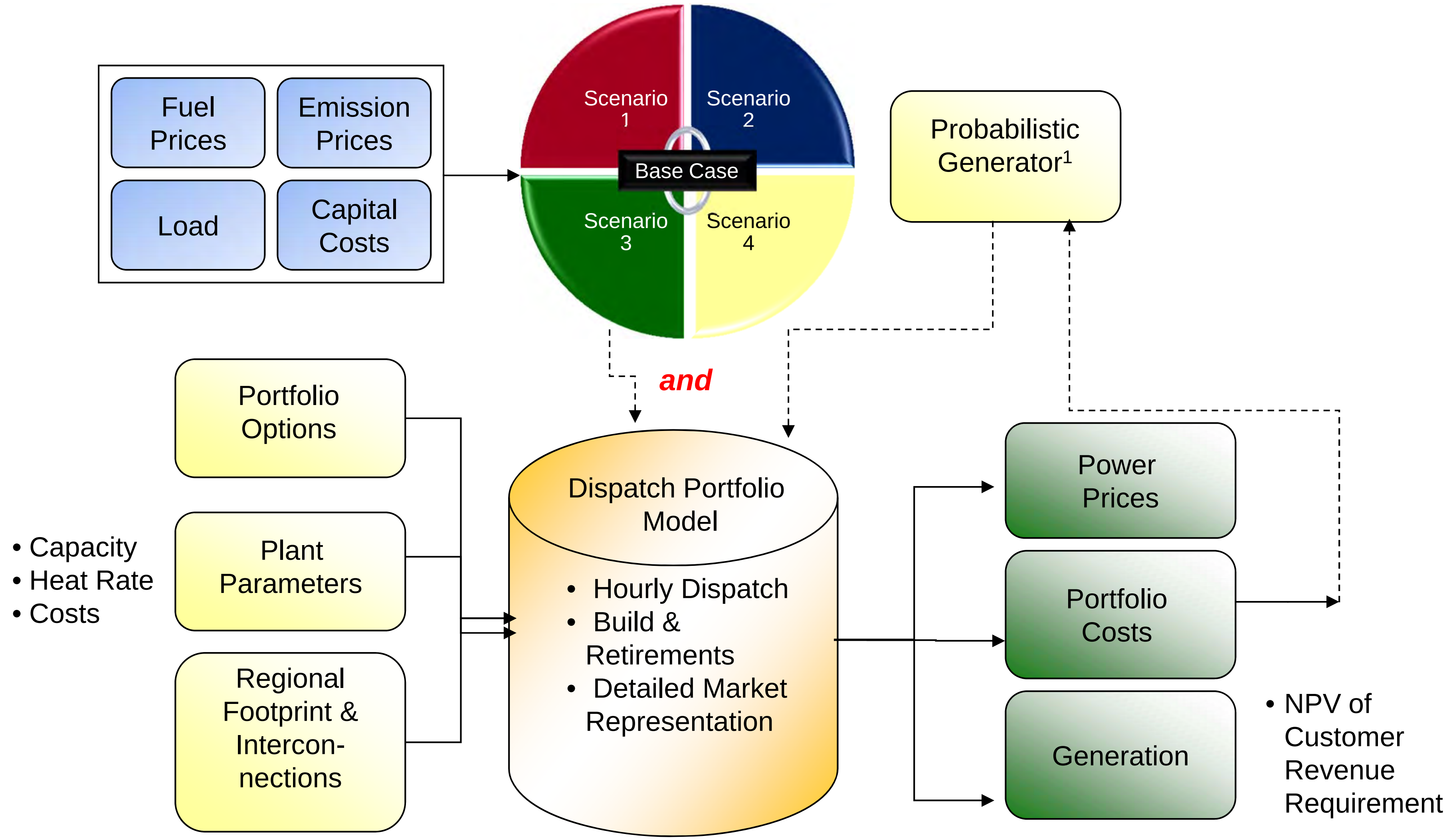
Collaborate with Vectren to construct portfolio options that meet constraints and incorporate various strategy options

Test each portfolio against external market risks and all key metrics (Full portfolio assessment)

Select Integrated Portfolio

1 Distributed generation may not be controlled by the utility

5-6 Process for Addressing Uncertainty



[1] Stochastic modeling is for the purpose of estimating the probability of outcomes within a forecast to predict what conditions might be like under different situations

Step 2: Selection of Drivers, Portfolios and Futures (Stakeholder Input)

VECTREN
Energy Delivery

Purpose and Guidelines for Scenario Development

Vectren is seeking to develop a base case and 5-7 alternatives, internally consistent scenarios (potential futures), to test which portfolios are optimal over a wide range of future market and regulatory conditions. We would like to solicit your list of risk factors/drivers, options and scenarios

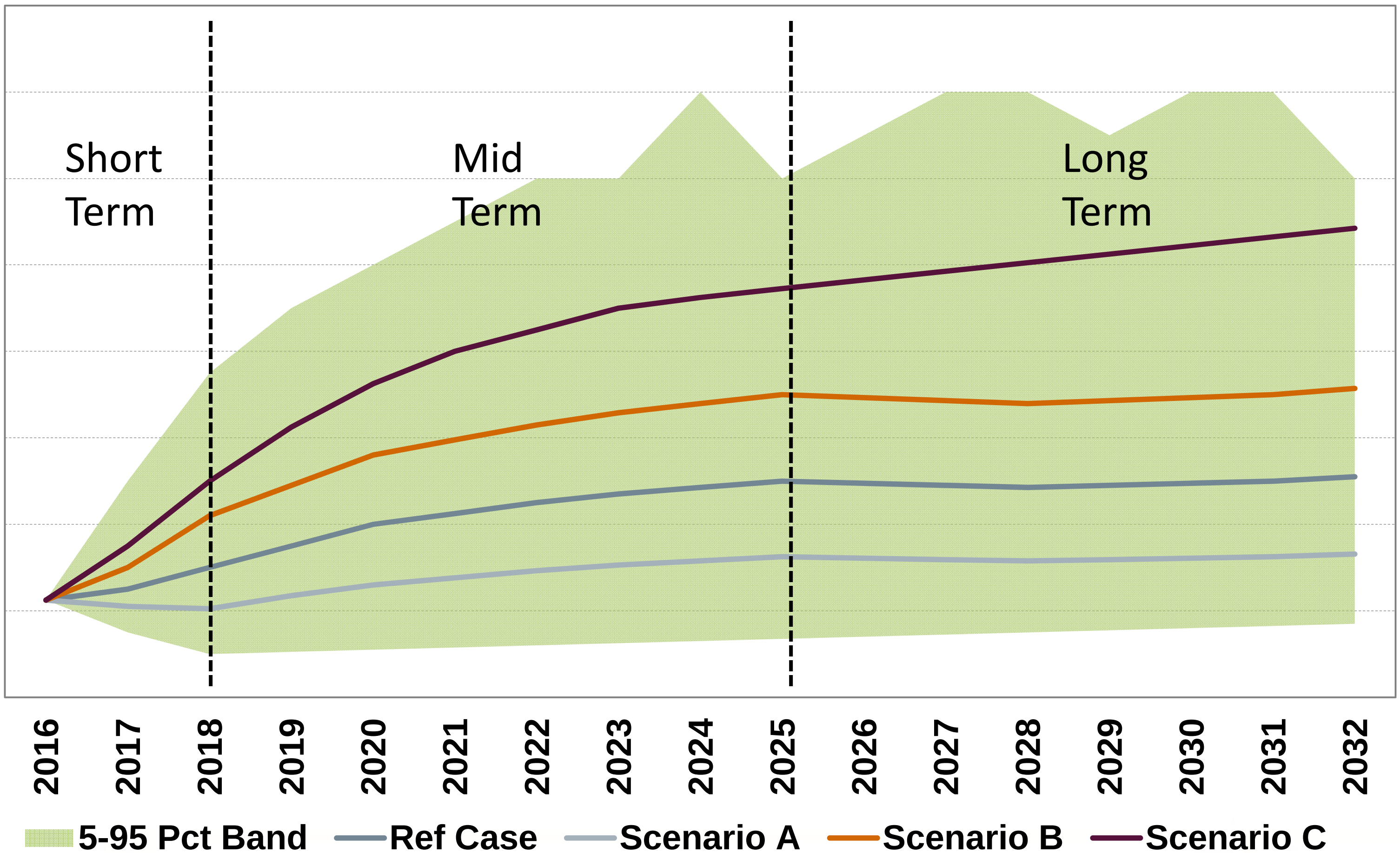
- **List Risk Factors**
  - **Environmental Regulations:**
  - **Technological Assumptions (Speed of technological growth and adoption):**
  - **Market Drivers:**

Purpose and Guidelines for Portfolio Development

- Next we want to ensure we consider all of the relevant demand side and supply side options, which we will expose to the scenarios we develop around the key drivers:

- **Stakeholder input into the consideration of options**:
  - **Demand Side Resources (Energy efficiency and demand response):**
  - **Distributed Energy Resources:**
  - **Supply Side Resources (Generation options):**

The Objective of this Analysis is to Find Portfolios that Perform Well Against a Range of Boundary Conditions



Step 3: Vectren's Base Case Assumptions

Vectren's Base Case

- **Load**
  - Today, Matt Rice (Vectren) will review Vectren's reference forecast as the Base Case
  - In addition, Customer-Owned Distributed Generation forecast will be discussed by Mike Russo from Itron
- **Technology Options**
  - Today, Mike Borgstadt (Burns & McDonnell) and Scott Brown (Vectren) will discuss technology choices, and Shawn Kelly (Vectren) will discuss Energy Efficiency
- Other model inputs/major assumptions will be discussed in our next public meeting in July

Step 4: Selection of Portfolios

Purpose and Guidelines for Scenario Development

- From the Screening Analysis, Vectren will select a range of portfolios which capture least cost portfolios, diverse portfolios and renewable portfolios to ensure all relevant portfolios are considered.
- Then, a risk assessment is performed.

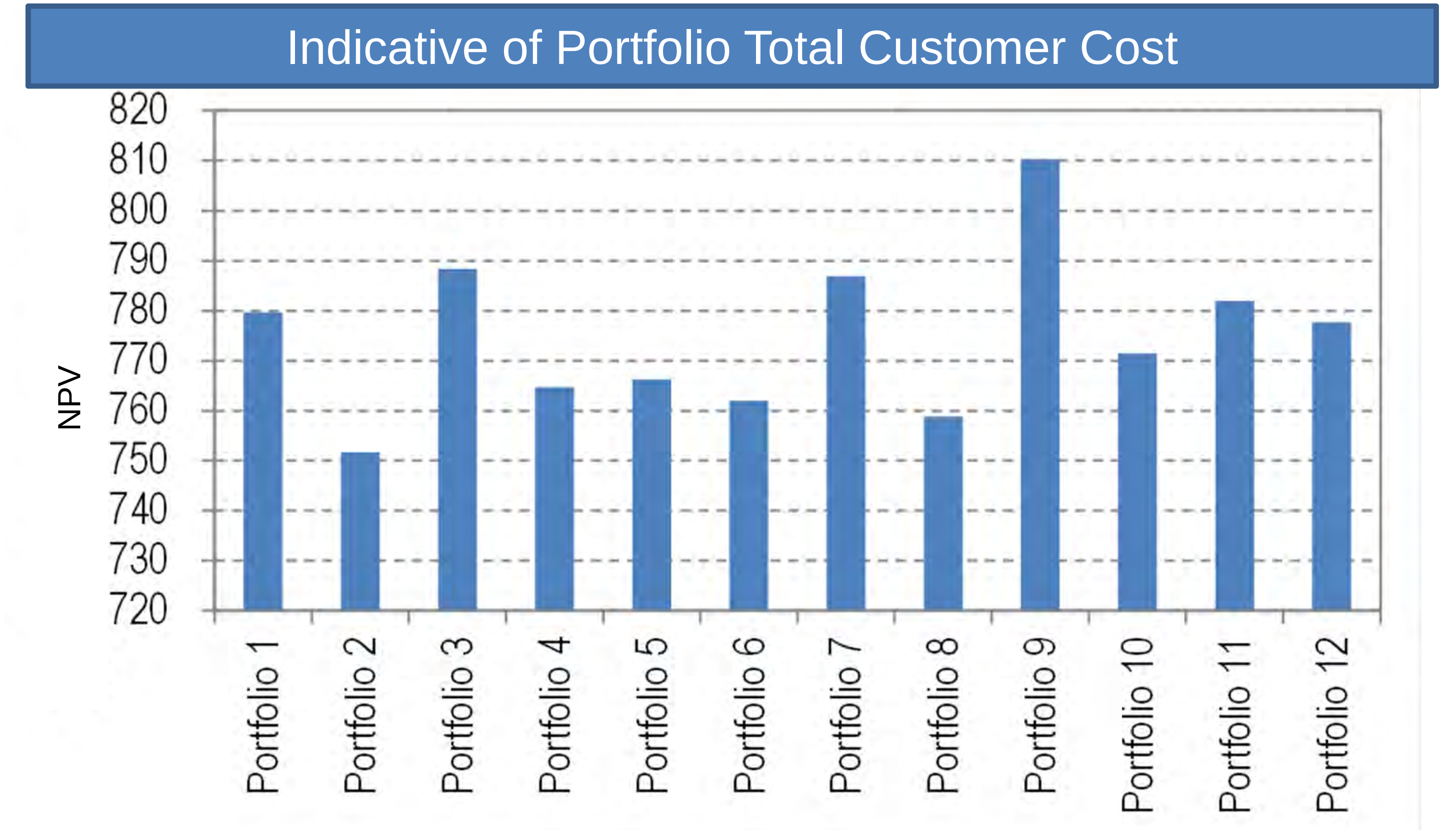
- **Guidelines for portfolio development:**
  - Screening assessment will determine least cost portfolios for each scenario (potential future)
  - Next, Vectren will select other portfolios that capture more diverse, green, or modular generation and/or achieve reliability objectives
  - From this group of portfolios, a risk assessment is performed
- **Graph will show selection of "best" portfolios for conducting risk assessment**

(i) Dispatch portfolio model will select least cost portfolios

(ii) Selection of more diverse portfolios

(iii) Other portfolios suggested by stakeholder process

Results of Technology Screening Assessment



NPV = Net Present Value

Step 5: Stochastic Risk Assessment

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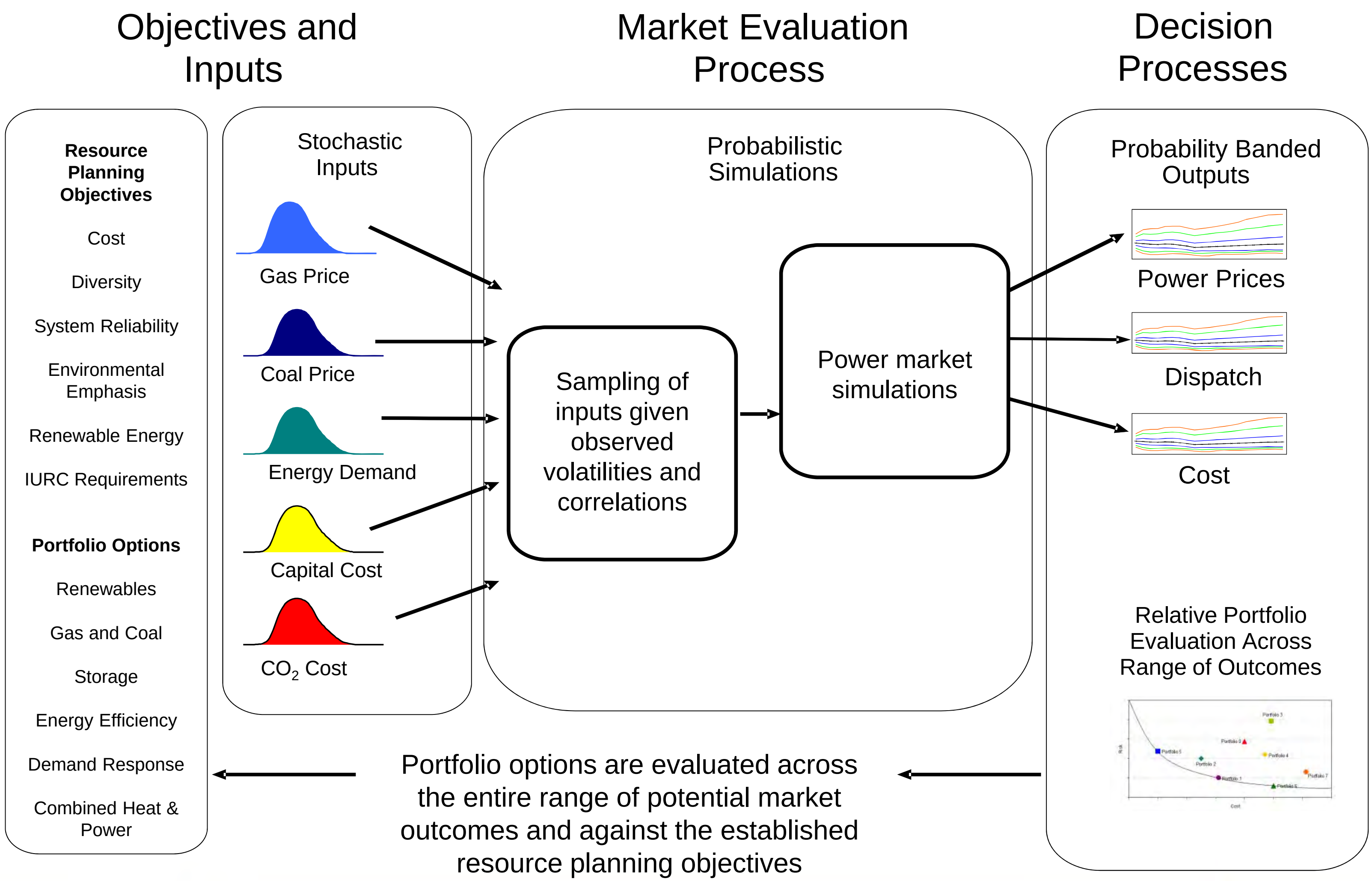
Energy Delivery

Incorporating Stochastic Risks into the Planning Process Tests Portfolios against Wide Range of Outcomes



CO_2 = Carbon Dioxide

Step 6: Selection of Preferred Portfolio

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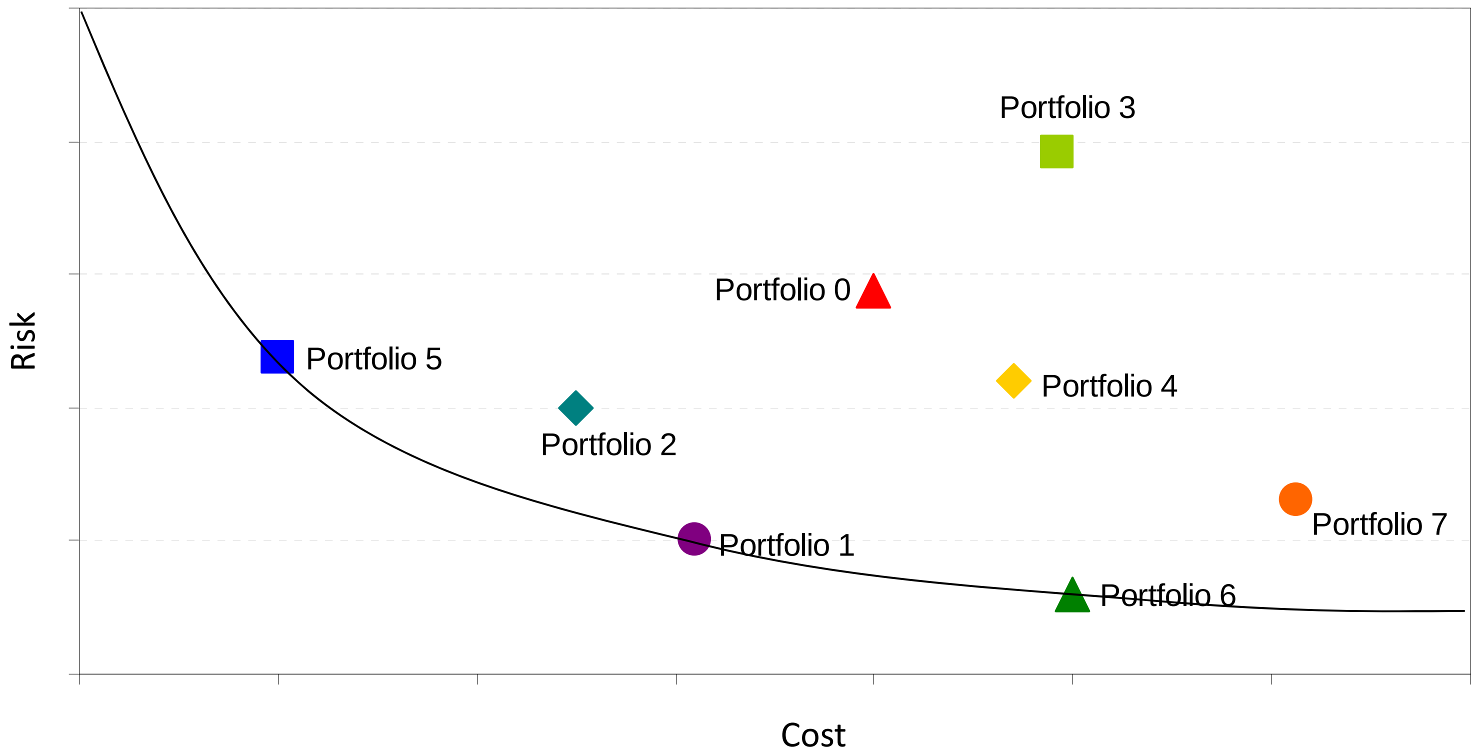
Illustrative Results Presentation

- Portfolios above line are less desirable because of higher expected cost and risk



Illustrative

Illustrative Example: Scorecard Summary of Portfolio Options

Criteria		Cost			Risk			Environmental		
Portfolio		Cost Metric 1	Cost Metric 2	Cost Rating Score	Risk Metric 1	Risk Metric 2	Risk Rating Score	Environmental Metric 1	Environmental Metric 2	Environmental Stewardship Score
Portfolio 1										
Portfolio 2										
Portfolio 3										
Portfolio 4										
Portfolio 5										
Portfolio 6										
Portfolio 7										
Portfolio 8										
Portfolio 9										
Portfolio 10										

Score Rating: Favorable Neutral Unfavorable

Illustrative

Preferred Portfolio

Preferred Portfolio

- **The preferred portfolio best meets objectives over a range of scenarios:**
  - Volatility in demand and prices for both gas and power
  - Significant conservation measures
  - Consideration of alternative energy (solar, wind, cogen)
  - Environmental regulation changes
  - Pace of infrastructure replacement
  - Decarbonization commitments that ratchet over time
  - Local economic factors

Long-Term Energy and Demand Forecast

Presented by Matt Rice, Manager of Market Research & Analysis

2016 Vectren IRP Stakeholder Meeting

April 7, 2016

VECTREN Energy Delivery

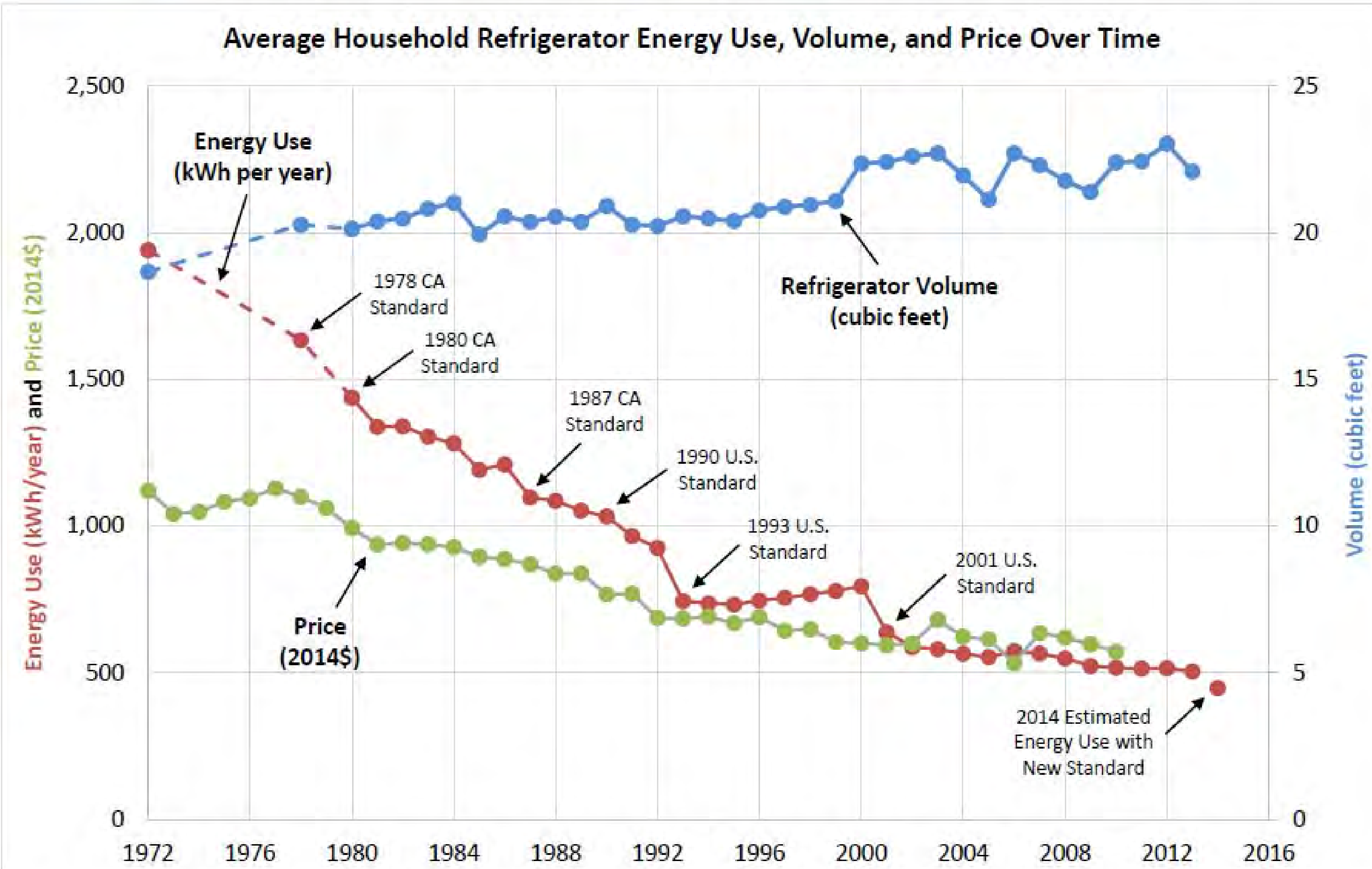
Forecast Summary

- Expect demand to remain relatively flat through the forecast period (Compound Annual Growth Rate (CAGR) is 0.1%)[1]
  - A large customer's adoption of customer-owned generation in 2017
- Moderate growth (Compound Annual Growth Rate is 0.5% beyond 2017)
  - Slow long-term population growth (0.2% annual growth) & moderate income growth (1.6% annual growth)
  - Strong end-use efficiency gains reflecting new and existing Federal codes and standards
    - Air conditioning, heating, lighting, refrigeration, cooking, etc. are all becoming more efficient over time
  - Residential and general service adoption of rooftop solar

[1] Future energy efficiency programs are not included in the sales and demand forecast and will be considered a resource option

Usage Trend Example

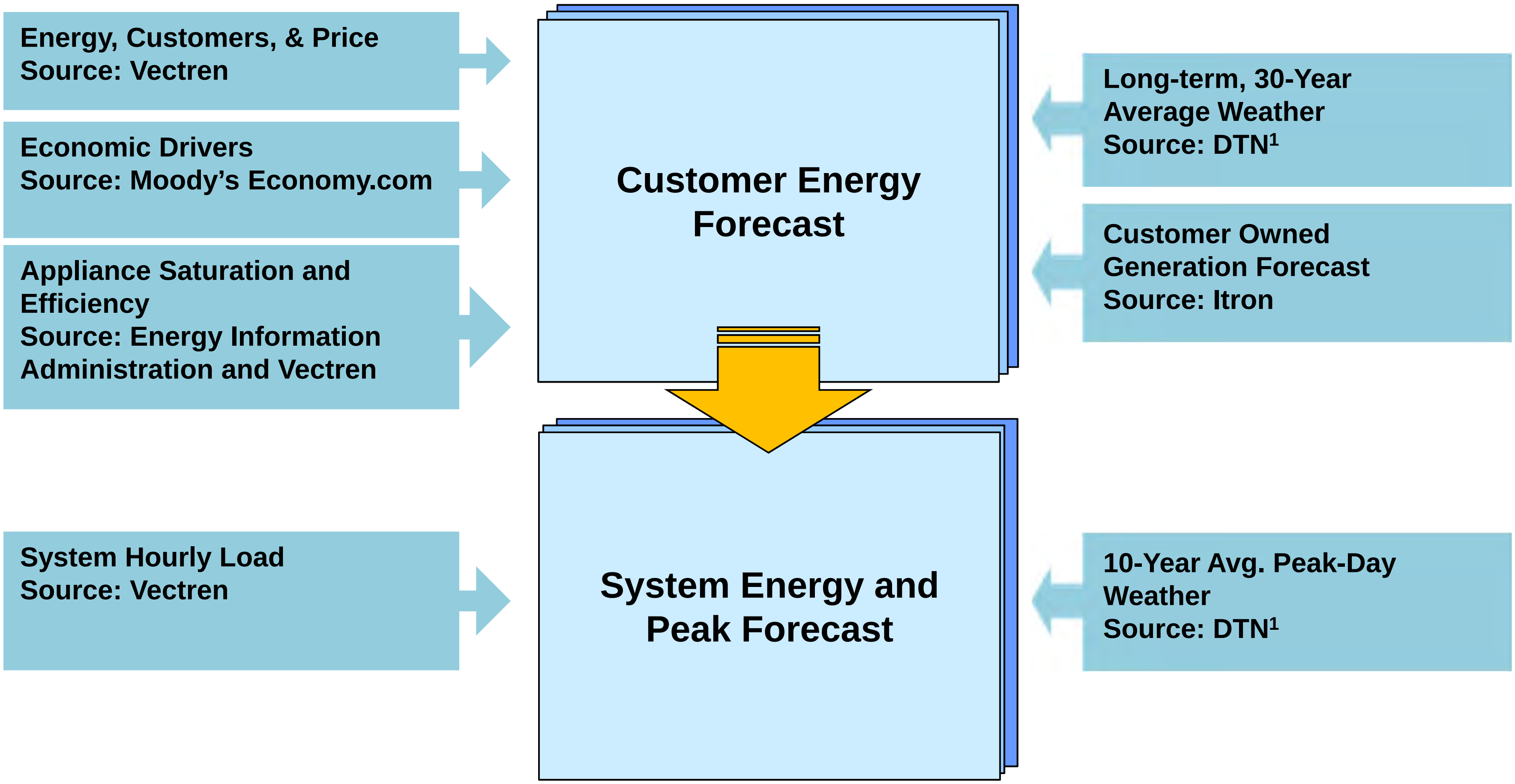
ASAP | APPLIANCE STANDARDS AWARENESS PROJECT



Sources: Association of Home Appliance Manufacturers (AHAM) for energy consumption and volume; U.S. Census Bureau for price.

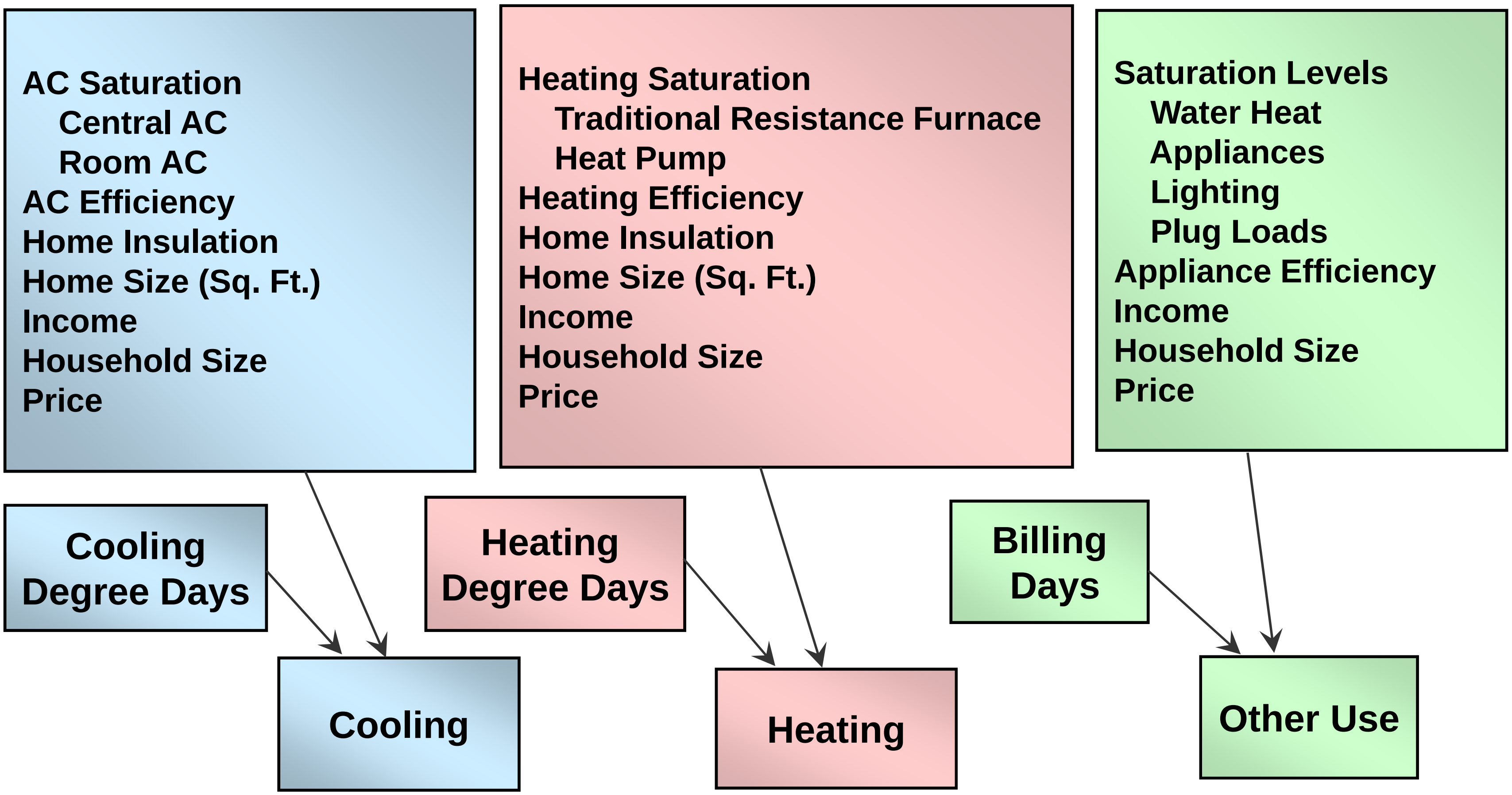
kWh = Kilo Watt Hour

Bottom-Up Forecast Approach

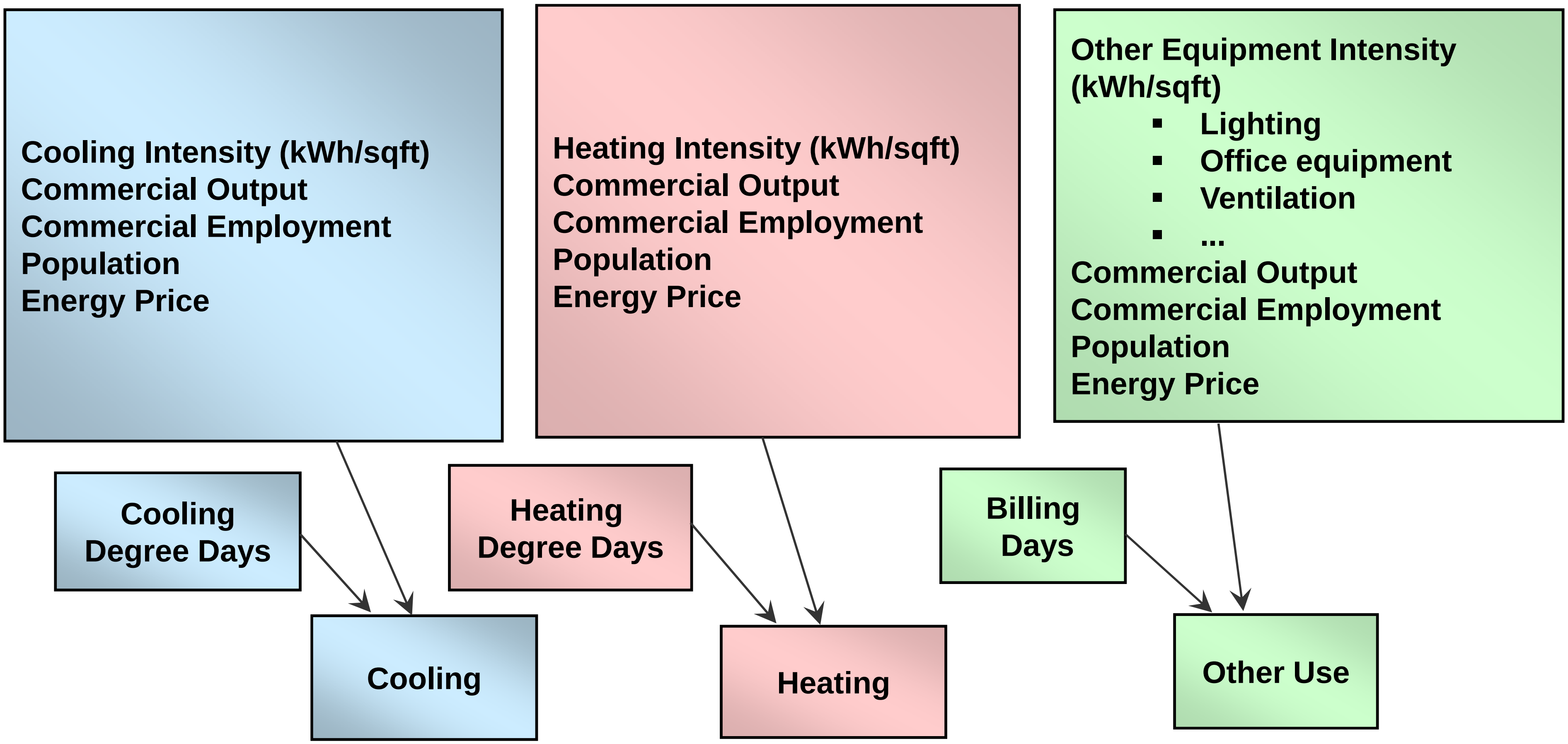


[1] Formerly Data Transmission Network, now known as DTN

Residential Forecast Model

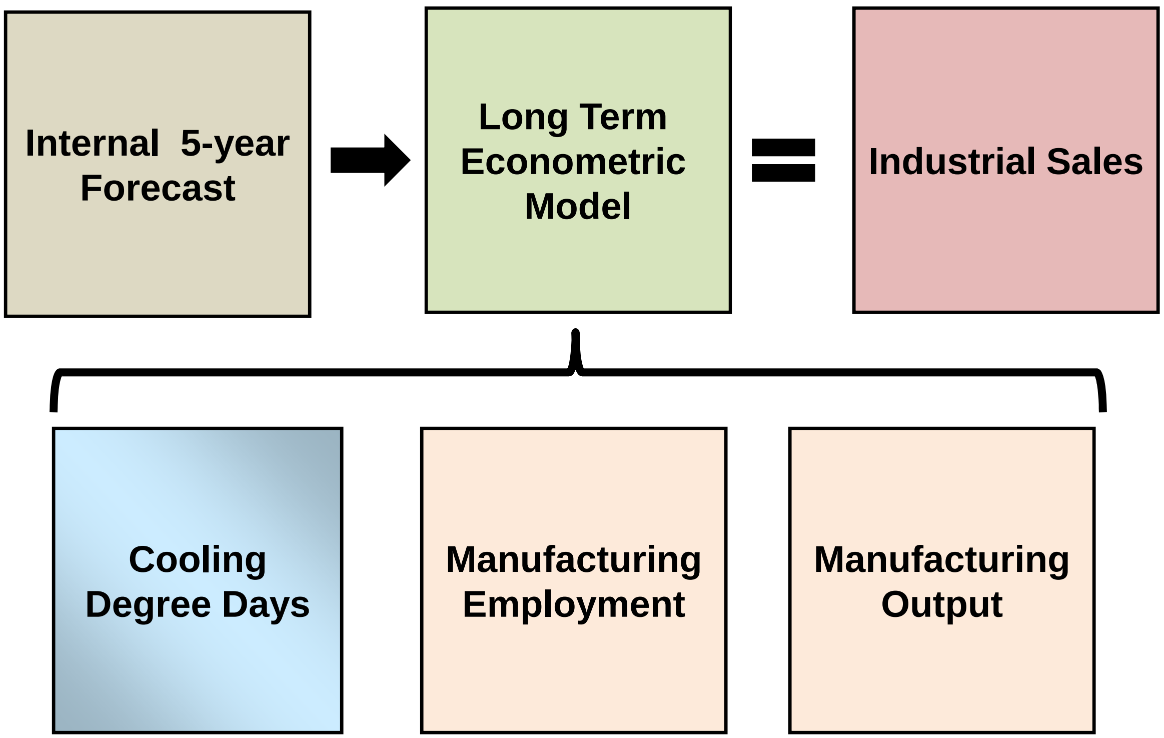


Commercial Forecast Model



Industrial Forecast

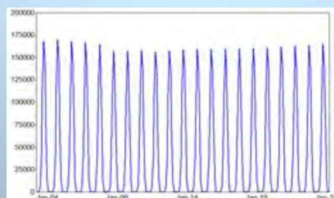
- The industrial (large customer) forecast is a two step approach
  - The first 5 years is based on Vectren's internal forecast
  - The long term growth rate is developed using the econometric model framework



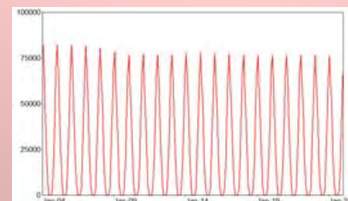
Peak Demand Forecast

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

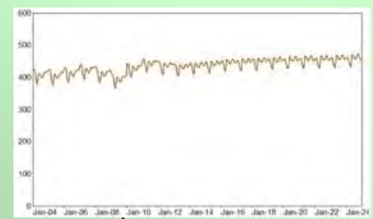
Cooling Load Requirements
- **Residential**
- **General Service**
- **Large Customer**



Heating Load Requirements
- **Residential**
- **General Service**



Base Load Requirements
- **Residential**
- **General Service**
- **Large Customer**
- **Street Lighting**



Peak-Day Temperature

Peak Day Cooling

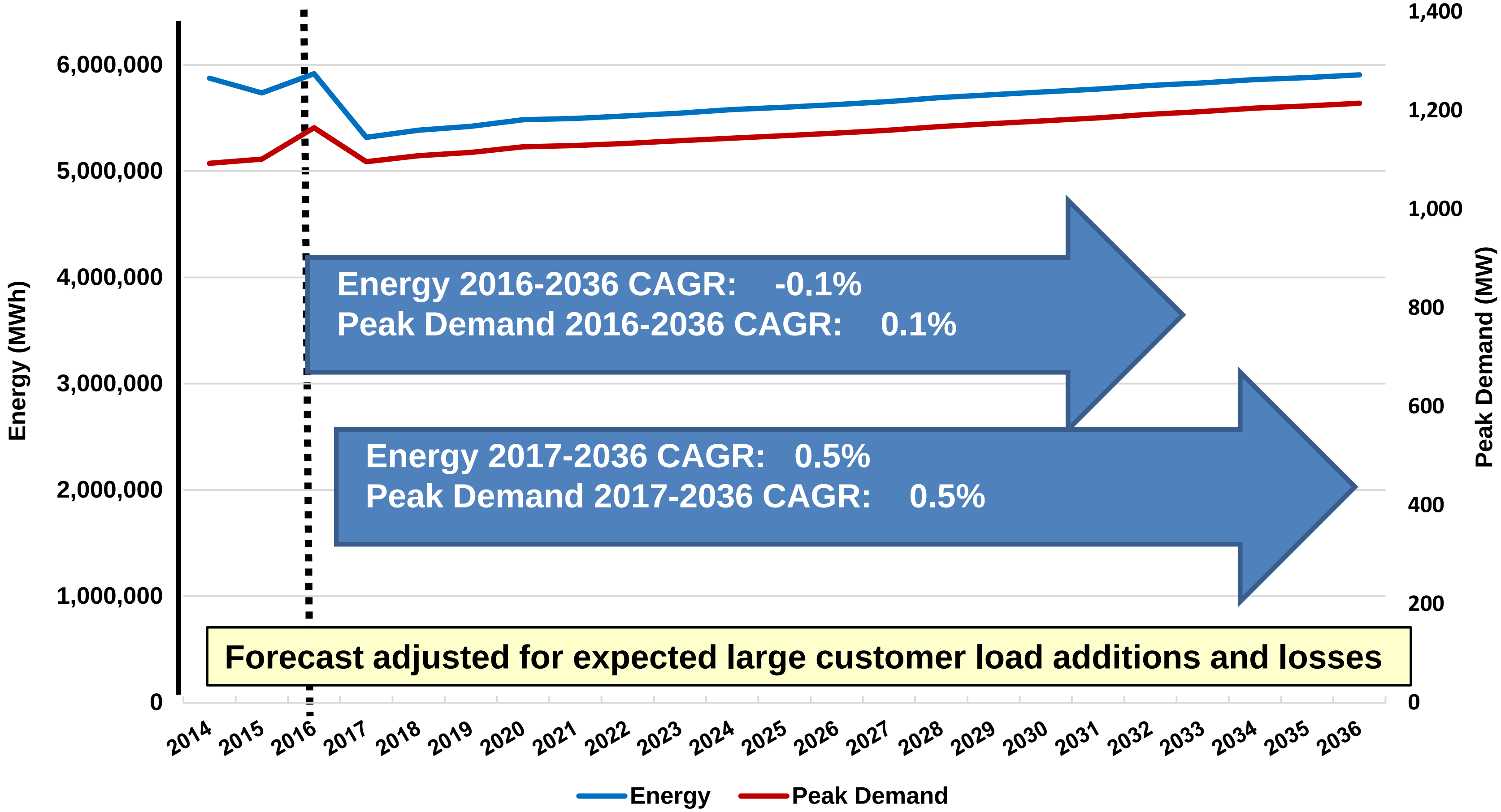
Peak-Day Temperature

Peak Day Heating

Peak Day Base Load

Energy and Demand Forecast[1]

Includes customer-owned generation forecast



[1] Future energy efficiency programs are not included in the sales and demand forecast and will be considered a resource option

CAGR = Compound Annual Growth Rate
MWh = Mega Watt Hour
MW = Mega Watt

VECTREN Energy Delivery

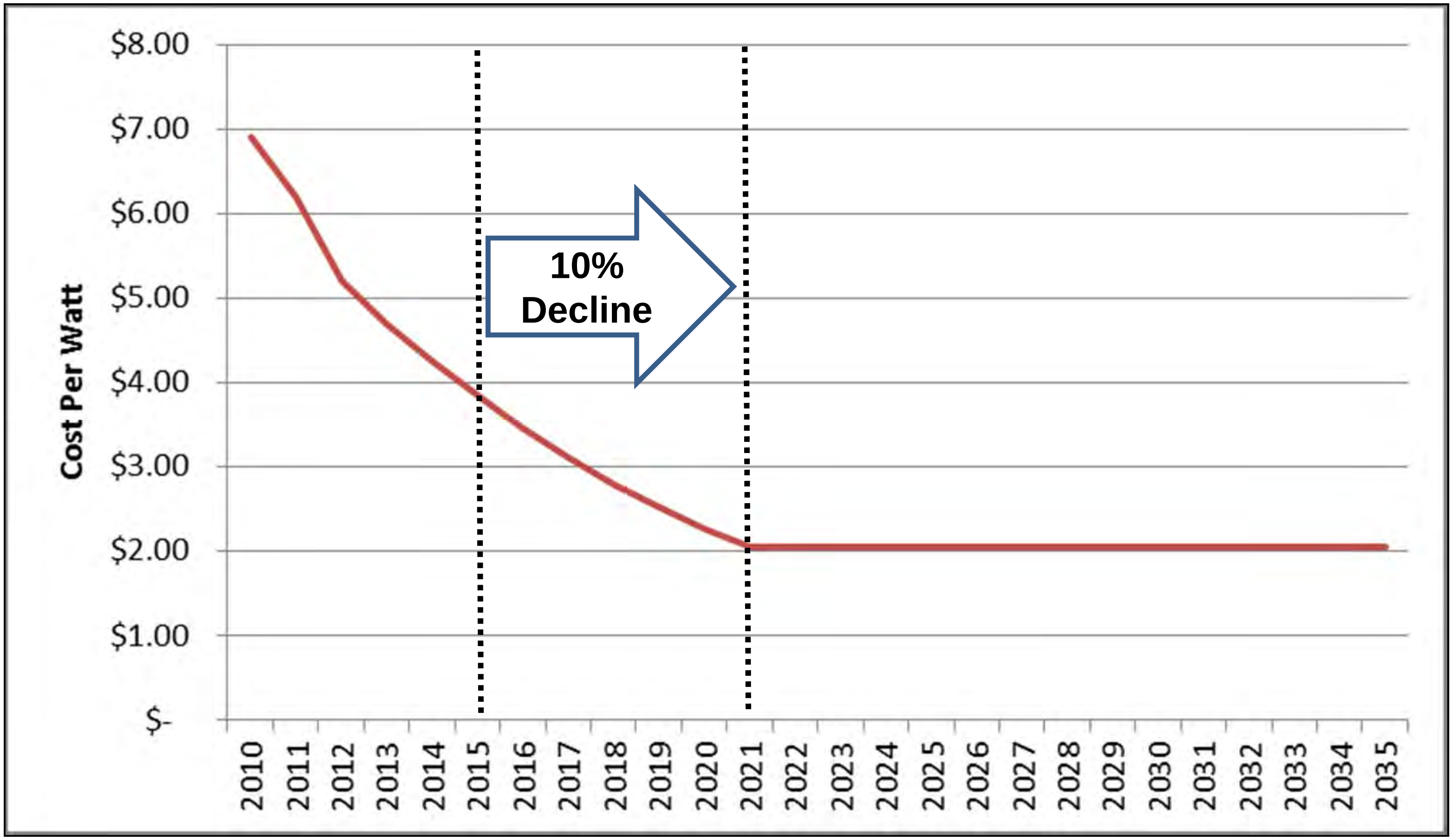
Questions?

Customer-Owned Distributed Generation Forecast

Presented by Michael Russo, Forecast Analyst, Itron Inc.
2016 Vectren IRP Stakeholder Meeting
April 7, 2016

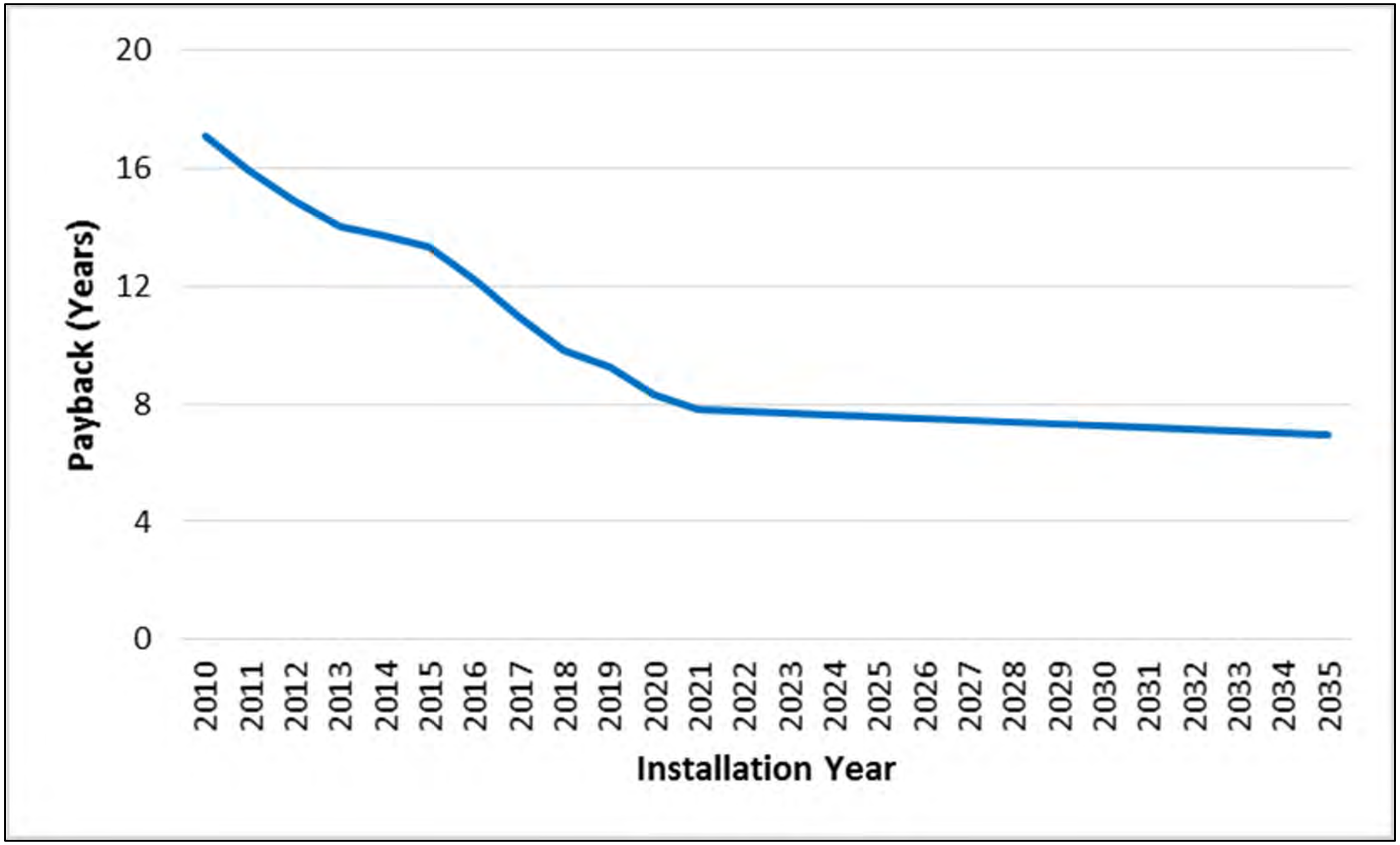
VECTREN
Energy Delivery

Solar System Cost Assumption



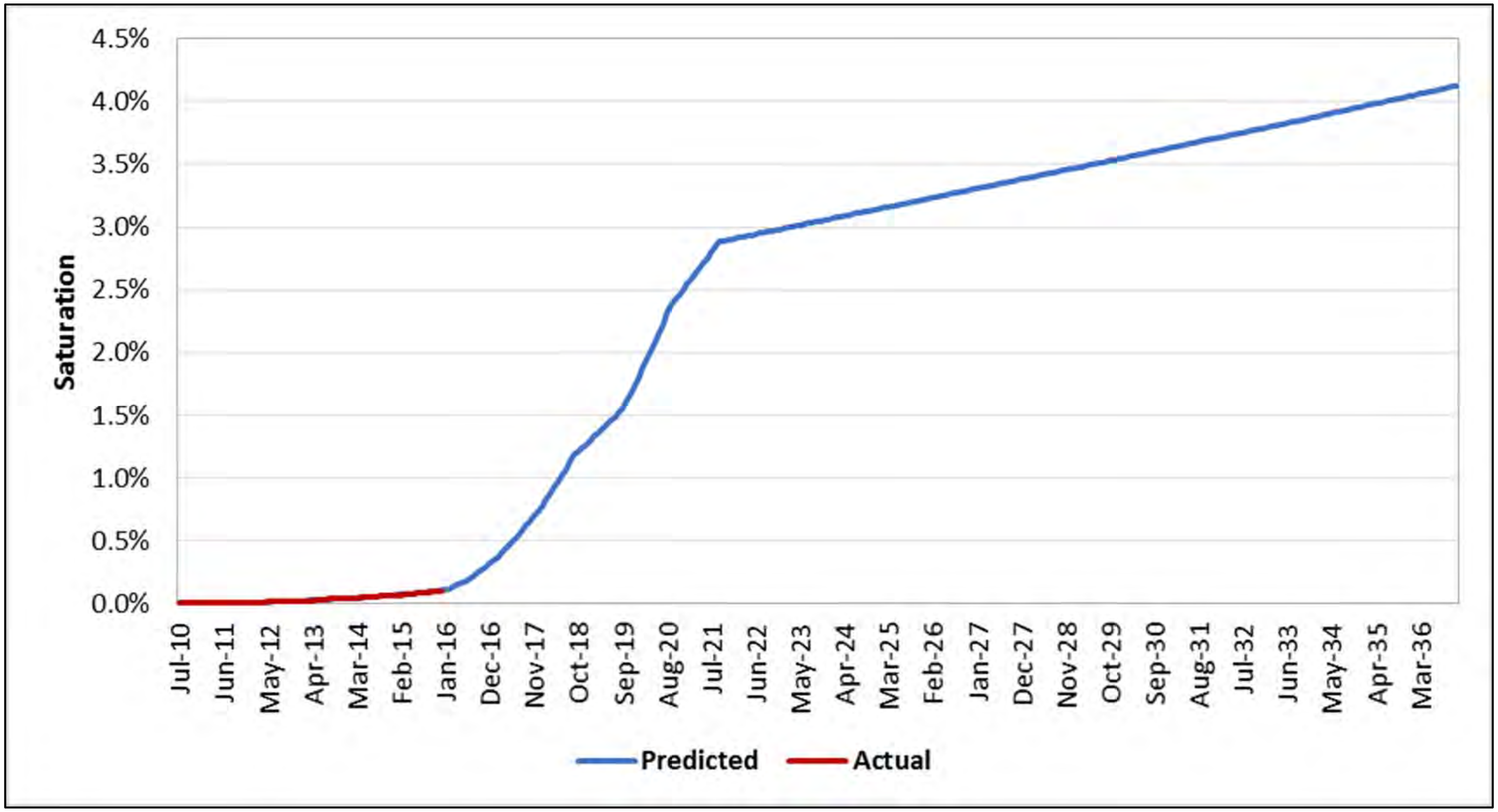
- Cost projections based on the Department of Energy's Sun Shot solar goals

Residential System Payback



- Vectren specific residential solar system payback; incorporates declining solar cost projections, federal tax incentives, and Vectren electric rates

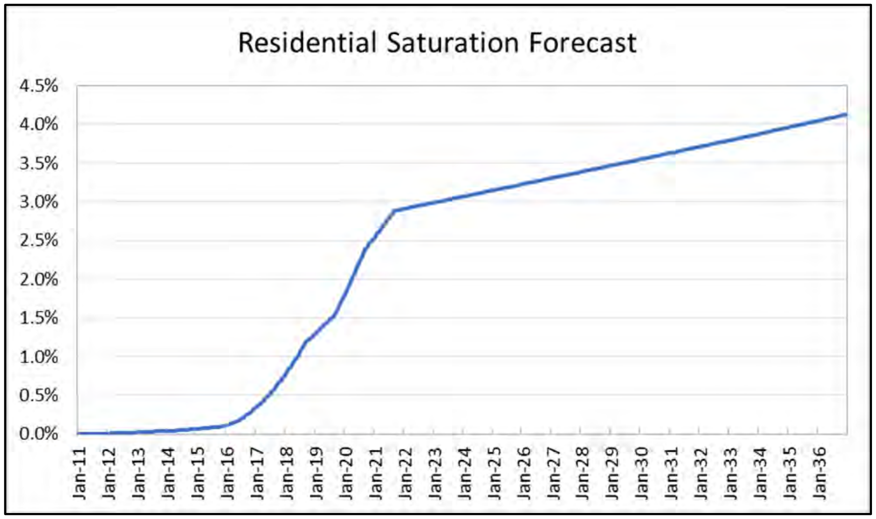
Residential Solar Saturation Model

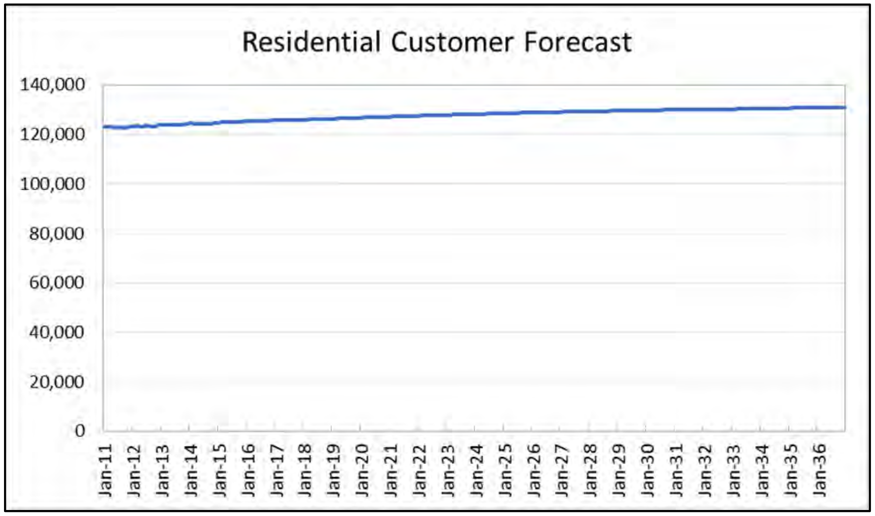


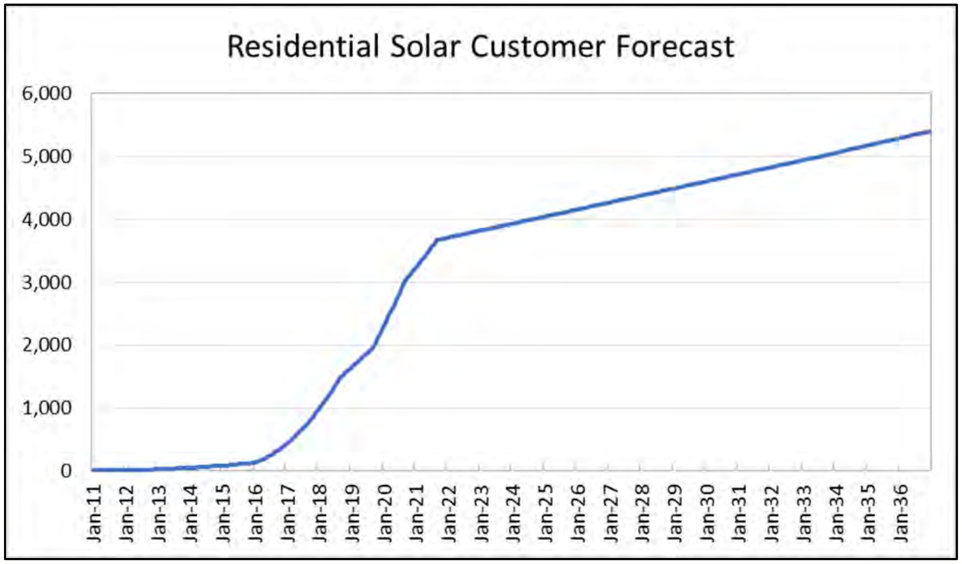
- Solar saturation is modeled as a function of system payback; incorporates declining solar costs, federal incentives, and Vectren electric rates

VECTREN Energy Delivery

Residential Solar Customer Forecast







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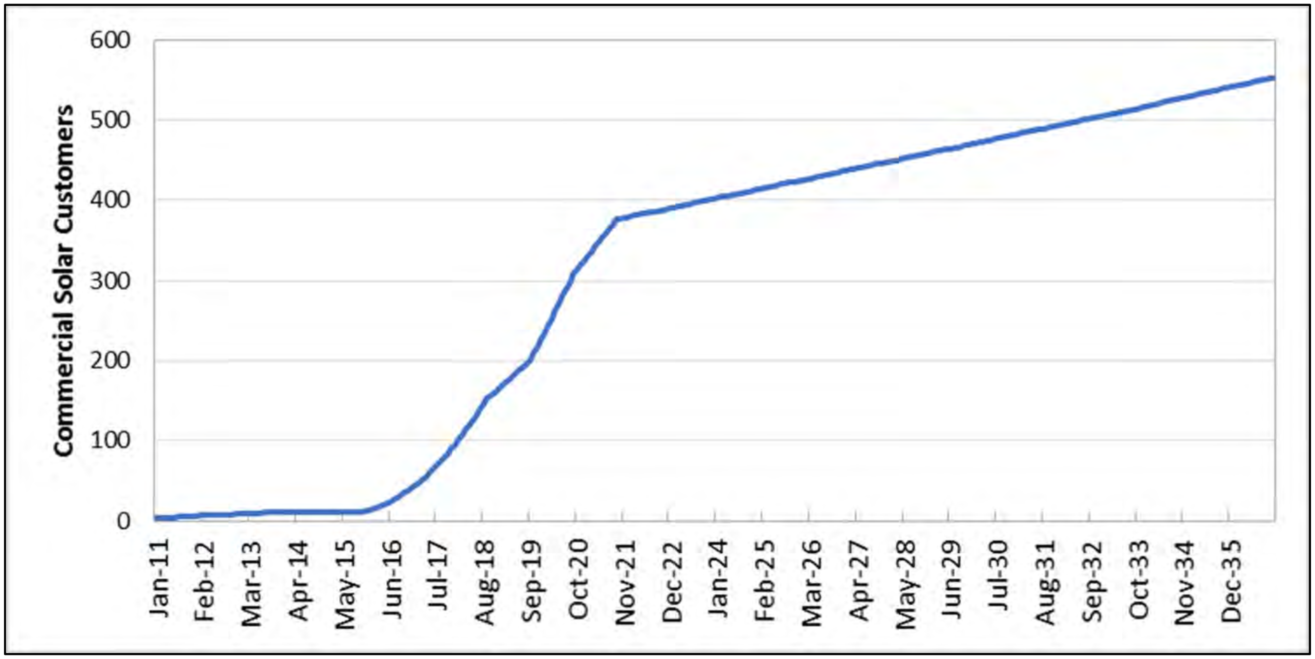
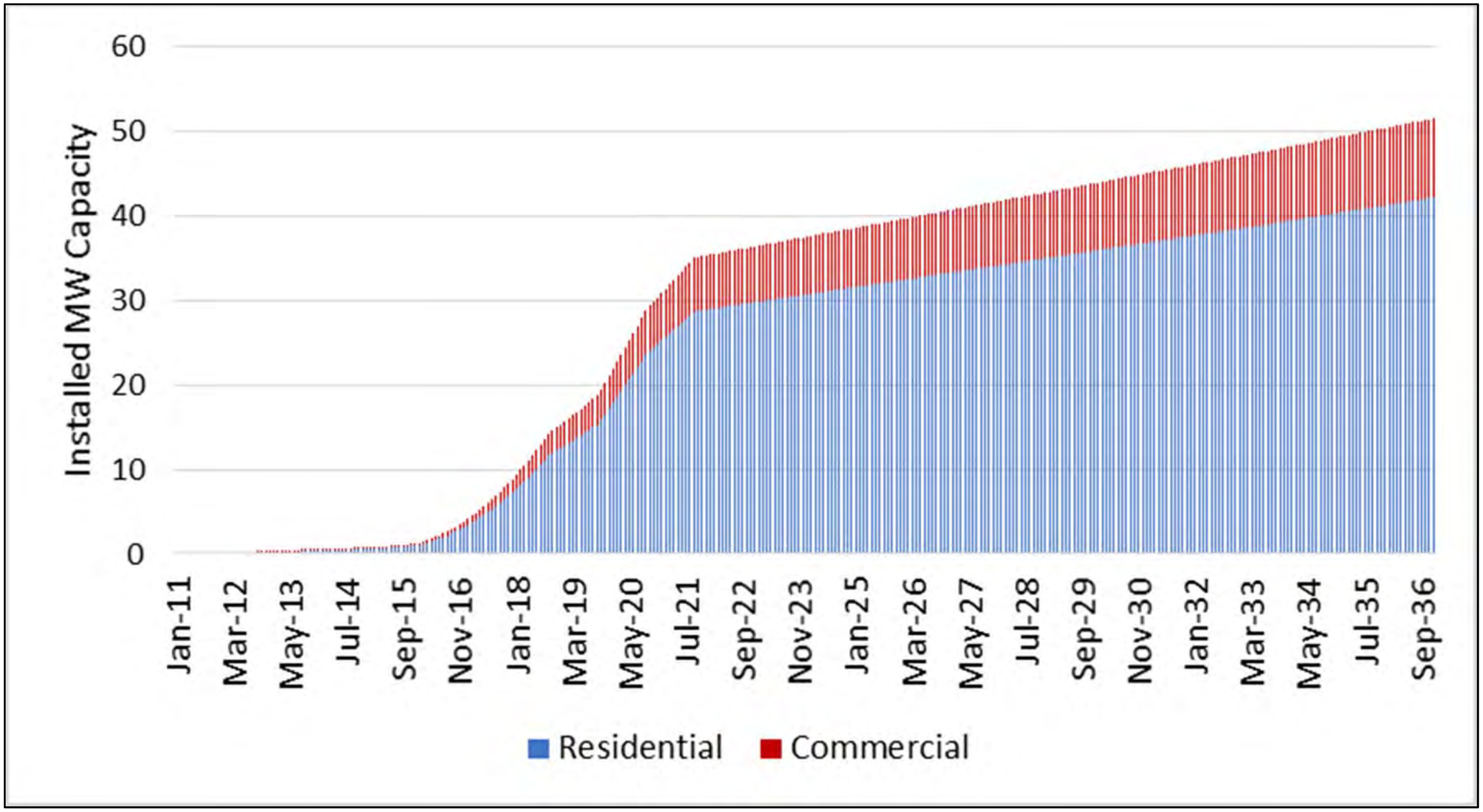
Commercial Solar Customer Forecast

- Limited adoption of commercial systems
  - Physical and ownership constraints
- Relationship between commercial and residential adoption maintained through the forecast period



Total Solar Capacity

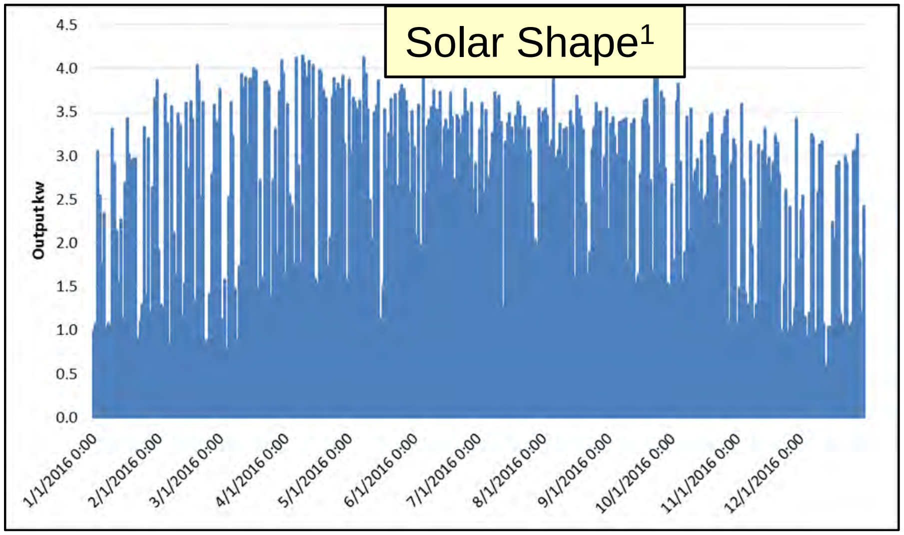


- Capacity forecast is the product of the solar customer forecast and a system size of 7.8 kW for residential systems and 17 kW for commercial system (based on Vectren average)

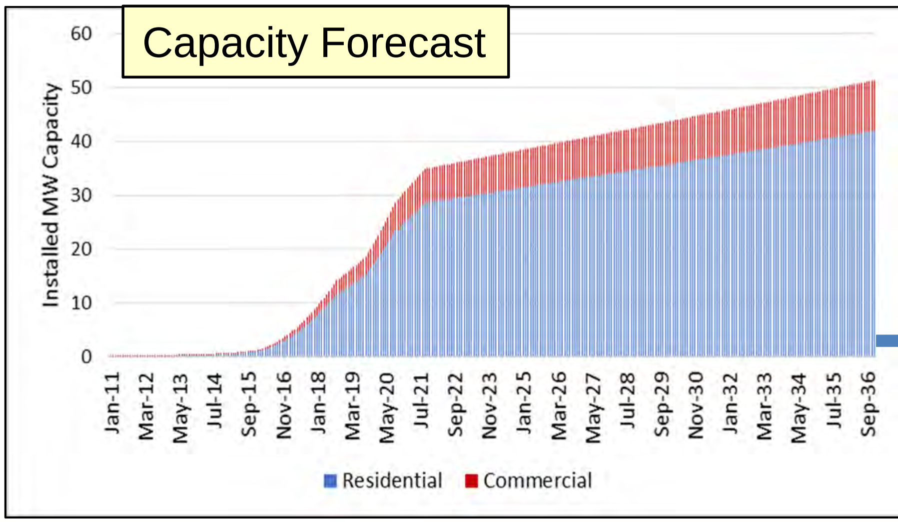
MW = Mega Watt
kW = Kilo Watt

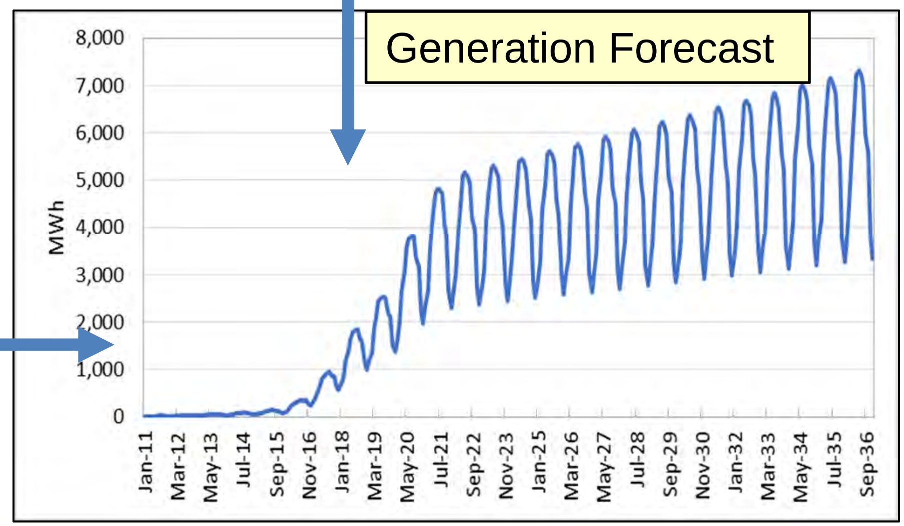
VECTREN Energy Delivery

Solar Generation Forecast (MWh)



Month	Monthly Load Factor
Jan	10.1%
Feb	12.6%
Mar	15.1%
Apr	17.6%
May	19.1%
Jun	20.0%
Jul	19.0%
Aug	18.4%
Sep	16.2%
Oct	14.6%
Nov	10.5%
Dec	8.7%



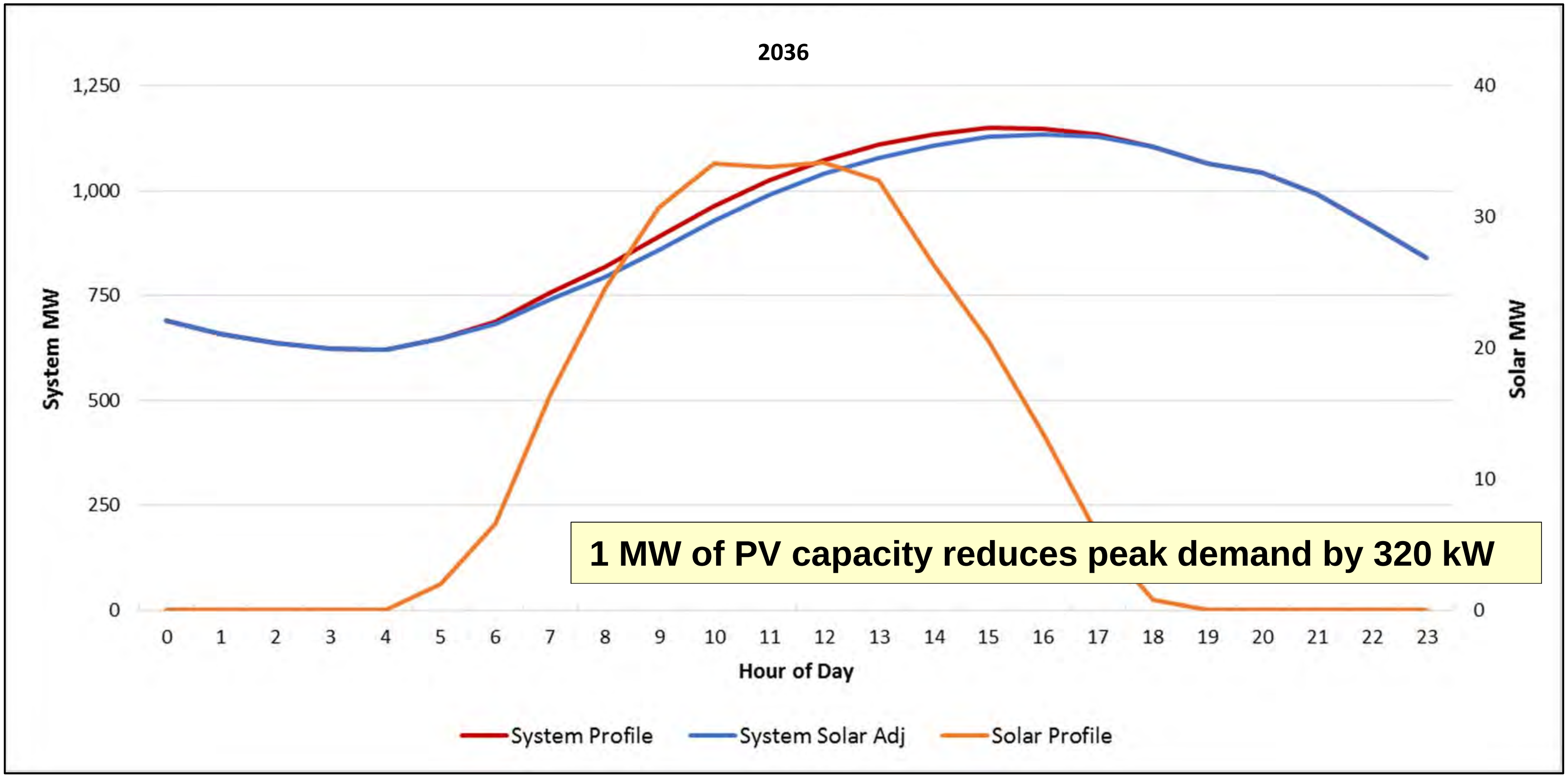


[1] Source: Evansville solar shape from National Renewal Energy Laboratory (NREL), a laboratory of the U.S. Department of Energy

MWh = Mega Watt Hour
MW = Mega Watt
kW = Kilo Watt

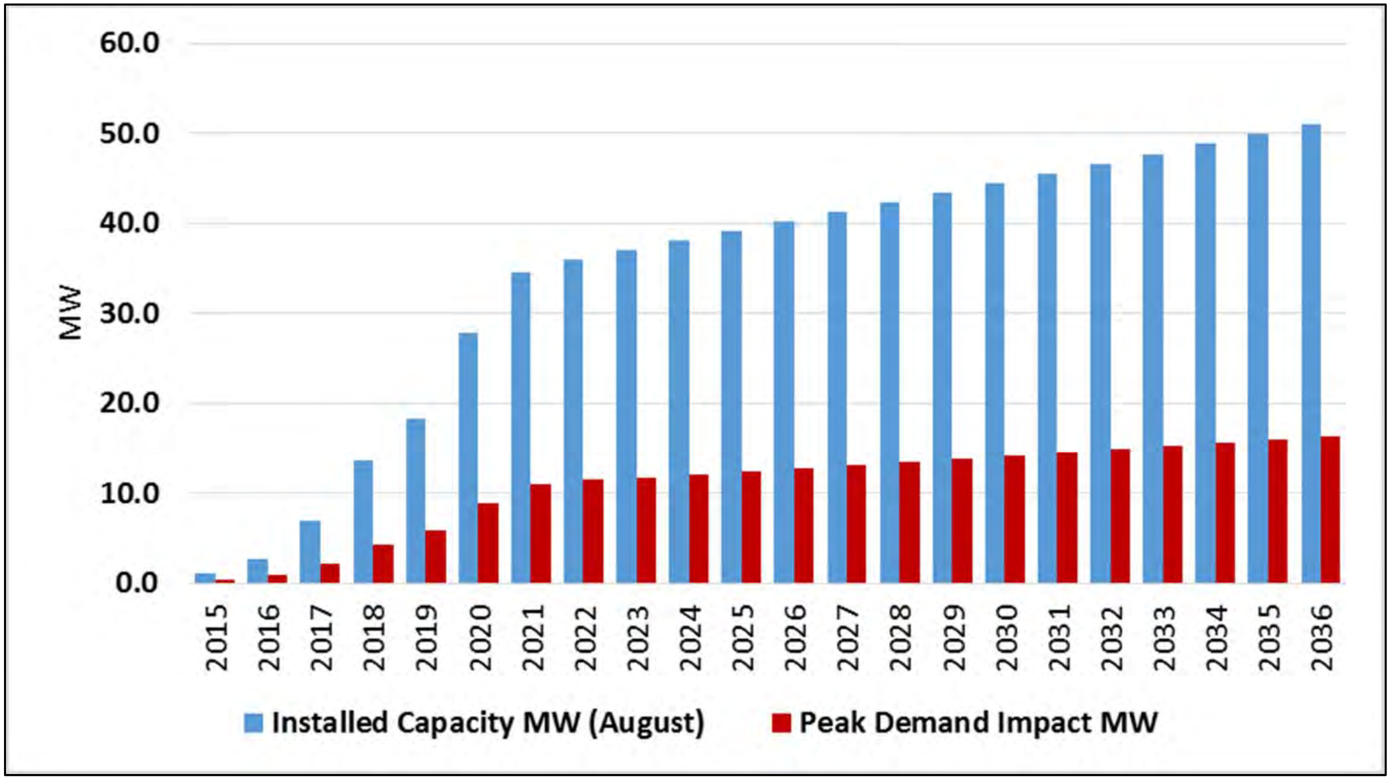
VECTREN Energy Delivery

Impact on Summer Peak Demand



- Demand impacts based on a 0.32 peak demand impact factor – derived by combining the solar generation hourly load forecast with Vectren's system hourly load forecast

Solar Capacity & Demand Impact Forecast



- 51.1 MW of Capacity by 2036 translates into 16.2 MW peak demand impact

MW = Mega Watt

Questions?

2016 IRP
Technology Assessment
Generation Resource Alternatives

Presented by Mike Borgstadt, Project Manager – Burns and McDonnell

2016 Vectren IRP Stakeholder Meeting

April 7, 2016

VECTREN
Energy Delivery

Overview

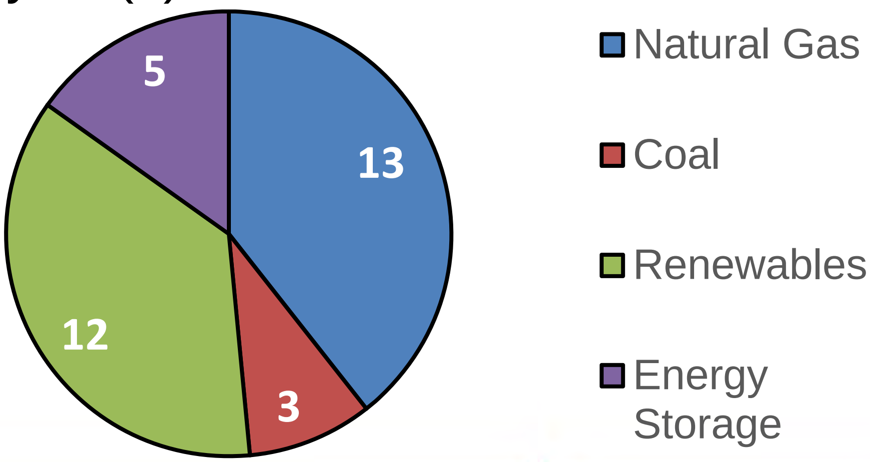
- Burns & McDonnell produced a Generation Technology Assessment that looks at a wide range of generation resources to place into the Strategist model
- The model will create10 and 20 year forecasts for the generation portfolios
- The Strategist model will consider what to deploy and when to meet customer energy requirements based on customer costs
  - Capital Costs
  - Fuel Costs
  - Operations & Maintenance Costs
  - Environmental Compliance Costs

Generation Technology Assessment

Burns & McDonnell's Generation Technology Assessment Report includes the following types of resources:

Generation Resource Options (33):

- Simple Cycle Gas Turbine Technology (4)
- Combined Cycles Gas Turbine Technology (5)
- Combined Heat and Power Turbine Technology (sited at customer facility) (4)
- Coal (2) – (Pulverized coal with carbon capture 500MW & 750MW)
- Integrated Gasification Combined Cycle (1)
- Wind (4)
- Solar Photovoltaic (5)
- Hydro (1)
- Wood (1)
- Landfill Gas (1)
- Battery (4)
- Compressed Air (1)



MW = Mega Watt

Generation Technology Assessment

Examples of candidates for gas fired generation:

Gas Simple Cycle (Peaking Units)	Example 1	Example 2	Example 3	Example 4
Combustion Turbine Type	LM6000	LMS100	E-Class	F-Class
Size (MW)	43.4 MW	99.5 MW	90.1 MW	219.8 MW
Fuel Efficiency (At Full Load)	37.0%	38.6%	30.2%	35.0%
Total Project Costs (2015 $/kW)	$1,880	$1,485	$1,230	$650

Examples of candidates for combined cycle generation:

Gas Combined Cycle (Base / Intermediate Load Units)	Example
Combustion Turbine Type	1x1 F-Class[1]
Size (MW)	317.5 MW
Fuel Efficiency (At Full Load)	51.6%
Total Project Costs (2015 $/ kW)	$1,190

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

kW = Kilowatt
MW = Mega Watt

VECTREN Energy Delivery

Generation Technology Assessment

Example of a candidate for combined heat and power gas generation:

Gas Combined Heat and Power[1]	10 MW Combustion Turbine
Net Plant Electrical Output (MW)	10.3 MW
Fired Plant Steam Output (pph)	117,500
Turbine Cycle Efficiency	27.9%
Overall Plant Efficiency	68.8%
Total Project Costs (2015 $/kW)	$3,874

[1] Utility owned and sited at a customer facility

MW = Mega Watt
pph = Pounds per hour
KW = Kilo Watt

Generation Technology Assessment

Examples of candidates for renewable energy and energy storage:

Renewable Generation & Storage Technologies	Solar Photovoltaic Cells	Indiana Wind Energy	Lithium Ion Battery Storage
Base Load Net Output (kW)	9 MW (Scalable Option)	50 MW (Scalable Option)	10 MW/40 MWh (Scalable Option)
Capacity Factor (Energy output (MWh) 24/7 – 365)	Intermittent 19%	Intermittent 33%	Varies based on market application
Total Project Costs (2015 $/KW)[1]	$2,490	$1,940	$3,050
Peak Planning Capacity (MW credit towards planning reserve margin)	38%	10%	100%

- Solar & battery storage are forecasted at decreasing costs (on a real dollars basis) to be built in the future

[1]Total Project Costs (2015 $/kW) may change based on economies of scale. The Technology Assessment contains unique costs for the different scales of the projects.

MWh = Mega Watt Hour
MW = Mega Watt
kW = Kilo Watt

Questions?

2016 IRP
Technology Assessment
Supplemental Studies
Generation Retrofit Alternatives

Presented by Scott Brown, Manager of Generation Planning

2016 Vectren IRP Stakeholder Meeting

April 7, 2016

VECTREN Energy Delivery

Retrofit Studies Overview

- As previously stated the Burns & McDonnell Technology Assessment looks at a wide range of generation resources that could be built
- Vectren additionally has studied several retrofit projects that could utilize existing generation assets in new ways…

Retrofit Studies Overview

- Retrofits were studied considering various factors:
  - Feasibility (Will it physically fit in the space)
  - Estimated cost to build / retrofit
  - Expected performance
    - MWs of capacity
    - Efficiency
    - CO_2 emissions
    - NO_x emissions
    - SO_2 emissions
    - Mercury
  - Expected costs to operate and maintain
  - Costs and feasibility to deliver the needed fuel

MW = Mega Watt
CO_2 = Carbon Dioxide
No_x = Nitrogen Oxide
SO_2 = Sulfur Dioxide

Potential retrofit projects that were studied:

- Conversion of the existing AB Brown gas turbine peaking units into a combined cycle unit
  - Achieve higher efficiency gas generation
  - Adds a small increment of generating capacity
- Co-firing up to 33% natural gas on the AB Brown Coal and FB Culley Coal Units
  - Reduces CO_2 and other emissions
  - Minimizes gas infrastructure build costs
- Conversion of the existing coal boilers at AB Brown and FB Culley to burn 100% natural gas
  - Eliminates issues associated with burning coal
  - Does not compete well with other 100% gas generation from an operational perspective

CO_2 = Carbon Dioxide

Retrofit Studies Overview

Potential retrofit projects that were studied:

- "Re-Powering[1]" existing coal units into gas fired combined cycle units
  - Reduces build costs compared to building a new Combined Cycle Unit
  - Retains many systems from the former coal unit
    - Steam Turbine and Condenser
    - Electric Generator, Step-up Transformer and Switchyard connections
    - Circulating Water System and Cooling Towers

[1] Repowering consists of reusing the existing steam turbine, electric generator, circulating water system, step-up transformer and switchyard connections from an existing coal unit. The boiler is replaced by using the waste heat from gas turbines via heat recovery steam generators. The gas turbines also drive electric generators.

Questions?

Energy Efficiency Modeling Discussion

Presented by Shawn Kelly, Director of Energy Efficiency

2016 Vectren IRP Stakeholder Meeting

April 7, 2016

VECTREN Energy Delivery

Brief Overview of Vectren Energy Efficiency and Demand Response

- Energy Efficiency is using less energy without impacting level of service
- Vectren's culture has and will continue to fully embrace Energy Efficiency
- Energy Efficiency Programs since 2010 have saved nearly 700 million kWh
  - Enough to power nearly 60,000 homes for one year
- 2015 programs achieved almost 41 million kWh of annual savings
- Vectren offers a variety of residential and business programs[1]
- Successful collaborative oversight board approach with the CAC and OUCC
- Approved 2016 and 2017 plan
  - 74 million kWh of energy savings (16.1 MW of demand savings)
  - Over 1% of eligible sales (non-industrial opt out sales)
- Demand Response
  - 19.3 MW in 2016 from approximately 34,000 Summer Cycler switches
  - 56 MW in 2016 in interruptible contracts

[1] Joint with gas energy efficiency programs where possible to be more cost effective

kWh = Kilowatt hour
CAC = Citizens Action Coalition
OUCC = Office of Utility Consumer Counselor
MW = Mega Watt

Major Energy Efficiency Modeling Assumptions

- Energy Efficiency savings amounts in 2016-2017 will be based on Energy Efficiency plan approved in Cause No. 44645. Included as an existing resource in our dispatch portfolio model
- No minimum level of Energy Efficiency embedded into our sales and demand forecast (IRP will select amount of EE)
- The forecast has not been adjusted for Energy Efficiency already captured in the history (we will monitor going forward)
- Energy Efficiency blocks will include both residential and commercial savings, which allows flexibility in future years to determine the proper mix
- Levelized Energy Efficiency costs over the measure life

Major Energy Efficiency Modeling Assumptions Cont.

- The model will select up to 8 blocks at 0.25% of eligible sales for a total of 2% of eligible sales[1] annually
- If the model selects peaks and valleys of Energy Efficiency, we will re-evaluate as year-to-year inconsistencies in programs is undesirable
- 80% net to gross ratio, which is consistent with our most recent evaluation
- Current plan costs used as the base cost for block pricing
  - Escalated in real dollars based on penetration model. The prices increase from block 1 up to block 8 and increases over time
- 50% load factor to convert energy to demand, consistent with the current plan

[1] 2% is slightly higher than Vectren's most recent market potential study at the high achievable level

Questions?

Stakeholder Questions, Feedback, and Comments

Gary Vicinus – Meeting Facilitator

Vice President and Managing Director, Pace Global

April 7, 2016

Vectren's Next Steps

▪Additional questions and suggestions may be sent to IRP@vectren.com for a period of two weeks after this meeting

▪At the next stakeholder meeting in July, Vectren will discuss and get stakeholder input on:

- its inputs for the 5-7 scenarios;
- the results of our initial Strategist runs;
- the resulting construction of the portfolios;
- the risk assessment assumptions; and
- gather input to build a stakeholder portfolio

▪ At the third and final stakeholder meeting in late fall, Vectren will discuss and get comments on:

- the results of the risk analysis, and
- the preferred portfolio

Vectren 2016 Integrated Resource Plan (IRP)

April 7, 2016 Stakeholder Meeting 1 Summary

The following is a summary of the first of three Vectren IRP stakeholder meetings in 2016 and is meant to provide a high level overview of the discussion on April 7th. Stakeholder feedback gathered at these meetings will be considered within Vectren's evolving IRP process.

Welcome
Carl Chapman, President and Chief Executive Officer

Mr. Chapman opened the meeting and welcomed our guests to Vectren headquarters, located within Vectren's service territory in Evansville, IN. He reminded stakeholders of Vectren's commitment to continuous improvement regarding the IRP process and discussed several changes to the process based on feedback from stakeholders, including: holding a joint education session with stakeholders on February 3, 2016 to discuss the IRP process (presentations and audio files of that session can be found at www.vectren.com/irp), developing a robust risk analysis, and evaluating a wider range of resources to help serve Vectren customers in the future. Finally, Mr. Chapman discussed Vectren's commitment to developing a plan for the future that maintains reliable service, keeps customer cost as low as possible, and is environmentally acceptable. Mr. Chapman then introduced the moderator, Gary Vicinus.

Vectren IRP Process Overview (Slides 4-26)
Gary Vicinus, Pace Global – Managing Director of Consulting Practice

Mr. Vicinus discussed, in detail, Vectren's approach to the 2016 IRP. He discussed the objectives of the IRP and types of metrics that will be used to help ensure that objectives are met. Additionally, Mr. Vicinus talked about how Vectren plans to develop 5-7 scenarios. These scenarios will represent a wide range of possible futures. Vectren will model each of these future states to determine the optimal mix of resources to meet customer load for each. Vectren will develop additional portfolios of resource options for evaluation, including 1-2 developed with stakeholder input. Each will be tested against all scenarios to determine which perform well under a wide range of possible future states. Finally, these portfolios will be analyzed using probabilistic modeling in the risk analysis. Ultimately, one portfolio will be selected as the preferred plan.

Discussion of Uncertainties
Gary Vicinus, Pace Global – Managing Director of Consulting Practice

Mr. Vicinus then lead a workshop exercise to help gather stakeholder input for scenario development. The following topics were raised by stakeholders for consideration:

- Consider additional environmental regulations that have not yet been proposed
- Factor in the Clean Power Plan (CPP) compliance costs
- Factor in specific technology costs for environmental requirements
- Review transmission technology options
- Consider how electric vehicle technology affects your plan

- Consider distributed generation risk mitigation
- Capture avoided costs with the various technologies in the assessment
- Consider diversifying generation
- Consider political/regulatory risk
- Consider Combined Heat and Power (CHP) as a potential resource
- Consider additional cogeneration being developed within the Vectren territory
- Factor in price elasticity of demand into energy and demand forecast

Long-term Energy and Demand Forecast (Slides 27-36)
Matt Rice, Vectren Manager of Market Research & Analysis

Mr. Rice discussed Vectren's long term energy and demand forecast. Demand is expected to be relatively flat over the 20 year time frame due to one large customer's adoption of customer-owned generation in 2017. Beyond 2017, Vectren demand is expected to grow at a moderate pace due to downward pressure from population growth, efficiency gains from appliances, and adoption of customer owned rooftop solar. It was noted that future utility sponsored energy efficiency programs were not netted out of the forecast; however customer owned solar generation was. Mr. Rice described the inputs to each energy and demand model that Vectren utilizes and fielded questions from the audience.

Vectren clarified that the Itron (a forecasting consultant) Statistically Adjusted End-use (SAE) framework is used for residential and commercial energy forecasting and demand forecasting. Additionally, Vectren was asked about how efficiency is incorporated into the energy and demand models. The stakeholder stated that efficiency trends are offset by increased usage of the highly efficient products. Customer behavior is included in these models through historical usage and appliance saturation trends. Stakeholders asked if Vectren's models incorporate climate change. The peak demand forecast incorporates the last 10 years of peak producing weather. The 10 year average incorporates recent weather and helps inform the peak forecast.

Customer-Owned Distributed Generation (Slides 37-47)
Michael Russo, Forecast Analyst, Itron Inc.

Mr. Russo discussed the Vectren specific customer-owned solar model used to forecast adoption of customer-owned solar within Vectren's electric territory. The model that Itron developed is based on payback period, how long it takes for energy savings to pay for the system. It incorporates declining solar system costs, federal incentives, and Vectren electric rates. The results of the forecast show that over 50 MW of solar is likely to be built within the Vectren territory over the next twenty years, which equates to a reduction of 16 MW to the Vectren peak demand forecast in 2036.

Stakeholders asked if solar costs were national or based on the Vectren service territory. National numbers were used. Itron is not aware of a source for solar system costs specific to the Evansville area; however, they are confident that these numbers are reasonable. Another stakeholder asked about the assumption on Vectren rates. It was assumed that Vectren rates would increase by about .9% per year throughout the forecast. Stakeholders had questions about why the installed capacity of more than 50 MW was not applied directly to the demand forecast.

Mr. Russo explained that the peak output for solar panels, in this case around 50 Megawatt (MW), would happen around noon, while Vectren's system peak is around 4:00 pm. By that time, residential solar output is expected to be 32% of the output at noon, based on Evansville specific NREL data.

2016 IRP Technology Assessment Generation Resource Alternatives (Slides 48-54)
Mike Borgstadt, Project Manager, Burns and McDonnell

Mr. Borgstadt discussed the technology assessment that Burns and McDonnell (an engineering company) developed for Vectren's 2016 IRP. The technology assessment describes the cost and performance characteristics of over 30 utility owned resource options, including coal, gas, renewables, and energy storage. He described how these options would be incorporated into Vectren's modeling efforts.

Mr. Borgstadt fielded questions. He discussed how most combined heat and power facilities need to be located adjacent to a thermal host to save on steam piping. One stakeholder asked about the scalability of solar and how that may be an advantage in resource planning. While scalability can be an advantage, it is cheaper per MW to build larger systems. The modeling will take this into account.

2016 IRP Technology Assessment Supplemental Studies Generation Retrofit Alternatives (Slides 55-60)
Scott Brown, Vectren Manager of Generation Planning

Mr. Brown discussed the results of retrofit alternatives for Vectren coal plants, including: conversion from coal to gas, co-firing gas and coal, conversion of gas peaking units into a combined cycle gas unit, and re-powering existing coal units into gas fired combined cycle units. Each of these options will be considered for modeling. While Vectren has enough capacity to meet peak load in the future, these options could be attractive because they could help Vectren emit less CO_2 into the atmosphere. Detailed studies were necessary for these options because they are site specific. The advantages and disadvantages of these options were discussed.

Some of the discussion that followed this presentation was around retrofitting an aging facility and if the condition of the existing equipment was considered. The condition of the facilities was taken into account for these studies. Additionally, some of these options may be screened out prior to optimization modeling based on the levelized cost of energy.

Additionally, there was some discussion to clarify the difference between conversion (bottom of slide 58) and re-powering (slide 59). Conversion is switching the fuel source from coal to gas to generate steam. With re-powering, the old boiler is removed. Two gas turbines would be built, and the waste heat from those two units is run to a heat recovering steam generator that would be used to power the existing steam turbine and run its electrical generator. It is then a combined cycle unit, which is more efficient than the conversion option.

Energy Efficiency Modeling Discussion (Slides 61-65)
Shawn Kelly, Vectren Director of Energy Efficiency

Mr. Kelly began by defining energy efficiency, using less energy without impacting the level of service, and discussed Vectren's on-going commitment to energy efficiency. He discussed Vectren's history of energy efficiency programs and collaborative approach with the oversight board. He then mentioned that we recently received approval for the 2016-2017 plan, which amounts to approximately 1% of eligible sales (residential, commercial, and non-opt out large sales).

Then, Mr. Kelly gave an overview of Vectren's energy efficiency modeling assumptions. For the 2016 IRP, Vectren has not netted out any expected future level of energy efficiency plans from the sales and demand forecast. The optimization model will evaluate the amount of energy efficiency that is needed in each year of the forecast beyond what is included in the 2016-2017 plan.

A stakeholder asked if Vectren has any energy efficiency street lighting programs. Vectren mentioned the recent utilization of LED lighting at the new Hwy. 41 and Lloyd Expressway with LED lighting technology. Vectren is also working to develop an LED program to utilize LED lighting technology on new streetlights as well as replace failed street lights with LED technology for municipal street lighting customers. Mr. Kelly answered some clarifying questions on model assumptions and discussed some difference from Vectren's approach in 2016 vs. 2014. One stakeholder asked if Vectren tracks energy efficiency efforts for large customers that have opted out of Vectren programs. Vectren does not directly track this information but does provide opportunities for customers to opt back into Vectren programs. Finally, one stakeholder suggested that Vectren consider painting black roofs white as an energy efficiency program.

Stakeholder Questions, Feedback, and Comments
Gary Vicinus, Pace Global – Managing Director of Consulting Practice

The final portion of the meeting was dedicated to answering any additional questions and capturing stakeholder feedback. By this point, Vectren stakeholders only had a few questions/comments. One stakeholder wanted to make sure that Vectren was factoring in the risk to coal prices, given the pressure on coal companies. Mr. Vicinus mentioned that future scenarios will be discussed at the July stakeholder meeting. Additionally there was a discussion on the ability of Vectren to finance portfolio options. Vectren assured the stakeholder that the ability to finance resource options will be considered.

Mr. Vicinus mentioned that this is the first of three stakeholder meetings. The next meeting will be held in July to discuss model inputs/assumptions followed by one in the fall to discuss the preferred portfolio.

Vectren Integrated Resource Plan (IRP) Stakeholder Meeting

Gary Vicinus – Meeting Facilitator
Vice President and Managing Director, Pace Global
July 22, 2016

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Vectren Commitments for the 2016 IRP

- Will construct scenarios (possible future states) with coordinated data inputs with a well-reasoned narrative
- Will conduct a probabilistic risk analysis to explore the outer bounds of probability
- Future utility sponsored energy efficiency will be modeled as a resource (not built into the load forecast)
- Will evaluate if retirement dates make sense for any of Vectren's existing coal generating units within the 20 year time frame under each scenario
- Will actively monitor Combined Heat and Power (CHP) developments and will include CHP as a resource option
- Will consider conversion of coal units to gas
- Renewable options will be fully considered in this analysis
- Update the IRP document format to be more readable

First Meeting Recap (April 7th)

- Vectren IRP Process Overview
- Discussion of Uncertainties
- Long-term Energy and Demand Forecast
- Customer-Owned Distributed Generation
- 2016 IRP Technology Assessment Supplemental Studies Generation Retrofit Alternatives
- Energy Efficiency Modeling Discussion

Agenda

1:00 p.m.	Sign-in/ refreshments	
1:30 p.m.	Welcome	Carl Chapman, Vectren President and CEO
1:40 p.m.	Environmental Compliance (CCR, ELG, CPP)	Angila Retherford, Vectren Vice President of Environmental Affairs & Corporate Sustainability
1:55 p.m.	Base Case/Modeling Inputs	Gary Vicinus, Pace Global – Managing Director of Consulting Practice
2:05 p.m.	Busbar Analysis and Optimization Modeling	Matt Lind, Burns & McDonnell – Associate Project Manager
2:40 p.m.	Scenario Development/ Modeling Inputs (including risk assessment)	Gary Vicinus, Pace Global – Managing Director of Consulting Practice
3:20 p.m.	Break	
3:30 p.m.	Stakeholder Discussion and Portfolio Development Workshop	Led by Gary Vicinus, Pace Global – Managing Director of Consulting Practice
4:20 p.m.	Stakeholder Questions and Feedback	
4:30 p.m.	Adjourn	

CCR = Coal Combustion Residuals
ELG = Effluent Limitations Guidelines
CPP = Clean Power Plan

Meeting Guidelines

1. Please hold most questions until the end of the presentation. (Clarifying questions about the slides are fine throughout.) You may write questions on these topics or others using the cards at your table. We will collect them as we go and use to facilitate the discussion.
2. For those on the webinar, we will open the (currently muted) phone lines for questions within the allotted time frame. You may also type in questions via the chat feature.
3. At the end of the presentation, we will open up the floor for "clarifying questions," thoughts, ideas and suggestions.
4. There will be a parking lot for items to be addressed at a later time.
5. Vectren does not authorize the use of cameras or video recording devices of any kind during this meeting
6. Additional questions and suggestions may be sent to IRP@vectren.com for a period of two weeks after this meeting.
7. We will address most verbal questions here. Please allow up to two weeks for responses to written questions submitted to IRP@vectren.com or follow-up questions from this meeting.

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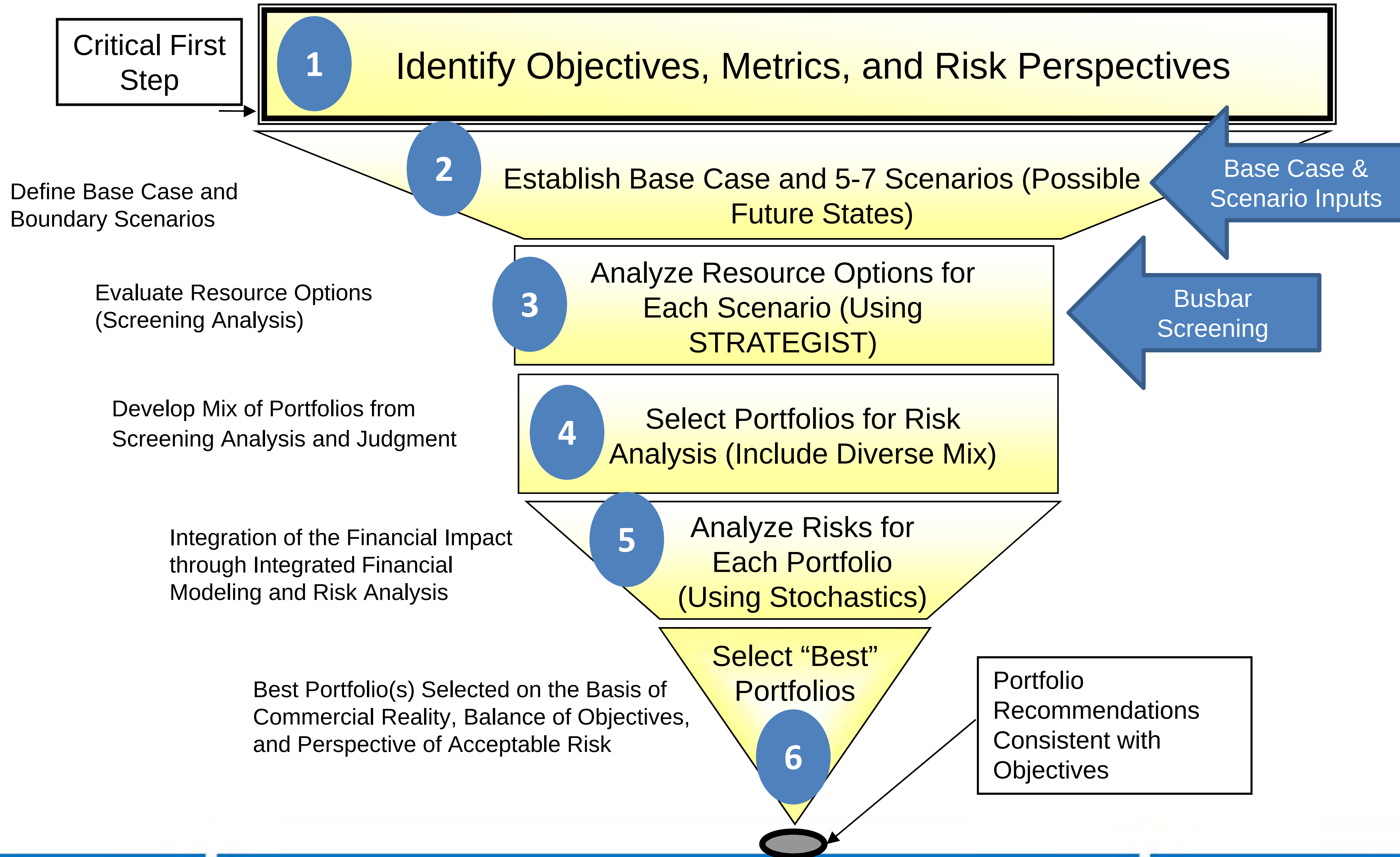

Environmental Compliance (CCR, ELG, CPP)

Angila Retherford, Vectren Vice President of Environmental Affairs & Corporate Sustainability

CCR = Coal Combustion Residuals
ELG = Effluent Limitations Guidelines
CPP = Clean Power Plan

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Review - Environmental Controls

Unit	In Service Date	Installed Generating Capacity	SO_2 Control	NO_x Control	Soot Control
Culley 2	1966	90 MW	Scrubber (1995)	Low NO_x (1995)	ESP (1972)
Culley 3	1973	270 MW	Scrubber (1995)	SCR (2003)	Fabric Filter (2006)
Brown 1	1979	250 MW	Scrubber (1979)	SCR (2005)	Fabric Filter (2004)
Brown 2	1986	250 MW	Scrubber (1986)	SCR (2004)	ESP (1986)
Warrick 4	1970	150 MW	Scrubber (2009)	SCR (2004)	ESP (1970)

SO_2 = Sulfur Dioxide
NO_x = Nitrogen Oxide
ESP = Electrostatic Precipitator (used for particulate removal)
MW = Megawatt
SCR = Selective Catalytic Reduction

Recent Control Additions

- Mercury and Air Toxic Standards (MATS)
  - Set plant-wide emission limits for mercury and other air toxics
  - Compliance deadline: April 2015
  - Installation of sorbent injection systems for MATS compliance
- Sorbent injection systems installed to address incremental increases in H_2SO_4 from installation of selective catalytic reduction technology (SCRs) for NO_x control

H_2SO_4 = Sulfuric Acid
NO_x = Nitrogen Oxide

Coal Combustion Residuals Rule

- Final Rule issued April 2015
- Allows continued beneficial reuse of coal combustion residuals
  - Majority of Vectren's fly ash beneficially reused in cement application
  - Scrubber by-product at Culley and Warrick beneficially reused in synthetic gypsum application.
- Culley and Brown dams to meet new more stringent structural integrity requirements by October 2016
- Three years of groundwater monitoring commenced
- Reviewing close-in-place and clean-closure options
- Timing for commencement of closure activities based upon results of groundwater monitoring or unit retirement
- Same closure strategy assumed under all scenarios

Effluent Limitation Guidelines

- On September 30, 2015, the EPA finalized its new Effluent Limitation Guidelines (ELGs) for power plant wastewaters, including ash handling and scrubber wastewaters.
- The ELGs prohibit discharge of water used to handle fly ash and bottom ash, thereby mandating dry handling of fly ash and bottom ash.
  - Vectren has previously converted its generating units to dry fly ash handling, however we currently anticipate additional modifications to the existing dry fly ash handling system at Brown to comply with the ELGs.
- The ELG compliance deadline is November of 2018, however, the rule provides that utilities can seek an alternative compliance schedule through the water discharge permit renewal process.

Effluent Limitation Guidelines (con't)

- The ELG rules provide an alternative compliance date of December 2023 for generating units that agree to a more stringent set of discharge limits, which could include retirement.
- While we continue to work on engineering solutions to reduce potential compliance costs, the following high-level, preliminary estimates for ELG compliance for Vectren plants will be used for IRP modeling purposes:
  - Culley $75M
    - Includes dry bottom ash conversion, scrubber wastewater treatment and ash landfill construction
  - Brown $115M
    - Includes dry fly ash system upgrades, dry bottom ash conversion, an ash landfill and a new lined process pond
  - Warrick (Vectren's ½ of Unit 4) $40M
    - Includes dry bottom ash conversion, scrubber wastewater treatment and a new ash landfill

Clean Water Act 316(b)

- In May 2014 EPA finalized its Clean Water Act §316(b) rule which requires that power plants use the best technology available to prevent and/or mitigate adverse environmental impacts to fish and aquatic species
- The final rule did not mandate cooling water tower retrofits
- The Brown plant currently uses closed loop technology
- Vectren has commenced the multi-year studies required under the rule
- For purposes of IRP modeling, Vectren has assumed intake screen modifications in the range of $10-$12M for both the Culley and Warrick 4 plants combined and assumed a 2020 deadline for compliance

EPA = Environmental Protection Agency

Future Air Regulations

- Phase II of the Cross State Air Pollution Rule (CSAPR) is effective January 2017
  - Compliance does not require additional controls
- Revised National Ambient Air Quality Standards (NAAQS) for ozone
  - Ozone standard lowered to 70 parts per billion
  - EPA proposing to update CSAPR NO_x limits
    - Compliance does not require additional controls but does increase O&M
- One hour SO_2 Standard
  - Brown plant listed as a contributor of SO_2 in Posey County
  - Vectren agreed to voluntarily revise its operating permit for the Brown units to ensure that Posey County remains in attainment for the revised One Hour SO_2 air quality standard

SO_2 = Sulfur Dioxide
EPA = Environmental Protection Agency
NO_x = Nitrogen Oxide
O&M = Operations and Maintenance

Clean Power Plan

- Rule finalized August 2015. Rule establishes carbon dioxide (CO_2) emission standards for a state's electric generation fleet
  - States can set unit emission limits, or adopt a mass-based or rate-based allowance trading program
- Preliminary state implementation plans were to be due in September 2016, with an opportunity to request a 2 year extension, but implementation of the rule has been stayed by order of the US Supreme Court
  - Currently do not anticipate final orders on judicial review until 2017 at the earliest
- For purposes of base case assumptions, Vectren assumed that the CPP would be upheld by the US Supreme Court, but compliance would be delayed two years (2024) due to the implementation of the stay

Base Case/ Modeling Inputs

Gary Vicinus, Pace Global – Managing Director of Consulting Practice

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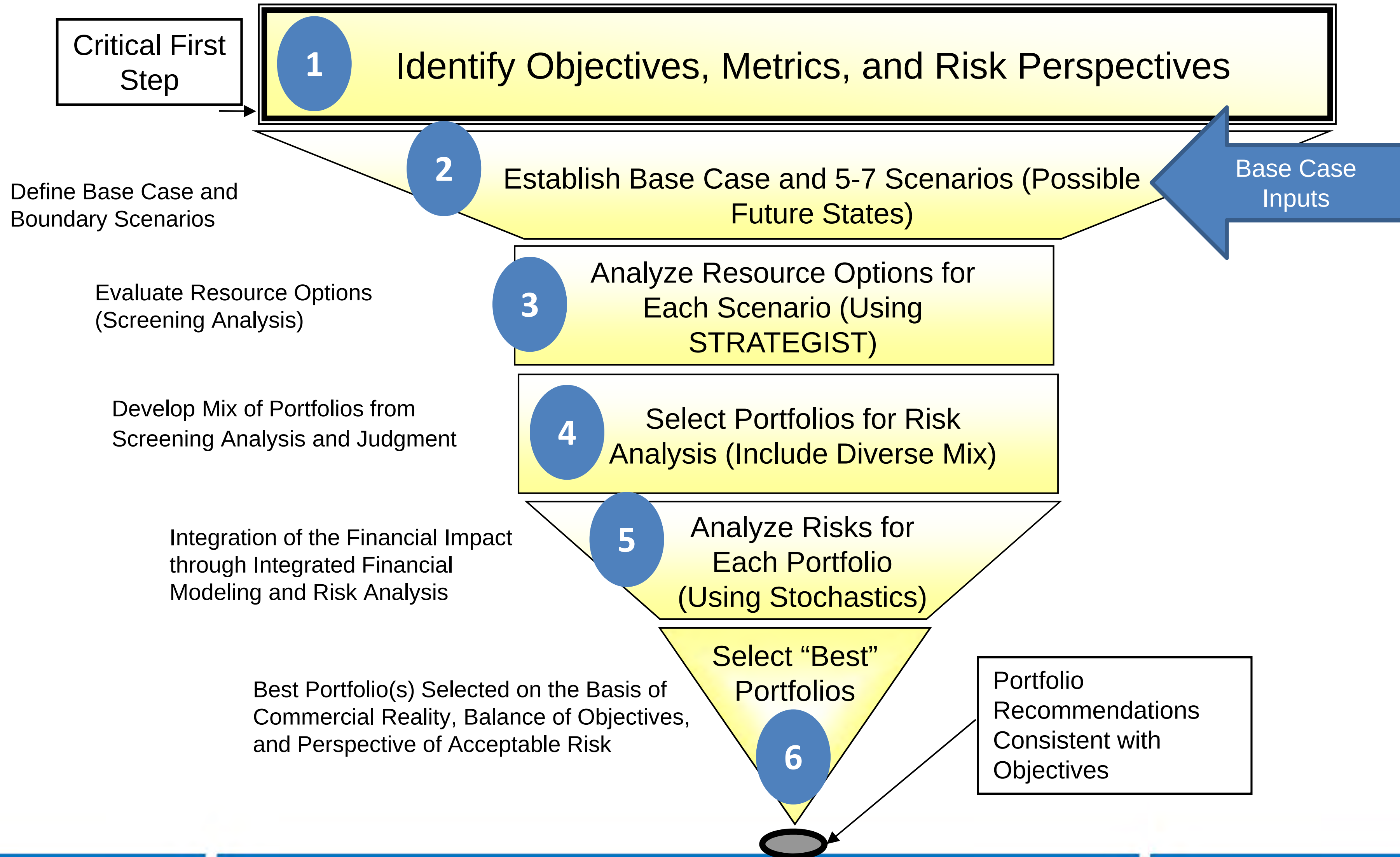


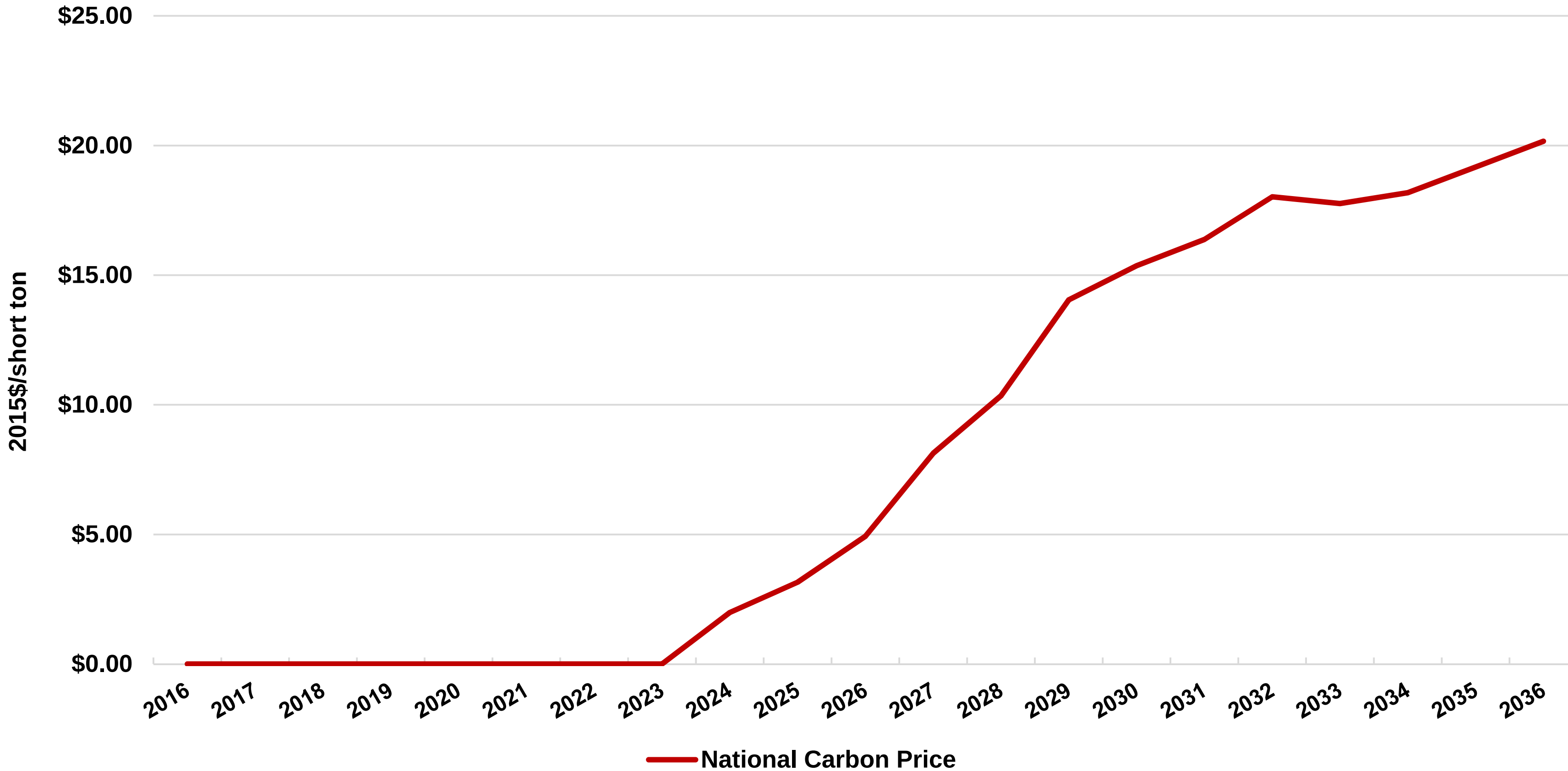
Vectren's Base Case Assumptions

Vectren surveyed and incorporated a wide array of sources in developing its base case assumptions, which reflect a current consensus view of key drivers in power and fuel markets.

- Base 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 minemouth and delivered coal prices
  - Carbon (CO_2) prices
  - Capital cost decline curves for various generation technologies
  - On- and off-peak power prices
- Vectren uses a "consensus" base case view by averaging forecasts from several sources, including recent forecasts from Pace Global, Ventyx, Wood Mac, PIRA, and EVA where available
  - This ensures that reliance on one forecast or forecaster does not occur

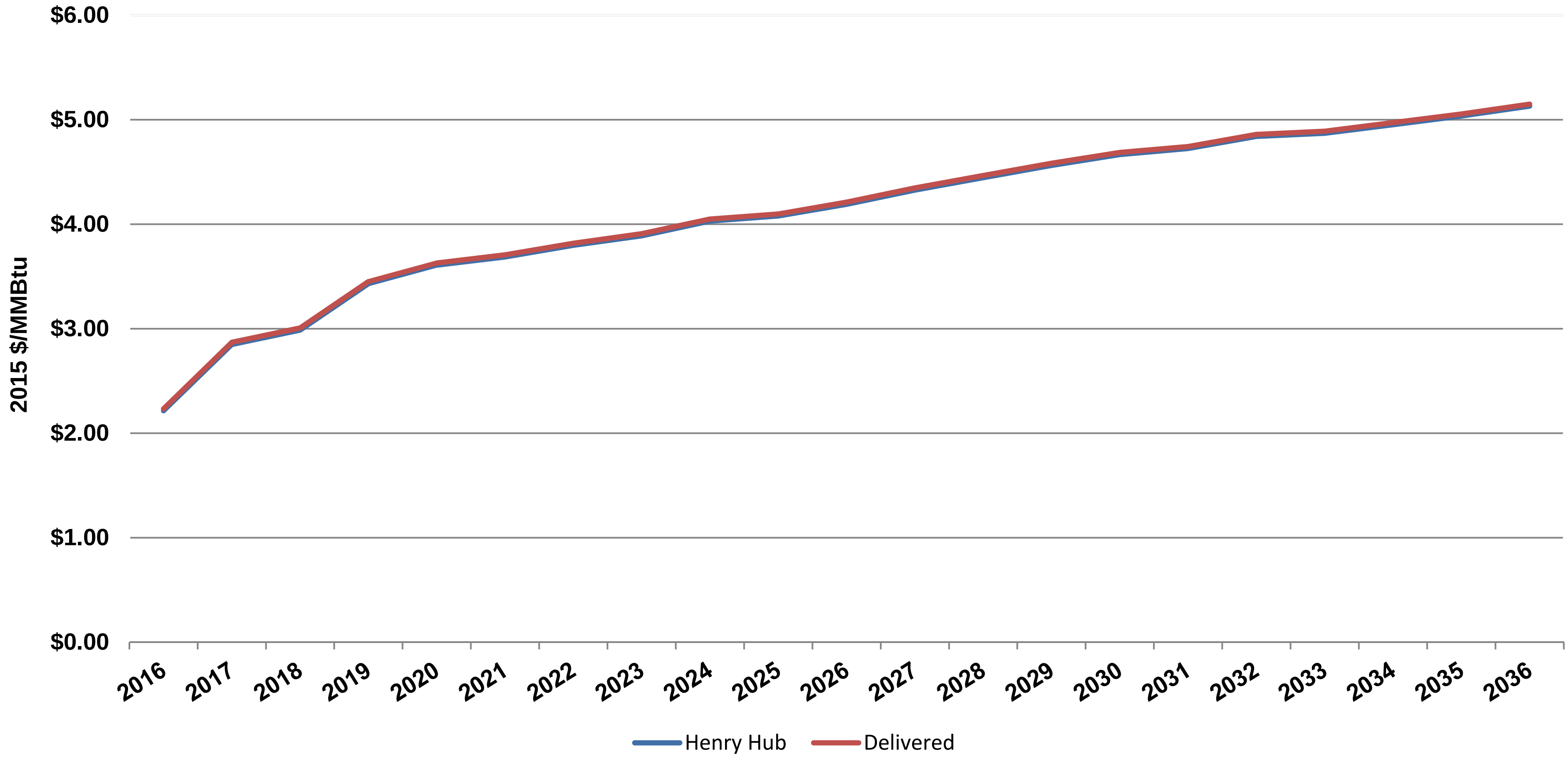
MISO = Midcontinent Independent System Operator

Base Case Carbon Price Forecast
CO_2 Price (2015$/short ton)



Note: Forecast assumes a two year delay in the implementation of the Clean Power Plan.

Base Case Natural Gas Price Forecast
Henry Hub and Delivered to Indiana (2015$/MMBtu)



Note: $0.02/MMBtu transportation adder over Henry Hub included in delivered gas price.

MMBtu = One Million British Thermal Units

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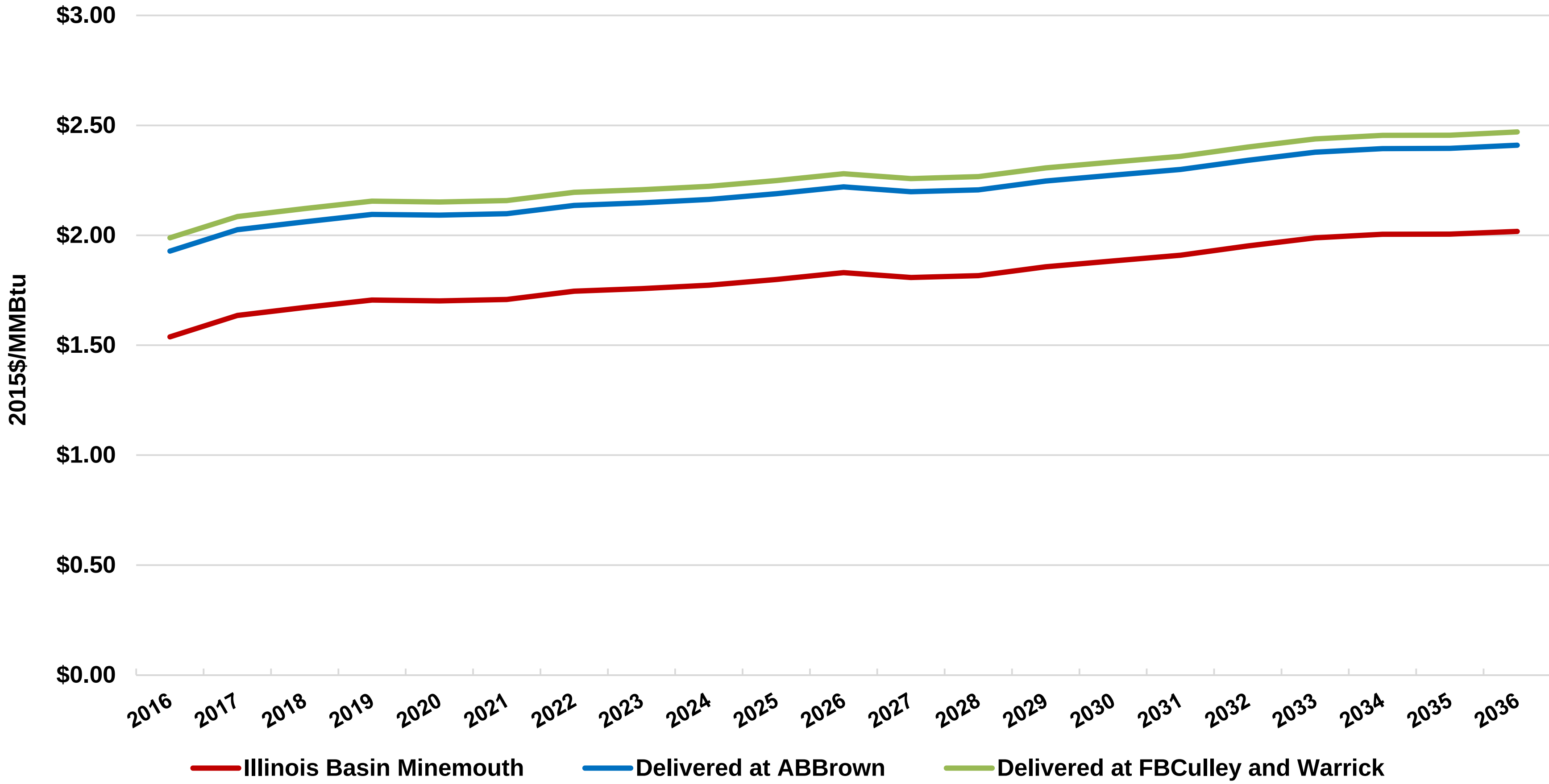
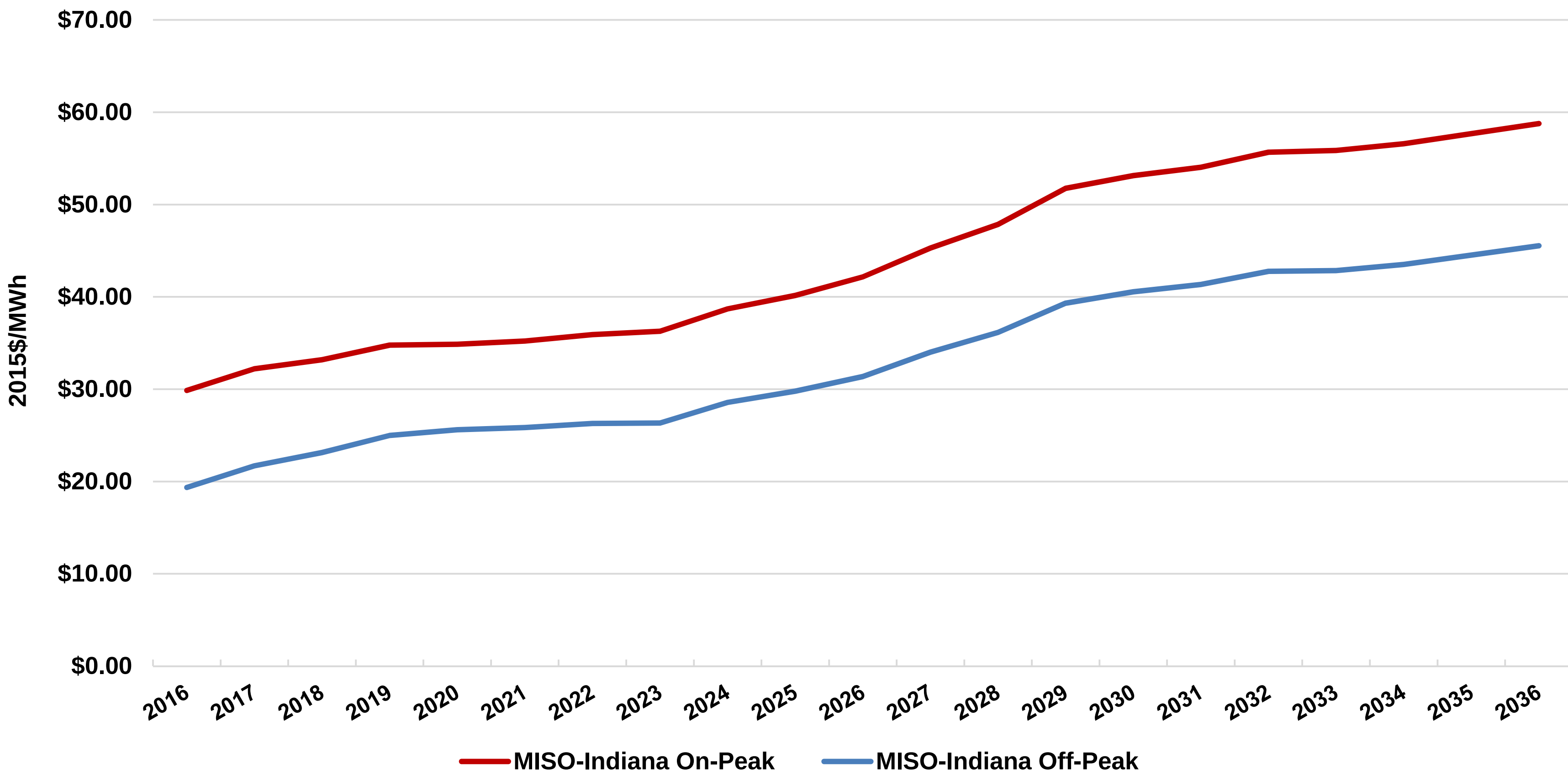
Base Case Coal Price Forecast

Illinois Basin Minemouth and Delivered (2015$/MMBtu)



MMBtu = One Million British Thermal Units

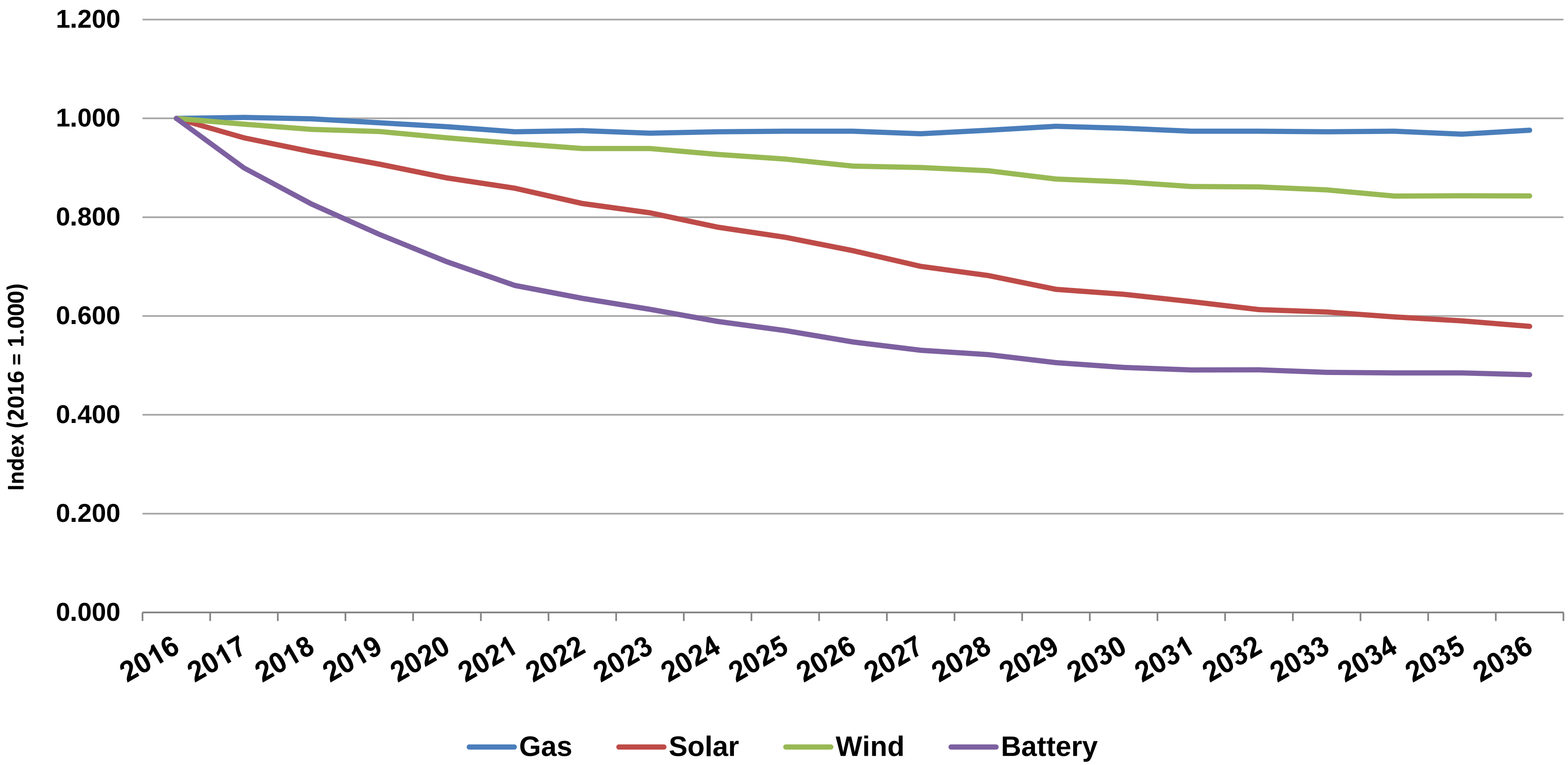
Base Case Power Price Forecast
MISO-Indiana On-Peak and Off-Peak (2015$/MWh)



Source: Pace Global
Note: Power price forecast is an output of Pace Global's AuroraXMP power dispatch model using the Base Case load, gas, coal, CO_2, and capital cost forecasts

MISO = Midcontinent Independent System Operator
MWh = Megawatt Hour
CO_2 = Carbon Dioxide

Base Case Capital Costs
All-In Capital Costs (Index: 2016=1.000)



Note: 2016 overnight capital costs provided by Burns & McDonnell. Capital cost decline curves to 2036 provided by Pace Global.

Questions?

Busbar Analysis and Optimization Modeling

Matt Lind, Burns & McDonnell – Associate Project Manager

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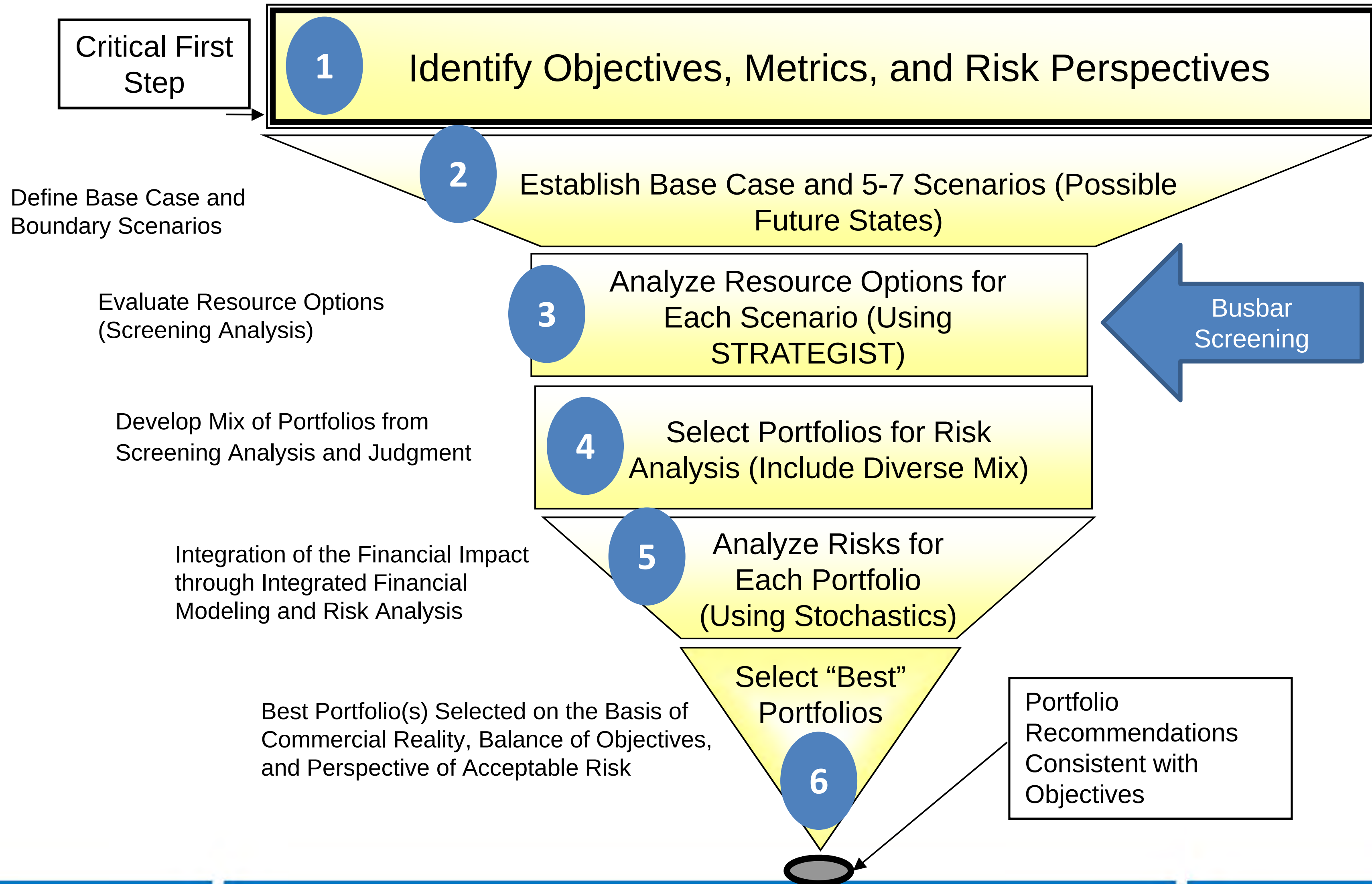
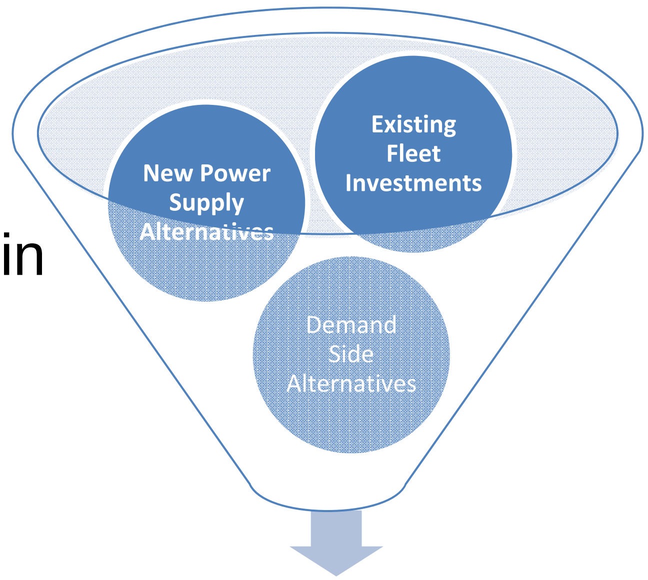


Resource Modeling

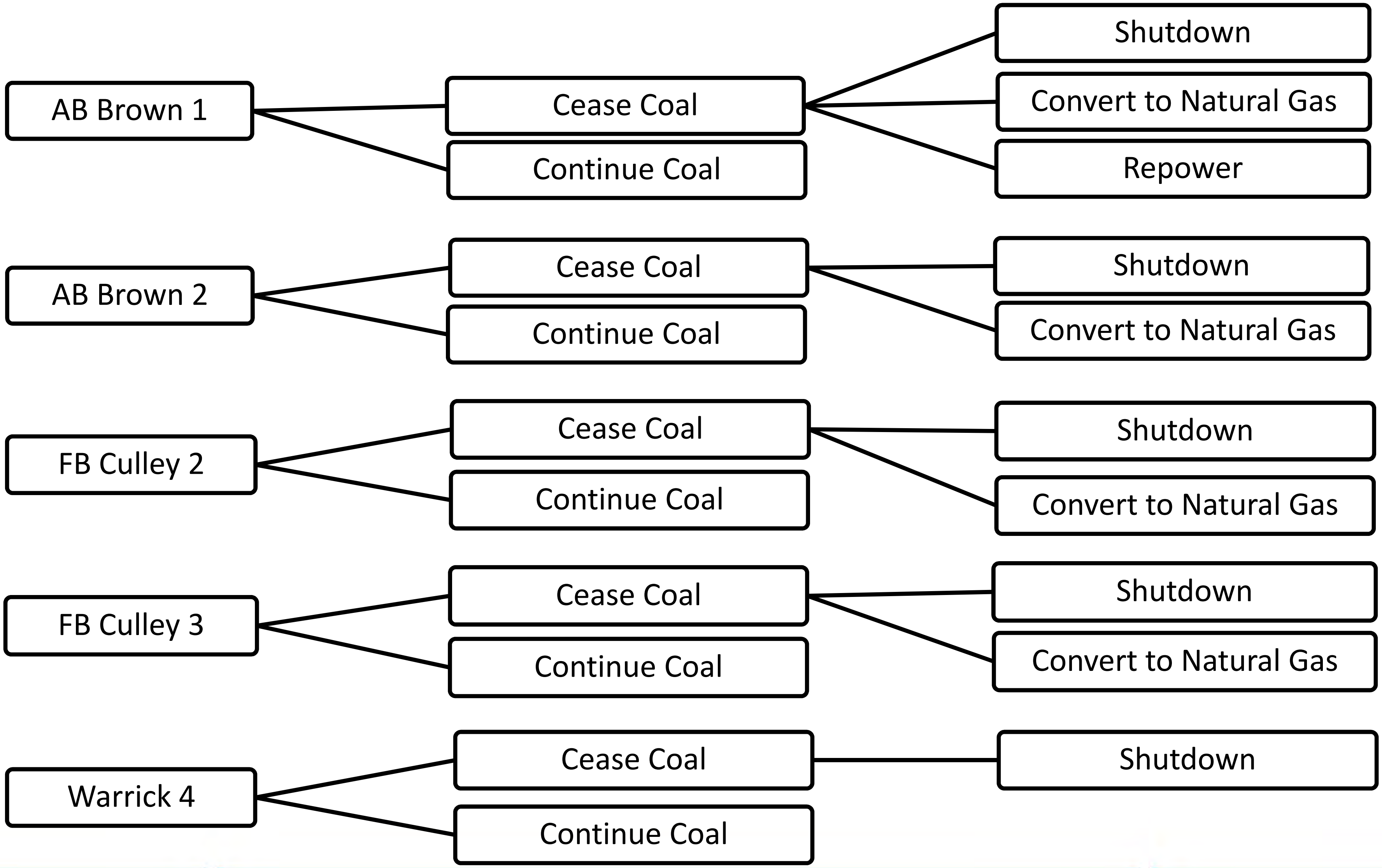
- **IRP Purpose**: To select a portfolio to best meet customers' needs for reliable, low cost, environmentally acceptable power over a wide range of future market and regulatory conditions

- Objectives:
  - Maintain sufficient capacity to satisfy planning reserve margin
  - Minimize power cost
- Inputs:
  - Existing fleet
  - New supply-side alternatives
  - Demand-side alternatives



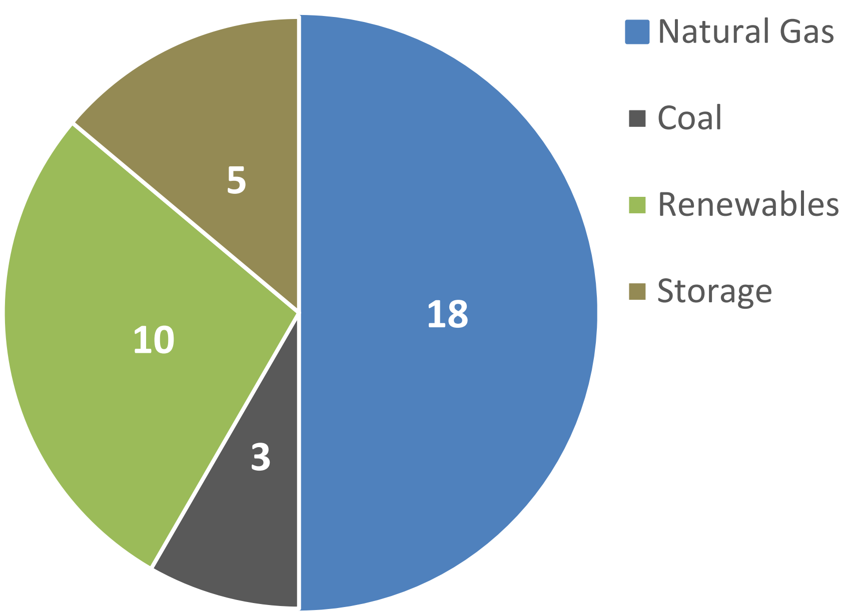
Portfolio Development

Existing Unit Alternative Paths



Busbar Screening

- 36 new power supply choices from Technology Assessment
- Must filter/screen the options to a smaller data set
- Will screen for each world view

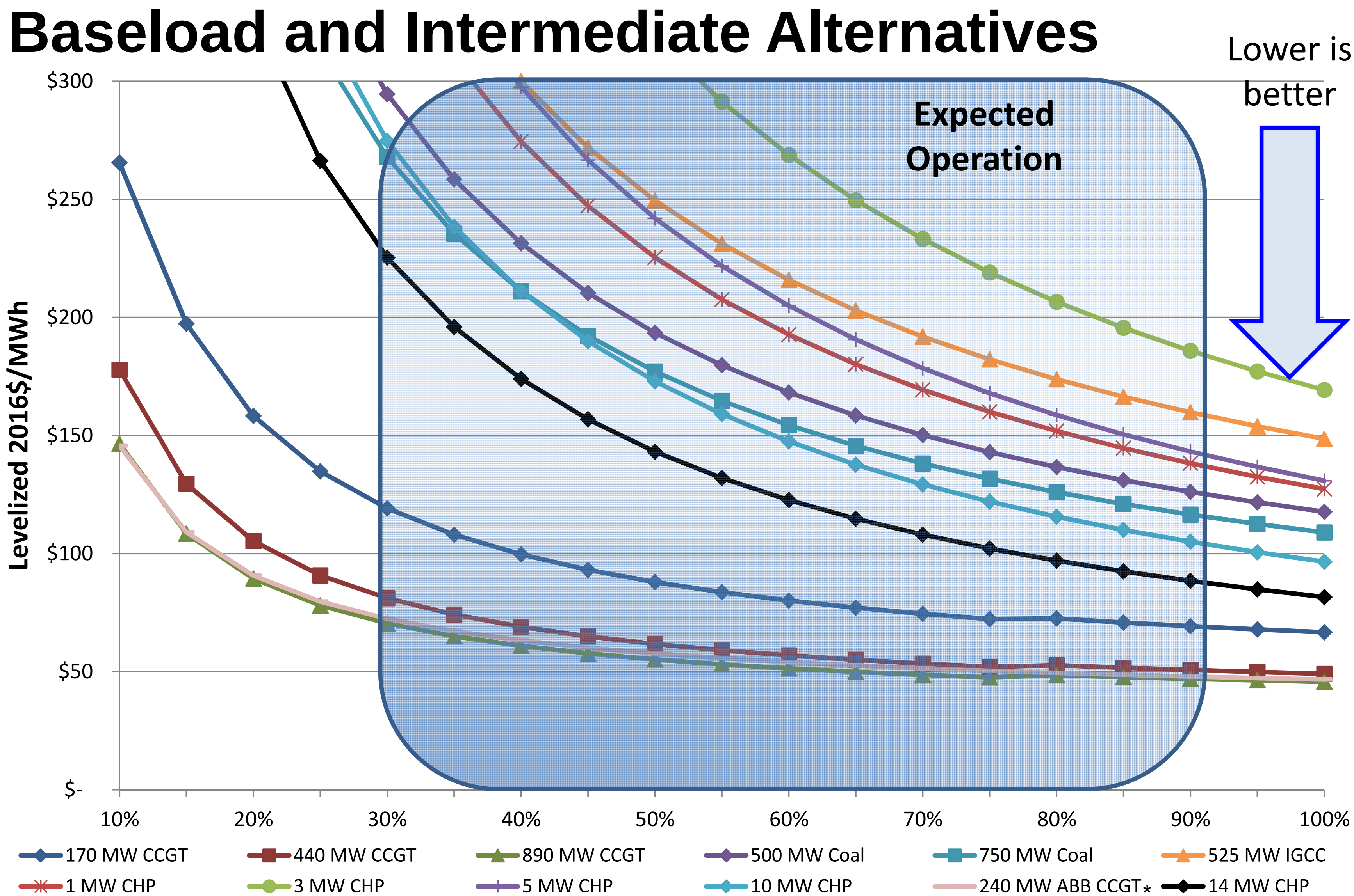


Like comparing a mortgage when buying a home…

- Busbar or Levelized Cost of Electricity comparison common tool for screening cost to produce power
- Considers
  - Investment cost
  - Operation & maintenance cost (plant personnel, repairs, etc)
  - Fuel cost (natural gas, coal)
  - Emissions cost (CO_2)

CO_2 = Carbon Dioxide

Baseload and Intermediate Alternatives



*240MW ABB CCGT option represents a one-time conversion of existing GT's to combined cycle operations

MW = Megawatt
ABB = AB Brown
CHP = Combined Heat and Power (gas turbine)
IGCC = Integrated Gasification Combined Cycle (coal)
CCGT = Combined Cycle Gas Turbine
MWh = Megawatt Hour

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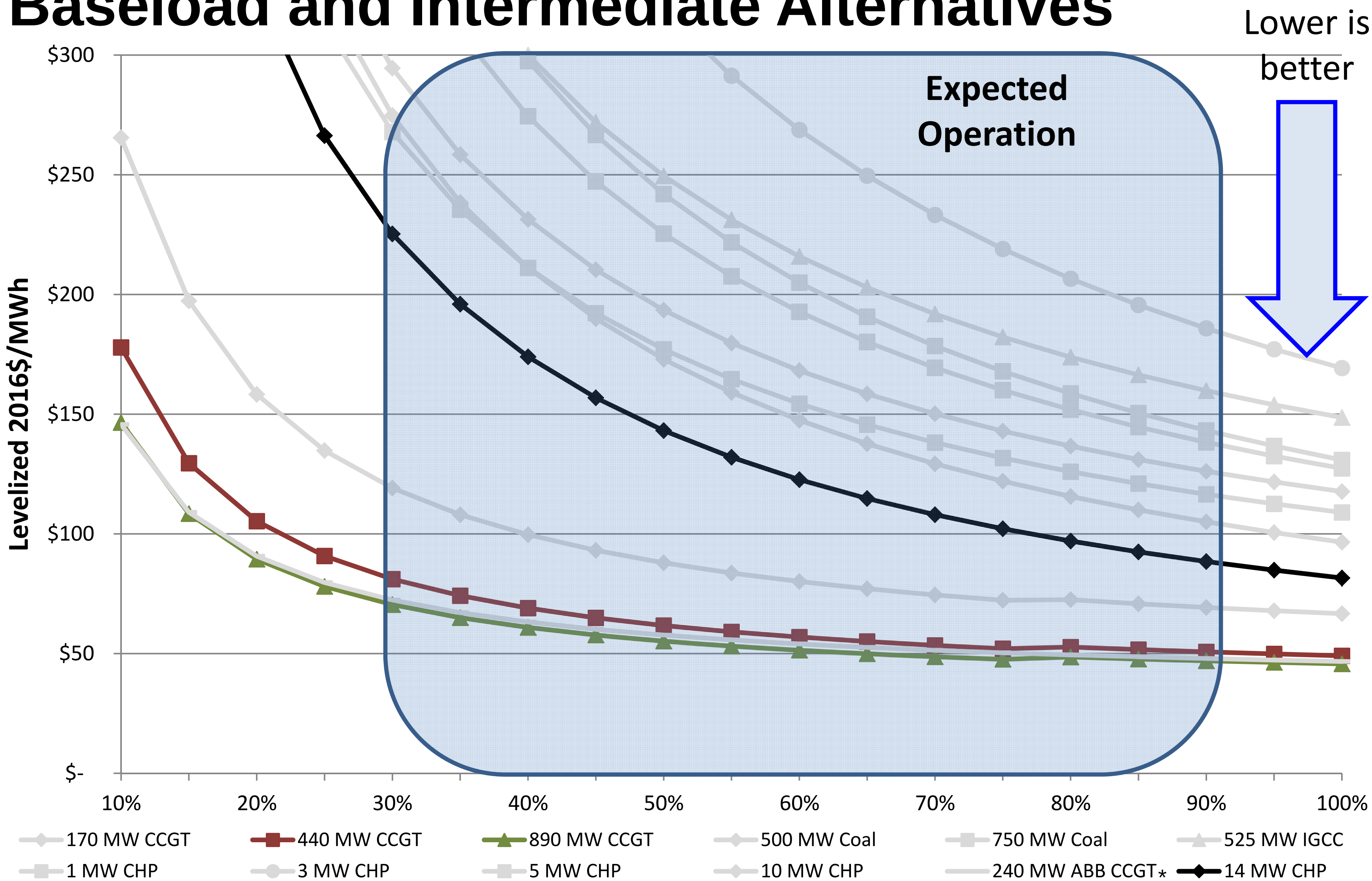
Baseload and Intermediate Alternatives



*240MW ABB CCGT option represents a one-time conversion of existing GT's to combined cycle operations

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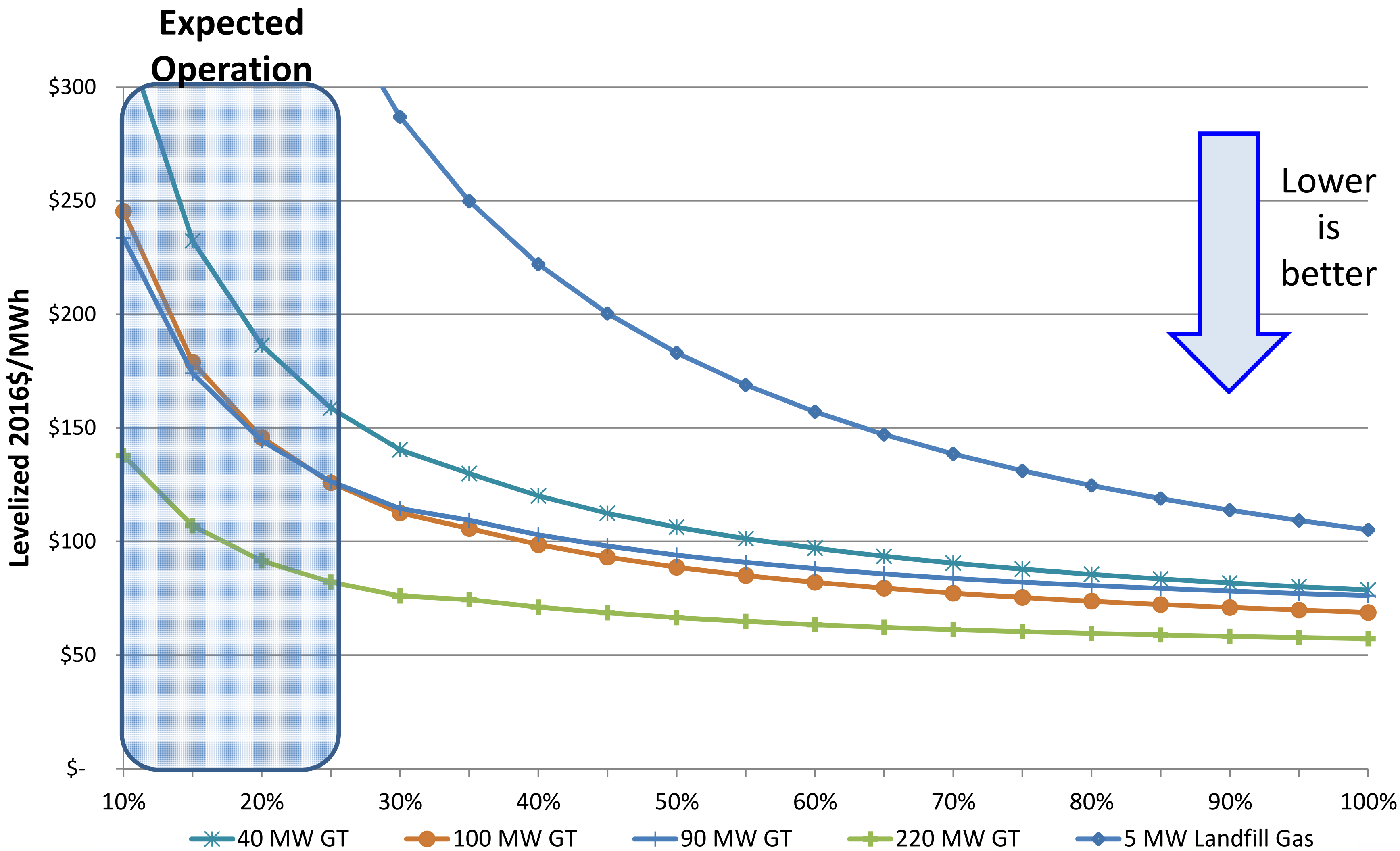
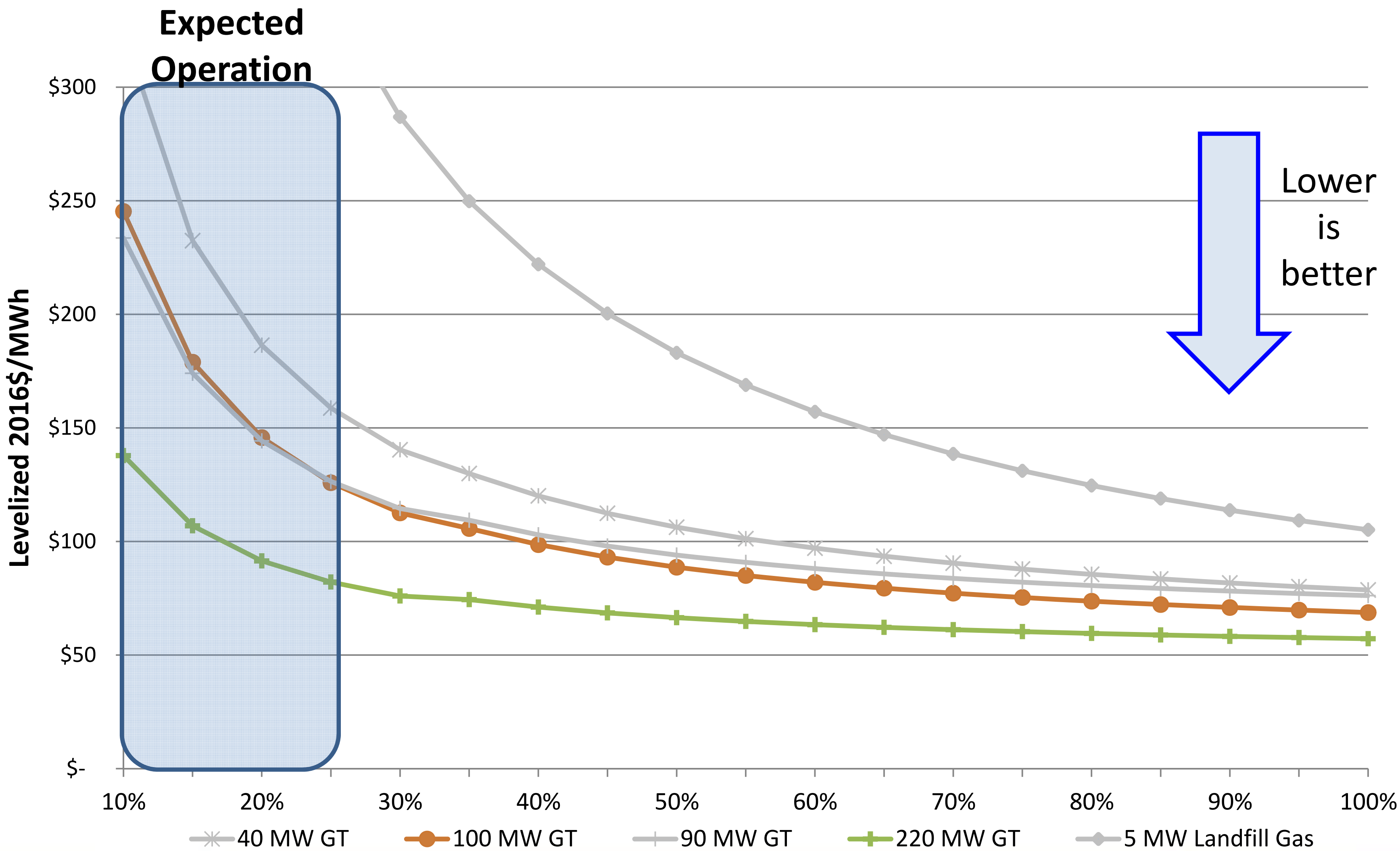
Peaking Alternatives



MW = Megawatt
MWh = Megawatt Hour

GT = Gas Turbine

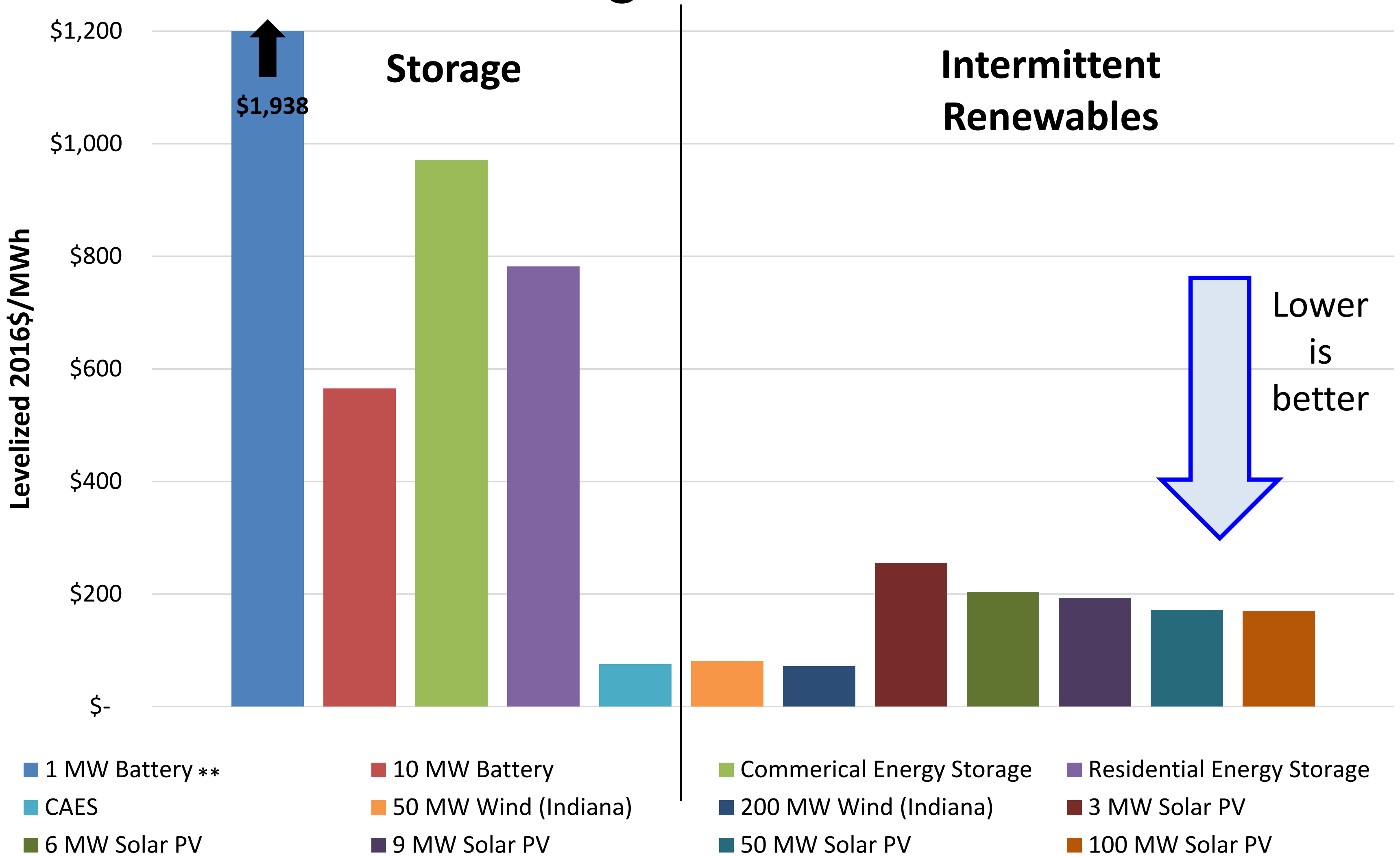
Peaking Alternatives



MW = Megawatt
MWh = Megawatt Hour

GT = Gas Turbine

Renewable and Storage Alternatives*



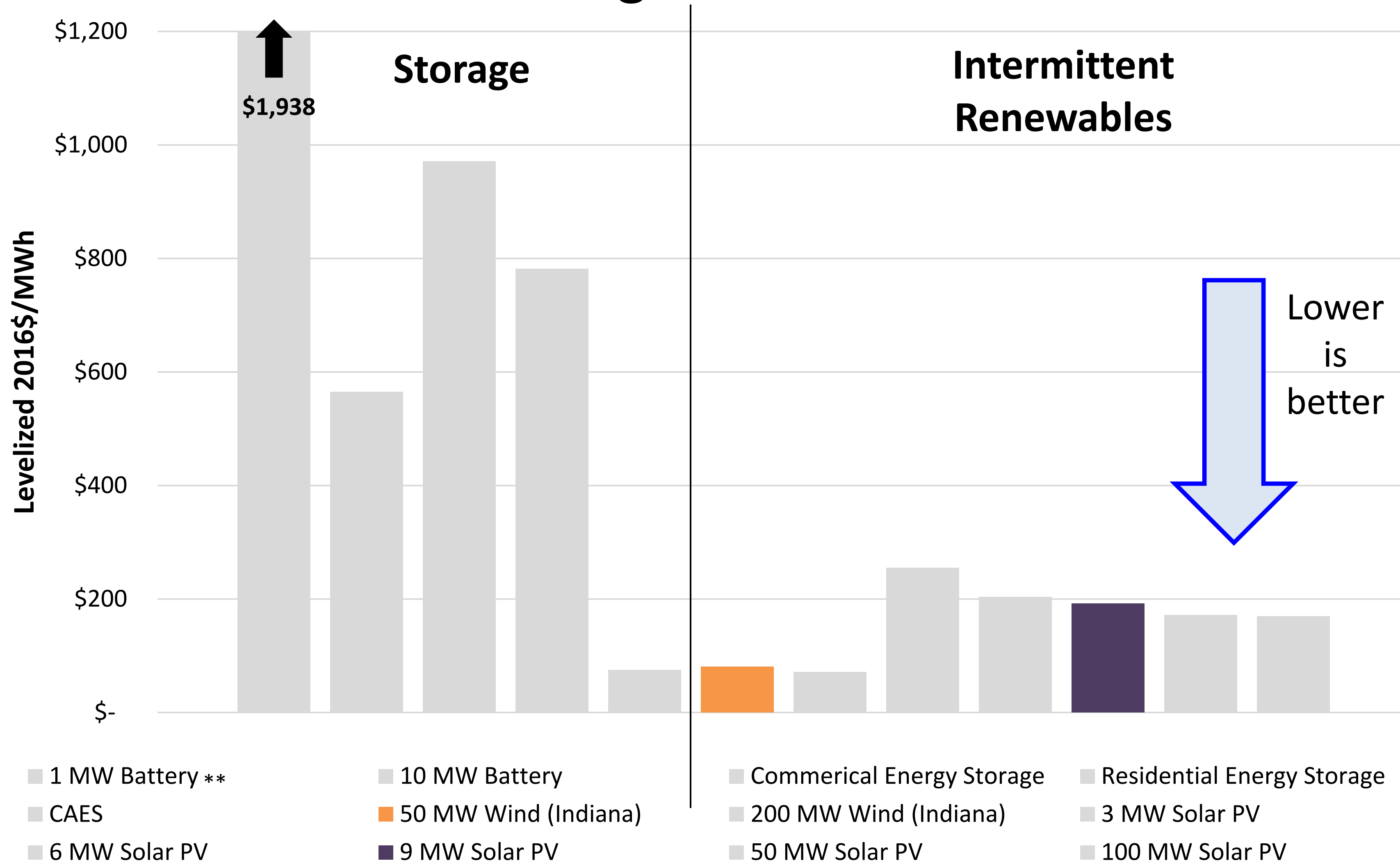
*Alternatives are shown on an indicative capacity factor based on technology potential and location

** 1 MW Battery / 1 MWh Discharge

MW = Megawatt
MWh = Megawatt Hour

CAES = Compressed Air Storage
PV = Photovoltaic

Renewable and Storage Alternatives*



*Alternatives are shown on an indicative capacity factor based on technology potential and location

** 1 MW Battery / 1 MWh Discharge

MW = Megawatt
MWh = Megawatt Hour

CAES = Compressed Air Storage
PV = Photovoltaic

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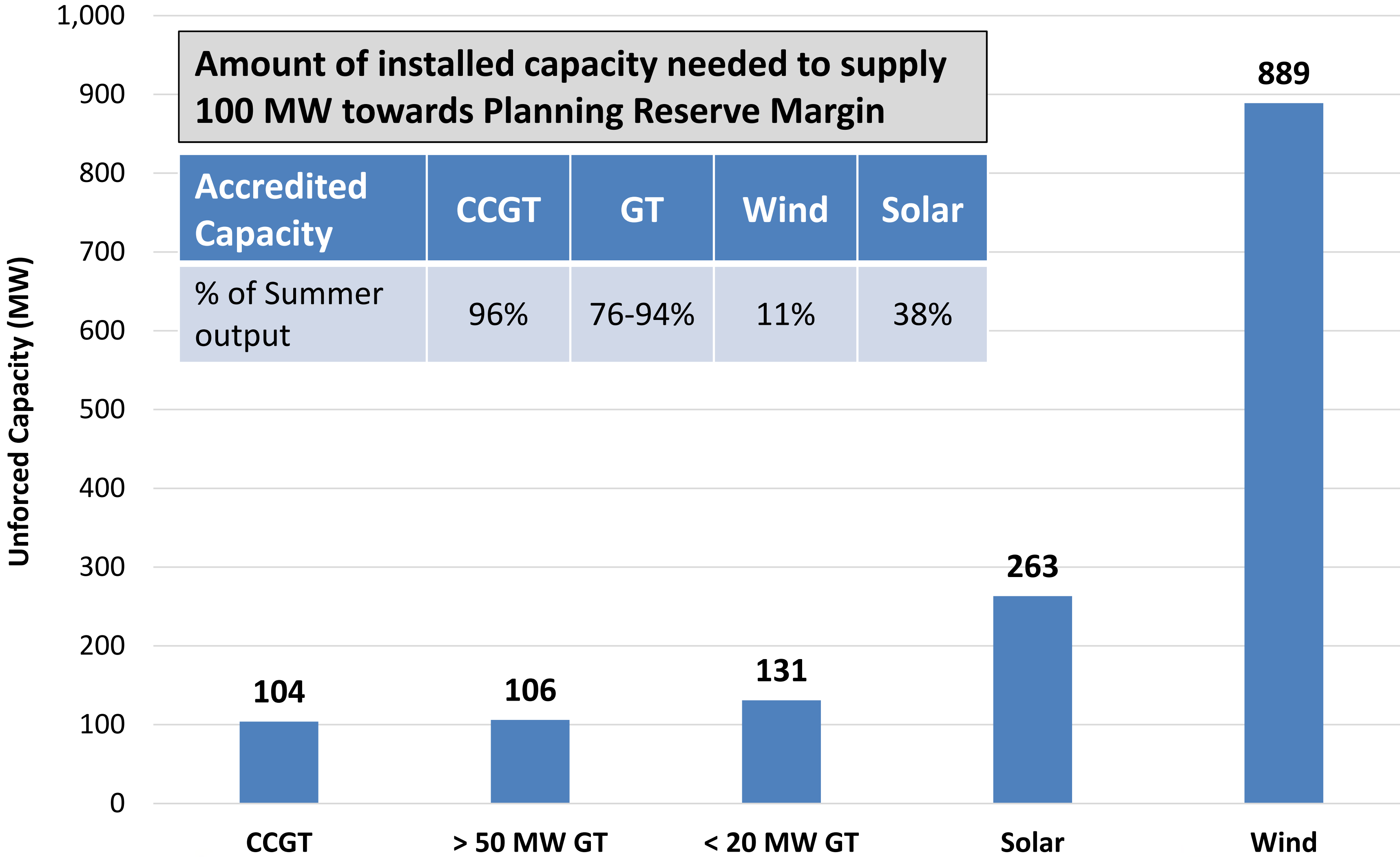
Capacity – Another Portfolio Building Block

Amount of installed capacity needed to supply 100 MW towards Planning Reserve Margin

Accredited Capacity	CCGT	GT	Wind	Solar
% of Summer output	96%	76-94%	11%	38%



GT = Gas Turbine
CCGT = Combined Cycle Gas Turbine
MW = Megawatt

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Filtered/Modeled Alternatives

Existing Fleet

- Continue on Coal
- Convert to Natural Gas
- Repower CCGT
- Idle / Shutdown

New Supply-Side

- 890 MW CCGT
- 690 MW CCGT
- 440 MW CCGT
- 340 MW CCGT
- 220 MW GT
- 100 MW GT
- 50 MW Wind (IN)
- 15 MW CHP
- 9 MW Solar PV

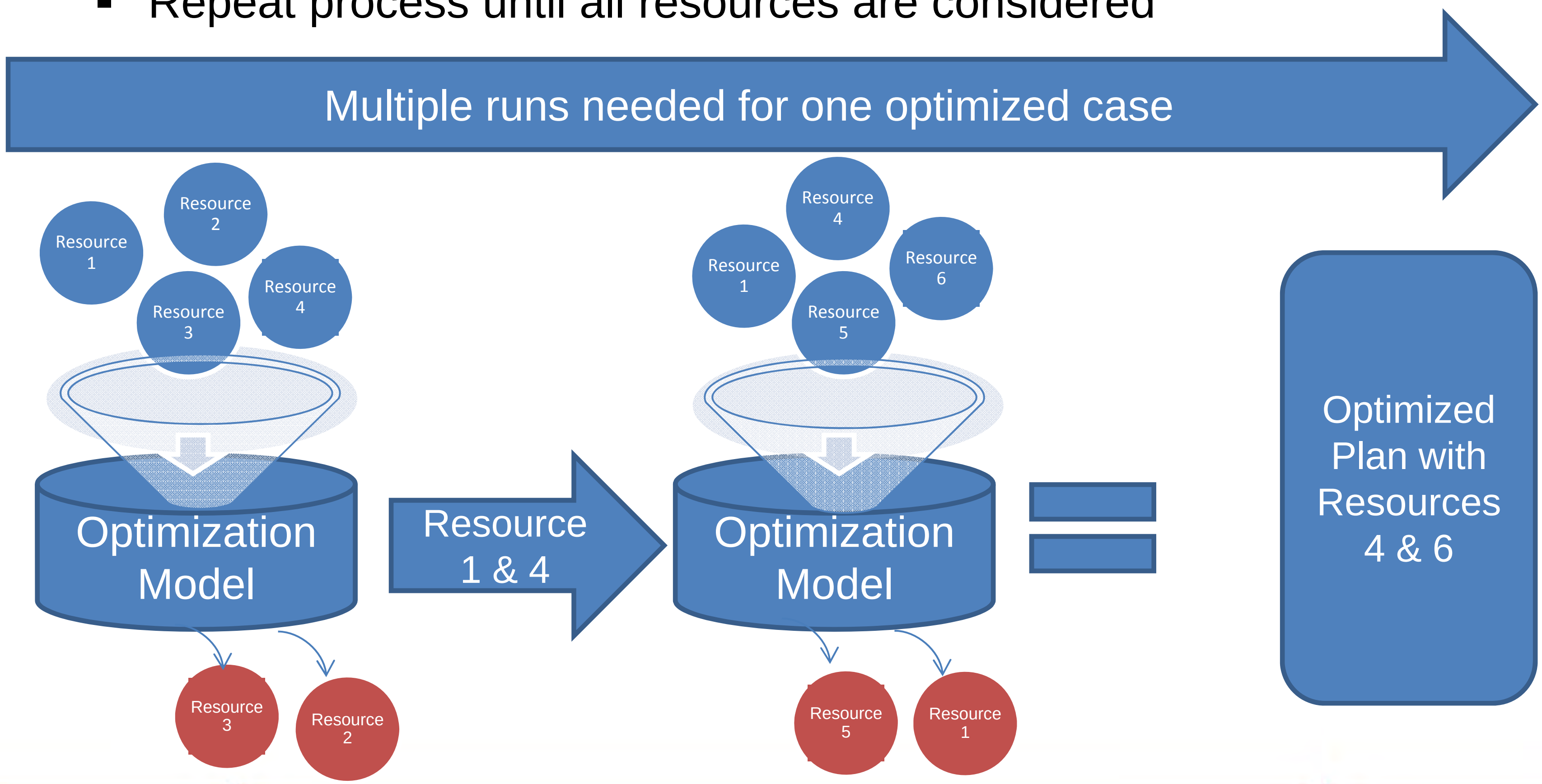
Demand-Side

- Energy Efficiency
- Demand Response

GT = Gas Turbine
CCGT = Combined Cycle Gas Turbine
PV = Photovoltaic
IN = Indiana
MW = Megawatt
CHP = Combined Heat and Power

Optimization Modeling Is an Iterative Process

- Still too many options to model at one time
  - Model several options to determine what is selected
  - Keep selected options, rotate in new alternatives
  - Repeat process until all resources are considered



Questions?

Scenario Development

Gary Vicinus, Pace Global – Managing Director of Consulting Practice

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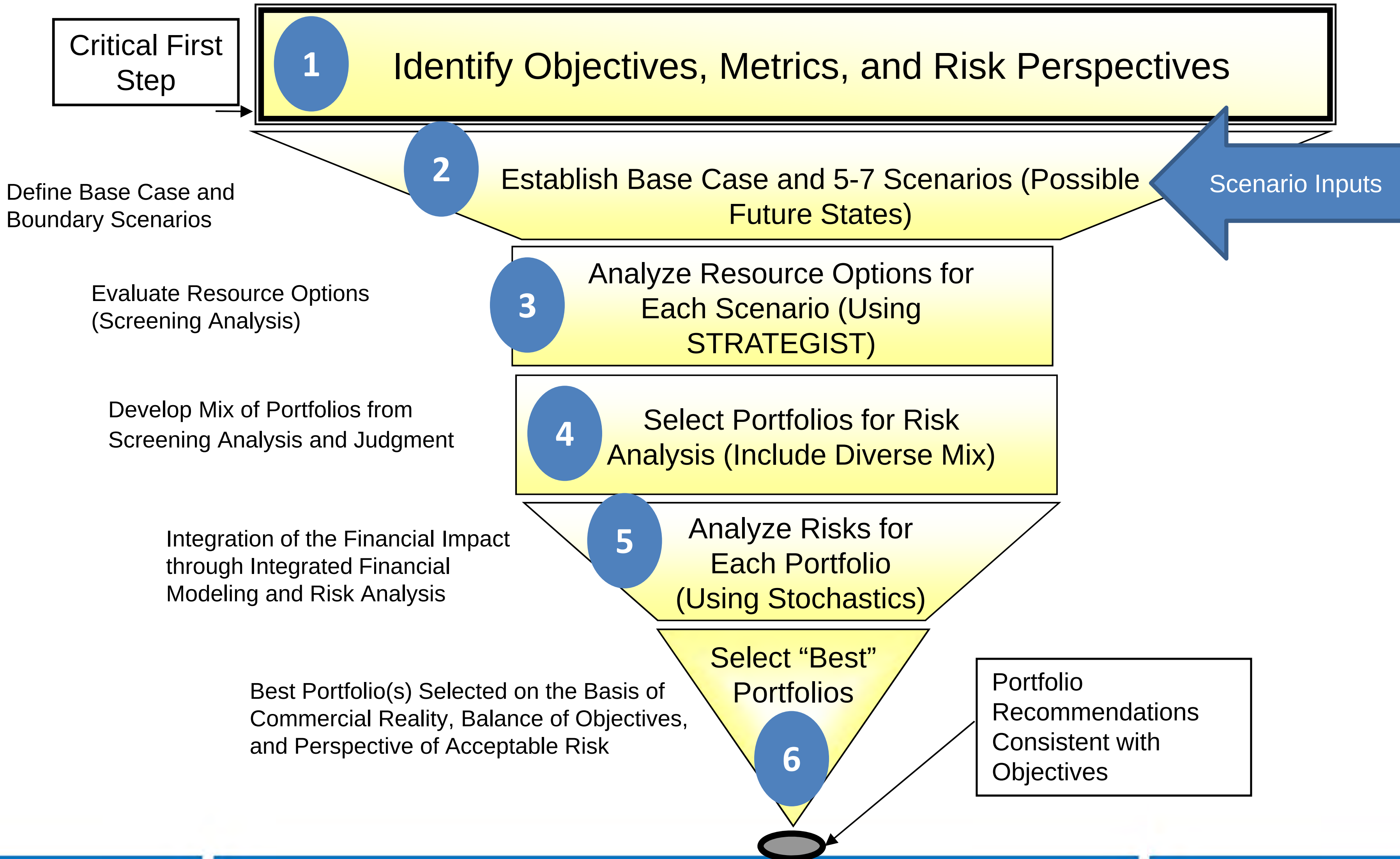


Stakeholder Feedback From April 7th Uncertainty Workshop

The following topics were raised by stakeholders for consideration in scenario development:

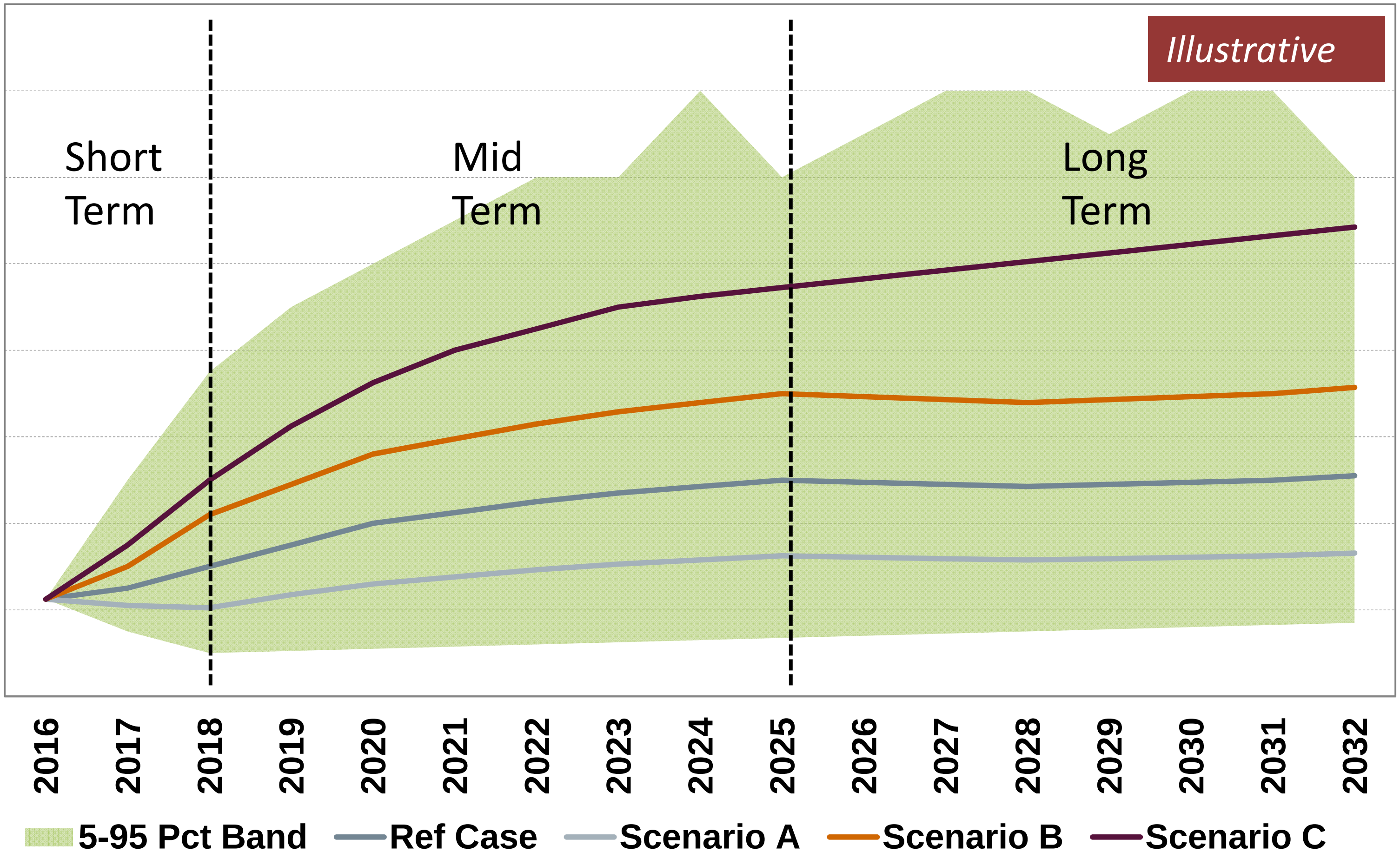
- Consider additional environmental regulations that have not yet been proposed
- Factor in the Clean Power Plan (CPP) compliance costs
- Consider how electric vehicle technology affects your plan
- Consider distributed generation risk
- Consider diversifying generation
- Consider political/regulatory risk
- Consider additional cogeneration being developed within the Vectren territory

Purpose and Guidelines for Scenario Development

Vectren worked with PACE to develop a base case and five alternative, internally consistent scenarios (potential futures), to test which portfolios are optimal over a wide range of future market and regulatory conditions.

- Scenarios include a high and low regulatory case, a high and low economy case and a high technology case. Each is described in the following pages:
  - First with broad trends in the short term, mid term, and long term.
  - Then with defined paths with annual forecasts (and in some cases monthly forecasts).
- Inputs for key variables were developed to ensure that they were internally consistent with the scenario by first developing directional changes for each variable (load, gas prices, coal prices, carbon prices, power prices, and capital costs) relative to the base case forecast in the near, mid, and long term.
- Values were then selected for each scenario that reflect one standard deviation from the mean in the direction indicated, and in a few limited cases a ½ standard deviation or other larger variation.

The Objective of this Analysis is to Find Portfolios that Perform Well Against a Range of Boundary Conditions



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The Base Case Scenario

- The Base Case is provided by Vectren. Key assumptions driving the Base Case are:
  - In the short-term (2016-2018), the Base Case assumes a business-as-usual perspective for all market drivers, consistent with market forwards.
  - It is assumed that most states, including Indiana, will opt for a mass-based CPP compliance path, effective in 2024 (a delay of two years from the original 2022 start date):
    - Easier to administer than rate-based
    - Retirements can be counted toward compliance
    - States will join to create most liquid trading market
  - Gas prices increase somewhat from current low levels beginning around 2018 as demand catches up to shale supply
  - Power prices move up with gas and as CPP compliance begins in 2024
  - Long term, gas and power prices tend to level out in real terms

Note: These scenarios describe the general market and may differ from specific outcomes for Vectren.

CPP = Clean Power Plan

Scenario 1: The High Regulatory Scenario

- The High Regulatory scenario is characterized by a more heavily regulated CPP and shale gas (fracking limits, methane emissions) path and assumes (relative to the Base Case):
  - A generally higher CPP compliance cost. Less coordination among states results in a greater mix of rate-based and mass-based compliance. Several states do not opt in to a national EPA-backed program and in general more state-by-state command and control efforts for CO_2 emissions.
  - More renewable and less new gas generation adoption pushed through via mandates – greater coal retirements.
  - Additional regulations on carbon on the horizon post 2030 that are higher than in the Base Case.
  - Greater adoption of DER in the form of solar and CHP.
  - As the next target after coal, gas markets see restrictions on fracking and methane emissions that limit gas supply growth, drive up gas prices, and result in an additional push and economic case for renewable energy.
  - Overall regulations that dampen economic growth.

Note: These scenarios describe the general market and may differ from specific outcomes for Vectren.

CPP = Clean Power Plan
EPA = Environmental Protection Agency
CHP = Combined Heat and Power
DER = Distributed Energy Resources
CO_2 = Carbon Dioxide

Scenario 2: The Low Regulatory Scenario

- The Low Regulatory scenario is characterized by:
  - Low regulatory restrictions as the CPP is delayed and with less aggressive targets, given legal challenges that result in changes to the final rule
  - No national carbon price
  - Less regulation that encourages greater economic growth in sector and load growth
  - Gas prices that sustain growth in the mid term (no fracking limits) but over time, renewable costs will tend to push down long term growth
  - Fewer coal retirements in the mid term, resulting in some increases in prices
  - Capital costs rise over time as economic growth and load result in new builds

Note: These scenarios describe the general market and may differ from specific outcomes for Vectren.

CPP = Clean Power Plan

Scenario 3: The High Technology Scenario

- The High Technology Scenario is characterized by:
  - Significant (breakthrough) advances in solar, wind, and energy storage technology, resulting in greater renewable energy deployment, along with some improvement in high efficiency gas-fired generation, and also natural gas extraction productivity
  - Overall there are higher levels of DER and energy efficiency, which helps to mitigate the load growth that might otherwise be expected in a High Technology scenario with robust economic growth and adoption of electric vehicles
  - Storage breakthroughs in the mid term result in greater levels of renewable development without the need for back-up gas generation – reducing the effective cost of renewable and DER generation
  - There will be faster replacement of coal (low coal prices), stable gas prices, and lower power prices long term due to lower demand and higher supply
  - There could be higher interest rates with good growth, raising capital costs

Note: These scenarios describe the general market and may differ from specific outcomes for Vectren.

DER = Distributed Energy Resources

Scenario 4: The High Economy/Market Scenario

- The High Economy/Market Scenario is characterized by:
  - A robust and growing U.S. economy that keeps upward pressure on all of the major market outcome categories, including load growth, fuel costs, power prices, and capital costs
  - This growth is in the absence of a major technological breakthrough
  - Existing generation resources are needed to maintain this economic expansion, limiting the number of retirements while accelerating the number of capacity additions, which favors gas in the near and mid term, but renewables will outpace gas in the long term
  - While this scenario shares many of the attributes of the previous "High Technology" scenario, the pace of technological innovation is not as dynamic and therefore not beneficial to keeping prices and costs in check
  - Regulations are similar to those in the Base Case

Note: These scenarios describe the general market and may differ from specific outcomes for Vectren.

Scenario 5: The Low Economy/Market Scenario

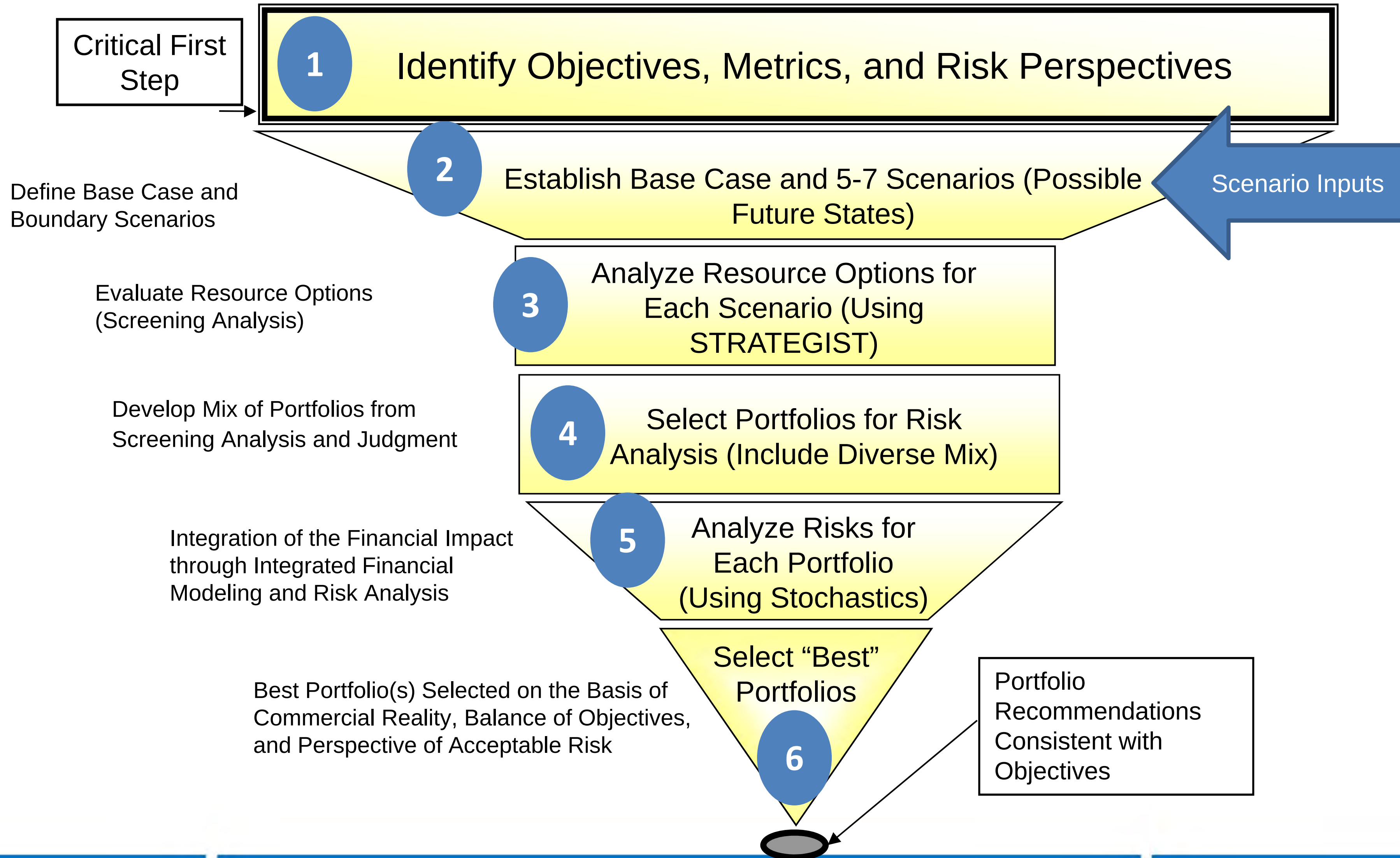
- The Low Economy/Market Scenario is characterized by:
  - Sluggish economic growth both domestically and globally
  - While some conditions are favorable to the U.S. economy, including low fuel costs, most indicators point toward headwinds for growth in the GDP level
  - Low load growth restricts additions and keeps power prices on the low end of the scale, which in turn keeps capacity additions low
  - Market regulators have less latitude to implement new regulations, as the economy cannot afford them in this low economy scenario

Note: These scenarios describe the general market and may differ from specific outcomes for Vectren.

Scenario Modeling Inputs

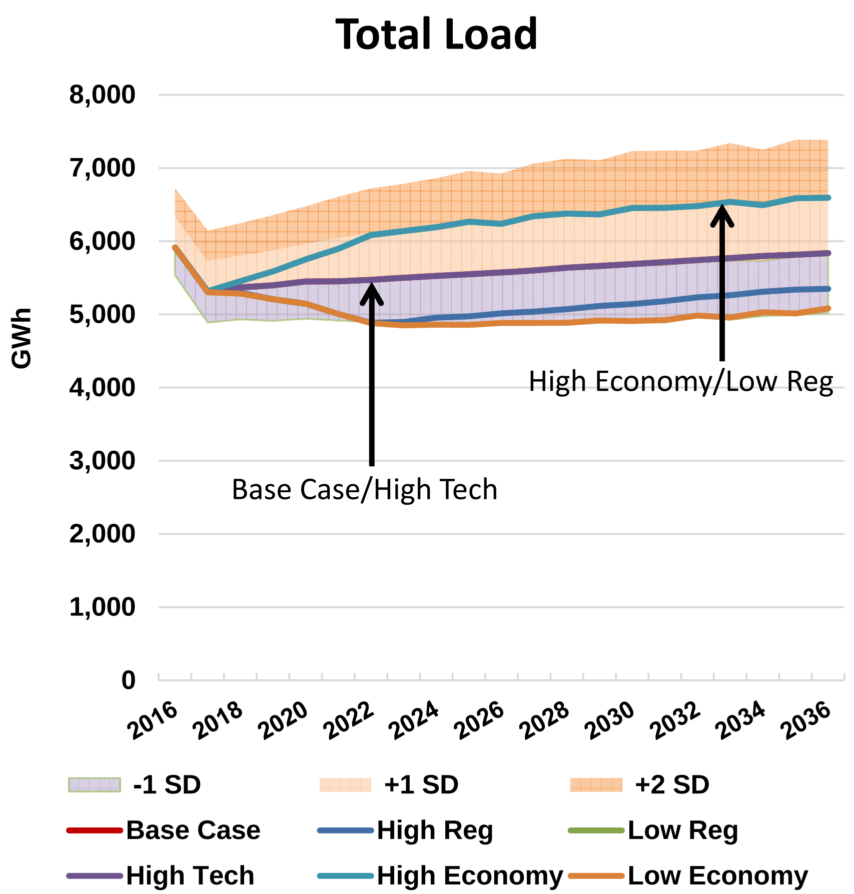
Testing of Portfolios against
Wide Range of Outcomes

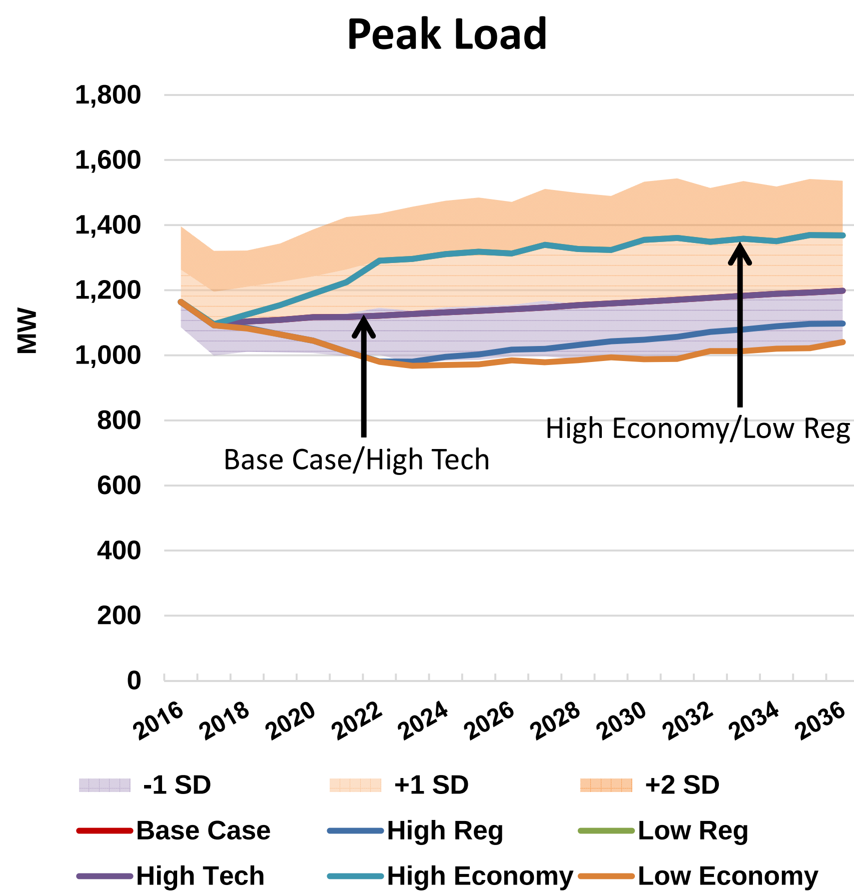
Vectren Is Following a Structured Approach



Vectren Total and Peak Load Scenarios

GWh and MW



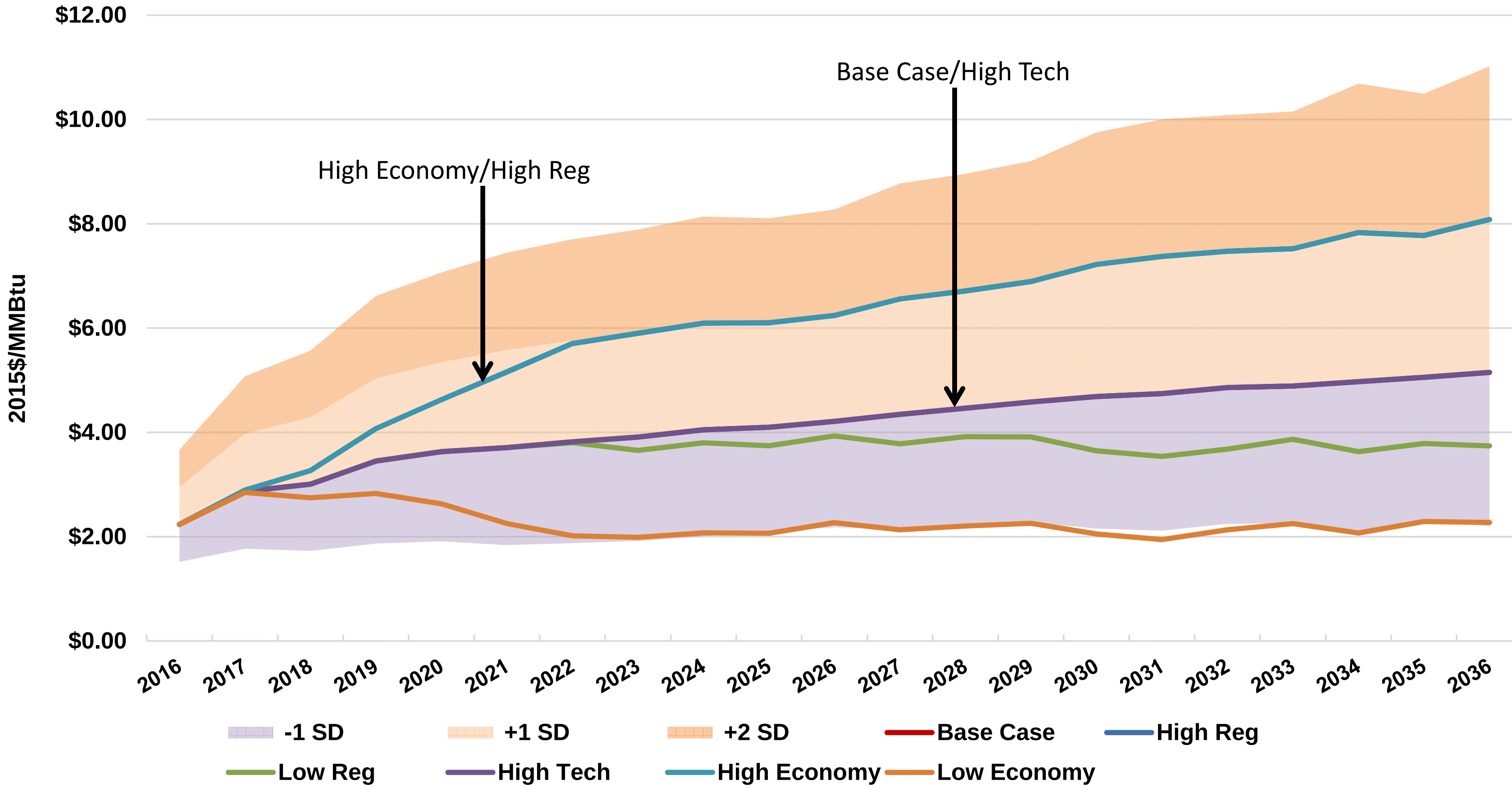


SD = Standard Deviation
MW = Megawatt
GWh = Gigawatt Hour

VECTREN Energy Delivery

Natural Gas Price Scenarios

Delivered to Indiana (2015$/MMBtu)

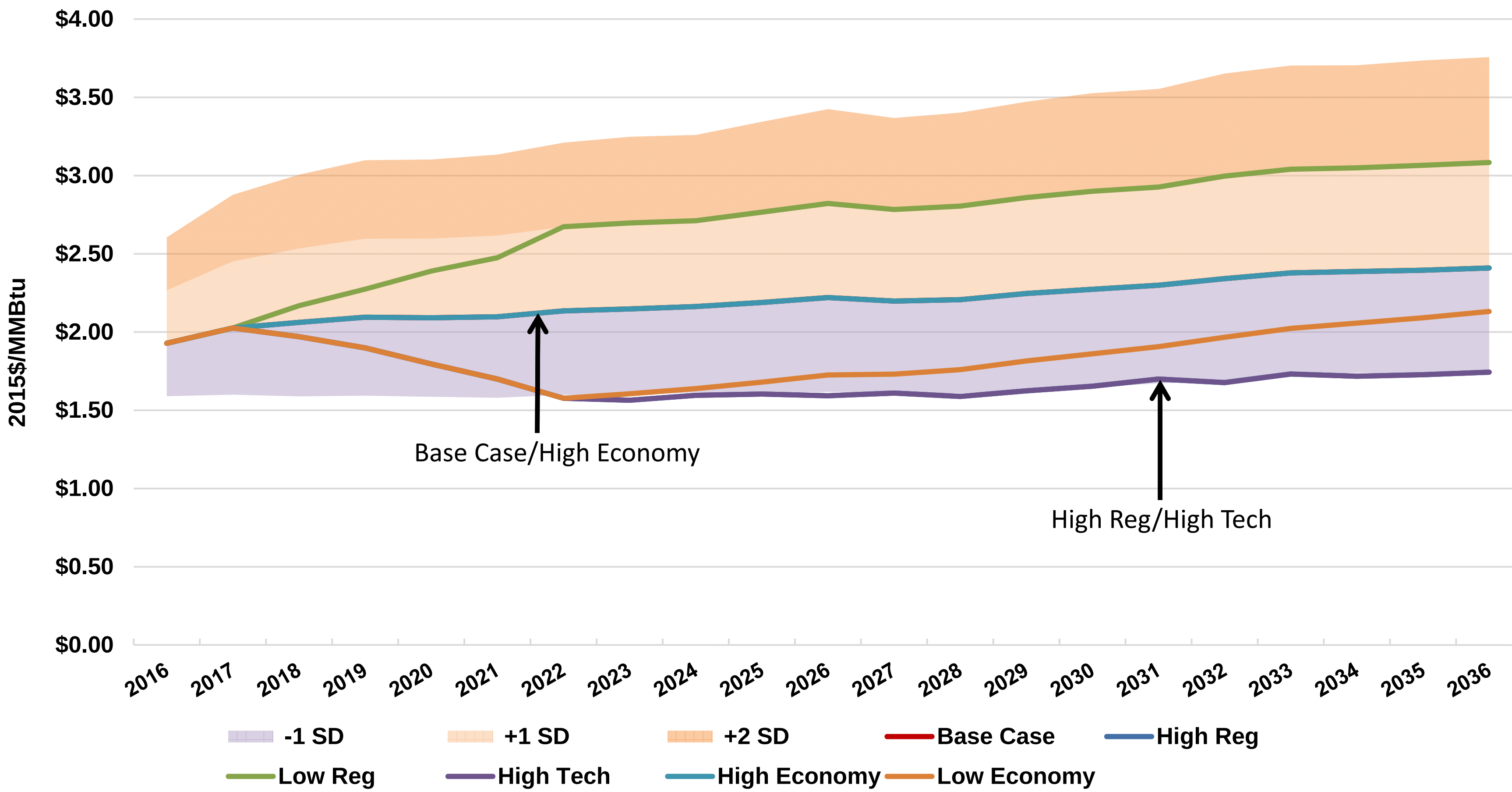


MMBtu = One Million British Thermal Units

SD = Standard Deviation

VECTREN Energy Delivery

Coal Price Scenarios
Illinois Basin Delivered (2015$/MMBtu)



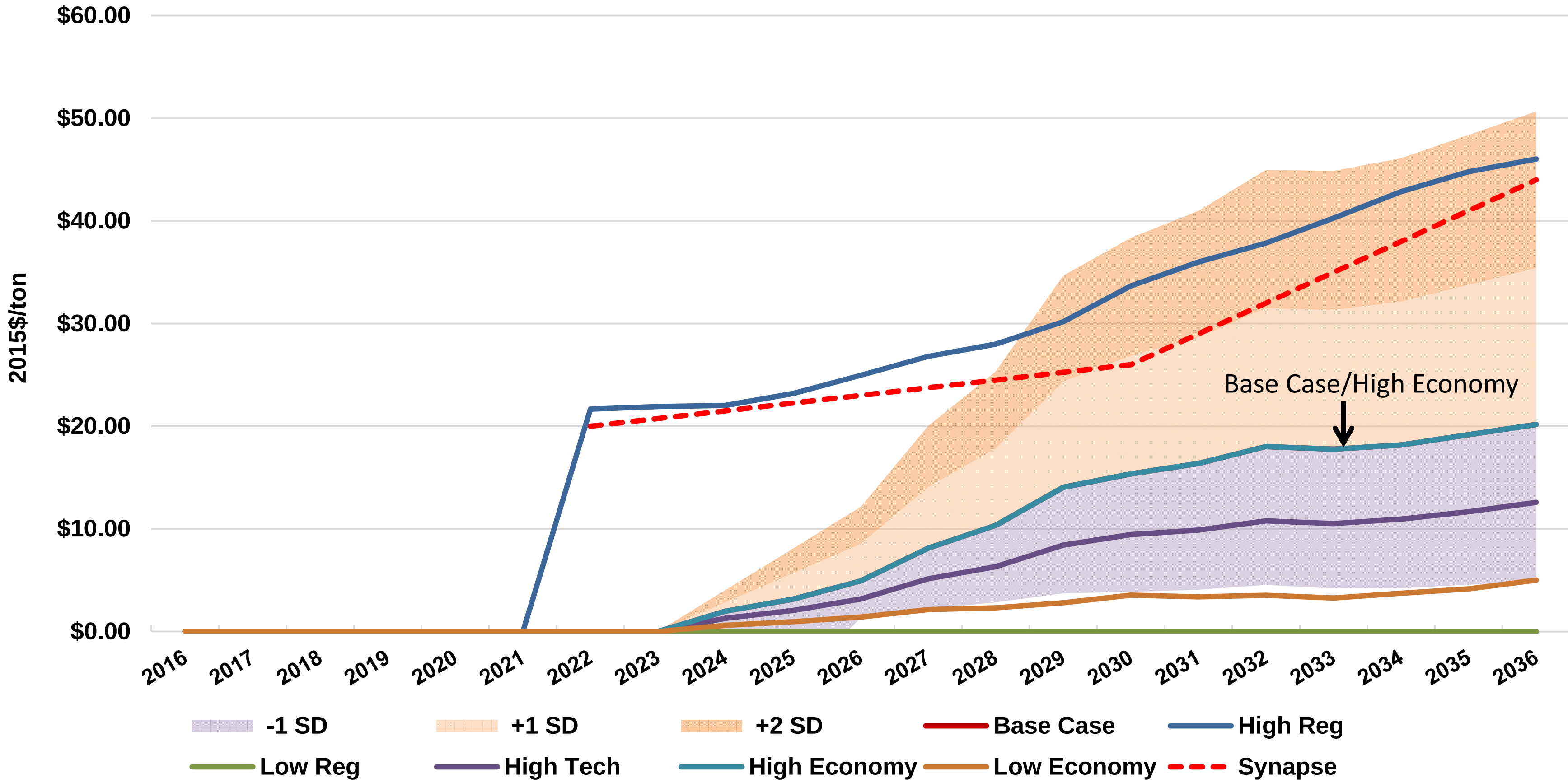
Note: Forecast reflects Illinois Basin minemouth price plus delivery to AB Brown.

MMBtu = One Million British Thermal Units

SD = Standard Deviation

VECTREN Energy Delivery

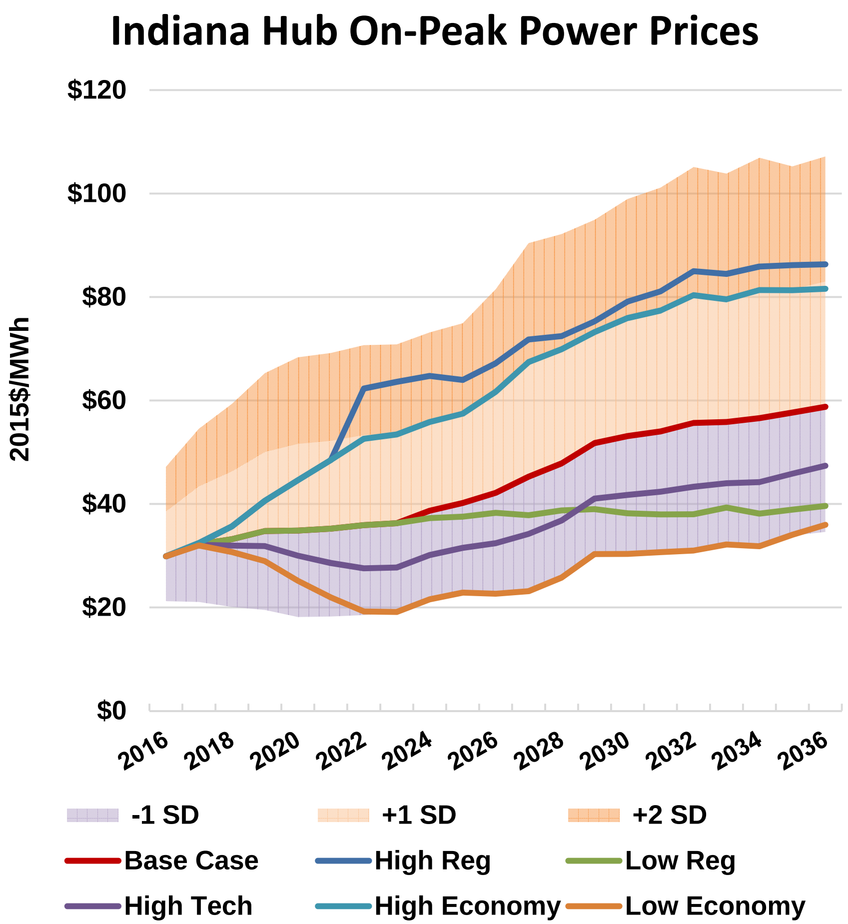
Carbon (CO_2) Price Scenarios
National Price (2015$/short ton)

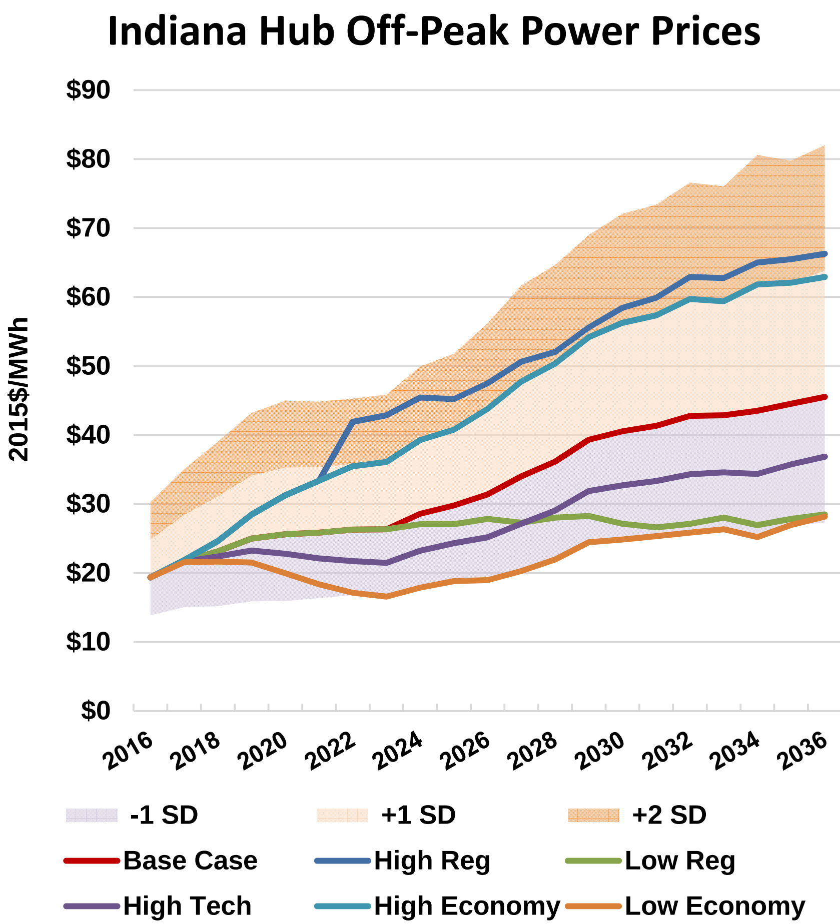


Note: Synapse price from Synapse Energy Economics, Inc. report (dated 3/16/16) entitled “Spring 2016 National Carbon Dioxide Price Forecast ” – Mid Case

Power Price Scenarios

On-Peak and Off-Peak Vectren Hub Prices (2015$/MWh)



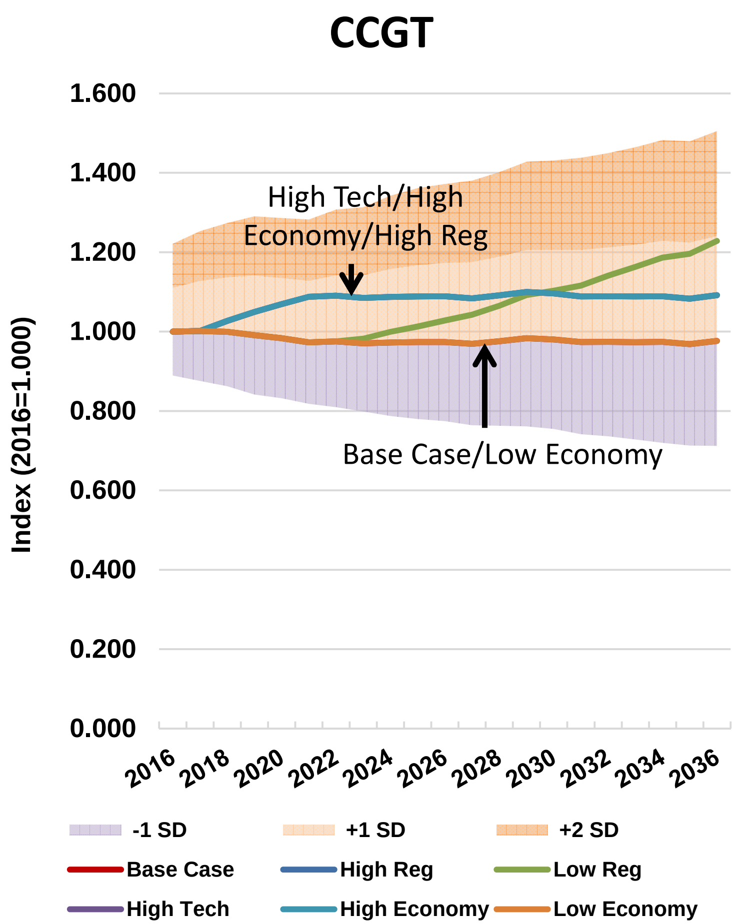


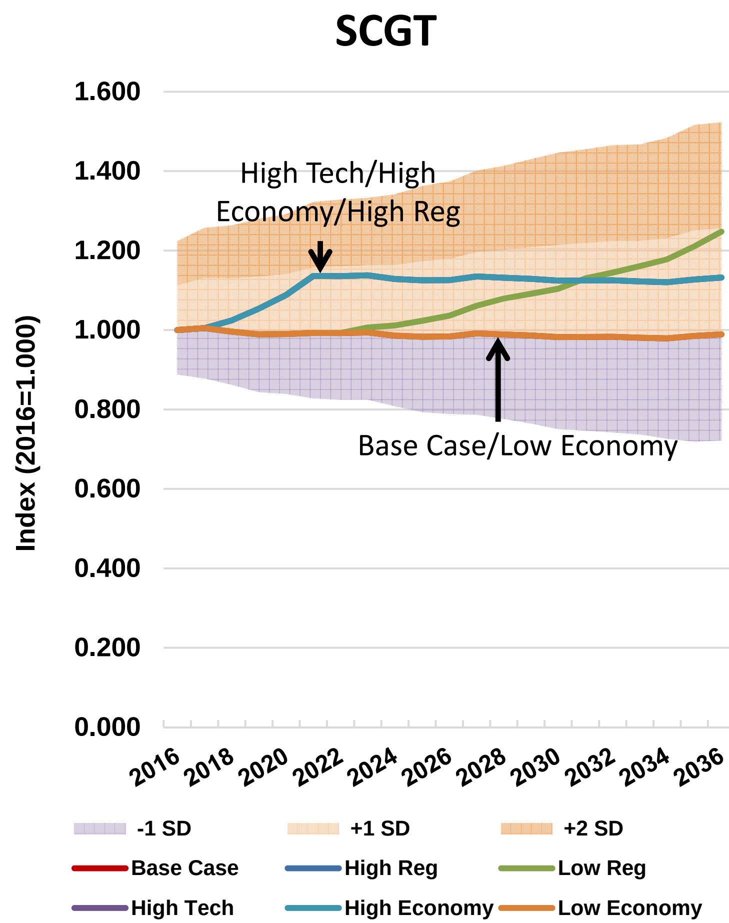
SD = Standard Deviation

MWh = Megawatt hour

Capital Cost Scenarios (1 of 3)

Index Values (2016=1.000)



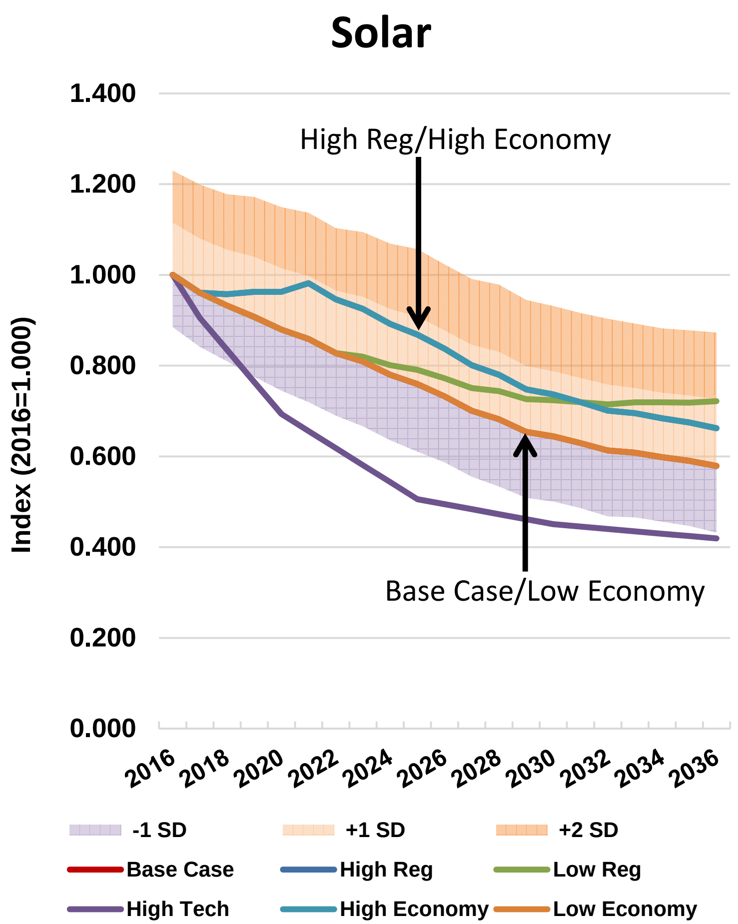


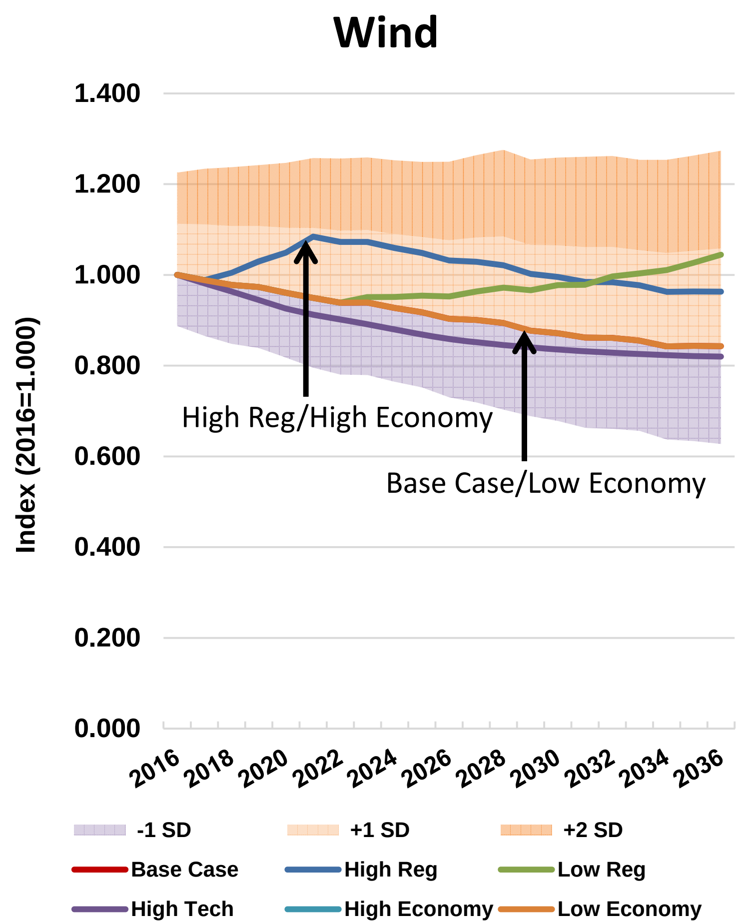
SD = Standard Deviation
SCGT = Simple Cycle Gas Turbine

CCGT = Combined Cycle Gas Turbine

VECTREN Energy Delivery

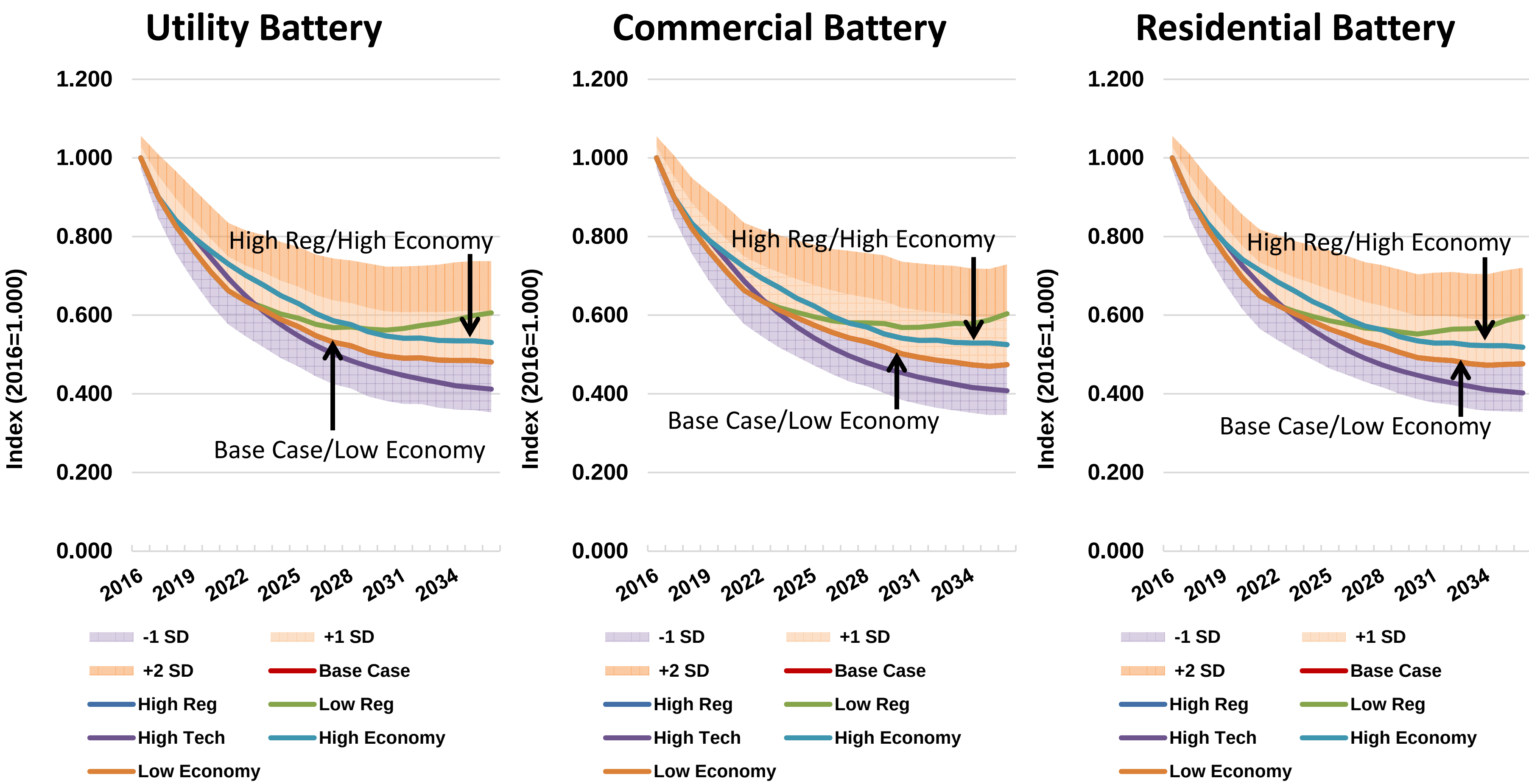
Capital Cost Scenarios (2 of 3)
Index Values (2016=1.000)





SD = Standard Deviation

Capital Cost Scenarios (3 of 3)
Index Values (2016=1.000)



SD = Standard Deviation

VECTREN Energy Delivery

Initial Screening Analysis of Resource Options for Each Scenario

Analysis using STRATEGIST Model

(Results Will Be Presented at Next Stakeholder Meeting)

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Energy Delivery

Selection of Portfolios for Risk Analysis

Diverse Mix of Portfolios Developed from Screening Analysis and Judgment (Will Be Presented at Next Stakeholder Meeting)

Stakeholder Input to the Portfolio Selection

Designed to Capture Options that Vectren May Have Missed that Stakeholders Would Like to See

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Energy Delivery

Criteria and Selection of Stakeholder Portfolios

Portfolio Selection

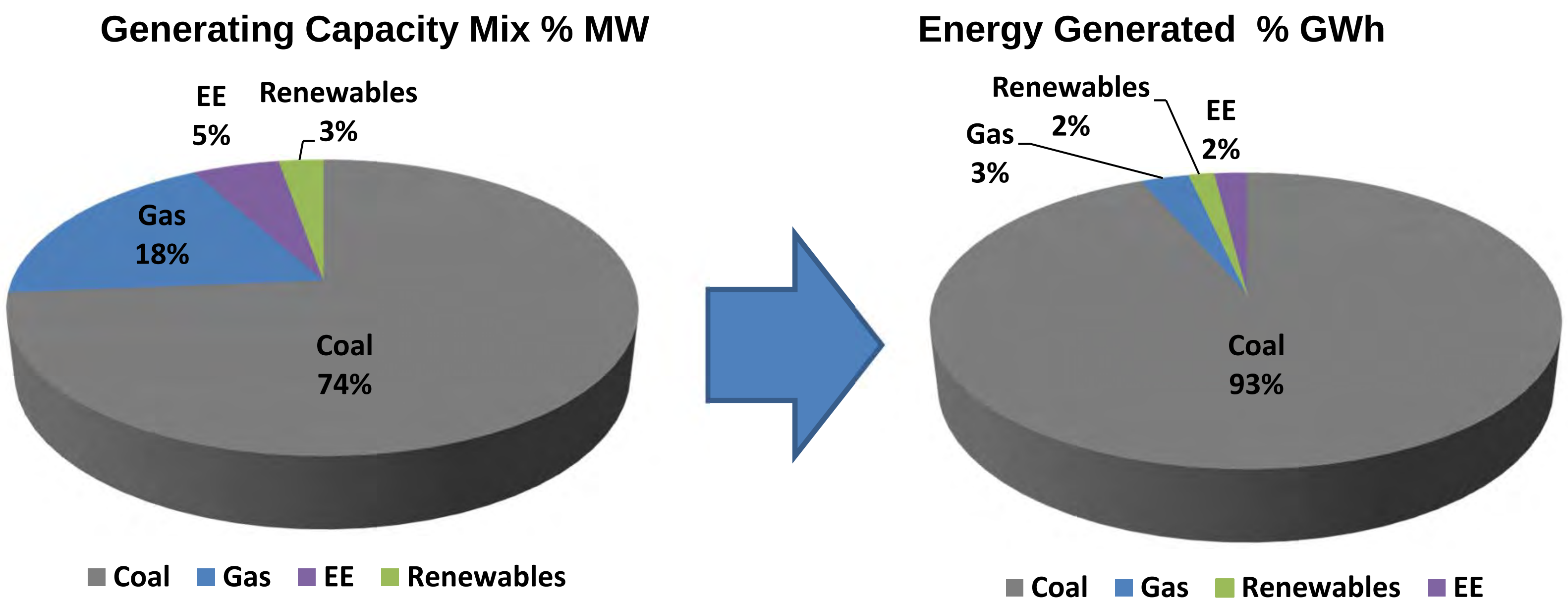
- The process to come up with 1-2 additional portfolios:
  - Stakeholder discussion
  - I will show three possible future energy mixes for comparison
  - Then I will break stakeholders into 3-4 groups and have them develop 1-3 portfolios per group
    - Combinations of coal, gas (CC or CT or CHP), renewables (solar or wind), EE/DR, storage
  - Next I will allow another 15-20 min for stakeholder groups to briefly speak on their preferences and reasons
  - Vectren will use input from this exercise to develop 1-2 additional portfolios for consideration
  - Vectren will post portfolios on www.vectren.com/irp within one week and will ask stakeholders to provide written comments for further input

Stakeholder Input for Preferred Portfolio

Illustrative

Portfolio Input Gathering

- Possible Future Portfolio Alternative



EE = Energy Efficiency
GWH = Gigawatt Hour

MW = Megawatt

VECTREN Energy Delivery

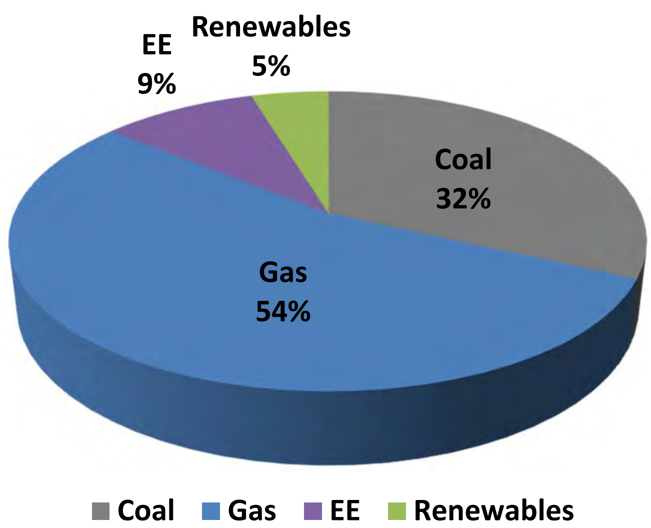
Stakeholder Input for Preferred Portfolio

Illustrative

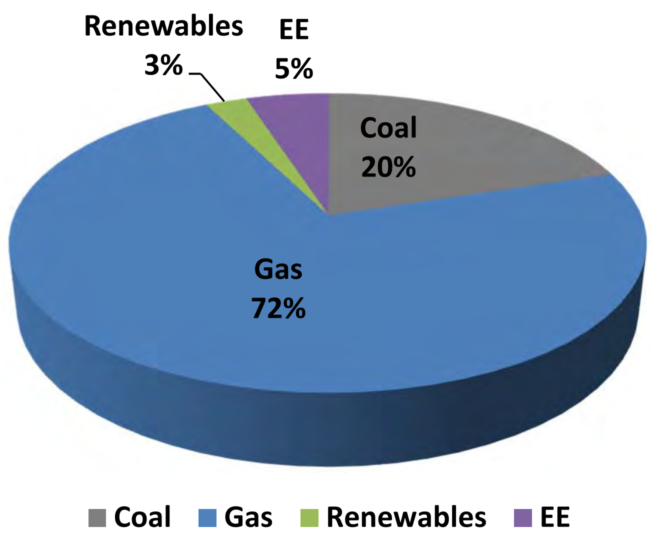
Portfolio Input Gathering

- Possible Future Portfolio Alternative

Generating Capacity Mix % MW



Energy Generated % GWh



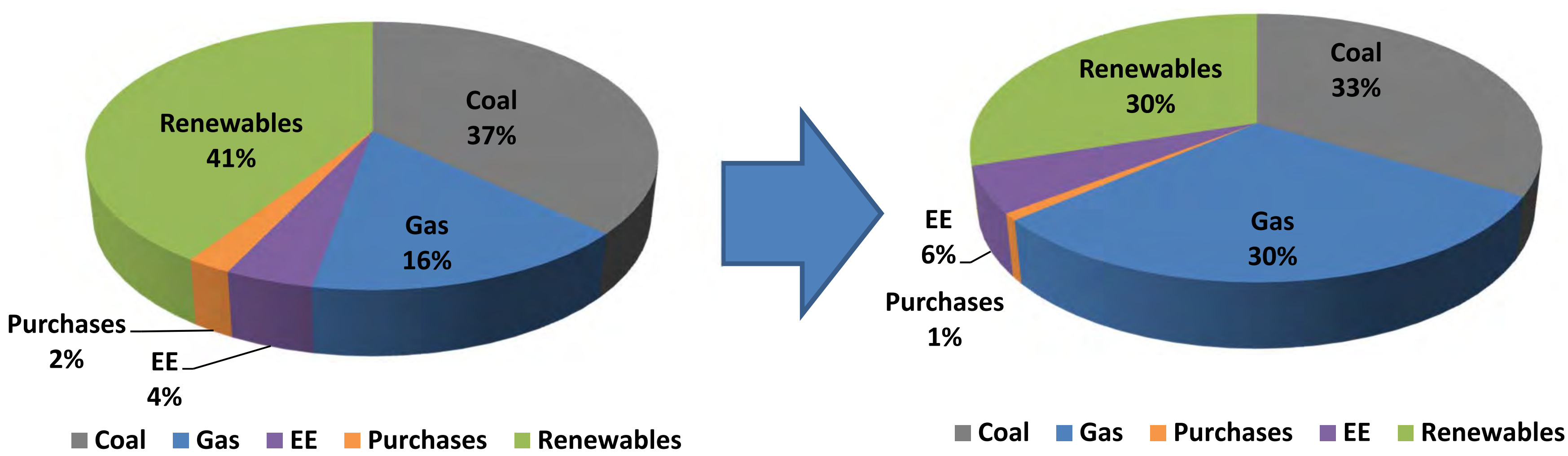
Stakeholder Input for Preferred Portfolio

Illustrative

Portfolio Input Gathering

- Possible Future Portfolio Alternative

Generating Capacity Mix % MW | **Energy Generated % GWh**



Stakeholder Input for Portfolios to Consider

Portfolio Input % of Capacity Mix by 2025				
	Group #1	**Group #2**	**Group #3**	**Group #4**
Coal				
Gas Combined Cycle				
Gas Combustion Turbine				
Gas Combined Heat & Power				
Wind				
Solar				
Storage				
Energy Efficiency/Demand Response				
#Votes				

Stakeholder Questions, Feedback, and Comments

Gary Vicinus – Meeting Facilitator

Vice President and Managing Director, Pace Global

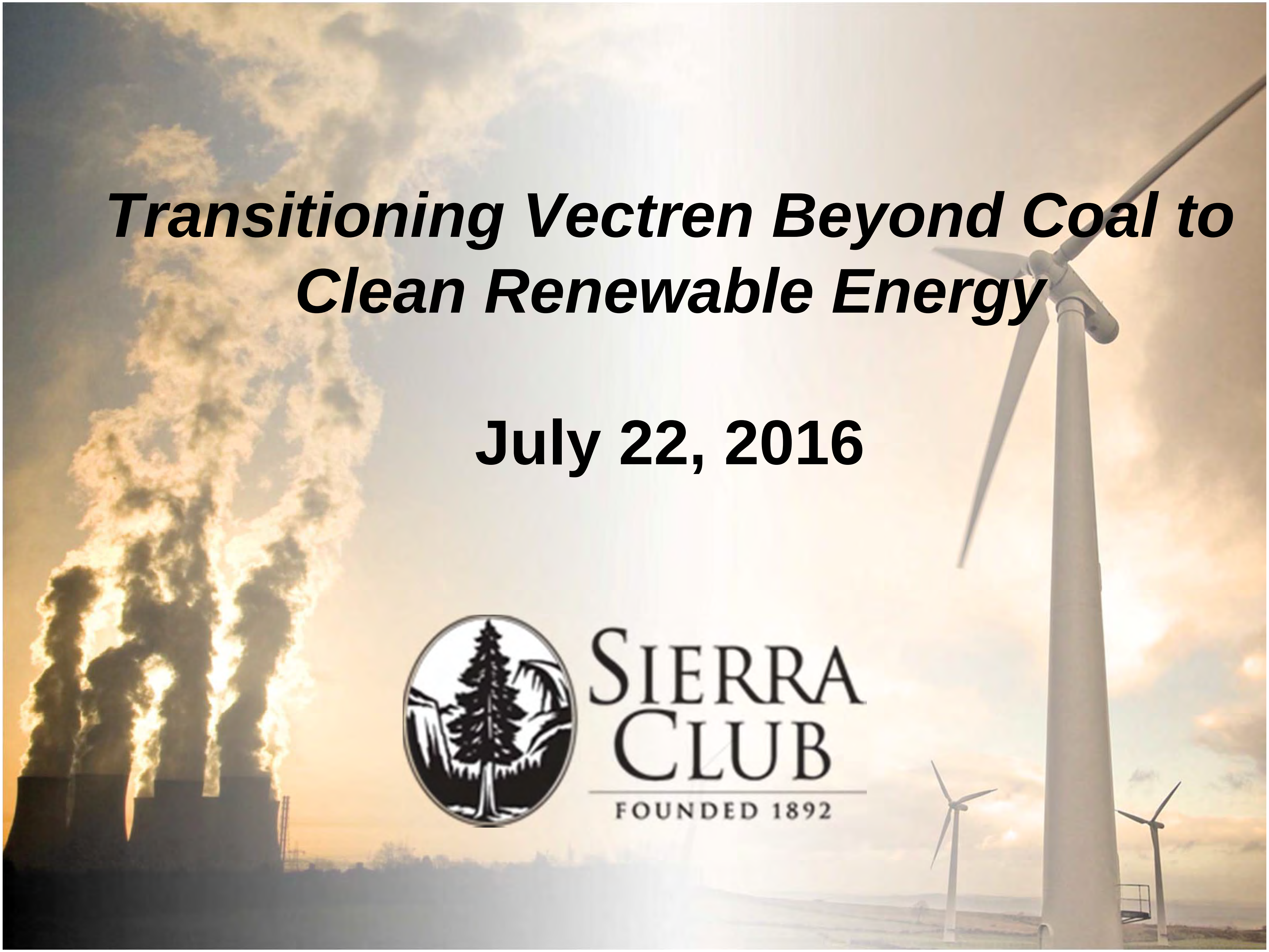
July 22, 2016

VECTREN
Energy Delivery

Questions/Comments?

Vectren's Next Steps

- At the third and final stakeholder meeting in late fall, Vectren will discuss and get comments on:
  - the selection of the portfolios for the risk analysis
  - the final results of the risk analysis, and
  - the preferred/recommended portfolio


Transitioning Vectren Beyond Coal to Clean Renewable Energy
July 22, 2016
SIERRA CLUB
FOUNDED 1892

Vectren's Coal Plants Aren't Competitive Today

Brown, Culley, and Warrick units are not competitive in today's electric market.

Wind and solar prices have steadily declined and continue to expand in MISO. Energy efficiency has helped keep power prices relatively low (though much more should be done).

Natural gas prices have dropped significantly in recent years relative to coal prices. United States Energy Information Administration and other forecasts show gas prices remaining relatively low through the early 2020s.

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Vectren’s Coal Plants Aren’t Competitive Today

Vectren’s coal units are costly and trending toward obsolescence.

- **Culley unit 2: 2015 capacity factor 9%; 2011-2015 average 22%.**
- **Culley unit 3: 2015 capacity factor 57%; 2011-2015 average 60%.**
- **Brown unit 2: 2015 capacity factor 53%; 2011-2015 average 56%.**
- **Brown unit 1: 2015 capacity factor 62%; 2011-2015 average 59%.**

All capacity factor data is from SNL Energy

Vectren's Coal Plants Face Increasing Costs

Bad today, the economic position of Vectren's coal plants will further deteriorate in the near future as costs increase.

Vectren's Coal Plants Face Increasing Costs

<u>Effluent Limitations Guidelines</u> ("ELGs") rule: ELGs will cause Vectren to have to spend tens of millions of dollars *unless it retires coal units by Dec. 2023*.

- **Vectren currently discharges bottom ash transport water from the Culley and Brown units and on occasion discharges fly ash transport water. These practices will have to cease, driving up costs by tens of millions of dollars—potentially more than $100 million*.**

***Sanford C. Bernstein & Co., LLC, U.S. Utilities: EPA Finalizes Water Effluent Guidelines; How Much Will It Cost the Industry? at 10 (Oct. 1, 2015)**

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Vectren's Coal Plants Face Increasing Costs

<u>Coal Combustion Residuals</u> rule: Vectren may have to close ash ponds and landfills and construct new landfills, among other obligations.

<u>Clean Power Plan</u> will create a carbon price that further increases the costs of these plants.

<u>SO2 NAAQS</u>: A.B. Brown's new SO2 limit will increase operational costs. Air modeling shows that Warrick is violating the SO2 NAAQS and a cleanup plan for that plant is due Dec. 2017.

Need to Move Beyond Coal In This IRP

Vectren produced 97 percent of its electricity from coal in 2015 and consistently has the highest retail electricity costs in the state.

Investing more customer money in these plants – to comply with the ELG rule, for example – will only create greater stranded costs when they retire.

Southern Indiana is unfairly burdened by pollution from 13 coal plants within an hours' drive of Evansville. Our region regularly tops lists of most polluted places to live.

Need to Move Beyond Coal In This IRP

Vectren's load growth is flat at best.

- **SABIC's cogeneration project significantly impacts demand.**
- **Toyota has pledged to eliminate carbon emissions in all operations by 2050.**
- **AstraZeneca has pledged to go 100 percent renewable by 2020.**

Need to Move Beyond Coal In This IRP

MISO now predicts a region-wide capacity surplus of 2.7 gigawatts in 2017 (an increase from its previous estimate for 2016), including a .6 gigawatt surplus in Zone 6 (which includes Indiana).

Moving Vectren beyond coal is thus good for customers and our economy, imperative for our health, and consistent with maintaining a reliable electric system in Southern Indiana.

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Ohio River Valley Campaign Representative
Sierra Club Beyond Coal Campaign
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VALLEY WATCH, Inc.
800 Adams Avenue • Evansville, IN 47713 • (812) 464-5663

Statement of John Blair, president of Valley Watch, Inc. , at the second public meeting regarding Vectren's Integrated Resource Plan. 7/22/16

Thanks for this opportunity. Valley Watch's purpose since 1981 is simple. It is our mission to "Protect the Public Health and Environment of the Lower Ohio River Valley." As such, we remain concerned for the health of area residents due to the massive burning of coal in this region, including Vectren's old coal fired plants at Culley and Brown.

We have known for several years that Culley 2 costs more to operate than the revenue it brings in, yet, Vectren seems hell bent on keeping the dinosaur alive for some unknown reason.

Now, testimony in a current rate case by Vectren's own consultant, Black and Veach indicates that it is also uneconomic to place an additional burden on ratepayers for so called environmental upgrades on the ABBrown plants instead of retiring them and either building new, more economic capacity or purchasing power from the grid. Vectren claims that to embrace alternatives would leave stranded costs but then they decided unilaterally to increase those stranded costs onto their ratepayers. That makes their argument dubious and untrustworthy.

No one forced Vectren to stick with ABBrown and invest nearly $100 million in these antiquated plants. In fact, they did so without even first asking Indiana Regulators for permission, confident they would gain approval without much scrutiny.

Already, Vectren residential and commercial electric rates are among the highest in the nation and definitely the highest in the midwest. That fact will never change as long as Vectren pursues the nefarious position of spending good money after bad.

For years, Valley Watch has recognized that Vectren has quickly and without objection followed the edicts of EPA, at least after their settlement with EPA over New Source Review violations in the early part of this century. And while we acknowledged that, we remained concerned with the manner of doing so spending millions incrementally and often with the seeming intent of increasing stranded costs when the inevitable issue of carbon costs would rise, forcing retirement of those plants.

Now, of course, we are faced with similar issues when it comes to the ELG rule and the coal ash rule. Coal ash in particular is problematic for ratepayers since that money will have to be spent whether or not those plants continue to operate.

Yes, Valley Watch fully supports a broad range of renewable options. Solar, wind, geothermal and hydro power where dams already exist make abundant sense in a carbon constrained world, but most importantly in this equation is the efficacy of energy efficiency. We have only begun to tap the surface of energy efficiency in this country. Everywhere it is used with commitment and passion , it proves to be the most economical way to reduce cost and pollution. Vectren's commitment to both production and end use efficiency has a long way to go before it makes sense to develop additional energy generation capacity that will their customers, especially the poor to choose between eating and freezing.

Greater help for customers than offering now antiquated compact fluorescent bulbs is badly needed if we are to adapt to this new reality of carbon constraints and common sense energy policy.

Valley Watch will be happy to assist Vectren in planning and implementing policies and programs to get this job done in a way that is fair, both to Vectren consumers and assuring reasonable profits for a monopoly business model that has a return on their investments that is nearly 50 times greater than any of us can earn through savings, if we have anything left to save after paying Vectren each month.

2016 Vectren Public IRP Stakeholder Meeting #2
July 22, 2016
Portfolio Exercise Summary

During Vectren's public IRP stakeholder meeting on Friday, July 22nd Vectren held a portfolio development workshop to gain input from stakeholders on additional portfolios to be considered within the IRP analysis. A portfolio is a mix of future resources to meet expected future demand for electricity. Those present divided into 4 tables, listed as groups 1-4 in the tables below, and were asked to provide Vectren with their preferred mix of coal, gas, wind, solar, storage, and energy efficiency resources by 2025.

At the end of the session, Vectren collected the results (7 individuals' worksheets and 4 group worksheets) from each table. Preferences were grouped by year where available (2025, 2030, 2035). The percentages that were most often stated were used to develop general guidelines for developing a stakeholder portfolio.

The general consensus among the 17 participants was that Vectren should develop a diversified portfolio that moves away from a significant amount of coal by 2025 while renewables and energy efficiency increase. Over the long term, all coal should be retired while renewables and energy efficiency further increase.

Vectren will work to develop a stakeholder portfolio that fits the general profile in the table below. This portfolio will be modeled and evaluated along with other portfolios within the IRP analysis. Note that current and future generation options have specific sizes; therefore, the stakeholder portfolio will not exactly match the percentages below. Additionally, the market potential for gas combined heat and power and energy efficiency may limit the amount that of each resource that can reasonably be considered. Combined heat and power is a combined cycle gas turbine that is sited at a customer location. Typical candidates for CHP require a high steam load to determine the feasibility of siting this resource at their facility. Also, energy efficiency has technical and achievable limits.

	Stakeholder Portfolio		
Stakeholder Portfolio	**2025**	**2030**	**2035**
Coal	40%	15%	0%
Gas Combined Cycle	10%	15%	15%
Gas Combustion Turbine	0%	0%	0%
Gas Combined Heat and Power	10%	10%	10%
Wind	10%	10%	10%
Solar	10%	15%	25%
Storage	0%	10%	10%
Energy Efficiency/Demand Response	20%	25%	30%
Total	100%	100%	100%

Below is a summary of the portfolios that were mentioned at each table and some stakeholder commentary on each.

Group 1 developed two scenarios for two different time frames (2025 and 2050). They stated that their ultimate goal is to transition away from fossil fuels completely. Group one had a desire to generate electricity as close as possible to the source; therefore, solar accounts for a higher percentage of capacity in their portfolio than wind in Southern Indiana. Additionally, there was a preference to conserve as much energy as possible.

	Group 1	
	2025	2050
Coal	5%	0%
Gas Combined Cycle	15%	0%
Gas Combustion Turbine	15%	0%
Gas Combined Heat & Power	10%	0%
Wind	10%	20%
Solar	25%	50%
Storage	0%	0%
Energy Efficiency/Demand Response	20%	30%
Total	100%	100%

Group 2 also provided guidance beyond 2025 as shown in the table below. This group chose not to include any gas combusting turbines because they are inefficient. This group stated a desire to increase energy efficiency while decreasing the use of coal.

	Group 2		
	2025	2030	2035
Coal	40%	15%	0%
Gas Combined Cycle	10%	15%	15%
Gas Combustion Turbine	0%	0%	0%
Gas Combined Heat & Power	10%	10%	10%
Wind	10%	10%	15%
Solar	10%	15%	20%
Storage	0%	10%	10%
Energy Efficiency/Demand Response	20%	25%	30%
Total	100%	100%	100%

Group 3 provided two possible resource mixes by 2025.

	Group 3	
	2025	2025*
Coal	40%	40%
Gas Combined Cycle	30%	20%
Gas Combustion Turbine	0%	0%
Gas Combined Heat & Power	0%	0%
Wind	15%	15%
Solar	5%	15%
Storage	0%	
Energy Efficiency/Demand Response	10%	10%
Total	100%	100%

*Group 3 also indicated that 10% of capacity should be allocated to storage under option 2

Group 4 felt that we should consider how climate change would affect each form of generation in terms of efficiency. This group indicated that their preference was option 1; however, they provided two additional options for consideration. The second option shuts down Culley 2 and distributes the capacity over renewable options, while the third portfolio shuts down Culley 2 and Brown 1, and converts Brown 2 to gas.

	Group 4		
	2025	2025	2025
Coal		85%	45%
Gas Combined Cycle			25%
Gas Combustion Turbine			0%
Gas Combined Heat & Power			0%
Wind	30%	5%	6%
Solar	55%	7%	20%
Storage	10%	1%	1%
Energy Efficiency/Demand Response	5%	2%	3%
Total	100%	100%	100%

Vectren 2016 Integrated Resource Plan (IRP)

July 22, 2016 Stakeholder Meeting 2 Summary

The following is a summary of the second of three Vectren IRP stakeholder meetings in 2016 and is meant to provide a high level overview of the discussion on July 22nd. Stakeholder feedback gathered at these meetings will be considered within Vectren's evolving IRP process.

Welcome (slides 1-2)
Carl Chapman, President and Chief Executive Officer

Mr. Chapman opened the meeting and welcomed guests to Vectren headquarters, located within Vectren's service territory in Evansville, IN. He mentioned that this is an important IRP for Vectren, and several things are setting the stage for this analysis. 1) EPA regulations are putting great pressure on coal resources. Several regulations that were recently finalized (Effluent Limitations Guidelines (ELG), Coal Combustion Residuals (CCR), and the Clean Power Plan (CPP)) are more stringent than expected. 2) Gas prices are low and projected to be stable over the long term. Shale gas has revolutionized the industry, driving these currently low gas prices. This has fueled a surge in gas generation. 3) Renewable costs continue to decline, but they are still expected to be more expensive than other alternatives in the next several years. 4) More than ever, the future is uncertain. Vectren will evaluate a wide range of input assumptions within the risk analysis. 5) Vectren is observing developments in MISO, which is Vectren's regional transmission operator. Within Vectren's zone, MISO is projecting a shortfall in generation or demand side options needed to maintain reliability beginning in 2018 for high certainty resources. The shortfall continues to grow through 2021. Mr. Chapman said that regardless of the final plan, reliability needs to be maintained, and customer cost minimization must be a priority. Mr. Chapman then introduced the moderator, Gary Vicinus.

Vectren IRP Process Overview (Slides 3-6)
Gary Vicinus, Pace Global – Managing Director of Consulting Practice

Mr. Vicinus briefly reviewed the information that was provided at the first public stakeholder meeting and the general IRP process. Materials from the first meeting can be found at www.vectren.com/irp. He also outlined the agenda for the day and discussed the ground rules for the meeting.

Environmental Compliance (Slides 7-15)
Angila Retherford, Vice President Environmental Affairs and Corporate Sustainability

Ms. Retherford reviewed the current environmental controls on Vectren's generation fleet. All units are controlled for SO_2, NO_X, and Soot. She then discussed the recent control enhancements to sorbent injection systems to comply with the Mercury and Air Toxic Standards (MATS) rule. Regarding the Coal Combustion Residuals (CCR) rule, Ms. Retherford pointed out that the majority of Vectren's fly ash is beneficially reused in cement application, and Culley and Brown dams will meet the new, more stringent structural integrity requirements by October 2016. She pointed out that preliminary engineering cost evaluations are underway for compliance with the new Effluent Limitations Guidelines (ELG). Finally, Ms. Retherford commented that Vectren's IRP will assume that the Clean Power Plan (CPP) will be upheld by the US Supreme Court, but compliance will be delayed until 2024.

Stakeholders asked why are there no mercury controls shown on Slide 8. It was noted that mercury control is handled though sorbet injection systems that enhance the mercury removal of the existing scrubbers, and are not considered separate environmental controls. A stakeholder pointed out that there are not emissions costs for solar. Vectren stated that the IRP process incorporates all costs for various technologies. A stakeholder asked how moral (health) considerations are taken into account, and it was explained that the health considerations are among the primary factors considered when government standards, like ozone limits, are developed. Finally, a stakeholder asked how Vectren complies with the operating permit for Brown to make sure that Posey County remains in attainment for the revised One Hour SO_2 air quality standard. Vectren lowered averaging time which effectively lowers the compliance target.

Base Case/Modeling Inputs (slides 16-24)
Gary Vicinus, Pace Global – Managing Director of Consulting Practice

Mr. Vicinus explained that Vectren surveyed and incorporated a wide array of sources in developing its base assumptions for key drivers. He then showed the consensus forecasts for the following drivers: carbon price, natural gas, coal, on-peak and off-peak power prices, and capital costs. A question was asked about how climate change models were factored into the IRP analysis. Within the IRP analysis, the demand forecast includes average 10-year peak producing weather. Additionally, the risk analysis will consider a wide range of demand forecasts.

Busbar Analysis and Optimization Modeling (slides 25-40)
Matt Lind, Burns & McDonnell – Associate Project Manager

Mr. Lind explained the concept of busbar or Levelized Cost of Electricity (LCOE) screening which involves narrowing 36 new power supply choices from the technology assessment into a manageable data set that will then be modeled. Within the busbar screening, similar generation options are compared within expected operation ranges. Generally, the lowest cost resources within each category are then selected for modeling. Modeled options are representative of a class of generation.

Slide 38 describes the resource alternatives that will be modeled within the IRP analysis. The following alternatives were chosen in the busbar screening: 4 combined cycle gas turbine options, 2 simple cycle gas turbine options, Indiana wind, combined heat and power, and utility scale solar. Note that energy efficiency and demand response were not screened options and will be modeled as potential resources. In the base case all battery storage (lithium-ion) options were screened out due to high cost relative to other options. A stakeholder asked if other kinds of battery storage technologies besides lithium-ion were considered, and it was noted lithium ion batteries seem to be the most likely technology over the next twenty years.

To help stakeholders understand the relative capacity differences among various power supply resource alternatives, Mr. Lind discussed the amount of installed capacity needed to supply 100 MWs towards the planning reserve margin. Reserve margin is the amount of capacity above the peak demand forecast required by MISO, Vectren's regional transmission operator, to maintain reliability. MISO's most recent Loss of Load Expectation Study Report[1] (Planning Year 2016-2017) requires that utilities have 7.6% capacity above expected demand. Vectren is able to count 11.25% of installed wind capacity towards the MISO planning reserve margin. In other words, only 11.25 MWs per 100 MWs of installed wind capacity is credited towards the planning reserve margin. The chart on slide 37 shows that it will take approximately 889 MWs of installed wind capacity to receive 100 MW credit towards the required reserve margin (100/.1125 = 889).

A stakeholder asked if Purchase Power Agreements (PPA) for solar would be considered. Solar will be modeled as a utility resource; however, PPAs will be considered at the time of a generation build.

Scenario Development (slides 41-61)
Gary Vicinus, Pace Global – Managing Director of Consulting Practice

Mr. Vicinus started by reviewing direct stakeholder input that was provided to Vectren on April 7th at the first 2016 Vectren IRP stakeholder meeting. Slide 43 shows stakeholder input that was considered in scenario development.

PACE has helped a variety of utilities across the country construct scenarios. Scenarios are possible future states that can aide in the IRP process of developing and evaluating portfolios. The process involves identifying key drivers (regulations, technology, and the economy) and constructing scenarios by varying key inputs such as gas, coal, CO_2, load, capital, and market power prices. Vectren worked with PACE to develop 5 internally consistent scenarios (each is described in slides 46-51):

1. High Regulatory
2. Low Regulatory
3. High Technology
4. High Economy
5. Low Economy

Mr. Vicinus then presented the range of key input prices for each scenario: carbon price, natural gas, coal, on-peak and off-peak power prices, and capital costs.

A stakeholder asked about the plausibility of the low regulatory scenario. It was explained that the low regulation scenario includes existing regulations and associated economic/social costs; however, this scenario assumes that there is no CO_2 price. Another stakeholder asked if wholesale sales will be considered in the scenarios, and the answer was that economic/efficient dispatch opportunities in the marketplace will be included.

A stakeholder asked if the risk analysis will include +/- 2 standard deviations in outcomes for key inputs, and the answer was yes.

[1] Source: https://www.misoenergy.org/Library/Repository/Study/LOLE/2016%20LOLE%20Study%20Report.pdf

A stakeholder asked if PPAs for renewables are better for customers because they do not include capital costs. It was explained that capital costs are included in pricing for both developers and utilities. Purchased power agreements embed those costs in the price of power.

Stakeholder Input to the Portfolio Selection (slides 64-69)
Gary Vicinus, Pace Global – Managing Director of Consulting Practice

Vectren held a portfolio development workshop to gain input from stakeholders on additional portfolios to be considered within the IRP analysis. A portfolio is a mix of future resources to meet expected future demand for electricity. Details of that workshop can be found in the 2016 Vectren Public IRP Stakeholder Portfolio Exercise Summary[2], posted on www.vectren.com/irp. The table below shows the summarized results of the stakeholder exercise. Note that Vectren did not receive any additional stakeholder input on the stakeholder portfolio summary after being posted.

	Stakeholder Portfolio		
Stakeholder Portfolio	2025	2030	2035
Coal	40%	15%	0%
Gas Combined Cycle	10%	15%	15%
Gas Combustion Turbine	0%	0%	0%
Gas Combined Heat and Power	10%	10%	10%
Wind	10%	10%	10%
Solar	10%	15%	25%
Storage	0%	10%	10%
Energy Efficiency/Demand Response	20%	25%	30%
Total	100%	100%	100%

During this session, representatives from Valley Watch and the Sierra Club presented their input to the group.

Valley Watch Comments

Valley Watch believes that Vectren should retire “uneconomic coal plants” instead of investing in additional pollution control equipment. They feel that this would address public health concerns and would prevent incremental spend, which drives up rates and increases stranded costs. Valley Watch supports renewable options and energy efficiency programs, and is willing to work with Vectren to satisfy both investors and customers to achieve this.

[2] https://www.vectren.com/assets/cms/pdfs/2016%20Vectren%20Public%20IRP%20Stakeholder%20Portfolio%20Exercise%20Summary.pdf

Sierra Club Comments

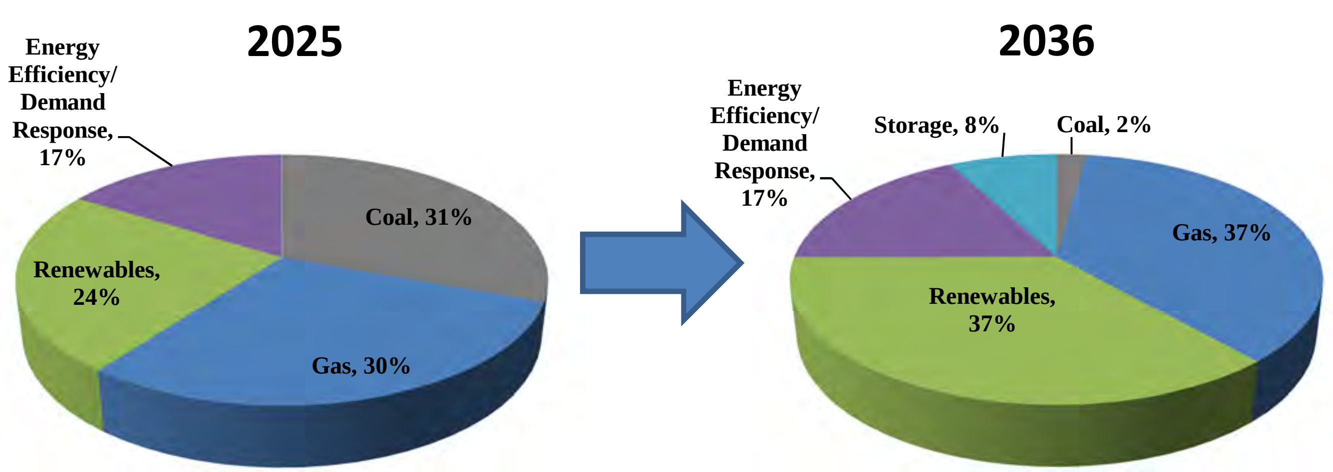
Sierra Club believes that now is the time to transition to clean energy. There is the moral case for public health and protecting the environment. They stated that Vectren's coal plants are not competitive and are not needed based on surplus capacity in the region. The Sierra Club believes that there is no reason to invest in coal plants in an area with high rates. Renewable generation is increasing within MISO. Sierra Club feels that energy efficiency programs are most cost effective in reducing customer costs. Sierra Club noted that there are incentives for early adoption of renewables (as proposed by the Clean Power Plan). A number of companies are setting goals addressing their energy mix.

Stakeholder Portfolio

Vectren and Burns and McDonnell used stakeholder input received during this session to build a diversified stakeholder portfolio that is largely consistent with input received during the meeting.

Because current and future generation options have specific sizes, the stakeholder portfolio does not exactly match the percentages that were discussed in the stakeholder meeting. In this portfolio, nearly all coal is retired in the long term while renewables increase. Energy efficiency remains at approximately 17% in 2025 and 2036, which equates to 2% of eligible sales (non-industrial opt-out load) each year between 2017 and 2036, which is the highest level of energy efficiency included in Vectren's modeling. Energy efficiency blocks are modeled using a ten year life.

The percentages below were developed by dividing unforced capacity (UCAP), the amount of capacity applied towards meeting MISO's reserve margin requirement, by the expected demand plus the reserve margin requirement (totals are slightly higher than 100% due to surplus capacity). The chart below shows the stakeholder portfolio that will be modeled and evaluated along with other portfolios within the IRP analysis.



Stakeholder Questions, Feedback, and Comments (slide 70)
Gary Vicinus, Pace Global – Managing Director of Consulting Practice

The final portion of the meeting was dedicated to answering any additional questions and capturing stakeholder feedback.

A stakeholder asked how many technologies are available to help meet load. There are many vendors that have slightly different technologies within each resource category. The IRP analysis generally considers one or two resources within each category that are representative of what is available. When a company goes out for bid on new generation, they can consider multiple options, including PPAs.

A stakeholder asked about how Vectren incorporates the 1% cap on distributed solar generation, consistent with current regulations, into the IRP analysis. Within the load forecast used for the IRP, Vectren did not cap the forecast of customer owned solar at 1% and customer owned solar projection was netted out of the load forecast. Another stakeholder asked if feed-in-tariffs (FIT) were considered. Vectren has considered them in the past and will consider them again at the time of the next rate case. There is no rate case planned at this time.

A stakeholder asked what Vectren's plans are regarding solar. Vectren is constantly looking at solar in the near term, but over the last several years Vectren has not had a need for generation and wants to keep customer rates as low as possible. It was noted that the Vectren Foundation recently funded a solar lighting project in Evansville. The results of the IRP will inform next steps around solar. A stakeholder commented that customers would prefer that money be spent on solar and energy efficiency rather than on coal plants.

A stakeholder asked if we will be including all generation costs within Vectren's IRP analysis, including health costs. All costs are considered within the IRP. Governmental regulations include health costs, and anticipated regulations are included within the analysis.

A stakeholder noted that emission projections were not included in the presentation, and it was noted that it is included in the cost of generation. Emissions will be tracked for each portfolio as an output of the analysis.

Energy Efficiency Modeling Discussion

October 14th, 2016

Vectren Energy Delivery

Major Energy Efficiency Modeling Assumptions

- Vectren's IRP process will inform the level of Energy Efficiency (EE) to achieve in future program plans
- EE blocks will include both residential and Commercial/Industrial savings, which allows flexibility in future years to determine the proper mix
- No minimum level of EE has been embedded into our sales and demand forecast (IRP will determine the amount of EE)
- Naturally occurring EE included in sales and demand forecast
- EE savings amounts in 2016-2017 will be based on EE plan approved in Cause No. 44645. Included as an existing resource in our dispatch portfolio model
- Levelized EE costs over the measure life

EE = Energy Efficiency
IRP = Integrated Resource Plan

Major EE Modeling Assumptions Cont.

- The model may select up to 8 blocks at 0.25% of eligible sales for a maximum of 2% of eligible sales[1] annually
- 80% net to gross ratio, which is consistent with our most recent evaluation
- Current plan costs used as the base cost for block pricing
  - Escalated in real dollars based on penetration model. The prices increase from block 1 up to block 8 and increase each year

[1] 2% is aligned with Vectren's most recent market potential study for the 2015-2019 study period for technical potential including opt-out eligible customer sales

EE Blocks – Base Case

EE Resource Options Net of Free Riders										
Year	Eligible GWh Conservation Savings	Percent of Eligible Sales Potential	MWh Block 1	MWh Block 2	MWh Block 3	MWh Block 4	MWh Block 5	MWh Block 6	MWh Block 7	MWh Block 8
2016										
2017	3,493									
2018	3,525	2.00%	6,986	6,986	6,986	6,986	6,986	6,986	6,986	6,986
2019	3,545	2.00%	7,050	7,050	7,050	7,050	7,050	7,050	7,050	7,050
2020	3,571	2.00%	7,089	7,089	7,089	7,089	7,089	7,089	7,089	7,089
2021	3,577	2.00%	7,141	7,141	7,141	7,141	7,141	7,141	7,141	7,141
2022	3,594	2.00%	7,154	7,154	7,154	7,154	7,154	7,154	7,154	7,154
2023	3,613	2.00%	7,188	7,188	7,188	7,188	7,188	7,188	7,188	7,188
2024	3,640	2.00%	7,227	7,227	7,227	7,227	7,227	7,227	7,227	7,227
2025	3,654	2.00%	7,281	7,281	7,281	7,281	7,281	7,281	7,281	7,281
2026	3,672	2.00%	7,309	7,309	7,309	7,309	7,309	7,309	7,309	7,309
2027	3,692	2.00%	7,344	7,344	7,344	7,344	7,344	7,344	7,344	7,344
2028	3,721	2.00%	7,384	7,384	7,384	7,384	7,384	7,384	7,384	7,384
2029	3,739	2.00%	7,442	7,442	7,442	7,442	7,442	7,442	7,442	7,442
2030	3,755	2.00%	7,477	7,477	7,477	7,477	7,477	7,477	7,477	7,477
2031	3,772	2.00%	7,511	7,511	7,511	7,511	7,511	7,511	7,511	7,511
2032	3,796	2.00%	7,543	7,543	7,543	7,543	7,543	7,543	7,543	7,543
2033	3,810	2.00%	7,592	7,592	7,592	7,592	7,592	7,592	7,592	7,592
2034	3,831	2.00%	7,620	7,620	7,620	7,620	7,620	7,620	7,620	7,620
2035	3,850	2.00%	7,663	7,663	7,663	7,663	7,663	7,663	7,663	7,663
2036	3,876	2.00%	7,701	7,701	7,701	7,701	7,701	7,701	7,701	7,701

*EE savings amount for 2016-2017 will be based upon EE plan approved in 44645

EE = Energy Efficiency
GWh = Gigawatt Hour
MWh = Megawatt Hour

Major EE Modeling Assumptions Cont.

- The 8 blocks of 0.25% per year (2% of retail sales per year) for the 20 year planning horizon represents almost 40% of retail sales are EE options available for selection in the IRP process
- This level of optionality exceeds typical estimates of achievable potential or even technical potential
- As a result, Vectren needs to incorporate estimates of the cost to achieve these levels of impacts

EE Resource Cost

- Vectren's current 2016 operating plan used as a starting point for block pricing

- Vectren utilized the cost of EE programs approved in it's most recent filing (Cause No. 44645) as a starting point for 2017

- Energy Information Administration (EIA) data was used to determine the relationship between the cost to implement EE programs and market penetration
  - Statistical analysis provided insights on how costs change with changes in the size of EE load impact initiatives as well as increases in the overall cumulative penetration of the market.

EE = Energy Efficiency

EE Resource Cost

- Growth rates in cost were developed from two separate econometric models of EIA data
- The results from the two models were averaged to produce a growth rate in cost of 4.12% per 1% of retail sales achievement or 1.04% per 0.25% EE block.
- Developed 2 tiers of EE pricing
  - 1% of retail sales over the 20 year horizon exceeds an expected high achievable level
  - It is assumed that the second 1% of retail sales occurs at a higher marketing cost than the first

EE = Energy Efficiency
EIA = Energy Information Administration

EE Resource Cost

The starting cost for the second 1% of blocks is assumed to be the ending cost (in real dollars) for the first 1%.

- The process of computing the applicable growth rate for the second 1% was similar to that of the first 1%. This resulted in a growth rate of 1.72% per additional 1% of retail sales impacts or 0.43% per 0.25% block. This growth rate is applied to the remaining set of four 0.25% blocks or the next 1% of retail sales available for selection.

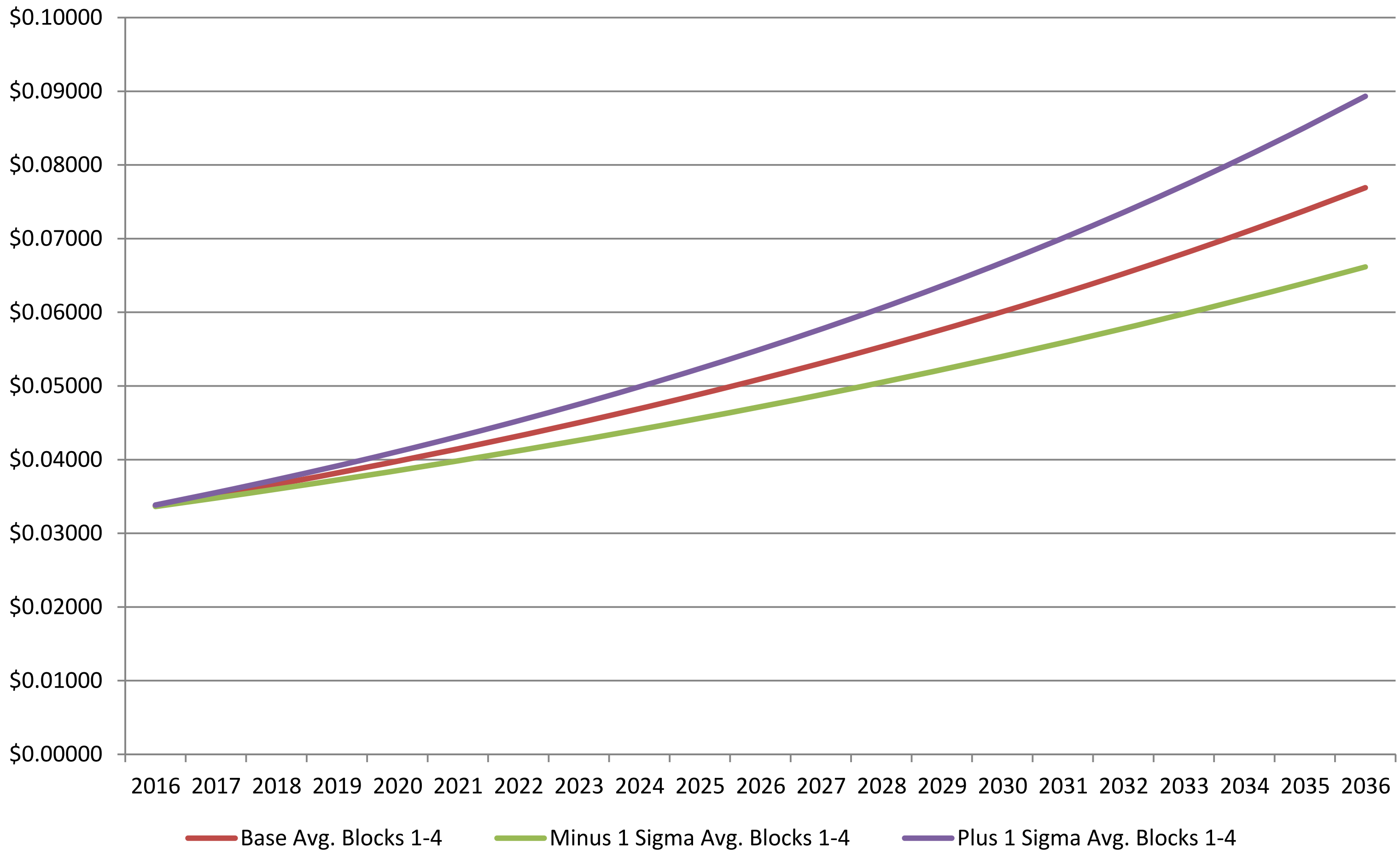
EE = Energy Efficiency

EE Resource Cost cont.

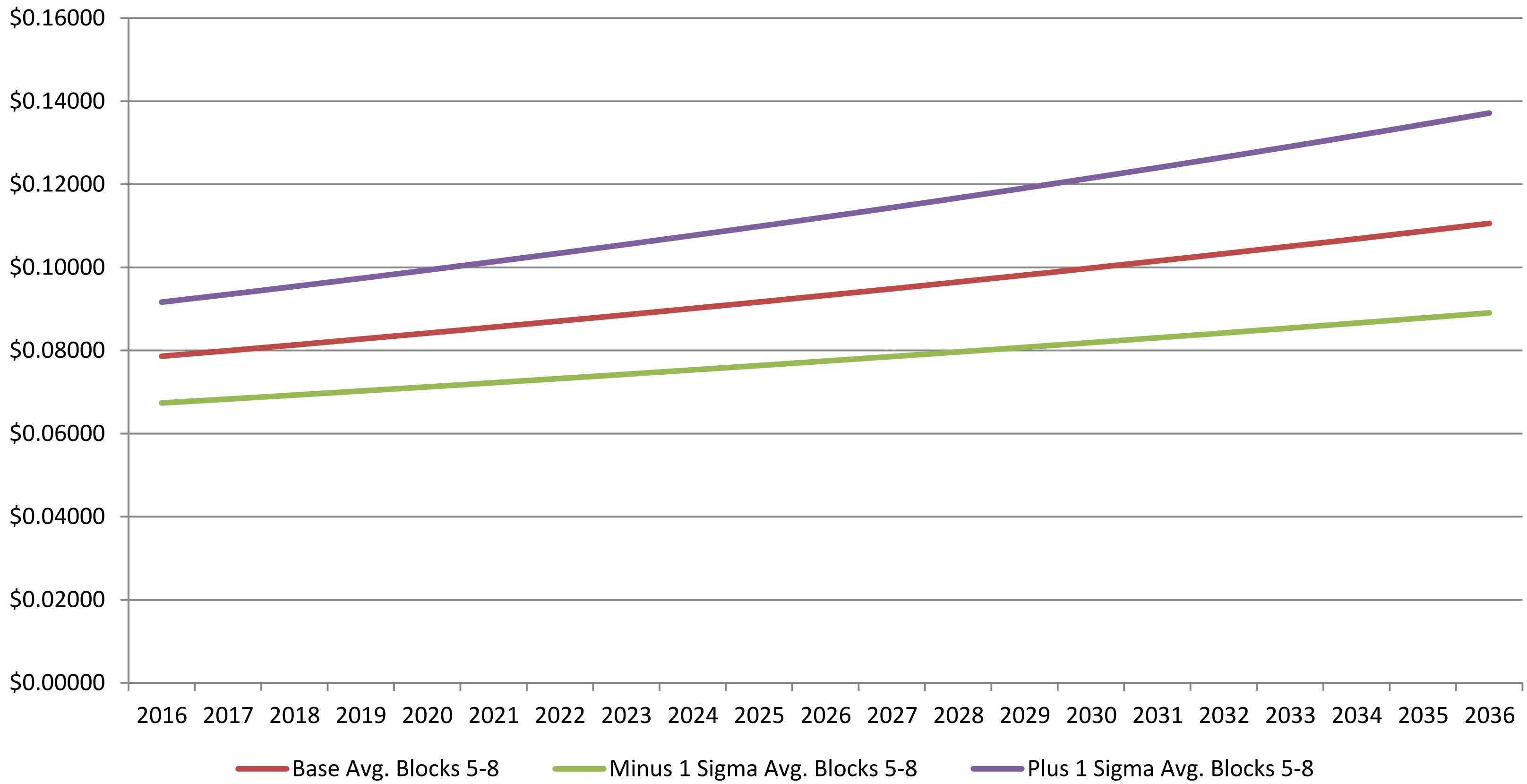
- Vectren recognizes that 20 year cost projections for EE achievement are subject to uncertainty
- As a result, Vectren also incorporated into the IRP analysis alternate levels of cost projection reflecting plus and minus one standard deviation in the projected growth rates in cost
- This helps assess whether alternate views on EE cost achievement would impact the selection of a resource plan

EE = Energy Efficiency
IRP = Integrated Resource Plan

Base Case Average Levelized Costs – Blocks 1-4



Base Case Average Levelized Costs – Blocks 5-8



VECTREN Energy Delivery

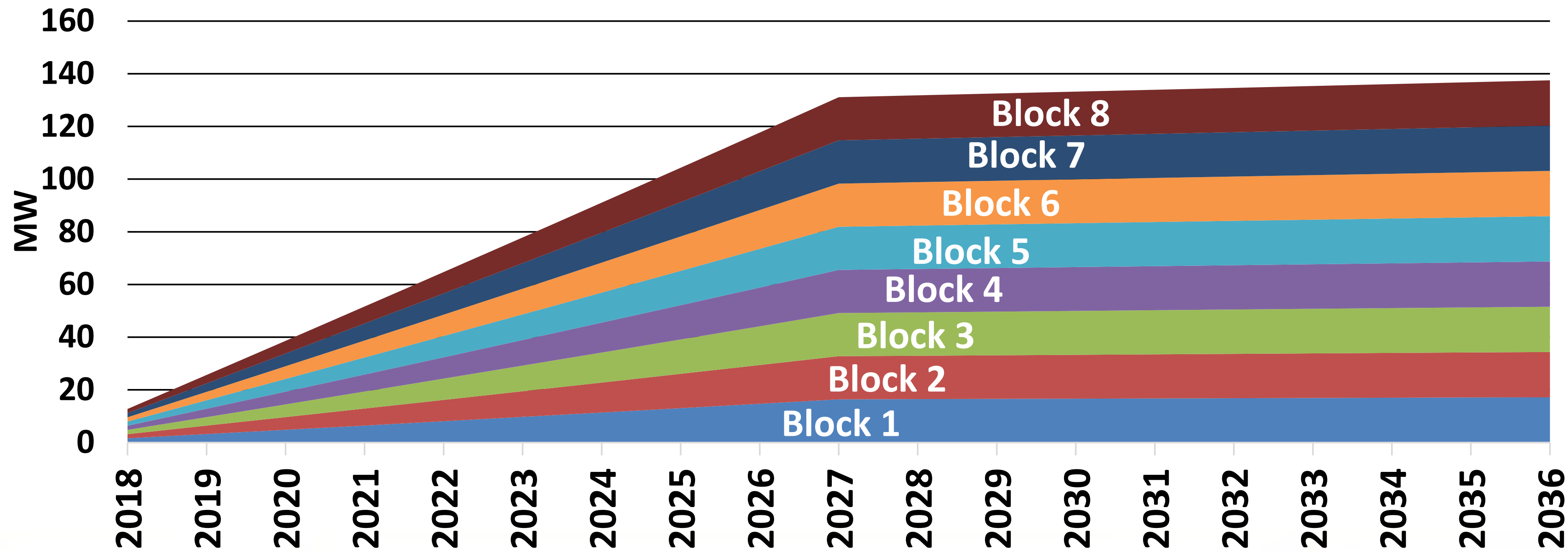
EE Resource Summary

- The EE Resource process provides EE savings and cost values for over 150 blocks of EE resources representing almost 40% of available retail sales for potential selection by the IRP analytical model
  - This level of EE resource options exceeds estimates of Technical Potential
  - Provides flexibility to the IRP model to identify and select an EE plan consistent with the IURC and legislative objectives

- Given that there is a potential for a modeled portfolio to exceed an estimate of Technical Potential, the results of the IRP analytical process should be evaluated to ensure that the resulting level of EE selected is viable

Energy Efficiency Program Modeling:
What Does EE Alternative Look Like?

- Modeled as 8 individual "blocks"
- Each block represents 0.25% of eligible sales
- Program life = 10 years



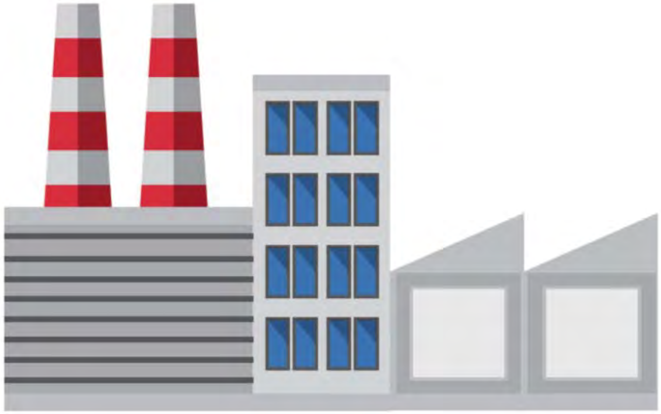
EE = Energy Efficiency
MW = Megawatt

Energy Efficiency Program Modeling:
Decision Constraints

- For optimization runs, if block selected, must continue throughout study period
  - Too many choices if year-to-year selection allowed
- Also built portfolios with varied levels of EE over time
- No more than 8 blocks can be selected (2% of eligible sales max)
- Decision to select any amount of EE is made in 2018
  - Level of EE selected in 2018 is carried throughout the study period

Energy Efficiency Program Modeling:
How Does Strategist Evaluate Alternatives?

- The screening model's primary objective: ***minimize customer costs***
- Selected portfolio must meet future customer requirements for:
  - Resource adequacy (or capacity)
  - Energy
- Supply and demand side options evaluated on a comparable basis



Energy Efficiency Program Evaluation:
How Does Strategist Select?

- Factors contributing to preference for energy efficiency programs:
  - Existing generation avoided energy cost
  - Long term cost of carbon
  - Ability to contribute to resource adequacy requirements

Questions?

Vectren 2016 Integrated Resource Plan (IRP)
October 14, 2016 Vectren DSM IRP Modeling Meeting Summary

The following is a summary of the Vectren DSM IRP Modeling meeting held on October 14, 2016.

Welcome and Introduction
Rina Harris, Director of Energy Efficiency

Ms. Harris opened the meeting welcoming guests and started the meeting with a safety message. She stated this meeting was to discuss the Energy Efficiency (EE) modeling assumptions in the IRP and encouraged an open dialogue.

Ms. Harris highlighted that Vectren's IRP process will inform the level of EE that will be achieved in future program plans. For modeling purposes, major assumptions include: treating DSM as a resource in its entirety, which includes residential and commercial/industrial blocks of EE , no minimum level of EE embedded in sales/demand forecast, EE in 2016-2017 will be based on the Energy Efficiency plan approved in Cause No. 44645 and will be included as a resource, and levelizing DSM costs over the measure life.

She explained the blocks of EE were represented in .25% blocks of eligible sales for the model to select for a maximum of 2% (8 blocks) per year. She indicated that 2% is aligned with Vectren's latest MPS for 2015-2019 for technical potential, which is the highest potential of DSM, as it assumes there are no market limitations.

She noted the prices increase from block 1 to block 8 and increase each year. The model can select up to 150+ blocks, which represents approximately 40% of sales. This level of potential exceeds typical estimates of achievable potential as well as technical potential.

Pricing Discussion
Dr. Richard Stevie
VP, Forecasting – Integral Analytics

Dr. Stevie discussed how the EE pricing was determined in the IRP model. He indicated as a starting point, Vectren used the current 2016 EE plan as the base cost for block pricing, which also aligns with the cost/kwh in their latest MPS. He noted that the escalation of those costs is based upon two econometric models developed to examine how EE costs change as market penetration changes. The models that he created were based on Energy Information Administration (EIA) data. The econometric model results indicate that the cost of EE increases as there is deeper penetration in the market.

The econometric analysis provided insights on how costs change with changes in the size of Energy Efficiency load impact initiatives as well as increases in the overall cumulative penetration of the market. He noted the growth rates in cost were developed from two separate econometric models of EIA data. The results of the two models were averaged to produce a growth rate of 4.12% per 1% of retail sales achievement or 1.04% per 0.25% energy efficiency block. Dr. Stevie indicated that he developed two tiers of Energy Efficiency pricing: first 1% of retail sales which over the 20 year horizon exceeds an expected high achievable and the second 1% of retail sales occurs at a higher marketing cost than the first.

Stakeholders inquired how energy efficiency is priced in the model, and there was discussion around whether or not EE pricing could decrease over time. A 2008 ACEEE study by Kenji Takahashi and David Nichols was referenced during this discussion. Dr. Stevie noted that he generally did not agree with the analysis and that the study suffers from numerous analytical issues that produce statistically biased results.

Related to the cost of EE, Vectren noted the electric EE Portfolio first year cost/kwh in 2013 was approximately $0.16/kwh, moving to $.18/kwh in 2015 and $0.20/kwh in 2016. With time implementation becomes harder and cost more due to costlier, available measures.

Dr. Stevie discussed the uncertainty related to 20 year cost-projections and for that reason, Vectren incorporated alternative levels of cost projections reflecting plus and minus one standard deviation in the projected growth rates. This helps assess whether alternative scenarios on EE cost achievement would impact the selection of an EE resource within each possible future state.

Modeling Discussion,
Matthew Lind
Burns & McDonnell

Mr. Lind discussed how modeling assumptions were put into the optimization software (Strategist). He indicated that 8 blocks of EE per year generates a tremendous number of options for the model to solve for given other resource options being considered. To help the model solve the decision to select EE was made in year 2018. If selected, the same level of EE would be selected for years 2018-2036. This assumption was consistent within Dr. Stevie's EE cost projections.

A stakeholder suggested that breaking the link between EE selected in the near term versus long term as costs increase over time may overly constrain the model as it could result in the model not selecting EE in the short term. Vectren requested feedback/suggestions from stakeholders on how we could model differently (i.e., model in 3 year increments) and no specific feedback was provided during the meeting. In response to Vectren's inquiry during the meeting, Stakholders said no specific feedback could be provided without being able to look at the model first.

Mr. Lind continued to review the screening model used to evaluate alternatives and noted that model's primary objective is to minimize customer costs. The model evaluates both resource adequacy (capacity) and energy.

He further descripted contributing factors for energy efficiency programs being considered as cost effective, which included ability to beat existing generation avoided energy costs, long term cost of carbon, and ability to contribute to resource adequacy requirements.

A stakeholder inquired about how our model determines which load shapes are available for selection. Mr. Stevie stated the load shape in the IRP model is aligned with Vectren's 2016 IRP plan.

Influencing Vectren's energy portfolio toward more renewables and less fossil fuels is an important step in improving the health and future electric rates of the Evansville Community.

The front page of the Evansville Courier & Press ran an important article on September 29, 2016. It was an abridged version of the report that resulted from a nine-month investigation that found Evansville to be at the center of the highest concentration of industrial pollution in the United States. Alarming for Evansville residents was a subtitle that read, "Living and Dying in Evansville". The Center for Public Integrity, USA Today, and the Weather Channel collaborated on the report. The report and an accompanying video can be found at superpolluters.com. Not Vectren, the mayor, nor any city official has made a public statement regarding the national report. They haven't submitted any plans to reduce our overload of industrial pollution. It appears that it is up to the residents to push for change. One change we can push for is to have Vectren transition to more renewable energy and away from fossil fuels.

The largest contributors to our industrial pollution are coal plants. In Evansville 97% of our electricity is generated by five coal-fired power plants that are between 30 and 50 years old. One of those plants, Culley Unit 2, operated at just a 9% capacity factor in 2015 according to SNL Energy data. This year Culley 3 had a coal silo collapse causing it to be down 4-5 weeks. Ratepayers are paying high Overhead and Maintenance (O&M) on these aging and underutilized plants.

Every two years utilities complete a report called an Integrated Resource Plan (IRP) during which time utility stakeholders (customers) can view and comment on the planning of generating facilities to meet projected customer demand. The IRP process grew from the 1970s when nuclear power plants ran up huge cost overruns, and then it was discovered that the extra generating capacity was not even needed to meet demand. The O&M costs for each Vectren coal plant was included in its 2011 IRP, but were kept from the public and submitted only to regulators in its 2013 IRP. It is reasonable to suspect that O&M far exceeds other US generating facilities. We pay the highest electric rate in the state for electricity. And for our high electric rates we also get industrial pollution causing high illness rates. Where our electricity is 97% coal, the average in the US is 33% coal.

Vectren is in the process of completing its 2016 IRP and here are the key points that stakeholders need to know.

- Vectren must not continue to maintain excess capacity. Generation plants must match projected usage plus a small overage required by law. National trends indicate that even as populations increase, electricity usage is down due to the greater efficiency of appliances and homes. Evansville is no different. In addition, a large industrial user, SABIC will soon be generating much of its own electricity with its new cogen plant. One or more of the oldest coal plants must be retired. Culley Unit 2 is obviously in need of immediate retirement in light of its underutilization.

- Vectren must not spend good money after bad. If the plants are not retired, Vectren proposes spending an additional $240 million dollars on pollution controls that will be passed on to ratepayers. Such investment in the old plants will further delay our transition to renewables, which is where we need to go to stabilize our electric bills and improve our community's health.

- Vectren must build up renewables now, so as to be able to retire more coal plants in the future. Vectren can operate with up to 30% renewables without storage or significant changes to the grid. We need to quickly ramp up to 30%.

    - Currently Vectren has an 80 MW contract with wind farms in Benton County IN that meet about 3% of our electricity needs. Wind is the cheapest electricity currently available, and Vectren needs more of it in its generation portfolio. According to the U.S. Department of Energy (DOE) Wind Technologies Market Report, the average Power Purchase Agreement (PPA) price in the central U.S. was only $22.40/MWh in 2014.

    - Vectren is the only investor owned utility in Indiana that does not have any solar in its generation portfolio. Vectren presented numbers in its July 22, 2016 IRP meeting for solar that were four times the cost cited for utility solar in the Lazard's Unsubsidized Levelized Cost of Energy Anaysis – Version 9.0. Lazard's reported that Utility Solar ranged from $43 to $70 per MWh, whereas Vectren's levelized numbers were from $190 -$210 per MWh. It's no wonder that when the Vectren's model is run with their costs for utility solar, it comes out as too expensive an option.

    - For comparison, the Lazard's cost for coal plants is $65 - $150 per MWh. With the age of our plants, the $150 per MWh seems likely. Clearly renewables will eventually lead to lower electric bills once the coal plants are history.

- Vectren must not replace fossil fuels with fossil fuels. Although gas plants would reduce some of our local industrial pollution, there is too much uncertainty to invest in new gas plants. Fracking releases methane, which will likely be subject to more regulation in the future. Fracking has also been shown to be a threat to ground water. These issues will subject natural gas to pricing uncertainties that rate payers just don't need. It would be a repeat of the issues we've had with coal.

- Vectren must expand effective efficiency programs for low-income customers.

- Vectren must increase Demand Side Management programs with customers to manage peak demand.

Our city leaders are not publically supporting action to save us from being at the center of the highest concentration of superpolluters in the United States. Vectren will not make any of the changes advocated here without pressure. The 2013 IRP modeling indicated that they should close Culley 2, they didn't. The 2013 IRP concluded no coal plant retirements or additional renewables for the next 20 years. We can't let them do that to us again. Please attend their next and final IRP meeting. The date has not yet been announced, but you can contact them to request the date when known at irp@vectren.com.

Jean Webb
201 Montclair Ct
Evansville, IN 47715

To: Vectren CEO Carl Chapman
From: Evansville residents

Dear Mr. Chapman,

As Evansville residents and Vectren customers, **we ask that Vectren be a leader in our region and present the community with a plan that responsibly transitions over time away from coal and to clean, renewable energy.**

Your company's stated values commit Vectren to "contribute to the social, economic and environmental sustainability of our communities." Yet Vectren customers pay the highest electric bills in the state and the cost of burning coal continues to rise precisely because Vectren has kept aging coal plants running rather than retiring them.

We ask that you avoid the $240 million in impending costs associated with reducing water pollution from your coal plants by including in your 20-year plan a retirement date for Brown and Culley that is before December 2023.

As a responsible community partner, you should present the community with a plan to transition away from harmful, polluting, and expensive coal and avoid further investments in fossil fuels. We are concerned that your plan will benefit your extensive natural gas financial interests rather than the communities you serve.

We ask that you do not build a new natural gas plant to replace your coal plants, and instead replace with energy efficiency, renewable energy and battery innovation.

The recent national investigation into Super Polluter coal plants in the United States demonstrated that Evansville residents are unfairly burdened by pollutants from coal-burning plants - including three owned by Vectren.

We ask that Vectren lead our community to a cleaner and healthier future with a plan to eventually reach 100 percent clean energy, a commitment already made by 19 U.S. cities and many companies.

No one suggests this transition will happen overnight, but Vectren can lead our region and move beyond coal to clean energy, create jobs, and attract businesses that increasingly demand clean energy.

Sincerely,

Ohio River Valley Beyond Coal to Clean Energy Team

Vectren Integrated Resource Plan (IRP) Stakeholder Meeting

Gary Vicinus – Meeting Facilitator
Pace Global – Managing Director of Consulting Practice
November 29, 2016

VECTREN
Energy Delivery

Meeting Guidelines

1. Please hold most questions until the end of each presentation. Time will be allotted for questions following each presentation. (Clarifying questions about the slides are fine throughout)
2. For those on the webinar, we will open the (currently muted) phone lines for questions within the allotted time frame. You may also type in questions via the chat feature. Only questions sent to 'All-Entire Audience' will be seen and answered during the session.
3. At the end of the presentation, we will open up the floor for "clarifying questions," thoughts, ideas, and suggestions.
4. There will be a parking lot for items to be addressed at a later time.
5. Vectren does not authorize the use of cameras or video recording devices of any kind during this meeting.
6. Questions asked at this meeting will be answered here or later.
7. Unfortunately, there is no more time for additional questions at IRP@vectren.com prior to filing.

Agenda

1:00 p.m.	Sign-in/Refreshments	
1:30 p.m.	Welcome, Safety Message, and Recap	Gary Vicinus, Pace Global – Managing Director of Consulting Practice
2:00 p.m.	Presentation of the Preferred Portfolio	Carl Chapman, Vectren Chairman, President and CEO
2:30 p.m.	Existing EPA Regulations	Angila Retherford – Vectren Vice President of Environmental Affairs and Corporate Sustainability
2:40 p.m.	Optimization Modeling Results and Portfolio Development	Matt Lind, Burns & McDonnell – Associate Project Manager
3:10 p.m.	Break	
3:20 p.m.	Risk Analysis Results	Gary Vicinus, Pace Global – Managing Director of Consulting Practice
4:10 p.m.	Stakeholder Questions and Feedback	Vectren Panel
4:30 p.m.	Adjourn	

CEO = Chief Executive Officer

Vectren Commitments for the 2016 IRP

- ✓ Constructed scenarios (possible future states) with coordinated data inputs with a well-reasoned narrative
- ✓ Conducted a probabilistic risk analysis to explore the outer bounds of probability
- ✓ Future utility sponsored energy efficiency was modeled as a resource (not built into the load forecast)
- ✓ Evaluated if retirement made sense for any of Vectren's existing coal generating units within the 20 year time frame under each scenario
- ✓ Renewable options were fully considered in this analysis
- ✓ Actively monitoring Combined Heat and Power (CHP) developments and included CHP as a resource option
- ✓ Considered conversion and repower of coal units to gas
- ✓ Updated the IRP document format to be more readable

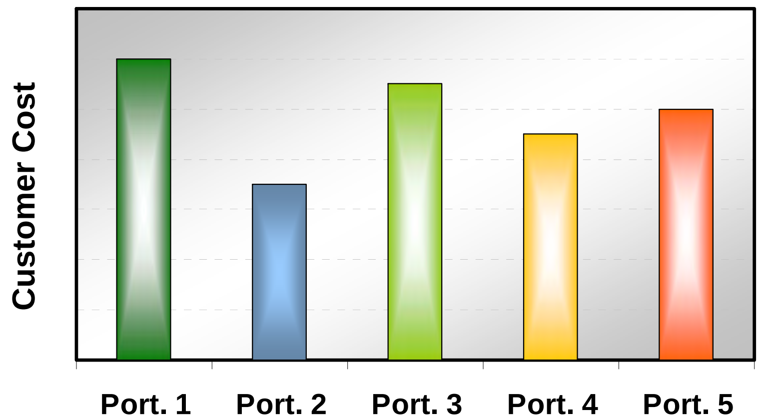
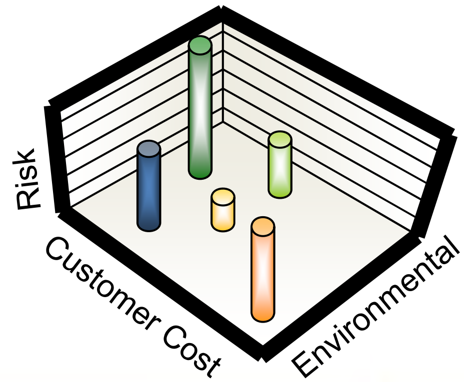
IRP = Integrated Resource Plan

Recap of Stakeholder Engagement

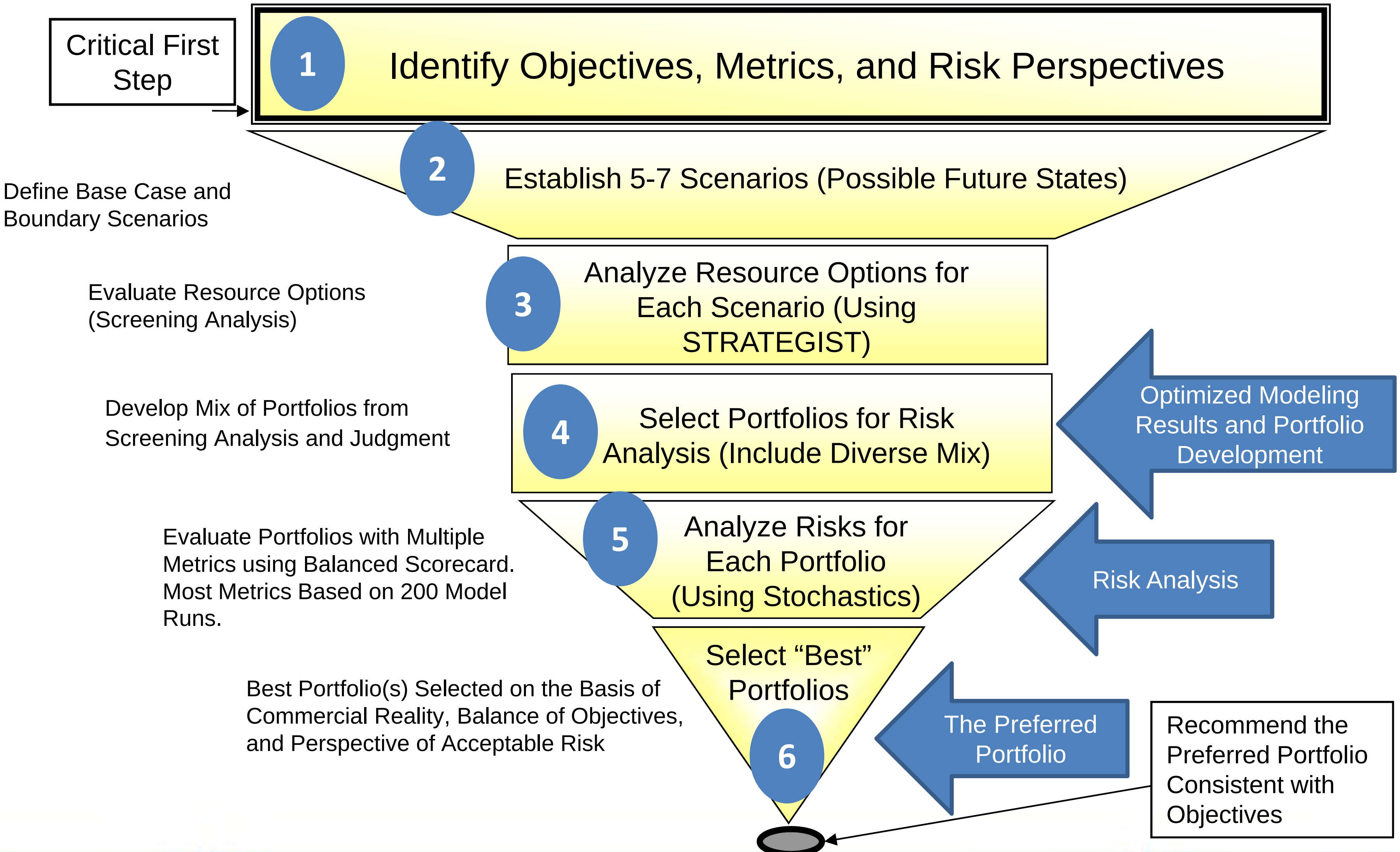
- February 3, 2016 - Participated in the Joint Utilities IRP Stakeholder Education Session with other Indiana investor-owned utilities
- April 7, 2016 - Vectren Public IRP Stakeholder Meeting
  - Vectren IRP Process Overview
  - Discussion of Uncertainties
  - Long-term Energy and Demand Forecast
  - Customer-Owned Distributed Generation
  - 2016 IRP Technology Assessment Generation Resource Alternatives
  - Generation Retrofit Alternatives
  - Energy Efficiency Modeling Discussion
- July 22, 2016 - Vectren Public IRP Stakeholder Meeting
  - Environmental Compliance
  - Base Case/Modeling Inputs
  - Busbar Analysis and Optimization Modeling
  - Scenario Development
  - Stakeholder Input to Portfolio Selection
- October 14, 2016 - Vectren Energy Efficiency Modeling Information Session
  - Met with the DSM oversight board and IURC staff. Webinar open for all stakeholders

DSM = Demand Side Management
IURC = Indiana Utility Regulatory Commission
IRP = Integrated Resource Plan

Vectren's Approach Builds on Traditional Approach

Traditional Approach	Vectren Approach
▪ Focuses on minimizing customer costs ▪ Portfolio evaluation is one-dimensional  	▪ Focuses on the simultaneous evaluation of multiple objectives and tradeoffs • Maintain reliability • Minimize rate/cost to customers • Mitigate risk to Vectren customers and shareholders • Provide environmentally acceptable power leading to a lower carbon future • Include a balanced mix of energy resources • Minimize negative economic impact to the communities that Vectren serves 

Vectren's Structured Analysis



The Preferred Portfolio

Carl Chapman – Vectren Chairman, President and CEO

CEO = Chief Executive Officer

Existing Coal Fleet

- Through investments in emissions control equipment over the past 15 years, Vectren's power system became one of the best controlled for emissions in the Midwest
- Vectren has reduced carbon emissions by 31% between 2005 and 2015

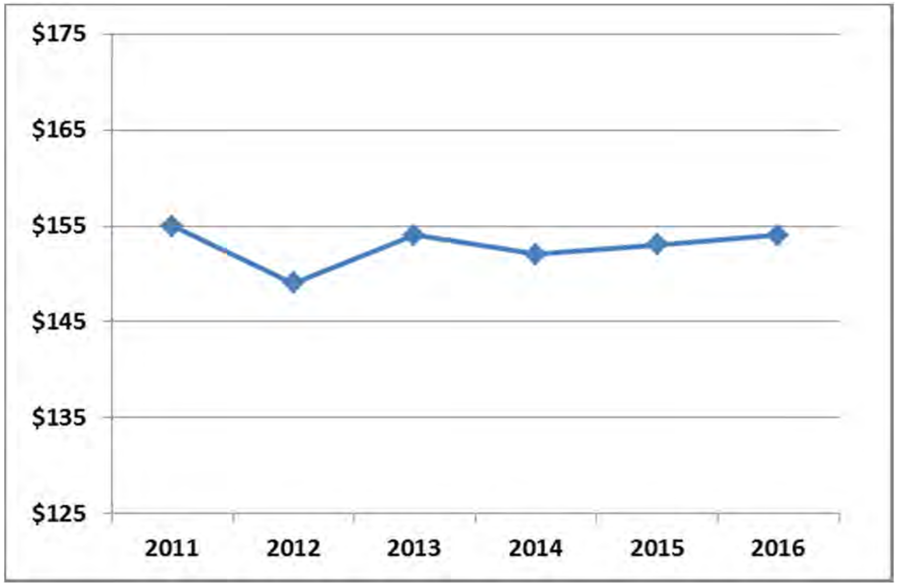
	FB Culley 2	FB Culley 3	Warrick 4	AB Brown 1	AB Brown 2
In Service	1966	1973	1970	1979	1986
MW (net)	90	270	150	245	245
NO_X	Low NO_X Burner	SCR	SCR	SCR	SCR
SO_2	FGD	FGD	FGD	FGD	FGD
PM	ESP	FF	ESP	FF	ESP
MATS	Shared w/ Unit 3	Injection	Injection	Injection	Injection
SO_3		Injection	Injection	Injection	Injection

SO_2 = Sulfur Dioxide
NOX = Nitrogen Oxide
SCR = Selective Catalytic Reduction
PM = Particulate Matter
MW = Megawatt
ESP = Electrostatic Precipitator
FGD = Flue Gas Desulfurization
FF = Fabric Filter
SO_3 = Sulfur Trioxide
MATS = Mercury Air Toxics Standards

Residential electric bills have remained flat

Electric billing history (weather normalized, 1,000 kWh per month)

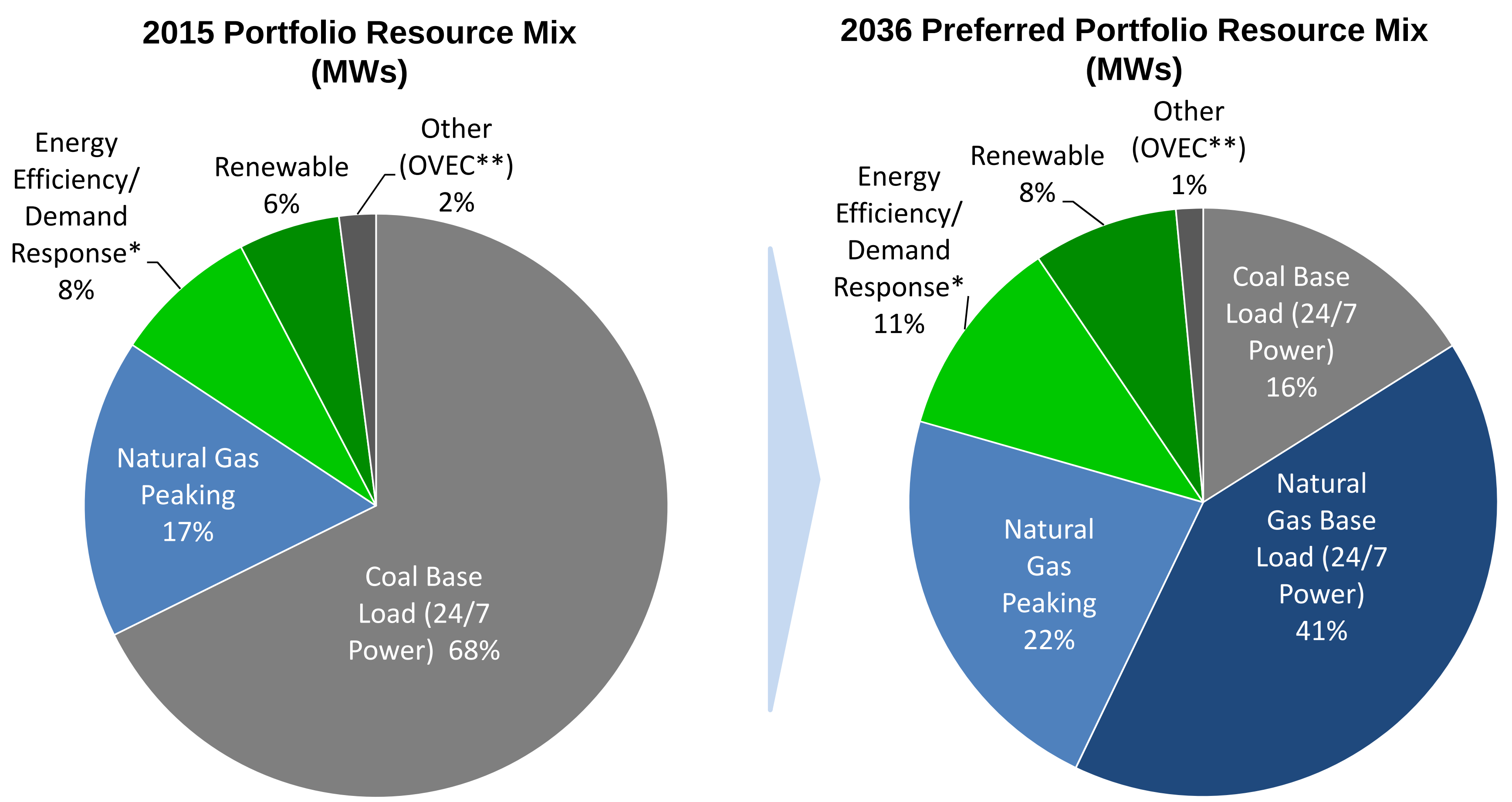
Year	Monthly billing amount
2011	$155
2012	$149
2013	$154
2014	$152
2015	$153
2016	$155



Source: IURC electric bill survey

Vectren has not filed a base rate case in 6 years.

Vectren Preferred IRP Portfolio Resource Mix

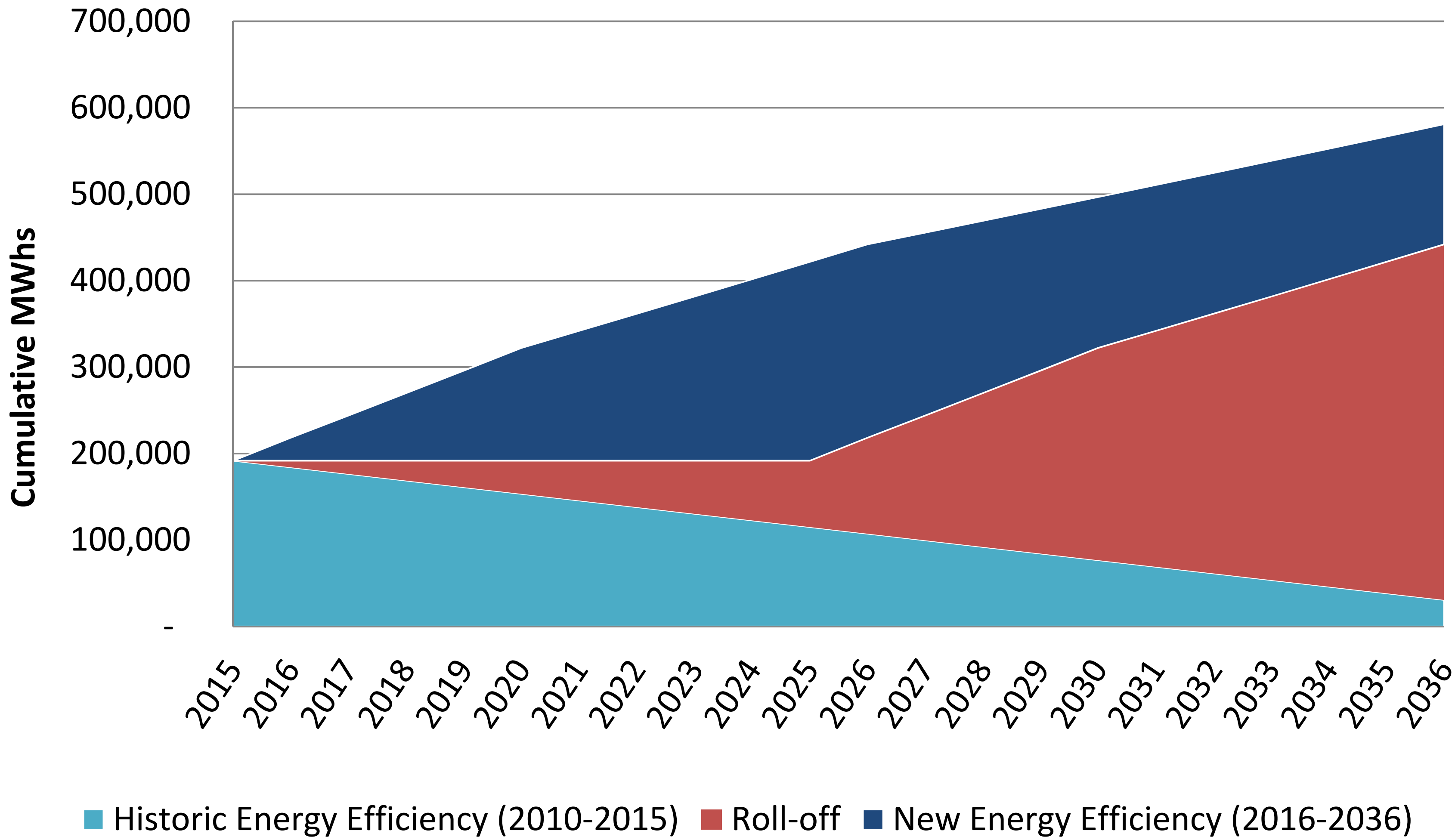


*Cumulative Demand Response & Net Energy Efficiency

**Vectren's 1.5% ownership of Ohio Valley Electric Corporation (OVEC) coal units. Per contractual obligations, all portfolios include OVEC.

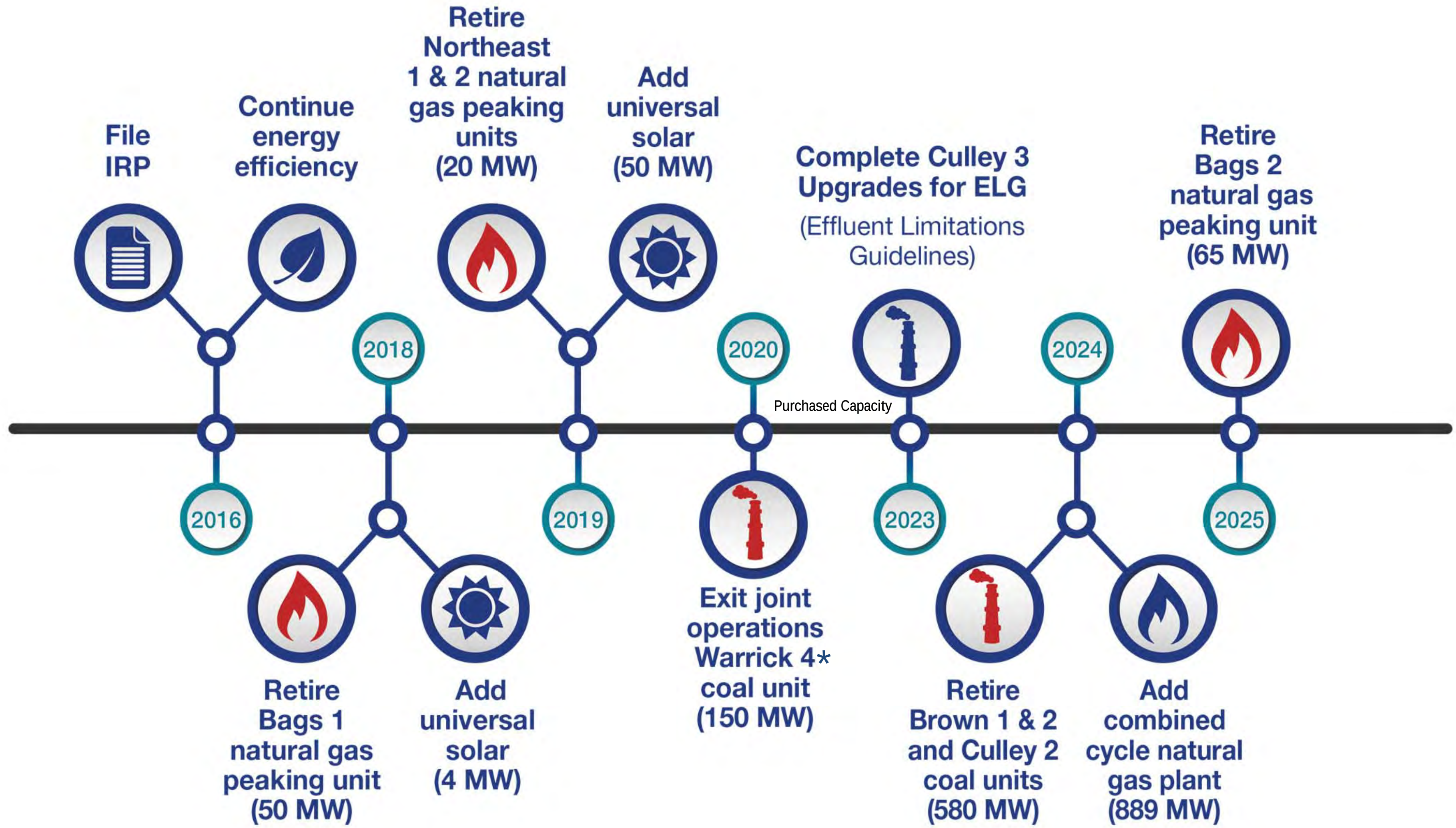
MW = Megawatt
IRP = Integrated Resource Plan

Cumulative Energy Efficiency MWhs in the Preferred Portfolio



Roll-off = Portion of Energy Efficiency savings no longer credited to Vectren
MWh = Megawatt Hour

Vectren's Preferred Portfolio Based on Current Modeling



*Warrick 4 jointly owned with Alcoa, which is in the midst of transition. We continue to discuss the future of Warrick 4 with Alcoa.

MW = Megawatt
IRP = Integrated Resource Plan
Bags = Broadway Avenue Gas Turbines

VECTREN Energy Delivery

Preferred Portfolio with Accelerated Renewables Provides Benefits to Vectren Customers and Other Stakeholders

- Is among the best performing portfolios across multiple measures on the balanced scorecard
- Is among the lower cost portfolios (within 4 percent of the lowest cost portfolio)
- Leads to a lower carbon future – Achieves almost 50 percent reduction in carbon (base year 2012) by 2024, which exceeds the Clean Power Plan (CPP) requirements - carbon emissions reduction from 2005 levels would be almost 60 percent
- Brings renewables into the portfolio by 2019. Renewables and ongoing Energy Efficiency account for approximately 20% of total capacity by 2036
- Provides low-cost peaking generation through duct-firing that enhances opportunities for economic development and wholesale sales, which lowers customer bills
- Avoids reliance on a single fuel and provides a balanced mix of coal, gas, and renewables. While reliance on gas is significant, a duct-fired plant would allow for back up of further intermittent renewable resources in the long term
- Is among the best portfolios in terms of limiting negative economic impact from job loss and local tax base. UE professors concluded that the economic ripple effect of losing 82 FB Culley jobs equates to 189 additional job losses in the community. Total state and local tax impact would be approximately 7 million dollars annually
- Reduces dependence on coal-fired generation over time and provides flexibility to adapt to changes in technology
- Takes advantage of tax incentives for solar installation

UE = University of Evansville

Why Build Combined Cycle Gas Generation?

- Vectren is unique, as our fleet is primarily coal generation - designed as a 24/7 power source. Vectren does not currently have a significant amount of gas generation
  - Coal units respond too slowly to effectively back up large amounts of intermittent renewable energy
- Gas generation positions Vectren for more renewables in the future
  - Solar and wind resources can experience rapid up and down fluctuations in output. Quick response is needed by other generation in order to maintain frequency and voltage support
  - Gas Fired Combined Cycle units provide a rapid response suitable for backing up significant amounts of renewable generation with the obvious benefits of being more efficient with very low emissions
  - The Duct-Firing option of a combined cycle unit provides quick response peaking capacity with a higher level of efficiency compared to simple cycle gas turbine peaking units
- Gas generation with Duct-Firing was selected in each of the modeled scenarios, including the high technology case with steep drops in renewables/storage cost, and possible future states with high gas prices
- Vectren modeled a new CCGT plant, built at a brown field site, which reuses some equipment. Should this site ultimately be chosen, Vectren will pipe gas to the location
  - Vectren does not earn a return on the gas commodity
  - A return on gas pipeline investments are subject to review and approval by the IURC

IURC = Indiana Utility Regulatory Commission

CCGT = Combined Cycle Gas Turbine

Duct-Firing

Depending on set up, Duct-firing can provide approximately 200 MWs (Installed Capacity) of efficient peaking capacity capability through gas burners located within the heat recovery steam generator. These burners can be fired to generate more power during times of high demand

Generic Technology Assumptions	Duct-Firing CCGT
Capital Costs (2015$/kW)	$300
Fixed O&M (2015$/kW-year)	Very minimal incremental costs
MISO (UCAP[1]) Accreditation	96%

- Duct-firing has significantly cheaper capital costs on a $/kW of UCAP accreditation than comparable simple cycle/peaker costs (~1/2 cost)
- Duct-firing capacity can provide peaking energy at a lower heat rate than many simple cycle technologies
- Decision for duct-firing needs to be incorporated in initial design decision

[1] UCAP = Unforced Capacity (the amount of capacity that can be depended on at time of peak)

CCGT = Combined Cycle Gas Turbine   kW = Kilowatt
O&M = Operations and Maintenance
MISO = Midcontinent Independent System Operator
MW = Megawatt

Renewables

- Vectren will build solar in the next several years to gain proficiencies with this resource
  - Vectren pulled solar generation forward in the preferred plan vs. when the model would suggest
    - Several small projects, followed by 50 MW of solar in 2019, which is partially dependent on current tax incentives remaining in place
- 2027 and beyond, solar tended to be selected more often than wind because it better met Vectren's capacity needs
  - 11% of rated wind capacity credited towards MISO planning reserve margin requirement
  - 38% assumed for solar

MW = Megawatt
MISO = Midcontinent Independent System Operator

Renewables (Continued) - Solar and Energy Storage

Several solar projects in the near term under consideration, totaling 4-6 MW

- Utility owned solar projects
  - Utility owned and operated 2 MW universal utility solar power plant with a 1 MWh battery storage system (pictured above)
  - Discussions with the city of Evansville on joint projects to be finalized in the first quarter 2017
  - Other potential project discussions on-going

- Urban Living Center – Vectren/Haier partnership in the Regional Cities project
  - Rooftop universal solar power plant with smart inverter
  - Residential/commercial energy storage with smart inverters
  - Building & Home Automation/Smart Appliances for Energy Management and Demand Response

Urban Living Research Center

MW = Megawatt MWh = Megawatt Hour

MISO Capacity Market Uncertainty

- MISO (Midcontinent Independent System Operator) is Vectren's Regional Transmission Operator (RTO). Vectren is required to maintain a 7.6% planning reserve margin[1] requirement through supply and demand side resources. This requirement can vary up or down each year
- MISO is projecting a shortfall for high certainty resources beginning in 2018 and grows through 2021

OMS-MISO Resource Adequacy Survey Results	Zone 6 Resource Adequacy Shortfall, Earliest Projection	MISO-wide Resource Adequacy Shortfall, Earliest Projection
2016	300 MW shortfall in 2019/20	400 MW shortfall in 2018

- Projected capacity shortfalls help drive volatility

Planning Year	Clearing Price for Zone 6 (Indiana & Kentucky)	Year-over-Year Price Change
2013-2014	$1.05	-
2014-2015	$16.75	~1,500% Increase
2015-2016	$3.48	~80% Decrease
2016-2017	$72.00	~2,000% Increase

[1] Accreditation towards the planning reserve margin is based on what MISO can expect a resource to generate during the peak season

MISO = Midcontinent Independent System Operator
MW = Megawatt
OMS = Organization of MISO States

Impact of Recent Election

- Potential for industry change over the next several years
  - EPA's Clean Power Plan at risk
  - Clean-Energy Tax incentives at risk
  - Paris agreement could be canceled
- Vectren is confident in the need for new gas generation by 2024
  - A duct-fired gas combined cycle unit was selected in all scenarios (possible future states), including the low regulatory scenario
  - Gas prices are low and stable
  - Age of Brown scrubber technology
  - New administrations will most likely push for a lower carbon future
  - Long lead time to file, gain approval, and build new gas combined cycle
  - Uncertainty regarding availability and cost of future capacity and energy
  - If necessary, can serve as back up for further cost effective renewables
- Other aspects of the plan are less certain
  - For example, Warrick 4 exit modeled in 2020; however, date could change
    - Plant jointly owned with Alcoa – Alcoa in midst of transition. We continue to discuss the future of Warrick 4 with Alcoa

EPA = Environmental Protection Agency

Next Steps

While this is the IRP preferred portfolio that will likely be filed in mid December, it is not a final generation transition plan. Vectren will use the coming months to develop an actual generation transition case, complete with timelines and spend that will be filed with the IURC for approval and execution in the future.

- File the IRP on December 16th
- File 2018-2020 Energy Efficiency
  - Guided by the Preferred Portfolio
- File for Solar Generation (4-6 MW)
- File for Generation Transition

Existing EPA Regulations

Angila Retherford – Vectren Vice President of Environmental Affairs and Corporate Sustainability

EPA = Environmental Protection Agency

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Post-election Regulations Update

- While much emphasis has been placed on potential impacts to the Clean Power Plan rulemaking under the new Trump administration, the Effluent Limitation Guidelines rule, or ELGs, in combination with the Coal Combustion Residuals rule, is the primary driver of near term environmental compliance expenditures modeled in the IRP
- By way of review, the US EPA finalized its new ELGs for power plant wastewaters in September of 2015.
  - Sets stringent wastewater discharge limits for selenium, arsenic and mercury
  - Prohibits any discharge of water used to handle fly ash and bottom ash, thereby mandating dry handling of ash

EPA = Environmental Protection Agency
ELG = Effluent Limitation Guidelines
US = United States
IRP = Integrated Resource Plan

Post-election Regulations Update

- President-elect Trump has indicated that he intends to review environmental regulations
- At this point, it is unclear which regulations President-elect Trump's new EPA administrator intends to review, other than the Clean Power Plan and the Waters of the US rule
- Final regulations, like the ELG and CCR rules, require notice and comment rulemaking to rescind and/or modify
  - An 18 to 24 month process
  - Rules such as the ELG rule which are technology mandates arising under legislation, in this case the Clean Water Act, are more difficult to set aside and must be supported by a technological or human health rationale

EPA = Environmental Protection Agency
ELG = Effluent Limitation Guidelines
CCR = Coal Combustion Residuals
US = United States

Post-election - Clean Power Plan

- With respect to the issue of carbon regulations, there are some things that the President-elect can do that will be easier than others
- US participation in the Paris Agreement, whose carbon reduction goals Vectren already met in 2015, is a non-binding commitment in the nature of an executive order, so it can be set aside immediately. Although, the diplomatic consequences may be more challenging for the new administration
- The CPP is a final regulation, so it must be rescinded/modified through a supplemental notice and comment rulemaking
  - Currently in litigation, and even if the Trump Department of Justice determines that it will no longer defend the rule, the rule is still being defended by other states and environmental groups
- Previous Endangerment Finding would also need to be rescinded and/or modified
- While it remains to be seen what measures, if any, the Trump administration will be successful in delaying or rescinding, Vectren's generation planning decisions are long term in nature, and the low regulatory scenario that we modeled assumed that there was no CPP in place during the planning period

Optimization Modeling Results and Portfolio Development

Matt Lind – Burns and McDonnell Associate Project Manager

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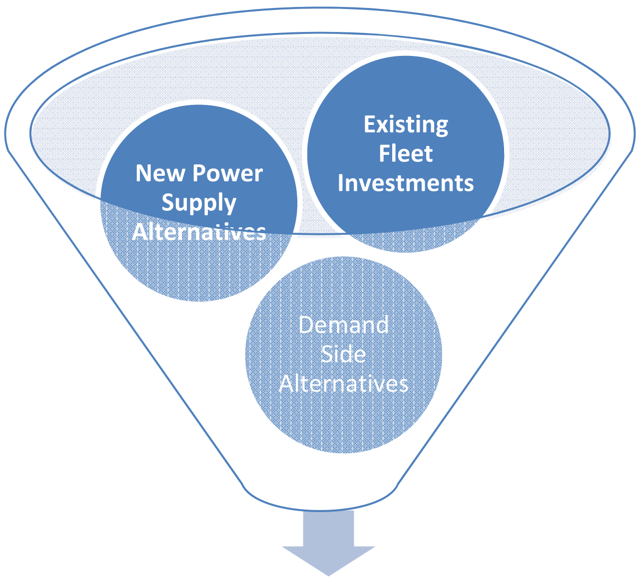
Resource Modeling – Computer Generated Portfolios

- **IRP Purpose**: To select a portfolio to best meet customers' needs for reliable, low cost, environmentally acceptable power over a wide range of future market and regulatory conditions

- Objectives:
  - Minimize power cost
  - Maintain sufficient capacity to satisfy MISO's planning reserve margin requirement
- Inputs:
  - Existing fleet
  - New supply-side alternatives
  - Demand-side alternatives



Portfolio Development

Filtered/Modeled Alternatives*

Existing Fleet

- Continue on Coal
- Convert to Natural Gas
- Repower CCGT
- Retire

New Supply-Side

- 890 MW CCGT
- 690 MW CCGT
- 440 MW CCGT
- 340 MW CCGT
- 220 MW GT
- 100 MW GT
- 50 MW Wind (IN)
- 100 MW Wind (IN)
- 15 MW CHP
- 9 MW Solar PV
- 50 MW Solar PV

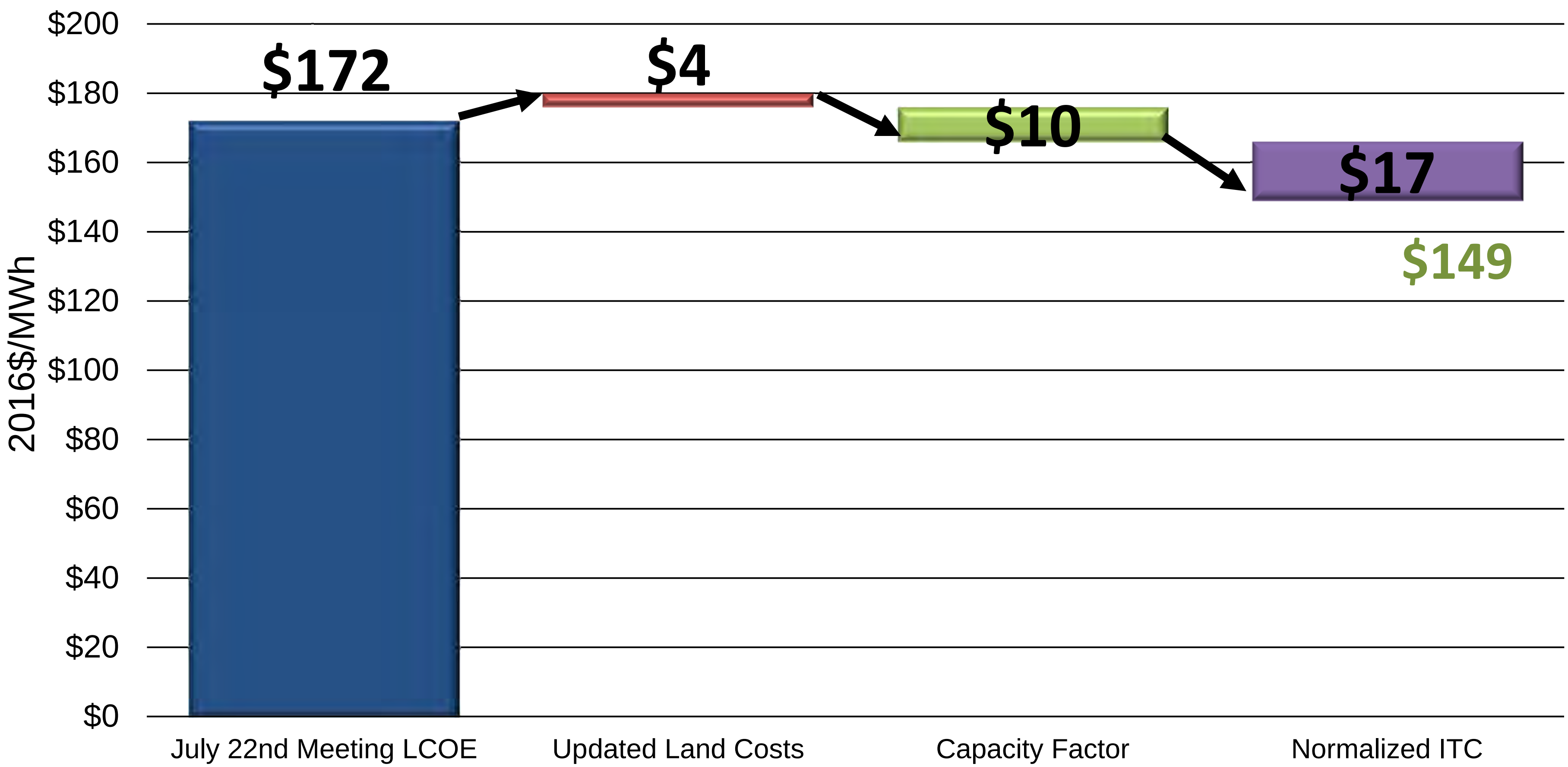
Demand-Side

- Energy Efficiency
- Demand Response

*Multiple blocks of each resource were available for selection. For example, some model runs chose 4 - 100 MW blocks of wind

GT = Gas Turbine
CCGT = Combined Cycle Gas Turbine
PV = Photovoltaic
IN = Indiana
MW = Megawatt
CHP = Combined Heat and Power

Update to 50 MW Solar Cost Prior to Optimization



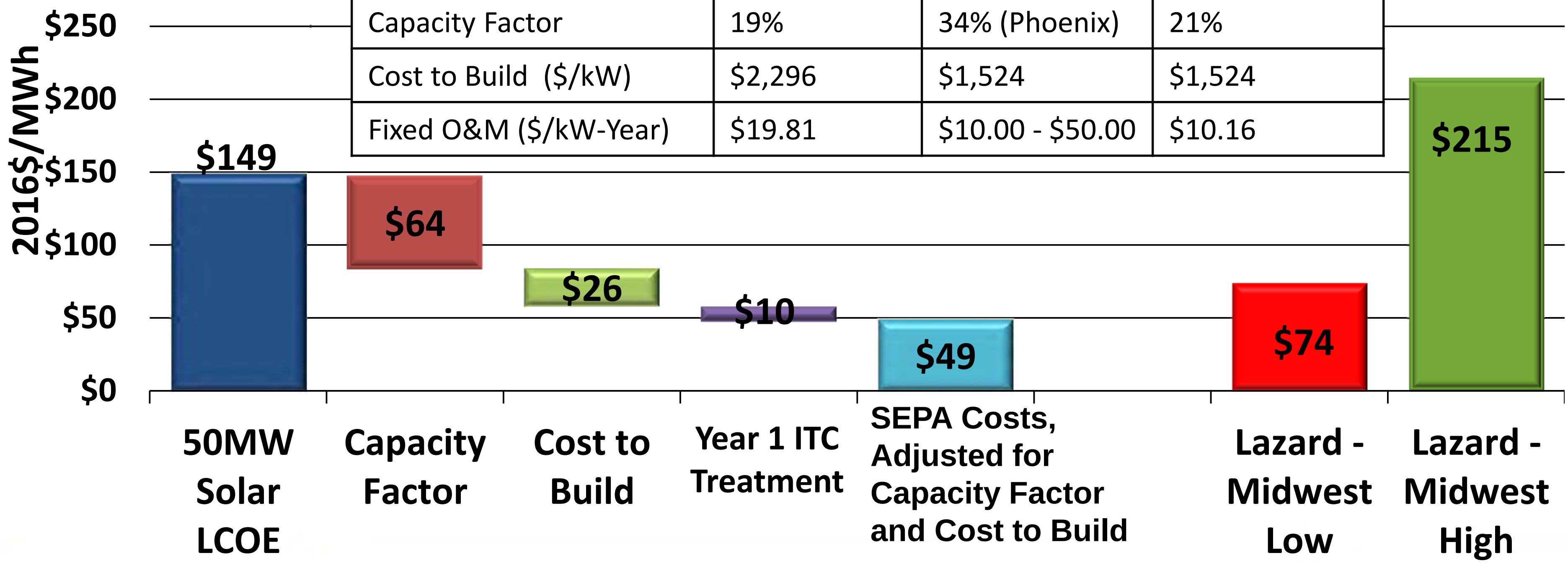
LCOE = Levelized Cost of Energy
ITC = Investment Tax Credit

MWh = Megawatt Hour
MW = Megawatt

LCOE Comparison to Other Public Sources

- Upon review of several LCOE studies, we are confident that Vectren IRP solar costs are reasonable
- The cost to build a solar facility in Indiana assumed within the IRP reflects the total cost to build for a project including PV modules, inverter, civil work, engineering contractor fees & contingency, owner's cost, owner's contingency, land, transmission interconnection, and AFUDC. Many numbers quoted in the public arena often exclude one or more of these components due to site specific and owner specific conditions

Variable (2016$)	Vectren IRP	SEPA	Lazard Midwest
Capacity Factor	19%	34% (Phoenix)	21%
Cost to Build ($/kW)	$2,296	$1,524	$1,524
Fixed O&M ($/kW-Year)	$19.81	$10.00 - $50.00	$10.16



SEPA = Solar Electric Power Association MWh = Megawatt Hour
LCOE = Levelized Cost of Energy kW = Kilowatt ITC = Investment Tax Credit
IRP = Integrated Resource Plan O&M = Operations & Maintenance
AFUDC = Allowance for Funds Used During Construction PV = Photovoltaic

VECTREN Energy Delivery

Portfolio Development

- Created 15 resource portfolios for the risk analysis (Listed as A-O on the following pages)
  - Vectren included a portfolio very similar to the current mix of resources (A)
  - 7 computer-generated portfolios, one for each pre-determined future (B-H)
  - Used judgment to consider other possibilities in creating portfolios with a balanced mix of resources
    - Worked with stakeholders to develop 2 balanced portfolios (I-J)
    - Worked with expert consultants to develop 5 additional balanced portfolios (K-O)
  - Note that all portfolios assume Vectren ends joint operations of Warrick 4 in 2020. Additionally, the Northeast peaking units and Broadway Avenue 2 retire due to age

Business As Usual - Existing Portfolio*

Time Period	Business As Usual – Existing Portfolio (A)	
	Retirement/ Exit Joint Operations	Additions
Early 2017-2022	• NE 1-2 • W4 Exit	• 1.0% EE (2017) • 12MW DR • 4 MW Solar
Middle 2023-2029	• BAGS 2	• 8MW DR • 220MW SCGT
Late 2030-2036		

Unit Abbreviations:

NE – Northeast W4 – Warrick 4 ABB 1 – AB Brown 1 ABB 2 – AB Brown 2

FBC 2 – FB Culley 2 FBC 3 – FB Culley 3 BAGS 2 – Broadway Avenue Gas Turbine 2

MW = Megawatt EE = Energy Efficiency DR = Demand Response

SCGT = Simple Cycle Gas Turbine

Computer-Generated Portfolios

- Developed portfolios for seven (7) different scenarios (possible future states)
  - Base Case
  - Base Large Load Addition (100 MW in 2024)
  - High Regulation
  - Low Regulation
  - High Economy
  - Low Economy
  - High Technology
- Model retired coal and selected a highly efficient combined cycle natural gas plant (all fully duct-fired) in all scenarios, with varying levels of energy efficiency, demand response, and renewables
  - No renewables are selected prior to 2027 (4 MW solar added to all portfolios in 2018 prior to optimization)
  - Energy Efficiency was selected at varying levels
    - None in Base, Low Economy, or High Technology
    - 1% in Low Regulation, High Regulation, and Base Large Load Addition
    - 2% in High Economy

MW = Megawatt

Computer-Generated Portfolios by Scenario

Time Period	Base Scenario, Portfolio B – Heavy Gas		Base + Load Growth Scenario, Portfolio C – Gas & Solar		High Technology Scenario, Portfolio H – Heavy Gas	
	Retirement/ Exit Joint Operations	Additions	Retirement/ Exit Joint Operations	Additions	Retirement/ Exit Joint Operations	Additions
Early 2017-2022	• NE 1-2 • W4 Exit	• 4MW Solar	• NE 1-2 • W4 Exit	• 1.0% EE • 4MW Solar • 12MW DR	• NE 1-2 • W4 Exit	• 4MW Solar
Middle 2023-2029	• ABB 1 • ABB 2 • BAGS 2 • FBC 2 • FBC 3	• 889MW Fired-CCGT • 220MW SCGT	• ABB 1 • ABB 2 • BAGS 2 • FBC 2 • FBC 3	• 889MW Fired-CCGT • 220MW SCGT • 8MW DR	• ABB 1 • ABB 2 • BAGS 2 • FBC 2 • FBC 3	• 889MW Fired-CCGT • 220MW SCGT
Late 2030-2036		• 36MW Solar		• 68MW Solar		• 1MW Battery • 9MW Solar

Unit Abbreviations:

NE – Northeast | W4 – Warrick 4 | ABB 1 – AB Brown 1 | ABB 2 – AB Brown 2

FBC 2 – FB Culley 2 | FBC 3 – FB Culley 3 | BAGS 2 – Broadway Avenue Gas Turbine 2

MW = Megawatt | EE = Energy Efficiency | DR = Demand Response

SCGT = Simple Cycle Gas Turbine | CCGT = Combined Cycle Gas Turbine

Computer-Generated Portfolios by Scenario

Time Period	High Regulatory Scenario, Portfolio D – Gas & Wind		Low Regulatory Scenario, Portfolio E – Heavy Gas		High Economy Scenario, Portfolio F – Gas & Wind		Low Economy Scenario, Portfolio G – Gas & Solar	
	Retirement/ Exit Joint Operations	Additions	Retirement/ Exit Joint Operations	Additions	Retirement/ Exit Joint Operations	Additions	Retirement/ Exit Joint Operations	Additions
Early 2017-2022	• NE 1-2 • W4 Exit	• 1.0% EE • 4MW Solar	• NE 1-2 • W4 Exit	• 1.0% EE • 4MW Solar • 12MW DR • 220MW SCGT	• NE 1-2 • W4 Exit	• 2.0% EE • 4MW Solar • 8MW DR	• NE 1-2 • W4 Exit	• 4MW Solar
Middle 2023-2029	• ABB 1 • ABB 2 • BAGS 2 • FBC 2 • FBC 3	• 889MW Fired-CCGT	• ABB 1 • ABB 2 • BAGS 2 • FBC 2 • FBC 3	• 8MW DR • 889MW Fired-CCGT • 220MW SCGT	• ABB 1 • ABB 2 • BAGS 2 • FBC 2 • FBC 3	• 12MW DR • 889MW Fired-CCGT • 220MW SCGT • 9MW Solar	• ABB 1 • ABB 2 • BAGS 2 • FBC 2 • FBC 3	• 20MW DR • 889MW Fired-CCGT
Late 2030-2036		• 400MW Wind				• 400MW Wind		• 59MW Solar

Unit Abbreviations:

NE – Northeast W4 – Warrick 4 ABB 1 – AB Brown 1 ABB 2 – AB Brown 2

FBC 2 – FB Culley 2 FBC 3 – FB Culley 3 BAGS 2 – Broadway Avenue Gas Turbine 2

MW = Megawatt EE = Energy Efficiency DR = Demand Response

SCGT = Simple Cycle Gas Turbine CCGT = Combined Cycle Gas Turbine

Balanced Portfolios - Stakeholder

- Held a portfolios development workshop on July 22, 2016 to gain input from stakeholders
  - Per input, developed 2 balanced portfolios – One keeps some coal beyond 2023 and one closes all coal by 2024
    - Maximum Energy Efficiency 2% per year
    - Maximum Combined Heat and Power (30 MW)
    - Increased utilization of renewables, particularly solar
    - Includes storage

MW = Megawatt

Stakeholder Portfolios

Time Period	Portfolio I – Stakeholder w/ Renewables		Portfolio J – Stakeholder w/Renewables (Cease Coal 2024)	
	Retirement/ Exit Joint Operations	Additions	Retirement/ Exit Joint Operations	Additions
Early 2017-2022	• NE 1-2 • W4 Exit	• 2.0% EE (2018-2036) • 4MW Solar • 12MW DR	• NE 1-2 • W4 Exit	• 2.0% EE (2018-2036) • 4MW Solar • 12MW DR
Middle 2023-2029	• ABB 1 • ABB 2 • BAGS 2	• 221MW CCGT Partial Ownership (50%) • 8MW DR • 30MW CHP • 500MW Solar • 800MW Wind	• ABB 1 • ABB 2 • FBC2 • FBC 3 • BAGS 2	• 331MW CCGT Partial Ownership (75%) • 8MW DR • 30MW CHP • 800MW Solar • 1,200MW Wind • 100MW/400MWh Battery
Late 2030-2036	• FBC 2 • FBC 3	• 100MW/400MWh Battery • 200MW Wind • 400MW Solar • 110MW CCGT Partial Ownership (25%)		• 100MW/400MWh Battery

Unit Abbreviations:

NE – Northeast W4 – Warrick 4 ABB 1 – AB Brown 1 ABB 2 – AB Brown 2

FBC 2 – FB Culley 2 FBC 3 – FB Culley 3 BAGS 2 – Broadway Avenue Gas Turbine 2

MW = Megawatt EE = Energy Efficiency DR = Demand Response

CCGT = Combined Cycle Gas Turbine MWh = Megawatt Hour

CHP = Combined Heat and Power

Balanced Portfolios - Vectren

- Worked with expert consultants to develop 5 additional balanced portfolios to evaluate the performance of a balanced mix of energy resources to mitigate risk
  - 3 continue to operate FB Culley 3 beyond 2023
    - Retire all other coal units and build a combined cycle gas unit (2 with a fully fired unit and 1 with an unfired unit)
    - FB Culley 3 is Vectren's most efficient coal unit
      - Controlled for SO_2, NO_X, Mercury, Particulate Matter, SO_3
    - Determined energy efficiency & varying levels of early renewables
  - 2 close all coal by 2024
    - Build a combined cycle gas unit (1 with fired unit and 1 unfired)
    - Build early solar (54 MW)
    - Optimize with energy efficiency, demand response, and renewables

MW = Megawatt
SO_2 = Sulfur Dioxide
NO_X = Nitrogen Oxide
SO_3 = Sulfur Trioxide

Other Portfolios – Keep One Coal Unit Beyond 2024 (FBC 3)

Time Period	Portfolio K – Diversified w/Coal		Portfolio L – Diversified w/Coal		Portfolio M – Diversified w/Coal	
	Retirement/ Exit Joint Operations	Additions	Retirement/ Exit Joint Operations	Additions	Retirement/ Exit Joint Operations	Additions
Early 2017-2022	• NE 1-2 • W4 Exit	• 1.0% EE (2018-2020) • 0.75% EE (2021-2022) • 4MW Solar	• NE 1-2 • W4 Exit	• 1.0% EE (2018-2020) • 0.75% EE (2021-2022) • 4MW Solar • 50MW Solar	• NE 1-2 • W4 Exit	• 1.0% EE (2018-2020) • 0.75% EE (2021-2022) • 4MW Solar • 50MW Solar
Middle 2023-2029	• ABB 1 • ABB 2 • FBC 2 • BAGS 2	• 0.75% EE (2022-2026) • 0.50% EE (2027-2029) • 889MW Fired-CCGT • 4MW DR • 9MW Solar • 50MW Wind	• ABB 1 • ABB 2 • FBC 2 • BAGS 2	• 0.75% EE (2023-2026) • 0.50% EE (2027-2029) • 889MW Fired-CCGT	• ABB 1 • ABB 2 • FBC 2 • BAGS 2	• 0.75% EE (2023-2026) • 0.50% EE (2027-2029) • 700MW CCGT
Late 2030-2036		• 0.50% EE (2030-2036)		• 0.50% EE (2030-2036)		• 0.50% EE (2030-2036) • 118MW Solar

Unit Abbreviations:

NE – Northeast W4 – Warrick 4 ABB 1 – AB Brown 1 ABB 2 – AB Brown 2

FBC 2 – FB Culley 2 FBC 3 – FB Culley 3 BAGS 2 – Broadway Avenue Gas Turbine 2

MW = Megawatt EE = Energy Efficiency DR = Demand Response

CCGT = Combined Cycle Gas Turbine

Other Portfolios – Shutdown All Coal in 2024 & Replace with EE, DR, and Renewables

Time Period	Diversified Portfolio (N)		Diversified Portfolio (O)	
	Retirement/ Exit Joint Operations	Additions	Retirement/ Exit Joint Operations	Additions
Early 2017-2022	• NE 1-2 • W4 Exit	• 1.0% EE (2018-2036) • 54MW Solar • 12MW DR	• NE 1-2 • W4 Exit	• 1.0% EE (2018-2036) • 54MW Solar • 12MW DR
Middle 2023-2029	• ABB 1 • ABB 2 • FBC 2 • FBC 3 • BAGS 2	• 8MW DR • 700MW CCGT • 220MW SCGT • 118MW Solar	• ABB 1 • ABB 2 • FBC 2 • FBC 3 • BAGS 2	• 8MW DR • 889MW Fired-CCGT • 168MW Solar
Late 2030-2036		• 100MW Solar		• 109MW Solar

Unit Abbreviations:

NE – Northeast W4 – Warrick 4 ABB 1 – AB Brown 1 ABB 2 – AB Brown 2

FBC 2 – FB Culley 2 FBC 3 – FB Culley 3 BAGS 2 – Broadway Avenue Gas Turbine 2

MW = Megawatt EE = Energy Efficiency DR = Demand Response

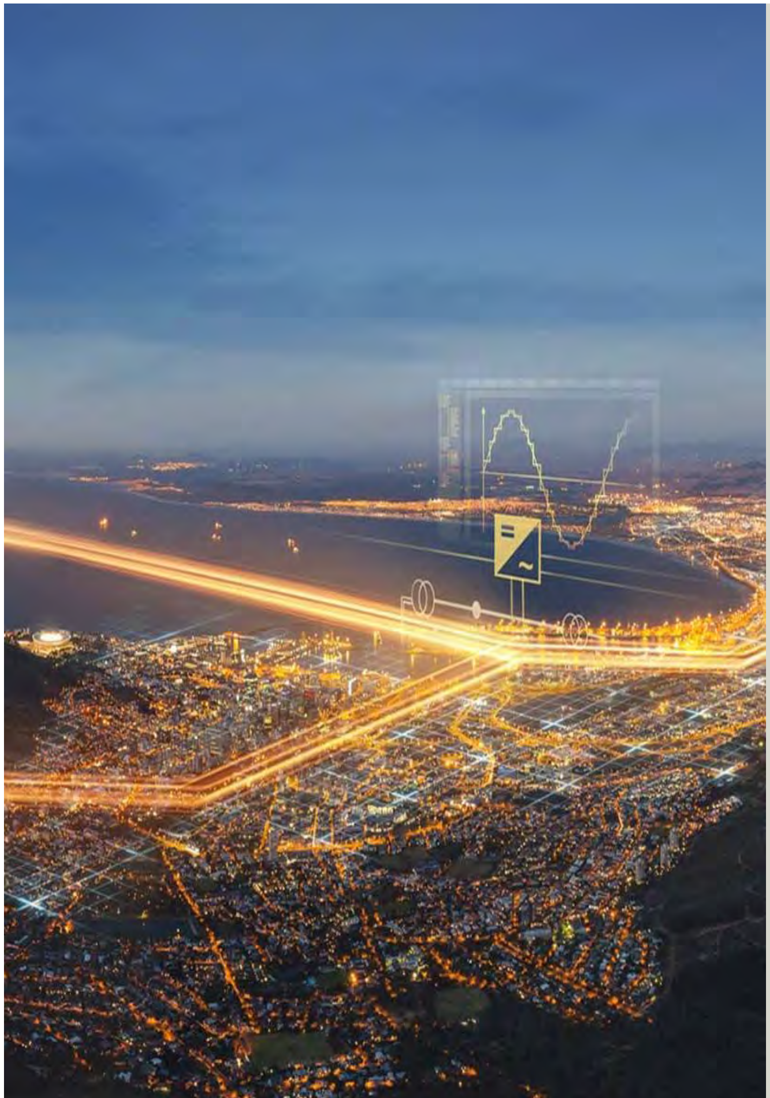
SCGT = Simple Cycle Gas Turbine CCGT = Combined Cycle Gas Turbine

VECTREN Energy Delivery

Risk Analysis

Gary Vicinus – Managing Director of Consulting Practice

Risk Analysis



A risk analysis was performed on 15 portfolios

- Approximately 200 iterations were developed from stochastic distributions of load, gas prices, coal prices, environmental costs, and technology capital costs to test each portfolio over a range of conditions
- Vectren selected six objectives and several metrics to assess portfolios

<u>Objective</u> <u>(metrics)</u>

- Rate Metric (20 year NPV RR)
- Risks (Standard Deviation of NPV, Average Unaccounted Capacity Purchase Needs, Market Purchase Risk, Remote Generation Risk)
- Cost Risk-Tradeoff (combined Expected NPV RR and Standard Deviation Risks)
- Balanced Energy/Flexibility (Concentration Metric, # distinct baseload sources, Generation Mix Balance, Market Flexibility)
- Environmental (Carbon reduction, SO_2/NO_X reduction)
- Local Economic Impact

NPV RR = Net Present Value Revenue Requirement SO_2 = Sulfur Dioxide
NO_X = Nitrogen Oxide

Base Case* Portfolio Construction

Portfolio	CT Additions		CC Additions		Wind Additions		CHP Additions	Solar Additions			Battery Additions		Capacity Market Purchase			Coal Retirements			Gas Retirements		DR			EE		
	Total MW		Total MW		Total MW		Total MW	Total MW			Total MW		Annual Average MW			Total MW **			Total MW		Total MW			Total MW		
	Early	*Middle*	*Middle*	*Late*	*Middle*	*Late*	*Middle*	*Early*	*Middle*	*Late*	*Middle*	*Late*	*Early*	*Middle*	*Late*	*Early*	*Middle*	*Late*	*Early*	*Middle*	*Early*	*Middle*	*Late*	*Early*	*Middle*	*Late*
A: Existing Portfolio		220						4					46	9	2	162			22	81	12	8	13			
B: Heavy Gas		220	889					4		36			51	11	4	162	899		22	81						
C: Gas & Solar		220	889					4		68			30	3	5	162	899		22	81	12	8		16	17	-2
D: Gas & Wind			889			400		4					34	77	87	162	899		22	81				16	17	-2
E: Heavy Gas	220	220	889					4					20	0	0	162	899		22	81	12	8		16	17	-2
F: Gas & Wind	220		889			400		4					6	0	0	162	899		22	81	12	8		32	34	-5
G: Gas & Solar			889					4		59			51	121	176	162	899		22	81		20				
H: Heavy Gas		220	889					4		9			42	13	4	162	899		22	81						
I: Stakeholder w/ Renewables			221	110	800	200	30	4	500	400		100	14	0	0	162	530	369	22	81	12	8		32	34	-5
J: Stakeholder w/ Renewables			331		1200		30	4	800		100	100	14	0	0	162	899		22	81	12	8		32	34	-5
K: Diversified w/ Coal			889		50			4	9				22	5	0	162	634		22	81				15	9	-8
L: Diversified w/ Coal			889					54					22	3	0	162	634		22	81				15	9	-8
M: Diversified w/ Coal		220	700					54		68			18	1	5	162	634		22	81	12	8		15	9	-8
N: Gas & Solar		220	700					54	118	100			17	4	3	162	899		22	81	12	8		16	17	-2
O: Gas & Solar			889					54	168	109			7	3	5	162	899		22	81	12	8		16	17	-2

Business As Usual (Existing Portfolio)

Computer Generated (Scenarios)

Balanced Portfolios - Stakeholder

Balanced Portfolios - Vectren

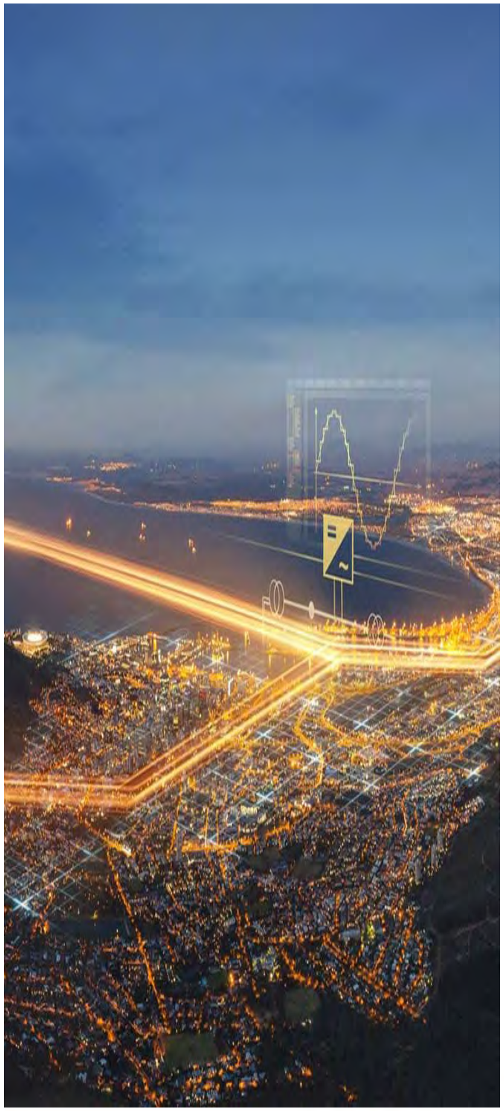
Early: 2017-2022
Middle: 2023-2029
Late: 2030-2036

* Modeling values reflect Base Case
** Includes exiting joint operations of Warrick 4

CT = Combustion Turbine CHP = Combined Heat and Power
DR = Demand Response EE = Energy Efficiency
CC = Combined Cycle MW = Megawatt

VECTREN Energy Delivery

Executive Summary



Portfolio L is Vectren's recommended Portfolio

Is among the best performing portfolios across multiple measures on the balanced scorecard

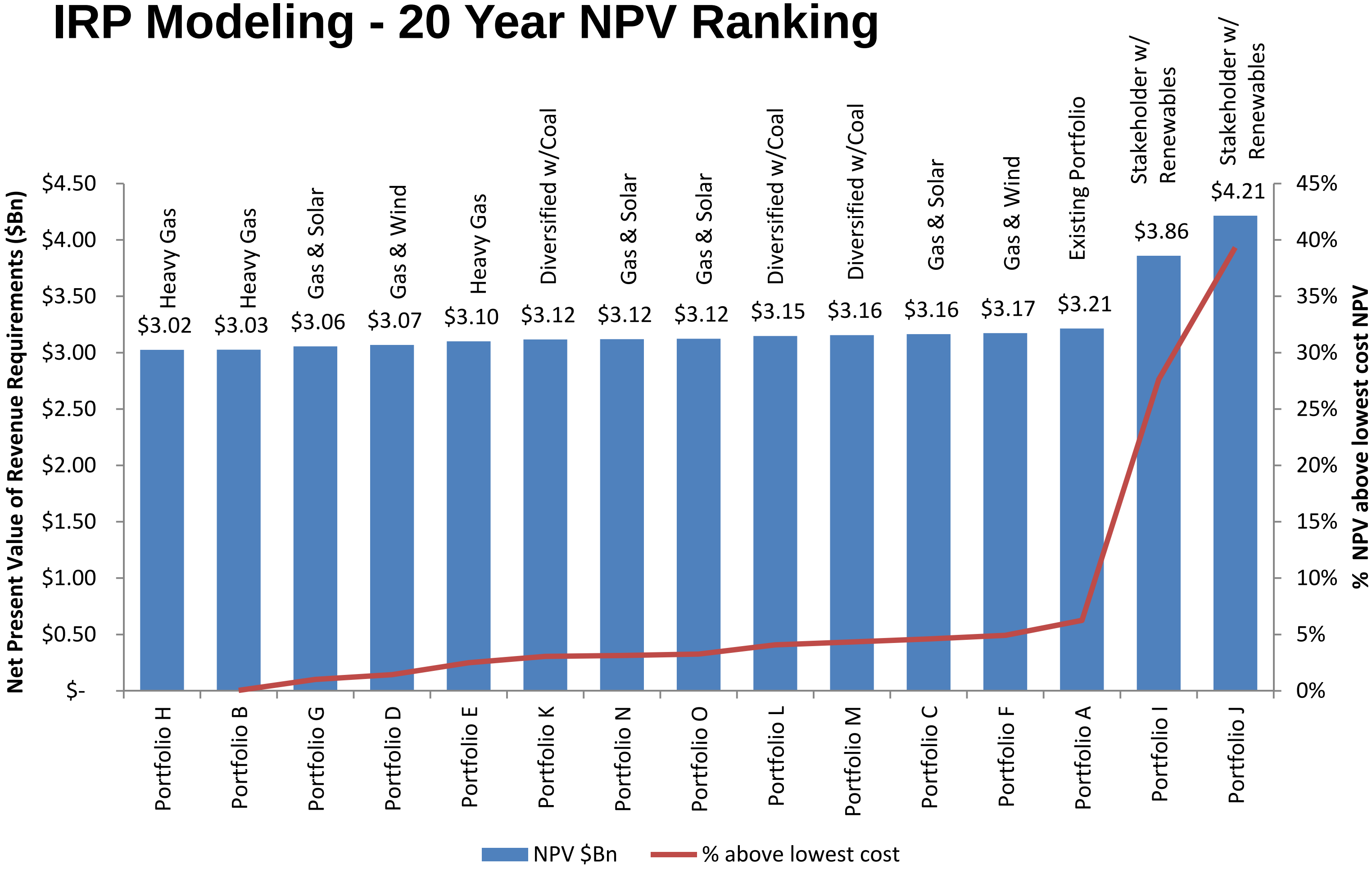
- Is among the lower cost portfolios (within 4 percent of the lowest cost portfolio)
- Leads to a lower carbon future with almost 50% reduction in CO_2 from 2012 levels
- Brings renewables into the portfolio early vs. model selection
- Provides low-cost peaking generation to back up renewable resources in the long term and provides economic development opportunity
- Provides a more balanced mix of coal, gas, and renewables
- Limits negative economic impact from job loss and local tax base
- Provides flexibility to adapt to changes in technology
- Takes advantage of tax incentives for solar installation

CO_2 = Carbon Dioxide

VECTREN Energy Delivery

Rate Metric Summary

IRP Modeling - 20 Year NPV Ranking



20 Year Portfolio Ranking Relative to Portfolio H

- Portfolios within 5%
- Portfolios between 5% and 10%
- Portfolio above 10%

NPV = Net Present Value Bn = Billions

IRP = Integrated Resource Plan

VECTREN Energy Delivery

Rate Metric*: NPV Portfolio Cost Ranking

Portfolio	Aurora 20-Year Mean NPV $ Billion: 20 Year NPV	% above lowest cost	Summary
H: Heavy Gas	$ 3.02		Green
B: Heavy Gas	$ 3.03	0.0%	Green
G: Gas & Solar	$ 3.06	1.0%	Green
D: Gas & Wind	$ 3.07	1.4%	Green
E: Heavy Gas	$ 3.10	2.5%	Green
K: Diversified w/ Coal	$ 3.12	3.1%	Green
N: Gas & Solar	$ 3.12	3.1%	Green
O: Gas & Solar	$ 3.12	3.3%	Green
L: Diversified w/ Coal	$ 3.15	4.1%	Green
M: Diversified w/ Coal	$ 3.16	4.3%	Green
C: Gas & Solar	$ 3.16	4.6%	Green
F: Gas & Wind	$ 3.17	4.9%	Green
A: Existing Portfolio	$ 3.21	6.3%	Yellow
I: Stakeholder w/ Renewables	$ 3.86	27.6%	Red
J: Stakeholder w/ Renewables	$ 4.21	39.3%	Red

- Portfolio L is about 4% higher than the lowest cost portfolio (Portfolio H)
- The stakeholder Portfolios (I and J) exhibit substantially higher costs than all other portfolios (25-40% over 20 years)

20 Year Portfolio Ranking Relative to Portfolio H

- Green: Portfolios within 5%
- Yellow: Portfolios between 5% and 10%
- Red: Portfolio above 10%

* The NPV of energy procurement is an indicative component of rates

NPV = Net Present Value

Rate Metric Summary

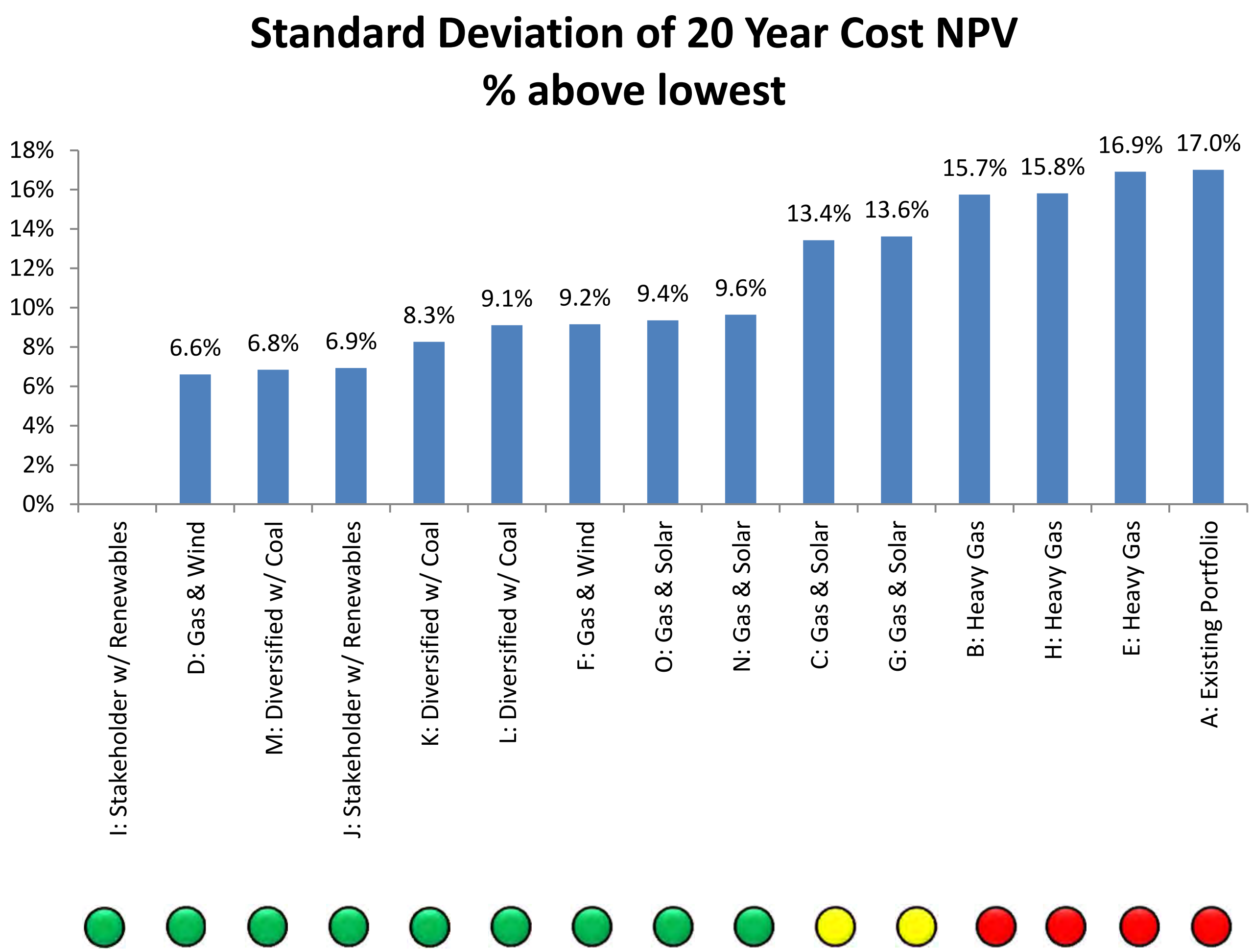
	Portfolio NPV
Portfolio L - Diversified w/ Coal	
Portfolio K – Diversified w/ Coal	
Portfolio M – Diversified w/ Coal	
Portfolio F – Gas & Wind	
Portfolio D – Gas & Wind	
Portfolio O – Gas & Solar	
Portfolio N – Gas & Solar	
Portfolio H – Heavy Gas	
Portfolio E – Heavy Gas	
Portfolio C – Gas & Solar	
Portfolio G – Gas & Solar	
Portfolio I – Stakeholder w/ Renewables	
Portfolio J – Stakeholder w/ Renewables	
Portfolio B – Heavy Gas	
Portfolio A – Existing Portfolio	

NPV = Net Present Value

VECTREN Energy Delivery

Risk Metric Summary

Variability (Standard Deviation) Measure of Risk Across 200 Iterations



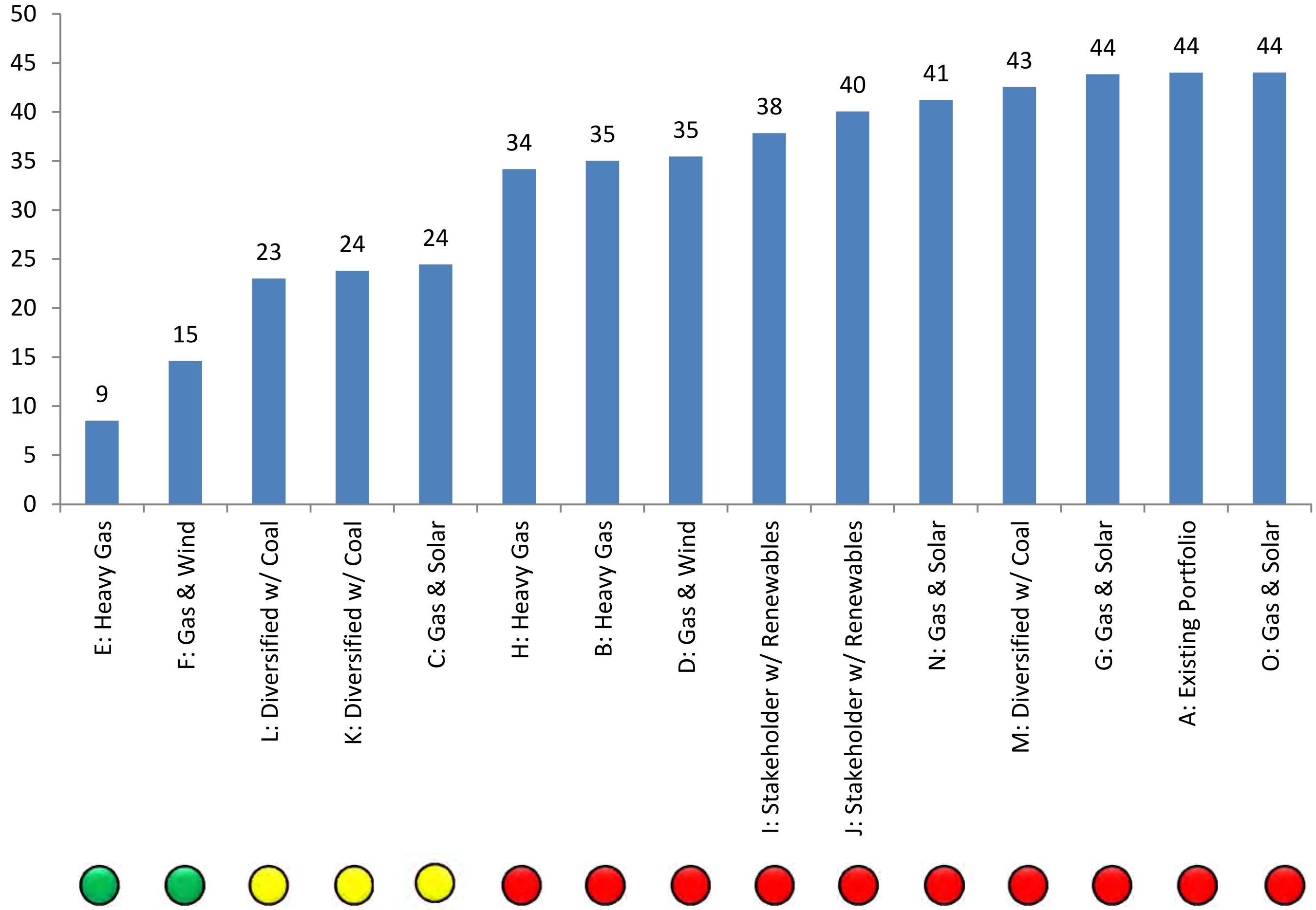
- Portfolios I and J have low variability, but are high cost portfolios
- Portfolios M and D have the smallest risk amongst the balanced and computer-generated portfolios.
- Portfolio L remains in the lower tier of cost risk
- Portfolios A, B, E, and H have the high variability risk

Standard Deviation Ranking

- Portfolios less than 10%
- Portfolios between 10% and 15%
- Portfolio above 15%

NPV = Net Present Value

20 Year Average Incremental Capacity Purchases Across 200 Iterations (MW)*



- Uncertainty in load creates the possibility that portfolios meeting UCAP (Unforced Capacity) and PRM (Planning Reserve Margin) in the reference case may need to purchase additional capacity in the high load iterations
- This risk analysis calculates average incremental capacity purchase needs across 200 iterations
- Given the high volatility of capacity prices, this is an additional risk to portfolios with highest purchases
- Portfolio L is among the lower tier of incremental capacity purchases

Capacity Purchase Ranking

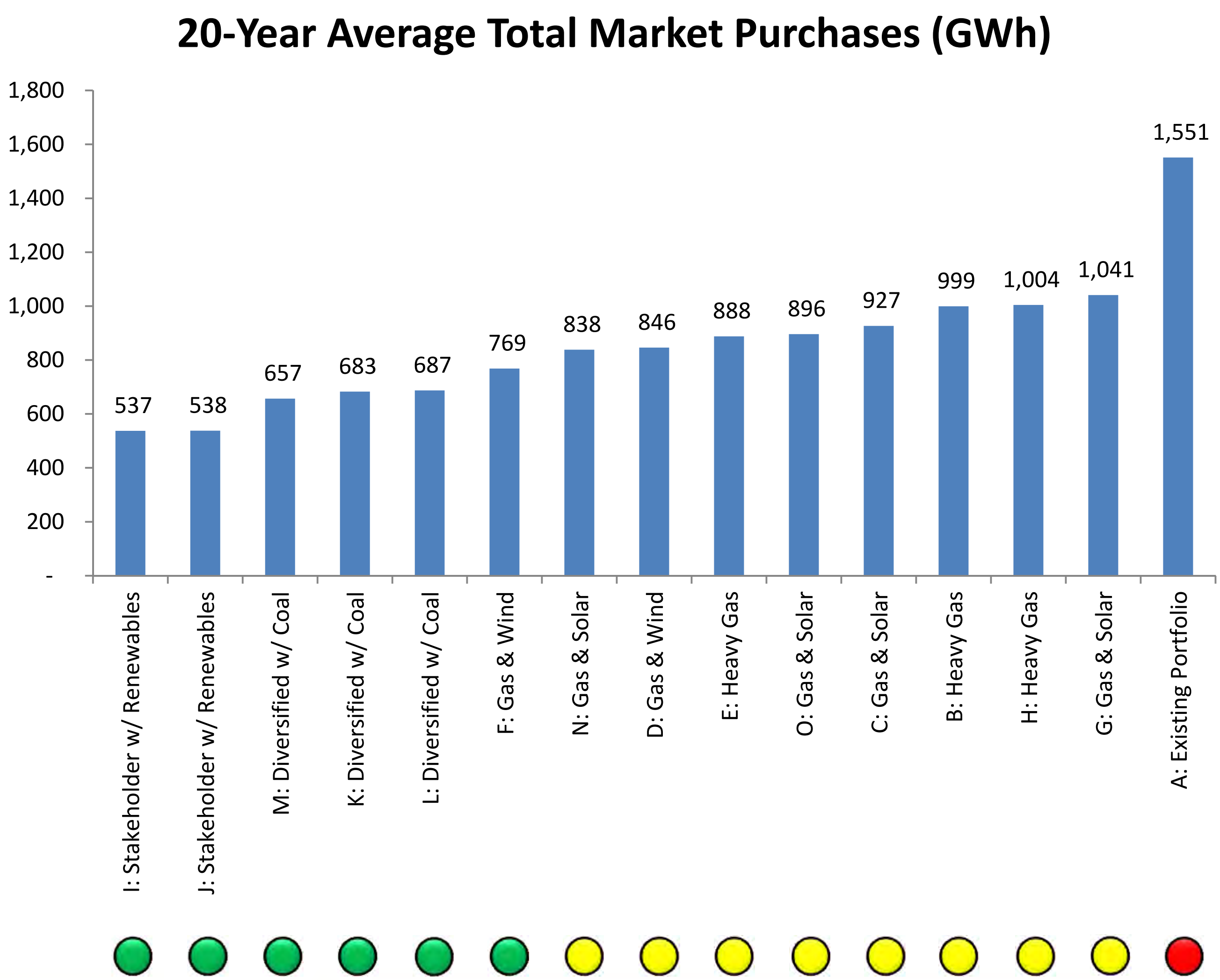
- Portfolios less than 20 MW (green)
- Portfolios between 21 and 30 MW (yellow)
- Portfolio above 31 MW (red)

*Capacity purchases shown are incremental purchases beyond levels on page 40 (Base Case Portfolio Construction)

MW = Megawatt

VECTREN Energy Delivery

Exposure to Market Purchase Risk



- Large Market purchase requirements expose a portfolio to market price volatility, and therefore presents another risk
- The portfolios with the lowest exposure to market price volatility are Portfolios I, J, K, L, M, and F
- The portfolio with the highest exposure to market purchase risk is the Existing Portfolio A

Market Purchase Ranking

- Portfolios less than 800 GWh
- Portfolios between 800 and 1,200 GWh
- Portfolio above 1,200 GWh

GWh = Gigawatt Hour

Risk Metric Summary

Portfolio	STD Dev. % above lowest		20 Year Average Capacity Purchases (MW)		20 Year Average Market Purchases (GWh)		Remote Generation Risk	Summary
L: Diversified w/ Coal	9.1%	🟢	23	🟡	687	🟢	🟡	🟢🟡
F: Gas & Wind	9.2%	🟢	15	🟢	769	🟢	🔴	🟢🟡
M: Diversified w/ Coal	6.8%	🟢	43	🔴	657	🟢	🟡	🟢🟡
K: Diversified w/ Coal	8.3%	🟢	24	🟡	683	🟢	🔴	🟢🟡
I: Stakeholder	0.0%	🟢	38	🔴	537	🟢	🔴	🟡
J: Stakeholder	6.9%	🟢	40	🔴	538	🟢	🔴	🟡
E: Heavy Gas	16.9%	🔴	9	🟢	888	🟡	🟡	🟡
O: Gas & Solar	9.4%	🟢	44	🔴	896	🟡	🟡	🟡
C: Gas & Solar	13.4%	🟡	24	🟡	927	🟡	🟡	🟡
N: Gas & Solar	9.6%	🟢	41	🔴	838	🟡	🟡	🟡
D: Gas & Wind	6.6%	🟢	35	🔴	846	🟡	🔴	🔴🟡
G: Gas & Solar	13.6%	🟡	44	🔴	1041	🟡	🟡	🔴🟡
H: Heavy Gas	15.8%	🔴	34	🔴	1004	🟡	🟡	🔴
B: Heavy Gas	15.7%	🔴	35	🔴	999	🟡	🟡	🔴
A: Existing Portfolio	17.0%	🔴	44	🔴	1551	🔴	🟡	🔴

- Remote Generation Risk reflects the risk of transmission issues from remote sources to Vectren. This is principally related to wind.
- The only portfolios that do not have a red light on one or more of the risk metrics are portfolios L and C.

Standard Deviation Ranking

🟢 Portfolios less than 10%

🟡 Portfolios between 10% and 15%

🔴 Portfolio above 15%

Capacity Purchase Ranking

🟢 Portfolios less than 20 MW

🟡 Portfolios between 21 and 30 MW

🔴 Portfolio above 31 MW

Market Purchase Ranking

🟢 Portfolios less than 800 GWh

🟡 Portfolios between 801 and 1,200 GWh

🔴 Portfolio above 1,200 GWh

Remote Generation Risk

🟡 Portfolios less than 50 MW of new remote generation

🔴 Portfolios greater than 50 MW of new remote generation

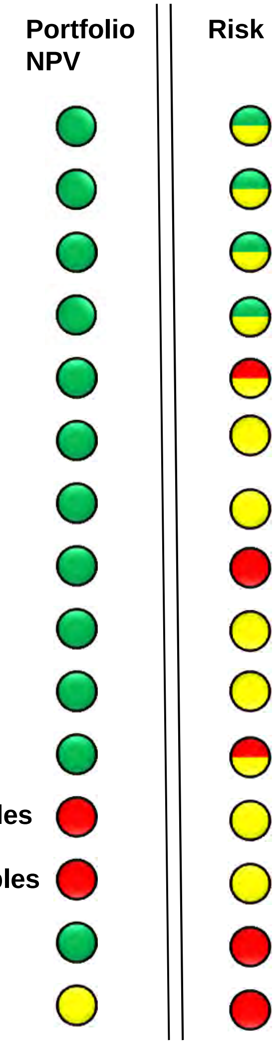
GWh = Gigawatt Hour

MW = Megawatt

STD Dev. = Standard Deviation

Risk Metric Summary

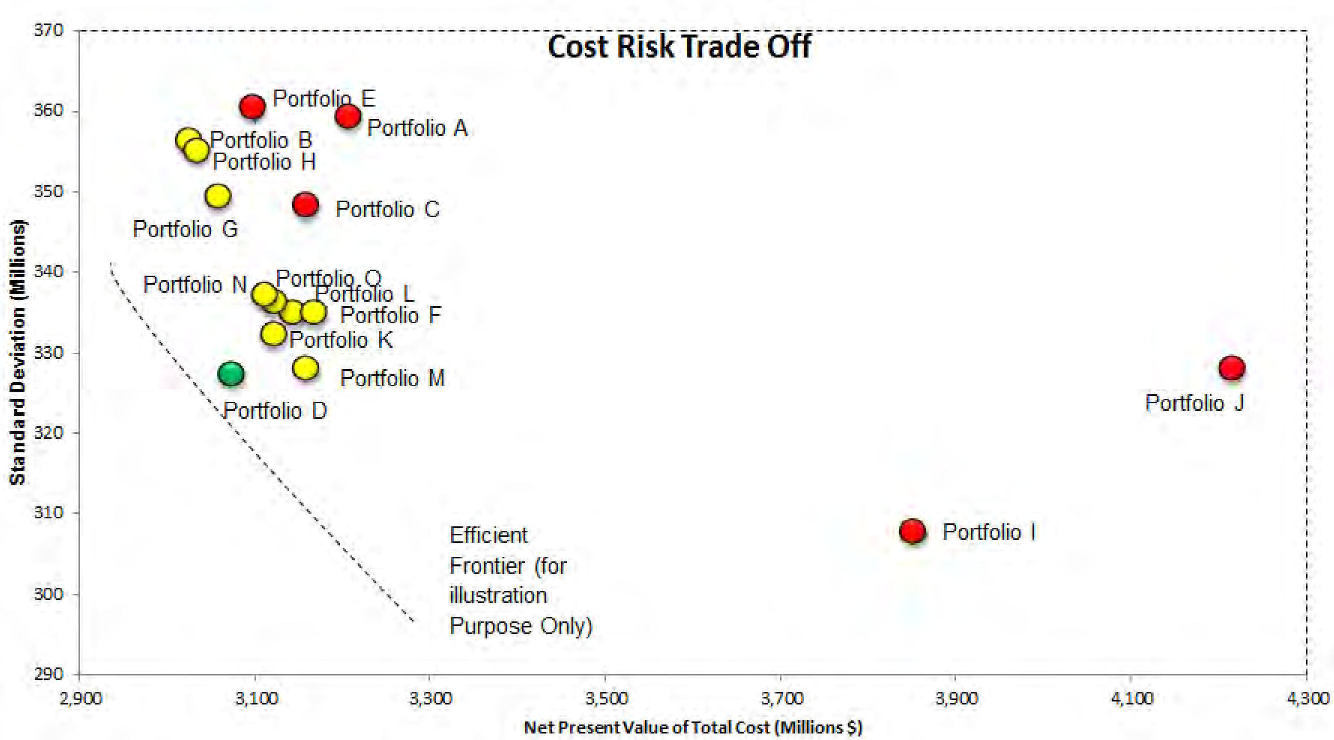
- Portfolio L - Diversified w/ Coal
- Portfolio K – Diversified w/ Coal
- Portfolio M – Diversified w/ Coal
- Portfolio F – Gas & Wind
- Portfolio D – Gas & Wind
- Portfolio O – Gas & Solar
- Portfolio N – Gas & Solar
- Portfolio H – Heavy Gas
- Portfolio E – Heavy Gas
- Portfolio C – Gas & Solar
- Portfolio G – Gas & Solar
- Portfolio I – Stakeholder w/ Renewables
- Portfolio J – Stakeholder w/ Renewables
- Portfolio B – Heavy Gas
- Portfolio A – Existing Portfolio



NPV = Net Present Value

Cost-Risk Trade-Off Summary

Portfolio Standard Deviation Risk (vertical axis) vs. Expected Cost (horizontal axis) Tradeoff



- Portfolios I and J are very expensive for only a moderate reduction in risk
- Portfolios A, C, and E have poor expected cost-risk tradeoffs compared to other portfolios
- Portfolio D has the best Cost-Risk tradeoff, while Portfolio L is among the best portfolios

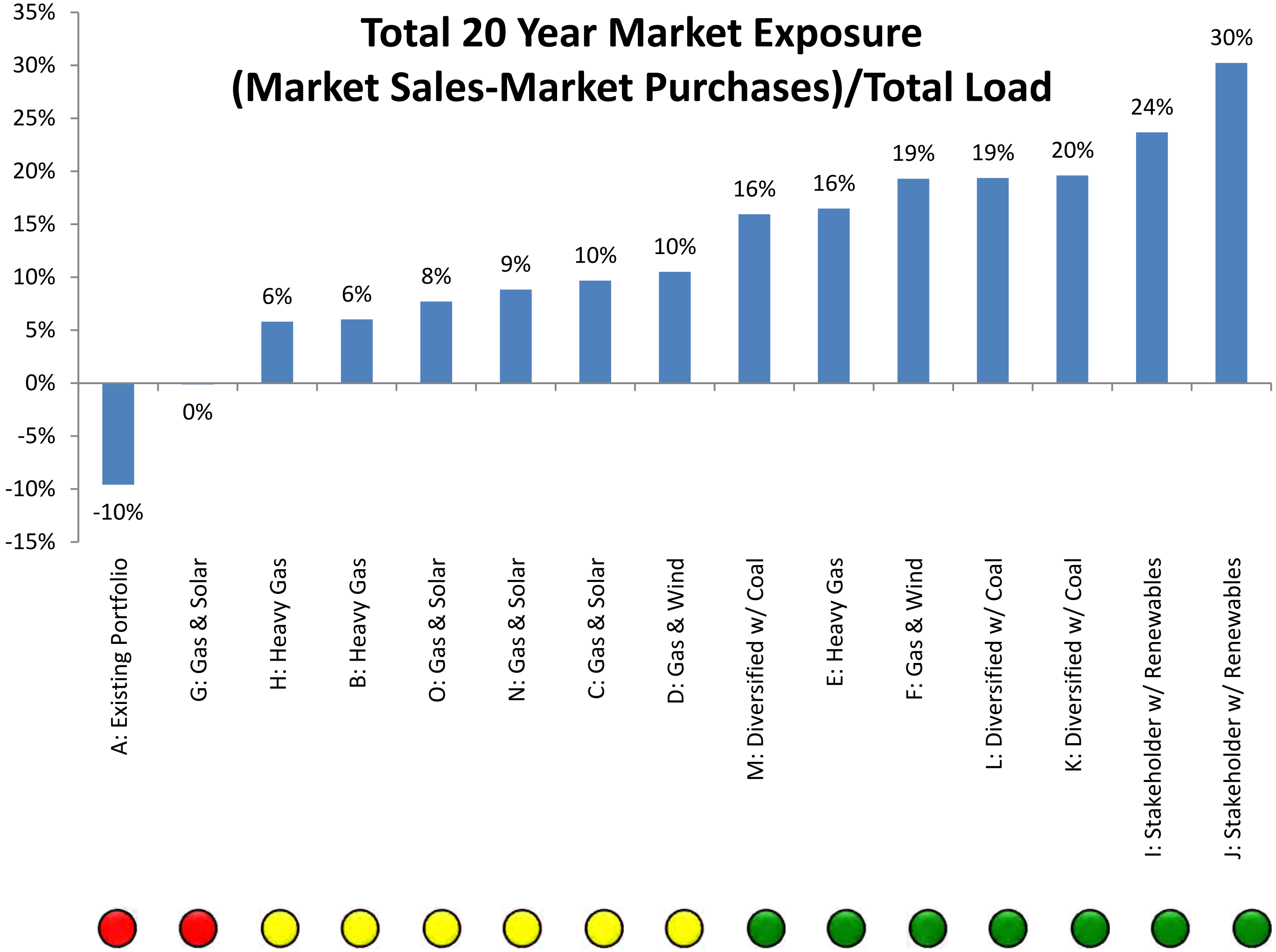
Cost Risk Trade-off Summary

	Portfolio NPV	Risk	Cost Risk Trade-off
Portfolio L - Diversified w/ Coal	Green	Green/Yellow	Yellow
Portfolio K – Diversified w/ Coal	Green	Green/Yellow	Yellow
Portfolio M – Diversified w/ Coal	Green	Green/Yellow	Yellow
Portfolio F – Gas & Wind	Green	Green/Yellow	Yellow
Portfolio D – Gas & Wind	Green	Red/Yellow	Green
Portfolio O – Gas & Solar	Green	Yellow	Yellow
Portfolio N – Gas & Solar	Green	Yellow	Yellow
Portfolio H – Heavy Gas	Green	Red	Yellow
Portfolio E – Heavy Gas	Green	Yellow	Red
Portfolio C – Gas & Solar	Green	Yellow	Red
Portfolio G – Gas & Solar	Green	Red/Yellow	Yellow
Portfolio I – Stakeholder w/ Renewables	Red	Yellow	Red
Portfolio J – Stakeholder w/ Renewables	Red	Yellow	Red
Portfolio B – Heavy Gas	Green	Red	Yellow
Portfolio A – Existing Portfolio	Yellow	Red	Red

NPV = Net Present Value

Balanced Energy/Flexibility Metric Summary

Flexibility Measure (Net Sales)



- Higher net sales provide a "cushion" against higher than expected load, as well as redundancy to quickly adapt to unexpected change
- Portfolios E, F, I, J, K, L, and M provide the most flexibility on this measure
- Portfolios A and G are net importers, and thus provide no hedge against unexpected changes of market prices

Market Flexibility Ranking

- Portfolios > 10%
- Portfolios between 0% and 10%
- Portfolios < 0%

Balanced Energy Summary Metric

Portfolio	2036 UCAP (MW) % Largest Technology in Portfolio	Tech	Largest 24/7 Power Source	2036 Concentration (GWh) % Reliance Largest Technology	Tech	Balanced Energy Metric 2036 (# of Technologies)*	Market Flexibility Net Sales	Summary
Portfolio I	51%	Wind	2 CC	47%	Wind	5 (Gas, Wind, Solar, EE, Bat)	24%	
Portfolio J	44%	Wind	1 CC	49%	Wind	5 (Gas, Wind, Solar, EE, Bat)	30%	
Portfolio M	57%	Gas	1 CC, 1 Coal	70%	Gas	5 (Coal, Gas, Wind, Solar, EE)	16%	
Portfolio K	65%	Gas	1 CC, 1 Coal	72%	Gas	5 (Coal, Gas, Wind, Solar, EE)	20%	
Portfolio L	66%	Gas	1 CC, 1 Coal	73%	Gas	5 (Coal, Gas, Wind, Solar, EE)	19%	
Portfolio F	69%	Gas	1 CC	73%	Gas	4 (Gas, Wind, Solar, EE)	19%	
Portfolio E	84%	Gas	1 CC	91%	Gas	4 (Gas, Wind, Solar, EE)	16%	
Portfolio D	57%	Gas	1 CC	73%	Gas	4 (Gas, Wind, Solar, EE)	10%	
Portfolio O	70%	Gas	1 CC	82%	Gas	4 (Gas, Wind, Solar, EE)	8%	
Portfolio N	73%	Gas	1 CC	83%	Gas	4 (Gas, Wind, Solar, EE)	9%	
Portfolio C	78%	Gas	1 CC	89%	Gas	4 (Gas, Wind, Solar, EE)	10%	
Portfolio H	85%	Gas	1 CC	94%	Gas	4 (Gas, Wind, Solar, Bat)	6%	
Portfolio A	61%	Coal	4 Coal	83%	Coal	4 (Coal, Gas, Wind, Solar)	-10%	
Portfolio B	85%	Gas	1 CC	93%	Gas	3 (Gas, Wind, Solar)	6%	
Portfolio G	70%	Gas	1 CC	92%	Gas	3 (Gas, Wind, Solar)	0%	

- *Wind Purchased Power Agreement included in Wind*

- Portfolios I, K, L, and M have two distinct baseload generation options – a hedge against outages
- The lower the concentration on any one technology in the generation mix, the better the protection offered to Vectren against early obsolescence
- Greater # of technologies provide more diversity

2036 Largest # of Baseload Units

Portfolios 3 units or above

Portfolios with 2 units

Portfolios with 1 unit

Concentration Ranking

Portfolios < 60% (GWh % reliance)

Portfolios between 61% and 79%

Portfolios > 80%

Balanced Energy Metric

Portfolios = 5 technologies

Portfolios = 4 technologies

Portfolios = 3 or less technologies

Market Flexibility Ranking

Portfolios > 10%

Portfolios between 0% and 10%

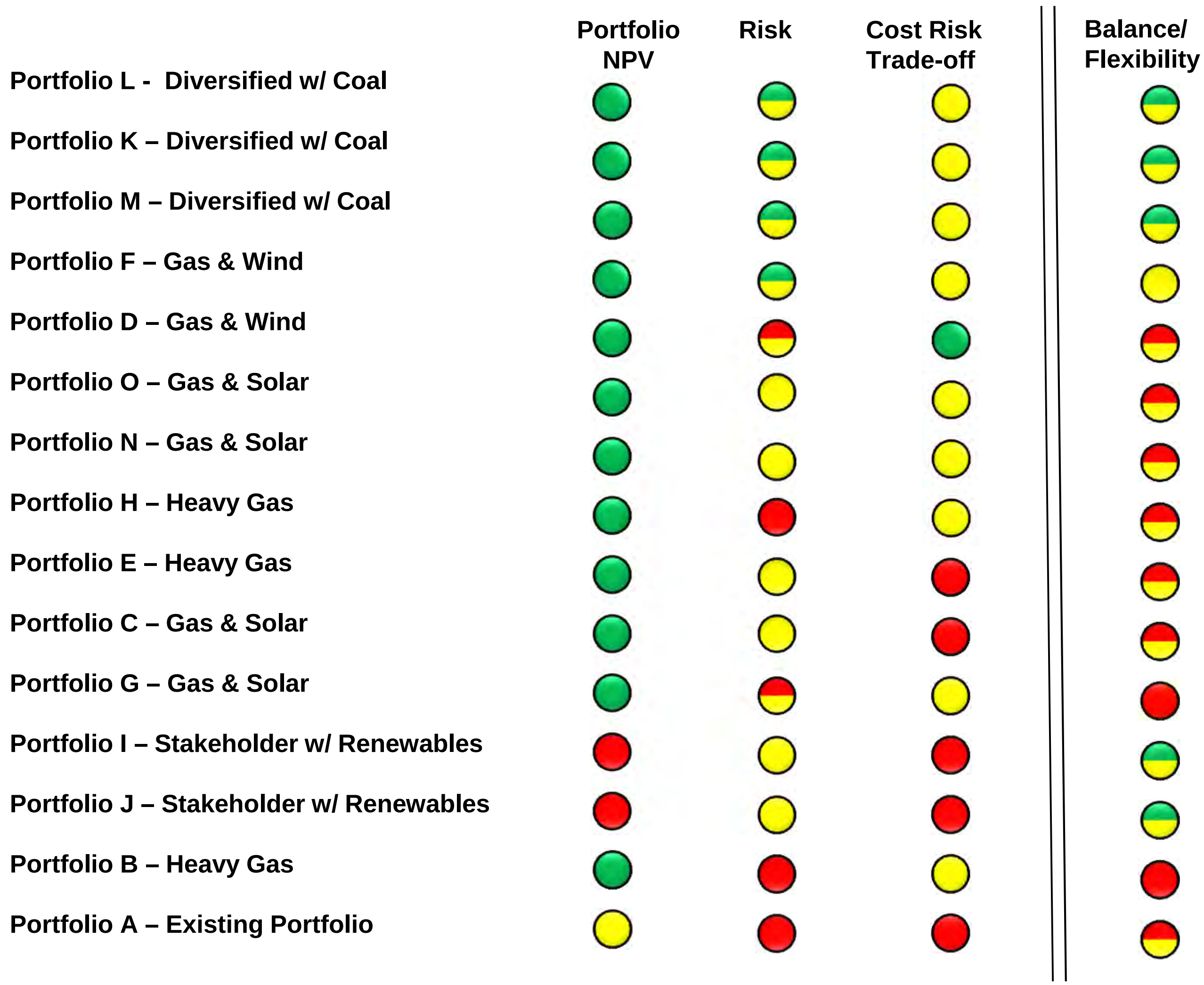
Portfolios < 0%

UCAP = Unforced Capacity
EE = Energy Efficiency
GWh = Gigawatt Hour
Tech = Technology

MW = Megawatt
Bat = Battery Storage
CC = Combined Cycle

VECTREN Energy Delivery

Balanced/Flexibility Summary

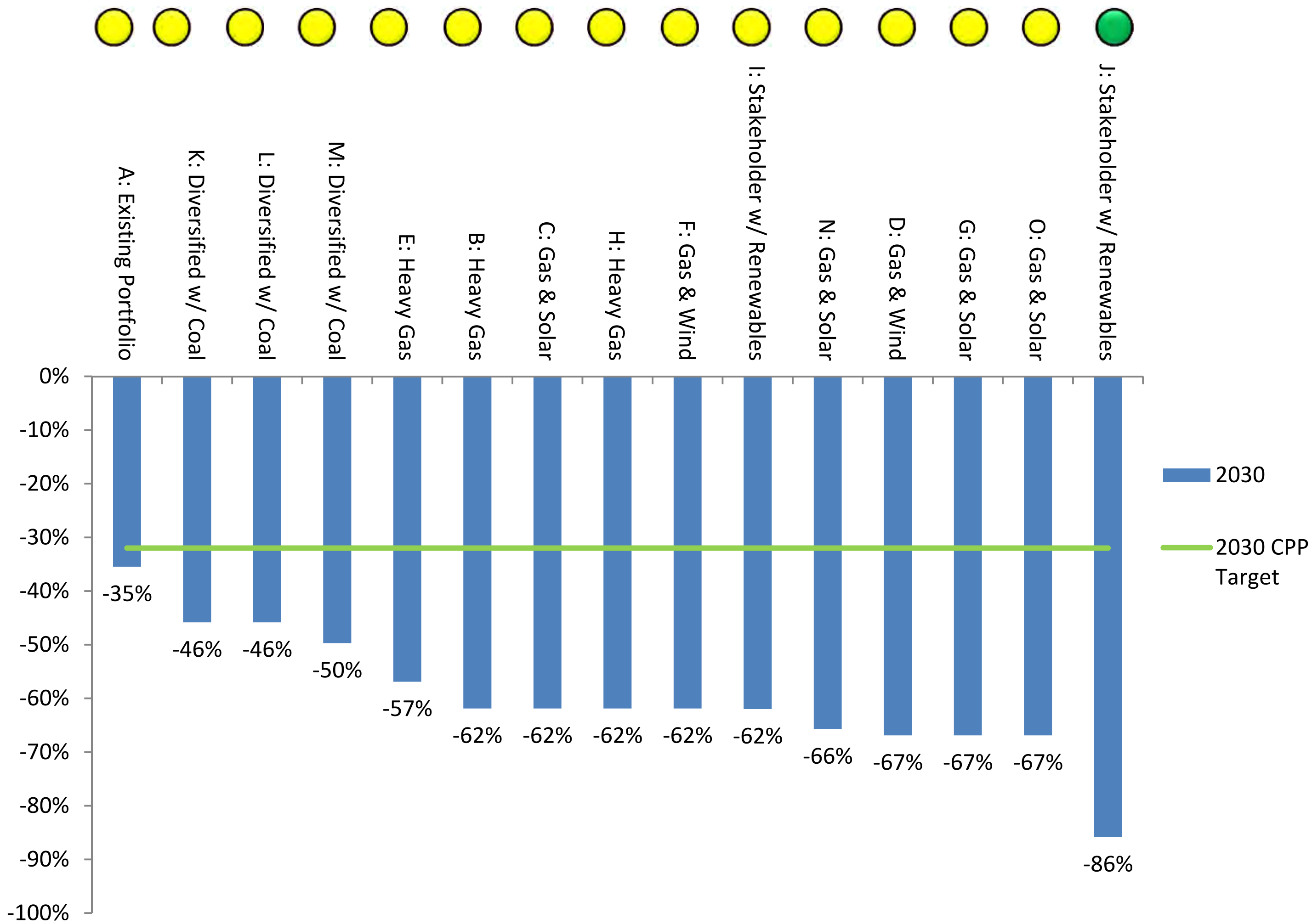


NPV = Net Present Value

VECTREN Energy Delivery

Environmental Metric Summary

Carbon Emission Reduction from 2012 Levels



Vectren has reduced Carbon emissions by 31% between 2005 and 2015

The CPP, if enacted, would require reductions of approximately 32% by 2030.

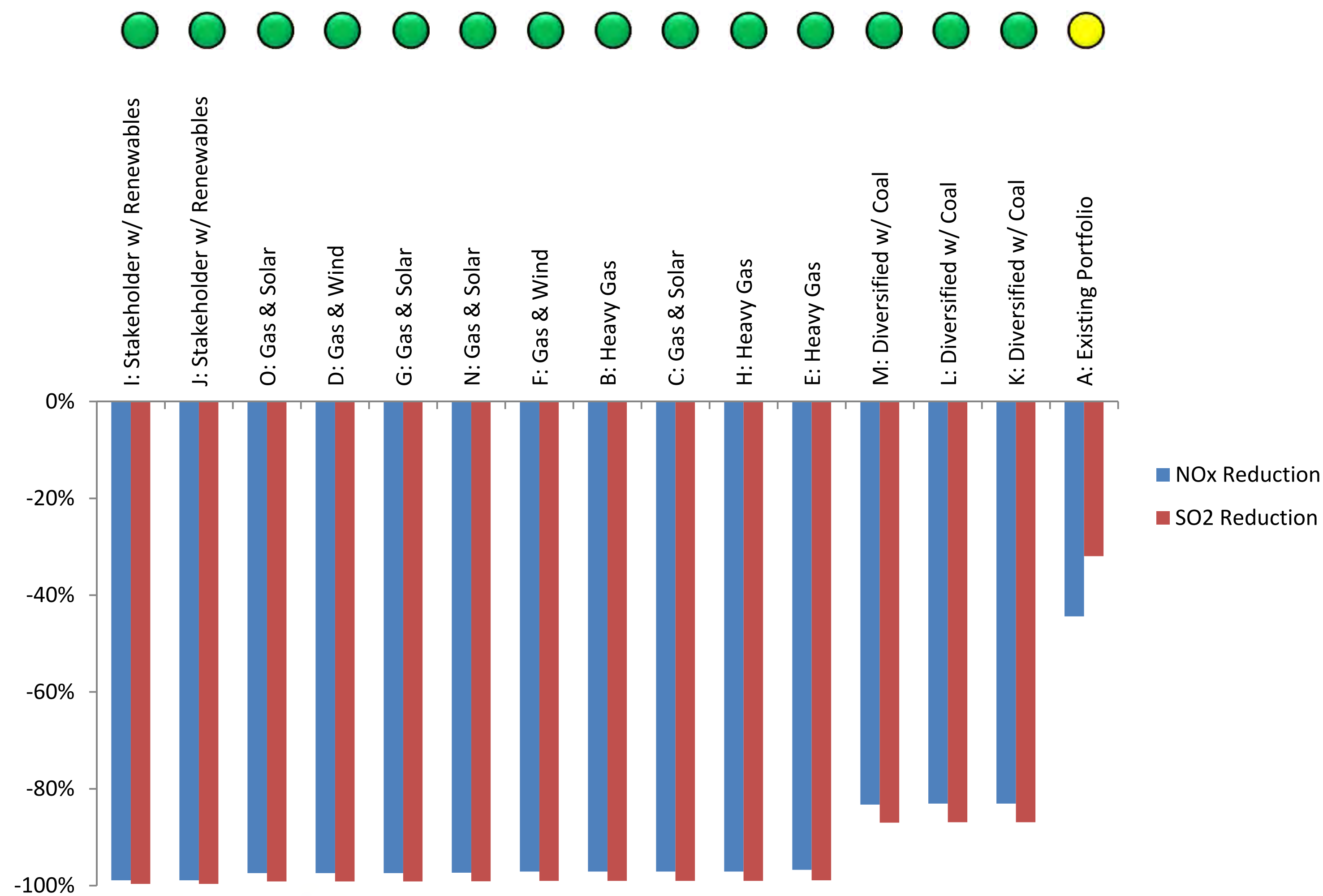
By 2030, every portfolio reduces carbon emissions by over 40% compared to 2012 except for Portfolio A. Note that coal units are not expected to run as often in the future.

All portfolios are judged as yellow in comparison to Portfolio J (Stakeholder), though all have significant reductions from 2012 levels.

CPP = Clean Power Plan

VECTREN Energy Delivery

2036 NO_X/SO_2 Emission Reduction from 2012-15 Levels



All exiting coal units are currently controlled for SO_2 and NO_X.

All portfolios are expected to achieve significant reduction in both NO_X and SO_2 emissions due to unit retirements and new resource additions.

All portfolios, except for Portfolio A, will exceed greater than 80% reduction in NO_X/SO_2 emission profile compared to the average of 2012-2015 level.

Existing Units are expected to dispatch less often than new gas capacity additions.

NO_X = Nitrogen Oxide SO_2 = Sulfur Dioxide

VECTREN Energy Delivery

Environmental Metric

	2030 % Carbon Reduction from 2012		NO_X/SO_2 Reduction 2036 vs. 2012-2015	Summary
J: Stakeholder w/Renewables	-86%	🟢	🟢	🟢
D: Gas & Wind	-67%	🟡	🟢	🟢🟡
G: Gas & Solar	-67%	🟡	🟢	🟢🟡
O: Gas & Solar	-67%	🟡	🟢	🟢🟡
N: Gas & Solar	-66%	🟡	🟢	🟢🟡
I: Stakeholder w/Renewables	-62%	🟡	🟢	🟢🟡
F: Gas & Wind	-62%	🟡	🟢	🟢🟡
B: Heavy Gas	-62%	🟡	🟢	🟢🟡
C: Gas & Solar	-62%	🟡	🟢	🟢🟡
H: Heavy Gas	-62%	🟡	🟢	🟢🟡
E: Heavy Gas	-57%	🟡	🟢	🟢🟡
M: Diversified w/Coal	-50%	🟡	🟢	🟢🟡
K: Diversified w/Coal	-46%	🟡	🟢	🟢🟡
L: Diversified w/Coal	-46%	🟡	🟢	🟢🟡
A: Existing Portfolio	-35%	🟡	🟡	🟡

- Portfolio L has 46% reduction in carbon from 2012 levels in 2036, exceeding CPP requirements by about 14%.
- Portfolio L achieves 61% reduction in carbon from 2005 levels in 2036.

% Carbon Reduction Rating

🔴 Portfolios within 32%

🟡 Portfolios between 33% and 75%

🟢 Portfolio above 75%

% NO_X and SO_2 Reduction Rating

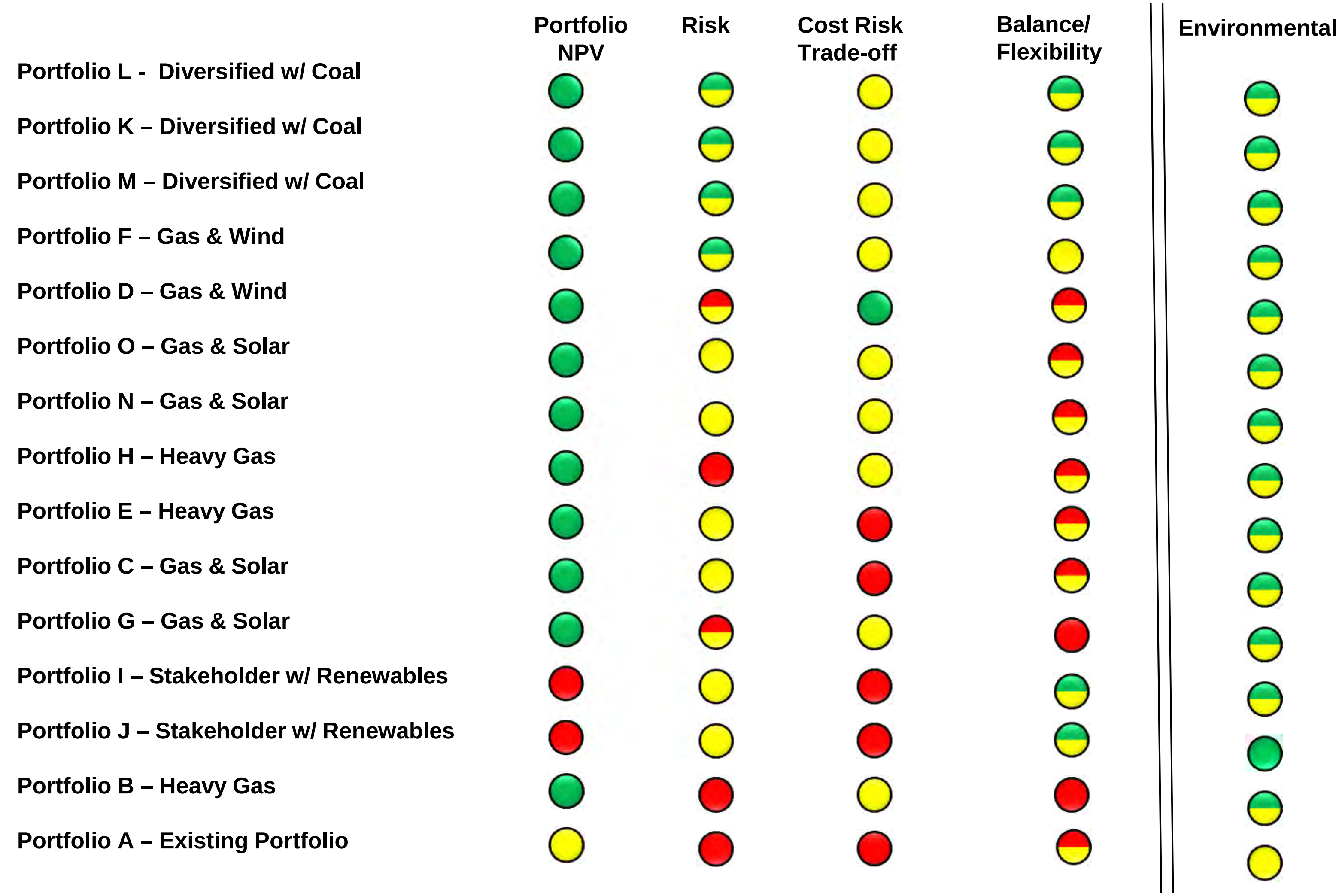
🔴 Portfolios below 30%

🟡 Portfolios between 31% and 80%

🟢 Portfolio above 80%

NO_X = Nitrogen Oxide SO_2 = Sulfur Dioxide CPP = Clean Power Plan

Environmental Metric Summary



NPV = Net Present Value

Local Economic Impact
Metric Summary

Local Economic Impact

	Local Economic Impact	Summary
A: Existing Portfolio	Green	Green
K: Diversified w/Coal	Green	Green
L: Diversified w/Coal	Green	Green
M: Diversified w/Coal	Green	Green
I: Stakeholder w/Renewables	Green	Green
B: Heavy Gas	Yellow	Yellow
N: Gas & Solar	Yellow	Yellow
O: Gas & Solar	Yellow	Yellow
J: Stakeholder w/Renewables	Yellow	Yellow
C: Gas & Solar	Yellow	Yellow
D: Gas & Wind	Yellow	Yellow
E: Heavy Gas	Yellow	Yellow
F: Gas & Wind	Yellow	Yellow
G: Gas & Solar	Yellow	Yellow
H: Heavy Gas	Yellow	Yellow

Closing FB Culley 3 by 2024 would have an adverse economic impact to the community, particularly hard hit Warrick County*

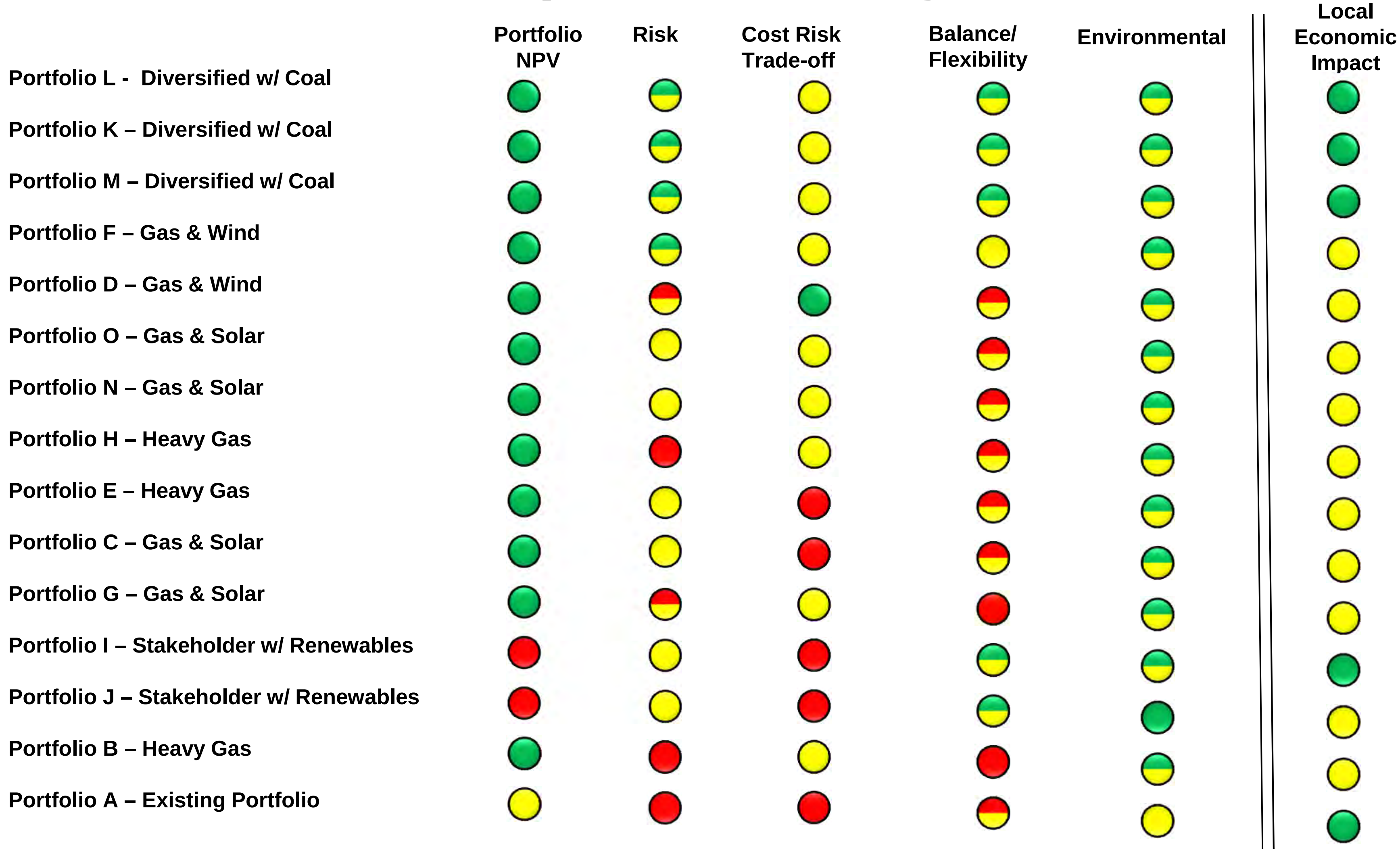
- Total 1-year Output Impact = $145 million
- Total 1-year State and Local Tax Impact = $7 million, of which Vectren's property taxes from Culley 3 alone currently contribute approximately $350 thousand dollars annually to Warrick County School Corp.
- Total Jobs Impact = 271, which includes 82 direct job losses at the plant

Building and operating a combined cycle gas plant within Vectren's service territory would minimize the economic impact to the community of closing the AB Brown Plant by 2024

- Total Output Impact of construction = $950 million
- Total Output Impact of operating the plant = $50 million per year

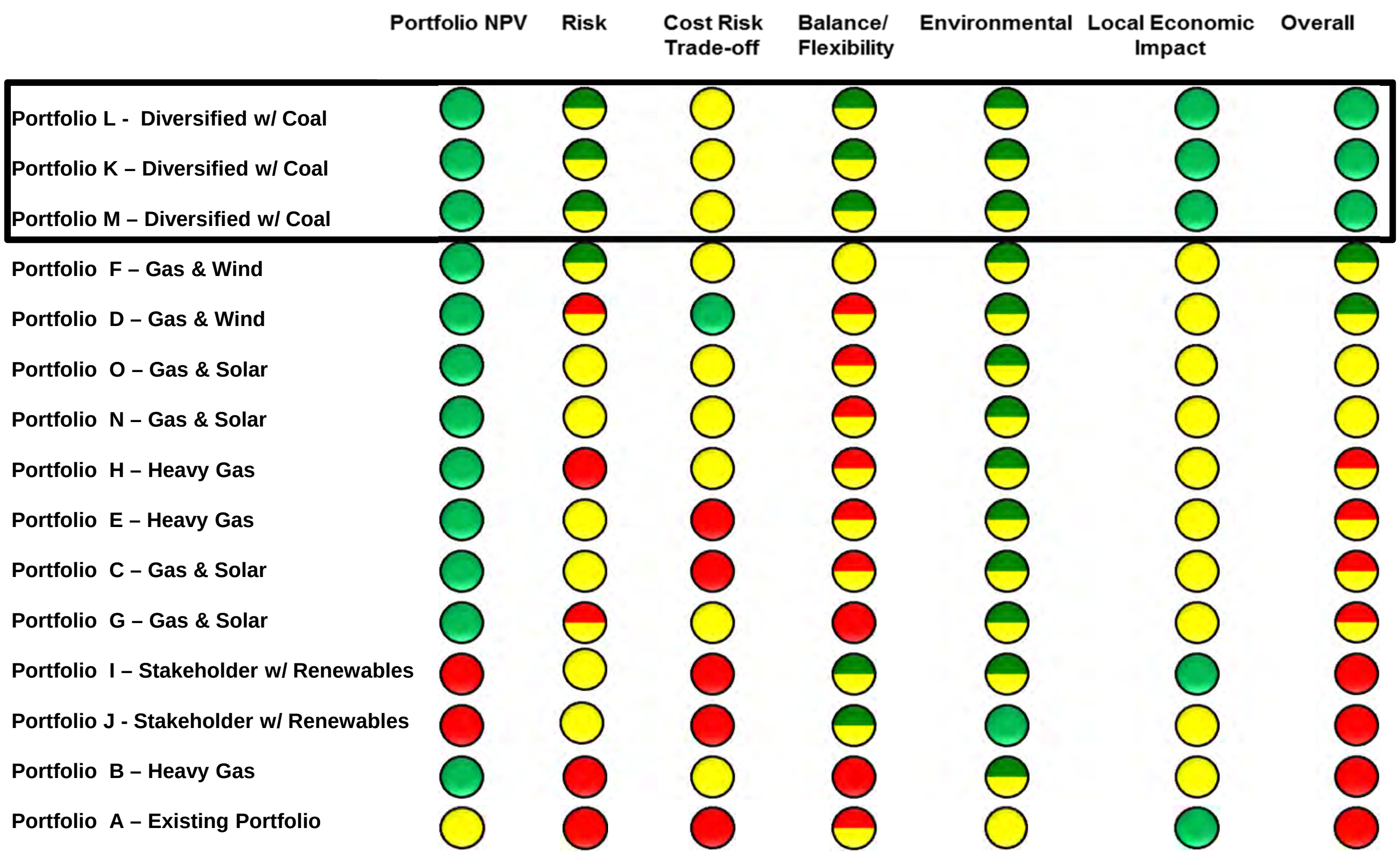
*Alcoa closed its smelter operation in the spring of 2016. The impact is compounded by FB Culley 2 by 2024. Economic impact study conducted by professors of economics and finance at the University of Evansville. Total economic impact based on an Economic Impact Study using IMPLAN social accounting system. Total impact includes direct, indirect, and induced effects.

Local Economic Impact Summary



NPV = Net Present Value

IRP Portfolio Balanced Scorecard



- Portfolios L, K, and M, the diversified with Coal Portfolios, perform best across all metrics
- Portfolio L has early renewables and low cost, highly efficient peaking capacity to back up intermittent renewable resources, mitigate capacity market risk, and allow for economic development opportunities

NPV = Net Present Value

IRP Next Steps

2016 Vectren IRP Schedule	
December 6, 2016	3rd Stakeholder meeting summary
December 16, 2016	Vectren files 2016 IRP with the IURC
90 days after filing: March 16, 2017	Interested party deadline to submit comments to the IURC
120 days after filing: April 17, 2017	IURC Director's Draft Report publication expected
30 days after submission of the Director's Draft Report: May 17, 2016	Interested party deadline to submit comments on the draft report
30 days following the deadline for supplemental response comments: June 17, 2017	Final Director's Report publication expected

IURC = Indiana Utility Regulatory Commission
IRP = Integrated Resource Plan

11/30/2016

Vectren 2016 Integrated Resource Plan (IRP)

November 29, 2016 Stakeholder Meeting 3 Summary

The following is a summary of the third of three Vectren IRP stakeholder meetings in 2016 and is meant to provide a high level overview of the discussion on November 29, 2016.

Welcome (Slides 1-3)
Gary Vicinus, Pace Global – Managing Director of Consulting Practice

Mr. Vicinus opened the meeting and welcomed guests to Vectren headquarters, located within Vectren's service territory in Evansville, IN. He mentioned that this is an important IRP for Vectren and reviewed meeting guidelines and the agenda.

Vectren IRP Process Overview (Slides 4-7)
Gary Vicinus, Pace Global – Managing Director of Consulting Practice

Mr. Vicinus briefly reviewed Vectren's commitments for the 2016 IRP and recapped the information that was provided at previous public stakeholder meetings. He commented on Vectren's approach and structured analysis process for this IRP. Materials from all meetings can be found at www.vectren.com/irp.

The Preferred Portfolio (Slides 8-21)
Carl Chapman, Vectren Chairman, President & CEO

Mr. Chapman reviewed the current environmental controls on Vectren's generation resources and stated that Vectren's current fleet is among the cleanest in the Midwest. Vectren has reduced carbon emissions by 31% between 2005 and 2015. Mr. Chapman stated that electric bills have remained flat since 2011, and that Vectren has not filed a base rate case in 6 years. He highlighted the following changes in Vectren's resource mix based on the preferred portfolio:

(MWs)	2015	2036
Coal Base Load (24/7 Power)	68%	16%
Natural Gas Peaking	17%	22%
Natural Gas Base Load (24/7 Power)	0%	41%
Energy Efficiency/Demand Response	8%	11%
Renewable	6%	8%
Other	2%	1%

Mr. Chapman reviewed the Vectren Preferred Portfolio timeline. Highlights include:

- Retire Broadway Avenue Gas Turbine 1 (50 MW) and add universal solar (4MW) in 2018
- Retire Northeast Gas Turbines 1 & 2 (20 MW) and add universal solar (50 MW) in 2019
- Exit joint operations of Warrick 4 (150 MW) in 2020
- Complete Culley 3 upgrades for Effluent Limitation Guidelines in 2023
- Retire Brown 1& 2 and Culley 2 coal units (580 MW) and add combined cycle natural gas plant (889 MW) in 2024
- Retire Broadway Avenue Gas Turbine 2 (65 MW) in 2025

Mr. Chapman reviewed the rationale for selecting the preferred portfolio and discussed the benefits of duct-fired combined cycle gas generation. Mr. Chapman reviewed the next steps in Vectren's IRP process which include filing the IRP on December 16, 2016 and preparing filings for energy efficiency, solar generation, and generation transition.

Duct-firing gas generation technology will be used because of significantly lower capital costs per installed MW and its ability to provide efficient peaking capacity. The Duct-firing option provides quick response peaking capacity energy at a lower heat rate than most simple cycle technologies.

Existing EPA Regulations (Slides 22-25)
Angila Retherford, Vectren Vice President of Environmental Affairs & Corporate Sustainability

Ms. Retherford commented on the post-election regulation outlook. It is unclear which regulations the new administration intends to review other than the Clean Power Plan (CPP) and Waters of the US rule. Final regulations like the Effluent Limitation Guidelines (ELG) and Coal Combustion Rule (CCR) require notice and comment to rescind and/or modify. These rules are difficult to set aside and must be supported by a technological or human health rationale. Compliance costs for these regulations are high and thus become a key driver to Vectren's plan. The Paris agreement can be set aside by an executive order. The CPP is currently in litigation and regardless of the Trump Administration's action, it is likely that some states will continue to defend the rule.

A stakeholder asked for clarification of the time periods that Vectren cited for its carbon reduction percentages. The 31% reduction is from 2005 through 2015. The 60% reduction from a 2005 baseline will be achieved by the end of the plan. A stakeholder asked about what investments are needed to comply with CCR. Controls for bottom ash conversion and a waste water treatment plant at Culley are needed. The timeline for this is being discussed with IDEM.

Multiple stakeholders commented that addressing health concerns from climate change, continued coal use, air quality, and ash pond issues are the "right thing to do." It was noted that Vectren is reducing its carbon emissions by 60%. The preferred plan also results in additional reductions of both SO_2 & NOx by approximately 80% from 2012-2015 average level.
A stakeholder asked what will happen to the Brown plant if a gas plant is built there. A final decision has not been made regarding the location of a gas plant, though it has been modeled for the Brown location. The biggest decommissioning issue is the ash pond, which must be done regardless. A stakeholder asked about the decision to exit operations at Warrick 4 vs. maintaining Culley 2 due to higher CO_2 emissions at Culley. Culley 2 is expected to be retired in 2024, and the impact on customer rates drove this decision.

A stakeholder asked how exiting operations at Warrick 4 is going to work. Alcoa is a large company making a major decision. At this time, Vectren still cannot make a final determination. A commercial customer asked if the additions or retirements of these generating units had been modeled in regard to how it would impact his facility. He was concerned that it could lead to additional costs to upgrade electrical equipment. The IRP analysis is focused on determining the best course of action to meet customers' needs for power over the next 20 years. The subsequent engineering phase will assure that the generating units, transformers, and transmission lines are designed to maintain electric service to all customers that meets federally mandated standards.

A stakeholder asked how MISO determines wind and solar capacity credit. MISO requires a reserve margin from all its members (not just Vectren) to meet peak day demand, and the reliability of renewable assets are part of this calculation. The credit is based on how much capacity can be counted on at peak demand.

A stakeholder asked for clarification on "roll-off" terminology associated with Energy Efficiency (EE) [slide 12]. Vectren assumes that EE savings are still in place even though Vectren does not continue to get credit for these "rolled-off" energy savings.

In a follow-up conversation with the CAC, Rina Harris, Vectren Director of Energy Efficiency, further explained the graph on slide 12. Vectren clarified the slide was a graphical illustration of the EE modeled in the preferred portfolio of the IRP. The total historical energy efficiency, roll off, and the new energy efficiency represented the 11% of EE illustrated on slide 11, showcasing the percent of EE in the preferred portfolio in 2036. Vectren noted that historical EE represented cumulative net savings between 2010 and 2015. Roll-off represented savings Vectren no longer gets credit for due to measure life constraints or technology baseline changes. An example of a CFL bulb was used as a reference. If a CFL bulb has an average a five-year measure life, Vectren can only claim credit for savings for five years, as it is assumed that codes and standards will require an efficient lighting replacement in the future. New EE represented the EE in the preferred portfolio, assuming a 10-year measure life.

Optimization Modeling Results and Portfolio Development (slides 26-40)
Matt Lind, Burns & McDonnell – Associate Project Manager

Mr. Lind reviewed the methodology used for the computer-generated portfolios. He provided an update to the 50 MW solar costs described at the July 22, 2016 public meeting to the cost modeled in the IRP. The Levelized Cost of Electricity (LCOE) for a 50MW solar facility was lowered from $172/MWh to $149/MWh in 2016$ based on changes to the cost of land, assumed capacity factor of the facility, and normalized treatment of the investment tax credit (ITC). Mr. Lind noted that the cost of solar was assumed to decline in the future, so costs would be lower in every future study year from that presented. Mr. Lind also provided a comparison of other public LCOE reference points. Differences in public LCOE numbers compared to Vectren LCOE numbers typically are due to capacity factor and cost to build assumptions. The capacity factor is calculated by dividing the total amount of energy a plant produces over the course of a year divided by the amount of energy the plant would have produced had it been running 24/7 - 365. For example, capacity factors in the Southwest are much higher than those in the Midwest. Typically, public LCOE studies do not include all of the costs included in Vectren's estimate. Typical items excluded include but are not limited to: land, PV modules, inverters, engineering work, transmission interconnection etc. Mr. Lind then reviewed details of the computer-generated, balanced, and stakeholder portfolios.

A stakeholder asked if input numbers to the portfolio model would be made available. Vectren did share major input costs at the public meeting on July 22, 2016. Additionally, the IRP report will include input costs, such as fuel costs, resource costs, etc. A stakeholder commented that Vectren should use land it already owns for solar. Vectren cannot assume solar will be on land owned by Vectren, as there may be sites more suitable elsewhere. A stakeholder asked which portfolio is the preferred portfolio. Portfolio L is the preferred portfolio. A stakeholder commented that competitive bids from PPAs are the best way to determine solar costs. Vectren will consider PPAs. A stakeholder asked if solar panels can last 25 years. It depends on their location and maintenance. Warranties can be up to 25 years.

A customer asked why we couldn't build solar in Arizona to reduce the cost per kW due to the higher annual solar output in that part of the country. There are several factors that make that impractical today:

1) Required capacity for our zone (MISO zone 6, which is mostly Indiana) must be predominately located within zone 6 due to transmission import limitations. This is referred to as the local clearing requirement (LCR). The requirement changes from year to year but is currently about 70%.
2) There are really three separate grids in the United States. The Eastern Interconnect, the Western Interconnect, and the third is most of Texas i.e. ERCOT (Electric Reliability Council of Texas). These three grids are not in synch with each other. Expensive AC to DC conversion equipment would be needed for power to flow across these grids.
3) Reliability is another issue as every mile that you are away from your generation is a mile in which something can go wrong such as tornados, lightning strikes, ice storms, wild fires, earthquakes, and transportation accidents.
4) Additionally, charges associated with transmission congestion and capacity would be expected to outweigh the benefit.

A stakeholder asked about the difference between the 38% solar rated capacity (Slide 17) and the Vectren capacity factor (slide 30). 38% referenced on slide 17 is the amount of capacity credit (measured in MWs) Vectren expects to receive from MISO for solar generation during MISO peak load periods in Southern Indiana. In other terms, Vectren expects to receive 38 MWs of credit towards meeting the planning reserve margin requirement for 100 MW of name plate capacity. The 19% annual capacity factor relates to the amount of expected energy production (measured in MWh) by solar generation in a typical year. The number is specific for Indiana and is derived from NOAA (National Oceanic and Atmospheric Administration) maps. Annual capacity factor is the amount of energy (measured in MWh) over the course of a year divided by what the panels could produce if the sun shined 24/7 - 365. This number is driven by weather conditions, panel orientation (south-facing or west-facing) and tilt, soiling, expected degradation, etc.

Risk Analysis (slides 41-71)
Gary Vicinus, Pace Global – Managing Director of Consulting Practice

Mr. Vicinus reviewed the risk analysis, which was conducted to evaluate expected performance of the 15 modeled portfolios. Mr. Vicinus walked the audience through how each portfolio compared to several risk factors and reviewed the rationale for Portfolio L as Vectren's preferred portfolio. The metrics used to evaluate each portfolio were:

1) 20 Year Net Present Value Revenue Requirement (NPVRR),
2) Risk, defined as a combination of:
    a) Standard deviation of NPV,
    b) Average unaccounted capacity purchase needs,
    c) Market purchase risk, and
    d) Remote generation risk,
3) Cost-risk tradeoff (combined expected NPVRR and standard deviation risk),
4) Balanced energy/flexibility, defined as a combination of:
    a) Concentration metric,
    b) # of distinct baseload sources,
    c) Generation mix balance, and
    d) market flexibility,
5) Environmental, defined as:
    a) Carbon reduction and
    b) SO_2 and NO_X reduction, and
6) Local economic impact.

A stakeholder asked if the risk factors were weighted equally. Each of the six factors weighted equally, as displayed, in the balanced scorecard (Slide 70). A stakeholder asked if a less volatile (as measured by standard deviation) portfolio would offset increases in costs. To determine this, one must consider the cost/risk trade-off, which is illustrated on Slide 56. As seen on this slide, portfolios I and J are not cost competitive. The lower risk does not offset the higher cost of these portfolios. A stakeholder asked how the existing portfolio can exceed CPP goals. This portfolio is called "existing" portfolio, however it assumes that Vectren exits joint ownership of Warrick 4 and replaces it with a simple cycle gas turbine. The model also takes into account expected dispatch of the units and purchases more energy from the wholesale market which doesn't contribute to Vectren's carbon emission totals. A stakeholder commented that solar technology will improve, making it more viable in Southern Indiana. The issue is how fast solar costs will decline from current levels, which was considered in the high technology scenario.

A stakeholder commented that Portfolio L has one of the lowest relative amount of carbon emission reductions. This is true; however, it still far exceeds CPP standards. A stakeholder commented that if all environmental ratings were relative to each portfolio there would be a difference in ranking. The portfolios were measured against known environmental standards for CO_2, SO_2, and NO_X. Other risk factors do not have a standard and were therefore measured against other portfolios.

A stakeholder commented that the choice of risk metrics is subjective; Vectren should consider fuel cost for traditional generation vs no fuel cost for renewables. Vectren measured fuel risk similarly to how other utilities measure it. Fuel prices were varied for this analysis, which included 200 iterations for each portfolio in the risk analysis. A stakeholder commented that EE costs are not accurate. EE costs are modeled on 2016 costs and escalated as penetration levels increase.

The final portion of the meeting was dedicated to answering any additional questions and capturing stakeholder feedback. Vectren management joined Gary Vicinus in a panel discussion.

A stakeholder asked if health care costs were included in the local economic impact analysis. They were not included within the economic impact analysis. Vectren worked with the University of Evansville to understand the economic impact to the local community, should Vectren coal plants shut down. The software that they utilized does not include a mechanism for calculating health impacts. However, health impacts are considered within known and expected EPA regulations, which were factored into the IRP analysis.

According to EPA, the Clean Air Act (CAA) was designed by Congress to protect public health and welfare from different types of air pollution. The CAA requires EPA to establish national ambient air quality standards for criteria pollutants based upon levels deemed necessary to protect public health, and in the case of "primary" standards, levels deemed necessary to not only protect public health in general but also the health of sensitive populations such as asthmatics, children, and the elderly. In addition, there are specific provisions to address hazardous or toxic air pollutants that pose health risks which are technology based. Congress requires EPA to issue "maximum achievable control technology" (MACT) emission standards which are reviewed every eight years. As part of the review, EPA is required to give consideration to whether more stringent, risk-based standards are required to protect public health with an ample margin of safety. Since EPA clean air standards, both national ambient air quality standards and public health-based risk standards for hazardous air pollutants, already take public health into account, there is no basis for trying to further account for health impacts from the preferred portfolio.

A stakeholder suggested that loss of jobs from closing the coal plants would be offset by new jobs in constructing solar. There is an immediate impact on jobs in construction; however, solar plant operations do not require as many workers as a coal plant, limiting the long term economic benefit to the community. A stakeholder asked if displaced workers will be given job assistance. Vectren has met with union leadership on this issue. While there are no guarantees, Vectren will work to minimize job losses. A stakeholder commented that companies (Vectren customers) located in our area have announced high renewable use goals by 2020. Vectren has had meetings with large customers on this topic and will continue to help find solutions to meet customer goals.

A stakeholder asked if additional capacity is needed. The scenarios in the IRP process considered varying load forecasts. Additionally, the rated capacity of different resources impact how much capacity is needed. Some resources retire due to age and some are projected to retire due to anticipated cost. This capacity must be replaced. A stakeholder asked about the production efficiency of coal vs gas. Combined cycle gas generation is more efficient than coal generation. Additionally, Natural gas CO_2 emissions are about 50% of coal; natural gas also has lower NO_X emissions. A stakeholder asked if EE was considered to offset projected capacity costs. The NPV calculation captures EE program costs/impact, and the analysis does consider avoided capacity.

A stakeholder asked if the gas plant in the preferred portfolio will go live in 2024. Yes. Referring to slide 51, a stakeholder asked why it is unacceptable to purchase more than 30 MW on the open market. Slide 51 is showing the average capacity shortfalls over the course of 20 years, based on 200 possible future states. The risk to market purchases is price volatility and capacity shortages. A stakeholder asked what the cost to customers would be for the 889 MW gas plant. Vectren will issue an RFP to finalize plant costs. The most recent tech assessment suggests that plant costs will be between $650 million and $710 million, not including gas line costs. A stakeholder asked about how Vectren will protect customers from costs associated with excess capacity that is used to sell power to the wholesale markets. The preferred portfolio includes very cost effective, highly efficient peaking capacity. Additionally, wholesale power market sales actually reduce customer rates. A stakeholder commented that in 20 years Vectren's current business model will no longer exist. Vectren considers its business model outside of the IRP process, which includes factoring customers' needs and desires.

Attachment 4.1 2016 Vectren Long-Term Electric Energy and Demand Forecast Report

Itron

Knowledge to Shape Your Future

Electric | Gas | Water

information collection, analysis and application

2016 Long-Term Electric Energy and Demand Forecast Report

Vectren Energy Delivery of Indiana - South

Submitted to:

Vectren Corporation
Evansville, Indiana

Submitted by:

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Itron

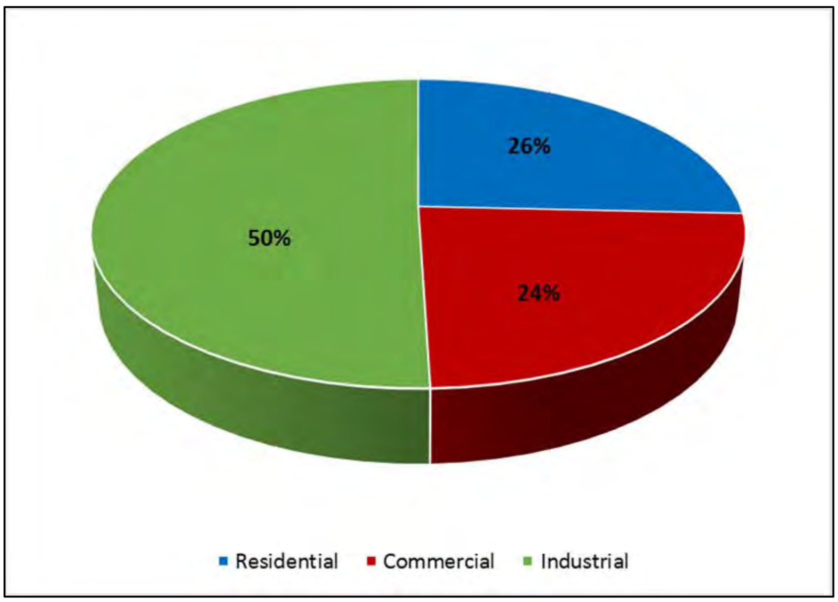
August 4, 2016

Contents

1 Overview

Vectren Energy Delivery of Indiana - South (VEDS) serves approximately 144,000 electric customers in Southwest Indiana. The service area includes a large industrial base with industrial customers accounting for approximately 50% of sales in 2015. The residential class accounted for 26% of sales and the commercial class 24% of sales. Total system 2015 energy requirements (including losses) were 5,737 GWh (a 2.3% decline from 2014) with system peak reaching 1,089 MW. Figure 1 shows 2015 class-level sales distribution.

Figure 1: 2015 Annual Sales Breakdown



Customer growth has been tracking regional population growth. Population and residential customer growth has averaged 0.4% over the last ten years. There were approximately 125,400 residential customers at the end of 2015. We expect to see just slightly slower growth over the next ten years with population and customer growth averaging 0.3% per year; this translates into approximately 350 new residential customers per year. Commercial customers have been flat over this period of time. At the end of 2015 there were 18,490 commercial accounts. We expect to see some commercial customer growth over the next ten years with increase in employment and residential customer growth. Commercial customer growth is expected to average 0.2% per year or approximately 50 new commercial customers per year.

New appliance efficiency standards coupled with DSM program activity has held sales growth in check particularly in the residential sector. While residential customer growth has averaged 0.4% annual growth over the last ten years, weather normalized average use has declined on average 1.3% per year. This translates into 0.9% annual decline in residential sales. Weather normalized commercial sales growth has averaged 0.2% per year. The industrial sector has shown the strongest growth with industrial sales averaging 1.2% average annual growth. When combined, total system energy has been flat with energy requirements averaging 0.1% annual growth over the last ten years.

We expect to see a sharp drop in 2017 sales from a large industrial customer; this customer is installing a cogeneration system that is expected to meet most of their electricity requirements. With this load loss, system energy requirements are not expected to reach 2016 levels over the twenty-year forecast and demand doesn't reach the expected 2016 peak-demand level until 2029.

For the IRP filing, the long-term energy and demand forecast does not include energy savings from future DSM programs; DSM activity is now considered a supply option and not a reduction to demand. Excluding DSM, total energy requirements and peak demand (after 2017) are expected to average 0.5% over the next twenty years. Expected savings from future DSM programs drive long-term sales growth to zero. Table 1-1 shows VEDS energy and demand forecast; the forecast includes the impact of customer owner distributed generation but excludes future DSM program savings.

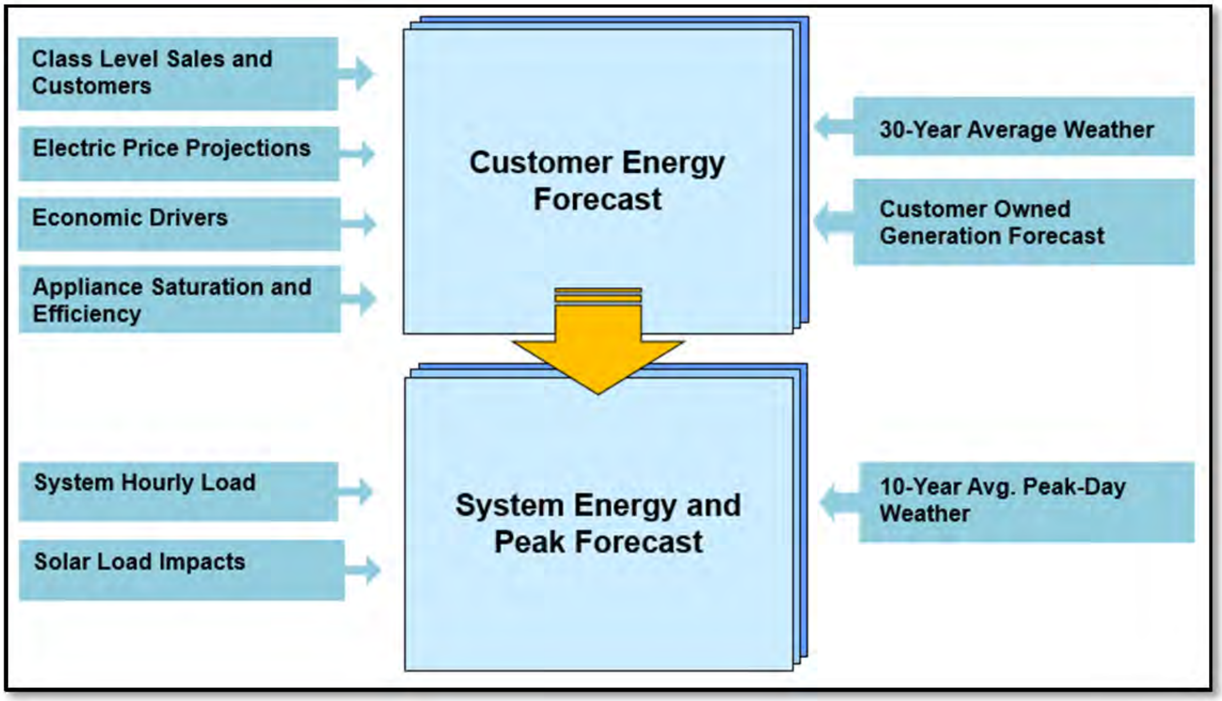
Table 1-1: Energy and Demand Forecast (Excluding DSM Program Savings)

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2016	5,913,198		1,164		896	
2017	5,309,089	-10.2%	1,094	-6.0%	825	-7.9%
2018	5,368,438	1.1%	1,104	0.9%	836	1.2%
2019	5,397,983	0.6%	1,109	0.5%	841	0.6%
2020	5,449,432	1.0%	1,117	0.7%	851	1.2%
2021	5,451,608	0.0%	1,118	0.0%	852	0.1%
2022	5,472,381	0.4%	1,122	0.4%	855	0.4%
2023	5,497,316	0.5%	1,126	0.4%	858	0.4%
2024	5,529,346	0.6%	1,132	0.5%	863	0.6%
2025	5,549,264	0.4%	1,136	0.4%	866	0.3%
2026	5,573,239	0.4%	1,141	0.4%	869	0.4%
2027	5,600,616	0.5%	1,147	0.5%	873	0.5%
2028	5,637,119	0.7%	1,154	0.6%	878	0.6%
2029	5,662,724	0.5%	1,159	0.5%	882	0.4%
2030	5,687,266	0.4%	1,165	0.5%	885	0.4%
2031	5,711,753	0.4%	1,170	0.5%	888	0.4%
2032	5,744,206	0.6%	1,177	0.6%	893	0.5%
2033	5,766,607	0.4%	1,183	0.4%	896	0.3%
2034	5,796,861	0.5%	1,189	0.5%	900	0.5%
2035	5,814,295	0.3%	1,193	0.3%	902	0.2%
2036	5,837,850	0.4%	1,198	0.4%	905	0.4%
CAGR 17-36		0.5%		0.5%		0.5%

2 Forecast Approach

The long-term energy and demand forecast is developed from the customer class total and end-use sales forecast. Customer class (residential, commercial, industrial, and street lighting) sales forecast are based on monthly sales forecast models that relate customer usage to weather conditions, economic activity, price, and end-use ownership and efficiency trends. The relationship is estimated using linear regression models. Energy requirements are then derived 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) derived from the class sales forecasts. Figure 2 shows the general framework and model inputs.

Figure 2: Class Build-up Model



In the long-term, both economic growth and structural changes drive energy and demand requirements. Structural changes include the impact of changing appliance owner-ship 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 a SAE specification. Industrial sales are forecast using a generalized econometric model that relates industrial sales to seasonal patterns and industrial economic activity. Street light sales are forecasted using a simple trend and seasonal model.

2.1 Residential Model

Residential average use and customers are modeled separately. The residential sales forecast is then generated as the product of the average use and customer forecasts.

Average Use. The residential average use model relates customer average monthly use to a customer's heating requirements (XHeat), cooling requirements (XCool), and other use (XOther):

$$ResAvgUse_m = (B_1 \times XHeat_m) + (B_2 \times XCool_m) + (B_3 \times XOther_m) + e_m$$

The model coefficients (B_1, B_2, and B_3) are estimated using a linear regression model. Monthly average use data is derived from historical monthly billed sales and customer data from January 2005 to March 2016.

The model variables incorporate end-use saturation and efficiency projections, as well as changes in household size, household income, price, and weather. The result is an initial estimated of monthly heating, cooling, and other use energy requirements on a kWh per household basis. Figure 3 to Figure 5 show the constructed monthly end-use variables. The specific calculations of the end-use variables are presented in Appendix B.

Figure 3: Residential XHeat

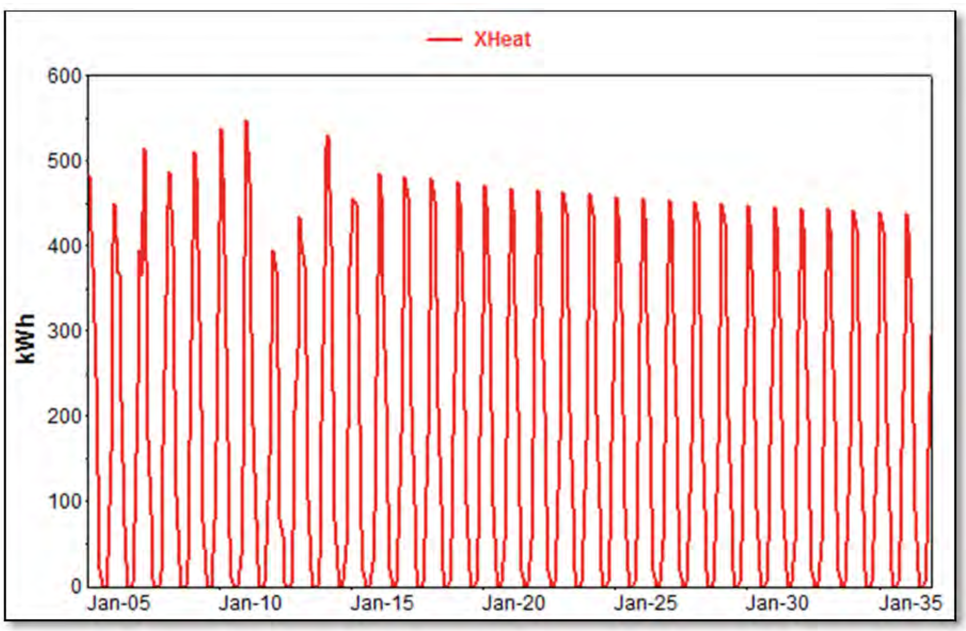


Figure 4: Residential XCool

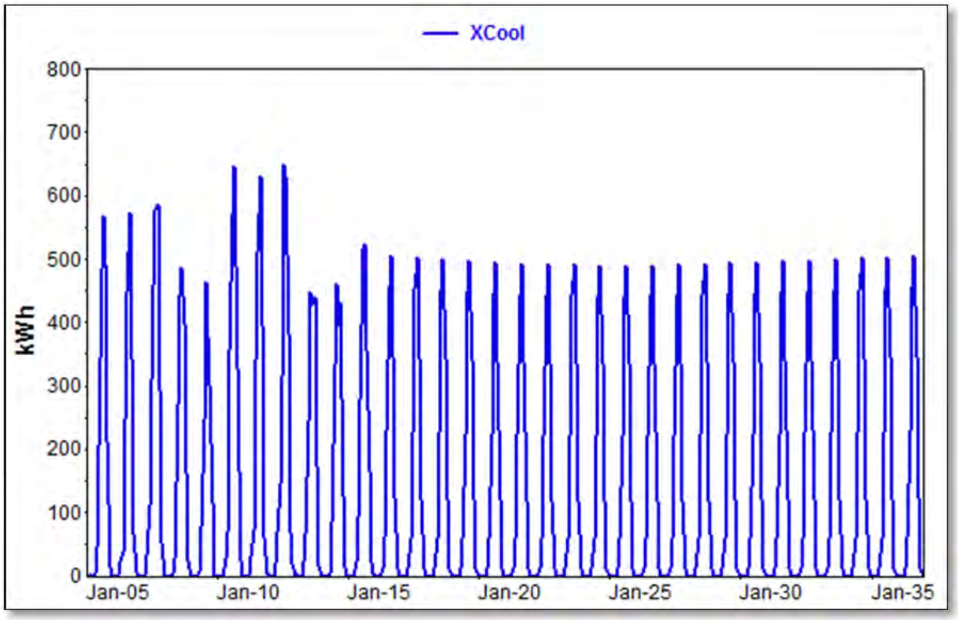
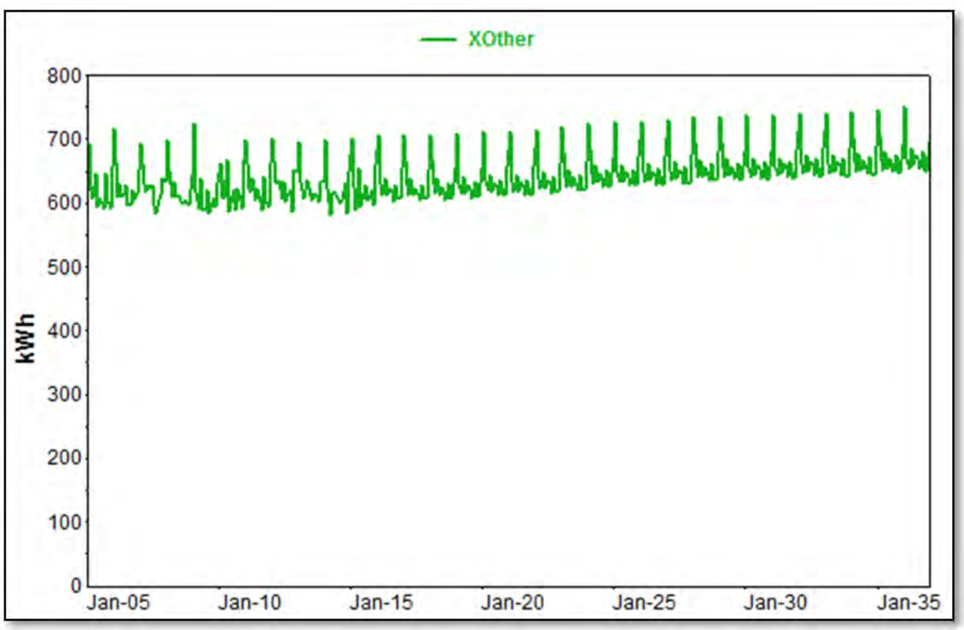


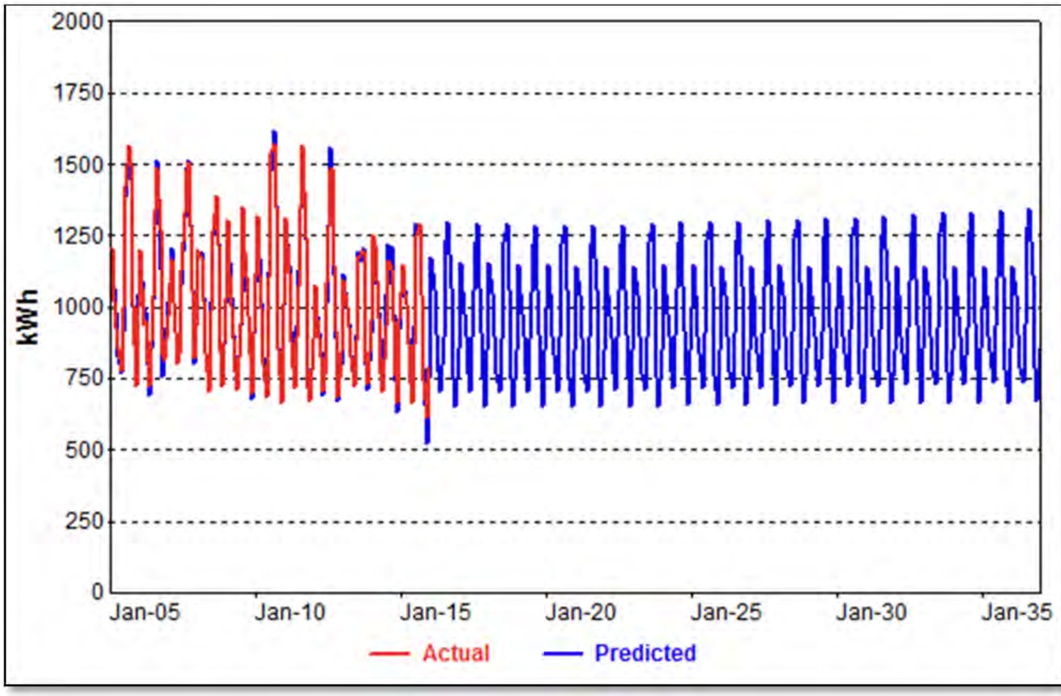
Figure 5: Residential XOther



The historical variation in XOther reflects differences in the number of days in the month as a result of the meter read schedule.

The average use model is estimated over the period January 2005 through December 2015 The model explains historical average use well with an Adjusted R^2 of 0.98 and in-sample Mean Absolute Percent Error (MAPE) of 2.7%. Model coefficients are statistically significant at the 95% level of confidence and higher. Model coefficients and statistics are provided in Appendix A. Figure 6 shows actual and predicted average use.

Figure 6: Actual and Predicted Residential Average Use



Given expected impact of new appliance standards and little growth in end-use saturation, there is little increase in average use. Average use increases just 0.1% annually over the forecast period.

Customer Forecast

The customer forecast is based on a monthly regression model that relates the number of customers to Evansville MSA (Metropolitan Statistical Area) population projections. There is a strong correlation between the number of customers and population with customer growth tracking population projections. The correlation coefficient between customers and population is 0.95.

With 0.1% increase in average use and 0.2% increase in customer growth residential sales averages 0.3% growth between 2016 and 2036. Table 2-1 summarizes the residential forecast.

Table 2-1: Residential Forecast (Excluding Future DSM)

Year	Sales (MWh)		Customers		AvgUse (kWh)	
2016	1,440,047		125,492		11,475	
2017	1,434,710	-0.4%	125,728	0.2%	11,411	-0.6%
2018	1,436,419	0.1%	126,067	0.3%	11,394	-0.1%
2019	1,438,630	0.2%	126,455	0.3%	11,377	-0.2%
2020	1,443,774	0.4%	126,870	0.3%	11,380	0.0%
2021	1,444,794	0.1%	127,254	0.3%	11,354	-0.2%
2022	1,451,508	0.5%	127,628	0.3%	11,373	0.2%
2023	1,458,672	0.5%	127,975	0.3%	11,398	0.2%
2024	1,469,169	0.7%	128,291	0.2%	11,452	0.5%
2025	1,473,649	0.3%	128,621	0.3%	11,457	0.0%
2026	1,477,227	0.2%	128,895	0.2%	11,461	0.0%
2027	1,482,163	0.3%	129,134	0.2%	11,478	0.1%
2028	1,490,722	0.6%	129,363	0.2%	11,524	0.4%
2029	1,494,384	0.2%	129,587	0.2%	11,532	0.1%
2030	1,498,058	0.2%	129,785	0.2%	11,543	0.1%
2031	1,501,118	0.2%	129,923	0.1%	11,554	0.1%
2032	1,507,658	0.4%	130,067	0.1%	11,591	0.3%
2033	1,510,294	0.2%	130,253	0.1%	11,595	0.0%
2034	1,516,343	0.4%	130,460	0.2%	11,623	0.2%
2035	1,522,640	0.4%	130,643	0.1%	11,655	0.3%
2036	1,531,162	0.6%	130,796	0.1%	11,707	0.4%
CAGR 17-36		0.3%		0.2%		0.1%

2.2 Commercial Model

The commercial sale model is also estimated using an SAE model structure. The difference is that in the commercial sector sales forecast is based on a total sales model rather than an average use and customer model. Commercial sales are expressed as a function of heating requirements, cooling requirements, and other commercial use:

$$ComSales_m = (B_1 \times XHeat_m) + (B_2 \times XCool_m) + (B_3 \times XOther_m) + e_m$$

The constructed model variables include Heating Degree Days (HDD), Cooling Degree Days (CDD), billing days, commercial economic activity variable, price, and end-use intensity trends. Figure 7 to Figure 9 show the constructed model variables. The specific variable construction is provided in Appendix B.

Figure 7: Commercial XHeat

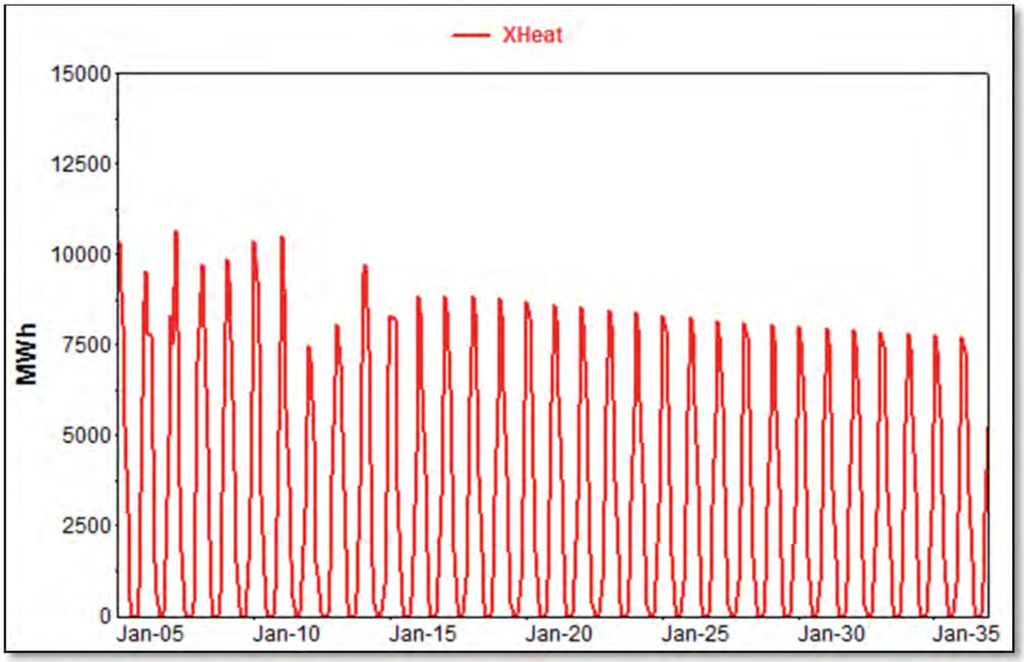


Figure 8: Commercial XCool

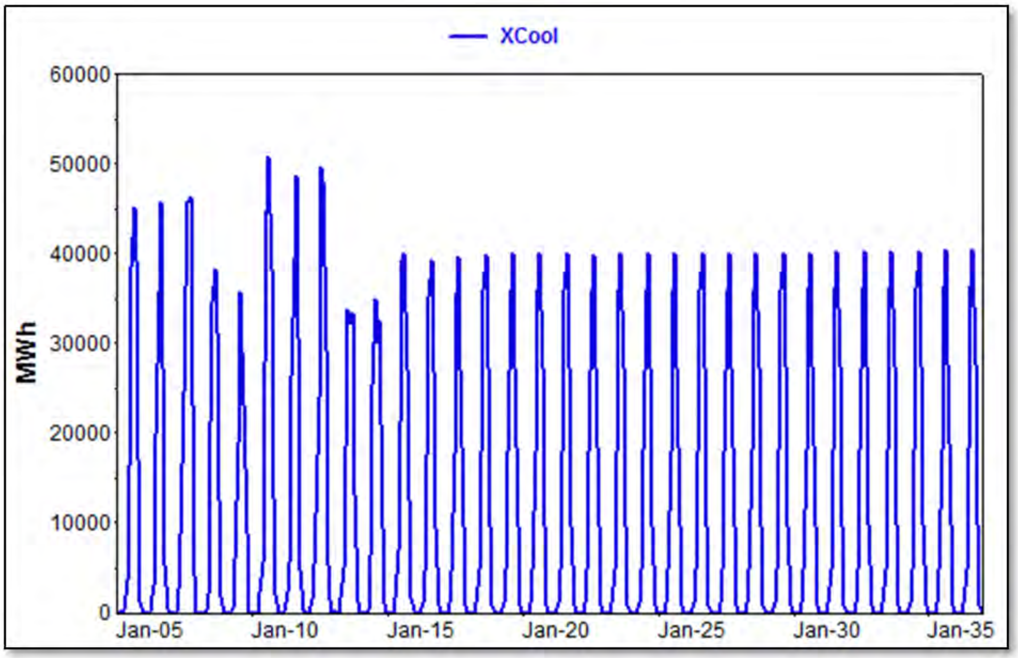
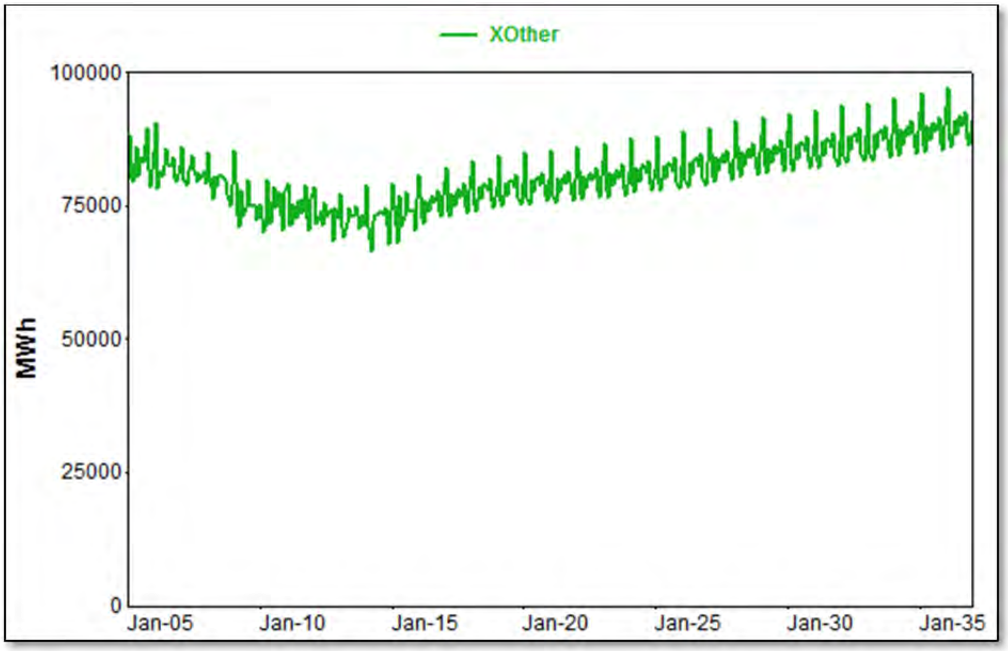


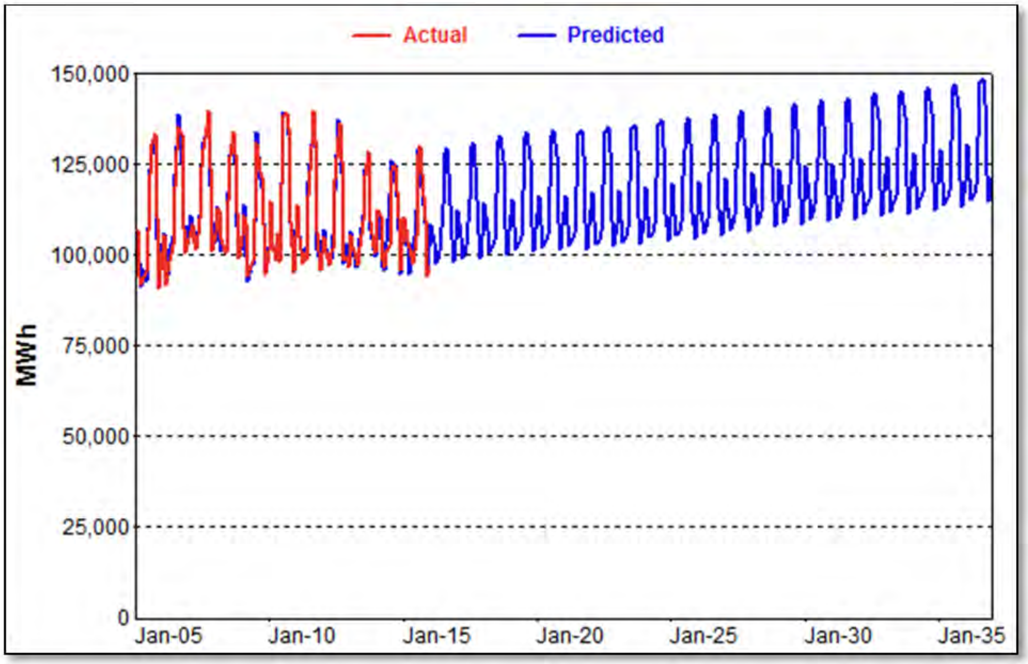
Figure 9: Commercial XOther



The estimated model coefficients (B_1, B_2, and B_3) calibrate the three model variables to actual commercial billed sales data. The model is estimated with monthly billed sales data from January 2015 to December 2015.

The resulting commercial sales model performs well with an Adjusted R^2 of 0.96 and an in-sample MAPE of 1.9%. Figure 10 shows actual and predicted monthly commercial sales.

Figure 10: Actual and Predicted Commercial Sales (Excluding Future DSM)



Commercial sales growth averages 0.7% per year through 2037, before adjustments for DSM. Commercial sales growth is largely driven by relatively strong non-manufacturing GDP projections. To capture the impact of population, and employment as well as GDP, non-manufacturing output, non-manufacturing employment, and population are combined through a weighted commercial economic variable called *ComVar*. *ComVar* is defined as:

$$ComVar_m = (Output_m^{0.25}) \times (Employment_m^{0.25}) \times (Population_m^{0.5})$$

The weights were determined by evaluating the in-sample and out-of-sample model statistics for different sets of output, employment, and population weights.

A separate model is estimated for commercial customers; customer projections are based on a monthly regression model that relates the number of customers to non-manufacturing employment in the Evansville MSA. Table 2-2 summarizes the commercial forecast.

Table 2-2: Commercial Forecast

Year	Sales (MWh)		Customers	
2016	1,312,909		18,522	
2017	1,333,082	1.5%	18,580	0.3%
2018	1,350,564	1.3%	18,635	0.3%
2019	1,361,378	0.8%	18,684	0.3%
2020	1,369,333	0.6%	18,726	0.2%
2021	1,372,122	0.2%	18,767	0.2%
2022	1,379,443	0.5%	18,810	0.2%
2023	1,388,147	0.6%	18,853	0.2%
2024	1,401,077	0.9%	18,897	0.2%
2025	1,407,730	0.5%	18,941	0.2%
2026	1,418,460	0.8%	18,986	0.2%
2027	1,429,816	0.8%	19,032	0.2%
2028	1,445,842	1.1%	19,078	0.2%
2029	1,455,609	0.7%	19,126	0.2%
2030	1,464,923	0.6%	19,174	0.3%
2031	1,474,443	0.6%	19,224	0.3%
2032	1,488,087	0.9%	19,274	0.3%
2033	1,495,276	0.5%	19,326	0.3%
2034	1,506,388	0.7%	19,379	0.3%
2035	1,517,965	0.8%	19,434	0.3%
2036	1,533,463	1.0%	19,489	0.3%
CAGR 17-36		0.7%		0.3%

2.3 Industrial Model

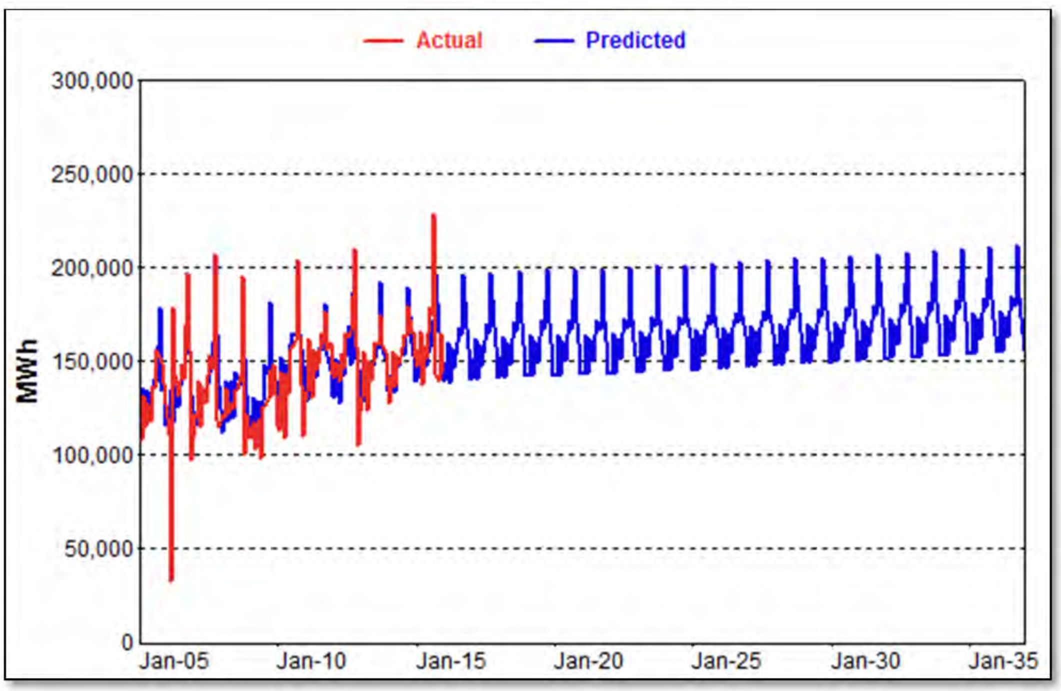
The industrial sales forecast is a two-step approach. The first five years of the forecast is based on VEDS's internal forecast. Industrial sales are forecasted using a historical baseline of 12 months ended December 2015. Vectren reviews baseline volumes at the customer level and is adjusted based on known customer activity such as closures and expansions. New customers are specifically identified and forecasted based on expected load. An overall growth rate of approximately 1% is then applied to the baseline period to capture growth that has not been specifically identified by customer. The forecast after that is based on a model-based forecasted growth rate; the forecasted growth rate is applied to the fifth year industrial sales forecast.

The industrial sales model is based on a generalized linear regression model that relates monthly historical industrial billed to manufacturing employment, manufacturing output, CDD, and monthly binaries to capture seasonal load variation and shifts in sales data. The economic driver is a weighted combination of manufacturing employment and manufacturing output. The industrial economic (*IndVar*) variable is defined as:

$$IndVar_m = (ManufEmploy_m^{0.5}) \times (ManufOutput_m^{0.5})$$

The imposed weights are determined by evaluating in-sample and out-of-sample statistics for alternative weighting schemes. The final model's Adjusted R^2 is 0.74 with in-sample MAPE of 5.3%. The relatively low Adjusted R^2 and high MAPE are due to the "noisy" nature of industrial monthly billing data. Actual and predicted monthly industrial sales are depicted in Figure 11.

Figure 11: Actual and Predicted Industrial Sales



The industrial model excludes a large customer that is installing cogeneration. The expected portion of load that Vectren will continue to serve was added back in. Table 2-3 summarizes the industrial sales forecast excluding the impact of DSM programs.

Table 2-3: Industrial Forecast[1] (Excluding Future DSM)

Year	Total Industrial	
2016	2,835,569	
2017	2,217,959	-21.8%
2018	2,262,272	2.0%
2019	2,283,667	0.9%
2020	2,329,890	2.0%
2021	2,336,776	0.3%
2022	2,345,264	0.4%
2023	2,354,201	0.4%
2024	2,362,591	0.4%
2025	2,371,200	0.4%
2026	2,380,813	0.4%
2027	2,391,632	0.5%
2028	2,403,106	0.5%
2029	2,414,742	0.5%
2030	2,426,242	0.5%
2031	2,438,074	0.5%
2032	2,450,165	0.5%
2033	2,462,405	0.5%
2034	2,475,157	0.5%
2035	2,475,157	0.0%
2036	2,475,157	0.0%
CAGR 17-36		0.6%

Load addition from specific customers contributes to relatively strong sales growth in the near-term. After 2020, industrial sales before DSM adjustments average 0.4% annual growth.

2.4 Street Lighting Model

Street light sales are fitted with a simple exponential smoothing model with a trend and seasonal component. Street lighting sales have been declining and are expected to continue to decline through the forecast period as increasing lamp efficiency outpaces installation of new street lights. shows the street light forecast.

[1] Large drop in 2017 due to one customer installing cogeneration

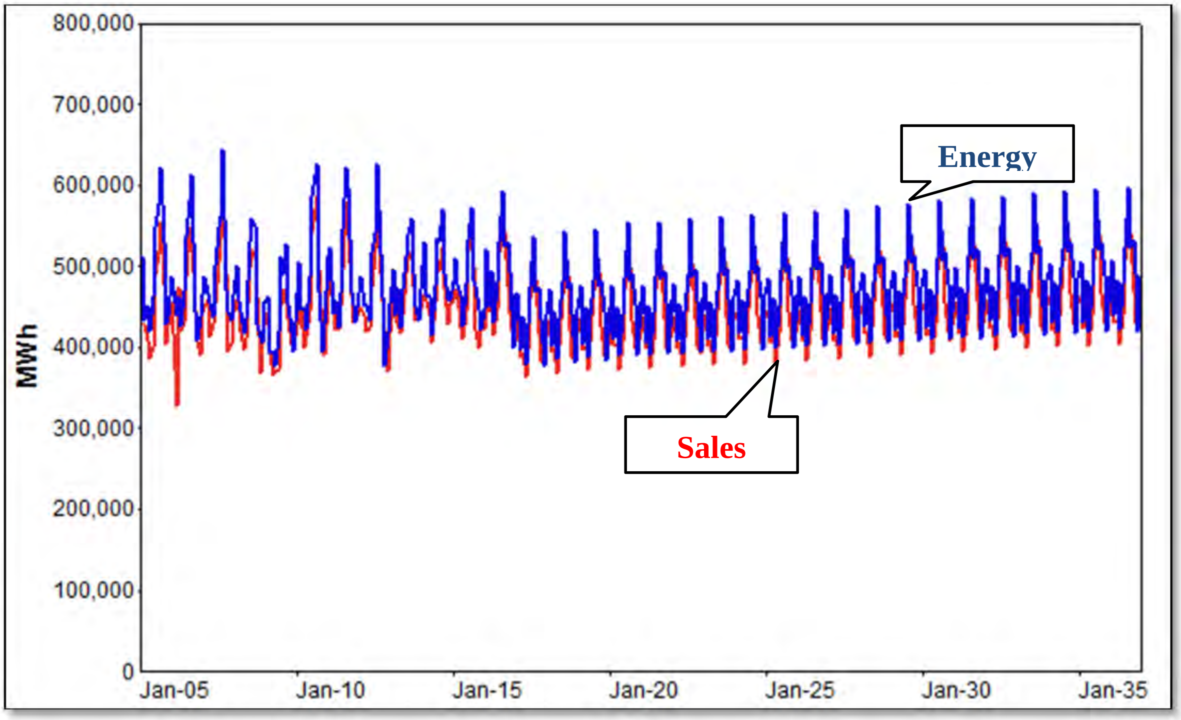
Table 2-4: Street Lighting Forecast

Year	Sales (MWh)	
2016	21,227	
2017	21,143	-0.4%
2018	21,059	-0.4%
2019	20,975	-0.4%
2020	20,891	-0.4%
2021	20,807	-0.4%
2022	20,723	-0.4%
2023	20,640	-0.4%
2024	20,556	-0.4%
2025	20,472	-0.4%
2026	20,388	-0.4%
2027	20,304	-0.4%
2028	20,220	-0.4%
2029	20,136	-0.4%
2030	20,052	-0.4%
2031	19,968	-0.4%
2032	19,885	-0.4%
2033	19,801	-0.4%
2034	19,717	-0.4%
2035	19,633	-0.4%
2036	19,549	-0.4%
CAGR 17-36		-0.4%

2.5 Energy Forecast Model

The VEDS energy forecast is derived directly from the sales forecast by applying a monthly energy adjustment factor to the monthly *calendar* sales forecast. The energy adjustment factor includes line losses and any differences in timing between monthly sales estimates and delivered energy (*unaccounted for energy*). Monthly adjustment factors are calculated as the average monthly ratio of energy to sales. Figure 12 shows the resulting monthly sales and energy forecast, excluding the impact of future energy efficiency programs. The energy forecast includes the impact of rooftop solar generation.

Figure 12: Energy and Sales Forecast (Excluding DSM)



2.6 Peak Forecast Model

The long-term system peak forecast is derived through a monthly peak regression model that relates peak demand to heating, cooling, and base load requirements:

$$Peak_m = B_0 + B_1 HeatVar_m + B_2 CoolVar_m + B_3 BaseVar_m + e_m$$

The model variables ($HeatVar_m$, $CoolVar_m$, and $BaseVar_m$) incorporate changes in heating, cooling, and base-use energy requirements derived from the class sales forecast models as well as peak-day weather conditions.

Heating and Cooling Model Variables

Heating and cooling requirements are driven by customer growth, economic activity, changes in end-use saturation, and improving end-use efficiency. The estimated SAE model coefficients allow us to isolate residential and commercial heating and cooling requirements for normal weather conditions. The impact of peak-day weather conditions is captured by interacting peak-day HDD and CDD with heating and cooling load requirements. The underlying theory is that the impact of peak-day weather conditions changes over time with changes in total system heating and cooling requirements. The peak model heating and cooling variables are calculated as:

- $HeatVar_m = HeatLoadIdx_m \times PkHDD_m$
- $CoolVar_m = CoolLoadIdx_m \times PkCDD_m$

Where $HeatLoadIdx_m$ is an index of total system heating requirements in month m and $CoolLoadIdx_m$ is an index of total system cooling requirements in month m. $PkHDD_m$ is the peak-day HDD in month m and $PkCDD_m$ is the peak-day CDD in month m.

Figure 13 and Figure 14 show *HeatVar* and *CoolVar*. The variation in the historical period is a result of variation in peak-day HDD and CDD.

Figure 13: Peak-Day Heating Variable

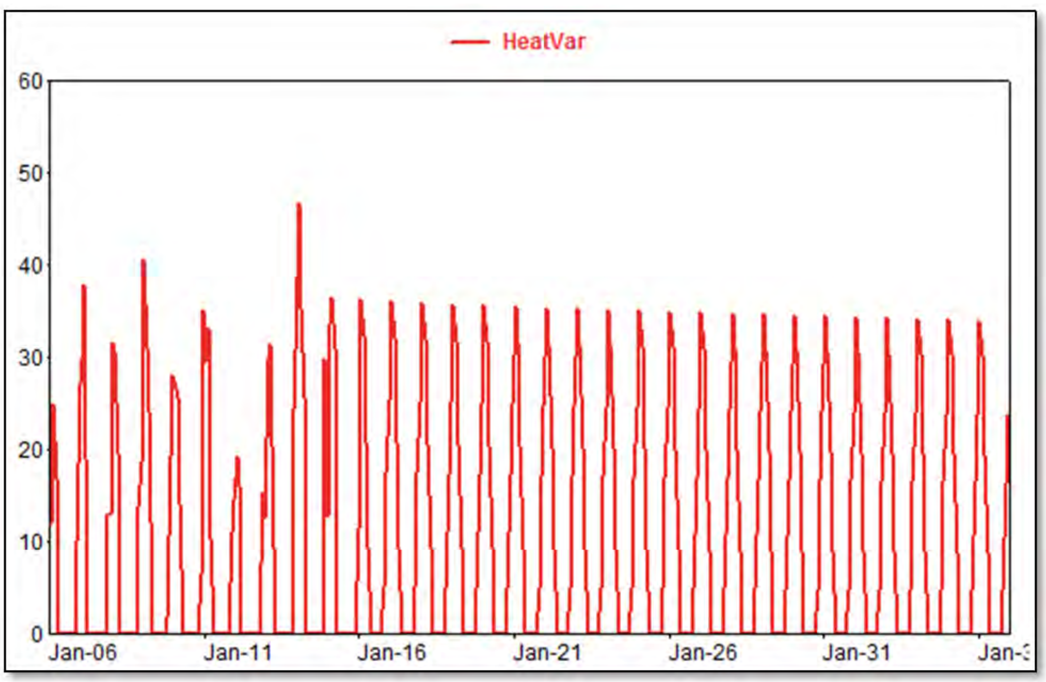
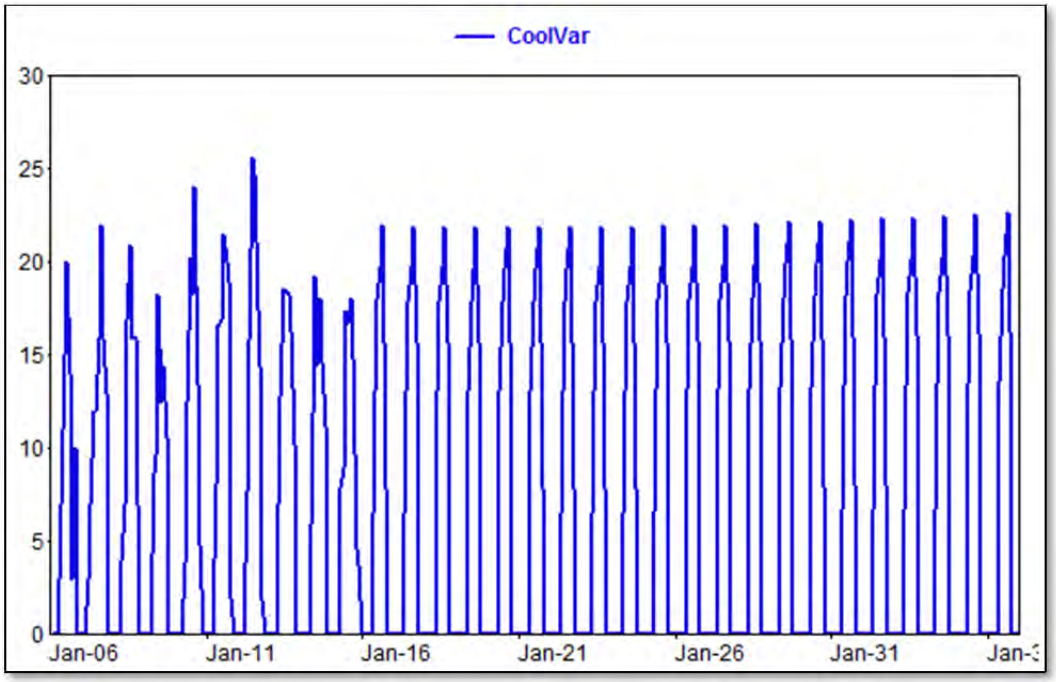


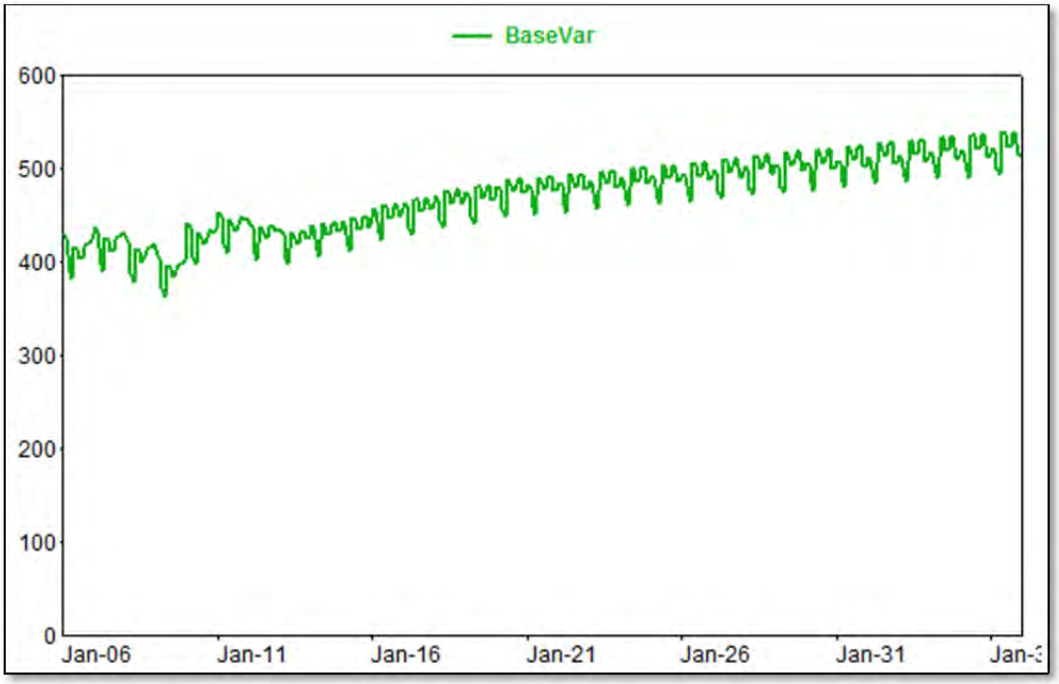
Figure 14: Peak-Day Cooling Variable



Base Load Variable

The base-load variable (*BaseVar*$_m$) captures non-weather sensitive load at the time of the monthly peak. Annual base-load energy requirements are derived by subtracting weather-normalized heating and cooling requirements from total sales. Monthly base-load estimates are calculated by allocating base-use energy requirements to end-use estimates at the time of peak. End-use allocation factors are based on a set of end-use profiles developed by Itron. Figure 15 shows the non-weather sensitive peak-model variable.

Figure 15: Peak-Day Base-Use Variable



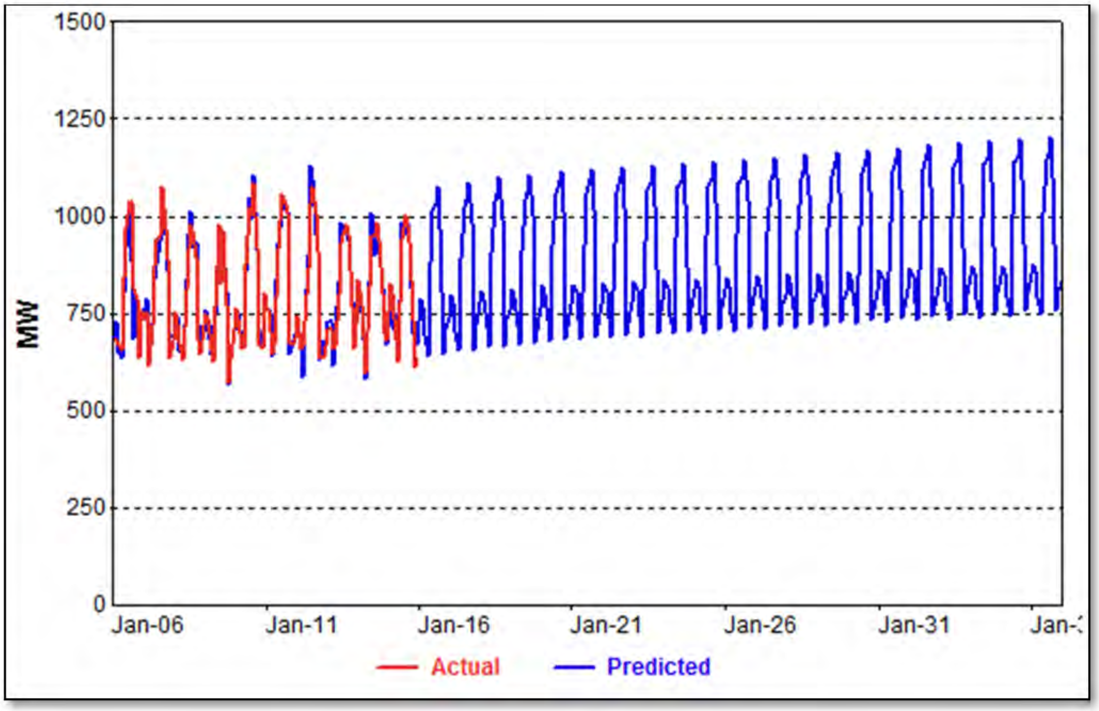
Model Results

The peak model is estimated over the period January 2006 to December 2015. The model explains monthly peak variation well with an adjusted R^2 of 0.94 and an in-sample MAPE of 3.14%. The end-use variables – *HeatVar*, *CoolVar*, and *BaseVar* are all highly significant.

Figure 16

~~Figure 16~~ shows actual and predicted results. Model statistics and parameters are included in Appendix A.

Figure 16: Actual and Predicted Peak Model (Excluding DSM)



The peak demand forecast is adjusted for solar load impacts but excludes DSM savings projections. Table 2-5 shows total energy and peak demand.

Table 2-5: Energy and Peak Forecast

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2016	5,913,198		1,164		896	
2017	5,309,089	-10.2%	1,094	-6.0%	825	-7.9%
2018	5,368,438	1.1%	1,104	0.9%	836	1.2%
2019	5,397,983	0.6%	1,109	0.5%	841	0.6%
2020	5,449,432	1.0%	1,117	0.7%	851	1.2%
2021	5,451,608	0.0%	1,118	0.0%	852	0.1%
2022	5,472,381	0.4%	1,122	0.4%	855	0.4%
2023	5,497,316	0.5%	1,126	0.4%	858	0.4%
2024	5,529,346	0.6%	1,132	0.5%	863	0.6%
2025	5,549,264	0.4%	1,136	0.4%	866	0.3%
2026	5,573,239	0.4%	1,141	0.4%	869	0.4%
2027	5,600,616	0.5%	1,147	0.5%	873	0.5%
2028	5,637,119	0.7%	1,154	0.6%	878	0.6%
2029	5,662,724	0.5%	1,159	0.5%	882	0.4%
2030	5,687,266	0.4%	1,165	0.5%	885	0.4%
2031	5,711,753	0.4%	1,170	0.5%	888	0.4%
2032	5,744,206	0.6%	1,177	0.6%	893	0.5%
2033	5,766,607	0.4%	1,183	0.4%	896	0.3%
2034	5,796,861	0.5%	1,189	0.5%	900	0.5%
2035	5,814,295	0.3%	1,193	0.3%	902	0.2%
2036	5,837,850	0.4%	1,198	0.4%	905	0.4%
CAGR 17-36		0.5%		0.5%		0.5%

3 Customer Owned Distributed Generation

The VEDS energy and peak forecast incorporates the impact of customer owned photovoltaic systems. Although relatively small when compared to other regions, there has been steady growth in the number of photovoltaic systems. System adoption is expected to increase as solar system costs declines. The recent extension of the Federal Investment Tax Credit (ITC) will also have a positive impact on solar adoption. As of December 2016 VEDS had 127 residential solar customers and 13 commercial solar customers, with an approximate installed capacity of 1.2 MW.

3.1 Market Share Model

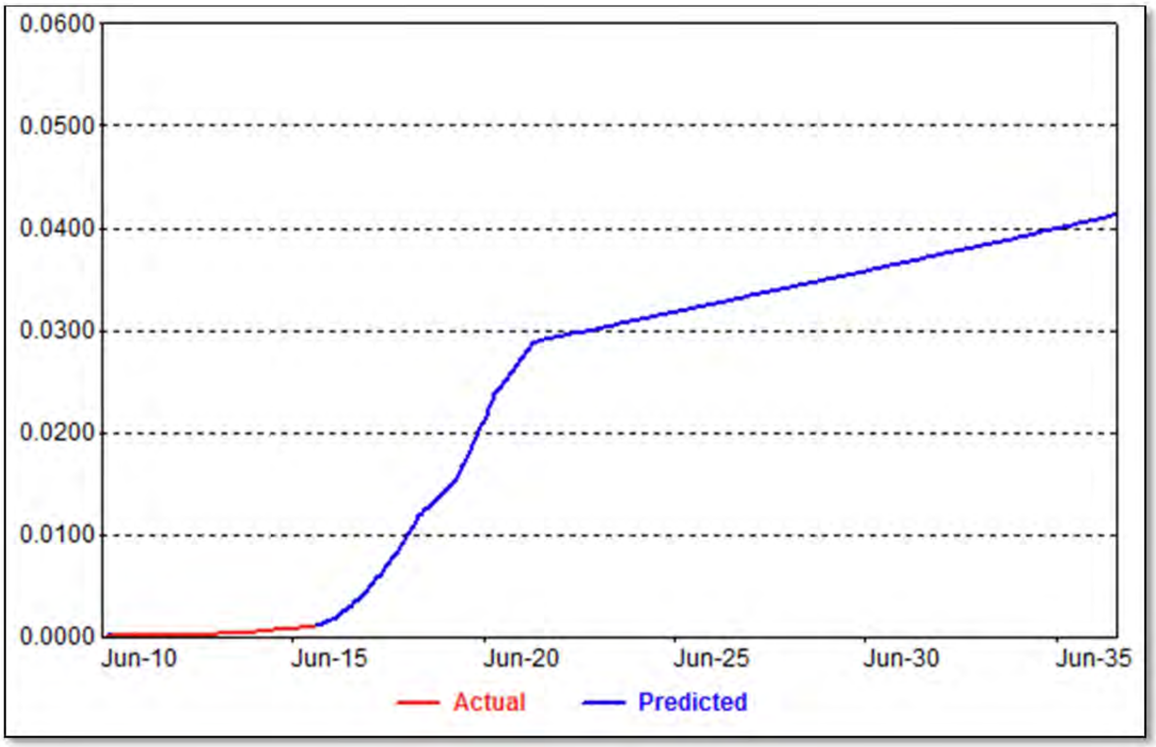
The primary factor driving system adoption is customer economics. Based on analysis of state-level system adoption, we have found a strong correlation between customer adoption and simple payback. Simple payback reflects the length of time needed to recover the cost of installing a solar system - the shorter the payback, the higher the system adoption rate. From the customer's perspective this is the number of years until electricity is "free". On an aggregate basis, simple payback also works well to explain leased system adoption; return on investment drives the leasing company's decision to offer leasing programs. Solar investment payback is calculated as a function of system costs, federal and state tax credits and incentive payments, retail electric rates, and treatment of excess generation (solar generation returned to the grid); for this forecast we assume excess generation is credited to the customer at retail energy rates.

One of the most significant factors driving adoption is declining system costs; costs have been declining rapidly over the last five years. In 2010, residential solar system cost was approximately $6.90 per watt. By 2015 costs have dropped to $3.84 per watt. For the forecast period we assume that system costs continue to decline 10% annually through 2021, at which point costs reach $2.00 per watt, in real terms, and are held constant. Cost projections are consistent with the U.S. Dept. of Energy's Sun Shot Solar goals and the Energy Information Administration (EIA), most recent cost projections.[2]

The solar adoption model relates residential solar saturation (expressed as the number of customers that have solar divided by total number of customers) to simple payback using a cubic specification; the cubic specification imposes an S-shaped adoption curve. Figure 17 shows the resulting residential solar market share forecast.

[2] "Photovoltaic System Pricing Trends". U.S Dept. of Energy, National Renewable Energy Laboratory. August 2015.

Figure 17: Residential Solar Share Forecast



Saturation slows after 2022 as system costs flatten out. Increasing real electric rates after this point continues to drive new adoptions.

In the commercial sector there have been too few adoptions to estimate a reasonable model; low commercial system adoption is true across the country. We believe limited commercial adoption reflects higher investment hurdle rates, building ownership issues (i.e., the person that owns the building often does not pay the electric bill), and physical constraints as to placement of the system. For this forecast we assume there continues to be some commercial rooftop adoption by allowing commercial adoption to increase over time based on the current relationship between commercial and residential adoptions rates.

As of December 2015 there were approximately 130 residential customer accounts, which equates to a 0.1% market share. With continued declining system costs and continued federal incentives the residential share increases to over 1.3 % within three years. As of December 2016 there were approximately 15 commercial customer accounts, which equates to a 0.07% market share. The commercial solar share continues to grow but due to the limiting factors only increases to 0.8% within three years. Table 3-1 shows projected solar saturation forecast and resulting number of solar customers.

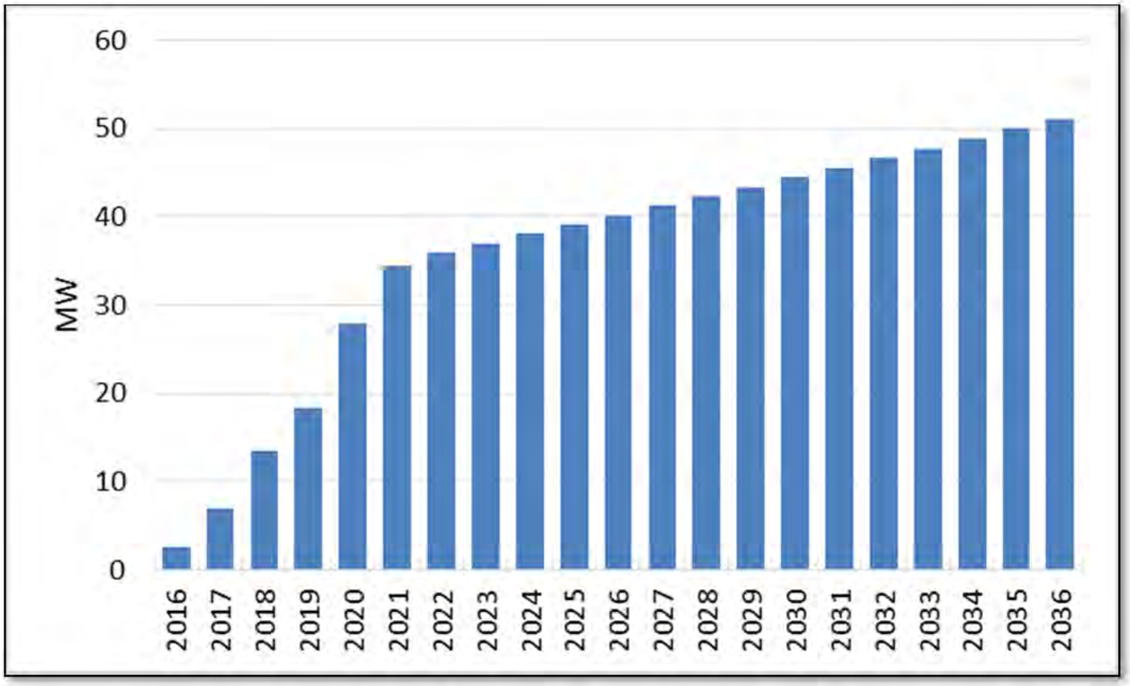
Table 3-1: Solar Customer Forecast

Year	Residential Saturation	Residential Systems	Commercial Saturation	Commercial Systems
2016	0.2%	253	0.1%	26
2017	0.5%	666	0.4%	68
2018	1.0%	1,314	0.7%	135
2019	1.5%	1,880	1.0%	192
2020	2.2%	2,769	1.5%	283
2021	2.8%	3,511	1.9%	359
2022	2.9%	3,761	2.0%	385
2023	3.0%	3,873	2.1%	396
2024	3.1%	3,984	2.2%	408
2025	3.2%	4,095	2.2%	419
2026	3.3%	4,208	2.3%	431
2027	3.3%	4,319	2.3%	442
2028	3.4%	4,431	2.4%	454
2029	3.5%	4,542	2.4%	465
2030	3.6%	4,656	2.5%	477
2031	3.7%	4,767	2.5%	488
2032	3.8%	4,878	2.6%	499
2033	3.8%	4,991	2.6%	511
2034	3.9%	5,110	2.7%	523
2035	4.0%	5,228	2.8%	535
2036	4.1%	5,345	2.8%	547
CAGR 17-36	11.4%	11.6%	11.3%	11.6%

3.2 Solar Capacity and Generation

Installed solar capacity forecast is the product of the solar customer forecast and average system size (measured in kW). Based on recent solar installation data, the residential average size is 7.8 KW, and commercial average system size is 16.9 KW. Figure 18 shows new installed solar capacity forecast beginning in January 2016.

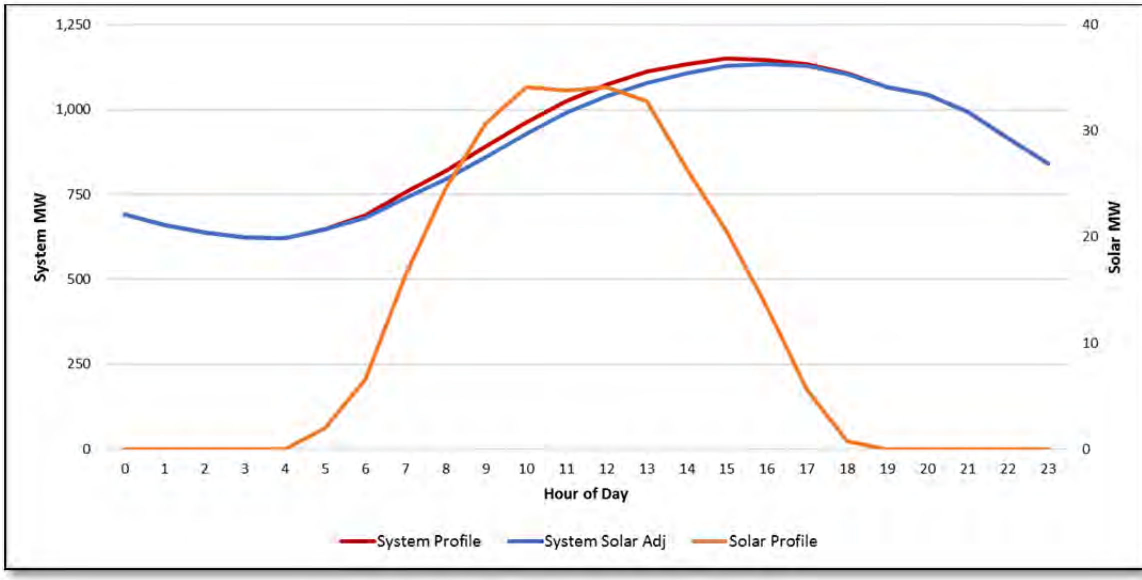
Figure 18: Solar Capacity Forecast



The capacity forecast (MW) is translated into system generation (MWh) forecast by applying monthly solar load factors to the capacity forecast. Monthly load factors are derived from a typical PV load profile for Evansville, IN. The PV shape is from the National Renewable Energy Laboratory (NREL) and represents a typical meteorological year (TMY).

The impact of solar generation on system peak demand is a function of the timing between solar load generation and system hourly demand. Even though solar capacity reaches 50 MW by 2035, solar load reduces system peak demand by only 16 MW. Given the system profile is relatively flat, solar generation effectively shifts the peak from 3:00 p.m. to 4:00 p.m. The peak demand savings is the difference between the 3:00 P.M. peak without solar generation and the 4:00 p.m. peak with solar generation. Figure 19 shows the gross system profile, solar adjusted system profile, and solar profile for a peak producing summer day.

Figure 19: Solar Hourly Load Impact



Based on system profile and solar load profile, a 1.0 MW of solar capacity reduces summer peak demand by approximately 0.32 MW. This adjustment factor is applied to the solar capacity forecast to yield the summer peak demand impact. Solar capacity has no impact on the winter peak demand as the winter peak is late in the evening when there is no solar generation.

Table 3-2 shows the PV capacity forecast, expected annual generation, and demand impacts given the PV solar load profile.

Table 3-2: Solar Capacity and Generation

Year	Total Generation MWh	Installed Capacity MW (Aug)	Demand Impact MW
2016	3,143	2.6	0.8
2017	8,341	6.9	2.2
2018	16,603	13.6	4.3
2019	23,681	18.3	5.8
2020	35,097	27.9	8.9
2021	44,497	34.5	11.0
2022	47,641	36.0	11.4
2023	49,054	37.0	11.8
2024	50,574	38.1	12.1
2025	51,874	39.2	12.5
2026	53,297	40.2	12.8
2027	54,712	41.3	13.1
2028	56,253	42.4	13.5
2029	57,532	43.4	13.8
2030	58,974	44.5	14.2
2031	60,390	45.6	14.5
2032	61,933	46.6	14.8
2033	63,216	47.7	15.2
2034	64,726	48.8	15.5
2035	66,223	50.0	15.9
2036	67,856	51.1	16.2
CAGR 17-36	11.7%	11.1%	11.1%

4 Forecast Assumptions

4.1 Weather Data

Actual and normal monthly HDD and CDD are key inputs in the monthly sales forecast models. Historical and normal monthly HDD and CDD are derived from daily temperature data for the Evansville airport. Normal degree-days are calculated over a 30-year period by averaging the historical monthly HDD and CDD for each month. Figure 20 and Figure 21 show historical and forecasted monthly HDD and CDD.

Figure 20: Heating Degree Days

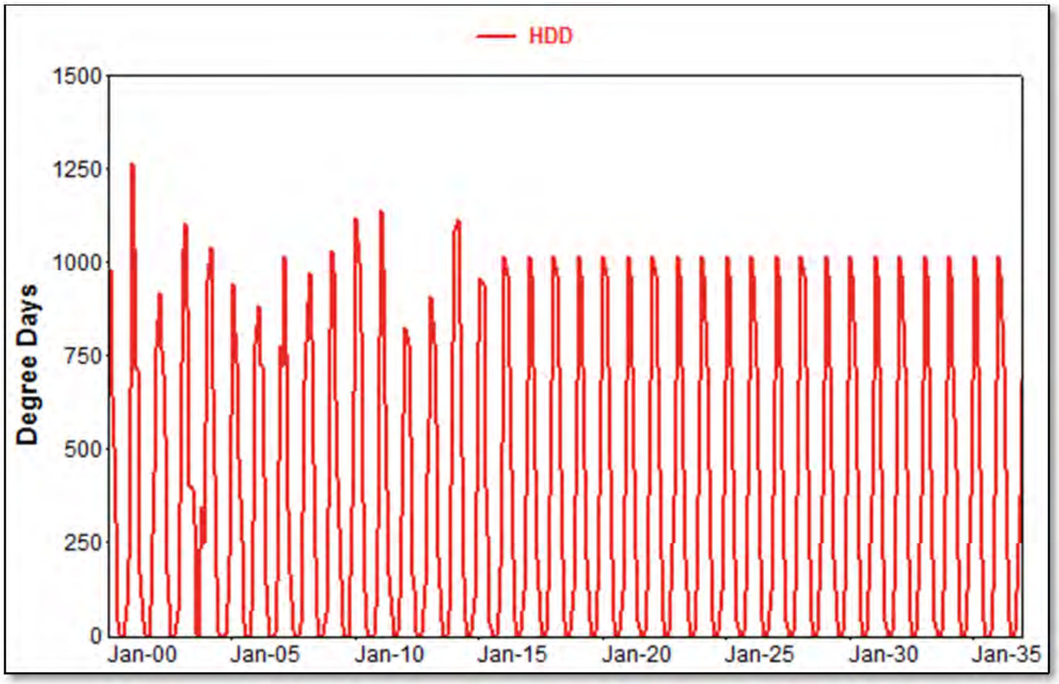
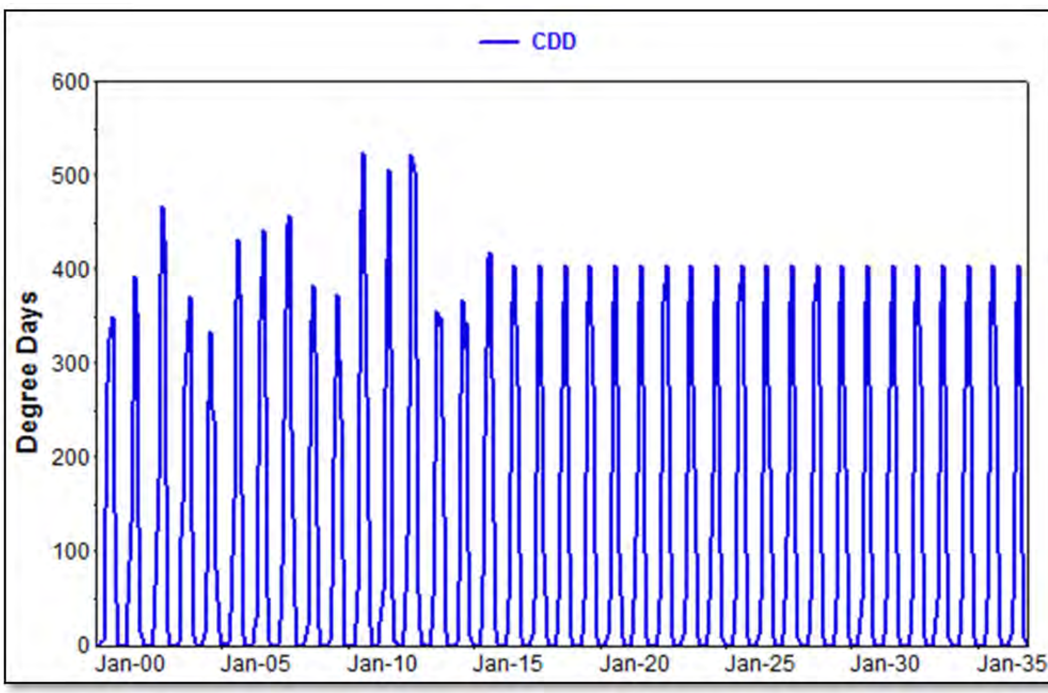


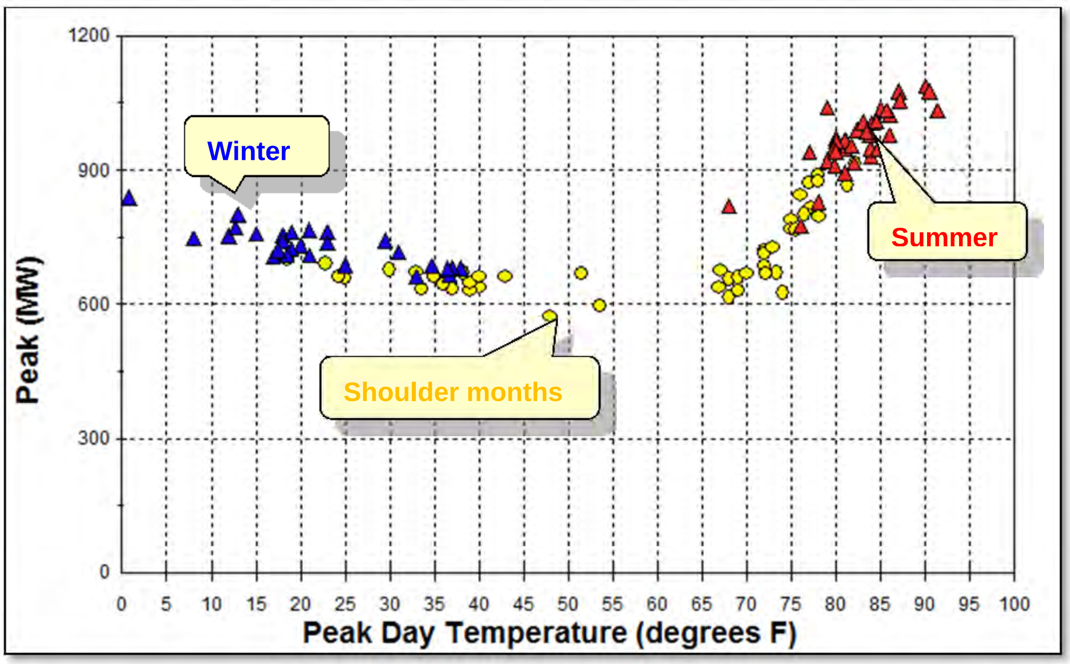
Figure 21: Cooling Degree Days



Peak-Day Weather Variables

Peak-day CDD and HDD are used in forecasting system peal demand. Peak-day HDD and CDD are derived by finding the daily HDD and CDD that occurred on the peak day in each month. The appropriate breakpoints for defining peak-day HDD and CDD are determined by evaluating the relationship between monthly peak and the peak-day average temperature as shown in Figure 22.

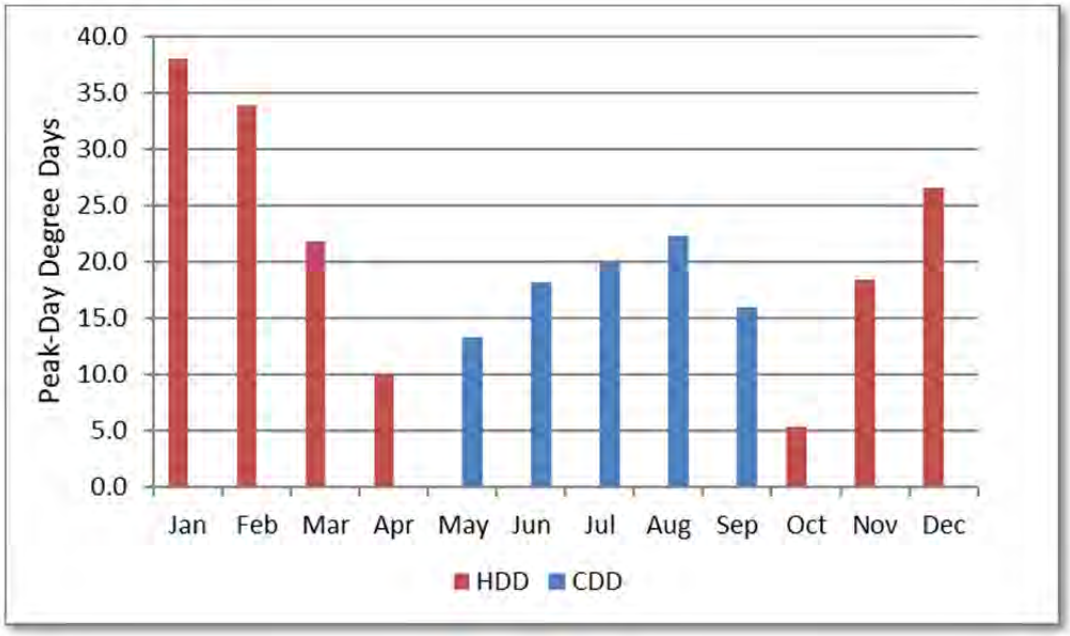
Figure 22: Monthly Peak Demand /Temperature Relationship



Peak-day cooling occurs when temperatures are above 65 degrees and peak-day heating occurs when temperatures are below 55 degrees.

Normal peak-day HDD and CDD are calculated using ten years of historical weather data. Normal peak-day HDD and CDD are based on the hottest and coldest days that occurred in each month over the historical time period. shows normal peak-day HDD (base 55 degrees) and peak-day CDD (base 65 degrees). Figure 23 shows the normal peak-day HDD and CDD values used in the forecast.

Figure 23: Normal Peak-Day HDD & CDD



4.2 Economic Data

Economic projections are key driver of the forecast. The class sales forecasts are based on *Moody's Economy.com* December 2016 economic forecast for the Evansville Metropolitan Statistical Area (MSA).

The primary economic drivers in the residential model are household income and the number of new households. Household formation is stable and increasing consistently though the forecast period with a CAGR of 0.4%, this is slightly stronger than population growth of 0.2%. Household income growth is forecasted to be stronger in the first 3 years of the forecast period, with a CAGR of over 2.5%, after which point growth declines to a long-term rate of 1.6%.

Commercial sales are driven by nonmanufacturing output, nonmanufacturing employment, and population. Moody's is forecasting strong near-term growth in non-manufacturing output, with a CAGR of 3.6% for the first three years of the forecast period, after which point growth declines to a long-term rate of 2.0%. Non-manufacturing employment fallows a similar path with strong near-term growth of 2.6% and long-term growth of 0.8%. Population is forecasted to increase at 0.2% annually through the forecast period.

Industrial sales are driven by manufacturing output, and manufacturing employment. Manufacturing output is not projected to grow as rapidly as non-manufacturing outpuy, with a long-term CAGR of 1.8%. Manufacturing employment is the only economic indicator which is declining, with a long-term CAGR of -0.4%.

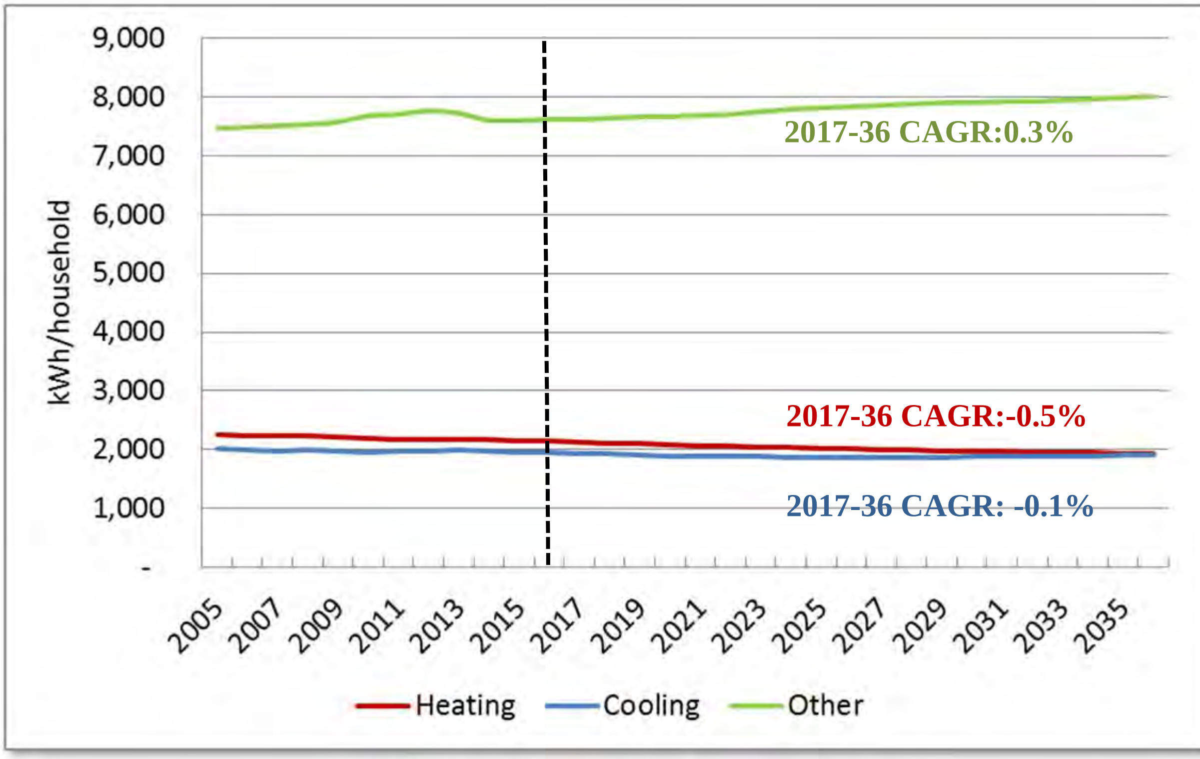
Historical electric prices (in real dollars) are derived from billed sales and revenue data. Historical prices are calculated as a 12-month moving average of the average rate (revenues divided by sales); prices are expressed in real dollars. Prices impact residential and commercial sales through imposed short-term price elasticities. Short-term price elasticities are small; residential and commercial price elasticities are set at -0.10. Price is not an input to the industrial sales model. Price projections are based on the Energy Information Administration's (EIA) long-term real growth rates for the East North Central Census Region. Over the next twenty years' residential prices average 0.9% annual growth, commercial prices average 0.7% annual growth.

4.3 Appliance Saturation and Efficiency Trends

Over the long-term, changes in end-use saturation and stock efficiency impact class sales, system energy, and peak demand. End-use energy intensities, expressed in kWh per household for the residential sector and kWh per square foot for the commercial sectors, are incorporated into the constructed forecast model variables. Energy intensities reflect both change in ownership (saturation) and average stock efficiency. As in general efficiency is improving faster than growth in end-use saturation, energy intensities are declining. Energy intensities are derived from Energy Information Administration's (EIA) 2015 Annual Energy Outlook and Vectren's appliance saturation surveys. The residential sector incorporates saturation and efficiency trends for seventeen end-uses. The commercial sector captures end-use intensity projections for ten end-use classifications across ten building types.

Residential end-use intensities are used in constructing residential XHeat, XCool, and XOther in the residential average use model. Figure 24 shows the resulting aggregated end-use intensity projections.

Figure 24: Residential End-Use Energy Intensities

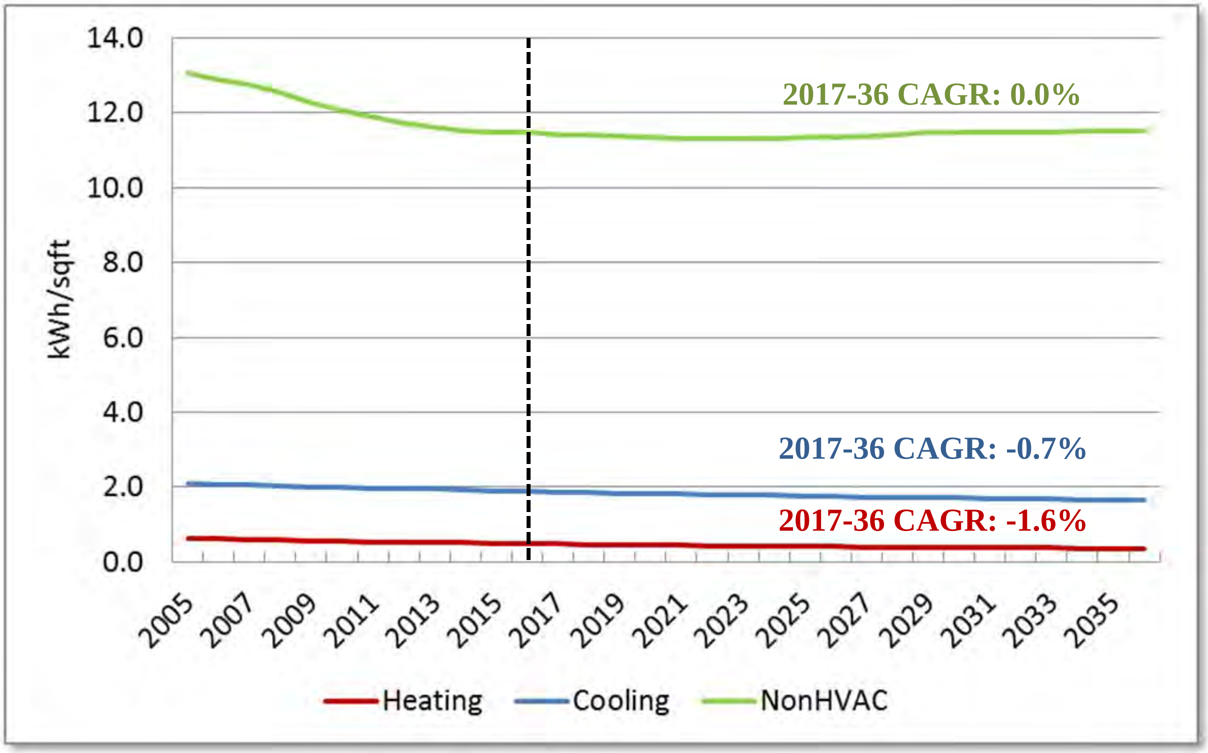


*CAGR=Compound Average Growth Rate

Heating intensity declines 0.5% annually through the forecast period reflecting declining share in electric heat saturation. Cooling intensity declines 0.1% annually through the forecast period as overall air conditioning efficiency improvements and change from less efficient room air conditioning to central air conditioning slightly outweighs overall increase in air conditioning saturation. Total non-weather sensitive end-use intensity increases 0.3% annually over the forecast period; this is primarily driven by miscellaneous use as intensities for most residential appliances are declining.

Commercial end-use intensities (expressed in kWh per sqft) are based on the EIA's East South Central census region forecast, calibrated to Vectren commercial sales. As in the residential sector, there have been significant improvements in end-use intensities as a result of new codes and standards. Figure 25 shows commercial end-use energy intensity forecasts for the aggregated end-use categories.

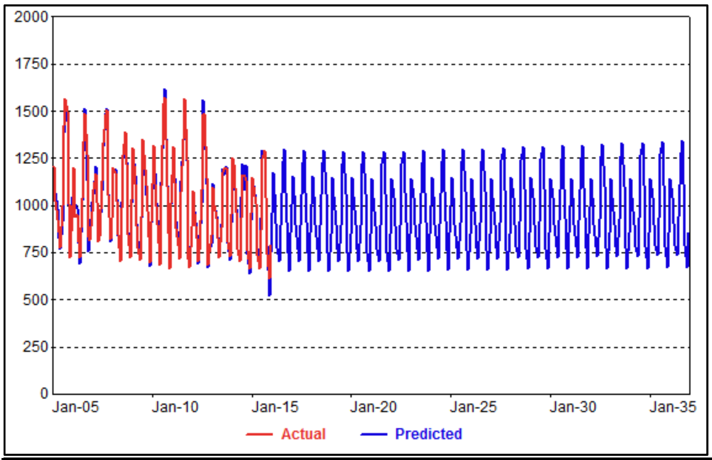
Figure 25: Commercial End-Use Energy Intensity



Commercial usage is dominated by non-weather sensitive (NonHVAC) end-uses, which over the forecast period are projected to be flat. Cooling intensity declines 0.7% annually through the forecast period. Heating intensity declines an even stronger 1.6% annual rate though commercial electric heating is relatively small.

5 Appendix A: Model Statistics

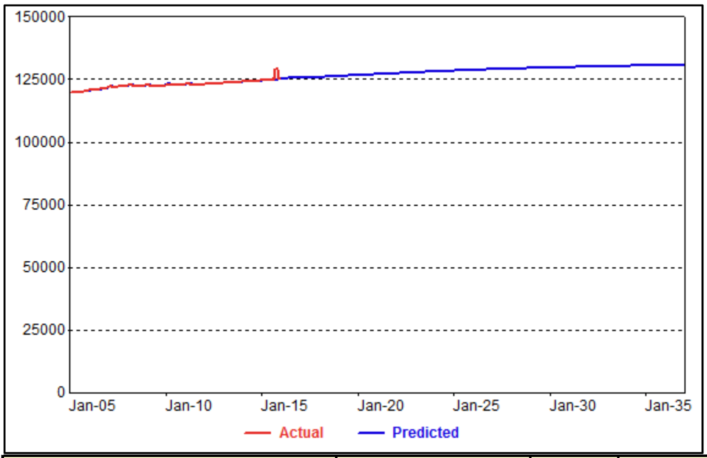
Residential Average Use Model



Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRev.XHeat	1.2	0.036	33.464	0.00%
mStructRev.XCool	1.615	0.027	59.458	0.00%
mStructRev.XOther	0.925	0.021	43.273	0.00%
mBin.Apr	-21.163	9.371	-2.258	2.57%
mBin.Nov	-67.314	10.908	-6.171	0.00%
mBin.Dec	-69.182	10.488	-6.596	0.00%
mBin.Yr12Plus	-75.293	13.33	-5.648	0.00%
AR(1)	0.555	0.079	7.029	0.00%

Model Statistics	
Iterations	15
Adjusted Observations	128
Deg. of Freedom for Error	120
R-Squared	0.981
Adjusted R-Squared	0.979
Model Sum of Squares	7,442,700.94
Sum of Squared Errors	147,211.33
Mean Squared Error	1,226.76
Std. Error of Regression	35.03
Mean Abs. Dev. (MAD)	26.76
Mean Abs. % Err. (MAPE)	2.66%
Durbin-Watson Statistic	1.918

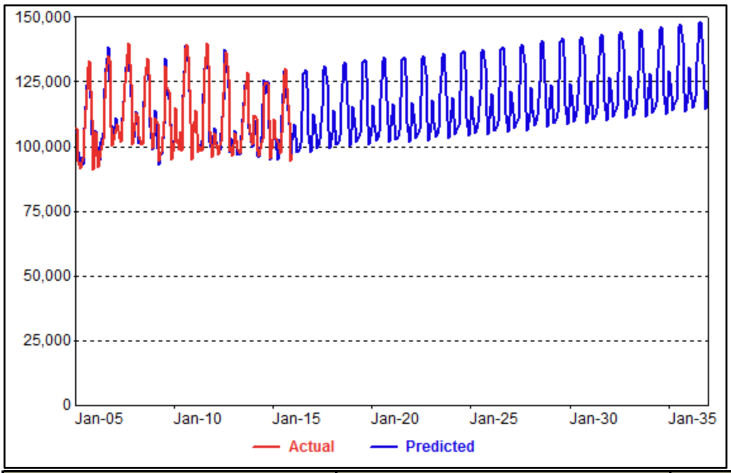
Residential Customer Model



Variable	Coefficient	StdErr	T-Stat	P-Value
Economics.PopEV	395.164	0.717	551.056	0.00%
AR(1)	0.933	0.034	27.417	0.00%
MA(1)	0.359	0.085	4.215	0.01%

Model Statistics	
Iterations	11
Adjusted Observations	129
Deg. of Freedom for Error	126
R-Squared	0.991
Adjusted R-Squared	0.99
Model Sum of Squares	219,755,683.75
Sum of Squared Errors	2,083,892.30
Mean Squared Error	16,538.83
Std. Error of Regression	128.6
Mean Abs. Dev. (MAD)	99.67
Mean Abs. % Err. (MAPE)	0.08%
Durbin-Watson Statistic	1.878

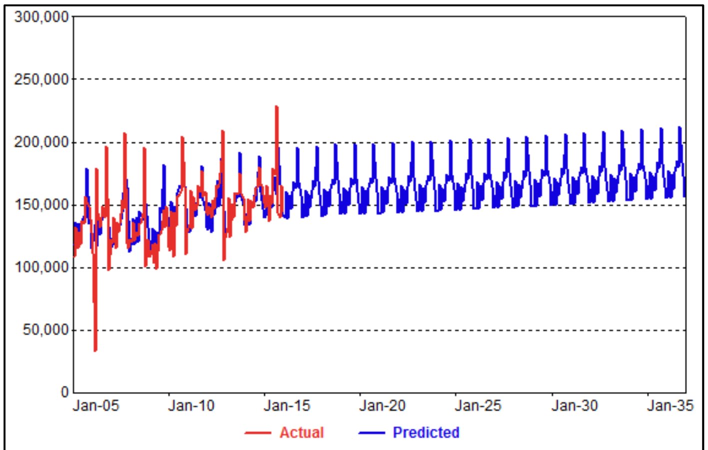
Commercial Sales Model



Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRev.XHeat	0.646	0.142	4.545	0.00%
mStructRev.XCool	0.791	0.03	26.616	0.00%
mStructRev.XOther	1.25	0.013	95.41	0.00%
mBin.Feb	3264.738	847.448	3.852	0.02%
mBin.Apr	-3802.326	791.115	-4.806	0.00%
mBin.BefMar06	-11561.965	1155.515	-10.006	0.00%
mBin.Jul09Plus	5717.858	733.503	7.795	0.00%
mBin.Yr15Plus	-1613.303	1168.753	-1.38	17.01%
MA(1)	0.42	0.087	4.821	0.00%

Model Statistics	
Iterations	24
Adjusted Observations	128
Deg. of Freedom for Error	119
R-Squared	0.961
Adjusted R-Squared	0.958
Model Sum of Squares	22,029,296,866.60
Sum of Squared Errors	904,726,010.29
Mean Squared Error	7,602,739.58
Std. Error of Regression	2,757.31
Mean Abs. Dev. (MAD)	2,101.97
Mean Abs. % Err. (MAPE)	1.91%
Durbin-Watson Statistic	1.768

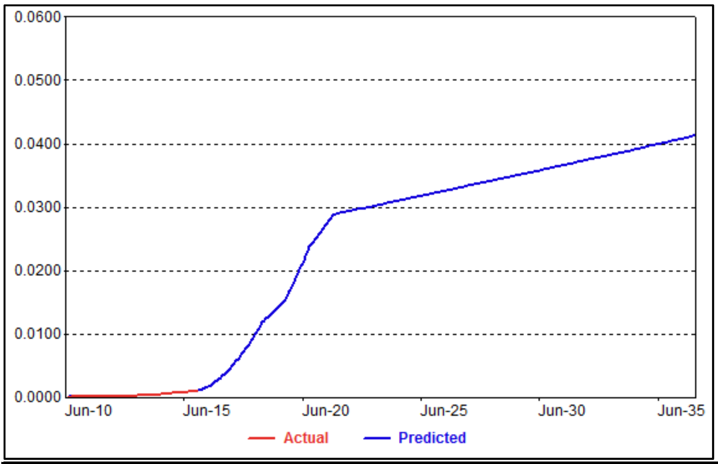
Industrial Sales Model



Variable	Coefficient	StdErr	T-Stat	P-Value
mEcon.IndVar	113780.018	2321.231	49.017	0.00%
mWthrCal.CDD	67.497	7.521	8.974	0.00%
mBin.Jul09Plus	23340.125	2401.404	9.719	0.00%
mBin.Feb	21251.022	3211.183	6.618	0.00%
mBin.Apr	17186.094	3063.395	5.61	0.00%
mBin.Sep	44663.222	3461.957	12.901	0.00%
mBin.Oct	26518.569	4404.05	6.021	0.00%
mBin.Nov	17098.713	3825.837	4.469	0.00%
MA(1)	0.338	0.095	3.553	0.06%

Model Statistics	
Iterations	9
Adjusted Observations	121
Deg. of Freedom for Error	112
R-Squared	0.756
Adjusted R-Squared	0.738
Model Sum of Squares	40,524,781,851.92
Sum of Squared Errors	13,090,186,756.82
Mean Squared Error	116,876,667.47
Std. Error of Regression	10,810.95
Mean Abs. Dev. (MAD)	7,627.40
Mean Abs. % Err. (MAPE)	5.34%
Durbin-Watson Statistic	1.658

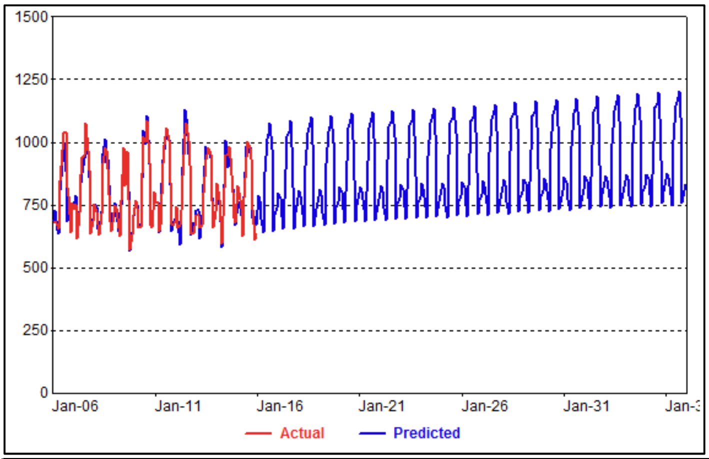
Residential Solar Share Model



Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	0.234	0.03	7.77	0.00%
Payback.ResPayback	-0.045	0.006	-7.848	0.00%
mAdopt.Payback_Sq	0.003	0	8.061	0.00%
mAdopt.Payback_Cb	-0.000	0	-8.218	0.00%
AR(1)	0.98	0.023	43.374	0.00%

Model Statistics	
Iterations	99
Adjusted Observations	66
Deg. of Freedom for Error	61
R-Squared	0.995
Adjusted R-Squared	0.995
Model Sum of Squares	0.00
Sum of Squared Errors	0.00
Mean Squared Error	0
Std. Error of Regression	0
Mean Abs. Dev. (MAD)	0
Mean Abs. % Err. (MAPE)	9.60%
Durbin-Watson Statistic	0.512

Peak Model



Variable	Coefficient	StdErr	T-Stat	P-Value
mCPkEndUses.HeatVar	3.512	0.371	9.457	0.00%
mCPkEndUses.CoolVar	19.581	0.567	34.545	0.00%
mCPkEndUses.BaseVar	1.51	0.022	69.383	0.00%
mBin.May	-39.804	11.289	-3.526	0.06%
mBin.Oct	-41.77	11.913	-3.506	0.07%
mBin.Yr11Plus	-30.43	6.26	-4.861	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	114
Deg. of Freedom for Error	108
R-Squared	0.947
Adjusted R-Squared	0.944
Model Sum of Squares	2,036,818.02
Sum of Squared Errors	114,564.82
Mean Squared Error	1,060.79
Std. Error of Regression	32.57
Mean Abs. Dev. (MAD)	25
Mean Abs. % Err. (MAPE)	3.14%
Durbin-Watson Statistic	1.804

6 Appendix B: Residential SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, econometric models are well suited to identify historical trends and to project these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are drive energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal shell integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes the SAE approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The source for the SAE spreadsheets is the 2015 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

6.1 Residential Statistically Adjusted End-Use Modeling Framework

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m} \tag{1}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$\text{USE}_m = a + b_1 \times \text{XHeat}_m + b_2 \times \text{XCool}_m + b_3 \times \text{XOther}_m + \varepsilon_m \qquad (2)$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

6.1.1 Constructing XHeat

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \qquad (3)$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \middle/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \middle/ Eff_{09}^{Type} \right)} \qquad (4)$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2009 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{09} \times SurfaceArea_{09}} \qquad (5)$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \qquad (6)$$

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 6-1.

Table 6-1: Electric Space Heating Equipment Weights

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	767
Electric Space Heating Heat Pump	127

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps are given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{05}}\right) \times \left(\frac{HHSize_{y}}{HHSize_{05,7}}\right)^{0.25} \times \left(\frac{Income_{y}}{Income_{05,7}}\right)^{0.15} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{05,7}}\right)^{-0.1} \quad (7)$$

Where:

- *HDD* is the number of heating degree days in year (*y*) and month (*m*).
- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2009). The first term, which involves heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

6.1.2 Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_{y} \times CoolUse_{y,m} \quad (8)$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m)
- $CoolIndex_y$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \big/ Eff_{09}^{Type} \right)} \tag{9}$$

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 6-2.

Table 6-2: Space Cooling Equipment Weights

Equipment Type	Weight (kWh)
Central Air Conditioning	1,219
Space Cooling Heat Pump	240
Room Air Conditioning	177

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. The estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{05}} \right) \times \left(\frac{HHSize_y}{HHSize_{05,7}} \right)^{0.25} \times \left(\frac{Income_y}{Income_{05,7}} \right)^{0.15} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{05,7}} \right)^{-0.1} \tag{10}$$

Where:

- *CDD* is the number of cooling degree days in year (*y*) and month (*m*).
- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2009). The first term, which involves cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

6.1.3 Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \qquad (11)$$

The first term on the right hand side of this expression ($OtherEqpIndex_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term (*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(\frac{Sat_y^{Type}}{\frac{1}{UEC_y^{Type}}} \right)}{\left(\frac{Sat_{05}^{Type}}{\frac{1}{UEC_{09}^{Type}}} \right)} \times MoMult_m^{Type} \times \quad (12)$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- $MoMult_m$ is a monthly multiplier for the appliance type in month (m)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{HHSize_y}{HHSize_{05,7}} \right)^{0.26} \times \left(\frac{Income_y}{Income_{05,7}} \right)^{0.15} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{05,7}} \right)^{-0.1} \quad (13)$$

The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_k ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \quad (14)$$

7 Appendix C: Commercial SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identifying historical trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency trends and saturation changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations and equipment efficiency levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

This document describes this approach, the associated supporting Commercial SAE spreadsheets, and *MetrixND* project files that are used in the implementation. The source for the commercial SAE spreadsheets is the 2015 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

7.1 Commercial Statistically Adjusted End-Use Model Framework

The commercial statistically adjusted end-use model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$\mathrm{USE}_m = a + b_1 \times \mathrm{XHeat}_m + b_2 \times \mathrm{XCool}_m + b_3 \times \mathrm{XOther}_m + \varepsilon_m \qquad (2)$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

7.1.1 Constructing XHeat

As represented in the Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating equipment saturation levels,
- Heating equipment operating efficiencies,
- Commercial output, employment, population, and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$\mathrm{XHeat}_{y,m} = \mathrm{HeatIndex}_y \times \mathrm{HeatUse}_{y,m} \qquad (3)$$

Where:

- *$XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m),*
- *$HeatInde_{xy}$ is the annual index of heating equipment, and*
- *$HeatUse_{y,m}$ is the monthly usage multiplier.*

The heating equipment index is composed of electric space heating equipment saturation levels normalized by operating efficiency levels. The index will change over time with changes in heating equipment saturations (*HeatShare*) and operating efficiencies (*Eff*). Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{04} \times \frac{\left(HeatShare_y \big/ Eff_y \right)}{\left(HeatShare_{04} \big/ Eff_{04} \right)} \qquad (4)$$

In this expression, 2004 is used as a base year for normalizing the index. The ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Base year space heating sales are defined as follows.

$$HeatSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Heating} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh \big/ Sqft_e} \right) \qquad (5)$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting $HeatIndex_y$ value in 2004 will be equal to the estimated annual heating sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, commercial level economic activity, prices and billing days. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{05}}\right) \times \left(\frac{EconVar_{y,m}}{EconVar_{05,7}}\right) \times \left(\frac{Price_{y,m}}{Price_{05,7}}\right)^{-0.10} \qquad (6)$$

Where:

- *HDD* is the number of heating degree days in month (m) and year (y).
- *EconVar* is the weighted commercial economic variable that blends Output, Employment, and Population in month (m), and year (y).
- *Price* is the average real price of electricity in month (m) and year (y).

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to one in the base year (2004). The first term, which involves heating degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will reflect changes in commercial output and prices, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.18 power).

7.1.2 Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling equipment saturation levels,
- Cooling equipment operating efficiencies,
- Commercial output, employment, population and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$\mathrm{XCool}_{y,m} = \mathrm{CoolIndex}_{y} \times \mathrm{CoolUse}_{y,m} \tag{7}$$

Where:

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m),
- $CoolIndex_y$ is an index of cooling equipment, and
- $CoolUse_{y,m}$ is the monthly usage multiplier.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Formally, the cooling equipment index is defined as:

$$CoolIndex_y = CoolSales_{04} \times \frac{\left(CoolShare_y \big/ Eff_y \right)}{\left(CoolShare_{04} \big/ Eff_{04} \right)} \tag{8}$$

Data values in 2004 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Estimates of base year cooling sales are defined as follows.

$$CoolSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Cooling} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh/Sqft_e}\right) \tag{9}$$

Here, base-year sales for space cooling is the product of the average space cooling intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space cooling sales value is defined on the *BaseYrInput* tab. The resulting *CoolIndex* value in 2004 will be equal to the estimated annual cooling sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, economic activity levels and prices. Using the COMMEND default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{05}}\right) \times \left(\frac{EconVar_{y,m}}{EconVar_{05,7}}\right) \times \left(\frac{Price_{y,m}}{Price_{05,7}}\right)^{-0.15} \tag{10}$$

Where:

- *HDD* is the number of heating degree days in month (m) and year (y).
- *EconVar* is the weighted commercial economic variable that blends Output, Employment, and Population in month (m), and year (y).
- *Price* is the average real price of electricity in month (m) and year (y).

By construction, the *CoolUse* variable has an annual sum that is close to one in the base year (2004). The first term, which involves cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will change to reflect changes in commercial output and prices.

7.1.3 Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Equipment saturation levels,
- Equipment efficiency levels,

- Average number of days in the billing cycle for each month, and
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherIndex_{y,m} \times OtherUse_{y,m} \tag{11}$$

The second term on the right hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{04}^{Type} \times \left(\frac{Share_y^{Type} \big/ Eff_y^{Type}}{Share_{04}^{Type} \big/ Eff_{04}^{Type}} \right) \tag{12}$$

Where:

- *Weight* is the weight for each equipment type,
- *Share* represents the fraction of floor stock with an equipment type, and
- *Eff* is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the main equipment categories. The weights are defined as follows.

$$Weight_{04}^{Type} = \left(\frac{kWh}{Sqft} \right)_{Type} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh \big/ Sqft_e} \right) \tag{13}$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

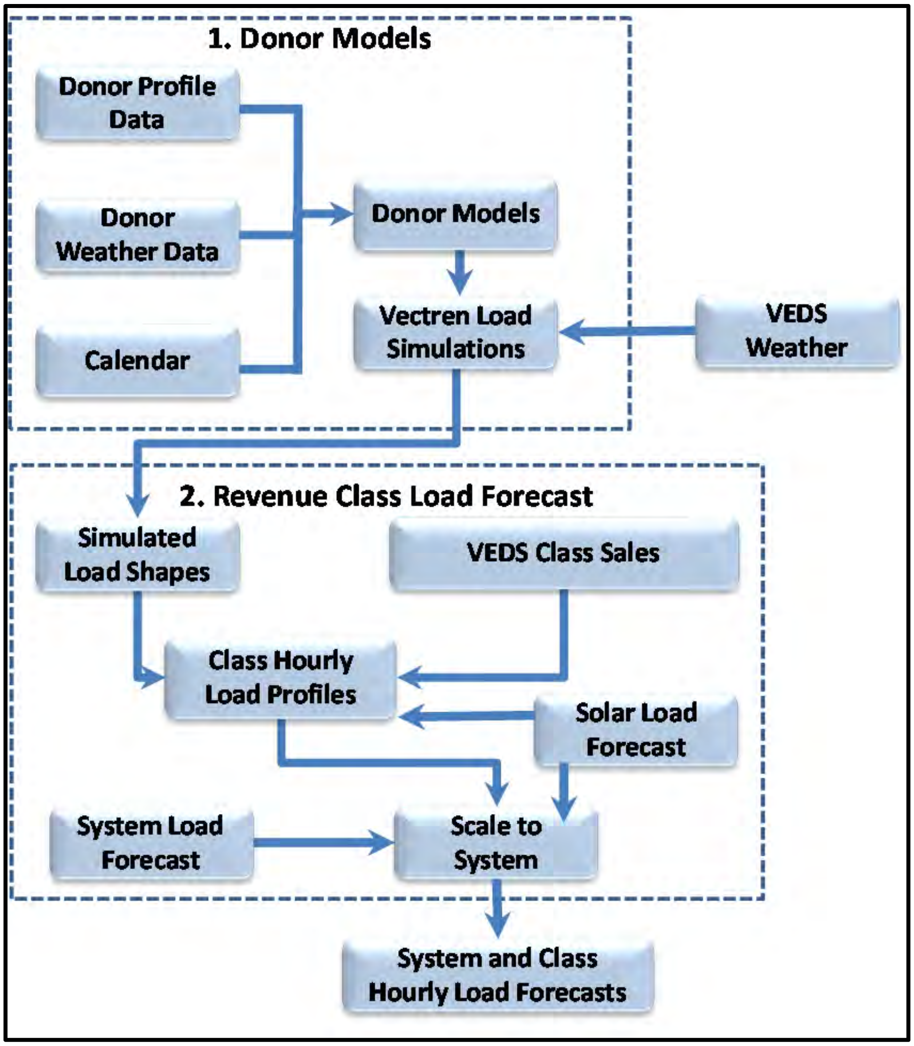
$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{EconVar_{y,m}}{EconVar_{05,7}} \right) \times \left(\frac{Price_{y.m}}{Price_{05,7}} \right)^{-0.15} \tag{14}$$

8 Appendix D: Hourly Load Profile Development

As part of the IRP forecast, Itron developed revenue class hourly load forecasts for residential, commercial, and industrial revenue classes. The process entailed constructing hourly customer class load models based on donor utility load research data for Indiana and then using the hourly load models to simulate hourly load for Vectren normal weather conditions.

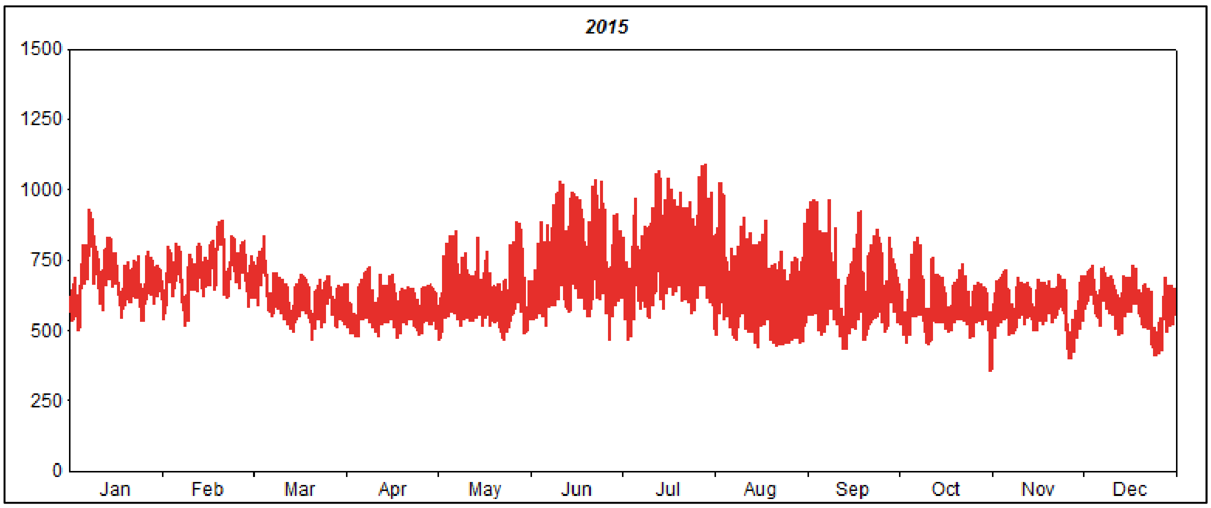
Resulting profiles are combined with forecasted class sales and calibrated to system hourly load forecast. Figure 1 shows the estimation process.

Figure 1: Profile Development Overview



System and class hourly load profiles are estimated using MetrixLT. MetrixLT is a load modeling application specifically designed for generating long-term hourly load forecasts. The system hourly load forecast is derived using MetrixLT *Transform Objects* that combines system peak, system, energy, and system hourly load profile. This initial system load forecast is then adjusted for total system solar load impact. Figure 2 shows the system hourly load for 2015.

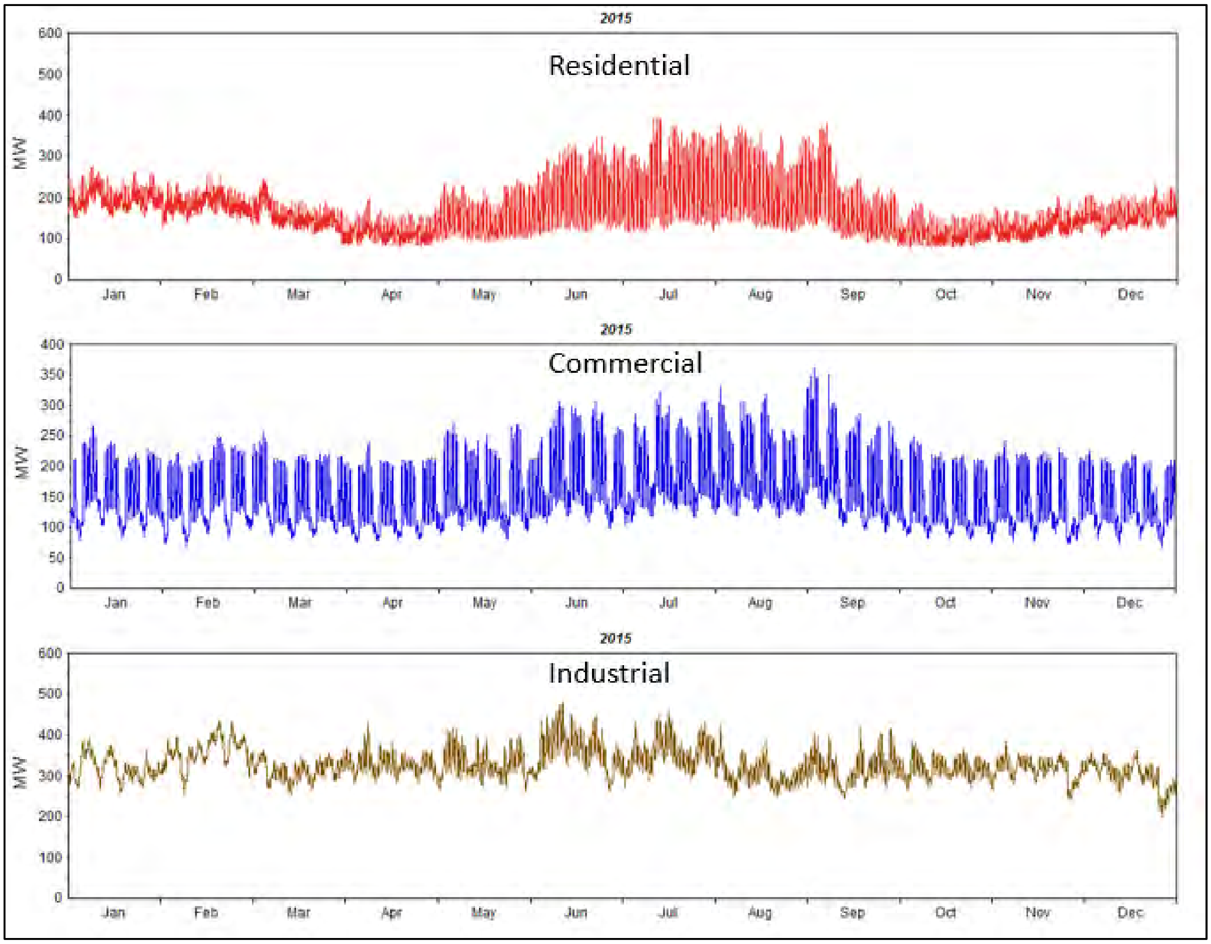
Figure 2: System Hourly Load



A similar process is used to construct class hourly load forecasts. Class hourly load forecasts are derived by combining class energy forecast with class hourly profiles. The residential and commercial class hourly load forecasts are adjusted for solar load impacts and then calibrated to the system hourly load forecasts.

Figure 3 shows the 2015 class hourly load estimates.

Figure 3: Class Hourly Load Estimates



The result of this process is a set of 8,760 system and class hourly load forecast that is consistent with system energy, system peak, and class energy forecasts. Figure 4 through Figure 15 shows the class contribution to monthly peak day load for 2015.

Figure 4: January Peak Day Profile

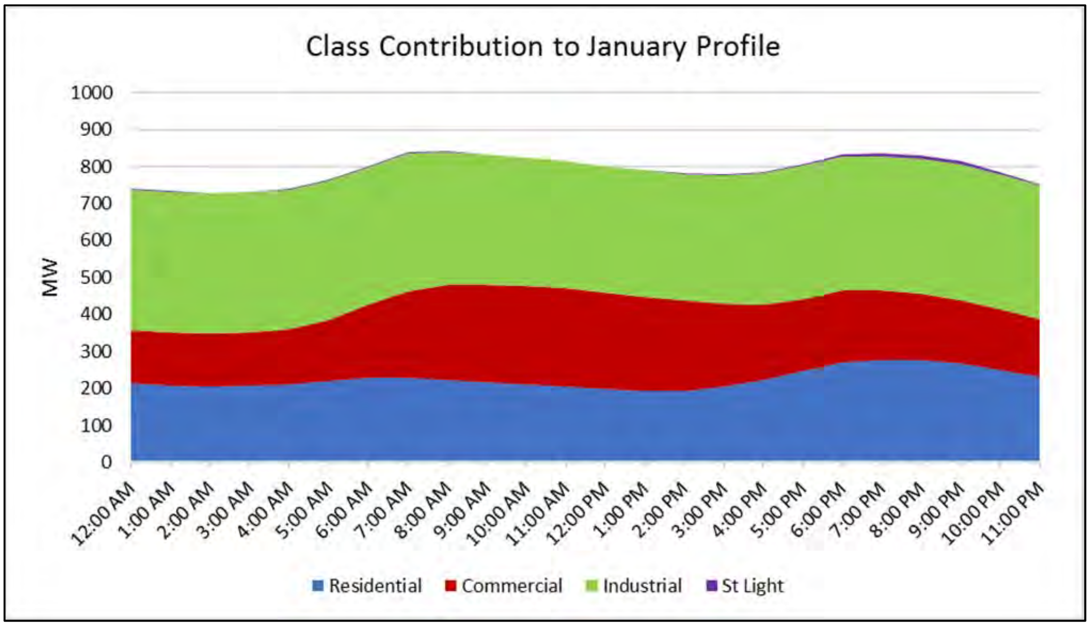


Figure 5: February Peak Day Profile

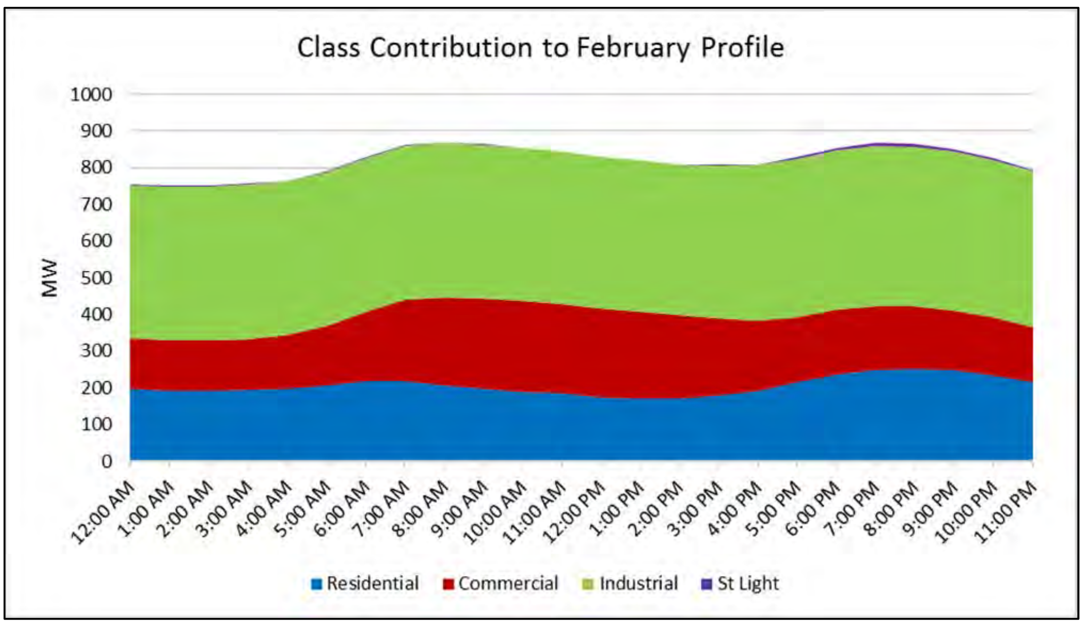


Figure 6: March Peak Day Profile

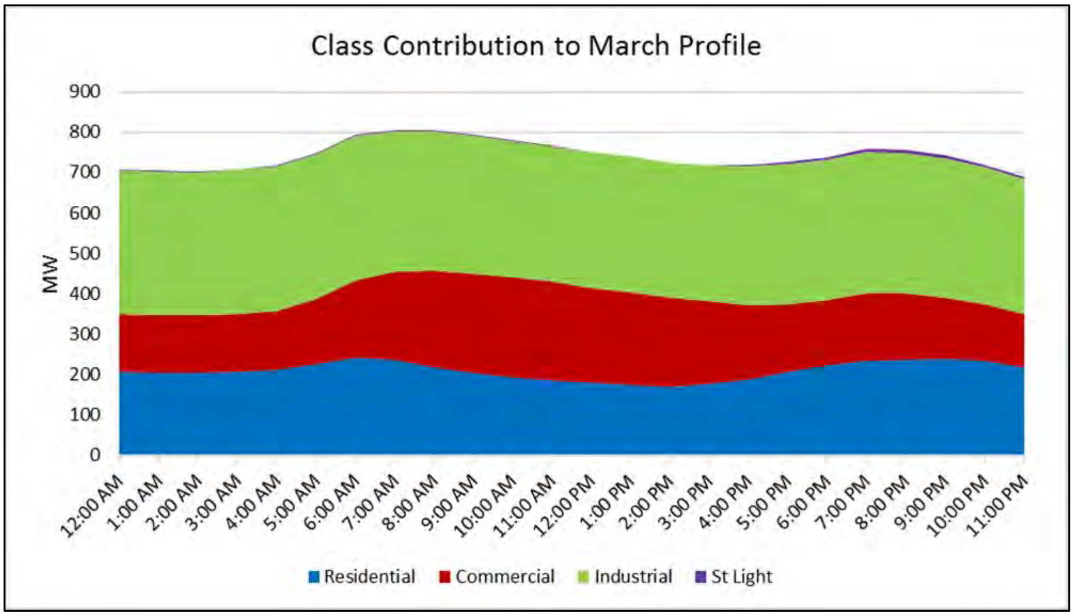


Figure 7: April Peak Day Profile

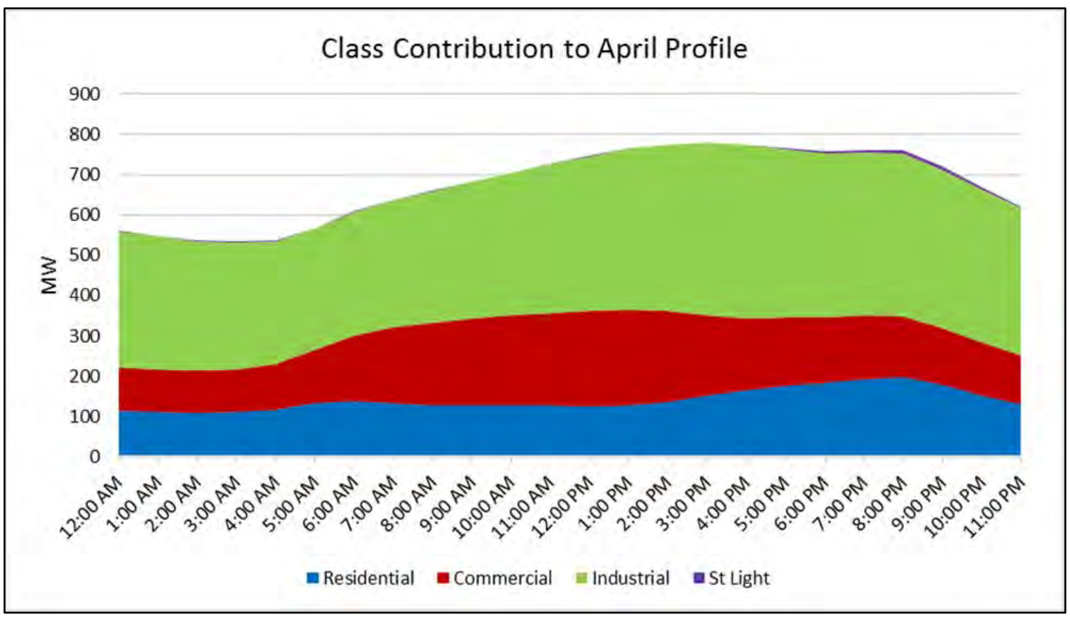


Figure 8: May Peak Day Profile

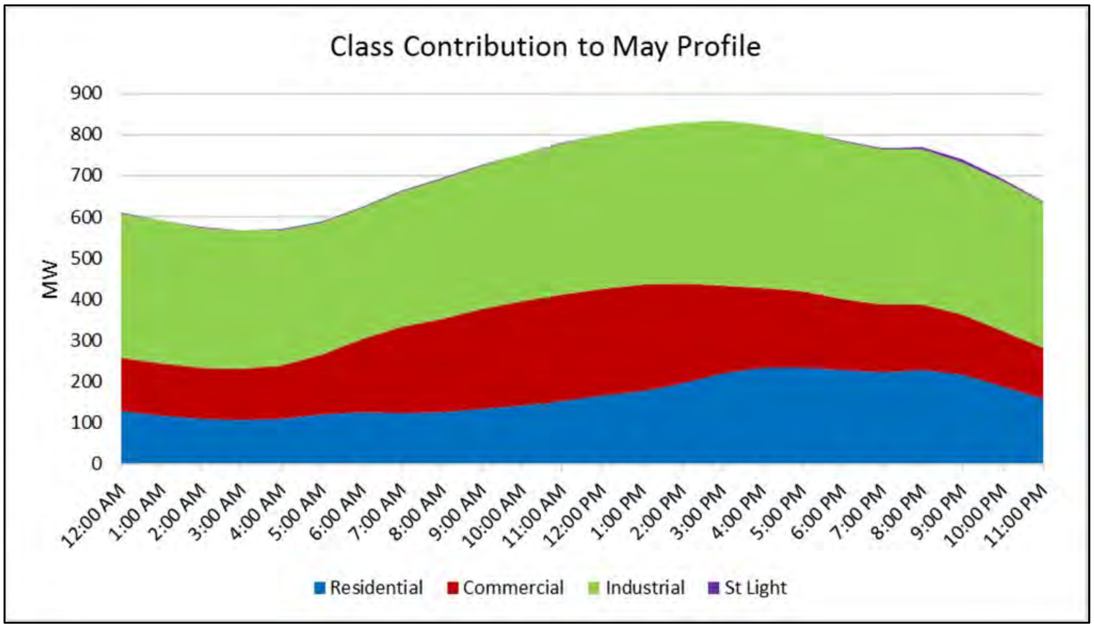


Figure 9: June Peak Day Profile

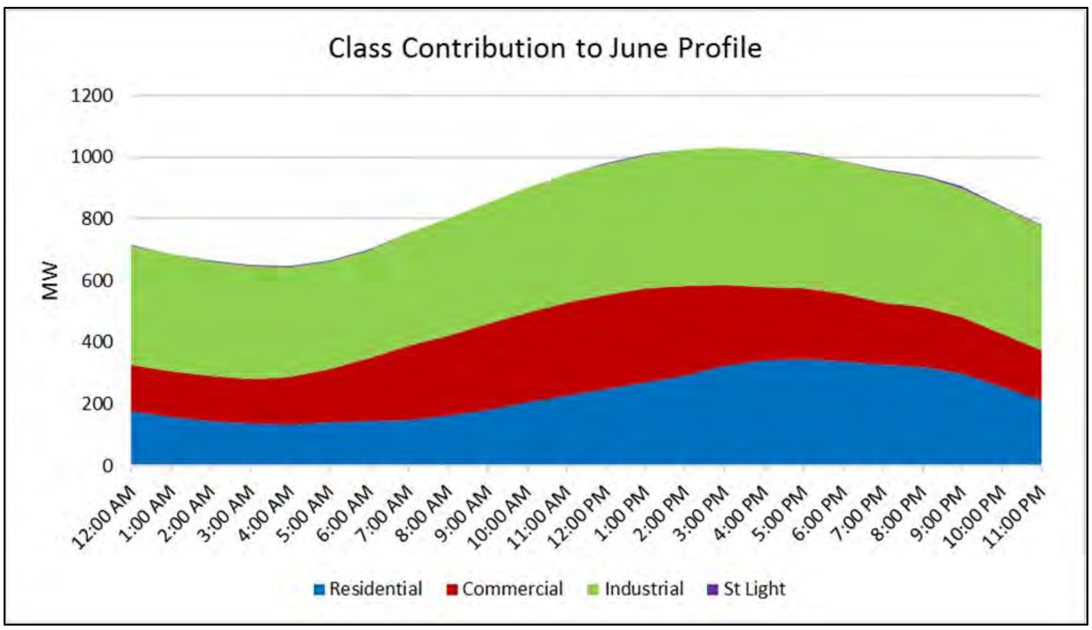


Figure 10: July Peak Day Profile

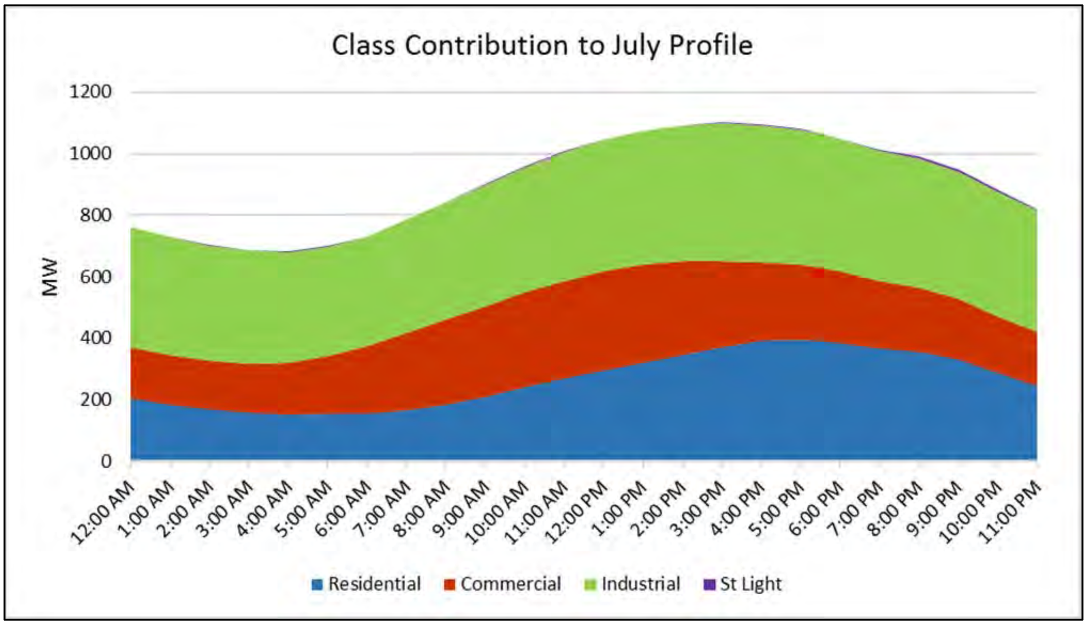


Figure 11: August Peak Day Profile

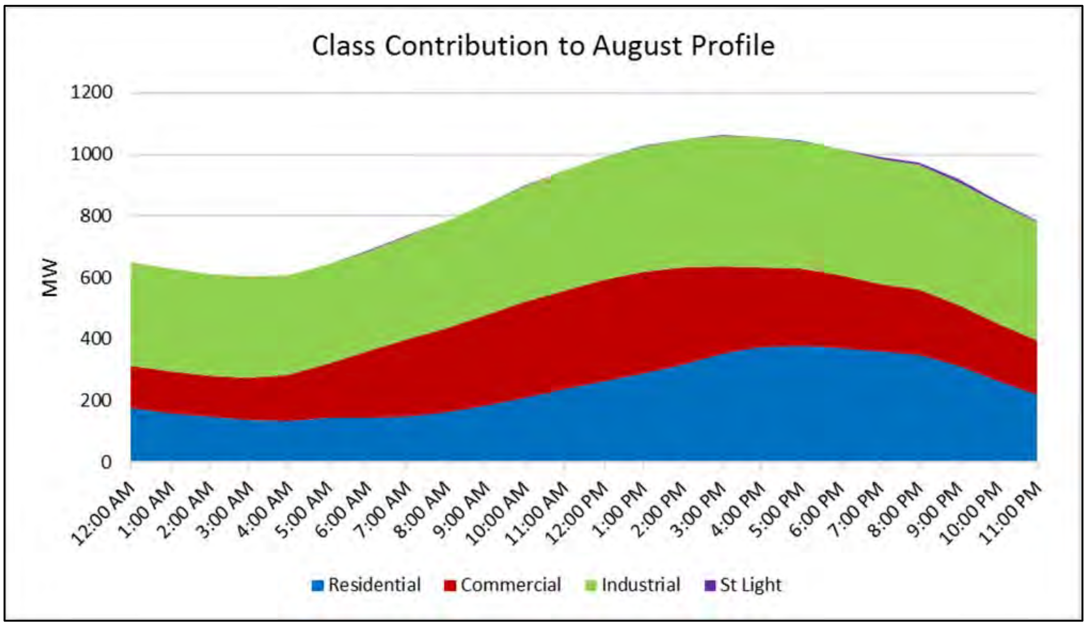


Figure 12: September Peak Day Profile

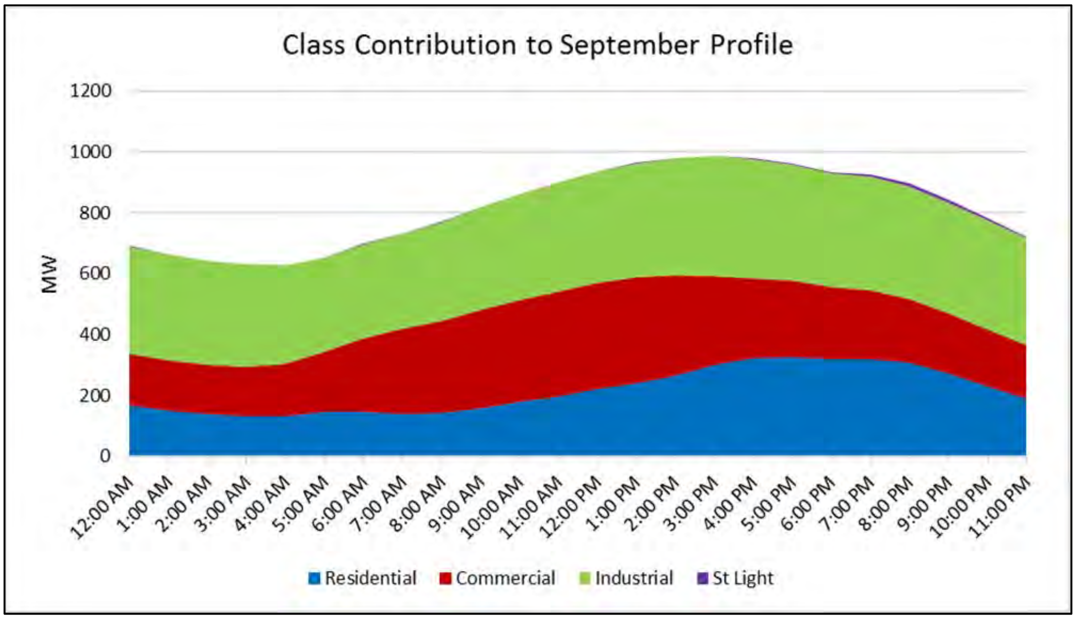


Figure 13: October Peak Day Profile

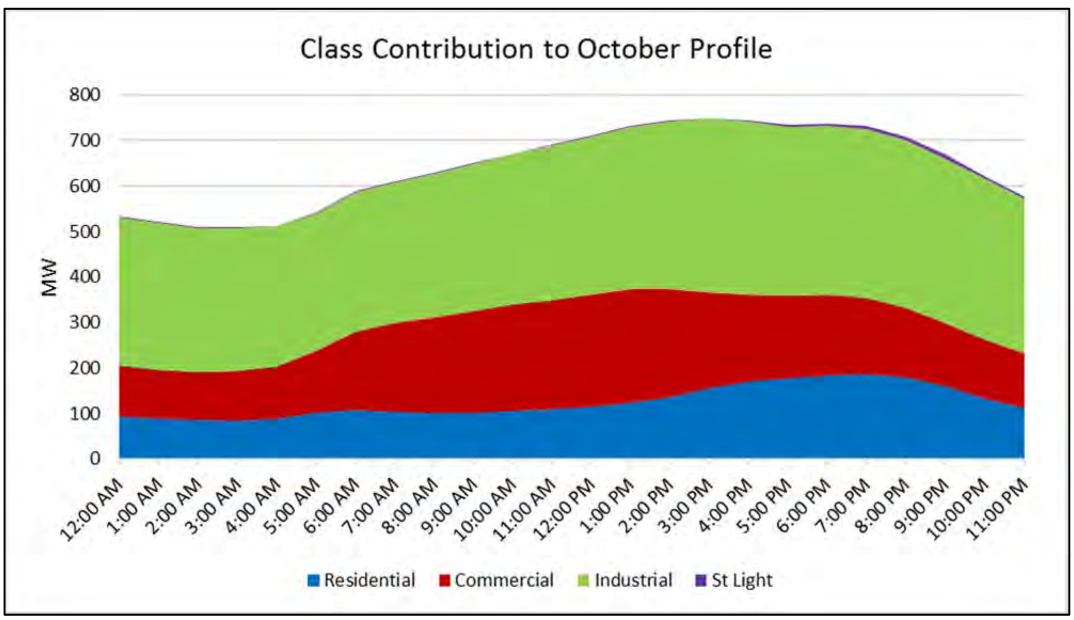


Figure 14: November Peak Day Profile

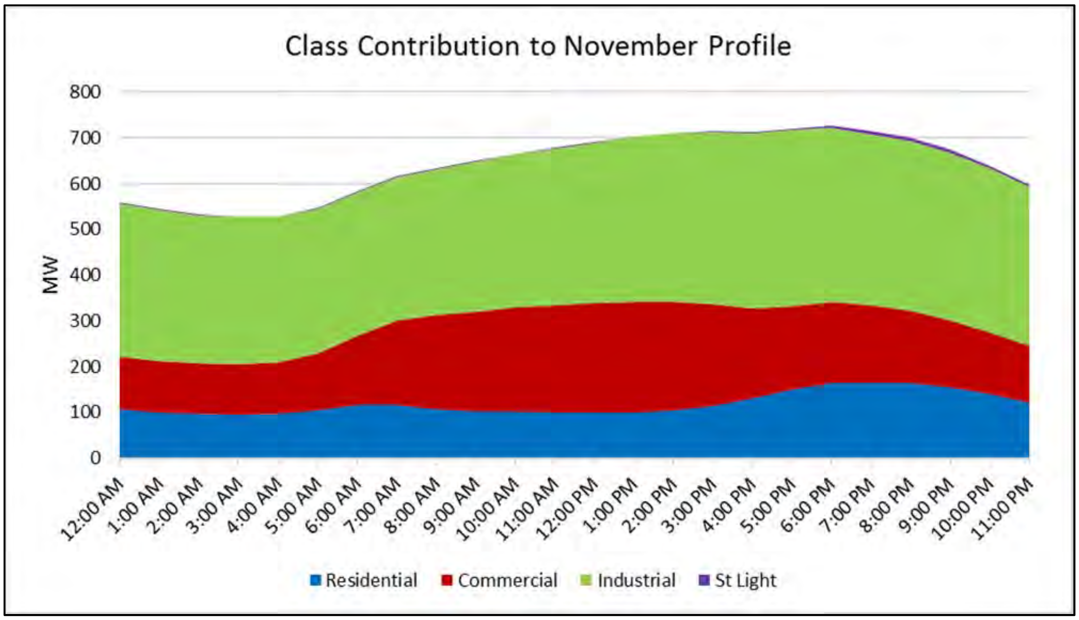
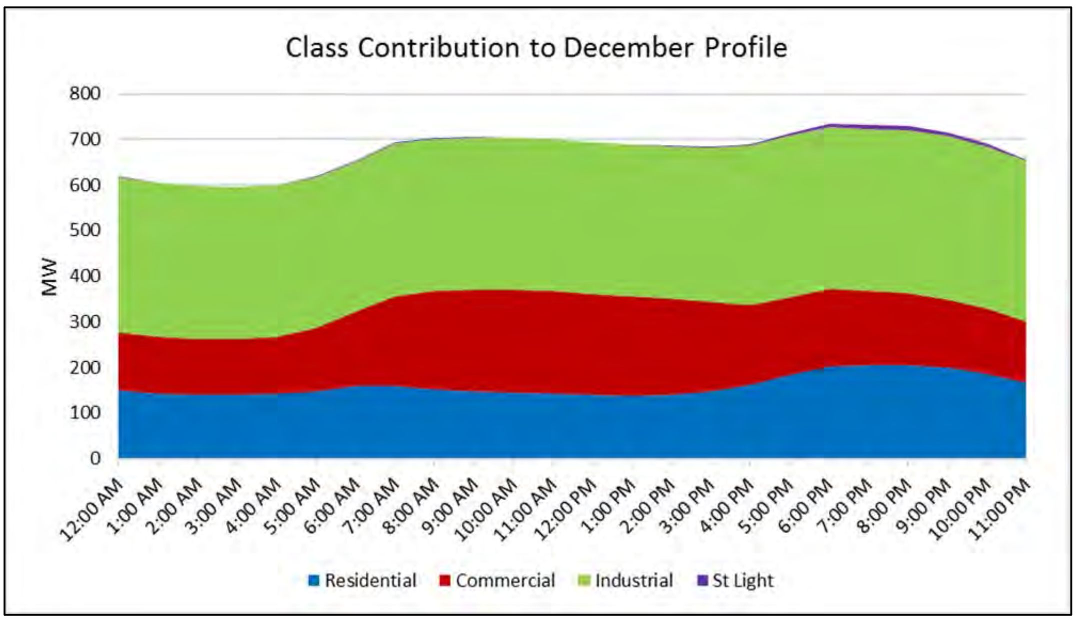


Figure 15: December peak Day Profile



Seasonal day-type profiles were estimate for total system load, differentiate weekend from weekend profiles. These can be seen in Figure 16 through Figure 19.

Figure 16: Winter Day Profile

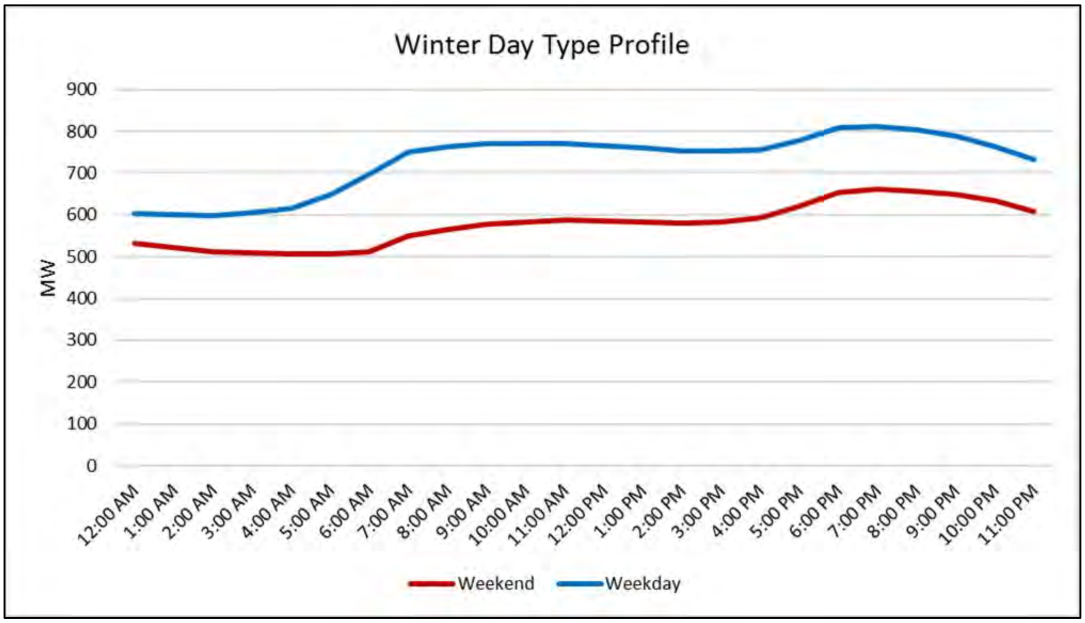


Figure 17: Spring Day Profile

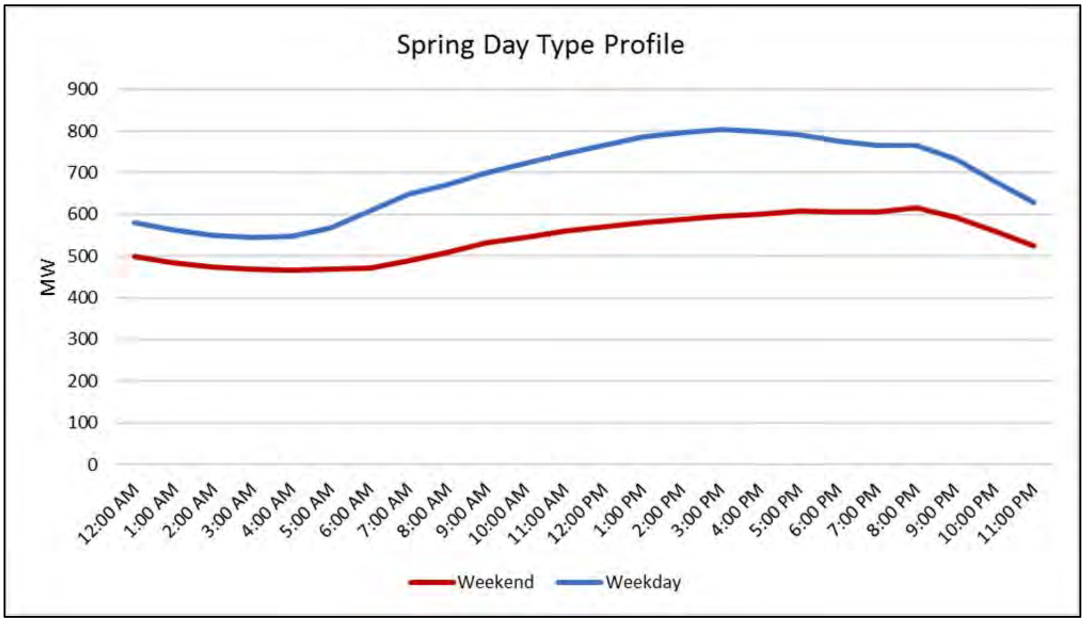


Figure 18: Summer Day Profile

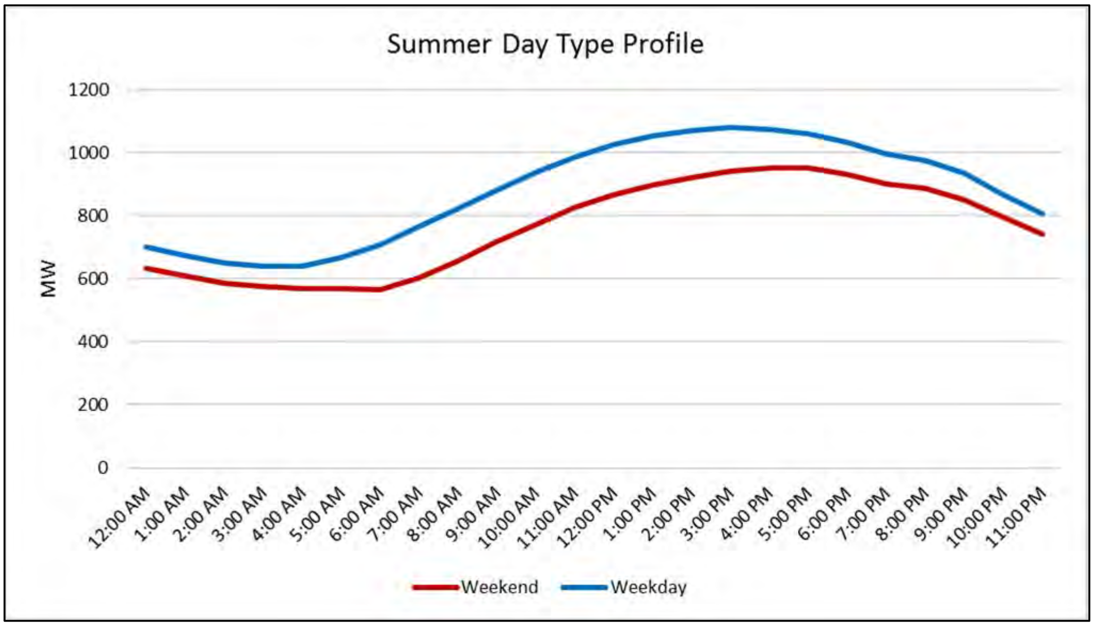
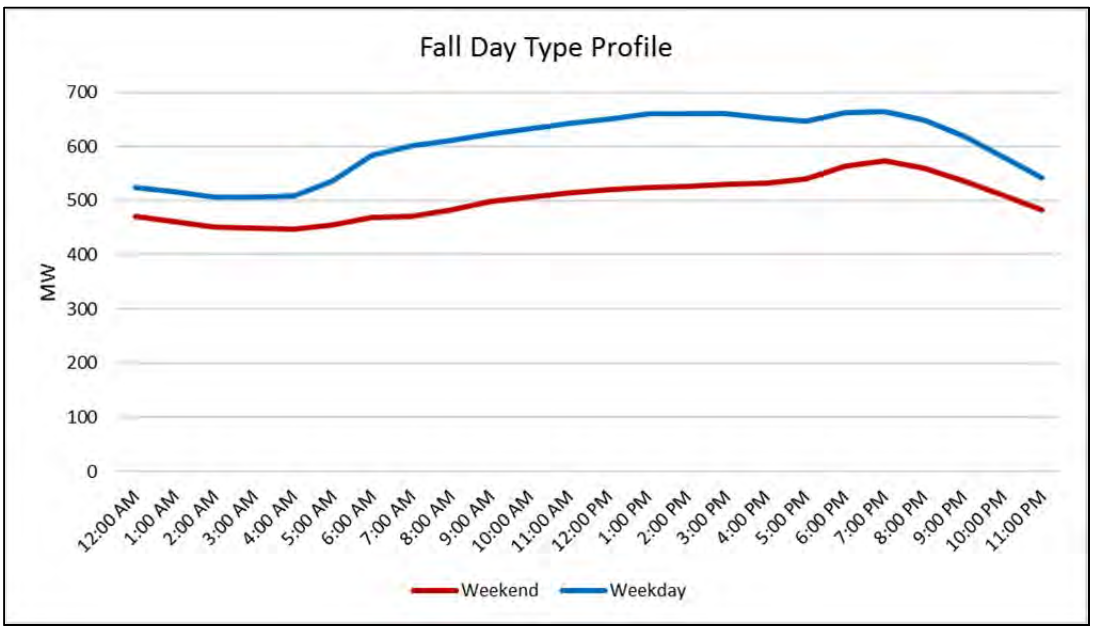


Figure 19: Fall Day Profile



Attachment 4.2 2015 Vectren Hourly System Load Data

Dt	Hour1	Hour2	Hour3	Hour4	Hour5	Hour6	Hour7	Hour8	Hour9	Hour10	Hour11	Hour12	Hour13	Hour14	Hour15	Hour16	Hour17	Hour18	Hour19	Hour20	Hour21	Hour22	Hour23	Hour24
1/1/2015	620.52	606.99	600.4	590.83	591.73	596.46	606.15	608.69	594.83	597.58	611	614.65	608.85	588.73	576.81	568.52	572.36	618.89	641.93	641.38	637.1	622.36	609.6	578.22
1/2/2015	559.46	551.34	534.45	536.97	537.11	555.01	568.81	611.96	633.79	648.22	656.07	661.93	665.8	660.47	665.1	652.19	658.97	673.79	684.96	676.86	660.93	647.89	634.17	604.84
1/3/2015	585.18	571.85	558.52	547.79	548.62	551.1	557.38	579.42	587.54	606.52	615.7	622.76	622.48	616.89	602.23	591.99	603.47	613.04	626.81	615.09	603.84	591.66	576.87	555.02
1/4/2015	538.27	514.35	503.61	502.82	503	510.32	517.37	548.01	553.74	562.95	581.18	599.49	600.98	617.78	625.18	632.26	659.71	689.49	737.03	731.72	737.85	722.92	697.63	676.15
1/5/2015	655.35	656.22	650.77	654.55	663.52	683.96	730.88	791.42	796.72	787.94	781.15	769.67	761.35	746.94	740.68	736.37	738.79	762.98	801.55	804.56	797.25	783.54	757.88	722.78
1/6/2015	693.6	677.72	670.4	667.26	666.5	682.27	702.97	757.31	762.73	764.02	760.35	751.89	736.7	735.58	733.76	733.14	745.31	765.72	795.03	802.32	794.17	788.18	765.12	730.27
1/7/2015	696.06	689.7	689.03	683.79	697.59	714.92	759.14	819.86	843.91	850.33	850.36	863.09	854.24	853.24	858.51	850.74	862.73	885.93	930.77	915.15	919.05	896.85	886.94	844.77
1/8/2015	820.29	805	804.8	798.77	806.19	820.51	848.3	902.48	900.6	876.95	853.81	856.8	840.31	838.28	826.96	826.62	826.59	837.75	849.38	843.83	827.9	808.63	784.75	739.44
1/9/2015	709.43	697.09	684.29	673.67	668.13	686.64	736.54	790.14	803.8	789.64	777.08	774.81	758.16	747.05	731.75	725.16	734.23	744.91	777.43	784.77	775.93	772.3	758.86	727.28
1/10/2015	708.49	701.72	700.02	703.42	704.34	713.87	732.46	744.62	757.66	749.89	731.7	722.85	703.5	679.69	662.41	659.89	648.91	676.44	715.7	722.55	714.79	713.57	695.72	677.71
1/11/2015	640.55	629.19	607.9	607.38	605.18	593.8	594.95	608.06	608.32	615.93	629.12	636.75	622.45	629.53	615.06	626.43	618.07	655.38	688.53	690.08	680.25	667.6	639.19	612.48
1/12/2015	583.82	581.05	570.45	571.71	578.31	595.12	636.97	693.02	712.75	732.61	737.31	742.47	745.34	738.07	743.06	745.09	750.27	771.72	785.11	782.15	784.23	768.36	756.4	717.43
1/13/2015	691.05	678.07	663.54	671.28	662.18	686.12	719.45	772.79	789.43	790.58	790.86	786.52	779.41	781.44	766.81	765.51	773.94	787.76	799.98	829.46	824.73	803.66	754.21	729.2
1/14/2015	691.65	693.52	683.58	688.57	688.91	708.28	734.64	788.2	802.16	809.46	831.46	787.63	769.87	758.7	745.97	743.38	752.52	762.22	789.76	792.02	777.94	766.63	737.91	702.1
1/15/2015	671.04	667.35	655.8	658.71	662.98	667.47	708.66	761.45	764.04	776.37	771.72	763.94	742.4	725.95	714.31	704.48	708.1	719.8	762.67	769.04	776.95	770.91	746.74	715.8
1/16/2015	679.97	673.85	672.54	666.97	672.09	687.45	713.57	768.71	777.68	765.88	739.45	720.84	709.1	685.91	680.11	671.47	664.21	678.14	710.99	718.52	718.65	720.29	709.67	677.78
1/17/2015	653	634.39	628.68	630.18	631.76	642.78	641.33	662.85	653.88	648.74	653.03	642.86	627.96	614.25	594.08	587.95	598.23	616.39	640.36	637.11	635.79	622.86	609.86	590.94
1/18/2015	561.88	554.6	546	554.71	547.5	557.08	562.29	592.04	587.28	600.3	601.41	590.3	600.39	590.88	578.3	575.03	576.09	591.9	637.91	651.77	648.93	637.57	634.34	612.51
1/19/2015	592.11	587.11	588.65	594.59	599.76	624.78	657.72	716.92	732.23	720.96	714.02	708.98	691.27	677.34	668.72	655.6	650.4	659.52	699.12	697.49	702.08	706.04	675.95	648.86
1/20/2015	619.26	614.47	612.25	621.69	623.32	639.02	680.87	725.43	744.5	720.77	707.48	694.81	680.97	668.14	666.3	655.69	662.66	677.48	707.1	713.6	700.74	689.78	675.35	638.75
1/21/2015	613.43	600.95	600.95	597.92	600.01	624.55	648.18	713.83	709.48	708.71	686.42	681.64	665.3	656.3	650.79	654.27	650.23	658.03	705.21	718.77	716.77	718.19	696.52	658
1/22/2015	630.71	631.19	623.22	620.89	630.52	651.21	683.82	736.61	743.43	749.06	741.97	731.05	701.62	694.28	687.6	693.95	703.81	708.15	732.86	742.77	734.79	726.16	700.54	668.82
1/23/2015	642.36	629.89	618.54	622.84	617.34	636.81	662.96	726.55	742.16	732.79	739.01	729.48	725.21	713.92	708.67	704.32	707.18	765.73	734.84	733.53	724.18	717.36	703.47	674.55
1/24/2015	643.64	632.42	625.94	633.7	624.74	646.07	639.17	664.12	664.24	663.79	657.77	648.51	629.76	618.32	586.34	584.23	574.96	591.29	637.46	648.59	636.08	622.56	614.27	587.59
1/25/2015	576.28	552.6	540.92	540.78	531.88	540.28	544.45	558.72	565.57	587.42	597.21	600.92	614.05	607.96	618.13	607.05	621.59	633.3	665.15	666.37	661.45	641.51	633.05	608.54
1/26/2015	597.72	598.02	595.57	604.06	604.19	630.89	674.31	734.6	751.72	747.93	757.35	765.29	757.19	760.54	758.89	750.04	753.22	761.29	781.96	782.37	769.34	756.46	732.14	698.07
1/27/2015	655.66	648.83	639.44	635.86	633.09	643.25	677.93	734.69	742.33	744.55	749.51	747.02	745.08	736.61	736.29	735.06	740.2	749.53	761.94	758.54	755.45	745.31	723.37	683.13
1/28/2015	655.36	645.88	632.65	636.03	625.69	646.41	678.45	737.89	747.62	731.24	724.6	716.43	699.61	692.24	675.51	674.4	669.59	670.66	717.89	728.23	727.93	722.57	695.46	661.85
1/29/2015	628.36	616.97	604.92	598.34	595.09	600.24	625.17	676.2	679.91	664.33	674.43	682.36	686.09	690.18	702.81	705.73	697.11	714.43	732.91	728.48	727.8	724.62	698.77	670.61
1/30/2015	642.63	630.18	621.62	622.37	620.69	633.35	669.05	713.1	723.24	714.9	709.1	701.71	689.09	667.52	668.94	660.61	655.81	668.6	702.88	712.47	717.34	717.08	704.51	685.52
1/31/2015	665.79	638.75	646.81	649.52	638.34	637.07	640.68	667.03	663.56	676.41	666.03	656.76	647.85	625.04	621.76	611.33	614.45	635.16	653.37	657.99	648.5	638.23	621.4	601.63
2/1/2015	577.54	557.45	549.92	549.08	542.19	549.78	553.41	574.05	579.62	594.5	609.13	620.82	617.47	622.74	627.56	624.07	625.03	633.41	646.49	635.56	628.17	623.73	616.53	603.57
2/2/2015	587.62	589.73	600.04	615.68	627.95	652.34	703.11	766.83	794.34	793.93	799.91	791.69	778.25	768.37	756.2	759.83	755.88	774.98	791.83	799.73	792.35	776.08	754.64	717.56
2/3/2015	686.05	678.43	675.75	669.47	684.86	697.38	732.96	787.43	786.97	778.45	762.13	750.42	730.94	706.62	695.96	694.38	685.04	694.14	733.96	745.65	745.07	731.16	703.29	673.67
2/4/2015	638.75	625.71	622	619.76	622.55	641.87	661.34	716.78	723.3	704.05	692.74	681.76	664.98	662.45	650.67	652.35	651.43	666.38	703.93	729.4	735.5	741.27	727.48	704.29
2/5/2015	674.71	685.29	681.47	687.04	693.41	707.34	743.8	796.27	806.89	792.86	780.75	767.45	746.44	740.71	728.35	721.84	714.53	719.39	755.41	773.26	786.71	781.55	768.99	728.56
2/6/2015	710.33	701.68	700.9	710.19	708.39	714.7	746.34	795.64	794.05	785.18	765.3	734.36	716.08	694.54	687.04	684.22	671.79	672.34	698.09	698.82	711.03	697.25	687.98	657.72
2/7/2015	624.34	614.39	604.52	607.55	600.8	607.4	615.52	639.06	643.42	645.05	639.08	628.83	614.05	598.19	587.64	584.48	571.98	576.73	602.91	618.97	614.17	611.18	599.78	580.91
2/8/2015	558.36	546.58	534.91	533.56	519.08	527.62	531.06	538.8	535.51	557.57	569.36	565.78	572.65	570.14	566.12	566.25	572.92	594.33	608.48	625.08	613.04	597.49	581.96	549
2/9/2015	536.49	532.64	531.31	537.22	547.45	569.7	622.35	677.83	705.33	708.41	721.02	727.06	725.78	727.72	741.02	731.18	742.39	749.4	765.83	770.15	768.29	753.62	729.8	697.07
2/10/2015	666.35	650.61	649.26	648.9	644.74	657.07	697.77	750.72	752.4	749.77	729	711.14	700.2	688.3	679.63	672.73	665.36	661.92	698.56	729.58	736.53	731.02	710.72	688.2
2/11/2015	656.62	651.8	649.23	645.62	641.31	655.11	688.94	738.88	738.35	738.13	725.44	705.7	693.18	677.32	670.31	659.41	669.11	692.92	708.96	727.01	720.75	721.04	701.84	667.7
2/12/2015	645.52	647.1	640.45	649.89	647.4	669.2	704.4	769.69	792.73	800.88	787.7	789.64	773.62	762.12	749.56	749.73	745.89	754.92	790.68	810.53	808.93	795.89	773.97	733.29
2/13/2015	710.35	702.71	692.51	686.7	700.48	704.37	745.25	797.53	792.96	776.17	761.77	748.29	725.38	718.47	717.64	704.95	687.87	705.45	713.45	741.98	732.29	730.94	718.26	692.57
2/14/2015	649.14	639.03	634.06	636.05	629.97	624.24	627.35	632.48	634.95	647.93	657.67	672.08	663.75	672.01	659.61	657.57	655.44	680.57	723.27	755.63	758.53	743.97	740.83	719.54
2/15/2015	702.53	692	680.58	682.63	676.17	687.99	697.65	704.76	707.84	718.02	721.92	713.44	704.67	699.89	690.43	693.25	696.2	717.71	749.25	750.45	743.35	728.34	715.27	690.91
2/16/2015	674.84	658.51	662.7	662.75	666.02	687.21	719.24	753.57	775.27	785.29	800.61	802.52	797.79	794.68	774.58	775.39	776.8	780.52	799.2	817.08	797.52	788.36	764.7	739.1
2/17/2015	722.79	730.81	729.26	732.23	740.06	755.96	785.35	816.25	820.98	810.22	802.6	803.43	790.39	768.74	757.24	737.05	721.54	738.14	775.63	793.94	786.9	775.97	736.17	687.74
2/18/2015	663.15	650.43	644.72	655.54	663.46	686.48	723.9	756.1	765.8	760.91	757.25	767.16	787.89	793.45	790.09	788.79	784.69	805.88	838.72	869.68	863.65	861.39	838.53	817.76
2/19/2015	786.9	793.13	795.07	797.34	802.95	817.29	848.38	880.74	885.14	875.43	873.09	873.7	850.59	843.03	836.66	829.37	816.51	816.24	859	887.38	886.37	880.17	860.71	837.19
2/20/2015	810.49	808.64	805.77	809.94	812.25	809.12	836.89	862.71	881.01	889.87	882.31	866.34	833.66	816.33	807.4	808.59	805.88	808.18	815.11	824.98	801.25	797.55	769.36	731.09
2/21/2015	692.69	676.18	661.01	651.31	646.86	628.87	637.28	647.79	653.38	666.17	677.34	689.73	692.04	689.76	678.99	663.2	658.45	670.55	694.77	710.17	693.33	685.68	674.32	653.85
2/22/2015	618.08	623.13	613.13	616.19	614.34	614.86	625.85	626.67	635.23	651.51	654.99	661.35	657.91	660.88	644.84	651.72	646.24	680.15	719.31	744.81	738.97	721.86	724.37	694.57
2/23/2015	685.08	683.13	682.78	687.45	698.33	725.36	774.97	829.14	837.31	828.4	815.01	810.64	786.76	775.96	763.65	757.39	754.19	755.49	795.88	827.7	829.62	821.16	810.81	782.19
2/24/2015	752.86	744.53	734.75	735.38	741.5	745.1	786.46	821.02	821.33	793.8	780.89	771.59	755.14	741.75	726.1	714.91	710.31	710.7	732.23	773.95	770.28	761.21	749.95	720.08
2/25/2015	689.84	688.76	673.53	678.54	679.78	701.03	725.7	772.44	773.66	770.31	746.51	737.54	700	710.67	699.91	699.45	697.21	698.89	715.61	741.71	738.31	739.58	712.34	689.77

Dt	Hour1	Hour2	Hour3	Hour4	Hour5	Hour6	Hour7	Hour8	Hour9	Hour10	Hour11	Hour12	Hour13	Hour14	Hour15	Hour16	Hour17	Hour18	Hour19	Hour20	Hour21	Hour22	Hour23	Hour24
2/26/2015	656.23	646.88	649.66	649.84	651.37	673.42	703.99	753.38	767.57	750.73	747.17	747.83	742.34	740.02	748.36	758.15	751.56	756.25	769.92	797.06	804.86	792.09	779.73	748.68
2/27/2015	726.13	713.76	707.36	718.47	719.23	730.33	775.1	816.83	813.69	803.54	786.05	766.54	745.2	738.52	732.89	723.27	706.9	719.11	745.34	772.26	760.71	769.24	752.28	729.71
2/28/2015	704.09	687.76	680.97	681.09	676.08	687.94	684.77	707.62	707.2	714.44	709.2	690.31	678.27	658.45	640.79	636.32	636.32	645.01	674.9	682.83	671.18	667.14	660.93	634.05
3/1/2015	612.25	599.94	592.35	583.54	583.44	588.39	599.99	607.06	617.1	626.65	643.5	634.65	634.74	638.29	629.65	631.55	635.02	655.05	668.99	696.06	692.31	733.55	658.22	636.56
3/2/2015	621.95	618.93	615.58	627.21	633.9	656.36	706.61	752.74	766.27	764.83	743.5	735.09	723.07	713.71	702.28	689.29	683.17	694.66	719.55	744.23	739.08	732.28	715.23	674.23
3/3/2015	651.33	627.89	621.19	621.46	618.73	631.74	663.08	711.22	717.52	730.15	728.44	718.02	704.41	711.61	692.4	695.26	695.6	700.72	698.04	709.73	703.24	695.86	671.3	639.81
3/4/2015	608.51	605.87	588.99	592.87	591.86	605.8	638.1	675.88	711.16	760	733.11	744.14	758.73	761.69	749.84	757.09	762.05	758.21	771.44	778.45	773.62	765.29	735.81	707.76
3/5/2015	680.06	671.12	661.2	659.17	663.54	670.91	707.43	721.62	742.83	753.13	736.77	736.02	725.51	722.64	716.59	714.53	707.11	713.59	739.82	790.6	788.23	778.88	760.31	739.61
3/6/2015	725.88	721.6	718.69	732.04	735.66	753.95	794.41	825.61	833.97	805.28	790.6	765.88	755.93	740.64	726.21	710.58	700.59	695.38	717.9	746.46	750.84	739.35	727.49	701.93
3/7/2015	671.67	658.48	659.08	652.48	646.93	652.51	661.7	655.1	657.88	651.78	641.9	634.03	619.65	605.06	588.35	585.41	583.17	575.46	603.03	632.87	632.04	627.46	615.74	596.86
3/8/2015	574.47	576.84	567.88	570.48	566.98	587.8	599.65	607.04	605.9	600.58	578.82	563.91	566.67	566.25	548.54	562.45	568.7	589.08	609.42	633.16	628.46	606.09	590.59	572.89
3/9/2015	560.32	560	558.07	564.31	585.05	622.95	687.64	704.11	694.35	702.77	675.01	689.08	676.26	677	672.18	649.1	661.27	665.06	666.52	692.65	690.07	663.55	623.81	602.52
3/10/2015	594.96	585.22	587.12	584.51	591.88	620.36	666.53	698.57	682.67	696.59	703.09	691.51	686.62	680.58	664.69	668.71	659.89	666.21	678.37	690.74	686.68	660.82	633.67	607.23
3/11/2015	578.7	585.47	575.06	577.72	585.41	619.35	670.45	686.44	682.92	690.6	676.9	667.51	656.83	649.52	640.71	636.41	622.38	623.12	629.37	664.56	666.26	644.56	614.3	588.19
3/12/2015	577.02	575.27	562.69	579.1	581.37	608.72	667.44	679.52	680.58	670.72	673.79	662.35	645.07	652.09	641.41	632.36	626.42	615.2	629.75	655.76	655.69	636.01	602.31	567.02
3/13/2015	551.88	541.39	543.93	536.45	548.05	577.94	634.1	655.49	656.45	664.84	662.28	663.01	658.48	663.53	657.13	645.62	645.76	628.23	642.24	654.79	645.47	631.35	602.3	562.01
3/14/2015	553.44	534.05	532.49	524.43	519.66	529.4	546.2	555.55	570.33	584.06	597.73	590.45	587.13	583.72	570.45	571.98	551.61	525.34	544.1	572.58	572.25	562.41	547.41	520.92
3/15/2015	503.15	512.63	506.72	505.43	503.35	512.49	528.9	538.06	544.58	546.78	540.67	537.94	537.44	533	524.45	529.58	530.07	541.82	545.79	590.43	584.44	571.19	541.16	523.91
3/16/2015	505.92	507.95	497.84	512.07	521.12	570.81	629.35	656.69	646.8	648.9	643.4	651.8	646.61	653.03	644.78	642.77	640.31	636.19	639.49	667.38	664.69	642.39	615.04	570.51
3/17/2015	559.19	555.72	542.52	543.98	538.8	555.19	605.19	621.33	620.73	622.01	631.07	626.1	627.19	618.05	612.39	617.74	610.86	609.51	602.03	646.57	652.08	633.71	596.09	572.05
3/18/2015	559.49	551.13	552.66	555.72	569.68	605.88	680.18	692.48	695.56	698.59	692.38	693.85	675.84	688.04	656.79	661.41	658.68	659.87	673.45	693.21	686.24	663.18	628.88	593.24
3/19/2015	582.63	579.87	571.75	577.23	583.8	610.85	662.89	684.38	690.4	685.93	682.73	680.64	671.75	674.96	665.61	661.94	661.59	670.55	667.79	685.46	679.86	656.23	629.13	591.28
3/20/2015	572.11	571.08	558.5	564.22	567.57	594.43	639.58	658.22	661.59	663.81	654.88	653.59	651.75	650.03	645.78	634.26	634.23	616.6	615.36	648.14	649.21	624.9	605.8	568.31
3/21/2015	560.15	556.57	547.39	551.53	544.95	552.6	566.58	567.09	568.78	568.87	570.95	557.98	547.35	547.64	534.92	536.38	537.63	528.17	539.09	565.2	556.22	545.27	519.46	497.35
3/22/2015	480.51	480.4	470.89	468.49	480.41	488.5	501.69	511.59	531.12	530.38	536.43	528.92	531.53	532.4	517.2	521.87	523.85	527.74	544.7	563.41	577.11	554.33	534.83	514.35
3/23/2015	505.99	509.09	505.78	517.11	532.91	569.28	614	633.16	638.87	640.99	627.51	628.19	623.2	614.38	613.15	612.57	607.73	603.61	602.96	638.89	627.66	617.66	580.94	552.88
3/24/2015	542.96	542.08	542.71	547.87	556.39	593.34	624.39	650.24	661.27	671.13	660.44	661.64	662.2	671.6	669.31	659.33	655.92	668.24	670.38	681.97	665.03	648.87	618.68	585.51
3/25/2015	565.43	559.64	552.95	514.49	514.69	584.5	607.43	623.16	632.35	640.09	628.22	634.78	633.57	625.32	629.43	631.49	615.01	615.78	609.99	637.94	636.67	617.4	589.72	551.37
3/26/2015	546.24	542.98	526.54	536.71	537.88	568.05	599.88	625.35	643.9	657.68	658.5	669.82	664.25	662.72	665.54	663.47	653.44	646.79	639.97	669.66	676.59	653.43	637.36	612.32
3/27/2015	598.62	597.81	595.15	607.07	616.06	633.88	668.63	685.98	694.4	682.57	675.24	678.14	679.71	672.89	668.48	669.15	656.72	657.81	656.02	692.03	689.46	685.64	660.1	630.91
3/28/2015	622.53	617.92	619.5	616.55	626.84	641.4	641.04	644.98	646.31	639.07	633.59	616.02	602.08	581.09	574.2	565.63	556.07	570.23	570.06	611.21	623.23	616.53	603.66	588.75
3/29/2015	573.14	579.14	582.38	584.2	579.3	597.22	609.69	603.16	605.22	604.22	588.02	582.15	573.72	562.15	562.04	550.7	552.25	574.16	581.68	604.2	597.77	571.24	546.55	525.32
3/30/2015	515.79	512.8	511.28	513.75	531.95	582.7	638.97	652.17	649.19	646.24	637.17	641.48	634.72	635.03	631.81	635.49	619.78	624.13	614.4	643.05	659.42	623.65	595.86	568.03
3/31/2015	548.15	541.49	538.28	547.74	560.59	587.83	644.6	644.99	645.56	648.85	648.36	643.95	645.37	652.76	642.79	642.45	637.81	626.03	619.97	652.53	654.96	628.17	587.36	559.46
4/1/2015	543.23	532.73	532.58	534.85	549.86	582.16	628.91	643.78	638.78	640.6	642.99	639.75	637.7	643.72	645.79	642.15	640.16	631.56	630.57	660.73	665.3	632.62	596.3	566.34
4/2/2015	541.05	539.57	524.63	528.12	537.69	559.81	581.64	630.64	645.74	652.35	656.67	661.95	658.25	662.25	658.64	653.06	651.3	651.24	642.29	665.55	662.08	635.66	589.22	549.6
4/3/2015	527.43	521.72	512.93	516.46	515.68	512.75	553.45	551.65	572.66	585.69	586.4	595.22	591.42	598.32	579.72	578.66	577.32	569.82	565.87	576.75	574.17	561.36	539.86	518.14
4/4/2015	489.74	495.9	493.01	493.63	503.89	507.11	529.85	536.49	552.63	559.9	556.13	548.83	545.79	537.65	524.3	531.68	525.92	527.63	533.38	547.89	560	547.92	532.99	519.03
4/5/2015	490.78	488.96	487.48	487.61	490.11	505.01	515.55	520.01	534.89	525.11	510.6	508.55	493.08	488.07	483.04	480.31	490.67	493.26	518.54	540.96	556.53	541.49	509.65	496.67
4/6/2015	477.23	483.57	480.84	481.17	498.15	540.45	605.97	624.73	631.85	645.58	640.69	654.89	651.93	646.99	647.51	647.02	642.1	638.67	637.34	662.13	664.11	628.85	602.38	561.28
4/7/2015	552.57	543.47	541.35	546.58	551.04	582.93	627.5	641.58	654.18	666.42	678.98	678.34	682.33	683.53	657.73	633.53	647.71	649.77	630.13	649.76	662.06	632.51	604.61	567.28
4/8/2015	558.39	546.22	541.04	542.54	545.83	580.22	622.61	647.24	657.7	663.64	678.47	688.04	692.81	692.13	706.73	694.1	693.95	679.96	689.55	697.61	707.57	674.29	636.23	600.25
4/9/2015	581.71	563.31	546.44	551.8	551.71	588.59	636.06	654.85	669.75	687.13	698.5	689.18	703.29	718.44	720.99	716.93	704.94	704.67	693.98	712.32	726.44	689.06	660.18	606.18
4/10/2015	583.61	563.75	541.68	537.23	527.11	550.91	595.3	598.66	615.02	628.5	628.6	634.02	630.57	644.63	641.79	633.74	628.84	623.53	609.45	627.89	640.97	606.85	587.82	553.6
4/11/2015	530.2	523.78	517.41	512.32	517.54	523.49	530.85	549.78	571.69	580.68	577.32	582.76	573.54	579.27	572.45	570.16	573.37	570.17	561.15	585.26	599.78	580.51	559.46	530.06
4/12/2015	515.08	508.73	501.63	504.92	493.63	494.66	494.9	511.33	523.25	530.87	538.1	543.61	540.93	549.59	548.32	558.12	562.73	581.5	580.69	594.29	606.33	578.6	545.83	509.38
4/13/2015	495.49	496.76	480.43	487.86	496.38	531.81	597.55	614.31	639.58	660.19	675.3	681.43	687.29	698.3	695.87	682.97	678.03	664.3	660.18	674.13	666.29	641.45	597.07	563.37
4/14/2015	542.13	534.66	521.24	520.06	527.41	548.99	602.88	622.04	627.2	645	638.8	645.78	643.65	647.07	653.51	646.43	651.5	636.81	625.52	650.63	658.3	634.96	592.74	563.53
4/15/2015	546.91	538.29	530.42	529.01	534.84	557.54	604.7	622.98	624.81	642.16	634.12	649.42	650.6	649.11	650.89	644.61	642.97	633.41	632.8	656.61	658.78	631.27	591.62	558
4/16/2015	544.11	536.42	526.51	527.62	536.54	558.54	609.18	635.56	640.25	661.42	663.2	664.78	675.97	671.93	680.35	687.42	688.69	676.19	669.04	686.39	692.14	661.43	625.7	574.67
4/17/2015	565.34	552.17	539.76	541.61	548.26	575	613.42	626.23	655.55	668.26	680.8	687.76	691.24	701.55	700.11	691.73	686.93	679.43	655.55	663.07	671.99	645.06	615.54	577.99
4/18/2015	545.64	531.31	517.52	527.37	509.48	524.18	509.92	522.12	542.17	572.68	577.5	598.84	604.12	615.55	625.26	619.59	634.82	631.56	612.08	621.04	628.09	598.77	572.34	538.55
4/19/2015	511.96	502.03	484.58	483.49	472.4	483.14	486.96	501.08	524.49	539.26	554.25	564.09	565.56	570.48	565.52	572.93	585.49	590.96	600.47	607.14	594.03	571.63	542.92	516.22
4/20/2015	506.12	500.29	492.25	491.03	504.7	543.36	586.23	612.2	620.46	637.25	639.18	636.95	640.79	647.52	626.04	624.91	632.27	608.59	596.04	644.19	641.24	614.86	588.21	549.45
4/21/2015	538.34	535.53	529.29	525.64	536.21	564.08	606.06	621.41	622.32	630.73	639.51	636.33	635.01	638.34	629.64	630.63	615.12	616.29	591.45	631.76	644.95	625.52	582.34	551.52
4/22/2015	532.49	533.98	528.91	524.15	536.52	562.74	597.9	622.8	625.79	630.52	630.22	631.93	633.93	633.53	623.05	629.13	620.33	609.94	612.3	626.61	655.38	629.61	598.4	556.97

Dt	Hour1	Hour2	Hour3	Hour4	Hour5	Hour6	Hour7	Hour8	Hour9	Hour10	Hour11	Hour12	Hour13	Hour14	Hour15	Hour16	Hour17	Hour18	Hour19	Hour20	Hour21	Hour22	Hour23	Hour24
4/23/2015	547.79	551.24	541.44	549.59	560.41	589.72	629.75	644.39	638.46	642.08	640.38	648.55	638.55	630.25	610.02	617.83	630.3	614.31	601.38	627.68	647.05	623.49	588.49	554.62
4/24/2015	550.42	540.81	536.71	539.62	554.52	586.01	624.56	634.64	646.75	638.7	643.19	633.72	636.07	626.23	628.73	626.23	620.92	599.9	599.04	621.18	630.18	605.87	578.26	549.13
4/25/2015	523.74	516.57	509.76	510.24	510.06	513.86	527.27	541.25	573.42	584.62	587.07	595.55	593.73	596.47	591	601.88	591.4	606.31	594.2	597.76	610.69	585.04	555.81	523.06
4/26/2015	516.97	502.37	495.99	495.16	486.96	489.81	490.01	501.88	524.79	539.87	530.5	546	544.19	541.09	538.58	546.18	546.65	555.39	558.19	572.21	586.93	566.58	541.75	513.78
4/27/2015	497.35	503.22	491.04	497.63	510.67	557.01	609.92	625.74	638.8	651.04	644.23	647.24	649.02	648.19	643.35	641.87	639.15	629.92	620.24	640.09	655.58	627.61	590.56	553.3
4/28/2015	540.46	528.31	526.14	535.65	538.59	571.3	611.28	627.83	638.12	641.62	645.08	646.32	642.84	654.98	644.62	645.81	632.33	627.32	615.33	635.16	644.73	625.55	587.83	559.49
4/29/2015	544.43	531.91	531.08	533.45	542.03	564.36	603.33	621.35	627.9	637.55	647.15	646.32	649.7	661.31	658.12	661.69	646.63	638.68	633.22	642.75	658.59	636.03	592.45	559.37
4/30/2015	537.32	536.92	523.83	523.92	527.52	564.64	603.07	614.56	639.84	637.19	645.94	646.22	642.58	655.2	645.49	640.96	635.31	619.73	610.63	628.07	648.44	624.58	592.39	555.06
5/1/2015	541.76	531.26	537.89	530.54	536	566.94	602.56	616.23	628.26	621.67	624.78	632.92	633.02	639.35	639.5	638.99	623.86	613.4	607.68	608.23	630.76	614.6	580.62	540.74
5/2/2015	523.8	509.53	506.49	503.18	505.59	512.53	507.84	523.41	532.14	549.68	563.37	565.82	575.92	572.92	575.56	583.38	577.22	582.36	571.8	580.51	587.53	577.39	540.26	517.43
5/3/2015	497.67	485.44	471.75	468.6	471.62	476.03	474.03	495.28	513.97	534.58	546.87	564.25	572.04	585.82	587.79	599.84	616.56	623.24	617.12	619.36	631.03	614.06	571.75	539.64
5/4/2015	519.14	510.67	495.44	503.79	514.68	554.22	600.01	625.95	641.45	661.74	689.67	702.69	733.18	750.58	762.83	766	767.22	753.67	748.61	744.32	752.54	722.1	669.32	626.5
5/5/2015	598.06	580.25	559.96	546.59	553.18	579.84	610.09	639.99	669.05	698.8	727.27	748.91	765.74	784.17	799.18	802.92	809.04	797.76	777.79	770.76	775.52	733.18	674.1	623.55
5/6/2015	594.3	576.85	555.92	555.27	549.28	585.41	612.2	652.17	674.21	699.56	727.64	758.02	783	805.22	819.25	836.37	825.41	823.87	801.16	785.65	791.4	761.93	701.81	646.9
5/7/2015	611.59	602.75	566.19	571.17	569.33	585.69	619.4	664.59	688.16	715.2	747.9	769.91	789.03	814.46	827.84	837.05	838.55	816.02	796.13	783.01	779.66	745.16	688.93	641.21
5/8/2015	608.85	595.21	585.11	563.12	573.76	585.34	619.25	667.59	688.13	725.86	755.89	778.53	801.88	836.66	837.66	850.43	817.46	770.16	742.92	733.92	730.33	711.44	667.59	616.1
5/9/2015	596.8	572.42	563.43	547.36	552.47	547.87	536.34	558.63	587.27	601.68	625.8	646.06	662.83	667.63	668.01	676.86	684.12	699.52	688.85	674.54	689.58	674.8	629.11	587.77
5/10/2015	563.81	541.34	532.58	522.09	519.04	522.7	522.79	546.45	576.07	613.5	632.94	654.55	694.12	710.15	735.79	754.38	757.19	758.56	737.68	735.03	737.99	692.94	633.26	595.19
5/11/2015	560.12	556.84	538.35	542.96	550.35	595.84	634.57	675.92	695.87	745.94	763.89	757.23	766.63	770.94	775.14	768	766.51	760.24	746.39	731.52	750.2	719.98	667.69	625.06
5/12/2015	590.84	575.2	553.17	553.95	546.04	579.84	600.12	634.59	648.46	669.54	675.36	685.36	684.88	692.96	700.35	694.3	699.11	669.92	657.1	659.13	676.45	650.46	610.89	575.27
5/13/2015	558.69	540.94	538.73	534.42	541.83	557.83	595.88	624.67	635.47	648.32	658.71	661.89	664.38	678.23	684.13	695.68	691.48	676.77	661.65	666.46	673.63	660.27	608.73	579.66
5/14/2015	549.12	548.04	531.88	534.74	539.69	553.58	592.31	618.33	634.62	648.8	653.72	662.86	671.7	678.63	678.09	687.4	679.19	669.57	656.48	671.37	693.63	678.3	638.08	589.23
5/15/2015	565.56	553.72	546.83	543.91	544.46	566.67	604.32	643.05	659.67	691.79	709.42	739.53	760.34	789.57	803.74	829.9	815.9	800.78	768.19	750.76	725.37	707.05	666.05	623.24
5/16/2015	587.15	575.68	557.83	560.92	562.75	557.97	564.1	595.49	619.49	649.42	656.42	669.16	667.41	681.99	681.49	675.46	665.64	663.27	667.65	661.73	679.97	673.71	636.57	603.76
5/17/2015	575.52	555.25	552.05	543.07	534.21	522.08	516.36	544.6	579.81	596.08	617.11	649.94	651.4	671.48	670.51	670.5	692.64	700.94	702.23	686.75	705.43	678.66	639.43	596.66
5/18/2015	570.01	561.8	543.11	547.15	562.59	594.44	645.84	678.85	703.94	715.5	732.56	737.58	738.38	748.55	748.93	759.84	773.62	781.29	772.33	766.25	770.66	734.84	685.22	634.27
5/19/2015	603	591.75	554.95	558.7	553.44	569.3	593.35	633.25	645.25	649.45	667.33	669.22	682.51	690.88	693.06	706.63	696.28	688.58	681.12	672.23	680.74	660.09	619.99	572.05
5/20/2015	563.82	518.6	532.61	533.08	535.22	553.16	586.11	610.71	618.73	632.29	650.92	648.99	648.44	653.22	654.3	642.79	644.14	628.37	628.42	639.52	647.88	627.39	592.63	565.25
5/21/2015	550.95	543.78	536.38	528.35	539.1	556.65	599.4	617.89	633.05	640.29	642.99	648.23	649.48	655.05	644.8	646.24	634.29	616.61	610.58	621.06	638.71	625.93	597.85	559.91
5/22/2015	546.22	543.69	535.39	534.93	543.13	556.66	591.29	614.58	629.17	633.22	644.25	640.62	652.68	653.95	661.49	664.43	658.45	640.32	631.43	628.97	640.77	633.92	605.46	555.27
5/23/2015	532.68	523.65	511.34	500.18	502.03	503.91	493.74	516.78	528.65	556.64	565.74	583.11	590.77	601.76	613.35	623.18	631.93	636.39	616.21	603.63	617.95	604.44	560.85	540.04
5/24/2015	511.5	496.74	486.23	473.83	474.21	472.59	469.03	499.11	528.31	550.31	578.38	603.98	624.41	645.64	662.86	675.67	681.72	683.78	671.77	654.41	661.39	646.1	605.97	580.84
5/25/2015	546.01	523.48	510.09	506.6	494.41	501.21	493.42	507.96	534.81	557.43	598.46	617.13	632.09	629.09	628.42	624.57	629.08	644.46	635.54	626.76	639.15	626.94	585.32	545.7
5/26/2015	537.45	517.66	517.58	509.38	527.37	538.67	594.02	660.7	703.28	724.76	739.03	757.58	761.56	783.01	797.68	804.64	803.03	780.44	758.85	748	751.8	729.86	676.76	630.06
5/27/2015	593.43	585.34	565.44	563.07	557.43	577.92	620	676.89	694.1	728.51	740.83	747.45	774.08	800.49	815.46	816.1	799.35	779.64	751.29	742.88	754.1	723.33	684.48	632.71
5/28/2015	606.54	592.91	582.63	581.03	580.5	592.95	624.6	670.22	699.45	735.4	779.58	806.47	834.27	862.92	872.93	885.91	882.57	877.01	856.35	835.31	827	808.78	738.51	682.05
5/29/2015	653.34	631.42	610.28	601.48	599.99	617.1	651.32	699.76	727.12	744.93	758.93	792.06	823.36	851.37	873.36	879.91	875.15	865.55	840.53	817.16	809.5	783.66	739.5	676.81
5/30/2015	638.67	618.81	598.74	584.34	578.24	567.65	572.45	607.83	655.82	698.94	741.46	763.1	771.67	784.75	791.22	787.67	768.8	720.91	712.85	689.53	691.47	680.94	641.3	602.92
5/31/2015	581.67	551.19	522.34	508.48	497.83	492.34	489.38	501.41	521.15	532.35	544.87	550.38	555.5	564.12	563.46	562.16	565.54	576.89	567.87	583.15	582.34	570.95	553.23	532.38
6/1/2015	513.29	504.24	504.34	500.58	513.81	543.82	578.22	617.91	633.69	647.54	663.85	658.41	668.5	678.72	681.39	675.7	655.77	646.02	643.36	645.04	660.28	644.3	609.28	575.35
6/2/2015	558.91	552.73	541.9	541.74	540.66	565.15	588.03	629.17	634.68	649.15	664.11	656.05	668.42	675.1	668.07	669.78	656.96	653.88	641.31	643.7	665.4	646.53	619.28	578.7
6/3/2015	560.42	554.5	537.61	540.71	554.26	551.68	572.13	610.04	635.1	650.37	662.5	673.81	690.12	706.95	712.7	713.13	714.9	710.11	695.81	682.57	691.93	679.34	636.39	585.74
6/4/2015	571.16	560.08	543.16	543.37	544.48	557.13	585.31	623.11	645.16	669.56	694.38	705.26	739.14	763.38	783.91	808.06	799.67	793.01	772.65	759.48	757.53	732.66	684	639.32
6/5/2015	608.2	586.75	573.01	569.83	562.27	576.22	599.6	650.73	683.07	735.23	778.94	802.07	829.34	853.45	875.35	888.28	878.52	876.35	862.44	828.55	840.1	766.93	748.33	678.68
6/6/2015	649.7	613.32	598.68	576.2	564.05	554.15	548.91	580.71	614.48	652.43	693.75	730.7	759.12	782.31	801.03	816.6	814.95	804.36	777.83	757.01	737.87	718.09	674.89	621.96
6/7/2015	580.53	562.23	541.8	526.28	521.78	517.7	526.61	560.22	613.1	667.06	722.47	761.22	786.68	816.62	833.59	849.81	861.89	873.75	857.46	831.01	829.28	795.17	746.28	694.74
6/8/2015	664.22	638.68	612.53	589.97	584.69	615.65	646.04	678.61	688.27	719.46	734.11	746.65	750.3	761.41	774.3	799.65	805.06	812.97	809.09	792.41	782.98	771.97	706.94	664.48
6/9/2015	630.99	609.19	602.4	594.16	588.62	599.29	637.58	683.31	727.24	781.38	817.3	862.72	886.56	926.38	930.35	946.33	936.21	924.71	900.34	874.56	856.52	809.02	745.11	686.8
6/10/2015	644.63	618.34	612.26	587.34	595.73	602.03	638.03	678.15	731.28	787.54	838.19	884.47	904.07	965.06	961.44	984.22	984.11	965.37	952.38	919.09	892.94	849.68	791.29	724.35
6/11/2015	679.61	650.68	622.96	619.28	612.81	630.76	664.29	725.76	780.62	838.85	893.26	941.99	962.65	993.66	1003.74	1029.28	1013.37	995.83	976.73	940.77	925.61	893.23	825.26	768.57
6/12/2015	723.84	695.84	675.72	661.49	657.83	677.49	699.14	761.2	804.22	863.54	916.09	946.81	971.87	1006.66	1001.37	1020.23	1003.48	981.03	934.61	876.25	851.45	832.99	785.39	723.3
6/13/2015	702.06	675.1	657.03	641.9	619.82	612.57	627.41	660.7	712.53	750.79	771.61	806.96	817.75	845.96	853.16	826.14	790.02	803.99	781.2	766.95	763.92	752.4	709.55	675.98
6/14/2015	626.75	617.33	594.57	581.66	580.86	574.84	580.69	616.72	659.09	703.49	738.92	765.2	809.01	839.43	842.4	859.03	864.19	868.98	837.61	818.02	778.37	754.03	707.52	636.13
6/15/2015	603.31	585.95	571.66	565.55	578.64	597.86	658.25	714.43	769.04	774.4	865.06	893.54	926.15	954.46	970.88	985.55	989.87	977.38	955.7	934.33	920.33	901.4	823.5	770.67
6/16/2015	728.1	700.44	685.24	670.3	666.49	685.19	712.87	755.32	791.48	841.95	859.82	876.18	904.1	940.13	968.57	984.45	979.32	955.62	925	902.63	911.88	872.11	806.02	757.26
6/17/2015	710.04	671.81	665.81	647.92	649.86	659.19	691.66	733.75	762.57	806.09	857.11	845.07	948.48	972.33	935.89	939.14	954.41	907.12	882.46	845.01	838.73	820.71	787.52	714.79

Dt	Hour1	Hour2	Hour3	Hour4	Hour5	Hour6	Hour7	Hour8	Hour9	Hour10	Hour11	Hour12	Hour13	Hour14	Hour15	Hour16	Hour17	Hour18	Hour19	Hour20	Hour21	Hour22	Hour23	Hour24
6/18/2015	667.23	660.71	613.14	625.73	624.91	643.25	685.34	734.4	778.29	823.24	896.62	904.7	938.59	961.51	964.14	939.36	935.04	872.06	848.06	832.72	837.57	802.83	744.51	706.27
6/19/2015	676.85	653.78	635.46	613.48	622.71	635.92	666.68	720.84	739.07	779.24	824.84	844.6	867.66	891.49	894.94	848.21	822.32	787.94	774.21	768.44	773.61	741.89	709.4	662.82
6/20/2015	634.33	620.95	602.02	589.02	578.68	590.39	590.97	596.74	626.05	654.86	669.48	690.65	695.83	724.56	741.6	769.56	786.74	796.84	779.5	759.06	737.32	714.19	676.51	631.69
6/21/2015	597.84	592.34	574.3	565.89	553.32	550.99	555.81	594.03	643.12	685.31	720.36	743.96	760.34	796.96	824.27	861.09	877.08	888.11	853.88	822.79	797.37	769.6	706.45	662.28
6/22/2015	612.01	601.86	583.73	576.31	581.41	604.75	634.08	693.39	753.97	801.86	856.87	901.05	940.83	988.64	1008.12	1010.92	993.64	976.31	953.94	940.42	932.91	907.88	838.07	781.96
6/23/2015	739.61	708.21	692.91	681.63	695.71	712.56	736.08	788.92	832.37	889.42	936.03	969.37	1003.38	1026.88	1033.95	1030.69	1018.29	1001.3	986.84	950.51	928.98	876.13	802.6	729.2
6/24/2015	687.98	655.17	629.96	616.94	616.3	622.89	652.38	699.22	734.07	767.69	807.29	844.62	889.25	906.25	915.54	929.82	932.5	924.67	910.61	868.95	855.6	822.05	758.15	706.28
6/25/2015	664.3	637.81	630.06	612.72	614.42	630.17	665.82	709.03	733.54	783.67	825.37	875.11	913.24	959.02	996.46	1026.23	1031.45	1023.15	1008.63	972.29	960.19	928.61	857.44	774.65
6/26/2015	714.03	679.25	655.33	645.43	634.59	649.76	671.26	703.16	749.93	770.18	790.93	819.48	877.29	916.1	930.49	914.41	861.58	822.58	785.91	766.9	755.87	747.68	702.66	660.78
6/27/2015	622.1	610.54	593.15	582.33	570.82	567.74	562.33	571.36	593.08	611.89	628.88	651.99	658.8	676.69	693.03	704.53	714.76	720.74	684.95	659.32	638.17	637.22	599.53	552.71
6/28/2015	533.34	509.81	491.96	482.4	485.86	467.7	482.63	500.77	534.44	565.56	599.36	620.63	652.96	674.14	689.92	711.92	727.37	720.8	713.83	701.74	699.73	691.51	648.91	609.12
6/29/2015	582.81	559.02	551.1	552.23	559.23	581.75	616.39	668.05	710.93	763.93	802.03	827.05	856.28	881.1	891.55	906.43	894.93	883.01	858.58	822.52	813.84	776.3	724.79	671.4
6/30/2015	630.3	619.13	594.24	590.94	595.21	614.56	631.96	683.15	711.52	761.64	806.48	853.66	894.52	909.59	913.75	914.05	898.29	888.42	852.58	843.47	822.47	799.31	745.63	693.68
7/1/2015	654.69	632.39	619.62	604.34	604.44	616.15	643.91	686.72	714.74	738.79	756.06	756.83	753.63	778.14	790.97	830.96	851.06	843.71	820.59	809.1	802.75	789.05	738.84	682.7
7/2/2015	656.34	634.33	617.16	614.18	614.5	624.83	643.96	683.04	696.27	720.39	740.95	760.14	791.81	806.54	832.65	828.19	819.24	801.5	790.7	769.7	773.16	756.74	706.41	644.99
7/3/2015	613.07	588.49	567.55	557.07	538.96	536.95	539.66	552.69	581.97	593.65	624.36	648.72	679.1	698.74	726.9	736.87	738.72	741.1	710.68	676.32	662.81	654.34	606.46	574.78
7/4/2015	535.41	515.84	492.84	486.19	473.2	477.76	468.45	493.38	541.9	585.41	621.79	661.34	676.85	696.71	708.96	720.93	714.46	709.09	671.65	655.41	626.39	617.59	598.4	571.22
7/5/2015	534.13	522.79	496.74	490.46	484.88	484.9	481.23	518.68	550.47	589.67	639.7	670.29	711.37	734.22	743.71	772.52	787.58	795.61	772.45	746.18	732.11	727.67	669.53	627.18
7/6/2015	586.87	568.09	553.89	541.91	548.82	571.83	608.64	663.57	719.56	777.87	832.13	870.21	907.26	937.83	955.52	970.69	965.18	954.06	928.86	913.27	895.19	867.87	808.76	752.1
7/7/2015	715.47	693.59	671.81	665.69	662.21	677.12	710.55	736.09	746.58	766.93	786.43	799.44	794.73	799.56	790.97	779.33	770.58	779.76	775.93	774.08	789.49	758.56	712.83	657.69
7/8/2015	625.45	602.7	586.57	579.39	575.42	588.32	613.66	642.77	652.81	666.23	687.14	690.83	715.75	750.73	786.08	818.94	837.04	837.21	827.01	821.12	819.87	798.45	756.18	708.99
7/9/2015	677.19	638.88	612.68	608.94	606.07	627.71	652.01	691.69	709.74	731.33	738.22	745.76	768.01	798.76	826.76	854.67	870.65	870.89	854.66	820.25	810.05	780.91	732.12	665.86
7/10/2015	640.91	613.22	596.98	593.88	585.12	607.3	633.23	673.08	687.81	735.68	770.54	802.15	816.56	847.09	856.85	866.24	851.41	828	800.04	774.58	762.21	744.16	697.14	644.52
7/11/2015	607.97	589.98	573.79	559.48	551.14	546.78	547.62	568.98	601.34	641.4	668.06	718.81	760.21	804.1	836.28	872.66	880.18	882.45	852.69	832.89	824.55	794.38	746.02	703.26
7/12/2015	656.2	630.64	610.43	599.09	591.25	597.63	589.1	629.54	676.37	731.82	761.44	809.65	833.34	871.66	885.15	921.67	934.37	937.25	916.69	890.55	880.91	850.3	798.07	739.8
7/13/2015	707.1	678.67	650.58	641.71	633.18	645.58	681.41	747.42	802.51	864.06	923.13	972.05	1004.16	1032	1054.39	1058.62	1049.51	1044.14	1023.34	984.06	967.77	931.15	865.69	823.9
7/14/2015	778.76	744.32	724.23	708.34	710.95	736.25	755.22	804.71	836.11	897.27	952.48	994.43	1032.5	1037.37	1055.33	1067.89	1054.4	1048.11	1008.81	963.12	949.18	896.88	837.2	767.18
7/15/2015	714.27	679.72	649.11	620.48	612.63	620.14	645.32	688.35	713.18	761.89	800.14	838.51	863.13	889.43	902.36	910.15	896.25	885.23	858.3	817.05	808.65	779.37	723.95	668.94
7/16/2015	633.34	607.24	597.06	576.94	585.16	601.27	630.08	681.76	724.31	770.48	828.41	856.87	895.21	921.43	942.84	963.99	962.42	957.08	931.79	894.29	879.88	852.54	776.62	727.42
7/17/2015	684.58	660.51	635.17	637.58	636.89	660.41	678.27	739.74	801.92	862.3	918.42	964.41	992.76	1031.25	1038.15	1038.25	1033.64	1018.33	990.29	949.17	933.21	905.06	837.61	780.94
7/18/2015	738.78	709.27	684.33	666.56	652.83	653.21	653.32	698.63	764.87	830.41	893.37	935.98	957.58	982.02	986.16	1001.81	992.32	979.81	956.9	928.3	912.21	871.37	827.96	773.97
7/19/2015	736.52	701.45	670.17	653.44	642.3	635.78	627.61	664.16	716.09	771.93	813.79	856.84	894.7	923.54	946.03	964.76	963.1	965.79	938.98	898.6	876.55	844.19	785.95	739.48
7/20/2015	691.85	668.85	641.75	639.46	642.6	667.59	708.65	750.74	773.41	804.2	837.24	858.73	887.93	902.96	907.42	931.8	942.07	942.96	918.34	908.88	886.82	842.66	795.81	745.93
7/21/2015	709.03	688.16	674.4	659.55	660.73	679.77	703.84	748.41	785.05	827.03	878.88	911.59	939.46	971.31	982.47	990.26	974.55	954.34	911.6	878.58	859.38	822.68	758.51	707.58
7/22/2015	662.04	651.54	624.65	614.88	607.85	618.96	642.54	685.71	718.56	764.16	800.12	828.37	864.37	895.34	925.51	936.69	932.23	902.72	871.2	850.67	840.7	811.27	759.68	690.49
7/23/2015	655.55	639.01	621.14	609.97	612.21	637.99	654.36	693.91	720.39	746.64	793.92	832.63	863.24	884.13	907.44	927.78	933	922.75	891.5	858.88	849.74	820.03	758.23	699.94
7/24/2015	662.23	628.81	613.07	601.4	607.13	613.4	634.23	682.89	733.72	781.77	825.46	866.31	890.91	918.44	934.65	956.18	949.56	934.79	903.39	879.4	857.05	817.33	752.86	695.17
7/25/2015	650.09	627.88	596.24	587.19	577.72	567.54	560.02	592.3	639.77	690.57	744.17	770.86	803.36	845.6	866	894.26	894.6	893.29	856.53	842.03	826.57	795.9	745.24	690.42
7/26/2015	656.02	622.52	602.15	583.97	582.09	579.83	573.78	606.79	662.63	709.34	740.56	757.33	789.96	799.31	820.15	845.78	850.49	870.97	857.49	837.01	824.77	796.84	747.76	695.88
7/27/2015	669.28	650.01	621.84	617.41	632.82	651.51	699.28	739.38	772.06	817.07	866.83	907.1	955.66	986.62	1016.47	1027.01	1046.53	1031.74	1001.04	968.04	953.73	909.27	843.18	774.86
7/28/2015	740.37	708.7	684.13	667.38	660.75	677.78	703.28	760.15	814.79	866.61	919.44	964.58	1014.27	1047.38	1064.02	1085.37	1075.8	1068.05	1017.83	964.02	940.89	896.01	823.89	773.52
7/29/2015	724.04	697.85	678.13	664.6	661.38	680.41	717.09	748.78	783.49	820.3	859.74	929.68	989.8	1041.16	1080.85	1089.05	1054.73	1033.14	983.3	957.07	956.93	921.65	856.7	780.6
7/30/2015	734.04	682.68	658.12	632.39	615.81	619	652.73	702.36	746.71	790.59	832.72	877.29	900.64	935.12	947.69	966.85	962.41	945.01	905.16	879.14	863.84	825.59	767.71	705.6
7/31/2015	658.54	632.75	614.15	598.19	600.27	615.2	634.59	694.09	743.52	793.68	841.93	881.63	923.69	955.76	971.06	987.2	988.44	964.58	946.56	911.72	884.34	849.38	792.86	724.79
8/1/2015	674.33	651.7	628.57	606.58	594.72	594.14	586.59	618.06	660.95	702.35	743.31	764.96	795.79	811.16	812.94	830.24	837.76	833.78	812.19	770.86	735.08	702.53	635.45	589.06
8/2/2015	553.65	522.14	505.09	496.8	490.9	485.73	488.9	525.48	565.03	614.65	665.27	709.63	746.41	787.27	813.55	839.46	857.94	865	845.12	811.21	797.67	760.82	700.02	655.69
8/3/2015	609.37	588.09	571.11	560.51	565.88	600.58	633.76	687.67	746.14	809.94	854.93	910.52	950.91	983.62	1009.72	1023.56	1017.63	1005.03	975.24	940.83	924.44	874.26	806.92	729.8
8/4/2015	684.86	651.19	618.79	597.71	603.37	609.17	636.46	670.87	704.65	751.65	786.85	843.84	890.93	946.24	981.19	985.74	909.85	835.56	774.29	739.4	727.21	695.54	649.53	607
8/5/2015	573.51	558.52	537.31	537.46	538.98	564.7	587.93	634.96	663.4	719.45	756.47	762.27	742.48	738.64	738.86	744.36	734.35	743.98	731.05	721.98	726.82	700.49	653.61	612.28
8/6/2015	586.49	564.7	555.19	552.18	548.54	575.66	606.32	634.91	651.91	678.28	690.33	700.15	709.66	706.54	700.9	706.82	702.9	679.59	673.45	672.66	674.44	652.87	616.9	565.75
8/7/2015	547.31	533.52	512.87	517.02	519.45	526.41	555.24	586.34	631.41	655.63	684.09	712.65	741.08	763.05	781.84	794.19	795.07	786.53	759.52	729.18	724.99	693.49	639.09	586.22
8/8/2015	542.99	531.84	507.5	497.5	486	487.9	475.3	499.07	529.7	576.83	612.02	649.4	685.1	714.7	723.5	748.3	766.2	765.3	735.91	708.45	701.38	667.13	618.24	570.07
8/9/2015	536.36	507.04	485.76	469.75	465.12	476.24	469.02	503.59	543.08	584.73	620.11	670.34	693.65	718.61	745.68	780.49	797.25	794.38	783.62	762.16	763.81	719.79	668.31	630.4
8/10/2015	597.97	572.88	550.54	547.42	551.82	586.7	624.37	661.4	684.48	726.4	758.37	792.92	809.34	844.52	848.53	855.25	870.26	868.33	855.65	837.85	837.25	790.2	726.47	659.4
8/11/2015	617.15	592.02	571.05	562.2	560.17	574.11	611.66	651.65	700.09	736.62	778.03	813.79	843.98	874.38	877	901.25	889.87	863.15	825.71	813.19	786.41	742.59	668.92	608.25
8/12/2015	568.05	548.83	521.99	509.98	508.71	539.73	556.61	604.26	628.45	667.04	700.29	736.56	756.89	791.75	815.06	821.76	827.36	809.9	790.93	753.33	753.65	702.54	635.25	576.8

Dt	Hour1	Hour2	Hour3	Hour4	Hour5	Hour6	Hour7	Hour8	Hour9	Hour10	Hour11	Hour12	Hour13	Hour14	Hour15	Hour16	Hour17	Hour18	Hour19	Hour20	Hour21	Hour22	Hour23	Hour24
8/13/2015	544.07	523.56	508.27	503.1	496.62	523.23	554.61	593.49	634.4	666	706.1	738.5	769.5	803.3	821.87	848.12	845.6	828.74	800.82	769.91	754.38	709.28	643.4	584.7
8/14/2015	549.7	525.26	506.86	494.15	504.53	516.03	555.39	580.32	606.01	629.2	668.1	692.3	709.6	751.3	779.7	802.2	785	773.13	747.21	715.01	709.99	673.43	623.2	562.75
8/15/2015	526.11	506.96	482.75	473.44	466.61	458.89	458.62	484.56	518.06	566.64	614.36	670.6	711	737.2	766.17	789.88	804.18	796.12	771.48	742.31	713.96	688.32	611.3	564.1
8/16/2015	520.02	491.95	469.35	455.1	451.29	450.85	441.87	473.57	521.03	581.2	644.1	690.59	724.17	758.46	784.33	809.48	816.89	811.65	789.23	765.85	743.76	700.45	637.75	589.6
8/17/2015	554.9	533.11	516.2	516.22	518.43	555.86	597.87	639.42	671.68	715.52	732.9	775.19	798.53	791.31	808.88	835.78	845.02	820.85	803.86	782.52	779.42	722.83	655.11	601.4
8/18/2015	567.17	549.1	530.9	520.4	525.1	553.7	590.37	621.89	641.58	690.8	747.1	793.5	821.7	863.1	877.5	890	888.6	863.8	846.32	828.9	813.66	755.87	692.61	639.02
8/19/2015	601.14	584.58	559.61	541.91	546.05	572.34	607.65	621.01	628.59	645.36	686.99	703.63	715.67	711.9	705.09	696.85	706.55	720.16	697.62	697.05	689.31	647.31	584.43	541.74
8/20/2015	502.79	495.05	481.6	468.69	478.51	495.38	527.18	559.15	588.4	610.4	638.28	658.02	679.2	699.5	721.4	734	729.2	717.26	690.34	662.03	662.07	614.48	570.83	520.5
8/21/2015	495	480.4	472	456.8	461.2	488.5	510.8	546.8	566.7	597.9	630	639.8	678	703.4	715	735.5	733.1	718.1	678.3	665.8	651.8	626.1	577.3	522.1
8/22/2015	491.7	470.7	462.6	449.9	446.8	450.2	449.4	477	512.6	540.8	579.7	606.6	638.3	671.7	694.8	701.9	714.2	704.8	677	668.8	666.9	640.2	602.8	554.9
8/23/2015	528.7	506.5	494	473.1	467.4	461.3	448.2	478.9	524.3	569.1	623.4	662.4	700.7	731.4	744.6	775.5	779.1	780.4	747.1	733.3	710.5	655	589.3	535.7
8/24/2015	489.3	479.4	455.1	450.7	450.1	484.1	524.9	552.4	579.6	611	627.3	630.7	657.2	688.9	697.2	716.5	711.9	705.3	676	658.5	660.9	612.7	557	512.1
8/25/2015	493.31	483.6	461.9	459.04	461.5	484.6	516.1	541	564.1	588.5	601.8	624.7	630.4	652.5	666.4	675.3	678.4	668.4	646.5	645.7	647.6	606.2	545.1	519.1
8/26/2015	488.1	475.02	464.3	461.69	456.51	480.3	513.46	540.4	564.7	584.7	601	620.29	637.3	662.8	678.5	692.3	700.7	690.11	672.72	668.47	658.85	623.3	569.68	531.6
8/27/2015	500.12	485.7	477.17	465.3	470.6	495.76	522.9	554.07	580.57	608.5	633.8	658.5	689.2	712.4	725.6	737.6	743.4	725.37	710.27	691.96	686.85	644.27	585.05	544.71
8/28/2015	507.2	492.3	478.09	473.85	471.31	494	521.69	546.31	571.9	607.8	636	650.13	681.4	707.6	724.3	753.4	758	731.7	708.2	687.58	692.24	648.2	619.8	575.4
8/29/2015	547.42	515.3	491.75	484	473.63	475.41	470.9	490.11	516.39	549.73	600.1	637.8	672	684.88	702	708.87	704.44	692.63	669.12	666.94	651.2	627.34	582.22	542.59
8/30/2015	512.1	487.1	471.19	461.7	458.3	467.07	464.3	490.5	514.9	558.6	609.04	649.49	686.3	719.8	724.17	743.77	738.7	758.5	714.59	709.77	691.89	642.76	583.79	541.96
8/31/2015	507.9	483.6	475.54	460.16	481.47	512.69	566.02	596.27	637.9	680.2	730	760.7	807.52	842.3	857.36	879.2	874.1	857.3	832.3	810.74	799.45	742.85	671.63	612.1
9/1/2015	581.3	559.9	539.3	536	530.4	558.9	596.1	632.3	672.4	725.8	770.7	814.6	857.3	895.3	916.7	928.4	928.9	905.2	867.3	857.3	829.3	783.8	704.8	657.6
9/2/2015	612.8	588.2	571.1	557.7	554.3	570.5	618.6	646.7	691.6	742.7	793.2	839.5	877.6	915.3	959.7	950.9	950.7	929.8	900.6	870	843.5	787.4	709.9	653.6
9/3/2015	611.6	589.3	573.7	559.8	555.4	582.7	619	654.6	694.2	753.1	804.4	853.3	895.2	932.87	941.8	962.4	954.5	937.5	898.4	881.6	852.7	794.3	724.8	666.6
9/4/2015	619	601.6	573.9	566.9	558	578.7	611.6	649.1	694	745.5	803.4	847.8	891.4	929.9	944.7	959.9	943.7	916.2	881.2	853.7	824.4	773.8	718.8	650.2
9/5/2015	609.3	586.1	555.9	547	518.6	518.2	501.9	529.1	572	632.9	687.4	749.6	794	834.8	838.1	854.1	854.2	843.6	806.5	777.6	748.7	700.3	659.7	599.4
9/6/2015	562.4	535.6	518.8	500.6	492.1	492	485.5	504	557.8	610.8	672.3	721.1	777.9	805.8	827.4	839.6	847	828.4	797.8	774.2	744.8	708.3	651.4	608.4
9/7/2015	565.9	530.7	515.9	499.8	492.1	496.5	492.4	508.8	551.6	622.3	679.2	743.6	772.6	813.5	827.1	833.3	848.7	846.7	813.3	802.2	774.3	723.4	655.4	608.5
9/8/2015	573	551.9	537.6	521.7	534.2	567.7	614	664.4	707.3	767	816.5	871.3	897.5	936.6	952	963.8	955.1	939.1	893	890.2	848.2	783.2	723.6	659.1
9/9/2015	624.7	599.2	579.1	575.2	580.7	600.5	649.7	677.9	687.6	701.4	739.1	742.2	739.9	741.1	729.3	716.7	732.1	727.7	716.7	727.4	719	673.3	637.8	583.7
9/10/2015	570.3	550	541	546.2	541.3	564.7	610.8	631.4	661.2	694.5	736.9	767.2	800.1	834.1	860	866.7	865.1	842.1	800.8	801.6	777	721.2	652.5	609.9
9/11/2015	567.9	553	534.3	529.7	524.8	556.4	587.6	625.1	649.5	667.4	667.5	671.9	674.2	680.4	671.3	671.5	656	638.3	627.8	641.3	632.8	615.9	574.4	541.2
9/12/2015	514.2	500.1	490.5	479.6	483	484.9	497.4	509.4	501.4	554.9	557.4	570.2	575.5	567.4	561.5	558.5	549	540.5	534.5	556.9	558.9	539.5	511.6	491.7
9/13/2015	465.9	463.7	455.8	447.6	435.4	432.6	433.8	444.9	464.5	484.4	495.7	506.4	511.5	522.2	532.9	543.5	530.9	543.6	536.3	552.1	541.7	514.9	485.8	455.6
9/14/2015	449.1	436.4	437.9	440.1	450.3	485.3	528.7	549.7	563.5	592.2	614.3	629.5	648.1	661.1	670.8	683.3	688.6	683.4	663.8	667.9	658.8	615.9	571.7	536.7
9/15/2015	513.3	502.9	497.7	496.9	488.3	521.4	554.3	576	587.1	616.9	643	659.6	681.2	698.1	717.5	730.3	739.6	727.2	698.7	717.5	691.9	652.4	603.7	564.1
9/16/2015	532.9	519.7	517	509.7	511.2	527.3	570.9	584.6	615	647.6	664.3	695.7	720.7	744.7	760.9	784.7	790.4	780.9	747	756.3	724	684.8	633.5	577.1
9/17/2015	553.9	524.6	513.5	515.4	508.2	541.2	574.6	598.8	628.8	656.4	687.5	722.3	755.1	790.1	814.4	843.4	836.4	822.5	792.9	793.3	781.7	721.6	664.8	616.9
9/18/2015	578.4	564.7	548.4	537.2	542.1	562.4	597	625.1	646.7	696.6	747.1	791.8	835	870.6	891.3	917.5	918.3	903.5	858.4	850.2	813.2	777.6	725.9	678.5
9/19/2015	629.3	611.6	581.1	572.9	566.5	582.9	572.1	587.9	616.1	635.2	634.1	633.6	655	679.8	690.7	710.5	694.9	670.1	640.1	647.3	621.2	603.3	562.9	528.3
9/20/2015	500.3	488.4	475.9	468.3	464.7	470.2	469.4	485.5	505.1	531.8	546.1	574.7	589.4	601.7	607.3	614.3	617.3	627.5	607.2	640.1	616.2	589.3	548	519.2
9/21/2015	497.8	486.1	483.6	484.5	501.1	533.9	587.7	604.7	638	656.2	672.8	693.1	706.6	737.9	752.8	765.9	772.1	775.1	746.6	750.3	720.5	676.7	629.1	598.2
9/22/2015	572.7	558.5	553.1	540.1	522.8	559.6	600.9	610.6	640.2	677	703.2	712.9	722.3	734.7	775.1	805.1	801.1	791	758.9	764.2	736.1	685.5	635.4	597.3
9/23/2015	564.7	559.2	550.2	540.3	547.7	571.8	620.2	622.2	640.7	686.7	708.7	731.1	759	788.1	800.2	836.2	829.5	812.9	794	782.9	761.2	700.2	662.7	608.3
9/24/2015	580.1	570.2	554.4	551.6	546.4	576.3	613.2	638.9	658.2	690	721.9	755.7	781.1	819.8	841	853.9	856.7	836	803.4	808	770.8	735.3	677.2	629.3
9/25/2015	603.9	588.7	567.6	566.3	567.2	589.4	625	648	669.5	706	725.3	752.6	777.9	809.6	791.1	805.5	790.4	778.5	722.3	728.3	661.3	687.1	641.6	598.7
9/26/2015	573.1	553.5	540.8	534.5	530.2	534.4	535	538.6	561.9	578.3	596.7	618.5	630.9	645.7	648.7	659.2	644.2	651.7	654	657.1	639	622.3	587.7	573.2
9/27/2015	525.9	513.1	523.7	497.1	496.5	496.6	499.8	509	538.3	558.3	566.6	598.6	616.2	631.4	637.8	635.8	640.1	647.7	659.1	676.9	654.1	629.7	586.1	557.4
9/28/2015	543.2	529.6	515.9	517.7	527.3	567.1	628.6	662.6	654.8	695.5	720	767.4	799.6	822.4	827	832.5	829.4	823.3	813	826.4	796.3	760.5	705.4	669.5
9/29/2015	635.9	614.4	601.9	602.7	604.1	632.5	686.2	717.3	718.1	728.4	734.9	742.9	743.7	747.4	755.3	749.3	749.9	739	745.7	755.5	740.5	712.7	667.8	621.2
9/30/2015	602.9	583.7	566.2	570.4	583.4	591.4	651.4	654.1	659.9	675.8	673.1	679.4	688.2	706.6	716.5	717.8	710.5	680.8	691.2	716.4	692.3	662.4	613	570.2
10/1/2015	556.6	541.7	528.9	529.7	534.6	556.1	602.7	610	619.2	631.2	637.9	653.2	666.3	658.7	663.8	652.5	648.1	624.2	644.1	665.1	658.8	625.3	591.1	562.9
10/2/2015	537.3	536.4	522.2	521.3	524.8	548.4	584.6	601.1	614	618.3	636.6	640.2	637.6	638.9	634.9	629.4	613.7	606.7	610.3	614.5	609.8	600.6	566.4	536.3
10/3/2015	515.5	500.2	494.6	485.5	486.5	491	498.2	509.2	523.6	539.5	542.3	546.4	546.9	538	542	538.8	540.3	543	558.5	565.9	559.2	534.3	519.5	495.9
10/4/2015	477.4	465.9	456.2	456	456.3	463.7	466.5	477.8	505.9	517	522.1	531.1	532.6	536.1	544.6	550.4	564.4	574.1	586.9	611.1	588.8	573.5	546.7	510.5
10/5/2015	504.7	490.2	484	493	506	525.5	547.2	603.5	641.2	666.9	654.3	682.6	714.2	751.8	754.8	767.8	763.1	744.8	743.9	750.8	733.1	700.4	658.1	608.7
10/6/2015	576.8	567.7	558.1	557.3	549.9	581.6	626.5	645.8	651.3	682.4	702.2	725.4	747.7	781.2	795.8	815.4	800.3	786.4	786.8	778.3	758.3	708.1	678.2	623.1
10/7/2015	582.5	572	556.6	550.1	555.1	585.5	620.5	636.2	656.2	670.9	689.2	720.1	726.6	761.5	788.9	830.5	791.8	735.7	754.5	769.8	735.4	694.3	646.7	613.5

Dt	Hour1	Hour2	Hour3	Hour4	Hour5	Hour6	Hour7	Hour8	Hour9	Hour10	Hour11	Hour12	Hour13	Hour14	Hour15	Hour16	Hour17	Hour18	Hour19	Hour20	Hour21	Hour22	Hour23	Hour24
10/8/2015	580	568.9	557.8	555.6	563.8	583.1	635.4	641.9	659.3	684.2	703.7	720.8	752.8	772.3	789.7	803.4	801.1	769	765.1	768.5	740.2	700.1	662.6	615.7
10/9/2015	584.7	571.4	563.6	557.1	563	586.9	621.5	636.6	664.9	679.8	682.3	692.5	684.8	679.5	677	680.1	653.1	649.7	650.4	661.2	644.3	625.4	591	558.4
10/10/2015	530.9	518.6	507.2	500.8	494.8	500.5	495.9	499	518.6	539.4	547.6	557	557.1	567.7	569.5	578.1	577.8	566.7	570.2	575.1	562.2	543.1	521.4	491.2
10/11/2015	484.7	470.3	462.2	458.4	452.9	457.3	477.7	475.9	497.7	513.9	518.3	533.5	538.6	526	537.5	543.8	559.1	553.9	565.2	580.4	558	530.1	511.8	485
10/12/2015	477.6	473.6	468	463.1	483.9	501.5	574.4	599.8	615	650.7	668.4	690.7	720.1	732.5	756.1	759	740.3	717.3	714.5	726.9	700.3	652.7	613.4	573
10/13/2015	558.6	544.8	534.6	533.1	539.8	568.1	607.1	627.3	630.2	650.8	652	665.3	678.2	683.8	697.3	691.5	680.2	668.7	678.2	687.2	677.4	640.7	604.9	565.5
10/14/2015	544.4	545.1	530.3	532.4	537.4	563.3	614	635	629.5	651	668.4	671.7	679	690.2	700.2	698.5	696.6	668.6	674.9	682.2	666.9	630	597.3	559.4
10/15/2015	544.6	533.9	532.7	530.3	536.6	560.6	609	621.7	628.3	640.8	642.7	666.9	659.1	678.3	685.6	684	687.9	667.3	682.8	688.1	681.8	649.3	611.5	572.4
10/16/2015	552.7	546.9	527.8	532.2	527.9	553.5	601.6	608.9	632.2	633.4	646.5	649	647	656.2	651.4	649.3	635.5	621.1	631.2	635.5	627	606.2	579.1	541.4
10/17/2015	530	515.7	515.9	509.7	505.8	514.3	526.9	534.6	556.4	567.2	566.9	567.5	563	552.4	556.7	547.7	554.7	550.2	577.5	577.8	581.4	565.5	542.7	524.7
10/18/2015	510.8	493.1	500.2	495	502.9	507.6	534.7	541	552.3	552.8	550.5	543.2	545.8	545.9	541.9	546.6	548.1	553.8	580.2	586.8	583.9	560	535.9	517.5
10/19/2015	512.5	502.3	505.4	511.8	527	562.5	612.9	637.9	641.3	636.5	638.7	638.4	640.8	646.7	649.6	643	643.8	652.8	662.1	672.3	653.1	625	593.9	560.5
10/20/2015	543.8	538.7	529.3	537	540.1	565.7	620.1	619.5	633.2	653.1	650.1	662	666.3	667.3	670.7	667.1	666.1	658.1	671.5	683.5	663.9	637.8	605.5	571.6
10/21/2015	557	551	540.4	544	550.1	569.8	631.3	637.4	643.6	654.1	660	676.4	687.7	697.9	717	705.3	706.8	698.9	706.9	710.2	688.1	658.7	619.3	581.3
10/22/2015	562.3	547.8	536.5	537.3	549.1	573.5	617.1	631.9	645.7	667.3	674.3	694.4	705	721.4	737.6	738.4	734.3	713.1	725.8	720.9	704.1	669.1	626.4	590.3
10/23/2015	555.2	552.4	533.3	534.2	534.8	554.7	602.8	616.2	634.5	644.8	666.5	682.6	691.5	694.5	678.1	687.1	677.1	664.9	682	672.7	662.7	638.2	596.2	553.6
10/24/2015	558	544.5	528.4	528.1	524	537.7	548.3	571	588.1	607	633.1	636.4	635.8	629.7	631.9	626.4	619.7	625.2	633.5	618.8	607.7	584.5	567.9	530.6
10/25/2015	507.9	500.4	484.3	479.8	471.9	475.6	476.4	486.9	502.2	520.8	524.1	526.6	534.7	537.6	534.2	532.6	537.2	549.8	583.7	575.5	569	547.3	523.7	504
10/26/2015	488.8	491.1	478	491.6	503.4	551.6	599.8	619.9	620.4	637.2	634.5	644.3	644.7	644.7	643.5	638.3	637	648.4	661.9	658.9	642.2	621.9	581.1	559.2
10/27/2015	546.6	533.2	528	528.7	537.1	566.9	608.6	628.8	647	646.3	652.4	656.7	662.5	663.7	661.4	657.2	651.4	651.2	663.9	669	649	618.2	587.6	557.9
10/28/2015	546.4	538	537.2	531	536.8	565.5	616.3	627.9	637.7	649.5	654.7	656.6	662.3	661.8	663.9	645.9	643.1	639.3	656.7	659.2	653.5	622.3	589.3	553.7
10/29/2015	540.2	531.8	523.5	528.6	532.5	553.8	609.1	627.7	627.9	636.3	630.6	641.7	637.3	632.6	627.3	620.4	613.5	618.9	645.2	657	647.9	627.6	593.6	561.1
10/30/2015	555.8	554	536.4	539.2	553.7	570.1	618.8	639.8	640.9	649.3	635	632.2	637.3	621.5	625.3	612.7	602.3	603.4	627.7	632.7	626	600.1	572.9	545
10/31/2015	522.8	523.1	501.4	502.2	507.2	508.8	517.1	522.8	537.3	556.4	561.7	569.3	554.7	557.1	544.5	543.9	543.7	554.7	564	560.7	558	543.8	519.6	357.1
11/1/2015	480.8	479	470.6	467.6	455.5	460	471.1	467.4	479.5	505.2	510.2	523.4	520	522.9	531.6	533.2	539.4	550.5	593	588.7	581.7	563.4	536	516.9
11/2/2015	495.9	486.6	472.9	489.4	483.9	501.4	536.4	587.3	610.4	611.1	621.2	630.2	633.3	635.7	651.4	654.9	642.9	651.3	671.3	675.6	654.8	636.4	612.7	588
11/3/2015	543	524.7	526.1	518.3	518.6	531.7	553.9	598.9	611.2	624.7	631.5	643	654.1	664.5	669.9	669.7	667.4	663.5	682.7	676.9	672.2	650.1	627.1	586.9
11/4/2015	559.7	542.7	532.9	527.8	532.7	530.4	562.8	602.4	619.7	623.6	649.1	676.6	670.5	687.3	684.9	675.3	676.8	677.3	698.3	695.7	683.5	665.2	634.2	598.7
11/5/2015	571.4	550.6	540.1	544.2	541.7	540.4	568.5	621.2	629.5	657	665.9	685	708.5	702.1	705.9	704.3	694	695.3	715.1	709.1	700.5	681	652.6	611.3
11/6/2015	584	564.4	549.9	543.1	544.8	550.9	572.1	614.3	637	647	645.5	651.1	647.3	646.1	641.4	629.9	627	628	640.8	630.5	627.2	617.9	592.7	562.8
11/7/2015	527.6	515.4	499.6	484.9	490.5	496.4	503.8	521	531.9	552.4	562.4	570.3	579	567.6	559.3	557.7	554.7	564.1	589.5	584.5	592	581.6	564.6	552.7
11/8/2015	529.8	515.9	510	504.3	498.2	495.9	495.6	492	512.9	518.6	519.9	521.6	522.4	524.8	519.1	519	524.4	537.7	577	579.8	578.3	565.9	551.4	522.5
11/9/2015	508.3	502.9	501.7	503.5	506.5	523.9	564.8	623.4	626.2	640.8	638.4	651.1	642.2	647.9	640.8	648.9	645.1	654.1	685	679.6	674.4	655.3	635.8	605.6
11/10/2015	572.2	558.5	546.7	544.2	547.8	547.1	579.4	623.5	636.4	636.5	637.8	634.9	634.3	637.4	636.7	642.8	639.6	645.6	669.9	671.8	666.1	661.1	632.8	604.9
11/11/2015	575.2	558.7	559.5	555.7	553.7	565.8	591.9	628.6	638.1	640.3	637.1	640.2	641.7	637	645.8	642.9	636.2	658.2	631	663.5	660.8	645.8	621.3	591.1
11/12/2015	560.2	551.9	540.7	535.4	523	534.8	561	604.9	618.9	631.5	636	638.1	642.3	636.1	635.3	636.6	631	634.7	672.3	658.9	662.5	647.7	627.2	599.6
11/13/2015	566	551.5	547.4	547.5	545	557.6	588.9	631.1	643.6	639.2	638.4	649	642.6	639.6	639.1	627.4	620.1	630.1	645.2	653.4	641.4	645.2	633.4	606.8
11/14/2015	577.6	558.8	555.2	551.5	558.1	559.8	570.8	577	578.8	580	571.3	569.6	552.3	549.8	546.3	536.6	539.9	553.9	592.2	580.2	578.3	571.1	559	532.4
11/15/2015	525.9	500.4	500.1	502.4	500.5	507.4	510.8	523.6	531.1	537	535.2	528	531	528.5	523.8	529.6	524.3	552.1	584.9	584.6	580	564.6	548.8	527.1
11/16/2015	506.9	506.3	506.1	503.1	500	529.6	566.1	611.7	641.3	645.7	645.1	645.8	651.4	653.8	658.2	657.6	659.3	674	684.4	675	665.2	654.9	630.7	589.6
11/17/2015	563.9	547.1	536.7	531.6	537.7	545.3	569.7	618	638.4	642.9	655.7	653.9	664	651.2	641.9	642.1	633.1	653.6	671.6	658.2	657.8	652.5	614.4	589
11/18/2015	553.1	537.3	535.2	524.1	524.1	524.5	544.9	584.7	612.5	611.6	632.6	634.7	639.5	630.1	626.9	626.5	629.2	629.8	672.5	664.4	657.8	643.9	619	591.7
11/19/2015	557.7	543.4	538.6	531.5	535	547.9	570.9	614.3	625.4	625.6	628.1	638.3	629.6	633.7	630.7	623.3	628.4	636	658.2	659.3	662.9	656.4	636	612.5
11/20/2015	583.1	574.8	577.5	561.9	572.9	586.6	619.1	671	676	662.4	651.5	644.8	629.5	626.8	620	620.3	609.5	622.1	648.5	638.8	646.6	636.5	620.9	596.3
11/21/2015	560.5	550.9	541.8	532.9	530.7	529.7	535.8	542	557	574.3	580.5	598.9	613	607.8	596.2	595.7	606	636.4	651	640.9	635.9	627.8	612.4	589.5
11/22/2015	569.6	559	548.9	549.2	544.1	556.6	573.6	583.4	590.9	603.4	602.3	594.8	577.2	576.7	557.2	564.4	563.9	600.1	644.8	654	649.2	647.8	632.1	600.4
11/23/2015	595	586.3	576.3	576.6	579	601.2	639.4	699.9	700.2	697.4	690.4	678.2	668.6	654.8	651.4	641.6	638.4	664.5	689.9	690.9	690.4	681.5	667	625.3
11/24/2015	605.1	595.5	582.3	585.2	594.1	603.3	638.7	677.2	680.2	675.8	663.7	656.9	632.2	633.7	636.2	619.3	629.4	644.9	663.2	667.2	656.4	654.9	628.8	599.3
11/25/2015	573.2	566.8	558.3	562	561.5	573.9	598.4	632	650.1	644.4	653.5	684.8	684.3	615.4	621.8	611.6	613.8	617.6	646.1	644.6	630.5	617.6	591.3	549
11/26/2015	498.3	478.1	459.8	444.9	444	432.6	438.8	452.6	464.5	483.4	508.3	521.6	499.8	482.7	457.4	445.8	441.9	456.7	466.5	474.7	466.5	461.1	455	442.7
11/27/2015	420.6	413.1	404.4	402.7	402.4	413.8	424.7	435.5	451.1	469.8	482.8	489.6	487	495.2	489.4	495.1	504.7	524.6	539.2	530.7	519.2	512.6	494.8	480.4
11/28/2015	451.7	442.4	425.2	421.6	427.5	429	436.7	451	478.1	495.7	515.6	532	533.7	534.7	535.2	529.2	542.8	558.5	573.7	569.3	562	553.3	541.5	517.7
11/29/2015	504	484.9	482.2	476.4	471.3	470.7	485.4	495.6	507.7	521.6	539.9	543.9	552.9	550.8	544.6	555.6	559.3	596.7	607.5	606.9	596.4	584.9	565.3	541.5
11/30/2015	523.6	518	505.1	510.7	509.5	528.7	563.2	625.3	643.4	654.6	653.3	668.2	645.6	663.8	663.1	652.9	676.4	678.9	692.7	683.3	679.5	667.3	638.2	600.5
12/1/2015	564.6	548.2	543.8	536.4	533.3	550.4	579.7	625.7	645.1	645.8	655.9	647.4	644.6	640.4	638.5	638.4	640.2	659.7	689.5	691.7	694.7	690.9	666.3	636.2
12/2/2015	600.2	588.8	577.4	577.2	576.6	588.8	624.9	667.1	678.5	674.6	684.1	682.8	675.7	668.7	670.2	659.7	660.9	696.2	711.1	709.5	708.1	702.7	678.2	648.1

Dt	Hour1	Hour2	Hour3	Hour4	Hour5	Hour6	Hour7	Hour8	Hour9	Hour10	Hour11	Hour12	Hour13	Hour14	Hour15	Hour16	Hour17	Hour18	Hour19	Hour20	Hour21	Hour22	Hour23	Hour24
12/3/2015	622.8	618	604.1	611.8	608.3	631	664.5	715.8	711.7	711.4	694.1	681.8	672.4	664	650.1	649.1	653.5	673	707.1	711.6	713.4	720.3	703.1	673.3
12/4/2015	647.6	637	628.4	633.4	638.2	647.6	674.2	728.8	730.1	714.7	697.2	676.3	666.4	651	640.7	634.2	630.9	654	679.3	682.2	681.4	683.2	669.8	654.1
12/5/2015	617	606	604.5	597	600.7	605.5	605.4	619.7	628.4	637	639.3	619.9	598.4	582.3	562.2	565.7	565.9	591	619.5	626.5	623.3	629	616.8	590.5
12/6/2015	579.4	561.1	554.7	552.3	552.9	562.8	565.6	581.3	590.2	600.3	579.2	570.9	559.4	561.1	543.2	549.1	549.5	594.8	616.3	627.9	612	603.1	593.1	555.2
12/7/2015	534.2	523.1	516	521.4	518.8	542.4	580.9	646.4	661.9	667.8	671.9	666.9	685	677.8	688.9	680.5	677.7	704.6	722.9	722.1	722.1	709.4	686.9	656.3
12/8/2015	616.3	616.3	605.3	605.7	605.9	620.4	653.1	699.2	707.2	703.1	681	675.6	651.3	655.6	649.5	638.9	645.5	653.2	690.2	682.4	688.8	680.9	661.3	630.6
12/9/2015	602.9	588.4	586	576.9	582.4	582.1	611	658.8	658.2	658	649.3	651.1	647.5	647.5	641.6	642.1	636.9	663.1	678.8	681.6	686	673.1	654.3	619.8
12/10/2015	586.2	571.9	563.3	570.1	574	583.1	609.9	654.4	661.8	670.4	662	649	648.9	644.3	638.9	638.5	644.4	662.6	688.7	693.5	678.9	684.5	659.3	625
12/11/2015	591	568	555.3	554.2	554	558.7	578.8	627.4	634.7	645.6	641.4	646.1	640.5	630.9	632.8	631.5	633.1	644.6	662.2	655.1	646.1	636.6	623.6	589.1
12/12/2015	551.2	534	513.6	506.8	507.1	507.2	507.7	529.5	546.2	565.4	580.2	592.6	598.1	590.5	589.1	583	584.8	603.1	626.2	625	616.2	610.9	595.9	573.8
12/13/2015	543.7	518.7	511.6	492.2	491.9	485	481.4	486.1	501.2	520.4	536.2	538.1	551	553.8	550.5	552.6	549.8	587.7	613.7	617.6	617.8	601	580.1	547.5
12/14/2015	521.5	511.1	501.1	494.1	490.7	506.8	540.1	599.9	613.2	632.7	643.7	645.9	647.2	650	650.2	647.2	646.2	679.6	691.7	693.9	687.1	682.1	658	616.2
12/15/2015	588.4	560	553.4	548.9	547.4	557.2	585.1	641.5	646.7	651.8	654.3	644.3	634.7	638.9	637.5	633.1	627.8	646.3	682.9	673.6	685.6	676.4	658.9	623.3
12/16/2015	593.5	578	570.2	566	565.4	575	601.1	654.8	654.8	667.4	662.5	664.3	657.8	657.4	653.2	651.1	657.2	673.4	685.7	682.1	672.4	682.4	648.4	617.7
12/17/2015	589.7	571.6	571.5	567.1	577.3	591.6	629.7	685.4	689.2	684	679.1	675.6	665.3	678.2	680.6	685.1	692.4	719.5	733.4	728	727.5	729.3	700.8	661.8
12/18/2015	629.6	609.5	603.6	597.2	600.2	607.4	632.9	688.1	699.3	709	699.6	699.8	693.4	683.8	669.7	660.1	654.9	689.8	715.4	708.9	721.8	710.3	704.7	661.8
12/19/2015	629.7	606.7	602.4	593.4	598.1	595.6	613.8	617	623.9	633	619.2	620.4	606.5	592.8	583.9	563.8	574.4	604.9	636.4	640	642.2	636.8	631	608.6
12/20/2015	592	580.9	560.2	565.4	556.7	558.2	564.9	574.9	585.2	599.3	602.4	598.4	583.5	565.7	552.1	553.7	559.5	604.7	629.2	631.3	632.4	624.3	597.6	569.8
12/21/2015	535.6	521.9	508.8	508.8	511.6	530.1	565.3	615.8	640.4	657	654.6	659.6	616.5	651	651.6	644.9	642.9	657	663.7	660.5	647.4	640.3	618.4	588
12/22/2015	554.2	527.9	524.7	521.5	513	521.2	553.3	595.3	611.2	626.6	632	643.9	629.8	630.6	627.2	622.4	623.5	642.7	651.4	651.8	650.4	643.5	618	579.6
12/23/2015	556.9	526.9	520.2	508.2	515.4	514.7	537.9	572.8	591.9	610.7	618.5	625.2	618.7	622.3	604.3	597	591.4	615.2	637.2	631.6	616.8	602.9	576.1	542.8
12/24/2015	498.3	479.5	450	450.1	437.7	445.4	459.1	484.8	489.9	506.3	510.6	504.9	503.3	491	486.2	481.4	477.3	489.5	513.5	501.8	497.3	488.6	486.4	472
12/25/2015	446.8	428.6	416.1	409.5	410.3	416.2	415.8	440.8	451.8	469.1	474.5	483.7	476.5	461.4	454.1	444.4	447	459.3	488.4	495.4	494.5	492.7	482.4	472
12/26/2015	442.1	435.7	420	424.2	419.2	429.8	440.9	459.2	473.4	490.4	516.3	525.9	529.3	525.6	524	515	517.3	538.3	544.2	540.5	533.1	529.5	520.6	495.7
12/27/2015	467.7	452.6	441.3	429.6	429.4	438.2	433.6	446.1	461.8	482.8	498.1	506.4	527.2	526.3	530.1	528.3	532	563.2	582.2	584.4	579.7	566.6	621.7	621.8
12/28/2015	602.8	586.5	582.5	584.1	587.3	594.6	607.5	647.1	658.9	687.4	653.9	619.5	621.1	622.1	622.6	600.8	592.8	598.7	624.5	615.8	608.8	601.5	581.9	570.5
12/29/2015	524.9	517.7	503.9	507.7	497.6	523.5	543	579.4	594.1	607.5	617.4	623.6	618	618.6	617.9	618.4	615.5	642.2	658.4	653.2	640.6	633.5	610.7	582.3
12/30/2015	550.3	538.8	527.4	522.6	519.2	532.6	549.4	588.4	601.5	614.1	619.1	632.4	635.1	628.5	626.3	624.5	624.2	646.2	661.1	647.5	645.4	631.6	611.9	578
12/31/2015	553.2	541.9	530.4	520.4	520.2	530.2	548.5	567.9	588	596.4	609	629.4	615.4	614.6	617.7	619.8	614.9	632.2	650.3	626.3	612.3	597.3	586.3	560.1

Attachment 4.3 2016 MISO LOLE Study Report

Planning Year 2016-2017 Loss of Load Expectation Study Report

Loss of Load Expectation Working Group

Revision History

Reason for Revision	Revised by:	Date:
Final Posted	MISO Staff	10/30/2015

1 Executive Summary

Midcontinent Independent System Operator (MISO) conducts an annual Loss of Load Expectation (LOLE) study to determine a Planning Reserve Margin Unforced Capacity (PRM UCAP), zonal per-unit Local Reliability Requirements (LRR), Capacity Import Limits (CIL) and Capacity Export Limits (CEL). The results of the study and its deliverables supply inputs to the MISO Planning Resource Auction (PRA). The 2016-2017 Planning Year LOLE study includes these key findings and results:

- Establishes a PRM UCAP of 7.6 percent to be applied to the Load Serving Entity (LSE) coincident peaks for the planning year starting June 2016 and ending May 2017
- Uses the GE Multi-Area Reliability Simulation (MARS) software for Loss of Load analysis to provide results applicable across the MISO market footprint; any impacts due to transmission limitations will be addressed in the PRA
- Provides the PRA with the overall 7.6 percent PRM UCAP requirement, the per-unit LRR values and the initial zonal CIL and CEL for each Local Resource Zone (LRZ) (Table 1.1-1). The CILs and CELs may be adjusted within the PRA to assure that the resources cleared in the auction can be reliably delivered simultaneously.
- Determines a minimum planning reserve margin that would result in the MISO system experiencing a less than one-day loss of load event every 10 years, as per the MISO Tariff.[1] The MISO analysis shows that the system would achieve this reliability level when the amount of installed capacity available is 1.152 times that of the MISO system coincident peak.
- On May 22, 2015, MISO proposed in a Tariff Filing to create a new LRZ 10, which would consist exclusively of Planning Resources and load in Mississippi. The Planning Resources and load in Texas and Louisiana would be in a reconfigured LRZ 9 that no longer would include any Mississippi resources or load. This proposal was conditionally accepted on July 22, 2015, and therefore this study was performed for a total of 10 LRZs.
- Sets forth zonal-based (Figure 1.1-1) PRA deliverables in the LOLE charter

RA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Default Congestion Free PRM UCAP	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%
LRR UCAP per-unit of LRZ Peak Demand	1.110	1.143	1.129	1.218	1.210	1.108	1.132	1.257	1.125	1.392
Capacity Import Limit (CIL) (MW)	3,432	1,703	1,998	4,328	4,359	5,570	3,406	2,425	3,563	2,010
Capacity Export Limit (CEL) (MW)	590	2,996	1,598	7,379	896	2,544	4,541	2,074	1,261	1,857

Table 1.1-1: 2016 Planning Resource Auction Deliverables

[1] A one-day loss of load in 10 years (0.1 day/year) is not necessarily equal to 24 hours loss of load in 10 years (2.4 hours/year).

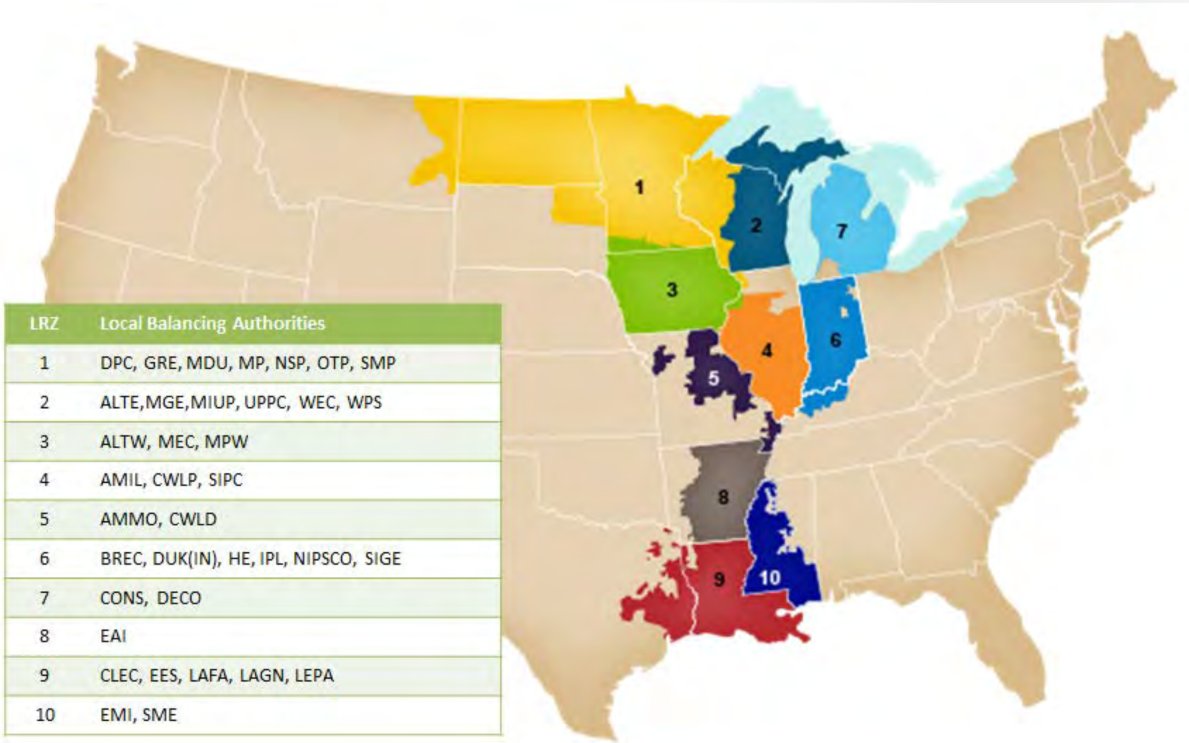


Figure 1.1-1: Local Resource Zones (LRZ)

1.1 Study Enhancements

For the 2016-2017 planning year, several changes were made to the LOLE modeling assumptions. Modeling enhancements are necessary in order to mature and stabilize the planning reserve margin and reliability requirements.

The 2016-2017 LOLE analysis includes these enhancements:

- Implementation of an Load Forecast Uncertainty (LFU)-smoothing function to reduce volatility (Section A.1)
- Filed Tariff language to implement a revised capacity adjustment methodology that more accurately reflects the fleet of resources available when determining Resource Adequacy requirements, outlined in 2015-2016 LOLE report (Section 4.5.1)
- Fixed External Non-firm support to reduce volatility, outlined in the 2015-2016 LOLE report (Section 4.4)
- Development of process for identification of transmission constraints and CIL and CEL values when available generation is limiter, not transmission
- Alignment MISO Transmission Expansion Plan (MTEP) and LOLE powerflow model development, review and updates

1.2 Acknowledgements

The stakeholder review process played an integral role in this study and the collaboration of the Loss of Load Expectation Working Group (LOLEWG) was much appreciated by the MISO staff involved in this study.

2 LOLE Study Process Overview

In compliance with Module E-1 of the MISO Tariff, MISO performed its annual Loss of Load Expectation (LOLE) study to determine the Planning Reserve Margin (PRM) on an unforced capacity (UCAP) basis for the MISO system and the per-unit Local Reliability Requirements (LRR) of Local Resource Zone (LRZ) Peak Demand for the planning year 2016-2017.

In addition to the LOLE analysis, a transfer analysis was performed to determine Capacity Import Limits (CIL) and Capacity Export Limits (CEL). CIL and CEL are used in conjunction with the LOLE analysis results in the Planning Resource Auction (PRA). The 2016-2017 per-unit LRR UCAP values determined by the LOLE analysis will be multiplied by the updated LRZ Peak Demand forecasts submitted for the 2016-2017 PRA to determine each LRZ's LRR. Once the LRR is determined, the CIL values are subtracted from the LRR to determine each LRZ's Local Clearing Requirement (LCR) consistent with Section 68A.6[2] of Module E-1. An example calculation pursuant to Section 68A.6 of the current effective Module E-1[3] shows how these values are reached (Table 1.2-1). The actual effective PRM Requirement (PRMR) will be determined when the updated LRZ Peak Demand forecasts are submitted by November 1 for the 2016-2017 PRA and the simultaneous feasibility test is complete, which ensures CIL and CEL values are not violated.

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP (1d in 10yr)	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Capacity Import Limit (CIL)	3,469	[G]
Capacity Export Limit (CEL)	2,317	[H]
Proposed PRA (UCAP) EXAMPLE	**Example LRZ**	**Formula Key**
Forecasted LRZ Peak Demand	14,270	[I]
Forecasted LRZ Coincident Peak Demand	13,939	[J]
Local Reliability Requirement (LRR) UCAP	16,376	[K]=[F]x[I]
Local Clearing Requirement (LCR)	12,907	[L]=[K]-[G]
Zone's System Wide PRMR	14,999	[M]=[1.076]X[J]
Planning Reserve Margin (PRM)	7.6%	[N]=[M]/[J]-1

Table 1.2-1: Example LRZ calculation

2.1 Future Study Improvement Considerations

MISO's LOLE analysis underwent enhancements in the past few years to ensure that MISO continues to send the appropriate capacity planning signals in the forward time horizon. Although MISO has

[2] https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx#
[3] Effective Date: September 21, 2015

confidence in the results, further improvements are still necessary to mature the process and stabilize the PRM and reliability requirements.

The 2016-2017 MISO PRM value shows a 0.5 percent increase on a UCAP basis compared to 2015-2016. While providing the accurate PRM value to stakeholders is important, a stable PRM value in the forward time horizon is equally important for Load Serving Entities (LSE) planning to meet their reliability requirement. MISO realizes the importance of both accuracy and stability of the PRM and will continue to investigate future study improvements. Five study enhancements outlined in section 2.1 of the 2015-2016 LOLE report were implemented for the 2016-2017 LOLE analysis:

- Perfect unit adjustment
- External non-firm support
- Re-evaluation of LRZ boundaries, which resulted in the creation of LRZ 10
- Develop a process for identification of transmission constraints and CIL and CEL values when available generation is the limiter, not transmission
- Align MISO Transmission Expansion Plan (MTEP) and LOLE powerflow model development, review and updates

Additional enhancements to provide a stable, forward-looking PRM are under consideration for future studies. The future PRM values are based on current Planning Year load forecast uncertainty (LFU), Equivalent Forced Outage Rate demand (EFORd), etc. This leads to a false conclusion that the future PRM values are certain. MISO has seen legitimate year-over-year changes of parameters impacting the PRM. By providing confidence bands around out-year PRMs, MISO will provide a more accurate reflection of anticipated values.

The LOLE transfer analysis utilizes MTEP powerflow models to calculate the CEL and CIL for each LRZ. Potential improvements to develop a consistent and stable powerflow model or development of a methodology to smooth out volatility caused by changes other than MISO transmission should be discussed for future studies.

The electric industry is going through resource portfolio changes and a reduction in overall reserve margins due, in large measure, to retirements of coal-based generation resources that are being replaced, in part, by generation fueled by natural gas and renewables. This has increased focus on Resource Adequacy within the MISO region. Drawing on stakeholder feedback, MISO developed three straw proposals to stimulate further discussion and develop policy consensus around potential solutions to these issues: seasonal, locational and the generation queue. Going forward the LOLE study will need to evolve to support the solutions to these issues.

MISO is identifying process improvements to limit volatility caused by controllable variables and determine the impact of non-controllable variables. Possible improvements for the 2016 study include:

- Consider impact of long-term transmission line and generator outages
- Adjust the implementation of unit retirements or suspensions that occur after summer peak
- Report additional constraints for each transfer, such as the top 3 or 5
- Align constraint re-dispatch methodology to reflect re-dispatch methodology practiced in real time operations

3 Transfer Analysis

3.1 Calculation Methodology and Process Description

Transfer analysis establishes CILs and CELs for LRZs in the PRM study for the 2016-2017 Planning Year. The objective of this study is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Methodology and process enhancements were put into place prior to the Planning Year 2015-16 analysis. Incremental enhancements put into place before this year's analysis includes:

- Improved redispatch for import and export studies
- Model topology alignment with MTEP (LOLE model built for same date as MTEP models)
- Improved and expanded coordination with seam areas
- Expanded redispatch for Reciprocal Coordinated Flowgate (RCF) constraints eligible for market-to-market dispatch
- Thorough modeling review documentation to aid in stakeholder model review for the planning year and five-year-out planning model

3.1.1Tiered generation pools

To determine an LRZ's import or export limits, a generation-to-generation transfer is modeled from a source subsystem to a sink subsystem. For import limits, the sink subsystem is the LRZ under study. To reduce the likelihood of remote constraints limiting zonal imports, limits are found by increasing MISO generation resources in adjacent Local Balancing Authorities (LBAs) to the LRZ under study while decreasing generation inside the LRZ under study Figure 3.1-1.

- Tier 1 – MISO LBAs adjacent to the LRZ under study
- Tier 2 – MISO LBAs adjacent to Tier 1

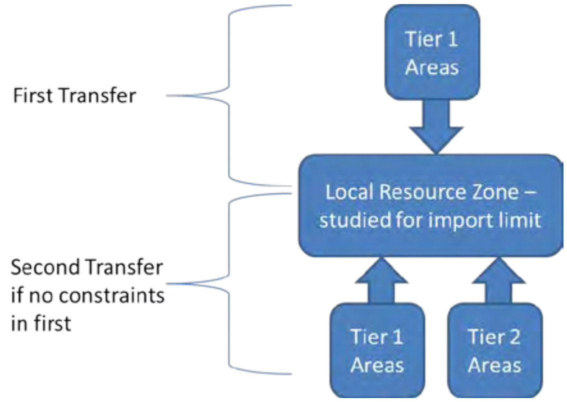


Figure 3.1-1: Tiered import illustration

Import limit studies are analyzed first using Tier 1 generation only. If a constraint is identified, redispatch is tested. If redispatch mitigates the constraint completely and an additional constraint is not identified, the limit is the adjusted available capacity in Tier 1 plus any base import or minus any base export. Available capacity must be adjusted to account for changes due to redispatch. If a constraint is identified using Tier 1 generation, no further analysis is required. If no constraint is identified using Tier 1 available capacity only, available capacity in both Tiers 1 and 2 is then used considering the same redispatch process.

It is not necessary to apply the tiered approach to export studies. Generation within the zone studied for an export limit is being ramped up and constraints are expected to be near the zone because the generation being ramped up is in a more concentrated area than import studies. The opposite is true for import studies — generation outside the study zone is ramped up, which could cause remote constraints limiting local imports if the source pool is large. Using a large source pool also impacts the distribution factors and could potentially mask valid constraints. The sink for export studies is the remaining LRZs.

3.1.2 Redispatch

Redispatch applied in the LOLE study was completed similarly to redispatch for baseline reliability projects, which is referenced in Appendix O, Section O.1.1.1 of the Transmission Planning Business Practice Manual (BPM)[4]. The common assumptions are as follows:

- Only shift factors greater than 3 percent are considered
- No more than 10 conventional fuel units or wind plants will be used
- Redispatch limited to 2,000 MW total (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units

Each zone's transfer studies might include application of multiple, independent redispatch scenarios depending on the constraints that are identified. Constraints found to be significantly impacted by different units and distant from each other will be redispatched separately.

Redispatch assumptions vary depending on LBA ties for import scenarios (Figure 3.1-2).

Planning Resources eligible to be ramped up	Generation resources eligible to be ramped down
• Source system (Tier 1 or Tiers 1 and 2) • Zone being studied for CIL • External resources for RCF constraints	• All MISO generation resources • External resources for RCF constraints

Figure 3.1-2: Import Redispatch Scenario

For import redispatch scenarios, all MISO generators will be eligible to ramp down if the generation shift factor is 3 percent or higher. Only Planning Resources in the zone and adjacent LBAs will be eligible to ramp up. It is unreasonable to assume ramping down a unit with a significant impact on the constraint by 2 MW, for example, can be offset by ramping up a unit on the other side of the footprint by 2 MW when

[4] BPM 020 – Transmission Planning: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=19215

transmission losses are considered. MISO is revisiting eligibility of units to ramp down based on the generation shift factor to be more in line with removing the cut off. By eliminating the cut off of 3 percent, a larger amount of generation may be available to use for redispatch. Removing the 3 percent generation shift factor would also align redispatch to be closer to what occurs in the real time operations.

For export redispatch scenarios, only generation within the zone being studied is considered to be ramped up. Any MISO generator with an impact of 3 percent or higher is eligible to be ramped down (Figure 3.1-3). Similar to the import redispatch, MISO is investigating removing the 3 percent generation shift factor cutoff to be in line with what occurs in real-time operations.

Generation resources eligible to be ramped up

- In zone being studied
- External resources for RCF constraints

Generation resources eligible to be ramped down

- All MISO
- External resources for RCF constraints

Figure 3.1-3: Export Redispatch Scenario

3.1.3 Generation Limited Transfer for CIL/CEL

When conducting transfer analysis to determine a CIL or CEL, an LRZ may not reach a constraint caused by a transmission limit before running out of generation to dispatch. MISO developed a process to identify transmission constraints, when possible, for both CIL and CEL. There may be instances in which a transmission limit is not identified due to new transmission, a change in generation or both.

After running the initial transfer analysis to determine limits for each LRZ CIL or CEL, MISO determines whether a zone experiences a generation limited transfer. If the LRZ experiences a generation limited transfer, MISO adjusts the base model dependent on whether it is a CIL or CEL analysis, and re-runs the transfer analysis.

For a CEL study, when a transmission constraint is not identified after dispatching all generation within the exporting system (LBAs under study) MISO adjusts load and generation to balance the base model. In order to determine a limit, MISO decreases load in exporting LBAs, as well as decreases the generation in the exporting LBAs. After the adjustments are complete, MISO performs transfer analysis on the adjusted model to be in line with section 5.2.2.1. If a generation limited transfer is observed, the adjustments to the model would be repeated.

For a CIL study, when a transmission constraint is not identified after (a) decreasing all generation within the LRZ under study, or (b) dispatching all generation within Tiers 1 & 2, MISO adjusts load and generation to balance the base model. In order to determine a limit for the LRZ under study, the load, generation dispatch, and maximum generation limit in the importing LRZ will be increased. When the adjustments are complete, the transfer analysis takes place on the adjusted model, which is in line with BPM-011 section 5.2.2.1. If a generation limited transfer is observed, the adjustments to the model would be repeated. This process can also be applied to Tiers 1 & 2 of an LRZ under study when completing a CEL Study.

Generation Limited Transfer methodology was reviewed with stakeholders prior to start of the calculation of the CIL and CEL. The methodology was applied to LRZ 7 CIL, LRZ 2 CEL, LRZ 3 CEL, LRZ 4 CEL, LRZ 5 CEL, LRZ 6 CEL and LRZ 7 CEL. Moving forward, MISO will evaluate the implementation to see if additional improvements are needed.

3.2 Powerflow Models and Assumptions

3.2.1 Tools used

Tools utilized for the transfer analysis are Siemens PTI Power System Simulator for Engineering (PSS E), Power System Simulator for Managing and Utilizing System Transmission (PSS MUST) and Transmission Adequacy and Reliability Assessment (TARA).

3.2.2 Inputs required

The study required powerflow models and PSS MUST Input files. PSS MUST contingency files from Coordinated Seasonal Assessment (CSA) and MTEP[5] reliability assessment studies were used (Table 3.2-1). Single-element contingencies in MISO/seam areas were evaluated in addition to submitted files.

Model	Contingency files used
2016-17 Planning Year	2015 Summer CSA
5-year-out peak	MTEP15 study

Table 3.2-1: Contingency files per model

PSS MUST subsystem files include LRZ, Tier 1 and Tier 2 definitions. See Appendix C for maps containing Tiers used for this study. The PSS MUST monitored file includes all facilities under MISO functional control.

3.2.3 Powerflow Modeling

Two summer peak models were required for the analysis: 2016 and 2021. All models were built using MISO's Model on Demand (MOD) model data repository, each with an effective date and base assumptions (Table 3.2-2).

Planning Year	Effective Date	Projects Applied	External Modeling	Load and Generation Profile
2016	7/15/2016	MTEP15 Appendix A and Target A	2014 Series 2016 Summer ERAG MMWG	Summer Peak
2021	7/15/2021	MTEP15 Appendix A and Target A	2014 Series 2021 Summer ERAG MMWG	Summer Peak

Table 3.2-2: Model assumptions

[5] Refer to the Transmission Planning BPM for more information regarding MTEP PSS MUST input files. https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=19215

Several types of units were excluded from the transfer analysis dispatch, meaning these units' base dispatch remained fixed in all analyses.

- Dispatch exclusions from the MTEP summer 2015 CSA study were applied, which included hydro, nuclear, SVC, motor loads, Behind-the-Meter generation and MISO swing generators
- MISO wind dispatch capped at wind capacity credit, meaning plants could be ramped down to facilitate transfers, but not be ramped up

System conditions such as load, dispatch, topology and interchange have an impact on transfer capability. Stakeholder review of models and input files was requested by notices sent to the LOLEWG in parallel with MTEP model. Files were made available on the MTEP ftp site. Stakeholder feedback was requested throughout the study period to capture any changes that may have occurred since the model build date. MISO worked closely with transmission owners in order to accurately model the transmission system, as well as validate constraints and redispatch.

3.2.4 General Assumptions

TARA uses the powerflow model and associated input files to determine the import and export limits of each LRZ by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions and is used as an indicator of transmission strength. The incremental amount of power that can be transferred will be determined through First Contingency Incremental Transfer Capability (FCITC) analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of power able to be transferred before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (Equation 3.2-1). All published limits represent the zone's FCTTC.

$$First\ Contingency\ Total\ Transfer\ Capability\ (FCTTC) = FCITC + Base\ Power\ Transfer$$

Equation 3.2-1: Total Transfer Capability

Facilities were flagged as potential constraints for loadings of 100 percent or more of the normal rating for North American Electric Reliability Corporation (NERC) Category A conditions and loadings of 100 percent or more of the emergency rating for NERC Category B contingencies. Linear FCITC analysis identifies the limiting constraints using a minimum Distribution Factor (DF) cutoff of 3 percent, meaning the transfer and contingency must increase the loading on the overloaded element by 3 percent or more.

A pro-rata dispatch is used, which ensures all available generators will reach their maximum dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit. Table 3.2-3 and Equation 3.3-2 show an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Unit Dispatch Max – Unit Dispatch Min)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	**310**

Table 3.2-3: Example subsystem

$$\boldsymbol{Machine\ 1\ Post\ Transfer\ Dispatch = \frac{Machine\ 1\ Reserve\ MW}{Source\ Subsystem\ Reserve\ MW} \times Transfer\ Level\ MW}$$

$$Machine\ 1\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Post\ Transfer\ Dispatch = 25.8$$

Equation 3.3-2: Machine 1 dispatch calculation for 100 MW transfer

3.3 Results

The results for each LRZ consists of a list of constraints and the corresponding FCTTC. Invalid constraints were identified for several reasons, such as outdated ratings, invalid contingencies, solution tolerance settings, invalid external base dispatch, or associated operating guides that mitigate the constraint. The CIL and CEL are the FCTTC of the corresponding limiting constraint. Section 5.2.2.3 of the Resource Adequacy BPM provides additional information regarding how the CIL impacts the Local Clearing Requirement calculation. Constraints and associated limits were presented and reviewed through the LOLEWG. This activity occurred in the meetings that took place in September through October 2015.

Significant stakeholder feedback resulted in these updated limits:

- MISO generation retirements and redispatch for LRZ(s) 8, 9, and 10 CIL and CEL
- Constraint validation and special protection scheme (SPS) application
- External base model and redispatch adjustments
- Redispatch using more impactful generation units

In the Planning Year 2015-2016 analysis Generation Limited Transfer methodology was followed in instances, mainly in the CEL calculation, where a transmission limit was observed when generation was scaled beyond its limits. For the CIL, this was observed in LRZ 7. After applying the language to the cases, a transmission limit was observed for each study. The five-year-out analysis also applied Generation Limited Transfer methodology for both Capacity Import and Export Limits.

Last year's LOLE out-year analysis focused on one- and two-year-out analyses due to impactful regulations in the 2016-2017 horizon. This year's study focused on a five-year-out model to align with MTEP timeframes and modeling data.

Detailed constraint and redispatch information for all limits is found in Transfer Analysis of this report. A summary of the Planning Year 2016-17 Capacity Import Limits is in Table 3.3-1.

LRZ	Tier	16-17 Limit (MW)[6]	Monitored Element	Contingent Element	Figure 3.3-1 Map ID	Initial Limit (MW)[7]	Generation Redispatch Details		15-16 Limit (MW)
							MW	Area(s)	
1	1 & 2	3,432	Colby to New Iowa Wind 161 kV Line	Adams to Barton 161 kV Line	1	3,432	N/A	N/A	3,735
2	1	1,703	Stoneman to Nelson-Dewey 161 kV Line	Wempltown to Paddock 345 kV Line	2	1,111	188	METC, XEL, MP, DPC	2,903
3	1	1,998	Palmyra 345-161 kV Transformer	Palmyra Tap to Sub T 345 kV Line	3	989	2,000	WEC, AMMO, AMIL, GRE, MPW	1,972
4	1 & 2	4,328	Palmyra 345/161 kV Transformer	Montgomery to Spencer 345 kV Line	3	1,970	2,164	WEC & EES	3,130
5	1	4,359	Russellville East to Russellville South 161 kV Line	Arnold Nuclear One to Fort Smith 500 kV Line	4	4,297	491	AMIL, ALTW, OTP, MEC	3,899
6	1&2	5,570	Rising 345/138 kV Transformer	Clinton to Browkaw 345 kV Line	5	3,598	3,020	METC & AMIL	5,649
7	1&2	3,406	Argenta to Battle Creek 345 kV Line	Paxton to Tompkins 345 kV Line	6	1,970	2,000	NIPS, CE, WEC	3,813
8	1	2,425	Montgomery to Clarence 230 kV Line	Hartburg to Layfield 500 kV Line	7	0	2,000	AMMO, EES	2,074
9	1	3,563	Andrus 230/115 kV Transformer	Andrus to Indianola 230 kV Line	8	2,579	717	EES & LAGN	*4,008
10	1	2,010	Ray Brasswell Transformer	Ray Brasswell to Lakeover 500 kV Line	9	172	2,000	SMEPA & EES-EMI	*2,630

*Values determined in LRZ Re-evaluation study presented on February 4, 2015 LOLE Working Group

Table 3.3-1: Planning Year 2016–2017 Capacity Import Limits

[6] The 15-16 Limit represents the limit after redispatch has been considered.
[7] The Initial Limit represents the limit before considering redispatch.

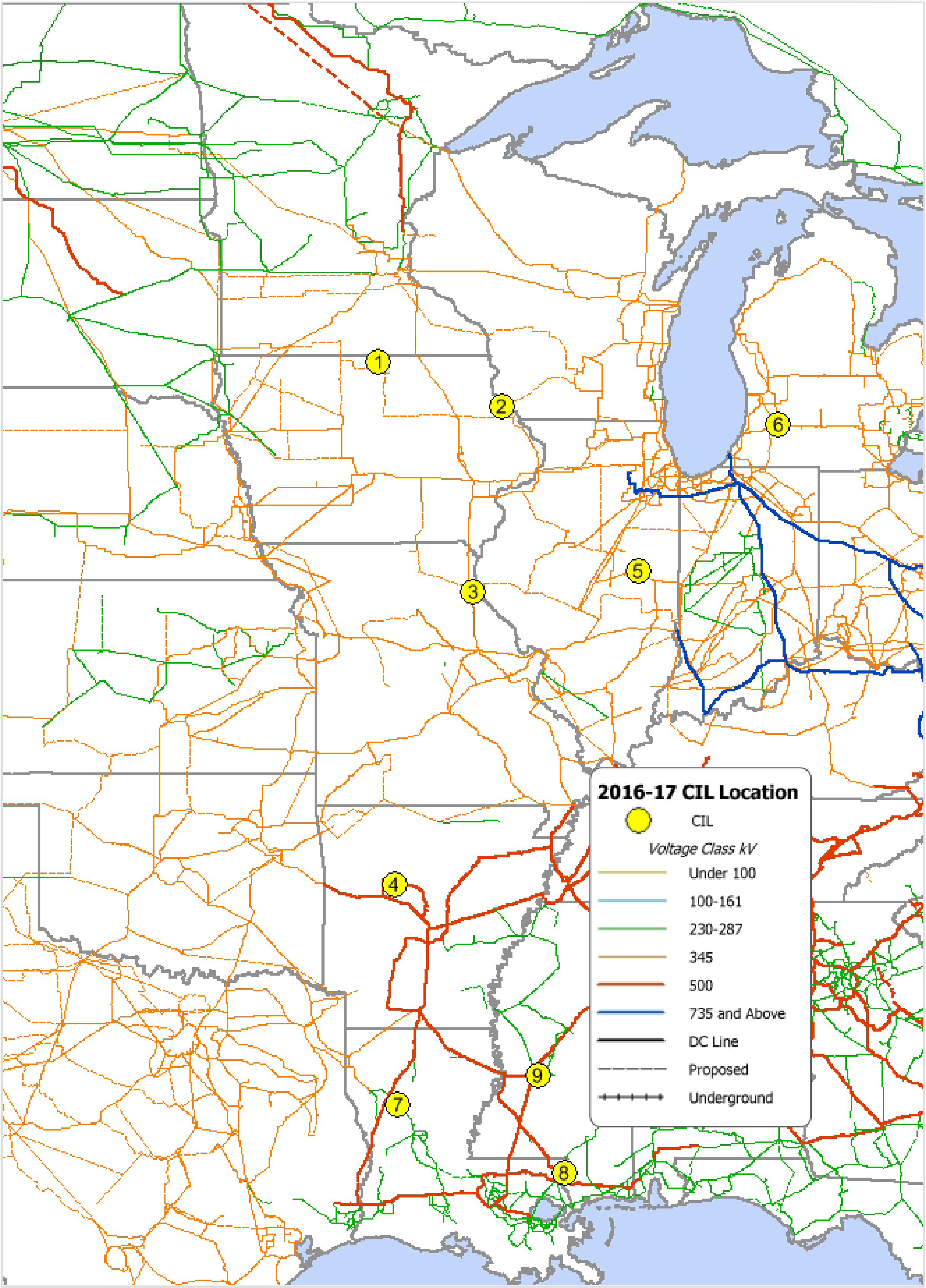


Figure 3.3-1: Planning Year 2016-17 CIL constraint map

Capacity Exports Limits were found by increasing generation in the zone under study and decreasing generation in the rest of the MISO footprint. Table 3.3-2 summarizes Planning Year 2016-17 Capacity Export Limits.

LRZ	16-17 Limit (MW)	Monitored Element	Contingent Element	Figure 3.3-2 Map ID	Initial Limit (MW)	Generation Redispatch Details		15-16 Limit (MW)
						MW	Area	
1	590	Lakefield to Dickinson 161 kV Line	Raun to Highland 345 kV Line	1	0	1,627	XEL, MP, GRE, OTP, ALTW, MEC, WPS	604
2	2,996	St Rita To Racine 138 kV Line	Racine to Elm Road 345 kV Line	2	1,259	965	CE	1,516
3	1,598	Oak Grove to Mercer 161 kV Line	Havana Unit 6	3	1,598	0	N/A	1,477
4	7,379	Newton to Casey 345 kV Line	Casey West to Neoga 345 kV Line	4	7,379	0	N/A	4,125
5	896	Newton To Casey 345 kV Line	Casey West to Neoga 345 kV Line	4	0	224	AMMO	0
6	2,544	Tap to AEP Rockport to Grandview 138 kV Line	AB Brown to Reid EHV Substation to Wilson 345 kV Line	5	2,544	0	N/A	2,930
7	4,541	Benton Harbor 345/138 kV Transformer	Benton to Cook 345 kV Line	6	4,541	0	N/A	4,804
8	2,074	Russelville North to Russelville East 161 kV Line	Arkansas Nuclear One to Fort Smith 500 kV Line	7	2,074	0	N/A	3,022
9	1,261	Port Neches Bulk to Flatland 138 kV Line	Sabine 345/138 kV Transformer	8	0	2,000	EES, LAFA, LEPA, CLECO	*2,418
10	1,857	Plant Morrow to Purvis Bulk 161 kV Line	Plant Morrow to Purvis Bulk 161 kV Line	9	0	2,000	EES-EMI, SMEPA	*1,959

*Values determined in LRZ Re-evaluation study presented on February 4, 2015, LOLE Working Group

Table 3.3-2: Planning Year 2016–2017 Capacity Export Limits

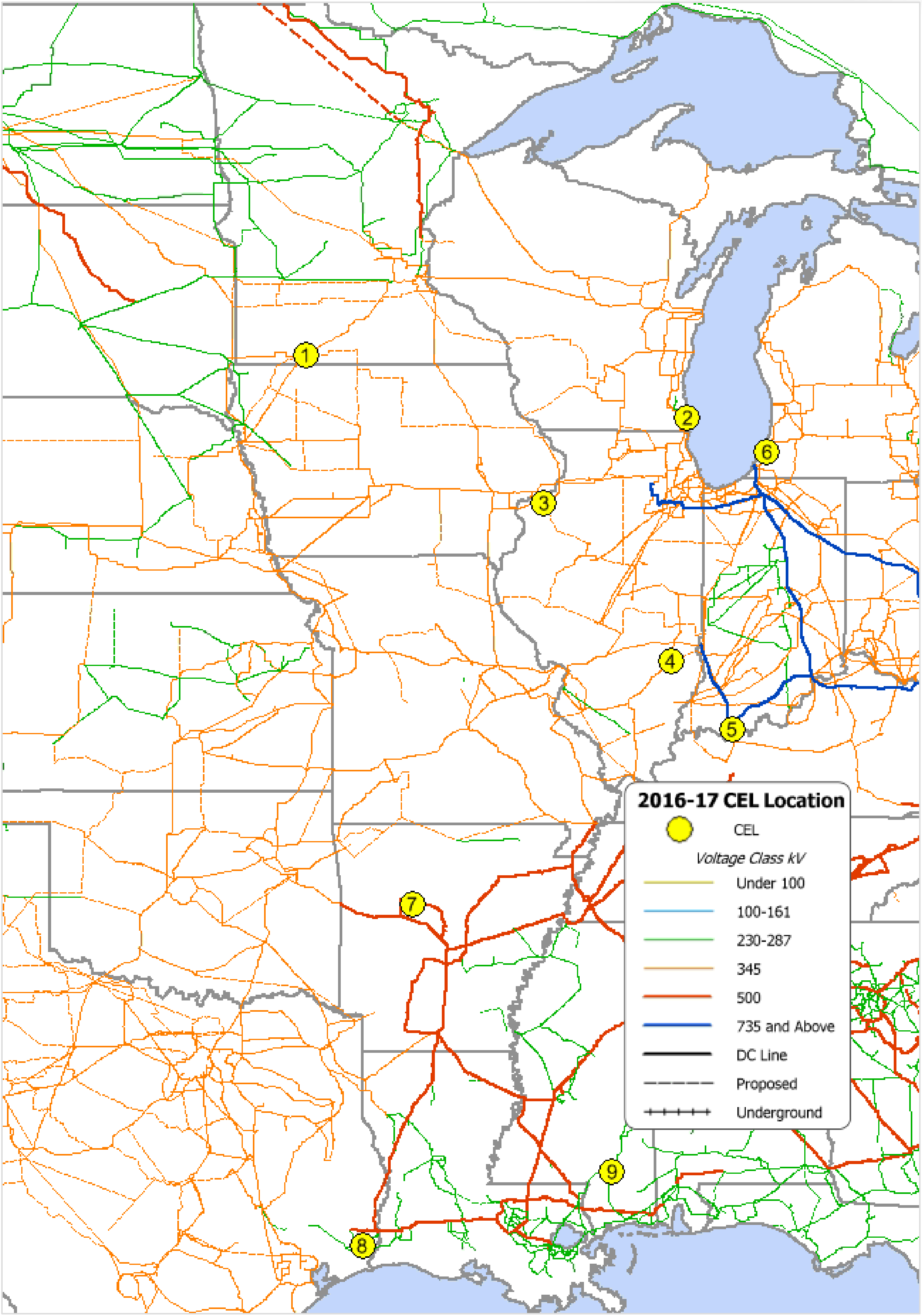


Figure 3.3-2: Planning Year 2016-17 CEL constraint map

Many of the Capacity Import and Export Limits are similar to limits identified for Planning Year 2015-2016. Limits that differ are primarily attributed to the following impacts:

- Transmission
  - Rating increases on transmission lines
  - MTEP phases or projects coming into service
- Generation dispatch
  - Retirements or suspensions
  - Cost of operation of fuel units
- Load
  - Increases
  - Decreases
- Methodology changes
  - Application of generation limited transfer for import and export when needed

LRZ	Transmission	Generation retirements or suspensions	Generation dispatch	Load	Methodology changes
1		CEL – suspended unit limiting redispatch options	CEL – suspended unit limiting redispatch options		CEL – Generation Limited Transfer methodology applied
2		CIL – impact of retirement noted in LOLE 2015 report			CEL – Generation Limited Transfer methodology applied
3			CIL- SPS is not active for contingency, units for SPS are not online.		
4	CIL and CEL – MTEP projects coming into service		CIL and CEL – generation dispatch impacts	CIL and CEL – adjustment in forecasted load	CEL – Generation Limited Transfer methodology applied
5	CIL – rating increase of previous limiter				CEL – Generation Limited Transfer methodology applied
6					CEL – Generation Limited Transfer methodology applied
7			CIL – External system modeling difference		CIL and CEL- Generation Limited Transfer methodology applied
8					
9		CIL and CEL – retirements in the area	CIL and CEL – generation dispatch impacts		
10		CIL and CEL – retirements in the adjacent area	CIL and CEL – generation dispatch impacts		

Table 3.3-3: CIL/CEL Change Summary

3.3.1 2020-2021 Results

Table 3.3-4 summarizes 2020-2021 Capacity Import Limits.

LRZ	Tier	2020-2021 Limit (MW)	Monitored Element	Contingent Element	Figure 3.3-3 Map ID	Initial Limit (MW)	Generation Redispatch Details	
							MW	Area (s)
1	1&2	4,769	Colby to New Iowa Wind 161 kV	Adams to Mitchell Co 345 kV	1	4,684	320	GRE, WPS
2	1&2	4,416	Rochester to Wabaco 161 kV	North Rochester to Briggs Road 345 kV	2	4,416	Not Applicable	
3	1	2,326	Ottumwa 345/161 kV Transformer 1	Ottumwa Generator	3	2,326	Not Applicable	
4	1&2	6,016	White Bluff to Keo 500 kV	Sheridan to Mabelvale 500 kV	4	5,220	470	EAI, AMIL
5	1	2,970	Russelville E to Russelville S 161 kV	ANO to Fort Smith 500 kV	5	2,970	Not Applicable	
6	1&2	6,087	Newton to Casey 345 kV	Casey to Neoga 345 kV	6	6,087	Not Applicable, GLT applied	
7	1&2	4,536	Zion Station to Zion 345 kV	Pleasant Prairie to Zion 345 kV	7	4,536	Not Applicable, GLT applied	
8	1	1,432	Montgomery to Clarance 230 kV	Montgomery to Winnfield 230 kV	8	1,432	Not Applicable	
9	1	3,413	Wyatt to Parnell Road 115 kV	Mt Olive to Eldorado 500 kv	9	3,413	Not Applicable	
10	1	1,802	Braswell 500/115 kV Transformer	Lakeover 500/115 kV Transformer	10	1,650	180	EMI,EAI,SMEPA

Table 3.3-5: 2020-2021 Capacity Import Limits

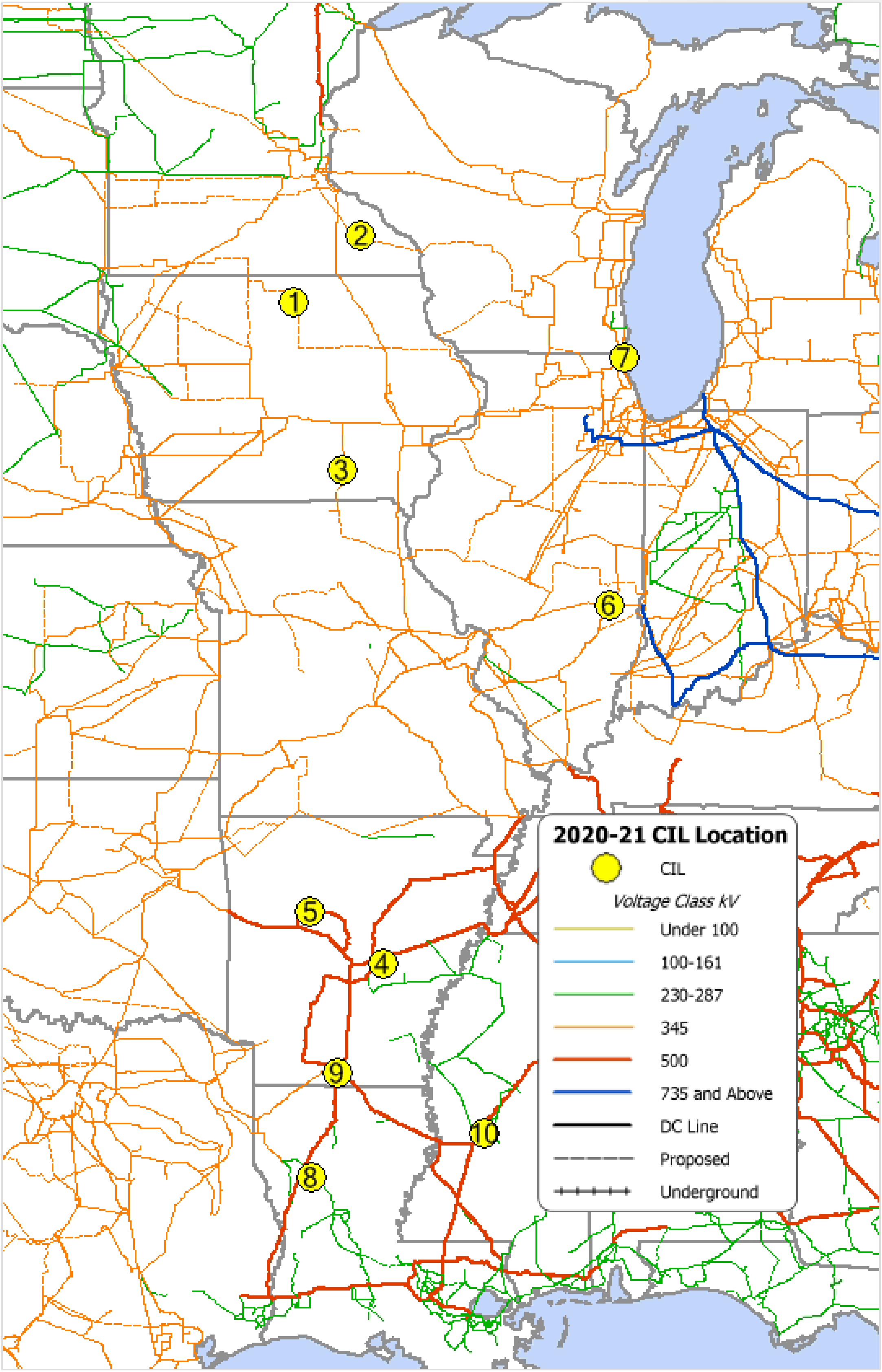


Figure 3.3-3: 2020-2021 CIL map

Table 3.3-6 summarizes 2020-2021 Capacity Export Limits.

LRZ	2020-2021 Limit (MW)	Monitored Element	Contingent Element	Figure 3.3-4 Map ID	Initial Limit (MW)	Generation Redispatch Details	
						MW	Area (s)
1	2,432	Eau Claire 345/161 kV Transformer 10	Eau Claire to King 345 kV + Eau Claire 345/161 Transformer 9	1	2,432	Not Applicable, GLT applied	
2	3,159	Zion Station to Zion 345 kV	Pleasant Prairie to Zion 345 kV	2	3,159	Not Applicable, GLT applied	
3	3,897[8]	Limited by the amount of generation in the LRZ, next potential transmission listed provided for informational purposes		3	3,897	Not Applicable, GLT applied	
		Ottuma 345/161 kV Transformer	Wapello to Apanose 161+Apanose 161/69 kV Transformer				
4	7,430	Gibson to Brokaw 138 kV	Gibson to Paxton E 138 kV	4	7,430	Not Applicable, GLT applied	
5	2,681	Cofeen to Pana 345 kV	Neoga to Holland 345 kV	5	2,681	Not Applicable, GLT applied	
6	5,677	Coleman to Colee EHV 161 kV	Coleman to Hancock 161 kV +SPS	6	5,677	Not Applicable, GLT applied	
7	5,158	Benton Harbor 345/138 kV Transformer	Benton Harbor to Cook 345 kV	7	5,158	Not Applicable, GLT applied	
8	2,679	Russelville E to Russelville S 161 kV	ANO to Fortsmith 500 kV	8	2,679	Not Applicable	
9	1,036	Montgomery to Clarance 230 kV	Montgomery to Winnfield 230 kV	9	1,036	Not Applicable	
10	1,819	Clarkmun to Clarksdale 115 kV	Crossroad to Moonlake 230 kV	10	1,687	667	EMI,SMEPA

Table 3.3-7: 2020-2021 Capacity Export Limits

[8] The GLT has been limited to 5,000 MW, Zone 3 limit has been capped based on the amount of generation available to export.

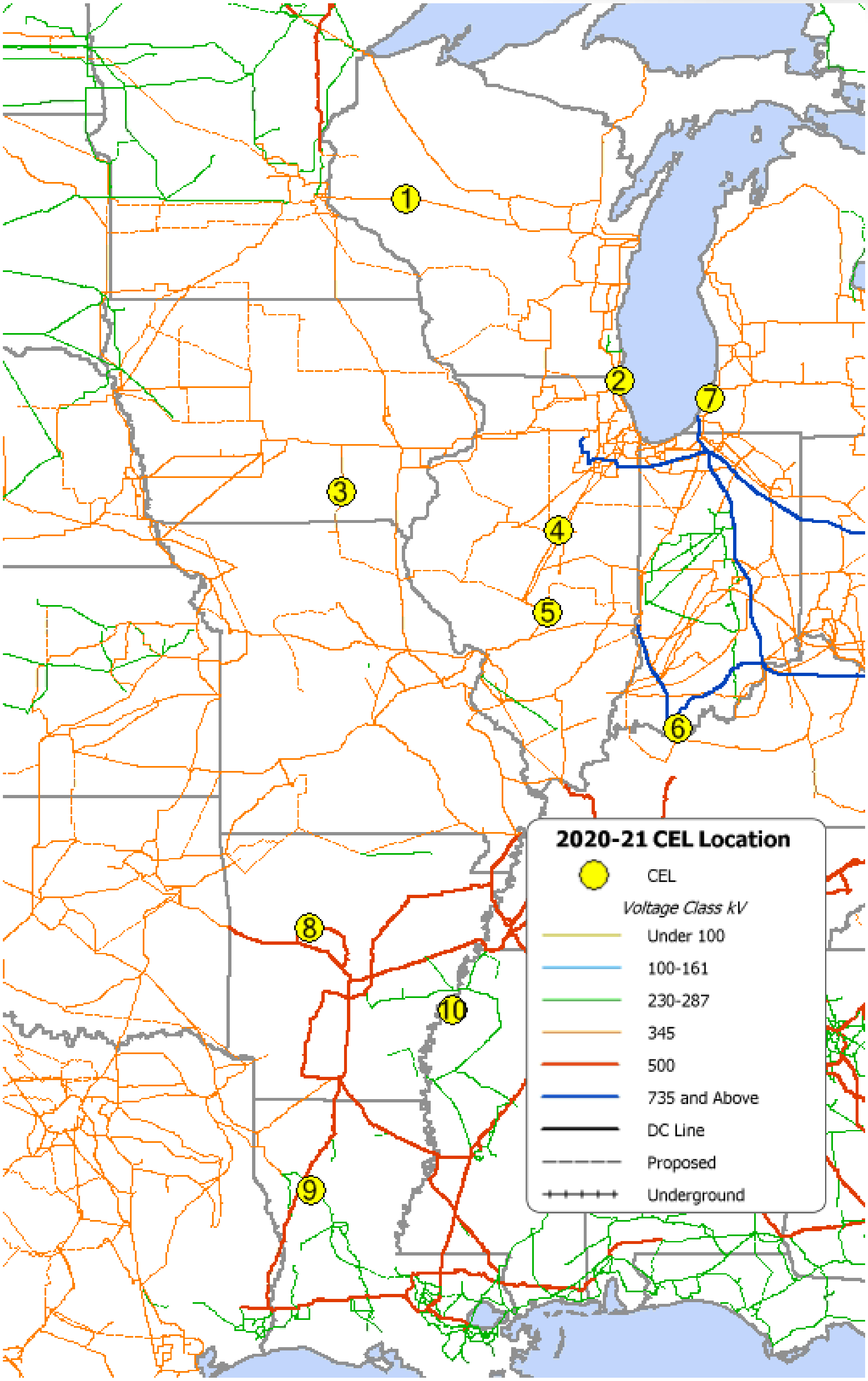


Figure 3.3-4: 2020-2021 CEL map

4 Loss of Load Expectation Analysis

4.1 LOLE Modeling Input Data and Assumptions

MISO utilizes a program developed by General Electric called Multi-Area Reliability Simulation (MARS) to calculate the LOLE for the applicable planning year. GE MARS uses a sequential Monte Carlo simulation to model a generation system and assess the system's reliability based on any number of interconnected areas. GE MARS calculates the annual LOLE for the MISO system and each LRZ by stepping through the year chronologically and taking into account generation, load, load modifying and energy efficiency resources, equipment forced outages, planned and maintenance outages, LFU and external support.

The GE MARS model builds are the most time-consuming tasks of the PRM study. Many cases are built to model different scenarios and to determine how certain variables impact the results. The base case models determine the MISO PRM Installed Capacity (ICAP), PRM UCAP and the LRRs for each LRZ for years one, five and 10.

4.2 MISO Generation

4.2.1 Thermal Units

The 2016-2017 planning year LOLE study utilized the 2015 PRA converted capacity as a starting point for which resources to include in the study. This was to better align the LOLE study with the PRA to ensure that only resources eligible as a Planning Resource were included. An exception was made for those resources in MISO's March 2015 Commercial Model that weren't part of the 2015 PRA but stated in the Organization of MISO States (OMS)-MISO Survey that they would be available in 2016. These resources were also included. All internal Planning Resources were modeled in the LRZ in which they are physically located.

Forced outage rates and planned maintenance factors were calculated over a five-year period (January 2010 to December 2014) and modeled as one value. Some units did not have five years of historical data in PowerGADS, but if they had at least 12 consecutive months of data then unit-specific information was used. If a unit had less than 12 consecutive months of unit-specific data in PowerGADS, then that unit was assigned the corresponding MISO class average forced outage rate and planned maintenance factor. If a particular MISO class had less than 30 units, then the overall MISO weighted class average forced outage rate of 7.98 percent was used.

Nuclear units have a fixed maintenance schedule, which was pulled from Ventyx PowerBase and was modeled for each of the study years.

4.2.2 Behind-the-Meter Generation

Behind-the-Meter generation data came from the Module E Capacity Tracking (MECT) tool. These resources were explicitly modeled just as any other thermal generator with a monthly capacity and forced outage rate.

4.2.3 Sales

This year's LOLE analysis incorporated firm sales to neighboring capacity markets as well as firm transactions off system where information was available. For units with capacity sold off system, the monthly capacities were reduced by the megawatt amount sold. This totaled 4,266 MW UCAP for

Planning Year 2016-2017. A more detailed breakdown is in section 4.4.These values plus additional information came from PJM's Reliability Pricing Model (RPM).

4.2.4 Attachment Y

For the 2016-2017 Planning Year, generating units that have approved suspensions or retirements (as of May 7, 2015) through MISO's Attachment Y process are accounted for in the LOLE analysis. Any unit retiring, suspending, or coming back online at any point during the Planning Year was excluded from the year-one analysis. This same methodology is used for the five- and 10-year analyses.

4.2.5 Future Generation

Future thermal generation and upgrades were added based on unit information in the MISO Generator Interconnection Queue. The LOLE model included only units with a signed interconnection agreement (as of June 1, 2015). These new units were assigned class-average forced outage rates and planned maintenance factors based on their particular unit class. Units upgraded during the study period reflect the MW increase for each month beginning the month the upgrade was finished. The LOLE analysis did not include future wind generation.

4.2.6 Intermittent Resources

Intermittent resources such as run-of-river hydro, biomass and wind were explicitly modeled as demand-side resources. Non-wind intermittent resources such as run-of-river hydro and biomass provide MISO with up to 15 years of historical summer output data during hours ending 15:00 EST through 17:00 EST. This data is averaged and modeled in the LOLE analysis as UCAP for all months. Each individual unit is modeled and put in the corresponding LRZ.

Each wind-generator Commercial Pricing Node (CPNode) received a capacity credit based on its historical output from MISO's top eight peak days in each past year for which data was available. The megawatt value corresponding to each CPNode's wind capacity credit was used for each month of the year. New units to the commercial model without a wind capacity credit as part of the 2015 Wind Capacity Credit analysis received a MISO-wide wind capacity credit of 14.7 percent as established by the 2015 Wind Capacity Credit Effective Load Carrying Capability (ELCC) analysis. The capacity credit established by the ELCC analysis determines the maximum percent of the wind unit that can receive credit in the PRA while the actual amount could be less. Each wind CPNode receives its actual wind capacity credit based on the capacity eligible to participate in the PRA. Only Network Resource Interconnection Service or Energy Resource Interconnection Service with firm point-to-point is considered an eligible capacity resource. The final value from the 2015 PRA for each wind unit was modeled at a flat capacity profile for the Planning Year. Aggregate megawatt values for wind-generating units are then determined for MISO and each LRZ. The detailed methodology for establishing the MISO-wide and individual CPNode Wind Capacity Credits can be found in the 2015 Wind Capacity Credit Report.

4.2.7 Demand Response

Demand response data came from the MECT tool. These resources were explicitly modeled as energy-limited resources. Each demand response program was modeled individually with a monthly capacity and energy, which is limited to the number of times each program can be called upon as well as limited by duration.

4.3 MISO Load Data

For the 2016-2017 LOLE analysis, the hourly LRZ load shape was a product of the historical load shape used as well as the 50/50 demand forecasts submitted by LSEs through the MECT tool with updates from the OMS-MISO Survey. The non-coincident peak demand forecasts (with transmission losses) by LSEs were aggregated by their respective LBAs and applied to the LBA's historical load shape in GE MARS. LRZs 1 through 7 used the 2005 historical load shape while zones 8, 9 and 10 used the 2006 historical load shape. For MISO North/Central, the 2005 load shape is typical for the area. MISO chose to use the 2006 historical shape for the South region, as the 2005 shape represented an extreme weather year due to Hurricane Katrina. In GE MARS, MISO utilized the ability to input monthly peaks, which MARS used to modify the historical load shape accordingly in order to adhere to the monthly peak forecasts that LSEs submitted. These are shown as the MISO System Peak Demand in Table 5.1-1 and LRZ Peak Demands in Table 6.1-1.

Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load.

4.3.1 Load Forecast Uncertainty

LFU, a standard deviation statistical coefficient, is applied to base 50/50 load forecast to represent the various probabilistic load levels. With transition into Module E-1 in 2012, MISO determines two separate requirements: LRR for each zone as well as an overall MISO-wide PRM.

- For the 2013 LOLE study, MISO began calculating LFU for each LRZ to derive the LRR by applying the NERC Bandwidth Method to associated zonal historic demand.
- In addition to that, a MISO-wide LFU was calculated and applied to an aggregate MISO load shape to determine a MISO-wide PRM. In the current LOLE study, enhancements were made to this LFU determination.

Through previous years' analysis results, it was determined that aggregating the MISO-wide footprint (including MISO South) into one load shape was no longer a prudent approach to derivation of the MISO-wide PRM given the large geographic footprint. A MISO-wide LFU applied to every load in MISO, regardless of its unique LFU and geographic location, misrepresents the local uncertainty in demand. The misrepresentation of local uncertainty in demand is amplified when applying the old method to such a large geographic area.

In the 2014 LOLE study, MISO identified a new modeling technique, which connected each LRZ to a central hub with infinite ties. This enabled MISO to model each LRZ's demand and generation uniquely. Use of this method to derive the MISO-wide PRM better aligns with the zonal construct. Since then, MISO continued using the updated modeling method. In addition to that, in order to reduce the year-over-year volatility in LFU[9], a three-year weighted-average smoothing function was implemented in 2015. The resulting LFU, through modeling in a probabilistic model, was determined to be 3.9 percent for the aggregate MISO footprint, which is in line with previously derived LFU. Further details of this determination are discussed in appendix A.

[9] This method was implemented to reduce the volatility that could not be related to the realworld and was mainly caused by modeling aspects

The method of modeling zones with a central hub ensures that the LRZ LRR is established in sync with MISO-wide PRM using the same model and applying the same zonal LFUs. Modeling the more granular zonal LFU values appropriately applies each LRZ's LFU to that LRZ's load. This application of LFU more accurately reflects the uncertainty impacts of each LRZ's geographic area.

In the zonal methodology, MARS applied the LFU of each LRZ to its corresponding hourly load; this application was not limited only to the peak loads. In other words, at every specific hour in the model, if one LRZ was taken away from its 50/50 load of that hour by one standard deviation (sigma), all other zones were one sigma away from their 50/50 loads of that very same hour, where the sigma value was a different value of LFU for each LRZ. The LRZ LFU values used in the MISO PRM analysis are provided in Table 4.3-1.

Zones	LFU
LRZ 1	2.8%
LRZ 2	4.5%
LRZ 3	3.0%
LRZ 4	4.8%
LRZ 5	4.5%
LRZ 6	3.4%
LRZ 7	5.3%
LRZ 8	5.1%
LRZ 9	2.7%
LRZ 10	4.2%

Table 4.3-1: 2016 Local Resource Zone LFU

Previously, MISO performed LFU sensitivity analysis to examine its effect on the PRM Requirement. MISO concluded that for the LFU ranges of 3 percent to 4 percent, a 1 percentage point increase in LFU contributes to an increase of about 2 percentage points in PRM UCAP.
More details about the LFU methodology are provided in Appendix A: Load Forecast Uncertainty.

4.4 External System

The 2016 LOLE study made a number of enhancements to the modeling of external areas within the LOLE analysis. Previous years' analyses saw year-over-year variance in the amount of non-firm external support. This variance was often due to changes in third party vendor data and was not easily discernible. Within the study 1 MW of non-firm support leads to 1 MW decrease in the reserve margin calculation. It is important to account for the benefit of being interconnected in the eastern interconnection while also providing a stable result. In order to provide a more stable result and remove the false sense of precision, the external non-firm support was set at the same amount as in the 2015 LOLE study. A detailed description of the methodology used in that study can be found in section 4.4 of the 2015 LOLE study.

As a result of the external non-firm support enhancement, more accurate firm external support modeling was possible. In previous studies firm support was modeled as a constant MW amount from external areas at the unforced capacity value. In this year's analysis, the specific external units were modeled with their specific installed capacity amount and their corresponding EFORd. This better captures the probabilistic reliability impact of firm external imports. These units are only modeled within the MISO PRM analysis and are not modeled when calculating the LRZ LRRs. The external resources to include for firm imports were based off of the amount offered into the 2015-16 Planning Year PRA. For 2015-16 Planning Year this amount was 4,510 MW ICAP.

Firm exports from MISO to external areas was modeled the same as previous years. As stated in section 4.2.3, capacity that is not eligible as MISO capacity due to transactions with external areas is removed from the model. Table 4.4-1 shows the amount of firm imports and exports in this year's study.

Contracts	ICAP (MW)	UCAP (MW)
Imports (MW)	4,510	4,380
Exports (MW)	4,266	4,015
Net	**244**	**365**

Table 4.4- 1: 2016 Planning Year Firm Imports and Exports

4.5 Loss of Load Expectation Analysis and Metric Calculations

Once the GE MARS input files were created, MISO determined the appropriate PRM ICAP and PRM UCAP for the 2016-2017 Planning Year as well as the appropriate Local Reliability Requirement for each of the 10 LRZs. These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year.

4.5.1 Enhancement to LOLE Capacity Adjustment Methodology

In order to drive the LOLE model to the 0.1-day-per-year LOLE standard, capacity or load must be adjusted within the model to either increase or decrease LOLE risk. For example, if a base model is run and results in a LOLE of 0.08 day/year then capacity needs to be decreased or load increased in order to drive the model to 0.1 day/year LOLE. Once the model output is 0.1 day/year LOLE the required reserve margin can be calculated.

In previous LOLE studies, MISO incrementally added the largest UCAP units to the model until the LOLE was at 0.1 day/year. MISO implemented this methodology by starting with the base model and removing the smallest UCAP units until reaching LOLE 0.1 day/year. This led to the removal of a large number of units from the model. Since small UCAP units correlate highly to high forced outage rates, a bias to include more reliable units within the model was introduced. To remove this bias in the analysis, an enhancement to the 2016 LOLE study was vetted through the stakeholder process and approved by the Federal Energy Regulatory Commission (FERC).

The enhanced capacity adjustment methodology adds a perfect negative unit with zero forced outage rate to the model if the LOLE is less than 0.1 day/year (e.g. 0.08 day/year). This is the same as adding load to the model with zero LFU. This ensures that all generator statistics are captured within the model and an accurate reserve margin is calculated. The methodology of adding proxy units when LOLE is greater than 0.1 day/year (e.g. 0.12 day/year) is unchanged from previous studies.

4.5.2 MISO-Wide LOLE Analysis and PRM Calculation

For the MISO-wide analysis, generating units were modeled as part of their appropriate LRZ as a subset of a larger MISO pool. The MISO system was modeled with no internal transmission limitations. In order to meet the reliability criteria of 0.1 day per year LOLE, capacity is either added or removed from the

MISO pool. The minimum amount of capacity above the 50/50 net internal MISO Coincident Peak Demand required to meet the reliability criteria was used to establish the PRM values.

The minimum PRM requirement is determined using the LOLE analysis by either adding or removing capacity until the LOLE reaches 0.1 day per year. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate is added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

For the 2016-2017 planning year, the MISO PRM analysis had to remove capacity using the perfect unit adjustment.

The formulas for the PRM values for the MISO system are:

PRM ICAP = (Installed Capacity + Firm External Support + ICAP Adjustment to meet a LOLE of 0.1 days per year) – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

PRM UCAP = (Unforced Capacity + Firm External Support + UCAP Adjustment to meet a LOLE of 0.1 days per year) – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

Where Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – XEFORd)

4.5.3 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the LRZ analysis, each LRZ included only the generating units within the LRZ and was modeled without consideration of the benefit of the LRZ's CIL. Much like the MISO analysis, unforced capacity is either added or removed in each LRZ such that a LOLE of 0.1 day per year is achieved. The minimum amount of unforced capacity above each LRZ's Peak Demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

The 2016-2017 LRR is determined using the LOLE analysis by either adding or removing capacity until the LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

For the 2016-2017 planning year, none of the 10 LRZs had sufficient capacity within the LRZ to achieve the LOLE of 0.1 day per year. In these cases proxy units of typical size (160 MW) and class average EFORd (5.69 percent) were added to the LRZ. When needed a fraction of the final proxy unit was added to achieve exactly the LOLE of 0.1 day per year for the LRZ.

5 MISO System Planning Reserve Margin Results

5.1 Planning Year 2016-2017 MISO Planning Reserve Margin Results

For the 2016-2017 planning year, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 15.2 percent and a planning UCAP reserve margin of 7.6 percent. These PRM values assume 4,380 MW UCAP of firm and 2,331 MW UCAP of non-firm external support. The non-firm support is determined by running a case without the external system to establish the PRM requirement without help from the external world. The difference between this case and the base case shows the approximate average non-firm support the MISO system is receiving. Table 5.1-1 shows all the values and the calculations that went into determining the MISO system PRM ICAP and PRM UCAP.

MISO Planning Reserve Margin (PRM)	2016/2017 PY (June 2016 - May 2017)	Formula Key
MISO System Peak Demand (MW)	128,718	[A]
Time of System Peak (ESTHE)	8/3/2016 16:00	
Installed Capacity (ICAP) (MW)	150,668	[B]
Unforced Capacity (UCAP) (MW)	140,334	[C]
Firm External Support (ICAP) (MW)	4,510	[D]
Firm External Support (UCAP) (MW)	4,380	[E]
Adjustment to ICAP (MW)	-3,907	[F]
Adjustment to UCAP (MW)	-3,907	[G]
Non-Firm External Support (ICAP) (MW)	2,987	[H]
Non-Firm External Support (UCAP) (MW)	2,331	[I]
ICAP PRM Requirement (PRMR) (MW)	148,284	[J]=[B]+[D]+[F]-[H]
UCAP PRM Requirement (PRMR) (MW)	138,476	[K]=[C]+[E]+[G]-[I]
MISO PRM ICAP	**15.2%**	[L]=([J]-[A])/[A]
MISO PRM UCAP	**7.6%**	[M]=([K]-[A])/[A]

Table 5.1-1: Planning Year 2016-2017 MISO System Planning Reserve Margins

5.1.1 LOLE Results Statistics

In addition to the LOLE results GE MARS has the ability to output several other probabilistic metrics (Table 5.1.1-1). These values are given when MISO is at its PRM UCAP of 7.6 percent. The LOLE of 0.1 day/year is what the model is driven to and how the PRM is calculated. The loss of load hours is defined as the number of hours during a given time period where system demand will exceed the generating capacity during a given period. Expected Unserved Energy (EUE) is energy-centric and analyzes all hours of a particular planning year. Results are calculated in Megawatt-Hours (MWh). EUE is the summation of the expected number of Megawatt-Hours of load that will not be served in a given planning year as a result of demand exceeding the available capacity across all hours.

MISO LOLE Statistics	
Loss of Load Expectation - LOLE [Days/Yr]	0.100
Loss of Load Hours - LOLH [hrs/yr]	0.365
Expected Unserved Energy - EUE [MWh/yr]	899.7

Table 5.1.1-2: MISO Probabilistic Model Statistics

5.2 Comparison of PRM Targets Across Six Years

Figure 5.2-1 compares the PRM UCAP values over the last seven planning years. The last endpoint of the green line shows the Planning Year 2016-2017 PRM value.

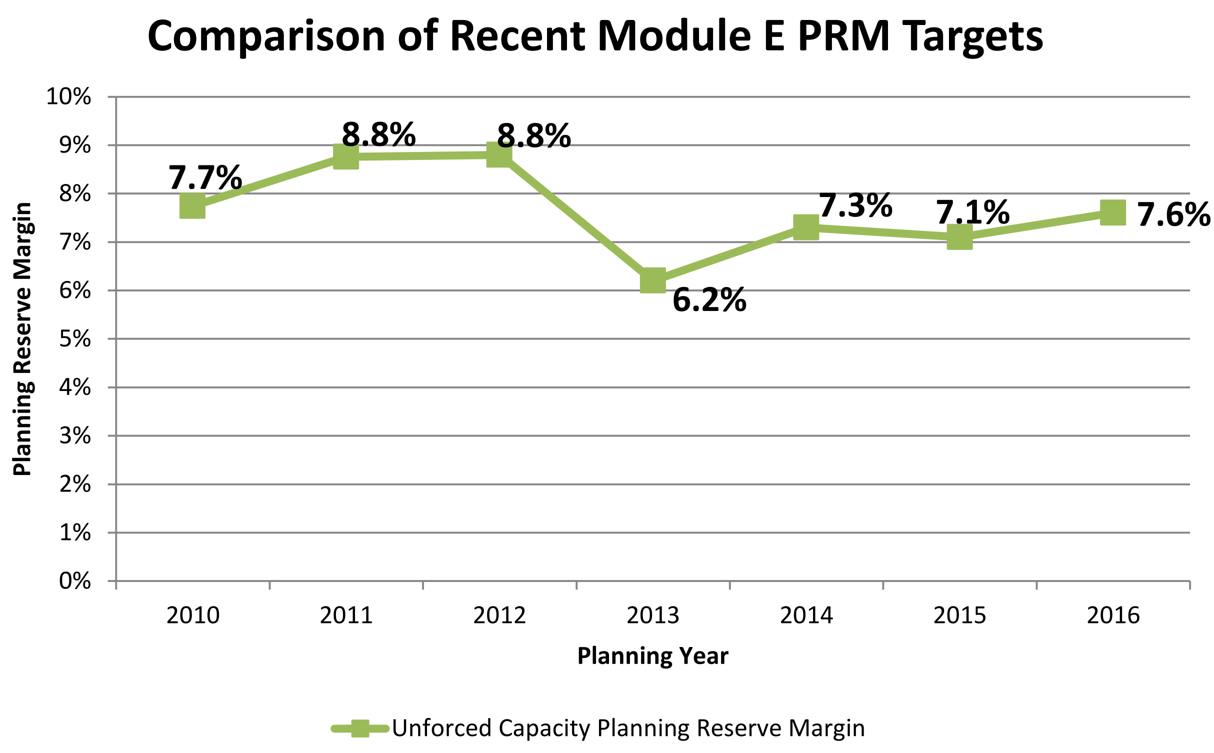


Figure 5.2-1: Comparison of PRM targets across six years

5.3 Future Years 2016 through 2024 Planning Reserve Margins

Beyond the planning year 2016-2017 LOLE study analysis, an LOLE analysis was performed for the five-year-out planning year of 2020-2021, and the 10-year-out planning year of 2025-2026. Table 5.3-1 shows all the values and calculations that went into determining the MISO system PRM ICAP and PRM UCAP values for those years. Those results are shown as the underlined values of Table 5.3-2. The years in between were arrived at through interpolation of the results from the years 2016, 2020 and 2025. Note that the MISO system PRM results assume no limitations on transfers within MISO.

In future years, MISO sees stability in the PRM UCAP, which is driven by MISO's assumption of constant LFU in out years. The 2025 PRM UCAP is lower than previous years due to the fact that capacity has to be added to the MISO system to meet the LOLE criterion of 0.1 day/year as well as an increase in system peak demand. This causes the resource mix to have a slightly better overall system weighted forced outage rate, which is driving the PRM UCAP down.

MISO Planning Reserve Margin (PRM)	**2020/2021 PY** (June 2020 - May 2021)	**2025/2026 PY** (June 2025 - May 2026)	**<u>Formula Key</u>**
MISO System Peak Demand (MW)	133,431	137,639	[A]
Time of System Peak (ESTHE)	8/4/2020 16:00	8/5/2025 16:00	
Installed Capacity (ICAP) (MW)	153,883	155,446	[B]
Unforced Capacity (UCAP) (MW)	143,345	144,861	[C]
Firm External Support (ICAP) (MW)	4,510	4,510	[D]
Firm External Support (UCAP) (MW)	4,380	4,380	[E]
Adjustment to ICAP (MW)	-2,224	731	[F]
Adjustment to UCAP (MW)	-2,224	689	[G]
Non-Firm External Support (ICAP) (MW)	2,987	2,987	[H]
Non-Firm External Support (UCAP) (MW)	2,331	2,331	[I]
ICAP PRM Requirement (PRMR) (MW)	153,182	157,700	[J]=[B]+[D]+[F]-[H]
UCAP PRM Requirement (PRMR) (MW)	143,170	147,598	[K]=[C]+[E]+[G]-[I]
MISO PRM ICAP	**14.8%**	**14.6%**	[L]=([J]-[A])/[A]
MISO PRM UCAP	**7.3%**	**7.2%**	[M]=([K]-[A])/[A]

Table 5.3-1: Future Planning Year MISO System Planning Reserve Margins

Metric	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PRM $_{ICAP}$	**<u>15.2%</u>**	**15.1%**	**15.0%**	**14.9%**	**<u>14.8%</u>**	**14.8%**	**14.7%**	**14.7%**	**14.6%**	**<u>14.6%</u>**
PRM $_{UCAP}$	**<u>7.6%</u>**	**7.5%**	**7.4%**	**7.4%**	**<u>7.3%</u>**	**7.3%**	**7.3%**	**7.3%**	**7.2%**	**<u>7.2%</u>**

Table 5.3-2: MISO System Planning Reserve Margins 2016 through 2025
(Years without underlined results indicate values that were calculated through interpolation)

6 Local Resource Zone Analysis – LRR Results

6.1 Planning Year 2016-2017 Local Resource Zone Analysis

MISO calculated the per-unit LRR of LRZ Peak Demand for years one, two and three (Table 6.1-1 through Table 6.1-3). The UCAP values in Table 6.1-1 reflect the UCAP within each LRZ and the adjustment to UCAP values are the megawatt adjustments needed in each LRZ so that the reliability criterion of 0.1 days per year LOLE is met. The LRR is the summation of the UCAP and adjustment to UCAP megawatts. The LRR is then divided by each LRZ's Peak Demand to determine the per-unit LRR UCAP. The 2016-2017 per unit LRR UCAP values will be multiplied by the updated demand forecasts submitted for the 2016-2017 PRA to determine each LRZ's LRR.

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
2016-2017 Planning Reserve Margin (PRM) Study											
Unforced Capacity (UCAP)-MW	18,232	14,574	9,495	10,775	7,856	19,348	21,858	10,137	21,873	6,171	[A]
Adjustment to UCAP (MW) (1d in 10yr)	1,961	220	1,326	1,104	2,563	930	2,857	248	1,268	836	[B]
LRR (UCAP)	20,193	14,794	10,821	11,879	10,420	20,278	24,715	10,385	23,140	7,007	[C]=[A]+[B]
Peak Demand	18,197	12,940	9,582	9,753	8,609	18,297	21,832	8,265	20,563	5,035	[D]
Time of Peak Demand (ESTHE)	7/12/16 16:00	7/14/16 16:00	7/20/16 19:00	8/9/16 17:00	8/3/16 16:00	7/25/16 16:00	7/25/16 17:00	8/14/16 17:00	8/14/16 17:00	8/15/16 17:00	
LRR UCAP per-unit of LRZ Peak Demand	111.0%	114.3%	112.9%	121.8%	121.0%	110.8%	113.2%	125.7%	112.5%	139.2%	[E]=[C]/[D]

Table 6.1-1: Planning Year 2016-2017 LRZ Local Reliability Requirements

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
2020-2021 Planning Reserve Margin (PRM) Study											
Unforced Capacity (UCAP)	18,301	15,165	10,107	11,111	7,860	20,174	22,129	10,137	22,176	6,171	[A]
Adjustment to UCAP (MW) (1d in 10yr)	2,627	-109	1,195	1,073	2,580	1,102	2,735	717	2,700	1,056	[B]
LRR (UCAP)	20,928	15,056	11,302	12,184	10,440	21,277	24,864	10,854	24,876	7,227	[C]=[A]+[B]
Peak Demand	18,913	13,175	9,994	9,936	8,592	19,170	21,944	8,694	22,132	5,224	[D]
LRR UCAP per-unit of LRZ Peak Demand	110.7%	114.3%	113.1%	122.6%	121.5%	111.0%	113.3%	124.8%	112.4%	138.3%	[E]=[C]/[D]

Table 6.1-2: Planning Year 2020-2021 LRZ Local Reliability Requirements

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
2025-2026 Planning Reserve Margin (PRM) Study											
Unforced Capacity (UCAP)	18,301	15,165	10,107	11,111	7,856	20,174	23,644	10,137	22,176	6,171	[A]
Adjustment to UCAP (MW) (1d in 10yr)	3,292	282	1,677	1,209	2,827	1,868	1,616	1,069	3,410	1,243	[B]
LRR (UCAP)	21,593	15,447	11,784	12,320	10,684	22,042	25,260	11,207	25,586	7,414	[C]=[A]+[B]
Peak Demand	19,547	13,522	10,471	10,063	8,848	19,935	22,143	9,069	23,059	5,455	[D]
LRR UCAP per-unit of LRZ Peak Demand	110.5%	114.2%	112.5%	122.4%	120.7%	110.6%	114.1%	123.6%	111.0%	135.9%	[E]=[C]/[D]

Table 6.1-3: Planning Year 2025-2026 LRZ Local Reliability Requirements

Appendix A Load Forecast Uncertainty

A.1 LFU Methodology for Planning Year 2015

Since the NERC load forecasting working group disbanded, MISO adapted the 2011 NERC bandwidth methodology to perform LFU analysis and developed regression models similar to NERC. MISO included historical load data (1993-2013) to determine LRZ LFU. Starting in the 2014 planning year, MISO South companies were included in the LFU calculation. This year, with Mississippi as a separate LRZ, 10 different LFU values were calculated.

Forecasts cannot precisely predict the future. Instead, many forecasts append probabilities to the range of possible outcomes. Each demand projection, for example, represents the midpoint of possible future outcomes. This means that a future year's actual demand has a 50 percent chance of being higher and a 50 percent chance of being lower than the forecast value.

For planning and analytical purposes, it is useful to have an estimate of the midpoint of possible future outcomes, as well as the distribution of probabilities on both sides of that midpoint. Accordingly (similar to NERC), MISO developed upper and lower 80 percent confidence bands. Thus, there is an 80 percent chance of future demand occurring within these bands, a 10 percent chance of future demand occurring below the lower band, and an equal 10 percent chance of future demand occurring above the upper band[10].

The principal features of the bandwidth methodology include:

1. A univariate time series model in which the projection of demand is modeled as a function of past demand. This approach expresses the current value of the time series as a linear function of the previous value of the series and a random shock. In equation form, the first-order autoregressive model can be written as:

$$y_t = a + y_{t-1} + \varepsilon_t$$

2. The variability observed in demand is used to develop uncertainty bandwidths. Variability, represented by the variance $\sigma\varepsilon$ of the historic data series, is combined with other model information to derive the uncertainty bandwidths.

More details about the NERC methodology can be found at NERC Bandwidth Methodology.

[10] LFU is not meant to capture the uncertainty in the load forecast modeling. It is meant to capture the uncertainty in weather, economy, etc.

This year, to reduce the unreasonable year-over-year volatility in LFU calculation, MISO implemented a weighted-average smoothing methodology. Since three years of LFU calculation with consistent methodology existed, the weighted-averaging was done for three years, based on the quality of the regressions for the common years of data. Every year that MISO performs the LFU study, a new year of annual historic load is added to each LRZ's data set, and a new regression analysis as explained above was performed. Comparing the regressions for only the common data points for the last three studies, revealed that the quality of regression (based on the sum of the square of errors) was not equal between them and therefore the weighted average methodology was performed. Figure A.1-1 graphically shows the different regressions and Table A.1-1 provides each year of LFU calculation as well as the weighted average results used in this LOLE study.

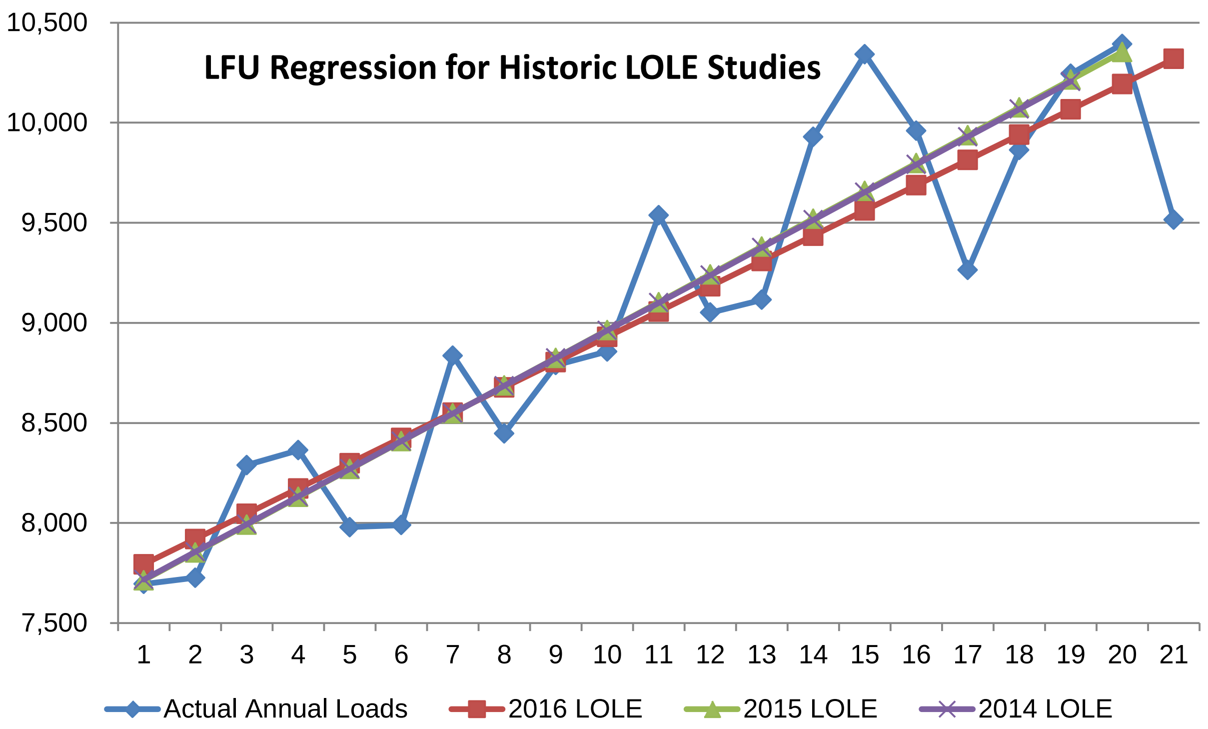


Figure A.1-1: LFU Regression Comparison for Historic LOLE Studies

Also, as mentioned in section 4.3.1, MISO calculated the system-wide LFU equivalent to MISO's current zonal methodology to be about 3.9 percent. In this calculation, the 50/50 hourly load of each LRZ was increased by one standard deviation and then aggregated up to get to one hourly load for the MISO footprint. This load was compared to the 50/50 MISO hourly load and an overall LFU for every hour was calculated. The average of these hourly MISO LFUs was about 3.9 percent.

A.1.1 Historical Data Used in the Model

For the 2016-2017 planning year, the LFU methodology did not change from the 2014-2015 planning year. Tables A.1-1 and A.1-2 list data sources used for calculation of 2016-2017 LFUs.

North Central Region	
Energy Velocity (EV) Data	**MISO Data**
All Members currently in MISO: 1993-2008	All Members Currently in MISO 2009-2012
Duke Indiana: 1993-2011	**Except:** Duke Indiana: 1993-2011 BREC: 2009-11/30/2010 DPC:2009-05/31/2010 MEC, MPW:2009-08/31/2009
BREC: 1993-11/30/2010	
DPC:1993-05/31/2010	
MEC, MPW:1993-08/31/2009	

Table A.1-1: MISO North/Central historical load data sources

South Region	
FERC 714- Part III-Schedule 2 (from Energy Velocity or from FERC Database)	**Directly from LBAs**
Entergy EES 1993-1995, 2003-2013	Billing data for EAI+AECC and EMI served by Entergy, and Entergy Systems 1993-2013
Zone 9 and 10 members excluding EES and SME: 1993-2013	
	Entergy EES FERC 714 data 1996-2002
	SME 1993-2013

Table A.1-2: MISO South historical load data sources

For Energy Velocity (EV) datasets, hourly loads are prepared by Ventyx (Energy Velocity) where the base data source for this dataset is FERC 714 form - Part III of Schedule 2. The raw data filed for FERC 714 form - Part III of Schedule 2 is usually reported at the level of a planning area. However, in some cases, several LSEs file their load data together as a single entity, resulting in less load resolution. Where practical, Ventyx separates filed loads into the smaller load entities that have originally filed load data individually using models developed by Ventyx. Available hourly data was in two categories of New Topology and Old Topology. Old Topology data was available from 1993-2008 at the level of LBA, LSE or Municipals where the new topology was available from 2003-2011 at the LBA level.

For each of these topologies, the monthly peaks were derived from the LBA/LSE hourly loads. Based on the correlation between old and new topologies, from six years of overlapping data, the new topology was back casted at a monthly level from 1993 to 2002 for each LBA/LSE. This data, along with the data collected from sources other than EV, were summed to get hourly loads for each of the 10 LRZs and MISO to the extent possible. MISO and LRZ monthly peaks were then derived from these hourly loads. Where calculating at an hourly level was not possible, the data was summed at a monthly peak level.

For Entergy, since the FERC 714 data is not broken down by state, or MISO LBA, MISO worked with them to separate the Arkansas and Mississippi portions of the load data from the rest. In order to do that, Entergy provided MISO with hourly billing load data for Arkansas and Mississippi as well as for the overall Entergy system. Since the assumptions in this data were different from FERC 714 actual loads, Entergy and MISO agreed to use the billing data to find the hourly ratios of Arkansas and Mississippi loads and apply that to the Entergy FERC 714 submission to get the appropriate proportions. This was agreed to be the best way available to us to split the zone 8 and zone 10 portions of Entergy system from the rest.

MISO collected LBA-level load data to be consistent with 2014 MISO footprint, the list of LBAs is provided in Table A.1-3. This table provides acronyms for LBAs.

No.	Local Balancing Area	Acronym	Zone
1	Dairyland Power Cooperative	DPC	LRZ-1
2	Great River Energy	GRE	LRZ-1
3	Minnesota Power	MP	LRZ-1
4	Montana-Dakota Utilities Co.	MDU	LRZ-1
5	Northern States Power Co. (Xcel)	NSP/XEL	LRZ-1
6	Otter Tail Power Co.	OTP	LRZ-1
7	Southern MN Municipal Power Agency	SMP	LRZ-1
8	Alliant East - Wisconsin Power and Light Co.	ALTE	LRZ-2
9	Madison Gas and Electric Co.	MGE	LRZ-2
10	Upper Peninsula Power Co.	UPPC	LRZ-2
11	Wisconsin Electric Power Co.	WEC/MIUP[11]	LRZ-2
12	Wisconsin Public Service Corp.	WPS	LRZ-2
13	Alliant West - Interstate Power & Light	ALTW	LRZ-3
14	MidAmerican Energy Co.	MEC	LRZ-3
15	Muscatine Power & Water	MPW	LRZ-3
16	Ameren Illinois	AMIL	LRZ-4
17	Southern Illinois Power Cooperative	SIPC	LRZ-4
18	Springfield Illinois - City Water Light & Power	CWLP	LRZ-4
19	Ameren Missouri	AMMO	LRZ-5
20	Columbia Missouri Water and Light Department	CWLD	LRZ-5
21	Big Rivers Electric Corp.	BREC	LRZ-6
22	Duke Energy Indiana	DUK(IN)	LRZ-6
23	Hoosier Energy Rural Elec.	HE	LRZ-6
24	Indianapolis Power & Light	IPL	LRZ-6
25	Northern Indiana Public Service	NIPSCO	LRZ-6
26	Southern Indiana Gas & Electric	SIGE	LRZ-6
27	Consumers Energy – METC	CONS	LRZ-7

[11] MIUP is a new Local Balancing Authority (LBA) that was previously a part of WEC. Since there is no change in the LRZ that the LBA resides in, the historic load collected was under WEC. If in the future, MIUP is in a different LRZ than WEC, historic breakdown of the LBAs should be collected to perform the LFU study

28	Detroit Edison Co.	DECO	LRZ-7
29	Entergy Arkansas	EAI	LRZ-8
30	Central Louisiana Electric Co. Inc.	CLECO	LRZ-9
31	Entergy Services, Inc.	EES	LRZ-9
32	Lafayette (City of)	LAFA	LRZ-9
33	Louisiana Energy and Power Authority	LEPA	LRZ-9
34	Louisiana Generating/Cajun Electric	LAGN	LRZ-9
35	South Mississippi Electric Power Association	SME	LRZ-10
36	Entergy Mississippi	EMI	LRZ-10

Table A.1-3: List of Local Balancing Authorities (LBA)

A.2 MISO LFU results

Using the methodology discussed in Section A.1 and the data set explained in Section A.1.1, the MISO equivalent LFU for the planning year 2016 is 3.9 percent. MISO developed an auto-regression model as well as a weighted-average smoothing approach for each LRZ and the LFU results are displayed in Table A.2-1. The definitions of the 10 LRZs are indicated in Table A.1-3.

LRZ	PY2014-2015	PY2015-2016	PY2016-2017	3 Year Average (LOLE Study Input)
Weights	33.6%	33.5%	32.9%	
Zone 1	2.9%	2.8%	2.8%	2.8%
Zone 2	4.5%	4.5%	4.6%	4.5%
Zone 3	3.0%	2.9%	3.0%	3.0%
Zone 4	4.7%	4.5%	5.3%	4.8%
Zone 5	4.4%	4.2%	5.0%	4.5%
Zone 6	3.5%	3.3%	3.5%	3.4%
Zone 7	5.3%	5.2%	5.4%	5.3%
Zone 8	5.0%	4.9%	5.5%	5.1%
Zone 9	2.7%	2.8%	2.7%	2.7%
Zone 10	4.0%	4.3%	4.4%	4.2%
MISO Overall			3.9%	3.9%

Table A.2-1: Zonal LFU results

Appendix B Comparison of Planning Year 2015 to 2016

To compute changes in the PRM target on an UCAP basis, from the 2015-2016 planning year to the 2016-2017 planning year, multiple study sensitivity analyses were performed. These sensitivities included one-off incremental changes of input parameters to quantify how each change affected the PRM result independently. The impact of the incremental PRM changes from 2015 to 2016 are shown in the waterfall chart of Figure A.2-1 and explained in section B.1, as well.

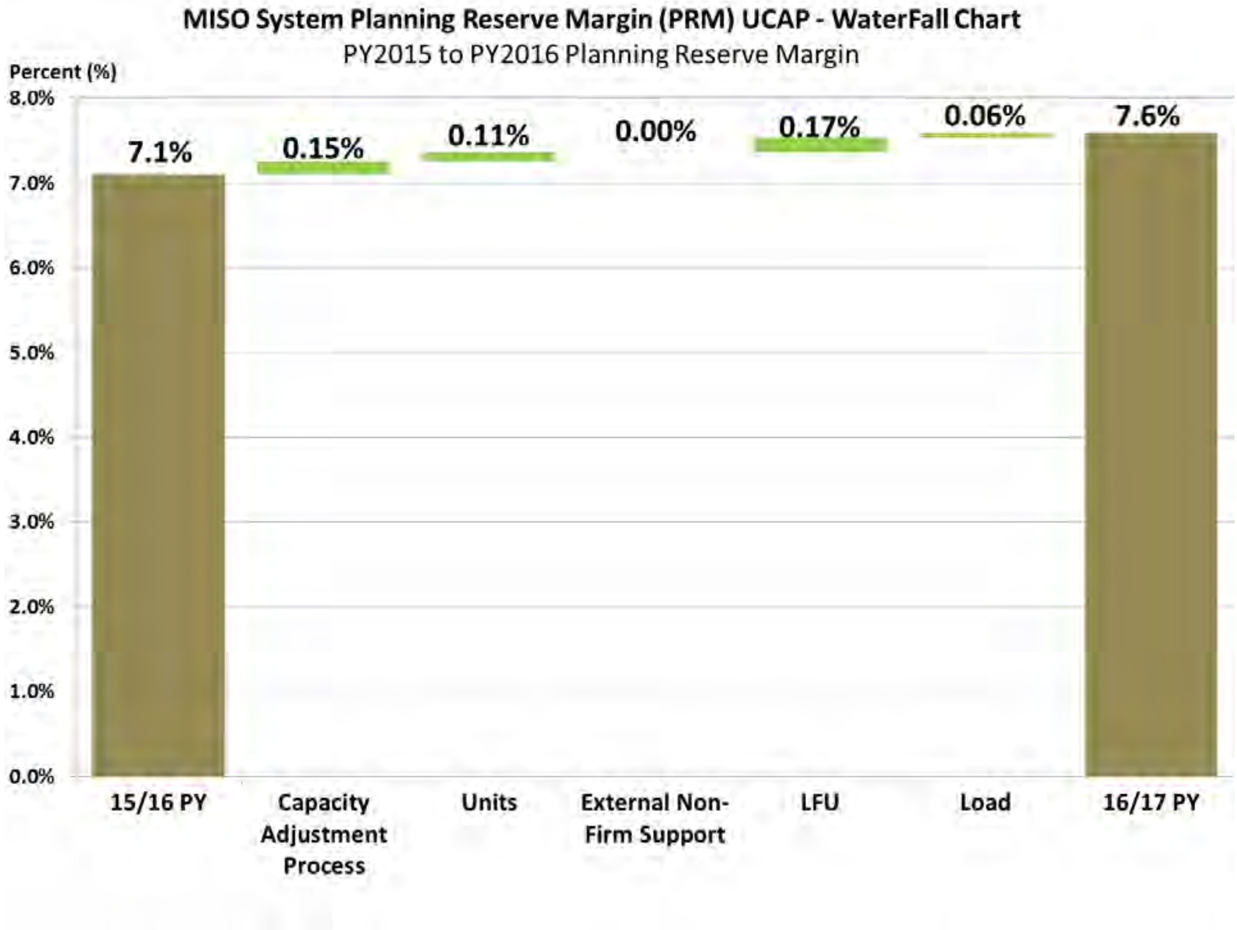


Figure A.2-1: Waterfall chart of 2015 PRM UCAP to 2016 PRM UCAP

B.1 Waterfall Chart Details

B.1.1 Capacity Adjustment Process

The 2016-2017 Planning Year study utilized an enhanced capacity adjustment methodology that is outlined in section 4.5.1. This change to the capacity adjustment process resulted in a 0.15 percent increase in MISO PRM UCAP. This increase is a one-time process improvement change and will not be present in future years' waterfall charts.

B.1.2 Units

The 2016-2017 planning year LOLE study utilized the 2015 PRA converted capacity as a starting point for which resources to include in the study. This was to better align the LOLE study with the PRA to ensure that only resources eligible as a Planning Resource were included. An exception was made for resources in MISO's March 2015 Commercial Model that weren't part of the 2015 PRA, but stated in the OMS-MISO Survey that they would be available in 2015. These resources were also included. All internal Planning Resources were modeled in the LRZ in which they are physically located. Changes from 2015-2016 Planning Year values are due to changes in Generation Verification Test Capacity (GVTC), EFORd or Equivalent forced outage rate demand with adjustment to exclude events outside management control (XEFORd), new units, retirements, suspensions etc.

Lastly, the overall MISO EFORd increased 0.31 percent. This coupled with the changes above resulted in an overall increase to the MISO PRM UCAP of 0.11 percent.

B.1.3 External Non-Firm Support

External non-firm support was set at the same amount as in the 2015-2016 Planning Year analysis. This resulted in 0.0 planning change in the PRM UCAP. Further description of this change can be found in section 4.4.

B.1.4 LFU

The MISO aggregate LFU value for Planning Year 2016-2017 increased 0.1 percent from the 2015-2016 value, which resulted in an overall increase to the MISO PRM UCAP of 0.17 percent. Without the weighted average smoothing function, there would have been an additional increase of about 0.2 percent to the PRM. Six of the 10 LRZ LFU values increased, which drove the overall MISO aggregate LFU value to increase.

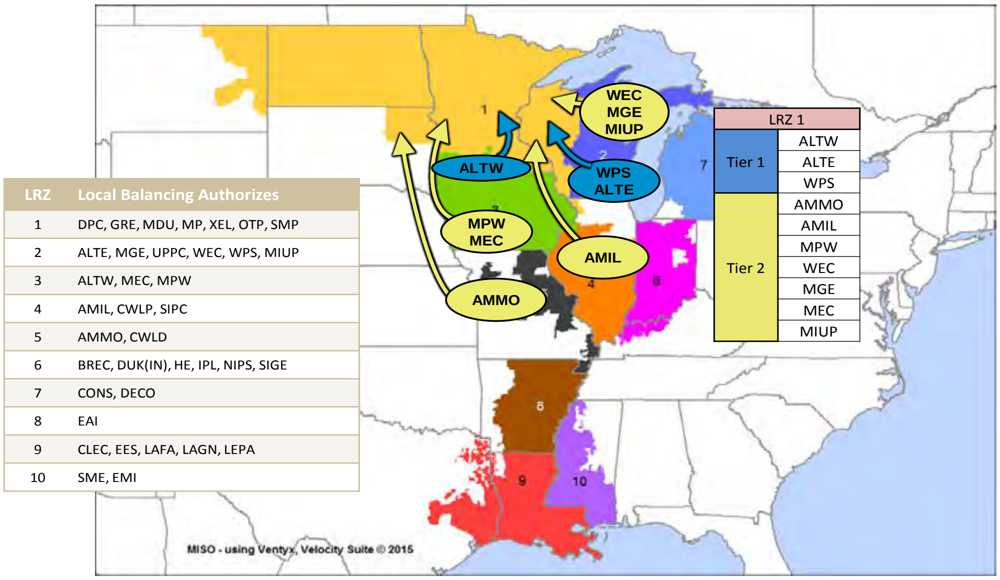
B.1.5 Load

For the 2016-2017 planning year, the MISO Coincident Peak Demand increased by 0.9 percent from the 2015-2016 planning year, which was driven by the updated actual load forecasts submitted by the LSEs. These updated forecasts in combination with the number of days the LOLE model experienced demands greater than 0.95 per unit of Peak Demand resulted in a 0.06 percent increase in PRM UCAP.

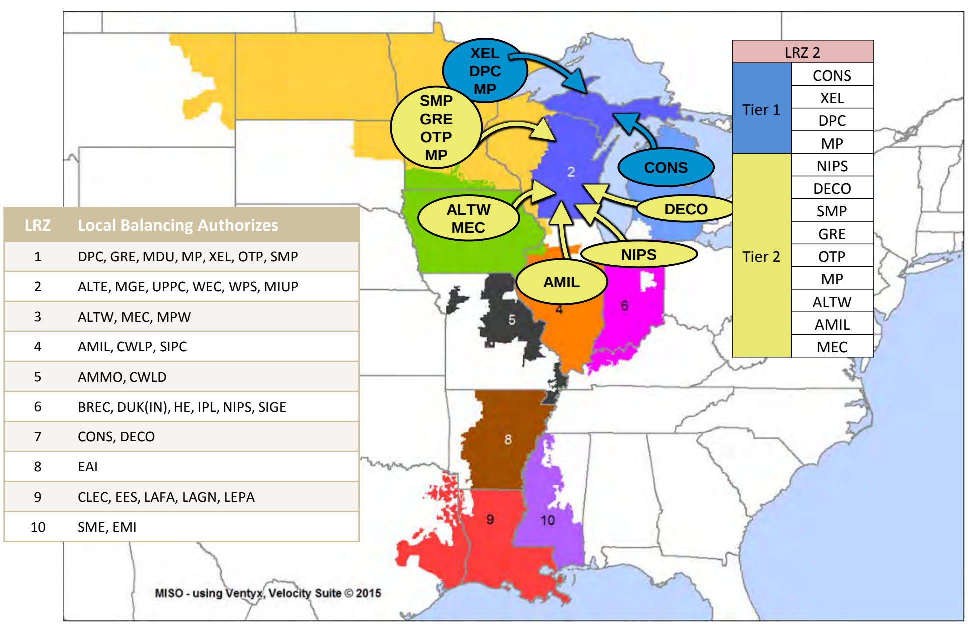
Appendix C Transfer Analysis

C.1 Tier Maps

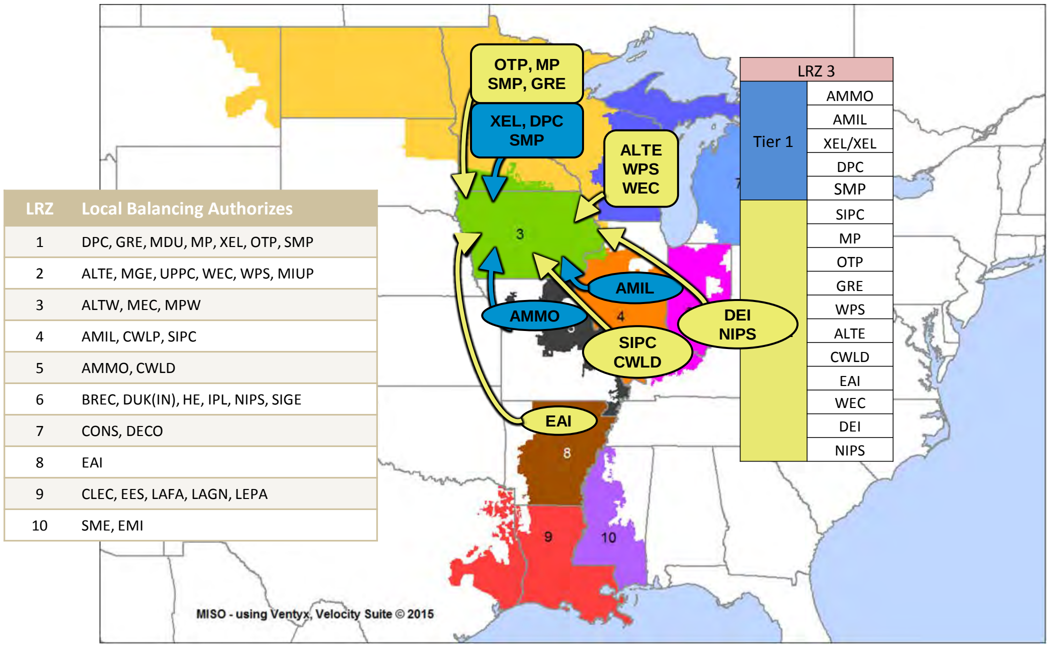
MISO Local Resource Zone 1



MISO Local Resource Zone 2



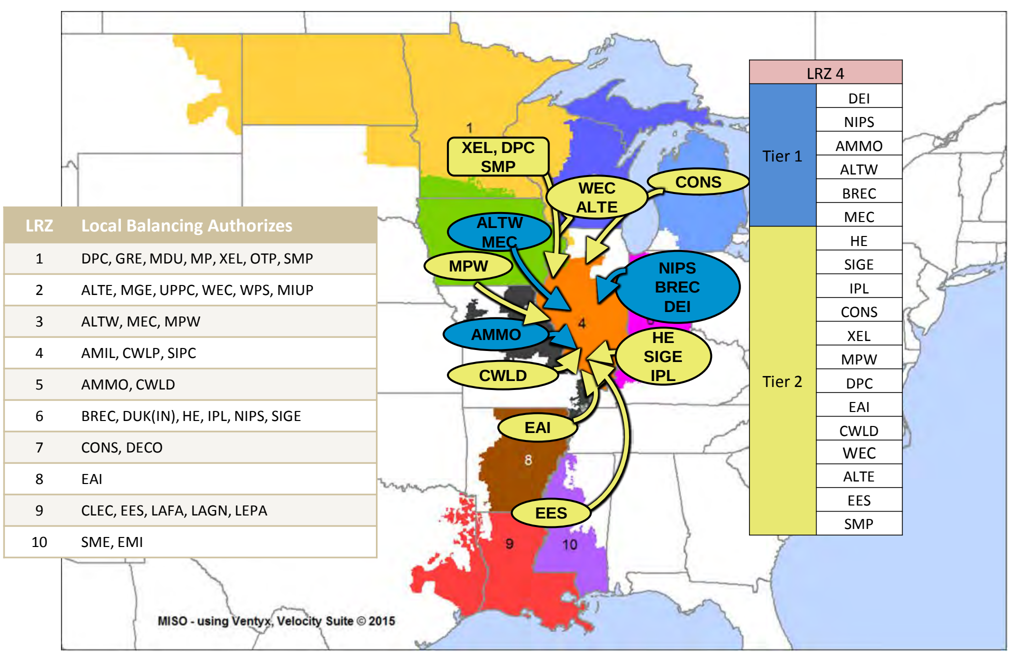
MISO Local Resource Zone 3



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

LRZ 3	
Tier 1	AMMO
	AMIL
	XEL/XEL
	DPC
	SMP
	SIPC
	MP
	OTP
	GRE
	WPS
	ALTE
	CWLD
	EAI
	WEC
	DEI
	NIPS

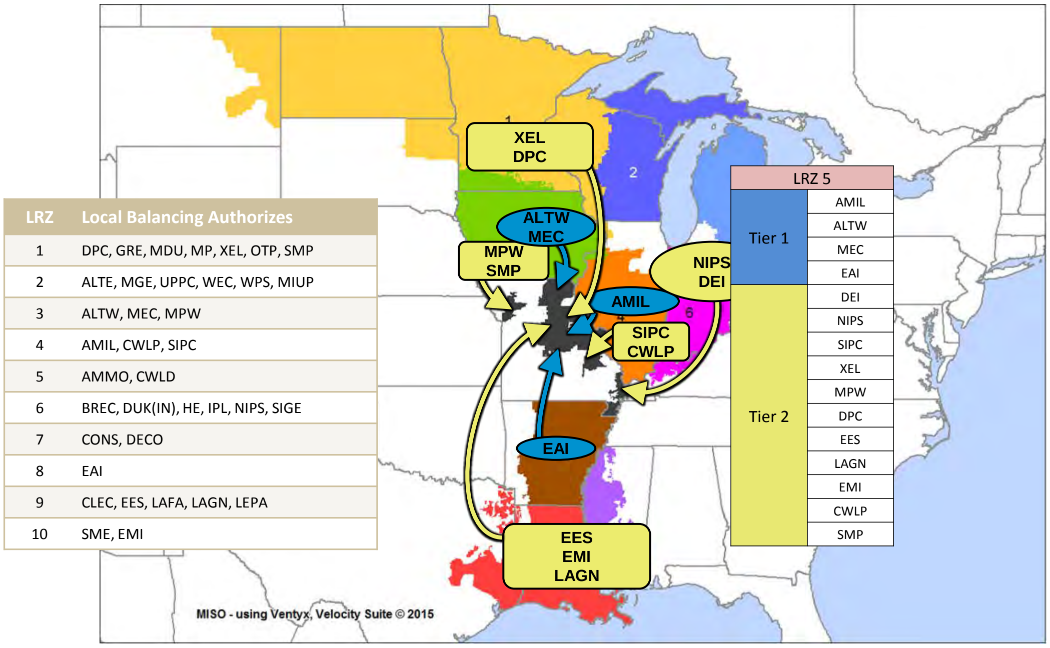
MISO Local Resource Zone 4



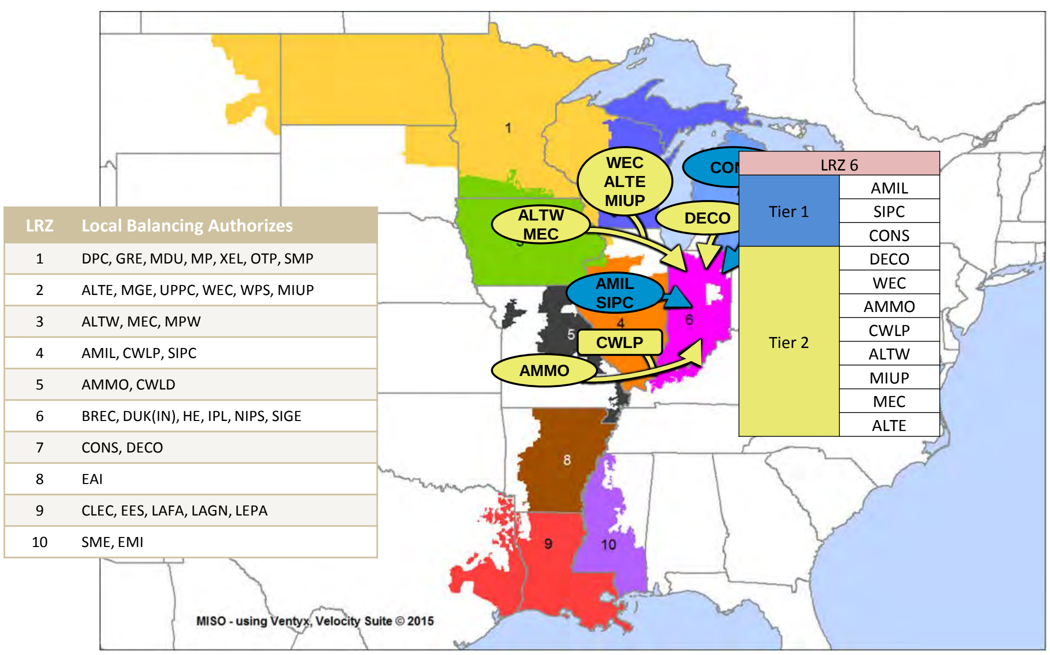
LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

LRZ 4	
Tier 1	DEI
	NIPS
	AMMO
	ALTW
	BREC
	MEC
Tier 2	HE
	SIGE
	IPL
	CONS
	XEL
	MPW
	DPC
	EAI
	CWLD
	WEC
	ALTE
	EES
	SMP

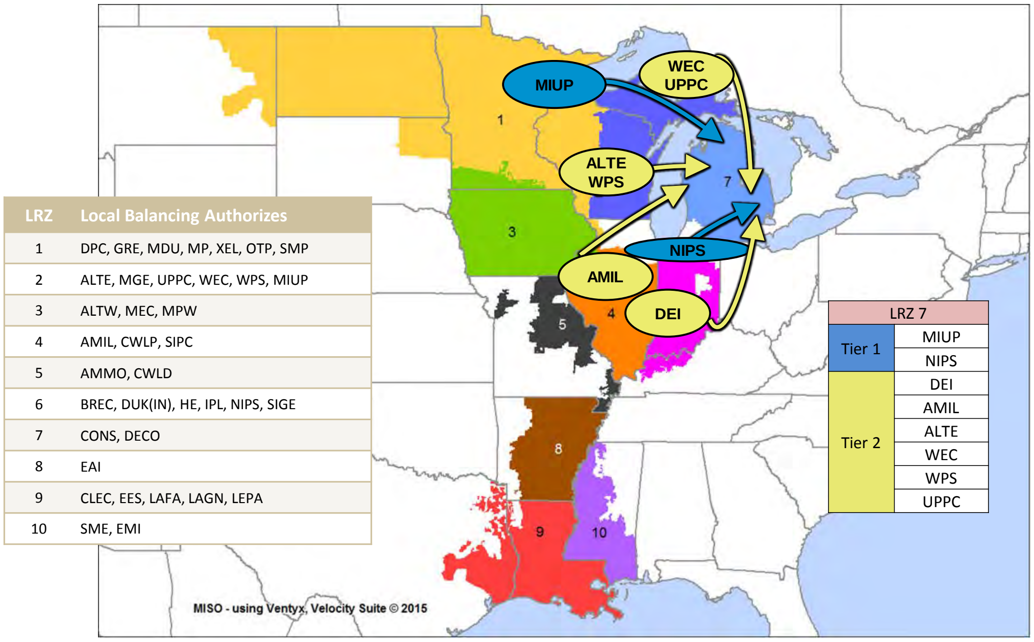
MISO Local Resource Zone 5



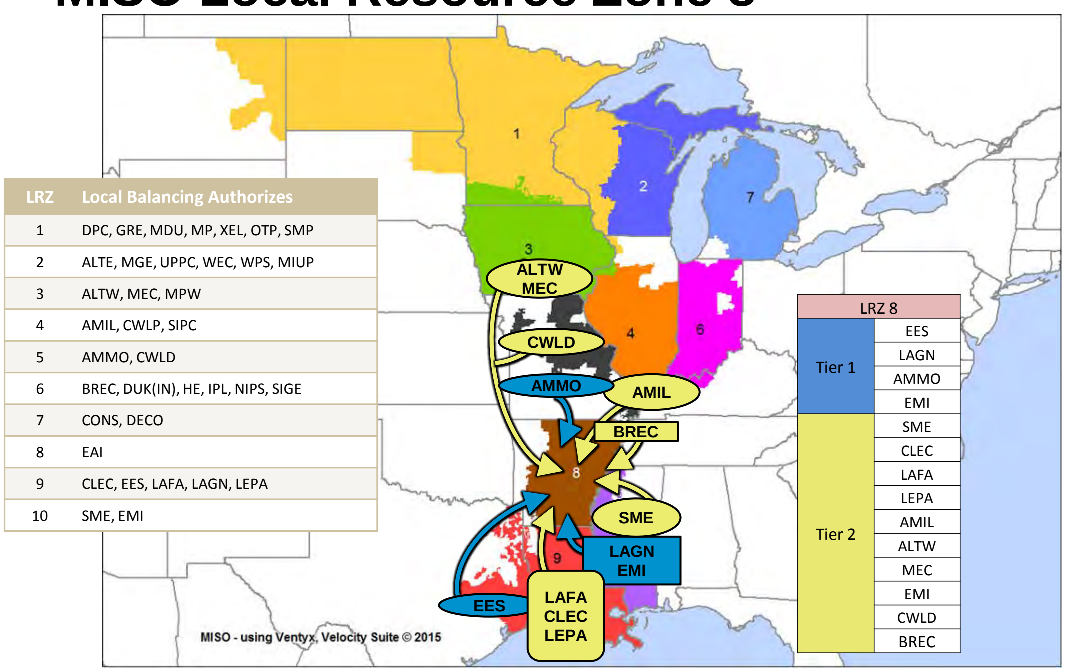
MISO Local Resource Zone 6



MISO Local Resource Zone 7

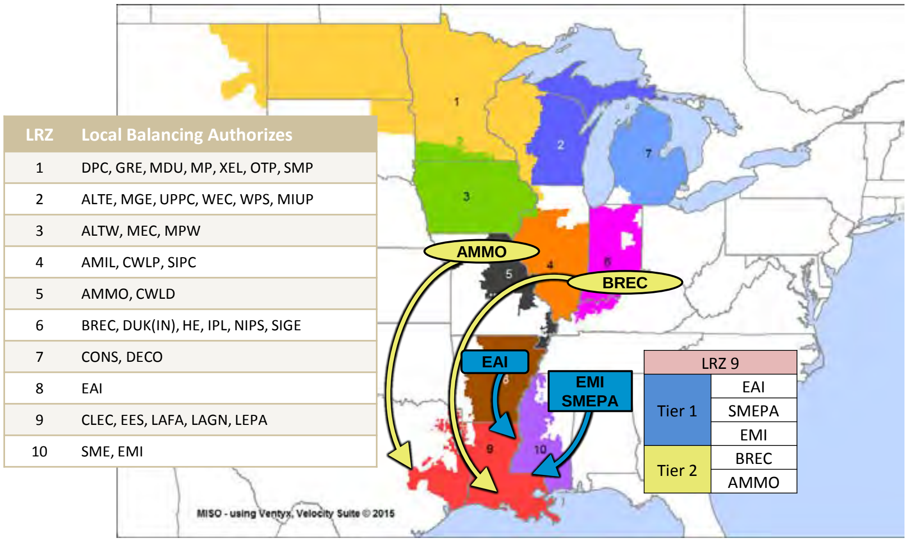


MISO Local Resource Zone 8



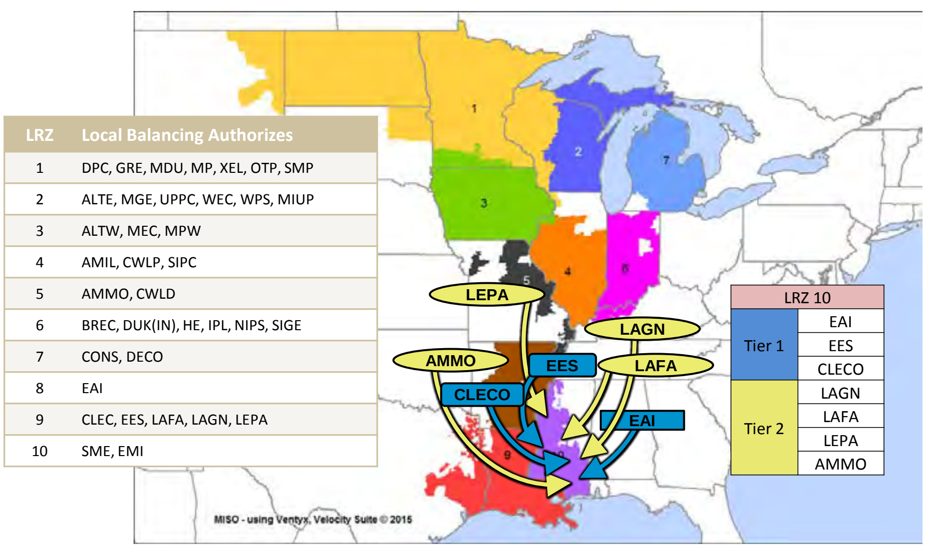
* PLUM, OMLP, WMU, CWAY, BUBA, PUPP, NLR now modeled in EAI power flow area

MISO Local Resource Zone 9



* BRAZ, DERS, EES-EMI, and BCA now modeled in EES power flow area

MISO Local Resource Zone 10



C.2 Planning Year 2016-17 Detailed CIL Results

Capacity Import Limits

Zone	Tier	16-17 Limit (MW) Post Redispatch	16-17 Limit (MW) Pre Redispatch	15-16 Limit Post Redispatch (MW)	15-16 Import in Auction	MWs Redispatched
1	1 & 2	3,432	3,432	3,735	Export	Not Applicable
2	1	1,703	1,111	2,903	Export	188
3	1	1,998	989	1,972	Export	2,000
4	1 & 2	4,328	1,970	3,130	1,568	2,164
5	1 & 2	4,359	4,297	3,899	1,026	491
6	1 & 2	5,570	3,598	5,649	394	3,020
7	1 & 2	3,406	1,970	3,813	Export	2,000
8	1	2,425	0	2,074	Export	2,000
9	1	3,563	2,579	4,008*	Export	717
10	1	2,010	172	2,630*	Included in zone 9	2,000

***Re-evaluation results**

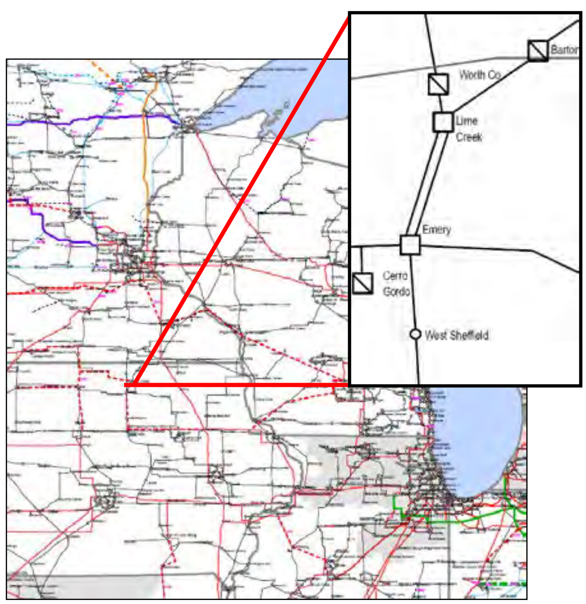
Capacity Import Limits

Zone 1 – MN and ND

Initial limit 3,432 MW

- Constraint: Colby to New Iowa Wind 161 kV Line
- Contingency: Adams to Barton 161 kV Line

No redispatch available



Capacity Import Limits

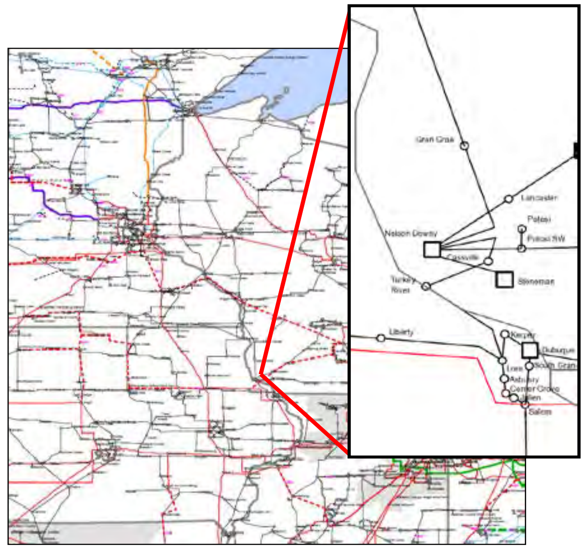
Zone 2 – WI and MI

Initial limit 1,111 MW

- Constraint: Stoneman to Nelson-Dewey 161 kV Line
- Contingency: Wempletown to Paddock 345 kV Line
- Re-dispatch of 2,000 MW in NIPS, METC, DPC, MEC

Re-dispatched limit 1,703 MW

- Constraint: Stoneman to Nelson-Dewey 161 kV Line
- Contingency: Wempletown to Paddock 345 kV Line



Capacity Import Limits

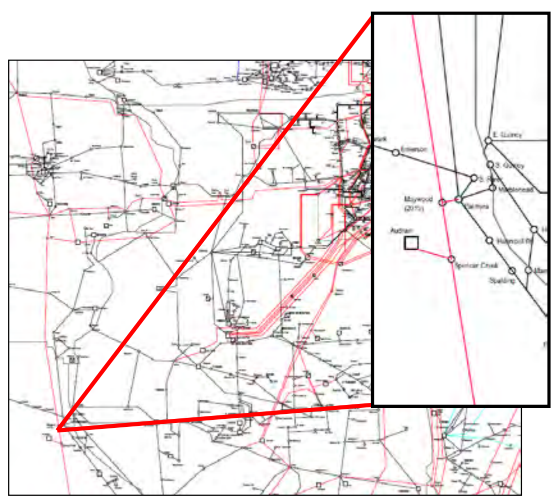
Zone 3 – IA & MN

Initial limit 989 MW

- Constraint: Palmyra 345/161 kV Transformer
- Contingency: Maywood to Sub T 345 kV Line
- Re-dispatch of 2,000 MW in WEC, AMMO, AMIL, GRE, MPW

Re-dispatched limit 1,998 MW

- Constraint: Palmyra 345/161 kV Transformer
- Contingency: Palmyra Tap to Sub T 345 kV Line



Capacity Import Limits

Zone 4 – IL

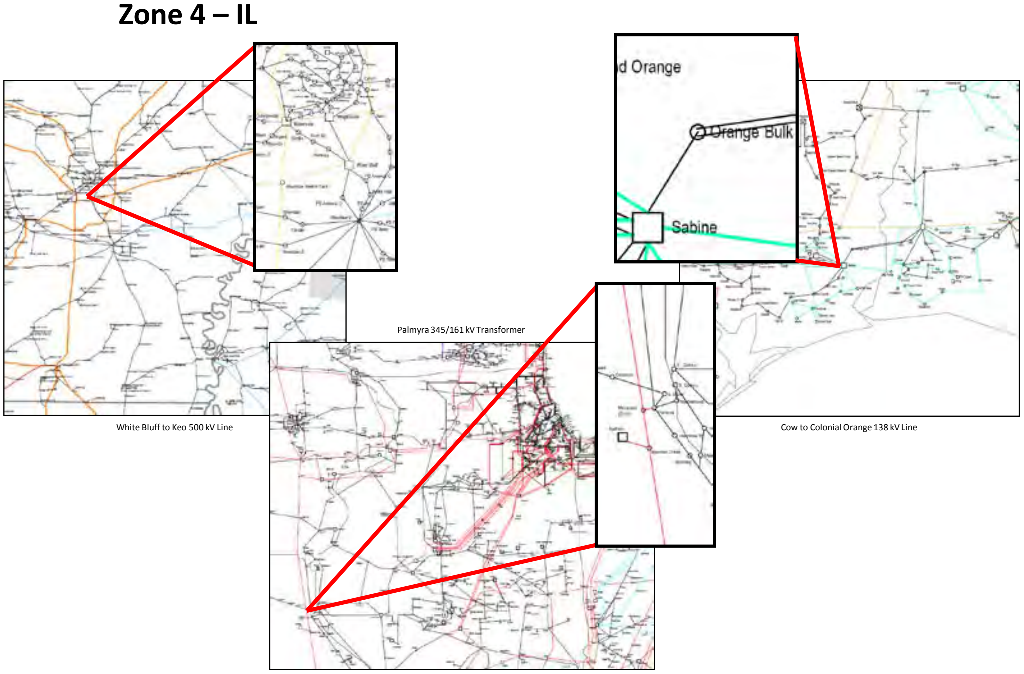
Initial limit 1,970 MW
- Constraint: White Bluff to Keo 500 kV Line
- Contingency: Sheridan to Mabelvale 500 kV Line
- Re-dispatch of 2,000 MW applied in WEC & EES

Next limit 4,286 MW
- Constraint: Cow to Colonial Orange 138 kV Line
- Contingency: Sabine to Cow 138 kV Line
- Re-dispatch of 163 MW applied in EES

Current limit 4,328 MW
- Constraint: Palmyra 345/161 kV Transformer
- Contingency: Montgomery to Spencer 345 kV Line

Capacity Export Limits

Zone 4 – IL



White Bluff to Keo 500 kV Line

Palmyra 345/161 kV Transformer

Cow to Colonial Orange 138 kV Line

Capacity Import Limits

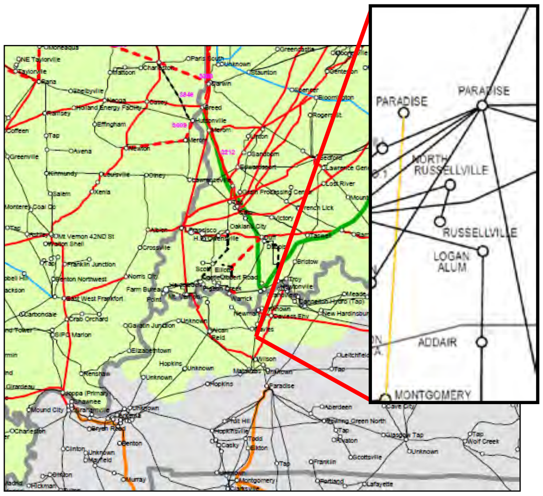
Zone 5 – MO

Initial limit 4,297 MW

- Constraint: Gratiot to Center 138 kV Line
- Contingency: Cahokia to Central 138 kV Line

Re-dispatched limit 4,359 MW

- Re-dispatch of 2,000 MW in AMIL, ALTW, OTP, & MEC
- Constraint: Russellville East to Russellville South 161 kV Line
- Contingency: Arkansas Nuclear One to Fort Smith 500 kV Line



Capacity Import Limits

Zone 6 – IN & KY

Initial limit 3,598 MW

- Constraint: Newton to Casey 345 kV Line
- Contingency: Casey to Neoga 345 kV Line
- Re-dispatch of 2,000 MW applied in AMIL & METC

Next limit 5,406 MW

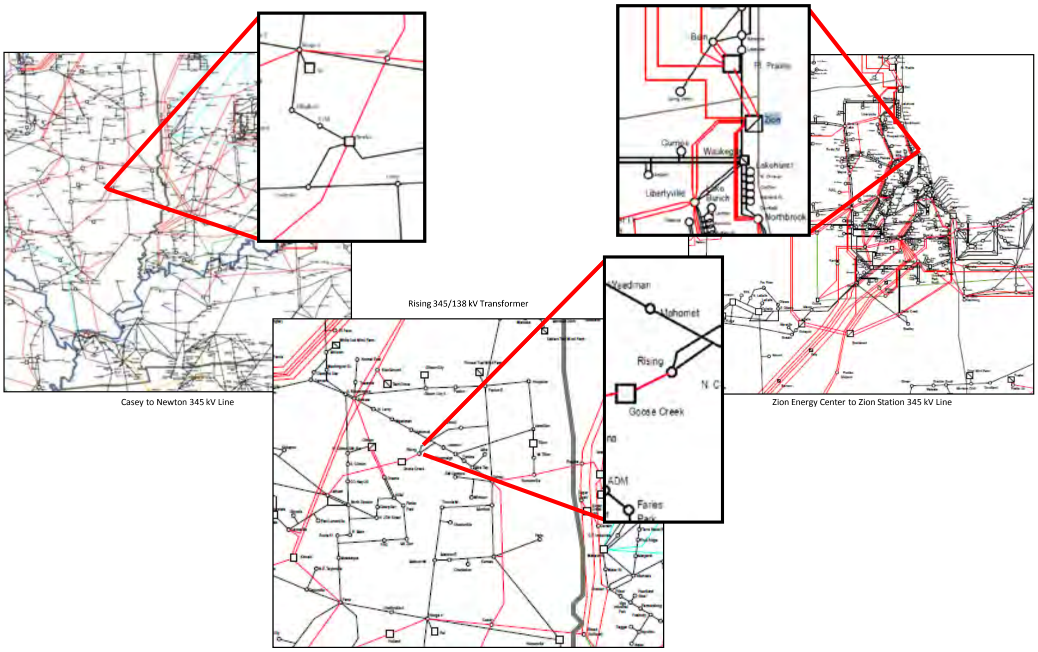
- Constraint: Zion Energy Center to Zion Station 345 kV Line
- Contingency: Pleasant Prairie to Zion 345 kV Line
- Re-dispatch of 1,020 MW applied in CE with coordination with PJM for RCF

Current limit 5,570 MW

- Constraint: Rising 345/138 kV Transformer
- Contingency: Clinton to Browkaw 345 kV Line

Capacity Import Limits

Zone 6 – IN & KY



Capacity Import Limits

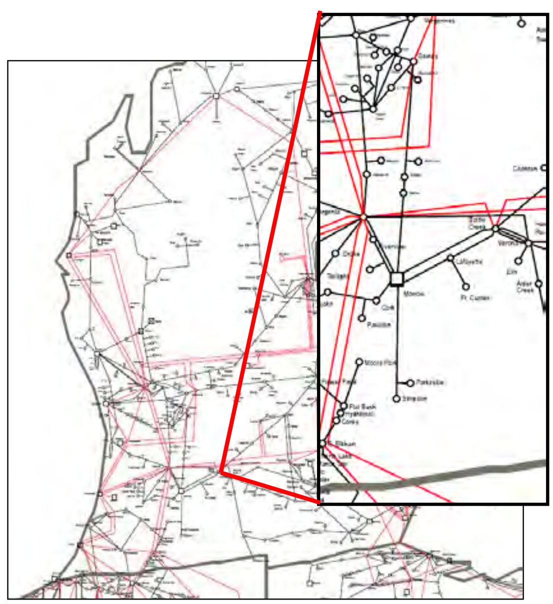
Zone 7 – MI

Initial limit 1,970 MW

- Constraint: Zion Station to Zion Energy Center 345 kV line
- Contingency: Pleasant Prairie to Zion 345 kV line
- Re-dispatch 2,000 MW in NIPS, WEC, & with coordination with PJM CE Units due to RCF.
- After re-dispatch was applied, a Generation Limited Transfer was applied to obtain limit

Re-dispatched limit 3,406

- Constraint: Argenta to Battle Creek 345 kV Line
- Contingency: Argenta to Tompkins 345 kV Line



Capacity Import Limits

Zone 8 – AR

Initial limit 0 MW

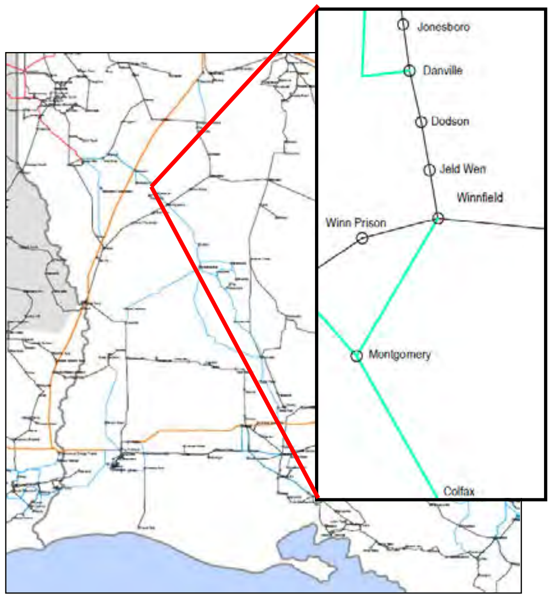
- Constraint: Addis to Tiger 230 kV Line
- Contingency: Dow Meter to Liquide Air Tap 230 kV Line
- Re-dispatch of 2,000 MW in AMMO & EES

Re-dispatched limit 2,425 MW

- Constraint: Montgomery to Clarence 230 kV Line
- Contingency: Hartburg to Layfield 500 kV Line

Cause of limit change

- TO submitted topology updates
- Retirement



Capacity Import Limits

Zone 9 – TX, LA

Initial limit 2,579 MW

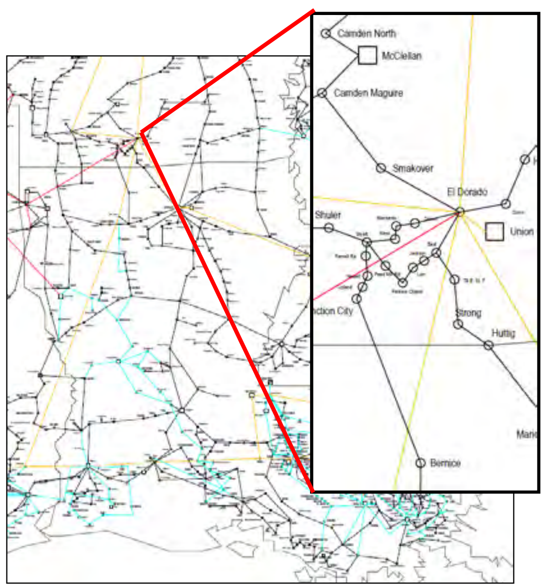
- Constraint: Cypress 500/138 kV Transformer
- Contingency: Cypress 500/138 kV Transformer
- Re-dispatch of 2,000 MW in EES & LAGN

Re-dispatched limit 3,563 MW

- Constraint: Wyatt SS To El Dorado Parnell Road 115 kV Line
- Contingency: Mount Olive to El Dorado 500 kV Line

Cause of limit change

- TO submitted topology updates
- Retirement



Zone 10 – MS

Initial limit 172 MW

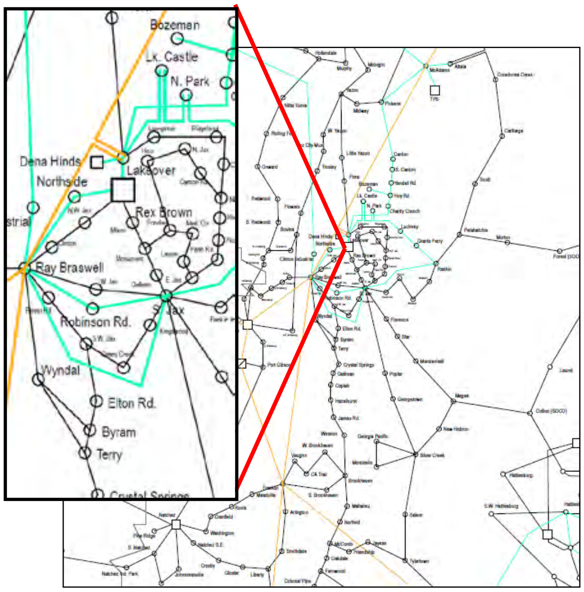
- Constraint: Ray Brasswell 500/115 kV Transformer
- Contingency: Ray Brasswell to Lakeover 500 kV Line
- Re-dispatch of 2,000 MW in EES-EMI & SMEPA

Re-dispatched limit 2,010 MW

- Constraint: Ray Brasswell 500/115 kV Transformer
- Contingency: Ray Brasswell to Lakeover 500 kV Line

Cause of limit change

- TO submitted topology updates
- Retirement



C.3 Planning Year 2016-17 Detailed CEL Results

Capacity Export Limits

Zone	16-17 Limit (MW) Post Redispatch	16-17 Limit (MW) Pre Redispatch	15-16 Limit Post Redispatch (MW)	15-16 Export in Auction	MWs Redispatched
1	590	0	604	176	0
2	2,996	1,259	1,516	931	965
3	1,598	1,598	1,477	45	0
4	7,379	7,379	4,125	Import	0
5	896	0	0	Import	224
6	2,544	2,544	2,930	Import	0
7	4,541	4,541	4,804	837	0
8	2,074	2,074	3,022	408	0
9	1,261	0	2,418*	592	2,000
10	1,857	0	1,959*	Included in zone 9	2,000

***Re-evaluation results**
FINAL

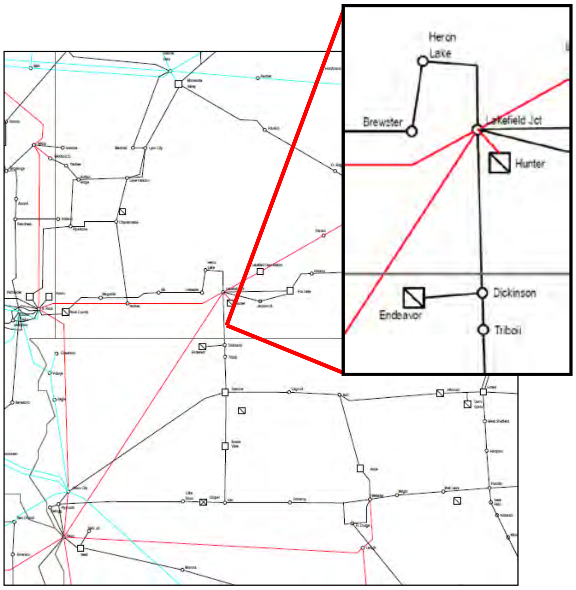
Capacity Export Limits

Zone 1 – MN and ND

Initial limit 0 MW
- Constraint: Lakefield to Dickinson 161 kV Line
- Contingency: Raun to Highland 345 kV Line
- Re-dispatch of 1,627 MW in XEL, MP, GRE, OTP, ITCM, MEC, WPS

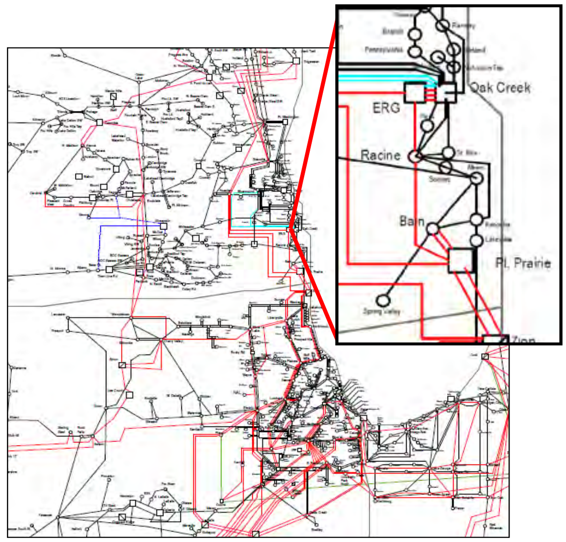
Re-dispatched limit 590 MW
- Constraint: Lakefield to Dickinson 161 kV Line
- Contingency: Raun to Highland 345 kV Line

Cause of limit change
- Confirmation of SPS and Topology



Capacity Export Limits

Zone 2 – WI & MI



Initial limit 1,259 MW

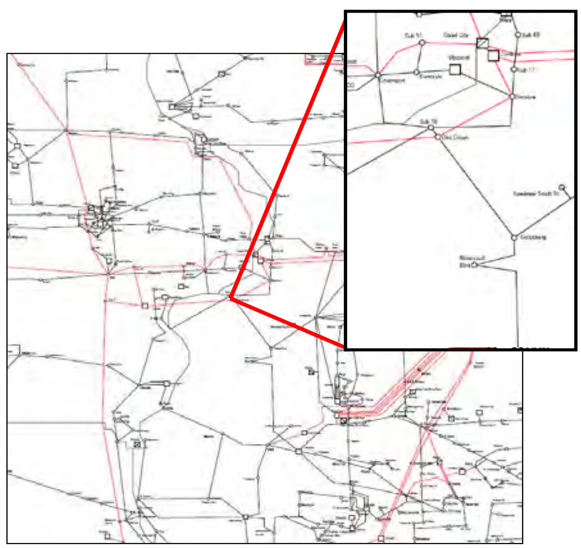
- Constraint: Zion Station to Zion Energy Center
- Contingency: Zion Station to Pleasant Prairie
- Before re-dispatch was applied, a Generation Limited Transfer was applied to obtain limit
- Re-dispatch of 965 MW in CE

Re-dispatched limit 2,996 MW

- Constraint: St. Rita to Racine 138 kV Line
- Contingency: Racine to Elm Road 345 kV Line

Capacity Export Limits

Zone 3 - IA



Initial limit 1,598 MW

- Constraint: Oak Grove to Mercer 161 kV Line
- Contingency: Havana Unit 6
- Generation Limited Transfer was applied to obtain limit

No Redispatch Available

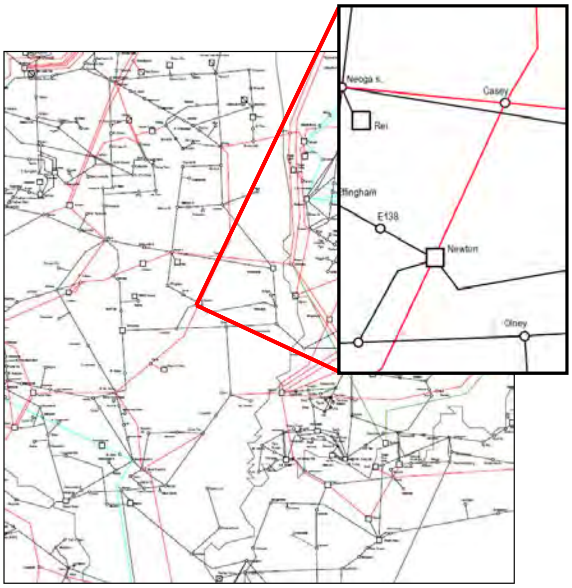
Capacity Export Limits

Zone 4 – IL

Initial limit 7,379 MW

- Constraint: Newton to Casey 345 kV Line
- Contingency: Casey to Neoga 345 kV Line
- Generation Limited Transfer was applied to obtain limit

No Redispatch Available



Capacity Export Limits

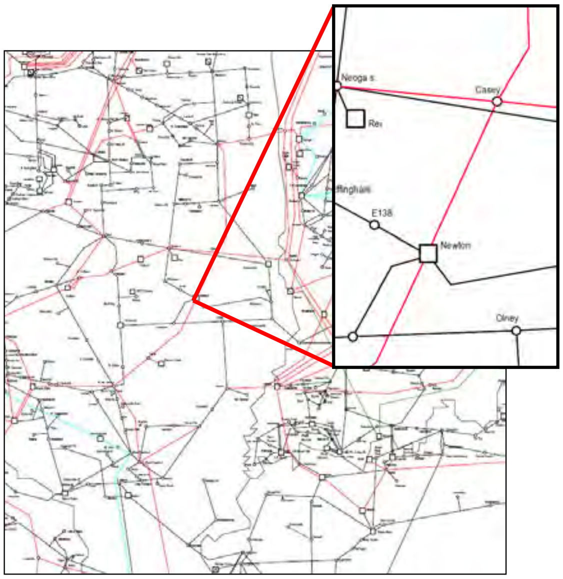
Zone 5 – MO

Initial limit 0 MW

- Constraint: Palmyra Transformer
- Contingency: Maywood to Sub T 345 kV Line
- Re-dispatch 224 MW generation in AMMO
- After re-dispatch was applied, a Generation Limited Transfer was applied to obtain limit

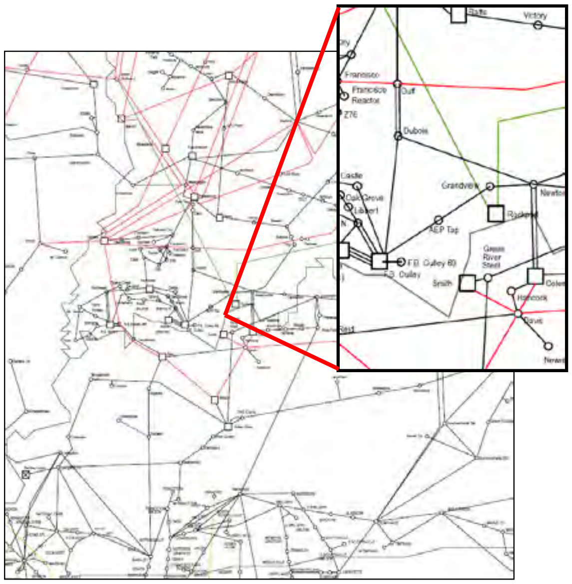
Re-dispatched limit 896 MW

- Constraint: Newton to Casey 345 kV Line
- Contingency: Casey to Neoga 345 kV Line



Capacity Export Limits

Zone 6 – IN & KY



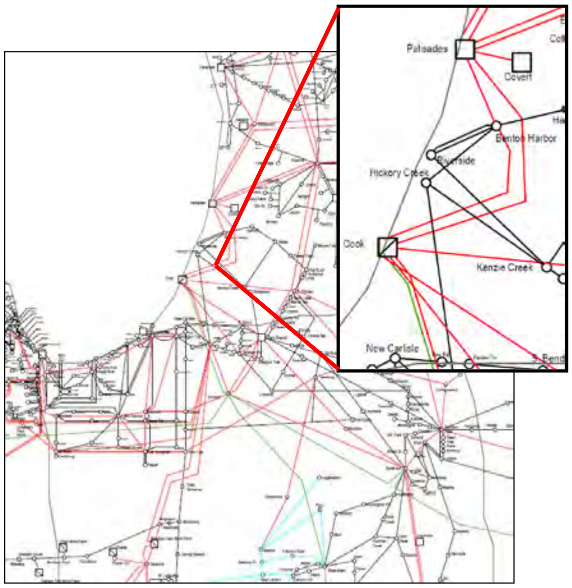
Initial limit 2,544 MW

- Constraint: Tap to AEP Rockport to Grandview 138 kV Line
- Contingency: AB Brown to Reid EHV Substation to Wilson 345 kV Line
- Generation Limited Transfer was applied to obtain limit

No Redispatch Available

Capacity Export Limits

Zone 7 – MI



Initial limit 4,541 MW

- Constraint: Benton Harbor 138/345 kV Transformer
- Contingency: Benton Harbor to Cook 345 kV line
- Generation Limited Transfer was applied to obtain limit

No Redispatch Available

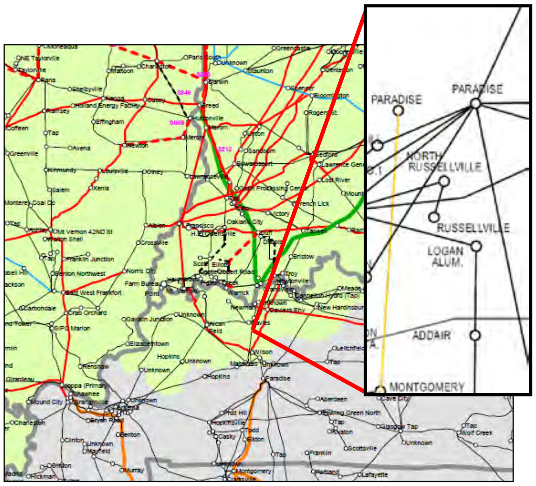
Capacity Export Limits

Zome 8 – AR

Initial limit 2,074 MW

- Constraint: Russellville North to Russellville East 161 kV Line
- Contingency: Arkansas Nuclear One to Fort Smith 500 kV Line

No Redispatch Available



Capacity Export Limits

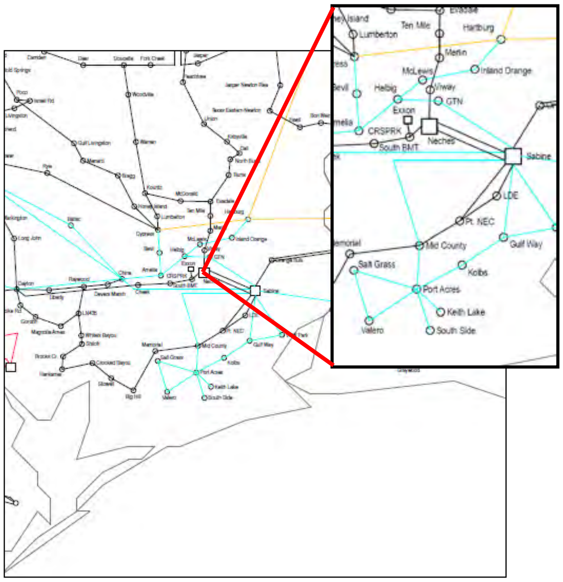
Zone 9 – TX, LA

Initial limit 0 MW

- Constraint: Addis to Tiger 230 kV line
- Contingency: Dow Meter to Liquide Air Tap 230 kV Line
- Re-dispatch 2,000 MW generation in EES, LAFA, LEPA, & CLECO

Re-dispatched limit 1,261 MW

- Constraint: Port Neches Bulk to Flatland 138 kV Line
- Contingency: Sabine 345/138 kV Line



Zone 10 – MS

Initial limit 0 MW

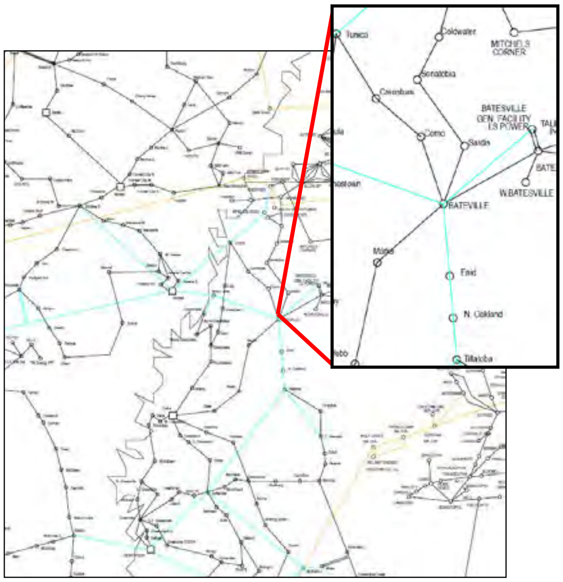
- Constraint: Batesville 230/115 kV Transformer
- Contingency: Homewood to Five Points 161 kV Line
- Re-dispatch 2,000 MW generation in EES-EMI & SMEPA

Re-dispatched limit 1,857 MW

- Constraint: Batesville 230/115 kV Transformer
- Contingency: Homewood to Five Points to Batesville 161 kV Line

Cause of limit change

- TO submitted topology updates
- Retirement



Appendix D Compliance Conformance Table

Requirements under: Standard BAL-502-RFC-02	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2016 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2016 through May 2017 and beyond. Analysis of Planning Year 2016 is in Sections 5.1 and 6.1 Analysis of Future Years 2017-2025 is in Sections 5.3 and 6.1
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of load for the integrated peak hour for all days of each planning year analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion.)	Section 4.5 of this report outlines the utilization of LOLE in the reserve margin determination. "These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year."
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of load probability.	Section 4.3 of this report "Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 4.5.2 of this report "The minimum amount of capacity above the 50/50 net internal MISO Coincident Peak Demand required to meet the reliability criteria was used to establish the PRM values."
R1.2 Be performed or verified separately for each of the following planning years	Covered in the segmented R1.2 responses below.

R1.2.1 Perform an analysis for Year One.	In sections 5.1 and 6.1, a full analysis was performed for planning year 2016.
R1.2.2 Perform an analysis or verification at a minimum for one year in the two- through five-year period and at a minimum one year in the six- though 10-year period.	Sections 5.3 and 6.1 show a full analysis was performed for future planning years 2020 and 2025.
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year	Analysis was performed
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.
R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts) • Load diversity • Seasonal load variations • Daily demand modeling assumptions (firm, interruptible) • Contractual arrangements concerning curtailable/Interruptible Demand	Median forecasted load — In section 4.3 of this report: "For the 2016-2017 LOLE analysis, the hourly LRZ load shape was a product of the historical load shape used as well as the 50/50 demand forecasts submitted by Load Serving Entities (LSE) through the MECT tool." Load Forecast Uncertainty — A detailed explanation of the LFU calculations is given in section 4.3.1 as well as in Appendix A. Load Diversity/Seasonal Load Variations — Section 4.3 of this report details the historic hourly load profiles used with their inherent diversity and seasonal variations. "LRZs 1 through 7 used the 2005 historical load shape while zones 8, 9 and 10 used the 2006 historical load shape. For MISO North/Central, the 2005 load shape is typical for the area. MISO chose to use the 2006 historical shape for the South region, as the 2005 shape represented an extreme weather year due to Hurricane Katrina" Demand Modeling Assumptions/Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E. As stated in section 4.2.7: "Each demand response program was modeled individually with a monthly capacity and energy, which is limited to the number of times each program can be called upon as well as limited by duration."

R1.3.2 Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area • Resource planned outage schedules, deratings and retirements • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration • Criteria for including planned resource additions in the analysis	Section 4.2. details how historic performance data and seasonal ratings are gathered, and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in section 4.4.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves	Section 3 of this report details the transfer analysis to capture transmission limitations that prevent the delivery of generation reserves. The results from this analysis are shown in section 3.3.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Inclusion of planned transmission addition assumptions is detailed in section 3.2.3.
R1.3.4 Assistance from other interconnected systems including multi-area assessment considering transmission limitations into the study area.	Section 4.4 provides the analysis on the treatment of external support assistance and limitations.

R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel • Common mode outages that affect resource availability • Environmental or regulatory restrictions of resource availability • Any other demand (load) response programs not included in R1.3.1 • Sensitivity to resource outage rates •Impacts of extreme weather/drought conditions that affect unit availability • Modeling assumptions for emergency operation procedures used to make reserves available • Market resources not committed to serving load (uncommitted resources) within the Planning Coordinator area	Fuel availability, environmental restrictions, common mode outage and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 4.2. The use of demand response programs are mentioned in section 4.2. The effects of resource outage characteristics on the reserve margin are outlined in section 4.5.2 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 3 treats worst-case theoretical outages by Perform First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category A (system intact) and Category B (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis	MISO internal resources are among the quantities documented in the tables provided in sections 5 and 6.
R1.7 Document that all load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis	MISO load is among the quantities documented in the tables provided in sections 5 and 6.

R2 The Planning Coordinator shall annually document the projected load and resource capability, for each area or transmission constrained sub-area identified in the Resource Adequacy analysis.	In Section 5 and 6, the peak load and estimated amount of resources for planning years 2016, 2020, and 2025 are shown. This includes the detail for each transmission constrained sub-area.
R2.1 This documentation shall cover each of the years in Year One through 10.	Section 5.3 and Table 5.3-2 shows the three calculated years, and in-between years estimated by interpolation.
R2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	Section 5.3 and Table 5.3-2 shows the three calculated years underlined.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One	The 2016 LOLE Study Report documentation is posted on November 1 prior to the planning year.

Appendix E Acronyms List Table

BPM	Business Practice Manual
CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
CSA	Coordinated Seasonal Assessment
DF	Distribution Factor
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
EUE	Expected Unserved Energy
EV	Energy Velocity
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GADS	Generator Availability Data System
GVTC	Generation Verification Test Capacity
ICAP	Installed Capacity
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
NERC	North American Electric Reliability Corp.
OMS	Organization of MISO States
PRA	Planning Resource Auction
PRM	Planning Reserve Margin

PRM ICAP	PRM Installed Capacity
PRM UCAP	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
PSS MUST	Power System Simulator for Managing & Utilizing System Transmission
RCF	Reciprocal Coordinating Flowgate
RPM	Reliability Pricing Model
SPS	Special Protetion Scheme
TARA	Transmission Adequacy and Reliability Assessment
UCAP	Unforced Capacity
XEFORd	Equivalent forced outage rate demand with adjustment to exclude events outside management control

Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan

Vectren South
2016 - 2017 Electric DSM Plan

October 28, 2015

Prepared by:
Southern Indiana Gas & Electric Company
d/b/a Vectren Energy Delivery of Indiana Inc. (Vectren South)

Table of Contents

I. Introduction

Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South" or "Company") provides energy delivery services to approximately 142,000 electric customers and 111,000 natural gas customers located in southwestern Indiana. Vectren South is a direct, wholly owned subsidiary of Vectren Utility Holdings, Inc. ("VUHI") and an indirect subsidiary of Vectren Corporation ("Vectren"), headquartered in Evansville IN. This Vectren South 2016 - 2017 Electric DSM Plan ("2016 - 2017 Plan") describes the details of the electric Energy Efficiency ("EE") and demand response ("DR") programs Vectren South plans to offer in its service territory in 2016 - 2017.

Vectren South designed the 2016 - 2017 Plan to save electric energy and reduce electric demand to cost effectively reduce energy use by approximately 1% of eligible retail sales. The 2016 - 2017 Plan recommends electric EE and DR programs for the residential, commercial, and industrial sectors in Vectren South's service territory. Where appropriate, it also describes opportunities for coordination with some of Vectren South's gas conservation programs to leverage the best total EE and DR opportunities for customers and to share costs of delivery.

Vectren South DSM Strategy

Vectren South has worked to instill a culture of conservation throughout the entire organization, including within its employees and customers. Vectren South has embraced EE and DR and actively promotes the benefits of EE and DR to its employees and customers. Vectren South has taken steps to implement this conservation culture starting with its employees. Vectren South encourages each employee, especially those with direct customer contact, to promote conservation and has provided employees with the tools they need to encourage customers to conserve and participate in Company sponsored EE and DR programs. Vectren South has used internal communications and presentations, conservation flyers and handouts, meetings with community leaders, and formal training to promote this culture of conservation. This cultural shift was a motivating factor in Vectren South creating Conservation Connection and launching its "Live Smart" motto to further emphasize EE, DR, and conservation. Vectren South's purpose statement is the foundation of the Vectren Strategy related to DSM:

> *Purpose:*
>
> *With a focus on the need to conserve natural resources, we provide energy and related solutions that make our customers productive, comfortable and secure. Customers are a key component of Vectren's values, and Vectren knows success comes from understanding its customers and actively helping them to use energy efficiently.*

As evidence of its long-term commitment to EE, Vectren South's recently completed 2014 Integrated Resource Plan ("2014 IRP") includes EE and DR programs for all customer classes and sets an annual savings target of 1% of retail sales for 2015 - 2019 and .5% annually thereafter. The 1% savings target assumes that 80% of eligible large customer load will opt-out of participation in Company sponsored EE and DR programs, as provided for in Senate Enrolled Act 340 ("SEA 340"). The load forecast also includes an ongoing level of EE related to codes and standards embedded in the load forecast projections. Ongoing EE and DR programs are also important given the integration of Vectren South's natural gas and electric EE and DR programs.

Vectren South EE and DR Planning Process

Vectren South has been offering a variety of EE programs since April 2010 and has engaged in a similar planning process each time a new portfolio is presented to the Indiana Utility Regulatory Commission ("Commission") for approval. Many factors, including past Commission orders establishing energy savings targets and subsequent passage of SEA 340 abolishing those targets and providing a mechanism for certain eligible customers to opt-out of participation in Company sponsored EE and DR programs, have influenced the planning process over the years.

The 2016 - 2017 Plan was developed in conjunction with the 2014 IRP planning process and therefore the 2014 IRP served as a key input into the 2016 - 2017 Plan. Consistent with the 2014 IRP, the framework for the 2016 - 2017 Plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 80% eligible load. Once the level of EE and DR programs to be offered from 2016 through 2017 was established, Vectren South engaged in a three-step process to develop the 2016 - 2017 Plan. The objective of the planning process was to develop a plan based upon market-specific information for Vectren South's territory, which could be successfully implemented utilizing realistic assessments of achievable market potential.

The first step in the process was to utilize the EnerNOC Market Potential Study ("MPS") that was completed in 2013. Vectren South, with guidance from the Vectren Oversight Board ("VOB"), engaged EnerNOC, Inc. to study its EE and DR market potential and develop an Action Plan. EnerNOC conducted a detailed, bottom-up assessment of the Vectren South market in the Evansville metropolitan area to deliver a projection of baseline electric energy use, forecasts of the energy savings achievable through efficiency measures, and program designs and strategies to optimally deliver those savings. The study developed technical, economic and achievable potential estimates by sector, customer type and measure.

The EnerNOC MPS and other study information were used to help guide the 2016 - 2017 Plan design. Study analysis and results details can be found in the MPS and its appendices. For planning purposes Vectren South used the "Recommended Achievable" scenario as a foundation for developing the 2016 - 2017 Plan.

The second primary step in the planning process was to hire outside expertise to assist with the plan design and development. Vectren South retained EMI Consulting to assist with designing the 2016 - 2017 Plan. Matthew Rose, Director of EMI Consulting, was the primary planner working with the Vectren South team.

The third primary step in the planning process was to obtain input from various sources to help develop and refine a workable plan. The first group providing input was Vectren South's EE and DR Program Managers who have been overseeing current Vectren

South programs. In addition, vendors and other implementation partners who operate the current programs were very involved in the process as well. They provided suggestions for program changes and enhancements. The vendors and partners also provided technical information about measures to include recommended incentives, estimates of participation and estimated implementation costs. These data provided a foundation for the 2016 - 2017 Plan based on actual experience within Vectren South's territory. These companies also bring their experience operating programs for other utilities. Once the draft version of the 2016-2017 Plan was developed, Vectren South solicited feedback from the VOB for consideration in the final design.

Other sources of program information were also considered. Current evaluations and the Indiana Technical Resource Manual ("TRM") were used for adjustments to inputs. In addition, best practices were researched and reviewed to gain insights into the program design of successful EE and DR programs implemented at other utilities.

EE and DR Screening Results

The last step of the planning process was the cost benefit analysis. Vectren South retained Richard Stevie, Vice President of Forecasting with Integral Analytics, to complete the cost benefit modeling. Utilizing DSMore the measures and programs were analyzed for cost effectiveness. The DSMore tool is nationally recognized and used in many states across the country to determine cost-effectiveness. Developed and licensed by Integral Analytics based in Cincinnati Ohio, the DSMore cost-effectiveness modeling tool takes hourly prices and hourly energy savings from the specific measures/technologies being considered for the EE program, and then correlates both to weather. This tool looks at over 30 years of historic weather variability to get the full weather variances appropriately modeled. In turn, this allows the model to capture the low probability, but high consequence weather events and apply appropriate value to them. Thus, a more accurate view of the value of the efficiency measure can be captured in comparison to other alternative supply options.

Utilizing a cost/benefit model, the measures and programs were analyzed for cost effectiveness. The outputs include all the California Standard Practice Manual results including Total Resource Cost ("TRC"), Utility Cost Test ("UCT"), Participant Cost Test ("PCT") and Ratepayer Impact Measure ("RIM") tests. Inputs into the model include the following: participation rates, incentives paid, energy savings of the measure, life of the measure, implementation costs, administrative costs, incremental costs to the participant of the high efficiency measure, and escalation rates and discount rates. Vectren South considers the results of each test and ensures that the portfolio passes the TRC test as it includes the total costs and benefits to both the utility and the consumer.

The model includes a full range of economic perspectives typically used in EE and DSM analytics. The perspectives include:

- Participant Cost Test
- Utility Cost Test
- Ratepayer Impact Measure Test
- Total Resource Cost Test

The cost effectiveness analysis produces two types of resulting metrics:

1. Net Benefits (dollars) = NPV ∑ benefits – NPV ∑ costs
2. Benefit Cost Ratio = NPV ∑ benefits ÷ NPV ∑ costs

As stated above, the cost effectiveness analysis is performed using each of the four primary tests. The results of each test reflect a distinct perspective and have a separate set of inputs demonstrating the treatment of costs and benefits. A summary of benefits and costs included in each cost effectiveness test is shown below in Table 1.

Table 1. Vectren South Cost Effectiveness Tests Benefits & Costs Summary

Test	Benefits	Costs
Participant Cost Test	• Incentive payments • Annual bill savings • Applicable tax credits	• Incremental technology/equipment costs • Incremental installation costs
Utility Cost Test (Program Administrator Cost Test)	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs
Rate Impact Measure Test	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs • Lost revenue due to reduced energy bills
Total Resource Cost Test	• Avoided energy costs • Avoided capacity costs • Applicable participant tax credits	• All program costs (not including incentive costs) • Incremental technology/equipment costs (whether paid by the participant or the utility)

The Participant Cost Test shows the value of the program from the perspective of the utility's customer participating in the program. The test compares the participant's bill savings over the life of the EE/DR program to the participant's cost of participation.

The Utility Cost Test shows the value of the program considering only avoided utility supply cost (based on the next unit of generation) in comparison to program costs.

The Ratepayer Impact Measure (RIM) Test shows the impact of a program on all utility customers through impacts in average rates. This perspective also includes the estimates of revenue losses, which may be experienced by the utility as a result of the program.

The Total Resource Cost (TRC) Test shows the combined perspective of the utility and the participating customers. This test compares the level of benefits associated with the reduced energy supply costs to utility programs and participant costs.

In completing the tests listed above, Vectren South used 7.29% as the weighted average cost of capital, as, approved by the Commission on April 27, 2011 in Cause No. 43839. For the 2016 - 2017 Plan, Vectren South utilized the avoided costs from Table 8-2 in the 2014 IRP.

Table 2 below confirms that all programs pass the TRC at greater than one.

The total portfolio for the Vectren South programs passes the TRC test for both Residential and Commercial & Industrial programs.

Table 2. Vectren South 2016 - 2017 Plan Cost Effectiveness Results without Performance Incentive

COMMERCIAL & INDUSTRIAL	TRC	UCT	RIM	Participant	Lifetime Cost/kWh**	1st Year Cost/kWh**	TRC NPV $	UCT NPV $
Small Business Direct Install	1.28	2.33	0.74	1.56	$0.03	$0.29	$1,732,739	$4,554,660
Commercial & Industrial Prescriptive	3.00	4.07	0.87	3.25	$0.02	$0.15	$5,485,762	$6,202,259
Commercial & Industrial New Construction	1.99	2.49	0.79	3.03	$0.03	$0.33	$400,143	$481,736
Commercial & Industrial Custom	1.07	2.74	0.77	1.18	$0.02	$0.28	$260,765	$2,468,576
Multi-Family Energy Efficient Retrofit	1.35	2.12	0.75	1.53	$0.03	$0.47	$100,549	$206,130
Conservation Voltage Reduction***	1.06	1.06	0.51	NA	$0.06	$0.15	$50,032	$50,032
Outreach	NA	NA	NA	NA	NA	NA	($289,808)	($289,808)
Commercial & Industrial Sector Portfolio*	**1.54**	**2.62**	**0.77**	**1.93**	**$0.02**	**$0.24**	**$7,740,183**	**$13,673,586**

RESIDENTIAL	TRC	UCT	RIM	Participant	Lifetime Cost/kWh**	1st Year Cost/kWh**	TRC NPV $	UCT NPV $
Residential Lighting	2.30	2.95	0.56	4.23	$0.03	$0.12	$2,711,715	$3,165,966
Home Energy Assessments & Weatherization	1.53	1.80	0.46	8.49	$0.04	$0.22	$508,549	$656,140
Income Qualified Weatherization	1.06	1.06	0.40	NA	$0.07	$0.47	$68,181	$68,181
Appliance Recycling	1.40	1.40	0.39	9.77	$0.04	$0.20	$160,494	$159,188
Energy Efficient Schools	3.39	3.39	0.53	NA	$0.02	$0.17	$551,397	$551,397
Residential Efficient Products	1.31	2.07	0.69	1.54	$0.05	$0.58	$586,114	$1,288,936
Residential New Construction	1.36	2.65	0.71	1.37	$0.03	$0.67	$133,067	$315,685
Multi-Family Direct Install	3.69	3.69	0.44	NA	$0.02	$0.09	$156,955	$156,955
Residential Behavior Savings	1.45	1.45	0.44	NA	$0.06	$0.06	$325,442	$325,442
Residential Smart Thermostat Demand Response	1.56	1.30	0.78	NA	$0.21	$1.39	$1,366,716	$886,947
Conservation Voltage Reduction***	1.38	1.38	0.52	NA	$0.06	$0.12	$515,434	$515,434
Outreach	NA	NA	NA	NA	NA	NA	($289,808)	($289,808)
Residential Sector Portfolio*	**1.57**	**1.71**	**0.56**	**5.00**	**$0.05**	**$0.22**	**$6,794,259**	**$7,800,464**

Tracking	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**($38,641)**	**($38,641)**
Total Portfolio*	**1.55**	**2.10**	**0.65**	**2.92**	**$0.04**	**$0.23**	**$14,495,801**	**$21,435,409**

*Sector level cost/benefit scores include Outreach, while portfolio level cost/benefit scores also include Tracking. Neither include utility performance incentives.

**Cost/kwh values do not include utility performance incentives

***1st Year Cost/kWh calculated by dividing total budget for 2016 and 2017 by the 2017 savings.

CVR is split in the table above based on Residential and Commercial & Industrial impacts and are included in the sector and total portfolio results. Table 3 below represents the combined total for the CVR program.

Table 3. Vectren South 2016 - 2017 CVR Cost Effectiveness Results without Performance Incentive

Conservation Voltage Reduction	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh*	TRC NPV $	UCT NPV $
Residential and Commercial & Industrial Combined	1.26	1.26	0.52	NA	$0.06	$0.13	$565,467	$565,467

*1st Year Cost/kWh calculated by dividing total budget for 2016 and 2017 by the 2017 savings.

Table 4 below demonstrates that even with the Utility Performance Incentive set at the maximum of 10%, each sector, as well as the total portfolio, remains cost-effective.

Table 4. Vectren South 2016 - 2017 Plan Cost Effectiveness Results with Utility Performance Incentive

2016 - 2017 Portfolio - Including Utility Performance Incentives	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Commercial & Industrial Sector Portfolio*	1.46	2.40	0.75	1.93	$0.03	$0.26	$6,973,481	$12,906,884
Residential Sector Portfolio*	1.48	1.61	0.55	5.00	$0.06	$0.24	$6,090,588	$7,096,793
Tracking	NA	NA	NA	NA	NA	NA	($38,641)	($38,641)
Total Portfolio*	**1.47**	**1.95**	**0.64**	**2.92**	**$0.04**	**$0.25**	**$13,025,428**	**$19,965,036**

*Sector level cost/benefit scores include Outreach and utility performance incentives, while portfolio level cost/benefit scores also incude Tracking. Vectren South is not requesting utility performance incentives on the CVR and Income Qualified Weatherization Programs therefore program costs relating to either program are not included.

Integration with Vectren South Gas

Opportunities exist to gain both natural gas and electric savings from some EE measures. When this occurs savings will be captured by the respective utility. For the programs where integration opportunities exist, Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric. Vectren South has a separate pending filing for 2016 - 2020 gas conservation programs and the same methodology was utilized in that plan. Below is a list of programs that Vectren South has identified as integrated:

- Home Energy Assessments and Weatherization
- Income Qualified Weatherization
- Energy Efficient Schools
- Residential New Construction
- Multi-Family Direct Install
- Residential Behavior Savings Program
- C&I New Construction
- Small Business Direct Install
- Multi-Family EE Retrofit

Oversight and Governance of EE and DR Programs

The VOB provides input into the planning and evaluation of Vectren South's EE programs. The VOB was formed in 2010 pursuant to the Final Order issued in Cause No. 43427 and included the OUCC and Vectren South as voting members. The Citizens Action Coalition ("CAC") was added as a voting member of the VOB in 2013 pursuant to the Final Order issued in Cause No. 44318. In 2014, the Vectren South Electric Oversight Board merged with the Vectren South Gas Oversight Board and Vectren North Gas Oversight to form one governing body, the VOB.

II. 2016 - 2017 Plan Objectives and Impact

The framework for the 2016 - 2017 Plan are consistent with the goals stated in the 2014 IRP and were designed to reach a reduction in sales of 1% of eligible retail sales, including the option for eligible large customer "opt-out'.

A. Plan Savings

The 2016 - 2017 Plan goal was calculated based on a percentage of forecasted weather normalized electric sales for 2016 and 2017 with a target of 1% of eligible retail sales. The forecast utilized to calculate the 2016 – 2017 Plan goal is consistent with Vectren South's 2014 IRP sales forecast. Goals are based on "gross" energy savings assuming 80% of eligible large customers will "opt-out" of the program. To reach the usage reduction goal of 1% of eligible retail sales, the savings targets for Residential and C & I were designated based on the percentage of sales revenue that each sector represents. Table 5 below demonstrates the portfolio, Residential and C&I energy savings targets at the 1% eligible retail sales level:

Table 5. Vectren South 2016 - 2017 Plan Portfolio Summary Planned Energy Savings

Portfolio Summary	2016 kWh Total	2017 kWh Total
Residential Total	20,147,744	20,362,245
Commercial & Industrial Total	16,168,861	17,428,270
Portfolio Total	**36,316,606**	**37,790,515**

Table 6 below lists the Commercial & Industrial and Residential programs' individual gross energy savings targets split by program:

Table 6. Vectren South 2016 - 2017 Plan Program Planned Energy Savings

COMMERCIAL & INDUSTRIAL	2016 kWh	2016 kW	2017 kWh	2017 kW
Small Business Direct Install	6,000,810	906	6,000,810	906
Commercial & Industrial Prescriptive	6,910,197	1,088	6,910,197	1,088
Commercial & Industrial New Construction	498,526	88	534,135	94
Commercial & Industrial Custom	2,557,544	339	2,906,300	385
Multi-Family Energy Efficient Retrofit	201,785	33	201,785	33
Conservation Voltage Reduction	0	0	875,044	163
Commercial & Industrial Total	**16,168,861**	**2,454**	**17,428,270**	**2,669**

RESIDENTIAL	2016 kWh	2016 kW	2017 kWh	2017 kW
Residential Lighting	6,612,901	839	6,831,909	865
Home Energy Assessments & Weatherization	1,935,719	290	1,935,719	290
Income Qualified Weatherization	1,282,577	254	1,282,577	254
Appliance Recycling	1,020,544	152	1,020,544	152
Energy Efficient Schools	675,508	106	675,508	106
Residential Efficient Products	1,075,888	623	1,075,888	623
Residential New Construction	146,775	68	146,775	68
Multi-Family Direct Install	335,000	20	335,000	20
Residential Behavior Savings	6,204,832	1,728	5,576,656	1,553
Residential Smart Thermostat Demand Response	858,000	1,800	0	0
Conservation Voltage Reduction	0	0	1,481,669	508
Residential Total	**20,147,744**	**5,880**	**20,362,245**	**4,439**

CVR is split in the table above based on Residential and Commercial & Industrial savings and are included in the sector and total portfolio results. Table 7 below represents the combined total for the CVR program.

Table 7. Vectren South 2016 - 2017 Conservation Voltage Reduction Planned Energy Savings

Conservation Voltage Reduction	2016 kWh	2016 kW	2017 kWh	2017 kW
Commercial & Industrial	0	0	875,044	163
Residential	0	0	1,481,669	508
Conservation Voltage Reduction Total	**0**	**0**	**2,356,713**	**671**

B. Comparison of Savings to Market Potential Study

The program design used the MPS for guidance to determine if the plan estimates were reasonable. While building from the bottom up with estimates from program implementers to help determine participation, this comparison to the MPS allowed the planning team to determine if the results were reasonable.

The MPS resulted in the following three scenarios for the plan: Low Achievable, High Achievable, and Recommended. It is important to note that the MPS was completed prior to the enactment of SEA340 and large customer opt-out. Therefore the MPS assumed all sales are eligible and the 2016 – 2017 Plan assumes an opt-out level of 80% of large customer sales. Tables 8 and 9 below compare the 2016 - 2017 Plan to the recommended savings estimates.

Table 8. EnerNOC MPS vs. Vectren South's 2016 - 2017 Plan for 2016

MPS Recommended MWh*		Vectren Plan MWh	
	2016	**2016**	
Commercial & Industrial Prescriptive	17,217	6,910	Commercial & Industrial Prescriptive
Commercial & Industrial Custom	17,519	2,558	Commercial & Industrial Custom
Commercial Schools	987	0	Commercial Schools
Strategic Energy Management	1,663	0	Strategic Energy Management
Commercial & Industrial New Construction	1,459	499	Commercial & Industrial New Construction
Small Business Direct Install	2,134	6,001	Small Business Direct Install
Multi-Family Energy Efficient Retrofit	NA	202	Multi-Family Energy Efficient Retrofit
Residential Lighting	10,167	6,613	Residential Lighting
Residential Efficient Products	3,697	1,076	Residential Efficient Products
Residential Income Qualified	1,799	1,283	Income Qualified Weatherization**
Residential Income Qualified Plus	141		
Residential New Construction	203	147	Residential New Construction
Multi Family Direct Install	448	335	Multi Family Direct Install
Home Energy Assessments	2,911	1,936	Home Energy Assessments & Weatherization
Whole House	2,037	0	Whole House
Residential School Kit	1,037	676	Energy Efficient Schools
Appliance Recycling	802	1,021	Appliance Recycling
Residential Behavioral Savings	5,177	6,205	Residential Behavioral Savings
Residential Smart Thermostat Demand Response	NA	858	Residential Smart Thermostat Demand Response
Totals	**69,397**	**36,317**	**Totals**

*The MPS was completed prior to the enactment of SEA340 and large customer opt-out. Therefore the MPS assumed all sales are eligible and the 2016 – 2017 Plan assumes an opt-out level of 80% of large customer sales.

**Vectren South is implementing some but not all of the measures recommended in the Market Potential Study for the Residential Income Qualified Plus Program.

Table 9. EnerNOC MPS vs. Vectren South's 2016 - 2017 Plan for 2017

MPS Recommended MWh*		Vectren Plan MWh	
	2017	**2017**	
Commercial & Industrial Prescriptive	19,297	6,910	Commercial & Industrial Prescriptive
Commercial & Industrial Custom	19,766	2,906	Commercial & Industrial Custom
Commercial Schools	1,081	0	Commercial Schools
Strategic Energy Management	2,757	0	Strategic Energy Management
Commercial & Industrial New Construction	1,611	534	Commercial & Industrial New Construction
Small Business Direct Install	2,278	6,001	Small Business Direct Install
Multi-Family Energy Efficient Retrofit	NA	202	
Conservation Voltage Reduction (Commercial & Industrial)	NA	875	Conservation Voltage Reduction (Commercial & Industrial)
Residential Lighting	10,230	6,832	Residential Lighting
Efficient Products	4,716	1,076	Residential Efficient Products
Residential Income Qualified	1,527	1,283	Income Qualified Weatherization**
Residential Income Qualified Plus	144		
Residential New Construction	232	147	Residential New Construction
Multi Family Direct Install	NA	335	Multi Family Direct Install
Home Energy Assessments	3,092	1,936	Home Energy Assessments & Weatherization
Whole House	2,153	0	Whole House
Residential School Kit	1,030	676	Energy Efficient Schools
Appliance Recycling	802	1,021	Appliance Recycling
Residential Behavioral Savings	5,177	5,577	Residential Behavioral Savings
Conservation Voltage Reduction (Residential)	NA	1,482	Conservation Voltage Reduction (Residential)
Totals	**75,892**	**37,791**	**Totals**

*The MPS was completed prior to the enactment of SEA340 and large customer opt-out. Therefore the MPS assumed all sales are eligible and the 2016 – 2017 Plan assumes an opt-out level of 80% of large customer sales.

**Vectren South is implementing some but not all of the measures recommended in the Market Potential Study for the Residential Income Qualified Plus Program.

C. Budgets

The program budgets were built based upon many inputs. First the measures were assigned incentives based upon existing program incentives, proposed incentives and leveraged evaluation recommendations. Program budgets were discussed with both current and potential delivery providers as a basis for the development of this plan. The second primary input for the costs were estimates for implementation informed by the current statewide program implementation costs. This helps to assure that the estimates are realistic for successful delivery. The third cost area is the administrative costs made up of the internal costs for Vectren South management of the programs and implementers and other costs such as marketing. Administrative costs were allocated back to programs and measures based on the percent of savings these programs and measures represent. The last cost area is the Evaluation, Measurement and Verification ("EM&V") costs based on 5% of the budget. Table 10 below lists the summary budgets by program.

Table 10. 2016 – 2017 Vectren South Plan Summary Budget

Commercial & Industrial	2016	2017	Total Program Costs
Small Business Direct Install	$1,760,611	$1,774,351	$3,534,962
Commercial & Industrial Prescriptive	$1,042,705	$1,049,906	$2,092,611
Commercial & Industrial New Construction	$162,562	$172,898	$335,460
Commercial & Industrial Custom	$726,584	$738,386	$1,464,971
Multi-Family Energy Efficient Retrofit	$95,081	$95,081	$190,162
Conservation Voltage Reduction*	$20,000	$117,146	$137,147
Outreach	$150,000	$150,000	$300,000
Commercial & Industrial Total	**$3,957,543**	**$4,097,768**	**$8,055,312**

Residential	2016	2017	Total Program Costs
Residential Lighting	$788,506	$897,321	$1,685,827
Home Energy Assessments & Weatherization	$419,910	$429,428	$849,339
Income Qualified Weatherization	$598,270	$604,045	$1,202,315
Appliance Recycling	$205,094	$207,948	$413,042
Energy Efficient Schools	$117,706	$120,901	$238,607
Residential Efficient Products	$622,492	$626,298	$1,248,790
Residential New Construction	$98,441	$99,536	$197,977
Multi-Family Direct Install	$29,776	$30,610	$60,387
Residential Behavior Savings	$382,000	$366,285	$748,285
Residential Smart Thermostat Demand Response	$1,196,455	$297,890	$1,494,345
Conservation Voltage Reduction*	$20,000	$166,861	$186,861
Outreach	$150,000	$150,000	$300,000
Residential Total	**$4,628,652**	**$3,997,122**	**$8,625,774**

Portfolio	2016	2017	Total Program Costs
Tracking	$20,000	$20,000	$40,000

Portfolio Total	$8,606,195	$8,114,891	$16,721,086

* With Commission approval, Vectren South will capitalize the costs to implement the CVR program and will seek to recover through the annual DSMA Rider the carrying costs and depreciation expense associated with the implementation along with annual, ongoing Operation and Maintenance ("O&M") expense, a representative share of Vectren South's DSM support staff and administration costs and related EM&V cost. The CVR budget in Table 10 is reflective of this request.

CVR is split in the table above based on Residential and Commercial & Industrial budget and are included in the sector and total portfolio results. Table 11 below represents the combined total for the CVR program.

Table 11. 2016 – 2017 Conservation Voltage Reduction Summary Budget

Portfolio	2016	2017	Total Program Costs
Total Conservation Voltage Reduction*	$40,000	$284,007	$324,007

* With Commission approval, Vectren South will capitalize the costs to implement the CVR program and will seek to recover through the annual DSMA Rider the carrying costs and depreciation expense associated with the implementation along with annual, ongoing Operation and Maintenance ("O&M") expense, a representative share of Vectren South's DSM support staff and administration costs and related EM&V cost. The CVR budget in Table 11 is reflective of this request.

Key Inputs

The programs are based on known existing measures and technologies. The measure savings were calculated using the Indiana TRM, any Company specific evaluation data and input from existing implementation partners. When a measure was not in the Indiana TRM, then other TRMs were referenced including Michigan and Illinois. If needed, estimates were made from actual projects or experience of the implementation contractors.

III. Program Administration

Vectren South will serve as the program administrator for the 2016 - 2017 Plan. Vectren South will likely utilize third party program implementers to deliver specific programs or program components where specialty expertise is required and will look to utilize a single implementer for integrated natural gas/electric Residential and a single implementer for integrated natural gas/electric C&I programs. Contracting directly with specialty vendors avoids an unnecessary layer of management, oversight and expense that occurs when utilizing a third-party administration approach.

There are three major components of program administration that were considered in the 2016 - 2017 Plan. They include: internal labor/program support, program tracking and customer outreach/education.

A. Internal Labor/Program Support

Based upon the EE and DR programs proposed in the 2016 - 2017 Plan, Vectren South is proposing to maintain the staffing levels that were previously approved to support the portfolio. The following four (4) positions are included as part of this 2016 - 2017 Plan:

- Electric DSM Manager – Oversees the overall portfolio and staff necessary to support program administration. Serves as primary contact for regulatory and oversight of programs.
- Electric DSM Analyst – Works with the selected EM&V Administrator and facilitates measurement and verification efforts, assists with program reporting/tracking.
- Electric DSM Financial Analyst – Responsible for all aspects of program reporting including, budget analysis/reporting, scorecards and filings.
- Electric DSM Representative – Serves as contact to trade allies regarding program awareness. Also serves as point of contact for residential and commercial/industrial customers to assist with responding to program inquiries.

Additionally, internal labor includes the following indirect costs which will be incurred to support the portfolio:

- Conservation Connection resources to answer customer inquiries on Vectren South programs
- Memberships with EE organizations such as Consortium for Energy Efficiency (CEE) and Midwest Energy Association (MEA)
- Annual license and maintenance fees for the online energy audit and bill analyzer tool
- Staff Development & Training

Vectren South allocated the costs of the proposed staffing and support requirements in the fixed cost budgets of the respective EE programs.

B. Program Tracking

Program tracking includes license and maintenance fees necessary to support the database that serves as the repository for all program data and reporting.

C. Customer Outreach and Education

Vectren South's Customer Outreach and Education program serves to raise awareness and drive customer participation as well as educate customers on how to manage their energy bills. The program includes the following goals as objectives:

1. Build awareness;
2. Educate consumers on how to conserve energy and reduce demand;
3. Educate customers on how to manage their energy costs and reduce their bill;
4. Communicate support of customer EE needs; and
5. Drive participation in the EE and DR programs.

The marketing approach includes paid media as well as web based tools to help analyze bills, energy audit tools, EE and DSM program education and information. Informational guides and sales promotion materials for specific programs are included in this budget.

This effort is the key to achieving greater energy savings by convincing the families and businesses making housing/facility, appliance and equipment investments to opt for greater EE. The first step in convincing the public and businesses to invest in EE is to raise their awareness.

It is essential that a broad public education and outreach campaign not only raise awareness of what consumers can do to save energy and control their energy bills, but to prime them for participation in the various EE and DR programs. The annual program outreach and education budget is $150,000 each for Residential and Commercial & Industrial programs, for a total of $300,000.

Table 12. 2016 – 2017 Customer Outreach and Education Budget

Customer Outreach	Residential	Commercial & Industrial	Total Outreach Costs
2016	$150,000	$150,000	$300,000
2017	$150,000	$150,000	$300,000
Total	**$300,000**	**$300,000**	**$600,000**

Marketing Plans

This effort will provide funding for cross-program public education activities, outreach, marketing and promotion to raise awareness of the benefits and methods of improving EE in homes and commercial & industrial businesses. Beyond EE education, an objective will be to motivate participation in the programs.

Types of activities that will be included in this effort are:

- Enhancement of the Conservation Connection website to include the latest electric EE information for residential and commercial & industrial use.
- Targeted educational campaign for businesses to support the programs.
- Targeted educational campaign for residences to support the programs.
- Targeted training and educational program for trade allies.
- Distribution of federal Energy Star and other national organization materials in the service territory.

Delivery Organization

Vectren South will oversee outreach and education for the programs. The Company will work closely with its implementation partners to provide consistent messaging across different program outreach and education efforts. Vectren South will utilize the services of communication and EE experts to deliver the EE and DR message.

IV. Program Descriptions

The 2016 - 2017 Plan is built from the existing programs currently being offered by Vectren South to its customers. The existing programs will continue to be offered by Vectren South through implementation partners. The programs in the 2016 - 2017 Plan include:

- Residential Lighting
- Home Energy Assessments and Weatherization
- Income Qualified Weatherization
- Appliance Recycling
- Energy Efficient Schools
- Residential Efficient Products
- Residential New Construction
- Multi-Family Direct Install
- Residential Behavior Savings Program
- Small Business Direct Install
- Commercial & Industrial Prescriptive Rebates
- Commercial & Industrial New Construction
- Commercial & Industrial Custom Program

The 2016 - 2017 Plan also includes several new programs that Vectren South will implement and then measure the cost and savings estimates for potential expanded program offerings. These programs include:

- Residential Smart Thermostat Demand Response
- Conservation Voltage Reduction (CVR)
- Multi-Family EE Retrofit

A. Residential Lighting

Program Description

The Residential Lighting Program is a market-based residential EE program designed to reach residential customers through retail outlets. The program consists of a buy-down strategy that provides incentives to consumers to facilitate the purchase of EE lighting products. The program as designed takes the Energy Independence and Security Act (*EISA*) policies into account by including a shift from compact fluorescent lamps ("CFL") bulbs to light emitting diodes ("LED") bulbs starting in 2016. The program not only empowers customers to take advantage of new lighting technologies and accelerate the adoption of proven energy efficient technologies, but also allows the customers to experience the benefits of EE and decrease their energy consumption.

Eligible Customers

Any residential customer who receives electric service from Vectren South.

Marketing Plan

The program is designed to reach residential customers through retail outlets. Proposed marketing efforts include point of purchase promotional activities, the use of utility bill inserts and coordinated advertising with selected manufacturers and retail outlets.

Barriers/Theory

The program addresses the market barriers by empowering customers to take advantage of new lighting technologies through education and availability in the marketplace; accelerating the adoption of proven energy efficient technologies through incentives to lower price; and working with retailers to allow them to sell more high efficient products.

It is assumed that participants will be adding new LED bulbs over time. The annual adoption levels for LED bulbs are as follows:

2016: LEDs assume an estimated 21.2% of qualifying bulb market share

2017: LEDs assume an estimated 29.5% of qualifying bulb market share

The inputs developed for this program reflect the blended values assuming a mixture of bulbs. The impacts and costs will vary each year as the mixture of bulbs changes.

Initial Measures, Products and Services

The measures will include a variety of ENERGY STAR-qualified lighting products currently available at retailers in Indiana, including CFLs, LEDs, fixtures, and ceiling fans.

Table 13. Residential Lighting Program Budget & Energy Savings Targets

Market	Program	2016	2017	Total Program
Residential	**Residential Lighting**			
	Number of Measures	233,168	233,899	467,067
	Energy Savings kWh	6,612,901	6,831,909	13,444,810
	Peak Demand kW	839	865	1,705
	Total Program Budget $	$788,506	$897,321	$1,685,827
	Per Participant Avg Energy Savings (kWh)*			28.8
	Per Participant Avg Demand Savings (kW)*			0.004
	Weighted Avg Measure Life*			8
	Net To Gross Ratio			57%

Table 14. Residential Lighting Estimated Energy Savings & Budget

Residential	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Residential Lighting	13,444,810	1,705	$120,000	$80,768	$408,618	$1,076,441	$1,685,827
2016	6,612,901	839	$60,000	$37,750	$201,488	$489,268	$788,506
2017	6,831,909	865	$60,000	$43,018	$207,130	$587,173	$897,321

Table 15. Residential Lighting Cost Effectiveness

Residential	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Residential Lighting	2.30	2.95	0.56	4.23	$0.03	$0.12	$2,711,715	$3,165,966

Program Delivery

Vectren South will oversee the program and may partner with an implementation provider to deliver the program.

Evaluation, Measurement and Verification

The implementation contractor will verify the paperwork of the participating retail stores. They will also spot check stores to assure that the program guidelines are being followed. A third party evaluator will evaluate the program using standard EM&V protocols.

B. Home Energy Assessments and Weatherization

Program Description

The Home Energy Assessment and Weatherization Program targets a hybrid approach that combines helping customers analyze and understand their energy use via an on-site energy assessment, providing direct installation of EE measures including efficient low-flow water fixtures and CFL bulbs, and providing deeper retrofit measures for customers who choose to pay 40% of the deeper retrofit measure cost.

Eligible Customers

Any residential customer who receives electric service from Vectren South at a single-family residence, provided the home:

- was built prior to 1/1/2010;
- has not had an audit within the last three years; and
- is owner occupied or non-owner occupied where occupants have the electric service in their name.

Marketing Plan

Proposed marketing efforts include utilizing Vectren South online audit tools, bill inserts as well as other outreach and education efforts and promotional campaigns throughout the year to ensure participation levels are maintained.

Barriers/Theory

The primary barrier addressed through this program is customer education and awareness. Often customers do not understand what opportunities exist to reduce their home energy use. This program not only informs the customer but helps them start down the path of energy savings by directly installing low cost measures. The program is also a "gateway" to other Vectren South gas and electric programs.

Initial Measures, Products and Services

The direct install measures available for installation at no cost include:

- CFL lamps
- Low flow kitchen and bath aerators
- Low flow showerheads
- Pipe wrap

For customers who elect to move forward with the deeper retrofit measures recommended in the audit report, the following measures are available at buy-down price of up to 40% of the installation costs:

- Improved air sealing
- Attic insulation (R11-R38)
- Wall insulation (R5-R13)
- Knee wall insulation
- ECM motor replacement
- LED 13 watt bulb (60 watt replacement)
- Programmable thermostat
- Duct sealing

Table 16. Home Energy Assessments & Weatherization Program Budget & Energy Savings Targets

Market	Program	2016	2017	Total Program
Residential	Home Energy Assessments & Weatherization			
	Number of Homes	2,125	2,125	4,250
	Energy Savings kWh	1,935,719	1,935,719	3,871,438
	Peak Demand kW	290	290	580
	Total Program Budget $	$419,910	$429,428	$849,339
	Per Participant Avg Energy Savings (kWh)*			910.9
	Per Participant Avg Demand Savings (kW)*			0.137
	Weighted Avg Measure Life*			6
	Net To Gross Ratio			88%

Table 17. Home Energy Assessments & Weatherization Estimated Energy Savings & Budget

Residential	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Home Energy Assessments & Weatherization	3,871,438	580	$90,000	$40,813	$601,000	$117,526	$849,339
2016	1,935,719	290	$45,000	$20,147	$296,000	$58,763	$419,910
2017	1,935,719	290	$45,000	$20,665	$305,000	$58,763	$429,428

Table 18. Home Energy Assessments and Weatherization Cost Effectiveness

Residential	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Home Energy Assessments & Weatherization	1.53	1.80	0.46	8.49	$0.04	$0.22	$508,549	$656,140

Program Delivery

Vectren South will oversee the program and may partner with an implementation provider to deliver the program.

Integration with Vectren South Natural Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

To assure compliance with program guidelines, field visits with auditors will occur as well as spot check verifications of measure installations. A third party evaluator will evaluate the program using standard EM&V protocols.

C. Income Qualified Weatherization

Program Description

The Income Qualified Weatherization program is designed to produce long term energy and demand savings in the residential market. The program is designed to provide weatherization upgrades to low income homes that otherwise would not have been able to afford the energy saving measures. The program provides direct installation of energy-saving measures and educates consumers on ways to reduce energy consumption.

Collaboration and coordination between gas and electric low-income programs along with state and federal funding is recommended to provide the greatest efficiencies among all programs.

Eligible Customers

The Residential Low Income Weatherization Program targets single-family homeowners and tenants, who have electric service in their name with Vectren South, and with a total household income up to 200% of the federally-established poverty level. Priority will be given to:

a. Single parent households with children under 18 years of age living in dwelling.
b. Households headed by occupants over 65 years of age.
c. Disabled homeowners as defined by the EAP.
d. Households with high energy intensity usage levels.

Marketing Plan

Vectren South will provide a list to the implementation contractor of high consumption customers who have received Energy Assistance Program ("EAP") funds within the past 12 months to help prioritize those customers who will benefit most from the program. This will also help in any direct marketing activities to specifically target those customers.

Barriers/Theory

Lower income homeowners do not have the money to make even simple improvements to lower their bill and often live in homes with the most need for EE improvements. They may also lack the knowledge, experience, or capability to do the work. Health and safety can also be at risk for low income homeowners, as their homes typically are not as "tight", and indoor air quality can be compromised. This program provides those customers with basic improvements to help them start saving energy without needing to make the investment themselves.

Initial Measures, Products and Services

Measures available for installation will vary based on the home and include:

- CFL standard lamps
- CFL specialty lamps
- Exterior LED lamps
- Low flow kitchen and bath aerators
- Low flow showerheads
- Pipe wrap
- Furnace filter whistles
- Infiltration reduction
- Attic insulation
- Duct repair, seal and insulation
- Refrigerator replacement
- Whole house fan
- Programmable thermostat
- Smart power strips

Table 19. Income Qualified Weatherization Program Budget & Energy Savings Targets

Market	Program	2016	2017	Total Program
Residential	**Income Qualified Weatherization**			
	Number of Homes	564	564	1,128
	Energy Savings kWh	1,282,577	1,282,577	2,565,154
	Peak Demand kW	254	254	508
	Total Program Budget $	$598,270	$604,045	$1,202,315
	Per Participant Avg Energy Savings (kWh)*			2,274.1
	Per Participant Avg Demand Savings (kW)*			0.450
	Weighted Avg Measure Life*			6
	Net To Gross Ratio			100%

Table 20. Income Qualified Weatherization Estimated Energy Savings & Budget

Residential	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Income Qualified Weatherization	2,565,154	508	$90,000	$52,048	$1,060,267	$0	$1,202,315
2016	1,282,577	254	$45,000	$25,899	$527,371	$0	$598,270
2017	1,282,577	254	$45,000	$26,149	$532,896	$0	$604,045

Table 21. Income Qualified Weatherization Cost Effectiveness

Residential	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Income Qualified Weatherization	1.06	1.06	0.40	NA	$0.07	$0.47	$68,181	$68,181

Program Delivery

Vectren South will oversee the program and may partner with an implementation provider to deliver the program.

Integration with Vectren South Natural Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

To assure quality installations, 10% of the installations will be field inspected. A third party evaluator will evaluate the program using standard EM&V protocols.

D. Appliance Recycling

Program Description

The Residential Appliance Recycling program encourages customers to recycle their old inefficient refrigerators and freezers in an environmentally safe manner. The program recycles operable refrigerators and freezers so the appliance no longer uses electricity, and keeps 95% of the appliance out of landfills. An older refrigerator can use up to three times the amount of energy as new efficient refrigerators. An incentive of $50 will be provided to the customer for each operational unit picked up.

Eligible Customers

Any residential customer with an operable secondary refrigerator or freezer receiving electric service from Vectren South.

Marketing Plan

The program will be marketed through a variety of mediums, including the use of utility bill inserts, retail campaigns coordinated with appliance sales outlets as well as the potential for direct mail, web and media promotional campaigns.

Barriers/Theory

Many homes have second refrigerators and freezers that are very inefficient. Customers are not aware of the high energy consumption of these units. Customers also often have no way to move and dispose of the units, so they are kept in homes past their usefulness. This program educates customers about the waste of these units and provides a simple way for customers to dispose of the units.

Table 22. Appliance Recycling Program Budget & Energy Savings Targets

Market	Program	2016	2017	Total Program
Residential	**Appliance Recycling**			
	Number of Measures	952	952	1,904
	Energy Savings kWh	1,020,544	1,020,544	2,041,088
	Peak Demand kW	152	152	305
	Total Program Budget $	$205,094	$207,948	$413,042
	Per Participant Avg Energy Savings (kWh)*			1,072.0
	Per Participant Avg Demand Savings (kW)*			0.160
	Weighted Avg Measure Life*			8
	Net To Gross Ratio			53%

Table 23. Appliance Recycling Estimated Energy Savings & Budget

Residential	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Appliance Recycling	2,041,088	305	$120,000	$20,178	$177,664	$95,200	$413,042
2016	1,020,544	152	$60,000	$9,975	$87,519	$47,600	$205,094
2017	1,020,544	152	$60,000	$10,203	$90,145	$47,600	$207,948

Table 24. Appliance Recycling Cost Effectiveness

Residential	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Appliance Recycling	1.40	1.40	0.39	9.77	$0.04	$0.20	$160,494	$159,188

Program Delivery

Vectren South will oversee the program and may partner with an implementation provider to deliver the program.

Evaluation, Measurement and Verification

Recycled units will be logged and tracked to assure proper handling and disposal. The utility will monitor the activity for disposal. Customer satisfaction surveys will also be used to understand the customer experience with the program. A third party evaluator will evaluate the program using standard EM&V protocols.

E. Energy Efficient Schools

Program Description

The Energy Efficient Schools Program is designed to impact students by teaching them how to conserve energy and to produce cost effective electric savings by influencing students and their families to focus on conservation and the efficient use of electricity.

The program consists of a school education program for 5th grade students attending schools served by Vectren South. To help in this effort, each child that participates will receive a take-home energy kit with various energy saving measures for their parents to install in the home. The kits, along with the in-school teaching materials, are designed to make a lasting impression on the students and help them learn ways to conserve energy.

Eligible Customers

The program will be available to selected 5th grade students/schools in the Vectren South electric service territory.

Marketing Plan

The program will be marketed directly to elementary schools in Vectren South electric service territory as well as other channels identified by the implementation contractor. A list of the eligible schools will be provided by Vectren South to the implementation contractor for direct marketing to the schools via email, phone, and mail (if necessary) to obtain desired participation levels in the program.

Barriers/Theory

This program addresses the barrier of education and awareness of EE opportunities. Working through schools, both students and families are educated about opportunities to save. As well, the families receive energy savings devices they can install to begin their savings.

Initial Measures, Products and Services

The kits for students will include:

- Low flow showerhead
- Low flow kitchen aerator
- Low flow bathroom aerator
- LED bulbs (2)
- LED nightlight
- Air filter alarm

Table 25. Energy Efficient Schools Program Budget & Energy Savings Targets

Market	Program	2016	2017	Total Program
Residential	**Energy Efficient Schools**			
	Number of Kits	2,400	2,400	4,800
	Energy Savings kWh	675,508	675,508	1,351,016
	Peak Demand kW	106	106	211
	Total Program Budget $	$117,706	$120,901	$238,607
	Per Participant Avg Energy Savings (kWh)*			281.5
	Per Participant Avg Demand Savings (kW)*			0.044
	Weighted Avg Measure Life*			8
	Net To Gross Ratio			96%

Table 26. Energy Efficient Schools Estimated Energy Savings & Budget

Residential	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Energy Efficient Schools	1,351,016	211	$60,000	$11,607	$167,000	$0	$238,607
2016	675,508	106	$30,000	$5,706	$82,000	$0	$117,706
2017	675,508	106	$30,000	$5,901	$85,000	$0	$120,901

Table 27. Energy Efficient Schools Cost Effectiveness

Residential	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Energy Efficient Schools	3.39	3.39	0.53	NA	$0.02	$0.17	$551,397	$551,397

Program Delivery

Vectren South will oversee the program and may partner with an implementation provider to deliver the program.

Integration with Vectren South Natural Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

Classroom participation will be tracked. A third party evaluator will evaluate the program using standard EM&V protocols.

F. Residential Efficient Products

Program Description

The program is designed to incent customers to purchase energy efficient appliances and equipment by covering part of the larger incremental cost. The program will be promoted through trade allies and appropriate retail outlets.

Eligible Customers

Any residential customer located in the Vectren South electric service territory.

Marketing Plan

The marketing plan includes program specific marketing materials that will target contractors and trade allies in the Heating, Ventilation and Air Conditioning ("HVAC") industry. The HVAC industry will be marketed to by using targeted direct marketing, direct contact by the program vendor personnel, trade shows and trade association outreach. Vectren South will also use web banners, bill inserts, and mass market advertising.

Barriers/Theory

First cost is one of the key barriers to the adoption of EE technology. Customers do not always understand the long term benefits of the energy savings from these efficient alternatives. Trade allies are also often reluctant to sell the higher cost items as they do not want to be the high cost bidder. Incentives help address this first cost issue and provide a good reason for Trade Allies to promote these higher efficient options.

Initial Measures, Products and Services

Details of the measures, savings, and incentives can be found in Appendix A. Measures included in the program will change over time as baselines change, new technologies become available and customer needs are identified.

Table 28. Residential Efficient Products Program Budget & Energy Savings Targets

Market	Program	2016	2017	Total Program
Residential	**Residential Efficient Products**			
	Number of Measures	2,216	2,216	4,432
	Energy Savings kWh	1,075,888	1,075,888	2,151,776
	Peak Demand kW	623	623	1,247
	Total Program Budget $	$622,492	$626,298	$1,248,790
	Per Participant Avg Energy Savings (kWh)*			485.5
	Per Participant Avg Demand Savings (kW)*			0.281
	Weighted Avg Measure Life*			16
	Net To Gross Ratio			74%

Table 29. Residential Efficient Products Estimated Energy Savings & Budget

Residential	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Residential Efficient Products	2,151,776	1,247	$180,000	$60,202	$253,188	$755,400	$1,248,790
2016	1,075,888	623	$90,000	$29,946	$124,846	$377,700	$622,492
2017	1,075,888	623	$90,000	$30,256	$128,342	$377,700	$626,298

Table 30. Residential Efficient Products Cost Effectiveness

Residential	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Residential Efficient Products	1.31	2.07	0.69	1.54	$0.05	$0.58	$586,114	$1,288,936

Program Delivery

Vectren South will oversee the program and may partner with an implementation provider to deliver the program.

Integration with Vectren South Natural Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

There will be 100% paper verification that the equipment/products purchased meet the program efficiency standards and a field verification of 10% of the measures installed. A third party evaluator will review the program using appropriate EM&V protocols.

G. Residential New Construction

Program Description

The Residential New Construction Program will provide incentives and encourage home builders to construct homes that are more efficient than current building codes. The Residential New Construction Program will work closely with builders, educating them on the benefits of energy efficient new homes. Homes may feature additional insulation, better windows, and higher efficiency appliances. The homes should also be more efficient and comfortable than standard homes constructed to current building codes.

Program incentives are designed to be paid to both all-electric and combination homes that have natural gas heating and water heating. Builders can select from two rebate tiers for participation. Gold Star homes must achieve a HERS rating of 65 or less. Platinum Star homes must meet a HERS rating of 60 or less. It is important to note that the program is structured such that an incentive will not be paid for an all-electric home that has natural gas available to the home site.

The Residential New Construction Program will address the lost opportunities in this customer segment by promoting EE at the time the initial decisions are being made. This will ensure efficient results for the life of the home.

Eligible Customers

Any home builder constructing a home to the program specifications in the Vectren South electric service territory.

Marketing Plan

In order to move the market toward an improved home building standard, education will be required for home builders, architects and designers as well as customers buying new homes. A combination of in-person meetings with these market participants as well as other educational methods will be necessary.

Barriers/Theory

There are three primary barriers addressed by the Residential New Construction program. The first is customer knowledge. The HERS rating system allows customers to understand building design and construction improvements through a rating system completed by professionals. The second barrier is first cost. The program provides incentives to help reduce the first cost of the EE upgrades. The third barrier is the lack of skill and knowledge of the builders. The program provides opportunities for builders and developers to gain knowledge and skills concerning EE building practices and coaches them on application of these skills.

Incentive Strategy

Incentives will be based on the rating tier qualification. For all-electric homes, where Vectren South natural gas service is not available, the initial incentives will be:

Tier	Total Incentive	Vectren Electric Incentive Portion
Platinum Star	$1,000	$1,000
Gold Star	$900	$900

For homes with central air conditioning and Vectren South natural gas space heating the electric portion of the incentive will be:

Tier	Total Incentive	Vectren Electric Incentive Portion
Platinum Star	$1,000	$500
Gold Star	$900	$450

Incentives will be paid to the builder.

Table 31. Residential New Construction Program Budget & Energy Savings Targets

Market	Program	2016	2017	Total Program
Residential	**Residential New Construction**			
	Number of Homes	103	103	206
	Energy Savings kWh	146,775	146,775	293,550
	Peak Demand kW	68	68	136
	Total Program Budget $	$98,441	$99,536	$197,977
	Per Participant Avg Energy Savings (kWh)*			1,425.0
	Per Participant Avg Demand Savings (kW)*			0.660
	Weighted Avg Measure Life*			25
	Net To Gross Ratio			86%

Table 32. Residential New Construction Estimated Energy Savings & Budget

Residential	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Residential New Construction	293,550	136	$20,000	$11,577	$61,000	$105,400	$197,977
2016	146,775	68	$10,000	$5,741	$30,000	$52,700	$98,441
2017	146,775	68	$10,000	$5,836	$31,000	$52,700	$99,536

Table 33. Residential New Construction Cost Effectiveness

Residential	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Residential New Construction	1.36	2.65	0.71	1.37	$0.03	$0.67	$133,067	$315,685

Program Delivery

Vectren South will oversee the program and may partner with an implementation provider to deliver the program.

Integration with Vectren South Natural Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

Field inspections of the home will occur during construction at least once and upon completion. All paperwork will be reviewed and the HERS ratings archived. A third party evaluator will evaluate the program using standard EM&V protocols.

H. Multi-Family Direct Install

Program Description

The Multi-Family Direct Install Program reached market saturation during 2014 for properties with electric water heating in the Vectren South territory and is not being offered as a stand-alone program. This program is being continued as an integrated natural gas and electric EE program to serve properties with natural gas water heating. Vectren South's electric division will cover the incremental cost to install CFL bulbs as part of Vectren South's natural gas division's EE program during 2016 - 2017. Additionally, Vectren South's electric division will cost share for the installation of programmable thermostats that include both natural gas and electric benefits.

Eligible Customers

Multi-Family properties with Vectren South natural gas and electric service.

Table 34. Multi-Family Direct Install Program Budget & Energy Savings Targets

Market	Program	2016	2017	Total Program
Residential	**Multi-Family Direct Install**			
	Number of Measures	5,500	5,500	11,000
	Energy Savings kWh	335,000	335,000	670,000
	Peak Demand kW	20	20	40
	Total Program Budget $	$29,776	$30,610	$60,387
	Per Participant Avg Energy Savings (kWh)*			60.9
	Per Participant Avg Demand Savings (kW)*			0.004
	Weighted Avg Measure Life*			6
	Net To Gross Ratio			100%

Table 35. Multi-Family Direct Install Estimated Energy Savings & Budget

Residential	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Multi-Family Direct Install	670,000	40	$0	$2,876	$57,511	$0	$60,387
2016	335,000	20	$0	$1,418	$28,359	$0	$29,776
2017	335,000	20	$0	$1,458	$29,153	$0	$30,610

Table 36. Multi-Family Direct Install Cost-Effectiveness

Residential	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Multi-Family Direct Install	3.69	3.69	0.44	NA	$0.02	$0.09	$156,955	$156,955

I. Residential Behavior Savings

Program Description

The Residential Behavioral Savings (RBS) Program motivates behavior change and provides relevant, targeted information to the consumer through regularly scheduled direct contact via mailed and emailed home energy reports. The report and web portal include a comparison against a group of similarly sized and equipped homes in the area, usage history comparisons, goal setting tools, and progress trackers. The Home Energy Report program anonymously compares customers' energy use with that of their neighbors of similar home size and demographics. Customers can view the past twelve months of their energy usage and compare and contract their energy consumption and costs with others in the same neighborhood. Once a consumer understands better how they use energy, they can then start conserving energy.

Eligible Customers

Residential customers who receive natural gas and electric service from Vectren South are eligible to participate in this integrated natural gas and electric EE program.

Barriers/Theory

The Residential Behavioral Savings program provides residential customers with better energy information through personalized reports delivered by mail, email and an integrated web portal to help them put their energy usage in context and make better energy usage decisions. Behavioral science research has demonstrated that peer-based comparisons are highly motivating ways to present information. The program will leverage a dynamically created comparison group for each residence and compare it to other similarly sized and located households.

Implementation & Delivery Strategy

The program will be delivered by OPower and include energy reports and a web portal. Customers typically receive between 4 - 6 reports annually. These reports provide updates on energy consumption patterns compared to neighbors and provide energy savings strategies to reduce energy use. They can promote other Vectren South programs to interested customers. The web portal is an interactive system for customers to perform a self-audit, monitor energy usage over time, access energy savings tips and be connected to other Vectren South gas and electric programs.

Table 37. Residential Behavior Savings Program Budget & Energy Savings Targets

Market	Program	2016	2017	Total Program
Residential	Residential Behavior Savings			
	Number of Participants	48,400	43,500	91,900
	Energy Savings kWh	6,204,832	5,576,656	11,781,488
	Peak Demand kW	1,728	1,553	3,280
	Total Program Budget $	$382,000	$366,285	$748,285
	Per Participant Avg Energy Savings (kWh)*			128.2
	Per Participant Avg Demand Savings (kW)*			0.036
	Weighted Avg Measure Life*			1
	Net To Gross Ratio			100%

Table 38. Residential Behavior Savings Estimated Energy Savings & Budget

Residential	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Residential Behavior Savings	11,781,488	3,280	$100,000	$33,285	$615,000	$0	$748,285
2016	6,204,832	1,728	$50,000	$17,000	$315,000	$0	$382,000
2017	5,576,656	1,553	$50,000	$16,285	$300,000	$0	$366,285

Table 39. Residential Behavior Savings Cost Effectiveness

Residential	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Residential Behavior Savings	1.45	1.45	0.44	NA	$0.06	$0.06	$325,442	$325,442

Program Delivery

Vectren South will oversee the program and partner with OPower to deliver the program.

Integration with Vectren South Natural Gas

Vectren South will offer this integrated natural gas/electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

To understand the savings with behavior programs detailed evaluation protocols will need to be used including having matching control groups of non-participants. Billing analysis will compare the participant and non-participant groups. A third party evaluator will complete the evaluation of this program and work with Vectren South to select the participant and non-participant groups.

J. Small Business Direct Install

Program Description

The Small Business Direct Install Program provides value by directly installing EE products such as high efficiency lighting, low flow water saving measures and vending machine controls. The program helps businesses identify and install cost effective energy saving measures by providing an on-site energy assessment customized for their business.

Eligible Customers

Any participating Vectren South business customer with a maximum peak energy demand of less than 400 kW.

Marketing Plan

The Small Business Direct Install Program will be marketed through direct mailing, trade associations, educational seminars, and direct personal communication from Vectren South staff and third party contractors.

Barriers/Theory

Small business customers generally do not have the knowledge, time or money to invest in EE upgrades. This program assists these small businesses with direct installation and turn-key services to get measures installed at no or low out-of-pocket cost.

There is an implementation contractor in place providing suggested additions and changes to the program based on results and local economics.

Initial Measures, Products and Services

The program will have two types of measures provided. The first are measures that will be installed at the time of the assessment at no additional cost. They will include but are not limited to the following:

- LEDs: 8-12W
- LEDs: MR16 track light
- LEDs: > 12 W flood light
- Vending machine miser
- Pre-rinse spray values
- Programmable thermostat turn down
- Faucet aerators
- Showerheads
- Cooler controller-occupancy sensor

The second types of measures are recommended during the assessment and require the customer to pay a portion of the labor and materials. These measures include:

- LED lighting
- Linear fluorescent lighting
- LED exit and outdoor lights
- Pipe insulation
- Programmable thermostats (100% discount)
- Delamping
- ECM in refrigeration equipment
- Smart switches
- Anti-sweat heater controls
- LED lighting for display cases

Incentive Strategy

In addition to the low cost measures installed during the audit, the program will also pay a cash incentive of up to 50% of the cost of any recommended improvements identified through the assessment.

Table 40. Small Business Direct Install Program Budget & Energy Savings Targets

Market	Program	2016	2017	Total Program
Commercial & Industrial	Small Business Direct Install			
	Number of Measures	17,235	17,235	34,470
	Energy Savings kWh	6,000,810	6,000,810	12,001,619
	Peak Demand kW	906	906	1,812
	Total Program Budget $	$1,760,611	$1,774,351	$3,534,962
	Per Participant Avg Energy Savings (kWh)*			348.2
	Per Participant Avg Demand Savings (kW)*			0.053
	Weighted Avg Measure Life*			10
	Net To Gross Ratio			98%

Table 41. Small Business Direct Install Estimated Energy Savings & Budget

Commercial & Industrial	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Small Business Direct Install	12,001,619	1,812	$120,000	$168,822	$965,000	$2,281,140	$3,534,962
2016	6,000,810	906	$60,000	$84,041	$476,000	$1,140,570	$1,760,611
2017	6,000,810	906	$60,000	$84,781	$489,000	$1,140,570	$1,774,351

Table 42. Small Business Direct Install Cost Effectiveness

Commercial & Industrial	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Small Business Direct Install	1.28	2.33	0.74	1.56	$0.03	$0.29	$1,732,739	$4,554,660

Program Delivery

Vectren South will oversee the program and may partner with an implementation provider to deliver the program.

Integration with Vectren South Natural Gas

Vectren South will offer this integrated natural gas and electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

To assure quality installation, 10% of the installations will be inspected. A third party evaluator will evaluate the program using standard EM&V protocols.

K. Commercial & Industrial Prescriptive Rebates

Program Description

The Commercial & Industrial (C&I) Prescriptive Program is designed to provide financial incentives on qualifying products to produce greater energy savings in the C&I market. The rebates are designed to promote lower electric energy consumption, assist customers in managing their energy costs, and build a sustainable market around EE.

Program participation is achieved by offering incentives structured to cover a portion of the customer's incremental cost of installing prescriptive efficiency measures.

Eligible Customers

Any participating commercial or industrial customer receiving electric service from Vectren South.

Marketing Plan

Proposed marketing efforts include trade ally outreach, trade ally meetings, direct mail, face-to-face meetings with customers, web-based marketing, and coordination with key account executives.

Barriers/Theory

Customers often have the barrier of higher first cost for EE measures which precludes them from purchasing the more EE alternative. They also lack information on high efficiency alternatives. Trade allies often run into the barrier of not being able to promote more EE alternatives because of first cost. Trade allies also gain credibility with customers for their EE claims when a measure is included in a utility prescriptive program. Through the program the Trade allies can promote EE measures directly to their customers encouraging them to purchase more efficient equipment while helping customers get over the initial cost barrier.

The range of qualifying measures and prescriptive incentive amounts may change over time due to market economics and possible baseline changes.

Initial Measures, Products and Services

High efficient lighting and lighting controls for various applications will be the primary measures included. In addition variable frequency drives (VFD) for HVAC system and compressors will be included in the program. Details of the measures, savings and incentives can be found in Appendix A.

Implementation & Delivery Strategy

The program will be delivered primarily through the trade allies working with their customers. Vectren South and its implementation partners will work with the trade allies to make them aware of the offerings and help them promote the program to their customers. The implementation partner will provide training and technical support to the trade allies to become familiar with the EE technologies offered through the program. The program will be managed by the same implementation provider as the Commercial & Industrial Custom program so that customers can seamlessly receive assistance and all incentives can be efficiently processed through a single procedure.

Incentive Strategy

Incentives are provided to customers to reduce the difference in first cost between the lower efficient technology and the high efficient option. There is no fixed incentive percentage amount based on the difference in price because some technologies are newer and need higher amounts. Others have been available in the marketplace longer and do not need as much to motivate customers. Incentives will be adjusted to respond to market activity and bonuses may be available for limited time if required to meet goals.

Table 43. Commercial & Industrial Prescriptive Program Budget & Energy Savings Targets

Market	Program	2016	2017	Total Program
Commercial & Industrial	Commercial & Industrial Prescriptive			
	Number of Measures	12,222	12,222	24,444
	Energy Savings kWh	6,910,197	6,910,197	13,820,393
	Peak Demand kW	1,088	1,088	2,176
	Total Program Budget $	$1,042,705	$1,049,906	$2,092,611
	Per Participant Avg Energy Savings (kWh)*			565.4
	Per Participant Avg Demand Savings (kW)*			0.089
	Weighted Avg Measure Life*			11
	Net To Gross Ratio			80%

Table 44. Commercial & Industrial Prescriptive Estimated Energy Savings & Budget

Commercial & Industrial	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Commercial & Industrial Prescriptive	13,820,393	2,176	$120,000	$100,139	$490,472	$1,382,000	$2,092,611
2016	6,910,197	1,088	$60,000	$49,855	$241,850	$691,000	$1,042,705
2017	6,910,197	1,088	$60,000	$50,284	$248,622	$691,000	$1,049,906

Table 45. Commercial & Industrial Prescriptive Cost Effectiveness

Commercial & Industrial	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Commercial & Industrial Prescriptive	3.00	4.07	0.87	3.25	$0.02	$0.15	$5,485,762	$6,202,259

Program Delivery

Vectren South will oversee the program and may partner with an implementation provider to deliver the program.

Evaluation, Measurement and Verification

Site visits will be made on 10% of the installations to verify the correct equipment was installed. Standard EM&V protocols will be used for the third party evaluation of the program.

L. Commercial & Industrial New Construction

Program Description

The Commercial and Industrial New Construction Program provides value by promoting EE designs with the goal of developing projects that are more EE than current Indiana building code. Incentives promoted through this program serve to reduce the incremental cost to upgrade to high-efficiency equipment over standard efficiency options for Vectren South customers. The program includes equipment with easily calculated savings and provides straightforward and easy participation for customers.

The program provides incentives as part of the facility design process to explore opportunities in modeling EE options to craft an optimal package of investments. Once designed, the program also offers incentives to reduce the higher capital cost for EE solutions.

The program requires qualifying facilities must exceed Indiana Energy Code for commercial or industrial buildings by at least 10 percent. Facilities earn $0.12 per kWh saved (over a conventional building energy performance) up to $100,000 based on first year energy savings.

Eligible Customers

Any participating commercial or industrial customer receiving electric service from Vectren South.

Marketing Plan

The Commercial & Industrial New Construction Program will be marketed through trade ally meetings, trade association training, educational seminars, and direct personal communication from Vectren South staff and third party contractors.

Barriers/Theory

There are three primary barriers addressed by the new construction program. The first is knowledge. For commercial and industrial buildings is it the knowledge and experience of the design team including the owner, architect, lighting and HVAC engineers, general contractor and others. This team may not understand new technologies and EE options that could be considered. The second barrier is cost. There is a cost during the design phase of the building in modeling EE options to see what can cost-effectively work within the building. The program provides incentives to help reduce the design cost for the consideration of EE upgrades. The third barrier is the first cost of the high efficiency upgrades in equipment and materials. The incentives from the standard programs will provide incentives to help reduce this first cost.

Implementation & Delivery Strategy

Standard Energy Design Assistance ("EDA") targets buildings that are less than 100,000 square feet, but is also available for larger new buildings that are beyond the schematic design phase or are on an accelerated schedule. Commercial and industrial new construction projects for buildings greater than 100,000 square feet still in the conceptual design phase qualify for Vectren South's Enhanced EDA incentives. The Vectren South implementation partner staff expert will work with the design team through the conceptual design, schematic design and design development processes providing advice and counsel on measures that should be considered and EE modeling issues. Incentives will be paid after the design team submits completed construction documents for review to verify that the facility design reflects the minimum energy savings requirements.

Incentive Strategy

All buildings in Vectren South's service territory receiving electric service qualify for the measure incentives available in the Prescriptive and Custom programs. In addition Vectren South will provide incentives to help offset some of the expenses for the design team's participation in the EDA process with the design team service incentive. The design team service incentive is a fixed amount based on the new conditioned square footage and is paid to the designated design team lead provided that the proposed EE projects associated with the construction documents exceed a minimum energy savings threshold. Vectren South will offer a one-time, lump-sum incentive to building owners for participation in the Enhanced EDA program. Facilities must exceed Indiana Energy Code requirements by 10 percent in order to qualify for an Enhanced EDA incentive. Facilities earn $0.12 per kilowatt hour (kWh) saved up to $100,000 based on the first-year energy savings determined in the final energy model.

Facility Size – Square Feet	Design Team Incentives	Minimum Savings
Small <25,000	$750	25,000 kWh
Medium 25,000 - 100,000	$2,500	75,000 kWh
Large >100,000	$3,750	150,000 kWh
Enhance Large >100,000	$5,000	10% beyond code

Table 46. Commercial & Industrial New Construction Program Budget & Energy Savings Targets

Market	Program	2016	2017	Total Program
Commercial & Industrial	**Commercial & Industrial New Construction**			
	Number of Projects	14	15	29
	Energy Savings kWh	498,526	534,135	1,032,661
	Peak Demand kW	88	94	182
	Total Program Budget $	$162,562	$172,898	$335,460
	Per Participant Avg Energy Savings (kWh)*			35,609.0
	Per Participant Avg Demand Savings (kW)*			6.280
	Weighted Avg Measure Life*			13
	Net To Gross Ratio			95%

Table 47. Commercial & Industrial New Construction Estimated Energy Savings & Budget

Commercial & Industrial	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Commercial & Industrial New Construction	1,032,661	182	$60,000	$16,219	$124,950	$134,290	$335,460
2016	498,526	88	$30,000	$7,842	$59,850	$64,870	$162,562
2017	534,135	94	$30,000	$8,377	$65,100	$69,420	$172,898

Table 48. Commercial & Industrial New Construction Cost Effectiveness

Commercial & Industrial	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Commercial & Industrial New Construction	1.99	2.49	0.79	3.03	$0.03	$0.33	$400,143	$481,736

Program Delivery

Vectren South will oversee the program and may partner with an implementation provider to deliver the program.

Integration with Vectren South Natural Gas

Vectren South will offer this integrated natural gas and electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

All construction documents will be reviewed and archived. A third party evaluator will evaluate the program using standard EM&V protocols.

M. Commercial & Industrial Custom

Program Description

The Commercial and Industrial Custom Program promotes the implementation of customized energy saving measures at qualifying customer facilities. Incentives promoted through this program serve to reduce the cost of implementing energy reducing projects and upgrading to high-efficiency equipment. Due to the nature of a custom EE program, a wide variety of projects are eligible.

The technical audit or compressed air system study offers an assessment to systematically identify energy saving opportunities for customers and provides a mechanism to prioritize and phase-in projects that best meet customer needs. In turn, the opportunities identified from the audit can be turned in for the customized efficiency program. These two components work hand in hand to deliver energy savings to Vectren South commercial and industrial customers.

The 2016-2017 Plan includes a pilot initiative within the C&I Custom Program focused on strategic energy management (SEM). SEM programs aim to continuously improve energy performance over the long term through organizational transformation focused on equipping facility management and staff with the organizational and technical skills required to reduce energy waste. The outcome of a successful SEM program is reduced energy consumption through operational and maintenance improvements.

An SEM program should utilize the ISO 50001 standard, which provides a well-defined framework for structuring various technical and management tactics included as part of the overall strategy. The ISO 50001 training and technical support initiative will provide interested customers additional education on the ISO 50001 standard and the benefits for pursuing the certification. Training on the ISO 50001 management system, as well as organizational and technical assistance will be offered to customers that are interested in participating in this initiative.

To prepare facility operators to complete an SEM strategy, this pilot initiative within the Custom Program will offer optional training as well as technical assistance and potential bonus incentives for companies agreeing to pursue ISO 50001 and/or Superior Energy Performance (SEP).

Eligible Customers

Any participating commercial or industrial customer receiving electric service from Vectren South.

Marketing Plan

Proposed marketing efforts include coordination with key account representatives to leverage the contacts and relationships they have with the customers. Direct mail, media outreach, trade shows, trade ally meetings, and educational seminars could also be used to promote the program.

Barriers/Theory

Applications of some specific EE technologies are unique to that customer's application or process. The energy savings estimates for these measures are highly variable and cannot be assessed without an engineering estimation of that application; however, they offer a large opportunity for energy savings. To promote the installation of these high efficient technologies or measures, the Commercial & Industrial Custom program will provide incentives based on the kWh saved as calculated by the engineering analysis. To assure savings, these projects will require program engineering reviews and pre approvals. Energy assessments offered will help remove customer barriers regarding opportunity identification and energy savings potential. The large commercial and industrial education provides a systematic approach to integrating energy management into an organization's business practices and creating lasting energy management processes that produce reliable energy savings.

Initial Measures, Products and Services

All technologies or measures that save kWh qualify for the program. Facility energy assessments, technical assistance and energy management educational services will be offered to eligible and motivated customers to implement multiple EE measures.

Implementation & Delivery Strategy

The implementation partner for this program will provide engineering field support to customers and trade allies to calculate the energy savings. Customers or trade allies with a proposed project will complete an application form with the energy savings calculations for the project. The implementation team will review all calculations and where appropriate complete site visits to assess and document pre installation conditions. Customers will be informed and funds reserved for the project. Implementation engineering staff will review the final project information as installed and verify the energy savings. Incentives are then paid on the verified savings expected.

The implementation partner will work collaboratively with Vectren South staff to recruit and screen customers for receiving facility energy assessments, technical assistance and energy management education. The program will seek to gain customer commitment towards setting up an energy management process and implementing multiple EE improvements. The implementation partner will help customers achieve agreed upon milestones in support for their commitment.

Incentive Strategy

Incentives will be calculated on a per kWh basis. The initial kWh rate will be \$0.12/kWh and is paid based on the first year annual savings reduction. Rates may change over time and vary with some of the special initiatives. Incentives will not pay more than 50% of the project cost nor provide incentives for projects with paybacks less than 12 months. As part of the SEM pilot initiative, bonus incentives may be offered to customers pursuing either ISO 50001 and/or Superior Energy Performance (SEP). Vectren South will offer a cost share on facility energy assessments that will cover up to 100% of the assessment cost. Energy education, technical assistance, and company-wide coaching will be offered to large commercial and industry customers that generate an agreement with Vectren South to implement strategies and projects that result from receiving those activities.

Table 49. Commercial & Industrial Custom Program Budget & Energy Savings Targets

Market	Program	2016	2017	Total Program
Commercial & Industrial	Commercial & Industrial Custom			
	Number of Projects	22	25	47
	Energy Savings kWh	2,557,544	2,906,300	5,463,844
	Peak Demand kW	339	385	724
	Total Program Budget $	$726,584	$738,386	$1,464,970
	Per Participant Avg Energy Savings (kWh)*			116,252.0
	Per Participant Avg Demand Savings (kW)*			15.404
	Weighted Avg Measure Life*			11
	Net To Gross Ratio			99%

Table 50. Commercial & Industrial Custom Estimated Energy Savings & Budget

Commercial & Industrial	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Commercial & Industrial Custom	5,463,844	724	$165,000	$69,760	$424,530	$805,680	$1,464,970
2016	2,557,544	339	$100,000	$34,599	$210,025	$381,960	$726,584
2017	2,906,300	385	$65,000	$35,161	$214,505	$423,720	$738,386

Table 51. Commercial & Industrial Custom Cost Effectiveness

Commercial & Industrial	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Commercial & Industrial Custom	1.07	2.74	0.77	1.18	$0.02	$0.28	$260,765	$2,468,576

Program Delivery

Vectren South will oversee the program and may partner with an implementation provider to deliver the program.

Evaluation, Measurement and Verification

Given the variability and uniqueness of each project, all projects will be pre-approved. Pre and post visits to the site to verify installation and savings will be performed as defined by the program implementation partner. Monitoring and verification may occur on the largest projects. A third party evaluator will be used for this project and use standard EM&V protocols.

V. New Program Initiatives

A. Residential Smart Thermostat Demand Response

Program Description

Vectren South's residential DR programs are an increasingly important part of how the Company provides services to its customers. The current system that Vectren South utilizes for its Direct Load Control ("DLC") program leverages one-way communication switches that do not provide the opportunity for customers to interact with the Company. Leveraging "smart devices" such as a "smart thermostat" for DR allows the Company to reach beyond the meter to interact with customers. These smart devices are connected to Wi-Fi and reside on the customer's side of the electric meter and are used by the program to communicate with customers' air conditioning systems. The program provides the Company with increased customer contact opportunities and the ability to facilitate customers' shift of their energy usage to reduce peak system loads. The smart thermostats offer energy savings and increase load reduction, deliver verifiable DR, and provide a platform for customer engagement. The Residential Smart Thermostat DR program is designed to analyze the different approaches of DR that are available through smart thermostats. For this program, Vectren South will analyze both Honeywell and Nest DR platforms. Vectren South will install, at no additional cost to the customer, a total of approximately 2,000 smart thermostats (1,000 Honeywell and 1,000 Nest) in customer homes during 2016. Vectren South will leverage the platform to manage DR events during the summer of 2016. Vectren South will work with an independent evaluator on a billing analysis to measure the effectiveness of both programs designs in 2017. Based on the billing analysis results Vectren South will work with the Vectren Oversight Board on possible expansion of the program in 2018 and beyond.

Eligible Customers

Any residential customer who receives electric service from Vectren South at a single-family residence. Approximately 2,000 customers will be included in the program.

Marketing Plan

Vectren South will market directly to potential customers. Vectren South will work with the independent evaluator to identify customers for the program.

Barriers/Theory

An opportunity exists to reduce residential energy use through enhancing users' control of home heating and cooling systems. In the past few years, smart thermostat manufacturers have introduced a new generation of residential space-conditioning control technologies, such as wireless communicating programmable thermostats. Users can control these thermostats from a thermostat keypad, a web or mobile device. The enhanced control afforded by Wi-Fi enabled thermostats reduces the costs of controlling the space heating and cooling systems and creates potential for energy savings by enabling users to better align home space conditioning with occupancy and actual demand. Smart thermostats provide customers increased visibility and control of their energy use through their mobile devices and Apps. In a more direct sense, the Company benefits because it can communicate with customers on their mobile device through "push" notifications (messages sent to the customers through their Apps) to call a DR event and receive a response back from the customer.

Initial Measures, Products and Services

Customers participating in the program will receive either a Honeywell or Nest Wi-Fi enabled smart thermostat.

Table 52. Residential Smart Thermostat Demand Response Program Budget & Energy Savings Targets

Market	Program	2016	2017	Total Program
Residential	Residential Smart Thermostat Demand Response			
	Number of Measures	2,000	0	2,000
	Energy Savings kWh	858,000	0	858,000
	Peak Demand kW	1,800	0	1,800
	Total Program Budget $	$1,196,455	$297,890	$1,494,345
	Per Participant Avg Energy Savings (kWh)*			429.0
	Per Participant Avg Demand Savings (kW)*			0.900
	Weighted Avg Measure Life*			15
	Net To Gross Ratio			100%

Table 53. Residential Smart Thermostat Demand Response Estimated Energy Savings & Budget

Residential	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Residential Smart Thermostat Demand Response	858,000	1,800	$70,000	$352,240	$972,105	$100,000	$1,494,345
2016	858,000	1,800	$30,000	$212,240	$904,215	$50,000	$1,196,455
2017	0	0	$40,000	$140,000	$67,890	$50,000	$297,890

Table 54. Residential Smart Thermostat Demand Response Cost Effectiveness

Residential	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Residential Smart Thermostat Demand Response	1.56	1.30	0.78	NA	$0.21	$1.39	$1,366,716	$886,947

Program Delivery

Vectren South will oversee the program and will partner with Honeywell and Nest to deliver the program.

Evaluation, Measurement and Verification

A third party evaluator will evaluate the program using standard EM&V protocols.

B. Conservation Voltage Reduction (CVR)

Program Description

The Conservation Voltage Reduction (CVR) Program is an energy savings and optimization program that requires some description to understand in the context of the Vectren South 2016 - 2017 Plan. CVR achieves energy conservation through automated monitoring and control of voltage levels provided on distribution circuits. End use customers realize lower energy and demand consumption when CVR is applied to the distribution circuit from which they are served.

A distribution circuit facilitates electric power transfer from an electric substation to utility meters located at electric customer premises. Electric power customers employ end-use electric devices (loads) that consume electrical power. At any point along a single distribution circuit, voltage levels vary based upon several parameters, mainly including, but not exclusive of, the actual electrical conductors that comprise the distribution circuit, the size and location of electric loads along the circuit, the type of end-use loads being served, the distance of loads from the power source, and losses incurred inherent to the distribution circuit itself. All end-use loads require certain voltage levels to operate and standards exist to regulate the levels of voltage delivered by utilities. In Indiana, Vectren South is required to maintain a steady state +/- 5% of the respective baseline level as specified by ANSI C84.1 (120 volt baseline yields acceptable voltage range of 114 volts to 126 volts).

Historically, utilities including Vectren South have set voltage levels near the upper limit at the distribution circuit source (substation) and have applied voltage support devices such as voltage regulators and capacitors along the circuit to assure that all customers are provided voltages within the required range. This basic design economically met the requirements by utilizing the full range (+/- 5%) of allowable voltages while only applying independent voltage support where needed. This basic design has worked well for many years. However, in the 1980's, utilities recognized that loads on the circuits would actually consume less energy if voltages in the lower portion of the acceptable range were provided. In fact, many utilities, including Vectren South, established emergency operating procedures to lower voltage at distribution substations by 5% during power shortage conditions.

The recent focus on EE and the availability of technology that allows monitoring and tighter control of circuit voltage conditions has led to development of automated voltage control schemes which coordinate the operation of voltage support devices and allow more customers on the circuit to be served at voltages in the lower portion of the acceptable range.

Industry studies have shown that certain end-use loads consume more power with higher voltage levels applied to them, resulting in less efficient operation than if voltage in the lower half of the acceptable range is applied. Additionally, when higher power consumption is experienced on a distribution circuit, the circuit itself experiences higher levels of system losses. Energy and demand reductions can be realized through the deployment of control technology to a distribution circuit where the bandwidth of voltage is more tightly controlled along the entire length of the distribution circuit. Reduced losses on the distribution circuit are also realized through reduced end-use power consumption.

Independent measurement and verification has verified that, on average, a 1% reduction in voltage on distribution circuits translates into an approximate 1% reduction in end-use consumption (energy and demand) and distribution circuit losses (energy and demand). Of that 1% power consumption reduction at the circuit level, approximately 96% is end-use consumption reduction and 4% is loss reduction.

Energy and demand savings occur when CVR is applied to distribution circuits. Once applied, a step change in energy and demand consumption by customers is realized, dependent upon where customer loads are located within the voltage zones, the load characteristics of the circuit, and how end-use loads respond to the voltage reduction. The resultant energy and demand consumption reduction persists at the new levels as long as tighter voltage bandwidth operation is applied. As a result, ongoing energy and demand savings persists for the duration of the life of the CVR equipment and as long as the equipment is maintained and operated in the voltage bandwidth mode.

Eligible Customers

Vectren South has identified substations that will benefit from the CVR program. For this program, one substation will be selected for implementation in 2017.

Barriers/Theory

CVR is both a DR and an EE program. First, it seeks to cost effectively deploy new technology to targeted distribution circuits, in part to reduce the peak demand experienced on Vectren's electrical power supply system. The voltage reduction stemming from the CVR program operates to effectively reduce consumption during the times in which system peaks are set and as a result directly reduces peak demand. CVR also cost effectively reduces the level of ongoing energy consumption by end-use devices located on the customer side of the utility meter as many end-use devices consume less energy with lower voltages consistently applied. Like an equipment maintenance service program, the voltage optimization allows the customer’s equipment to operate at optimum levels which saves energy without requiring direct customer intervention or change.

Initial Measures, Products and Services

Vectren South will install the required communication and control equipment on the appropriate circuits from the substation. No action is required of the customers.

Table 55. Conservation Voltage Reduction (CVR) Program Budget & Energy Savings Targets

With Commission approval, Vectren South will capitalize the costs to implement the CVR program and will seek to recover through the annual DSMA Rider the carrying costs and depreciation expense associated with the implementation along with annual, ongoing Operation and Maintenance ("O&M") expense, a representative share of Vectren South's DSM support staff and administration costs and related EM&V cost. The budget below is reflective of this request.

Market	Program	2016	2017	Total Program
Residential	Conservation Voltage Reduction			
	Number of Participants	0	5,324	5,324
	Energy Savings kWh	0	1,481,669	1,481,669
	Peak Demand kW	0	508	508
	Total Program Budget $	$20,000	$166,861	$186,861
	Per Participant Avg Energy Savings (kWh)*			278.3
	Per Participant Avg Demand Savings (kW)*			0.095
	Weighted Avg Measure Life*			15
	Net To Gross Ratio			100%

Market	Program	2016	2017	Total Program
Commercial & Industrial	Conservation Voltage Reduction			
	Number of Participants	0	558	558
	Energy Savings kWh	0	875,044	875,044
	Peak Demand kW	0	163	163
	Total Program Budget $	$20,000	$117,146	$137,147
	Per Participant Avg Energy Savings (kWh)*			1,568.2
	Per Participant Avg Demand Savings (kW)*			0.292
	Weighted Avg Measure Life*			15
	Net To Gross Ratio			100%

Table 56. Conservation Voltage Reduction (CVR) Estimated Energy Savings & Budget

Residential	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Conservation Voltage Reduction	1,481,669	508	$40,000	$68,891	$77,970	$0	$186,861
2016	0	0	$20,000	$0	$0	$0	$20,000
2017	1,481,669	508	$20,000	$68,891	$77,970	$0	$166,861

Commercial & Industrial	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Conservation Voltage Reduction	875,044	163	$40,000	$40,685	$56,461	$0	$137,146
2016	0	0	$20,000	$0	$0	$0	$20,000
2017	875,044	163	$20,000	$40,685	$56,461	$0	$117,146

Total	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Conservation Voltage Reduction	2,356,713	671	$80,000	$109,576	$134,431	$0	$324,007
2016	0	0	$40,000	$0	$0	$0	$40,000
2017	2,356,713	671	$40,000	$109,576	$134,431	$0	$284,007

Table 57. Conservation Voltage Reduction (CVR) Cost Effectiveness

For the purpose of determining cost-effectiveness of CVR, Vectren South modeled the full implementation cost. While Vectren South plans to install the technology on additional substations, the Company is only requesting authority to complete installation on one substation at this time. The TRC associated with installation of CVR technology on one substation is 1.26, which means the program is cost effective. Vectren South modeled the full implementation cost of CVR and utilized a conservative estimate of two and one half percent (2.5%) voltage reduction level.

Residential	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Conservation Voltage Reduction	1.38	1.38	0.52	NA	$0.06	$0.12	$515,434	$515,434

Commercial & Industrial	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Conservation Voltage Reduction	1.06	1.06	0.51	NA	$0.06	$0.15	$50,032	$50,032

Conservation Voltage Reduction	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Residential and Commercial & Industrial Combined	1.26	1.26	0.52	NA	$0.06	$0.13	$565,467	$565,467

Program Delivery

Delivery of the CVR Program will be achieved through the installation of control logic, telecommunication equipment, and voltage control equipment in order to control the voltage bandwidth on CVR circuits within voltage compliance levels required by the Indiana Utility Regulatory Commission.

Evaluation, Measurement and Verification

A third party evaluator will evaluate the program using standard EM&V protocols.

C. Multi-Family EE Retrofit

Program Description

The Multi-Family EE Retrofit program provides value by directly installing, on a cost-share basis, EE in multi-family common areas and units. Applicable measures include, but are not limited to, the following: high efficiency lighting, occupancy sensors, insulation, air sealing, and electronic commutated motors (ECM). The program helps to identify and install cost effective energy saving measures by providing an on-site energy assessment customized for the facility.

Eligible Customers

Multi-Family properties with Vectren South natural gas and electric service.

Marketing Plan

A highly-targeted marketing strategy will be employed. Recruitment efforts will target property management companies in an effort to secure agreements to address multiple properties through a single point of contact before targeting owners and managers of individual properties. Marketing tactics will include outreach to property management associations, in-person visits to property management firms and properties, and targeted media and mailings.

Barriers/Theory

There are many barriers to multi-family owners and tenants taking energy savings actions. The primary barrier is that the landowner usually does not pay the utility bill and the tenant does not have the authority to take action. This program direct installs low cost energy savings devices to save energy for the tenant and help them with their energy bill while not requiring large investments in improving the property due to the cost-sharing incentive. It is hoped that the landlords will not only take advantage of this program but will then proceed to install larger building improvements through the other program offerings.

Table 58. Multi-Family Energy Efficient Retrofit Program Budget & Energy Savings Targets

Market	Program	2016	2017	Total Program
Commercial & Industrial	**Multi-Family Energy Efficient Retrofit**			
	Number of Units	100	100	200
	Energy Savings kWh	201,785	201,785	403,570
	Peak Demand kW	33	33	66
	Total Program Budget $	$95,081	$95,081	$190,162
	Per Participant Avg Energy Savings (kWh)*			2,017.9
	Per Participant Avg Demand Savings (kW)*			0.330
	Weighted Avg Measure Life*			16
	Net To Gross Ratio			100%

Table 59. Multi-Family Energy Efficient Retrofit Estimated Energy Savings & Budget

Commercial & Industrial	kWh Total	kW	Administration	Other	Implementation	Incentives	Total Program Costs
Multi-Family Energy Efficient Retrofit	403,570	66	$10,000	$9,056	$26,000	$145,106	$190,162
2016	201,785	33	$5,000	$4,528	$13,000	$72,553	$95,081
2017	201,785	33	$5,000	$4,528	$13,000	$72,553	$95,081

Table 60. Multi-Family Energy Efficient Retrofit Cost Effectiveness

Commercial & Industrial	TRC	UCT	RIM	Participant	Lifetime Cost/kWh	1st Year Cost/kWh	TRC NPV $	UCT NPV $
Multi-Family Energy Efficient Retrofit	1.35	2.12	0.75	1.53	$0.03	$0.47	$100,549	$206,130

Program Delivery

Vectren South will oversee the program and may partner with an implementation provider to deliver the program.

Integration with Vectren South Natural Gas

Vectren South will offer this integrated natural gas and electric EE program in its combined natural gas and electric service territory. Vectren South has allocated implementation costs based on the net benefits split between natural gas and electric.

Evaluation, Measurement and Verification

A third party evaluator will evaluate the program using standard EM&V protocols.

VI. Appendix A – Program Measure Listings, Participation and Initial Incentives

Residential

Measures	Program Name	Measure Life	Install Adjusted Savings per unit (kWh)	2016 Total Paticipation	2017 Total Paticipation	NTG	Average Incentive Paid Per Unit	Incremental Cost per unit
Energy Star Specialty CFL V	Residential Lighting	5	32	1,166	0	49%	$2	$10
Energy Star Reflector CFL V	Residential Lighting	5	32	1,166	0	49%	$2	$10
CFL 0-15W	Residential Lighting	5	24	151,592	137,527	49%	$1	$2
CFL 16-20W	Residential Lighting	5	35	9,023	8,186	49%	$1	$3
CFL 21W or Greater	Residential Lighting	5	44	19,851	18,010	49%	$1	$3
LED 7W	Residential Lighting	15	27	9,327	11,695	80%	$6	$16
LED 9W	Residential Lighting	15	30	16,322	21,051	80%	$6	$16
LED 13W	Residential Lighting	15	38	4,663	8,186	80%	$6	$16
LED 22W	Residential Lighting	15	46	466	7,017	80%	$6	$20
Energy Star Reflector LED V	Residential Lighting	15	37	18,653	21,051	80%	$6	$15
Energy Star Fixtures	Residential Lighting	15	49	932	1,169	49%	$8	$30
Energy Star Ceiling Fans	Residential Lighting	10	108	6	6	49%	$15	$86
Compact Fluorescent Lamps V	Home Energy Assessments & Weatherization	5	35	24,000	24,000	88%	$0	$0
Kitchen Aerator V	Home Energy Assessments & Weatherization	10	232	500	500	88%	$0	$0
Bathroom Aerator V	Home Energy Assessments & Weatherization	10	232	500	500	88%	$0	$0
LF Showerhead (Whole House) V	Home Energy Assessments & Weatherization	5	417	1,000	1,000	88%	$0	$0
Pipe Wrap (5', 3/4" Wall) V	Home Energy Assessments & Weatherization	15	65	1,000	1,000	88%	$0	$0
Audit Recommendations V	Home Energy Assessments & Weatherization	1	263	1,000	1,000	88%	$0	$0
Air Sealing	Home Energy Assessments & Weatherization	6	89	15	15	88%	$58	$144
Attic Insulation	Home Energy Assessments & Weatherization	6	1	13,117	13,117	88%	$0.34	$0.85
Wall Insulation	Home Energy Assessments & Weatherization	6	1	5,634	5,634	88%	$0.26	$0.65
Knee Wall Insulation	Home Energy Assessments & Weatherization	6	3	100	100	88%	$0.24	$0.60
Prescriptive Duct Sealing	Home Energy Assessments & Weatherization	6	326	100	100	88%	$208	$520
Programmable Thermostat	Home Energy Assessments & Weatherization	6	176	50	50	88%	$13	$31
Prescriptive Duct Sealing-Ht Pump	Home Energy Assessments & Weatherization	6	894	2	2	88%	$400	$1,000
Programmable Thermostat-Ht Pump	Home Energy Assessments & Weatherization	6	430	2	2	88%	$50	$125
ECM Motor Replacement	Home Energy Assessments & Weatherization	6	733	25	25	88%	$400	$1,000
LED 13 Watt	Home Energy Assessments & Weatherization	6	46	875	875	88%	$15	$38
Assessment	Home Energy Assessments & Weatherization	6	0	125	125	88%	$52	$130

Measures	Program Name	Measure Life	Install Adjusted Savings per unit (kWh)	2016 Total Paticipation	2017 Total Paticipation	NTG	Average Incentive Paid Per Unit	Incremental Cost per unit
Energy Star Specialty CFL V	Income Qualified Weatherization	5	40	8,126	8,126	100%	$0	$0
Energy Star Speciality CFL - Interior	Income Qualified Weatherization	5	31	1,628	1,628	100%	$0	$0
Screw-in LED	Income Qualified Weatherization	15	46	500	500	100%	$0	$0
Smart Power Strips	Income Qualified Weatherization	4	23	250	250	100%	$0	$0
Duct Repair, Seal, Insulation	Income Qualified Weatherization	20	326	56	56	100%	$0	$0
Kitchen Aerator IQW V	Income Qualified Weatherization	10	225	131	131	100%	$0	$0
Bathroom Aerator IQW V	Income Qualified Weatherization	10	225	204	204	100%	$0	$0
LF Showerhead (Whole House) IQW V	Income Qualified Weatherization	5	411	102	102	100%	$0	$0
Pipe Wrap (10', 3/4" Wall) IQW V	Income Qualified Weatherization	15	80	127	127	100%	$0	$0
Furnace Filter Whistle IQW V	Income Qualified Weatherization	15	105	339	339	100%	$0	$0
30% Infil. Reduction Electric Furnace w/ CAC V	Income Qualified Weatherization	15	2,512	43	43	100%	$0	$0
30% Infil. Reduction Heat Pump V	Income Qualified Weatherization	15	1,245	9	9	100%	$0	$0
30% Infil. Reduction Electric Furnace no CAC V	Income Qualified Weatherization	15	2,314	0	0	100%	$0	$0
30% Infil. Reduction Gas Furnace w/ CAC V	Income Qualified Weatherization	15	336	283	283	100%	$0	$0
30% Infil. Reduction Gas Furnace no CAC V	Income Qualified Weatherization	15	38	3	3	100%	$0	$0
Attic Insulation V	Income Qualified Weatherization	15	339	17	17	100%	$0	$0
Refrigerator Replacement IQW V	Income Qualified Weatherization	17	1,251	282	282	100%	$0	$0
Audit Recommendations IQW V	Income Qualified Weatherization	1	155	564	564	100%	$0	$0
IQW Healthy and Safety	Income Qualified Weatherization	1	0	564	564	100%	$0	$0
Programmable Thermostat	Income Qualified Weatherization	15	176	100	100	100%	$0	$0
Whole House Fan	Income Qualified Weatherization	20	338	56	56	100%	$0	$0
Refrigerator Recycling	Appliance Recycling	8	1,092	761	761	53%	$50	$93
Freezer Recycling	Appliance Recycling	8	990	191	191	53%	$50	$93
Low Flow Showerhead	Energy Efficient Schools	5	100	2,400	2,400	96%	$0	$0
Faucet Aerators	Energy Efficient Schools	10	126	2,400	2,400	96%	$0	$0
LED Night Light	Energy Efficient Schools	10	7	2,400	2,400	96%	$0	$0
Filter Tone Alarm	Energy Efficient Schools	10	6	2,400	2,400	96%	$0	$0
9W LED	Energy Efficient Schools	15	21	4,800	4,800	96%	$0	$0
Heat Pump Water Heater	Residential Efficient Products	10	2,076	39	39	90%	$300	$700
Programmable Thermostat	Residential Efficient Products	15	176	350	350	80%	$20	$35
Duct Sealing Gas Heating with A/C	Residential Efficient Products	20	326	175	175	80%	$225	$450
Duct Sealing Electric Heat Pump	Residential Efficient Products	20	756	53	53	80%	$400	$450
Duct Sealing Electric Resistive Furnace	Residential Efficient Products	20	2,878	7	7	80%	$400	$450
Variable Speed Pool Pump	Residential Efficient Products	10	1,170	70	70	80%	$300	$750

Measures	Program Name	Measure Life	Install Adjusted Savings per unit (kWh)	2016 Total Paticipation	2017 Total Paticipation	NTG	Average Incentive Paid Per Unit	Incremental Cost per unit
Pool Heater	Residential Efficient Products	10	4,068	9	9	80%	$1,000	$3,254
Air Source Heat Pump 16 SEER - no gas available	Residential Efficient Products	18	1,025	12	12	51%	$400	$1,439
Air Source Heat Pump 16 SEER -gas available	Residential Efficient Products	18	1,025	12	12	51%	$300	$1,439
Dual Fuel Air Sourc Heat Pump 16 SEER	Residential Efficient Products	18	1,025	12	12	51%	$300	$1,439
Air Source Heat Pump 18 SEER - no gas available	Residential Efficient Products	18	1,170	2	2	80%	$600	$2,398
Air Source Heat Pump 18 SEER - gas available	Residential Efficient Products	18	1,170	2	2	80%	$500	$2,398
Duel Fuel Air Source Heat Pump 18 SEER	Residential Efficient Products	18	1,170	2	2	80%	$500	$2,398
Central Air Conditioner 16 SEER	Residential Efficient Products	18	344	123	123	51%	$300	$714
Central Air Conditioner 18 SEER	Residential Efficient Products	18	462	105	105	80%	$500	$1,192
ECM HVAC Motor	Residential Efficient Products	10	350	350	350	51%	$100	$250
Smart Programmable Thermostat	Residential Efficient Products	15	429	175	175	80%	$100	$200
Ductless Heat Pump 17 SEER 9.5 HSPF	Residential Efficient Products	15	3,939	1	1	80%	$750	$959
Ductless Heat Pump 19 SEER 9.5 HSPF	Residential Efficient Products	15	3,972	1	1	80%	$750	$1,439
Ductless Heat Pump 21 SEER 10.0 HSPF	Residential Efficient Products	15	4,093	1	1	80%	$1,000	$1,918
Ductless Heat Pump 23 SEER 10.0 HSPF	Residential Efficient Products	15	4,115	1	1	80%	$1,000	$2,398
Energy Efficient Room/Window AC	Residential Efficient Products	9	60	150	150	90%	$25	$80
Energy Star Refrigerator-CEE Tier 3	Residential Efficient Products	13	207	185	185	90%	$25	$250
Attic Insulation Integrated	Residential Efficient Products	25	781	212	212	70%	$250	$850
Wall Insulation Integrated	Residential Efficient Products	25	946	124	124	70%	$250	$850
Attic Insulation Electric Only	Residential Efficient Products	15	781	10	10	80%	$450	$850
Wall Insulation Electric Only	Residential Efficient Products	15	946	5	5	80%	$450	$850
Gold Star Vectren South HERS =<65	Residential New Construction	25	1,060	52	52	80%	$450	$1,475
Platinum Star Vectren South HERS =< 60	Residential New Construction	25	1,255	42	42	95%	$500	$1,669
Gold Star Vectren South HERS =<65 All Electric	Residential New Construction	25	4,093	7	7	80%	$900	$2,403
Platinum Star Vectren South HERS =< 60 All Electric	Residential New Construction	25	5,161	2	2	95%	$1,000	$3,792
OPower	Residential Behavior Savings	1	128	48,400	43,500	100%	$0	$0
CFL - 13W	Multi-Family Direct Install	5	44	3,000	3,000	100%	$0	$0
CFL - 23W	Multi-Family Direct Install	5	58	2,000	2,000	100%	$0	$0
Programmable Thermostat	Multi-Family Direct Install	15	176	500	500	95%	$0	$0

Commercial & Industrial

Measures	Program Name	Measure Life	Install Adjusted Savings per unit (kWh)	2016 Total Paticipation	2017 Total Paticipation	NTG	Average Incentive Paid Per Unit	Incremental Cost per unit
Cooler Controller - occupancy sensor V CDI106	Small Business Direct Install	10	1,209	28	28	100%	$0	$0
Faucet Aerators-electric V CDI112	Small Business Direct Install	10	184	20	20	100%	$0	$0
LEDs: >12W Flood V CDI121	Small Business Direct Install	8	231	100	100	100%	$0	$0
LEDs: 8-12W V CDI122	Small Business Direct Install	8	136	164	164	100%	$0	$0
Pre-Rinse Spray Valves - ele V CDI129	Small Business Direct Install	5	7,454	3	3	100%	$0	$0
Showerheads-electric V CDI130	Small Business Direct Install	10	250	1	1	100%	$0	$0
Programmable Thermostat Turn Down	Small Business Direct Install	5	65	20	20	100%	$0	$0
EC Motor Reach-in V CDI110	Small Business Direct Install	15	345	4	4	100%	$56	$150
EC Motor Walk-in V CDI111	Small Business Direct Install	15	392	4	4	100%	$119	$250
LED Fixture <250W, Replacing 400W HID, HighBay V CDI113	Small Business Direct Install	15	660	28	28	100%	$133	$500
LED for Walk in Cooler V CDI114	Small Business Direct Install	16	202	10	10	100%	$40	$300
LED for Walk in Freezer V CDI115	Small Business Direct Install	16	208	10	10	100%	$40	$300
LED Open Sign V CDI116	Small Business Direct Install	12	1,418	200	200	100%	$50	$200
LED Recessed Downlight V CDI117	Small Business Direct Install	15	257	1,165	1,165	100%	$35	$95
LED, Exit Sign, Retrofit V CDI118	Small Business Direct Install	16	83	270	270	100%	$33	$30
LED, Refrigerated Case, Replaces T12 or T8 V CDI119	Small Business Direct Install	16	272	140	140	100%	$60	$300
LEDs: >12W Flood V CDI120	Small Business Direct Install	8	231	169	169	100%	$30	$44
LEDs: 8-12W V CDI123	Small Business Direct Install	8	136	840	840	100%	$23	$35
LEDs: MR16 track V CDI125	Small Business Direct Install	8	165	500	500	100%	$23	$35
Occupancy Sensor, Wall Mount, <=200 Watts V CDI127	Small Business Direct Install	8	186	90	90	100%	$38	$60
T8 6L or T5HO 4L Replacing 400-999 W HID V CDI135	Small Business Direct Install	12	1,139	305	305	100%	$133	$300
Programmable Thermostat CDI137	Small Business Direct Install	5	905	125	125	100%	$130	$125
Strip Curtains Cooler CDI144	Small Business Direct Install	4	422	2	2	100%	$157	$445
Strip Curtains Freezer CDI145	Small Business Direct Install	4	2,974	2	2	100%	$157	$445
1 Lamp 4ft T12 to 1 Lamp 4ft 28W or 25W T8	Small Business Direct Install	10	79	400	400	100%	$18	$95
2 Lamp 4ft T12 to 2 Lamp 4ft 28W or 25W T8	Small Business Direct Install	10	100	1,480	1,480	100%	$22	$97
3 Lamp 4ft T12 to 3 Lamp 4ft 28W or 25W T8	Small Business Direct Install	10	181	100	100	100%	$30	$97
4 Lamp 4ft T12 to 4 Lamp 4ft 28W or 25W T8	Small Business Direct Install	10	206	28	28	100%	$34	$78
1 Lamp 8ft T12 to 2 Lamp 4ft 28W or 25W T8	Small Business Direct Install	10	112	100	100	100%	$23	$78
2 Lamp 8ft T12 to 4 Lamp 4ft 28W or 25W T8	Small Business Direct Install	10	122	10	10	100%	$38	$79
4 Lamp 4ft T12 to 3 Lamp 4ft 28W or 25W T8 - Delamp	Small Business Direct Install	10	297	8	8	100%	$39	$85
4 Lamp 4ft T12 to 2 Lamp 4ft 28W or 25W T8 - Delamp	Small Business Direct Install	10	388	5,000	5,000	100%	$36	$85
3 Lamp 4ft T12 to 2 Lamp 4ft 28W or 25W T8 - Delamp	Small Business Direct Install	10	272	40	40	100%	$36	$93
2 Lamp 4ft T12 to 1 Lamp 4ft 28W or 25W T8 - Delamp	Small Business Direct Install	10	200	58	58	100%	$37	$93
4 Lamp 8ft T12 to 4 Lamp 28W or 25W T8 - Delamp	Small Business Direct Install	10	614	281	281	100%	$50	$95
2 Lamp 2ft T12 U-tube to 2 Lamp 2ft T8 Linear w/ Reflector	Small Business Direct Install	10	160	273	273	100%	$26	$357
2 Lamp 8ft T12 to 2 Lamp 4ft HPT8 w/ Reflector	Small Business Direct Install	10	304	3,000	3,000	100%	$48	$355
LED Exterior <30W	Small Business Direct Install	12	403	350	350	80%	$198	$125
LED Exterior 30W-75W	Small Business Direct Install	12	497	300	300	80%	$226	$250

Measures	Program Name	Measure Life	Install Adjusted Savings per unit (kWh)	2016 Total Paticipation	2017 Total Paticipation	NTG	Average Incentive Paid Per Unit	Incremental Cost per unit
LED Exterior75W+	Small Business Direct Install	12	932	650	650	80%	$337	$375
LED Exterior1000W MH Replacement	Small Business Direct Install	12	3,003	100	100	80%	$506	$750
MH 150W Pulse Start To T5 46" 2 Lamp HO - Turnover	Commercial and Industrial Prescriptive	15	252	158	158	80%	$25	$150
MH 200W Pulse Start To T5 46" 3 Lamp HO - Turnover	Commercial and Industrial Prescriptive	15	194	158	158	80%	$25	$150
MH 320W Pulse Start To T5 46" 4 Lamp HO - Turnover	Commercial and Industrial Prescriptive	15	499	225	225	80%	$40	$150
MH 350W Pulse Start To T5 46" 6 Lamp HO - Turnover	Commercial and Industrial Prescriptive	15	187	113	113	80%	$40	$150
MH 1000W Pulse Start To T5 46" 10 Lamp HO - Turnover	Commercial and Industrial Prescriptive	15	1,886	113	113	80%	$125	$150
MH 1000W Pulse Start To T5 46" 12 Lamp HO - Turnover	Commercial and Industrial Prescriptive	15	1,441	95	95	80%	$125	$150
MH 250W To LED Low Bay 85 W3	Commercial and Industrial Prescriptive	8	800	39	39	80%	$80	$200
T8 HO 96" 2 Lamp To LED Low Bay 85 W3	Commercial and Industrial Prescriptive	8	286	50	50	80%	$40	$200
MH 200W To LED High Bay 139W	Commercial and Industrial Prescriptive	8	354	39	39	80%	$40	$200
MH 250W To LED High Bay 175W	Commercial and Industrial Prescriptive	8	457	194	194	80%	$50	$200
MH 175W To T5 46" 2 Lamp HO - Retrofit	Commercial and Industrial Prescriptive	15	347	158	158	80%	$25	$150
MH 175W To T5 46" 3 Lamp HO - Retrofit	Commercial and Industrial Prescriptive	15	103	158	158	80%	$25	$150
MH 400W To T5 46" 4 Lamp HO - Retrofit	Commercial and Industrial Prescriptive	15	854	225	225	80%	$40	$150
MH 400W To T5 46" 6 Lamp HO - Retrofit	Commercial and Industrial Prescriptive	15	408	225	225	80%	$40	$150
MH 1000W To T5 46" 10 Lamp HO - Retrofit	Commercial and Industrial Prescriptive	15	1,886	113	113	80%	$125	$150
MH 1000W To T5 46" 12 Lamp HO - Retrofit	Commercial and Industrial Prescriptive	15	1,441	63	63	80%	$125	$150
Fluorescent Exit Sign To LED Exit Sign	Commercial and Industrial Prescriptive	16	83	911	911	80%	$20	$30
Incandescent Traffic Signal To LED Traffic Signal Round 8" Red	Commercial and Industrial Prescriptive	10	299	61	61	80%	$30	$120
Incandescent Traffic Signal To LED Traffic Signal Pedestrian 12"	Commercial and Industrial Prescriptive	10	946	61	61	80%	$50	$200
Incandescent To CFL <15W Screw-In	Commercial and Industrial Prescriptive	3	92	305	305	80%	$2	$3
Incandescent To CFL 16-20W Screw-In	Commercial and Industrial Prescriptive	3	128	130	130	80%	$2	$3
Incandescent To CFL 21W+ Screw-In	Commercial and Industrial Prescriptive	3	165	25	25	80%	$5	$5
T12 48” 1 Lamp To Delamp	Commercial and Industrial Prescriptive	10	149	845	845	80%	$5	$0
T12 96” 1 Lamp To Delamp	Commercial and Industrial Prescriptive	10	286	384	384	80%	$5	$0
T12 46" 1 Lamp To T5 46" 1 Lamp	Commercial and Industrial Prescriptive	10	46	62	62	80%	$6	$25
T12 46" 2 Lamp To T5 46" 2 Lamp	Commercial and Industrial Prescriptive	10	91	185	185	80%	$9	$25
T12 46" 3 Lamp To T5 46" 3 Lamp	Commercial and Industrial Prescriptive	10	137	123	123	80%	$12	$25
T12 46" 4 Lamp To T5 46" 4 Lamp	Commercial and Industrial Prescriptive	10	191	246	246	80%	$15	$25
HID 75W-100W To T5 Garage 1 Lamp	Commercial and Industrial Prescriptive	7	76	156	156	80%	$35	$150
HID 101W-175W To T5 Garage 2 Lamp	Commercial and Industrial Prescriptive	7	114	156	156	80%	$60	$150
HID 176W+ To T5 Garage 3 Lamp	Commercial and Industrial Prescriptive	7	152	78	78	80%	$94	$150
LED Decoratives 2-4W	Commercial and Industrial Prescriptive	6	65	21	21	80%	$10	$29
LED A-Line 8-12W	Commercial and Industrial Prescriptive	6	118	371	371	80%	$10	$29
LED PAR 20 7-9W	Commercial and Industrial Prescriptive	8	100	53	53	80%	$10	$40
LED PAR 30 10-13W	Commercial and Industrial Prescriptive	8	114	212	212	80%	$10	$40
LED PAR 38 10-21W	Commercial and Industrial Prescriptive	8	193	350	350	80%	$20	$50
LED MR16 4-7W	Commercial and Industrial Prescriptive	8	71	53	53	80%	$15	$40
LED Outdoor Decorative Post <30W	Commercial and Industrial Prescriptive	12	403	42	42	80%	$50	$125

Measures	Program Name	Measure Life	Install Adjusted Savings per unit (kWh)	2016 Total Paticipation	2017 Total Paticipation	NTG	Average Incentive Paid Per Unit	Incremental Cost per unit
LED Outdoor Decorative Post 30W-75W	Commercial and Industrial Prescriptive	12	497	32	32	80%	$100	$250
LED Outdoor Decorative Post 75W+	Commercial and Industrial Prescriptive	12	932	32	32	80%	$150	$375
LED Parking Garage/Canopy <30W	Commercial and Industrial Prescriptive	12	403	28	28	80%	$50	$125
LED Parking Garage/Canopy 30W-75W	Commercial and Industrial Prescriptive	12	497	21	21	80%	$100	$250
LED Parking Garage/Canopy 75W+	Commercial and Industrial Prescriptive	12	932	21	21	80%	$150	$375
LED Exterior Wall-Pack <30W	Commercial and Industrial Prescriptive	12	403	50	50	80%	$50	$125
LED Exterior Wall-Pack 30W-75W	Commercial and Industrial Prescriptive	12	497	50	50	80%	$100	$250
LED Exterior Wall-Pack 75W+	Commercial and Industrial Prescriptive	12	932	50	50	80%	$150	$375
T8 U-Tube 2 Lamp 2' To LED U-Tube	Commercial and Industrial Prescriptive	12	61	19	19	80%	$75	$75
T8 3 Lamp 4' To LED 2 Lamp Linear 4'	Commercial and Industrial Prescriptive	12	131	115	115	80%	$125	$125
T8 2 Lamp 4' To LED 1 Lamp Linear 4'	Commercial and Industrial Prescriptive	12	102	249	249	80%	$100	$100
No controls To Wall-Mounted Occupancy Sensors	Commercial and Industrial Prescriptive	8	286	222	222	80%	$20	$42
No controls To Ceiling-Mounted Occupancy Sensors	Commercial and Industrial Prescriptive	8	560	222	222	80%	$20	$66
No controls To Fixture Mounted Occupancy Sensors	Commercial and Industrial Prescriptive	8	143	200	200	80%	$15	$125
No controls To Remote-Mounted Daylight Dimming Sensors	Commercial and Industrial Prescriptive	8	560	11	11	80%	$20	$65
No controls To Fixture Mounted Daylight Dimming Sensors	Commercial and Industrial Prescriptive	8	143	28	28	80%	$15	$50
No controls To Switching Controls for Multi-Level Lighting	Commercial and Industrial Prescriptive	8	143	28	28	80%	$20	$274
No controls To Central Lighting Controls (Timeclocks)	Commercial and Industrial Prescriptive	8	187	11	11	80%	$25	$103
Vending Machine Occ Sensor - Refrigerated Beverage	Commercial and Industrial Prescriptive	5	1,612	222	222	80%	$50	$216
Vending Machine Occ Sensor - Refrigerated Glass Front Cooler	Commercial and Industrial Prescriptive	5	1,209	7	7	80%	$50	$216
VFD Return Fan <20hp - Hospital	Commercial and Industrial Prescriptive	15	1,907	7	7	80%	$40	$199
VFD Tower Fan <20hp - Hospital	Commercial and Industrial Prescriptive	15	855	7	7	80%	$40	$199
VFD CHW Pump <20hp - Hospital	Commercial and Industrial Prescriptive	15	6,714	7	7	80%	$40	$199
VFD HW Pump <20hp - Hospital	Commercial and Industrial Prescriptive	15	5,696	3	3	80%	$40	$199
VFD CW Pump <20hp - Hospital	Commercial and Industrial Prescriptive	15	2,034	3	3	80%	$40	$199
VFD Return Fan <20hp - Hotel	Commercial and Industrial Prescriptive	15	150	4	4	80%	$40	$199
VFD Tower Fan <20hp - Hotel	Commercial and Industrial Prescriptive	15	1,176	7	7	80%	$40	$199
VFD CHW Pump <20hp - Hotel	Commercial and Industrial Prescriptive	15	6,776	4	4	80%	$40	$199
VFD HW Pump <20hp - Hotel	Commercial and Industrial Prescriptive	15	7,162	1	1	80%	$40	$199
VFD CW Pump <20hp - Hotel	Commercial and Industrial Prescriptive	15	73	1	1	80%	$40	$199
VFD Return Fan <20hp - Large Office	Commercial and Industrial Prescriptive	15	1,387	7	7	80%	$40	$199
VFD Tower Fan <20hp - Large Office	Commercial and Industrial Prescriptive	15	62	7	7	80%	$40	$199
VFD CHW Pump <20hp - Large Office	Commercial and Industrial Prescriptive	15	3,893	7	7	80%	$40	$199
VFD HW Pump <20hp - Large Office	Commercial and Industrial Prescriptive	15	3,806	3	3	80%	$40	$199
VFD CW Pump <20hp - Large Office	Commercial and Industrial Prescriptive	15	1,047	3	3	80%	$40	$199
VFD Compressor	Commercial and Industrial Prescriptive	15	944	20	20	80%	$75	$300
HID To Induction Lamp and Fixture 55-100W	Commercial and Industrial Prescriptive	16	114	6	6	80%	$20	$200
HID To Induction Lamp and Fixture >100W	Commercial and Industrial Prescriptive	16	381	53	53	80%	$40	$800
Barrel Wraps (Inj Mold Only)	Commercial and Industrial Prescriptive	5	1,439	7	7	80%	$40	$80
Clothes Washer CEE Tier 2	Commercial and Industrial Prescriptive	10	542	1	1	80%	$60	$475

Measures	Program Name	Measure Life	Install Adjusted Savings per unit (kWh)	2016 Total Paticipation	2017 Total Paticipation	NTG	Average Incentive Paid Per Unit	Incremental Cost per unit
Clothes Washer CEE Tier 3	Commercial and Industrial Prescriptive	10	542	1	1	80%	$70	$604
Clothes Washer ENERGY STAR/CEE Tier 1	Commercial and Industrial Prescriptive	10	542	1	1	80%	$50	$347
Cooler - Glass Door <15 vol	Commercial and Industrial Prescriptive	12	957	1	1	80%	$50	$143
Cooler - Glass Door >50 vol	Commercial and Industrial Prescriptive	12	1,037	1	1	80%	$70	$164
Cooler - Glass Door 15-30 vol	Commercial and Industrial Prescriptive	12	617	1	1	80%	$55	$249
Cooler - Glass Door 30-50 vol	Commercial and Industrial Prescriptive	12	845	1	1	80%	$60	$164
Cooler - Reach-In Electronically Commutated (EC) Motor	Commercial and Industrial Prescriptive	15	325	10	10	80%	$35	$50
Cooler - Solid Door <15 vol	Commercial and Industrial Prescriptive	12	496	1	1	80%	$50	$143
Cooler - Solid Door >50 vol	Commercial and Industrial Prescriptive	12	1,688	1	1	80%	$70	$164
Cooler - Solid Door 15-30 vol	Commercial and Industrial Prescriptive	12	617	1	1	80%	$55	$249
Cooler - Solid Door 30-50 vol	Commercial and Industrial Prescriptive	12	951	1	1	80%	$60	$164
Cooler - Walk-In Electronically Commutated (EC) Motor	Commercial and Industrial Prescriptive	15	354	8	8	80%	$35	$50
Cooler Anti-Sweat Heater Controls - Conductivity-Based	Commercial and Industrial Prescriptive	12	700	3	3	80%	$50	$200
Cooler Anti-Sweat Heater Controls - Humidity-Based	Commercial and Industrial Prescriptive	12	550	3	3	80%	$50	$300
Demand Controlled Ventilation - CO	Commercial and Industrial Prescriptive	15	747	3	3	80%	$75	$115
Demand Controlled Ventilation - CO2	Commercial and Industrial Prescriptive	15	747	5	5	80%	$75	$115
Electric Chiller - Air cooled, with condenser	Commercial and Industrial Prescriptive	20	305	1	1	80%	$30	$82
Electric Chiller - Air cooled, without condenser	Commercial and Industrial Prescriptive	20	35	5	5	80%	$10	$82
Electric Chiller - Water Cooled, Centrifugal <150 tons	Commercial and Industrial Prescriptive	20	216	1	1	80%	$30	$125
Electric Chiller - Water Cooled, Centrifugal >300 tons	Commercial and Industrial Prescriptive	20	174	1	1	80%	$30	$69
Electric Chiller - Water Cooled, Centrifugal 150-300 tons	Commercial and Industrial Prescriptive	20	177	1	1	80%	$30	$92
Electric Chiller - Water Cooled, Rotary Screw <150 tons	Commercial and Industrial Prescriptive	20	168	1	1	80%	$30	$83
Electric Chiller - Water Cooled, Rotary Screw >300 tons	Commercial and Industrial Prescriptive	20	178	1	1	80%	$30	$42
Electric Chiller - Water Cooled, Rotary Screw 150-300 tons	Commercial and Industrial Prescriptive	20	181	1	1	80%	$30	$60
Electric Chiller Tune-up - Air cooled, with condenser	Commercial and Industrial Prescriptive	5	186	1	1	80%	$8	$22
Electric Chiller Tune-up - Water Cooled, Centrifugal >300 tons	Commercial and Industrial Prescriptive	5	89	1	1	80%	$8	$22
Electric Chiller Tune-up - Water Cooled, Centrifugal 150-300 tons	Commercial and Industrial Prescriptive	5	96	1	1	80%	$8	$22
Electric Chiller Tune-up - Water Cooled, Rotary Screw >300 tons	Commercial and Industrial Prescriptive	5	92	1	1	80%	$8	$22
Electric Chiller Tune-up - Water Cooled, Rotary Screw 150-300 tons	Commercial and Industrial Prescriptive	5	101	1	1	80%	$8	$22
ENERGY STAR CEE Tier 1 Window\Sleeve\Room AC < 14,000 BTUH	Commercial and Industrial Prescriptive	12	136	1	1	80%	$16	$80
ENERGY STAR Commercial Dishwasher - Door Type, High Temp	Commercial and Industrial Prescriptive	15	14,143	1	1	80%	$500	$500
ENERGY STAR Commercial Dishwasher - Multi-Tank Conveyor, Low Temp	Commercial and Industrial Prescriptive	20	17,465	1	1	80%	$750	$970
ENERGY STAR Commercial Dishwasher - Under Counter, High Temp	Commercial and Industrial Prescriptive	10	7,471	1	1	80%	$350	$1,000
ENERGY STAR Commercial Dishwasher - Under Counter, Low Temp	Commercial and Industrial Prescriptive	10	1,213	1	1	80%	$150	$530
ENERGY STAR Commercial Fryer	Commercial and Industrial Prescriptive	12	983	1	1	80%	$100	$500
ENERGY STAR Commercial Hot Holding Cabinets Full Size	Commercial and Industrial Prescriptive	12	5,256	1	1	80%	$500	$1,110
ENERGY STAR Commercial Hot Holding Cabinets Half Size	Commercial and Industrial Prescriptive	12	1,862	1	1	80%	$250	$1,110
ENERGY STAR Commercial Hot Holding Cabinets Three Quarter Size	Commercial and Industrial Prescriptive	12	2,847	1	1	80%	$350	$1,110
ENERGY STAR Commercial Ice Machine < 500 lb/day harvest rate	Commercial and Industrial Prescriptive	9	397	3	3	80%	$100	$537
ENERGY STAR Commercial Ice Machine >=1000 lb/day harvest rate	Commercial and Industrial Prescriptive	9	1,693	1	1	80%	$250	$2,008
ENERGY STAR Commercial Ice Machine >=500 and <1000 lb/day harvest rate	Commercial and Industrial Prescriptive	9	958	1	1	80%	$175	$1,485

Measures	Program Name	Measure Life	Install Adjusted Savings per unit (kWh)	2016 Total Paticipation	2017 Total Paticipation	NTG	Average Incentive Paid Per Unit	Incremental Cost per unit
ENERGY STAR Commercial Steam Cookers 3 Pan	Commercial and Industrial Prescriptive	12	5,183	1	1	80%	$750	$3,500
ENERGY STAR Commercial Steam Cookers 4 Pan	Commercial and Industrial Prescriptive	12	5,488	1	1	80%	$1,000	$3,500
ENERGY STAR Commercial Steam Cookers 5 Pan	Commercial and Industrial Prescriptive	12	6,410	1	1	80%	$1,250	$3,500
ENERGY STAR Commercial Steam Cookers 6 Pan	Commercial and Industrial Prescriptive	12	6,972	1	1	80%	$1,500	$3,500
ENERGY STAR Convection Oven	Commercial and Industrial Prescriptive	12	3,235	1	1	80%	$350	$1,113
ENERGY STAR Griddles	Commercial and Industrial Prescriptive	12	6,996	1	1	80%	$700	$2,090
ENERGY STAR Window\Sleeve\Room AC < 14,000 BTUH	Commercial and Industrial Prescriptive	12	136	1	1	80%	$12	$40
ENERGY STAR Window\Sleeve\Room AC >= 14,000 BTUH	Commercial and Industrial Prescriptive	12	215	1	1	80%	$14	$40
ENERGY STAR CEE Tier 2 Window\Sleeve\Room AC < 14,000 BTUH	Commercial and Industrial Prescriptive	12	117	1	1	80%	$20	$250
ENERGY STAR CEE Tier 2 Window\Sleeve\Room AC >= 14,000 BTUH	Commercial and Industrial Prescriptive	12	206	1	1	80%	$22	$500
Freezer - Glass Door <15 vol	Commercial and Industrial Prescriptive	12	1,338	1	1	80%	$100	$142
Freezer - Glass Door >50 vol	Commercial and Industrial Prescriptive	12	8,579	1	1	80%	$350	$407
Freezer - Glass Door 15-30 vol	Commercial and Industrial Prescriptive	12	2,226	1	1	80%	$150	$166
Freezer - Glass Door 30-50 vol	Commercial and Industrial Prescriptive	12	4,407	1	1	80%	$200	$166
Freezer - Reach-In Electronically Commutated (EC) Motor	Commercial and Industrial Prescriptive	15	409	1	1	80%	$45	$50
Freezer - Solid Door <15 vol	Commercial and Industrial Prescriptive	12	458	1	1	80%	$100	$142
Freezer - Solid Door >50 vol	Commercial and Industrial Prescriptive	12	5,488	1	1	80%	$350	$407
Freezer - Solid Door 15-30 vol	Commercial and Industrial Prescriptive	12	868	1	1	80%	$150	$166
Freezer - Solid Door 30-50 vol	Commercial and Industrial Prescriptive	12	3,074	1	1	80%	$200	$166
Freezer - Walk-In Electronically Commutated (EC) Motor	Commercial and Industrial Prescriptive	15	620	1	1	80%	$45	$50
Freezer Anti-Sweat Heater Controls - Conductivity-Based	Commercial and Industrial Prescriptive	12	1,483	3	3	80%	$100	$200
Freezer Anti-Sweat Heater Controls - Humidity-Based	Commercial and Industrial Prescriptive	12	1,165	3	3	80%	$100	$300
Heat Pump Water Heater 10-50 MBH	Commercial and Industrial Prescriptive	15	2,903	3	3	80%	$2,000	$4,000
HID >400W to Exterior LED or Induction	Commercial and Industrial Prescriptive	16	3,266	75	75	80%	$200	$2
HID >400W to Garage LED or Induction	Commercial and Industrial Prescriptive	16	3,266	25	25	80%	$200	$2
High Efficiency Pumps - 1.5hp	Commercial and Industrial Prescriptive	15	617	1	1	80%	$60	$350
High Efficiency Pumps - 10hp	Commercial and Industrial Prescriptive	15	5,952	1	1	80%	$240	$332
High Efficiency Pumps - 15hp	Commercial and Industrial Prescriptive	15	7,848	1	1	80%	$280	$585
High Efficiency Pumps - 20hp	Commercial and Industrial Prescriptive	15	7,246	1	1	80%	$320	$850
High Efficiency Pumps - 2hp	Commercial and Industrial Prescriptive	15	900	1	1	80%	$100	$350
High Efficiency Pumps - 3hp	Commercial and Industrial Prescriptive	15	1,841	1	1	80%	$120	$350
High Efficiency Pumps - 5hp	Commercial and Industrial Prescriptive	15	3,528	1	1	80%	$160	$341
High Efficiency Pumps - 7.5hp	Commercial and Industrial Prescriptive	15	5,438	3	3	80%	$200	$498
Low Flow Pre-Rinse Sprayer - Electric	Commercial and Industrial Prescriptive	5	3,727	1	1	80%	$25	$35
MH 1000W To T8VHO 48" 8 Lamp (2 fixtures)	Commercial and Industrial Prescriptive	7	1,921	5	5	80%	$125	$150
MH 250W To T8VHO 48" 4 Lamp	Commercial and Industrial Prescriptive	7	549	20	20	80%	$50	$150
MH 400W To T8VHO 48" 6 Lamp	Commercial and Industrial Prescriptive	7	884	20	20	80%	$60	$150
MH 400W To T8VHO 48" 8 Lamp	Commercial and Industrial Prescriptive	7	648	5	5	80%	$60	$150
Network PC Power Management Software	Commercial and Industrial Prescriptive	4	135	10	10	80%	$3	$12
No Controls To Ceiling-Mounted Occupancy Sensors >500W Connected	Commercial and Industrial Prescriptive	8	1,143	10	10	80%	$40	$66
No Controls To Central Lighting Controls (Timeclocks) >500W Connected	Commercial and Industrial Prescriptive	8	381	1	1	80%	$20	$103
No Controls To Fixture Mounted Daylight Dimming Sensors >500W Connected	Commercial and Industrial Prescriptive	8	1,143	20	20	80%	$40	$50

Measures	Program Name	Measure Life	Install Adjusted Savings per unit (kWh)	2016 Total Paticipation	2017 Total Paticipation	NTG	Average Incentive Paid Per Unit	Incremental Cost per unit
No Controls To LED Case Lighting Sensor Controls	Commercial and Industrial Prescriptive	8	675	10	10	80%	$30	$130
No Controls To Remote-Mounted Daylight Dimming Sensors >500W Connected	Commercial and Industrial Prescriptive	8	1,143	3	3	80%	$30	$65
No Controls To Switching Controls for Multi-Level Lighting >500W Connected	Commercial and Industrial Prescriptive	8	1,143	3	3	80%	$30	$274
No Controls To Wall-Mounted Occupancy Sensors >500W Connected	Commercial and Industrial Prescriptive	8	1,143	10	10	80%	$30	$42
Outside Air Economizer with Dual-Enthalpy Sensors	Commercial and Industrial Prescriptive	10	350	1	1	80%	$50	$400
Packaged Terminal Air Conditioner (PTAC) <65,000 BtuH	Commercial and Industrial Prescriptive	15	669	20	20	80%	$75	$500
Packaged Terminal Air Conditioner (PTAC) 65,000-135,000 BtuH	Commercial and Industrial Prescriptive	15	1,341	10	10	80%	$150	$1,000
Packaged Terminal Heat Pump (PTHP) <65,000 BtuH	Commercial and Industrial Prescriptive	15	669	20	20	80%	$75	$500
Packaged Terminal Heat Pump (PTHP) 65,000-135,000 BtuH	Commercial and Industrial Prescriptive	15	1,341	10	10	80%	$150	$1,000
Pellet Dryer Duct Insulation 3in -8in dia	Commercial and Industrial Prescriptive	5	347	10	10	80%	$30	$65
Plug Load Occupancy Sensors	Commercial and Industrial Prescriptive	8	169	10	10	80%	$20	$70
PSMH 1000W To T8VHO 48" 8 Lamp (2 fixtures)	Commercial and Industrial Prescriptive	15	1,921	5	5	80%	$60	$150
Refrigerated Case Covers	Commercial and Industrial Prescriptive	5	158	4	4	80%	$15	$42
Smart Strip Plug Outlet	Commercial and Industrial Prescriptive	8	24	10	10	80%	$15	$15
Snack Machine Controller (Non-refrigerated vending)	Commercial and Industrial Prescriptive	5	343	10	10	80%	$30	$108
Split System Heat Pump <65,000 BtuH	Commercial and Industrial Prescriptive	15	669	1	1	80%	$75	$500
Split System Heat Pump 135,000-240,000 BtuH	Commercial and Industrial Prescriptive	15	1,966	4	4	80%	$250	$1,500
Split System Heat Pump 240,000-760,000 BtuH	Commercial and Industrial Prescriptive	15	3,120	2	2	80%	$400	$4,500
Split System Heat Pump 65,000-135,000 BtuH	Commercial and Industrial Prescriptive	15	1,341	4	4	80%	$150	$1,000
Split System Unitary Air Conditioner <65,000 BtuH	Commercial and Industrial Prescriptive	15	669	15	15	80%	$75	$500
Split System Unitary Air Conditioner >760,000 BtuH	Commercial and Industrial Prescriptive	15	3,253	4	4	80%	$500	$6,500
Split System Unitary Air Conditioner 135,000-240,000 BtuH	Commercial and Industrial Prescriptive	15	1,966	3	3	80%	$250	$1,500
Split System Unitary Air Conditioner 240,000-760,000 BtuH	Commercial and Industrial Prescriptive	15	3,120	3	3	80%	$400	$4,500
Split System Unitary Air Conditioner 65,000-135,000 BtuH	Commercial and Industrial Prescriptive	15	1,341	8	8	80%	$150	$1,000
T12 6' To Refrigerated Display Case Lighting 6' LED - Cooler	Commercial and Industrial Prescriptive	8	252	25	25	80%	$40	$250
T12 6' To Refrigerated Display Case Lighting 6' LED - Freezer	Commercial and Industrial Prescriptive	8	252	20	20	80%	$40	$250
T8 5' To Refrigerated Display Case Lighting 5' LED - Cooler	Commercial and Industrial Prescriptive	8	145	5	5	80%	$25	$250
T8 5' To Refrigerated Display Case Lighting 5' LED - Freezer	Commercial and Industrial Prescriptive	8	145	5	5	80%	$25	$250
T8 To 21" Tubular Skylight/Light Tube	Commercial and Industrial Prescriptive	10	413	3	3	80%	$50	$500
VFD CHW Pump 20-100hp - Hospital	Commercial and Industrial Prescriptive	15	402,820	1	1	80%	$2,400	$6,530
VFD CHW Pump 20-100hp - Hotel	Commercial and Industrial Prescriptive	15	406,540	1	1	80%	$2,400	$6,530
VFD CHW Pump 20-100hp - Large Office	Commercial and Industrial Prescriptive	15	233,560	1	1	80%	$2,400	$6,530
VFD CW Pump 20-100hp - Hospital	Commercial and Industrial Prescriptive	15	122,020	1	1	80%	$2,400	$6,530
VFD CW Pump 20-100hp - Hotel	Commercial and Industrial Prescriptive	15	4,380	1	1	80%	$2,400	$6,530
VFD CW Pump 20-100hp - Large Office	Commercial and Industrial Prescriptive	15	62,840	1	1	80%	$2,400	$6,530
VFD HW Pump 20-100hp - Hospital	Commercial and Industrial Prescriptive	15	341,760	1	1	80%	$2,400	$6,530
VFD HW Pump 20-100hp - Hotel	Commercial and Industrial Prescriptive	15	429,740	1	1	80%	$2,400	$6,530
VFD HW Pump 20-100hp - Large Office	Commercial and Industrial Prescriptive	15	228,340	1	1	80%	$2,400	$6,530
VFD Return Fan 20-100hp - Hospital	Commercial and Industrial Prescriptive	15	114,420	1	1	80%	$2,400	$6,530
VFD Return Fan 20-100hp - Hotel	Commercial and Industrial Prescriptive	15	9,000	1	1	80%	$2,400	$6,530
VFD Return Fan 20-100hp - Large Office	Commercial and Industrial Prescriptive	15	83,220	1	1	80%	$2,400	$6,530
VFD Supply Fan <100hp - Hospital	Commercial and Industrial Prescriptive	15	132,300	1	1	80%	$2,400	$6,530

Measures	Program Name	Measure Life	Install Adjusted Savings per unit (kWh)	2016 Total Paticipation	2017 Total Paticipation	NTG	Average Incentive Paid Per Unit	Incremental Cost per unit
VFD Supply Fan <100hp - Hotel	Commercial and Industrial Prescriptive	15	3,540	1	1	80%	$2,400	$6,530
VFD Supply Fan <100hp - Large Office	Commercial and Industrial Prescriptive	15	106,920	1	1	80%	$2,400	$6,530
VFD Tower Fan 20-100hp - Hospital	Commercial and Industrial Prescriptive	15	51,320	1	1	80%	$2,400	$6,530
VFD Tower Fan 20-100hp - Hotel	Commercial and Industrial Prescriptive	15	70,560	1	1	80%	$2,400	$6,530
VFD Tower Fan 20-100hp - Large Office	Commercial and Industrial Prescriptive	15	3,700	1	1	80%	$2,400	$6,530
Window Film	Commercial and Industrial Prescriptive	10	4	25	25	80%	$3	$3
T8 1L 4', 28W, CEE V	Commercial and Industrial Prescriptive	12	25	285	285	80%	$4	$33
T8 2L 4', 28W, CEE V	Commercial and Industrial Prescriptive	12	50	1,500	1,500	80%	$7	$67
T8 4L 4', 28W, CEE V	Commercial and Industrial Prescriptive	12	80	800	800	80%	$14	$93
T8 3L 4', 28W, CEE V	Commercial and Industrial Prescriptive	12	79	320	320	80%	$11	$80
EDA - Lighting Power Density Reduction	Commercial & Industrial New Construction	15	72,000	4	5	95%	$6,840	$10,274
EDA - Non Lighting Measures	Commercial & Industrial New Construction	10	45,000	4	4	95%	$4,275	$12,400
EDA - Design Team Participation Incentives - Small Buildings	Commercial & Industrial New Construction	10	0	1	1	95%	$750	$750
EDA - Design Team Participation Incentives - Med Buildings	Commercial & Industrial New Construction	10	0	3	3	95%	$2,500	$2,500
EDA - Design Team Participation Incentives - Large Buildings	Commercial & Industrial New Construction	10	0	1	1	95%	$5,000	$5,000
Commercial & Industrial Custom Project	Commercial & Industrial Custom	11	116,252	22	25	99%	$13,970	$66,551
MF- Duct Repair and Sealing	Multi-Family Energy Efficient Retrofit	15	271	50	50	100%	$114	$152
MF-Programmable thermostat	Multi-Family Energy Efficient Retrofit	20	115	50	50	100%	$90	$120
MF-Infiltration Upgrade	Multi-Family Energy Efficient Retrofit	5	562	90	90	100%	$9	$12
MF-Refrigerator Early Replacement	Multi-Family Energy Efficient Retrofit	10	226	5	5	100%	$205	$273
General Assessment	Multi-Family Energy Efficient Retrofit	20	0	100	100	100%	$0	$125
LED Exit Signs	Multi-Family Energy Efficient Retrofit	16	83	40	40	100%	$10	$30
4' T8 32W Lamps, Utility Space	Multi-Family Energy Efficient Retrofit	10	88	80	80	100%	$12	$36
4' T8 32W Lamps, Hallway	Multi-Family Energy Efficient Retrofit	10	193	80	80	100%	$7	$21
Occupancy Sensor	Multi-Family Energy Efficient Retrofit	8	701	20	20	100%	$25	$75
MF - ECM	Multi-Family Energy Efficient Retrofit	10	733	100	100	100%	$83	$250

Confidential Attachment 5.2 CCGT Site Selection Report
(Not Included in Public Document)

Attachment 5.3 Cost of Energy Efficiency Programs

Energy Efficiency Program Costs, Program Size, and Market Penetration

By

Richard Stevie[1]

1. Introduction

Utility sponsored[2] energy efficiency programs have been implemented in varying degrees for over 20 years across numerous customer segments. Demand response programs, however, have been around for decades beginning with interruptible or off-peak type rate offerings that existed in the 1940's and expanded to include cycling of end-use equipment and more sophisticated dynamic pricing structures.

Besides the fact that the implementation of energy efficiency and demand response programs involves significant complexity in marketing, communication, and cost-effectiveness analysis, information on the costs to implement are very difficult to unravel due to the multi-year life of measures in the portfolio of programs. The major source of historical data on costs and impacts is the Energy Information Administration (EIA) which is part of the Department of Energy. Using Form 861, the EIA has been collecting cost and load impact data, among other items, for energy efficiency and demand response efforts for all utility service areas in the United States since 1990.

This paper focuses only on the costs and load impacts associated with implementation of energy efficiency (EE) programs. Investigation of demand response costs is reserved for future

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[2] For purposes here, utility sponsored includes programs implemented by third parties, including third party administration efforts.

study. The energy efficiency cost and impact information available on the EIA web site includes current year direct program spending, indirect spending (e.g., administrative costs not directly associated with a program), current year energy efficiency MWH and MW impacts, as well as cumulative MWH and MW impacts for each utility service area for the period over which the EIA has been collecting the data[3]. However, the cost and impact data represent totals for the portfolio of energy efficiency programs. Values at the individual program level are not available from the EIA data. For the year 2012, the EIA data on direct plus incentive expenditures for the 50 states plus District of Columbia totaled $4.4 billion. Through this level of spending, the current year retail energy impacts were 21,478,470 MWH which results in a first year[4] cost of $0.205 per kWh. Furthermore, the cumulative[5] EE load impacts reported total 138,524,613 MWH. These on-going cumulative impacts represent the sum of the historical impacts achieved by the programs as reported to EIA.

The issue here is the cost. The value of $.205/kWh represents the total program spending per kWh in one year to gain a stream of kWh savings over the life of the installed measures. If one knew the life of the measures being implemented as well as the relevant discount rate, one could calculate a levelized cost in order to compute a levelized cost per kWh, a commonly used metric for comparing costs across supply-side and demand-side options. For example, for the $0.205/KWh first year costs cited above, if the discount rate were 8% and the measure life averaged to five years, the levelized cost per kWh converts to 5.1 cents/kWh.

To benchmark current costs and project future costs, there are three issues with this analysis. One, the discount rate and relevant measure life are unknown. Changes to either or both

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[3] EIA stated in the past that the cumulative impacts should represent total impacts since 1992. However, this may change in the future as the EIA has indicated it wants to incorporate measure life into these load impact estimates.
[4] First year cost is defined as the total program spending divided by the load impacts achieved in the first year of program implementation.
[5] For clarity, cumulative load impacts, defined as Annual by the EIA, represents the sum of the incremental load impacts.

significantly impact the resulting cost estimate. Two, the number represents an average. The cost for a specific program can vary substantially from this average estimate. And three, the level of historical penetration of EE in any one utility service area can be quite different from the average. In some utility service areas, the cumulative impacts can be large, exceeding 10% of retail sales. In other service areas, the cumulative impacts have been minor, less than 1%. Using an average cost estimate from the EIA data ignores all of the utility specific details that could affect cost. This raises a critical question. As the cumulative market penetration of EE rises, does the cost to achieve further incremental energy efficiency impacts rise or fall or stay the same? One typically expects the marketing cost to attract the early adopters to be somewhat elevated due to the cost of the startup. Then, as the program size expands, there can be some marketing economies of scale driving down the unit cost. But, as the cumulative market penetration rises, the marketing cost per unit to attract additional interest could be expected to rise.

This paper takes a new look at the EIA data in an effort to glean how the level of market penetration could affect unit implementation costs. By examining how the cost of implementing EE programs changes across the states, one can begin to gain insight on the incremental cost of EE through analysis of areas where the market penetration is low versus where it is high.

The following sections provide:

- Brief review of past studies of energy efficiency that reported implementation costs,
- Discussion of the modeling approach,
- Review of issues related to the use of the EIA data,
- Presentation of the modeling results, and
- Summary of the results along with comments on applicability and implications for future research.

2. Past Studies

A large volume of literature has been devoted to studies on energy efficiency and the costs associated with program implementation. Study categories include those that summarize costs and impacts based on other reports (meta-studies) and those that conduct a bottom-up analysis of end-use efficiency. The studies provide estimates of the market potential and the levelized cost to implement energy efficiency. The levelized cost estimates represent an average expected cost for implementing a program or measure or portfolio of programs.

Generally, the focus of these studies has been on market size and cost in a macro perspective, though a few examine the costs associated with individual programs or measures. As the spending on energy efficiency escalates due to energy efficiency portfolio standards (EERS) or potentially new EPA rules[6] requiring energy efficiency impacts of 1.5% of retail sales each year, the cost-effectiveness of energy efficiency programs and measures could change as the market penetration of energy efficiency increases. The research to-date has not provided any insight or guidance on this issue.

The American Council for an Energy Efficient Economy (ACEEE) has produced numerous reports, studies, and meta-studies on energy efficiency market size and cost-effectiveness[7]. The ACEEE reports tend to focus on the estimates of program costs per kWh. In addition to estimating the size of the potential, ACEEE compiled information on unit cost estimates from reports by state utility commissions as well as individual utility reports. While these reports provide a significant

[6] See Section 111d on energy efficiency in the U.S. EPA's GHG Abatement Measures in Docket ID No. EPA-HQ-OAR-2013-0602.

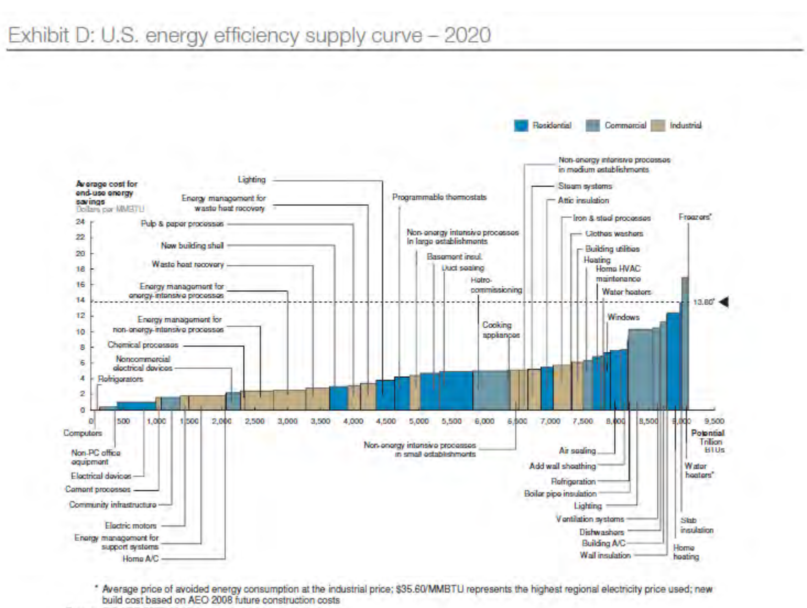
[7] See Chittum (2011), Eldridge et. al. (2010), Elliott et. al. (2007), Friedrich et.al. (2009), Kushler (2004), Laitner et. al. (2012), Nadel and Herndon (2014), Neubauer et. al. (2009), Neubauer and Neal (2012), Neubauer and Elliott et. al. (2009), Shipley and Elliott (2006), and Takahashi and Nichols (2008).

volume of cost related information, none of the reports investigate or estimate how the unit costs might vary as the cumulative market penetration increases.

The Electric Power Research Institute investigated the market potential for EE in two relatively recent reports[8]. These reports also examined program cost-effectiveness as well as market size. But again, neither of these reports provided insight on how the unit costs might vary as the cumulative market penetration increases.

McKinsey & Company also produced a report[9] on EE potential in 2009. In addition to providing estimates of market potential, McKinsey presented a graphical view of the EE supply curve as shown in Figure 1. The chart cleverly combines energy efficiency market potential for each end-use with the average annualized cost to implement the efficiency improvement on a dollars per MMBTU basis. The width of the bars represents the market potential while the height depicts the unit costs.

Figure 1



[8] See Electric Power Research Institute (2014) and Rohrmund et. al. (2008).
[9] See McKinsey & Company (2007) and (2009). See the Executive Summary page 6.

While the chart demonstrates that unit costs will increase as the market potential for the portfolio of programs is achieved, the report does not provide guidance on how the costs vary as the cumulative market penetration changes for each measure.

Several other studies[10] presented estimates of the market potential and/or the unit costs for energy efficiency. However, these studies also do not examine how the unit costs may change as the cumulative market penetration increases.

Four additional studies investigated the presence of economies of scale in the implementation of energy efficiency programs[11]. Two of these[12] essentially relied on the same research results. Both studies reported declines in the unit costs with increases in incremental first year energy saving (as measured by percent of retail sales). However, neither study considered the impact of cumulative market penetration in unit costs. A very recent report[13] published by Lawrence-Berkeley National Laboratory that found a slight decline in the levelized unit cost curve as participation increases for a specific program, appliance recycling. However, the report indicates that this relationship was not statistically significant for any other program studied. While the study claims that cost efficiency exists for this one program, the report does not indicate whether the unit cost estimates could have been influenced by the size of the different markets or whether or not unit costs decline as cumulative market penetration increases.

The fourth study[14] is the first identified to pose the question as to the existence of increasing returns to scale with diminishing marginal returns. In other words, the researchers contend that the unit costs of implementing energy efficiency programs will decline with increases

[10] See Barbose et. al. (2009), Brown et. al. (2010), Cappers and Goldman (2009), Chandler and Brown (2009), Energy Center of Wisconsin (2009), Forefront Economics et. al. (2012), Forefront Economics and H. Gil Peach and Associates (2012), GDS Associates (2006), GDS Associates (2007), Itron, Inc. et. al. (2006), La Capra Associates, Inc. et. al. (2006), McKinsey & Company (2007), Nadel and Herndon (2014), Midwest Energy Alliance (2006), Western Governors' Association (2006), Wilson (2009), and U.S. Department of Energy (2007).
[11] See Billingsley et. al. (2014), Hurley et. al. (2008), Plunkett et. al. (2012), and Takahashi and Nichols (2008).
[12] See reference number Hurley et. al. (2008) and Takahashi and Nichols (2008).
[13] See Billingsley et. al. (2014).
[14] See Plunkett et. al. (2012).

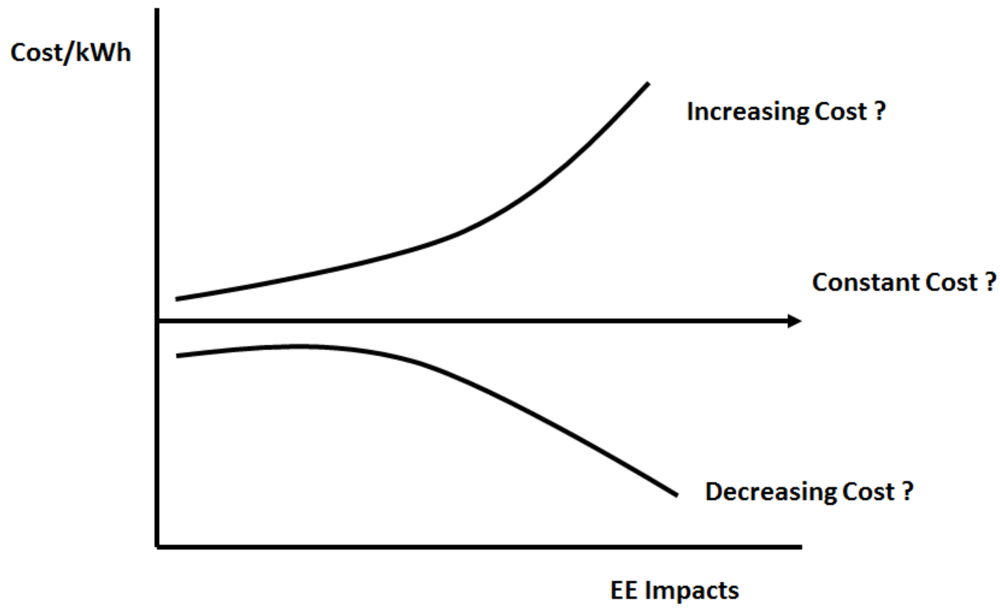
in scale (measured by percent of retail sales), but at some point unit costs for the first year savings will increase due to diminishing returns. The researchers arrive at this conclusion based on an econometric analysis that suffers from over-fitting of the data and an application that leads to a bias in the coefficients[15]. Further, this research only examined unit costs associated with incremental first year savings, not cumulative market penetration. While one of the first studies, if not the first, to pose the right questions, the research falls short of providing any enlightenment on the impact of cumulative market penetration on unit costs.

Finally, one study by Cicchetti[16] conducted extensive analysis on the unit cost of energy efficiency. Using the data compiled by the EIA, Cicchetti computed costs on a first year as well as a levelized basis. Cicchetti conducted an extensive analysis of the costs, however, again there is no insight provided on the impact of market penetration on costs.

In summary, this review of past studies on the costs of energy efficiency reveals that a significant void exists in our understanding of how the implementation costs of energy efficiency are affected by the level of market penetration. Assume for a moment that the cost-effective economic market potential for a utility service area is 20% of retail sales and that the levelized unit cost is assumed to be 5 cents/kWh. Then, the unanswered question is whether or not the 5 cents/kWh cost remains constant as the achieved percent of market potential rises from 10% (of the 20% economic potential) to 50% to 100% (see Figure 2). Can one reasonably assume that the cost to acquire the first 10% of market potential is the same as the cost to acquire the last 10% percent of the market? Or, does the unit cost become higher or lower as the portion of the market potential achieved increases?

[15] The researchers apparently tried multiple mathematical forms until they found the one with the best fit. In addition, besides using a model with specification issues, the researchers boosted the fit of the model by dropping the intercept term, an arbitrary approach that produces biases in coefficients.
[16] See Cicchetti (2009).

Figure 2



The following sections of this study will provide an initial attempt to shed light on this issue.

3. General Model Discussion

The cost of energy efficiency implementation depends significantly on the type of program or measure being implemented. The typical cost components include project administration, marketing, financial incentives paid to customers or marketing channels, and evaluation, measurement and verification. Indirect / overhead costs are not included in this list. Inclusion of indirect items could add another 30% to the total program costs[17].

The key drivers of annual cost are the number of measures or participants (program size) in a given year, which affects the volume of incentive payments and level of marketing. In other words, program size and marketing represent the key factors that influence the level of spending in a given year. Marketing costs will vary by type of program. Some programs can be implemented through direct marketing (e.g., mail, email, door-to-door) while others through marketing channels

[17] The program costs do not include incremental participant costs because the focus here is on the program administration costs which represent the costs recovered from ratepayers.

such as equipment distributors as well as retail suppliers. The issue under investigation here is whether or not the level of marketing and hence program cost is affected by the program size and how much of the market has already been reached. With regard to program size, marketing economies of scale could develop as the current period level of effort rises. However, there is a limit to the program size due to measure life of the end-use. For example, if a heat pump has a 20 year life, not all of the heat-pumps in a utility's service area become available for replacement at a given point in time. Instead, in this example, one can expect that 5% (1/20) of the heat pumps will be replaced each year. While there may be marketing cost efficiency gains in a given year, there is a natural limit based on the available equipment turnover[18]. In addition, as market penetration increases, energy efficiency implementation costs are expected to rise at higher levels of penetration of the market. The degree of impacts on program costs, from these factors, is a question to be empirically analyzed.

In addition to historical market penetration, other drivers that could potentially affect the level of program costs are the level of electric rates and the health of the economy. Regarding customer electric rates, the issue to be investigated here is the whether or not higher electric rates make it easier to market energy efficiency measures. With higher electric rates, the customer bill savings would be greater, thus reducing the payback period and making the investment in energy efficiency more cost-effective for the participating customer. With respect to the health of the economy, many economic measures could be used. The issue at question is whether or not it is tougher to market energy efficiency when the economy is under stress, e.g., during a recession or its aftermath. Since the Great Recession ended in 2009, economic growth has been lackluster and unemployment levels have remained elevated. One could contend that higher unemployment rates make it harder to market energy efficiency because energy consumers do not have the spare

[18] The volume of replacements in this example could exceed 5% if the incentives encourage customers to perform early replacement before the end of the useful life. However, these situations are not the typical expectation.

funds to invest in more efficient equipment. Conversely, one could contend that marketing energy efficiency is easier because energy consumers need to find ways to cut costs. Evidence of a relationship between program costs and electric rates and/or economic health can be explored empirically.

4. General Model Development

Assuming that energy efficiency program costs are affected by program size, historical market penetration, electric rates, and health of the economy, then a model can be specified as follows:

$$Program\ Cost = f(Market\ Size, Market\ Penetration, Electric\ Rate, Economic\ Health) \quad (1)$$

To assess the impact of these factors on program cost first requires obtaining data that can facilitate the analysis. As previously mentioned, the EIA has been collecting aggregate data for each utility jurisdiction on the impacts and costs associated with implementing energy efficiency. A discussion of the data as well as its limitations will be provided in the next section. However, the model variables need further specification for clarity prior to the actual data collection.

To compile a dataset for analysis, the definition of the variables is critical. For purposes of analysis, given the types of data available from the EIA data base, the following variable definitions will be employed:

Dependent variable:

Program cost includes the level of direct program spending (dollars) on energy efficiency programs only. Indirect costs are not included.

Independent variables:

Program size refers to the current year achievement of energy impacts as a percent of current year retail kWh sales. As program size increases, one expects the cost to increase, though it may not be an equal proportional increase due to the potential for marketing efficiencies. For example, the current year market size achieved may be 1% of retail sales in one geographic area, but in another geographic area it may be 2% of retail sales. By studying the relative impact on program spending across multiple areas with different levels of achievement, one can begin to understand how costs change as the size of the program increases.

Market penetration represents the cumulative achievement of energy efficiency sales as a percent of retail kWh sales. For this variable, as the market penetration increases and the available market potential begins to be depleted, the cost to reach deeper into the market potential may increase due to the higher cost to acquire participants who may find that the energy efficiency program offers are less interesting or compelling relative to other demands on their time and financial resources. An analysis of program spending between areas with lower market penetration versus higher market penetration may provide insights on how costs change relative to changes in market penetration.

Electric rate reflects the cost of power ($/kWh) to customers in an area. The electric rate drives the level of bill savings from implementation of the energy efficiency measures. The higher the electric rate, the easier it is for a participant to cost-justify investment in energy efficiency because the bill savings generated by the energy efficiency are greater. In this situation, higher electric rates should make it easier and less costly to market the energy efficiency programs. Including a measure of the average cost of electricity in a region should aid in understanding whether or not electric rates impact energy efficiency marketing.

Health of the economy, the final independent variable under consideration here, can be measured in a number of different ways. For example, the rates of growth in employment, per capita disposable income, or gross national product are all reasonable candidates. At the same time, the unemployment rate provides a good measure of overall economic health that is contemporaneous and reflects the state of consumer well-being as well as business confidence. The interesting issue is whether or not a higher unemployment rate indicates greater difficulty funding energy efficiency or lower difficulty. On the surface, higher unemployment rates would seem to imply that consumers have less cash to invest in energy efficiency, thus potentially raising marketing costs. Conversely, it could also mean that there is more demand for energy efficiency as a way to reduce operating costs. Analysis of this factor should also improve understanding of the drivers of program costs.

In general form, Equation 1 can be re-written as an econometric model as follows:

$$PC = \alpha + \beta 1 \cdot CPR + \beta 2 \cdot CPT + \beta 3 \cdot EP + \beta 4 \cdot UR + \varepsilon \quad (2)$$

where:

PC	=	Program cost or spending
CPR	=	Current kWh impacts as a percent of retail sales
CPT	=	Cumulative kWh impacts as a percent of retail sales
EP	=	Average retail price of electricity adjusted for inflation (real dollars)
UR	=	National unemployment rate
ε	=	Error term

This represents the general form of the econometric model to be developed. It is expected, on an a priori basis, that the signs of the coefficients should be: $\beta 1 > 0$; $\beta 2 > 0$; $\beta 3 < 0$; and $\beta 4 > or < 0$.

The data for the model development will come from the EIA data base as well as national data on the unemployment rate and inflation.

5. Model Data

The Energy Information Administration's (EIA) Form 861 has been utilized to collect a wealth of information on energy efficiency and demand response program spending and load impacts. The EIA data for the years 1990 through 2012 may be found on the EIA website. It contains information on a number of items for each utility service area including the following:

- Direct spending on energy efficiency programs
- Direct spending on load management (demand response or demand side management (DSM)) programs
- Indirect program spending – costs not directly related to a specific program
- Incremental energy efficiency MWH and MW – current year annualized load impacts
- Annual energy efficiency MWH and MW – cumulative load impacts
- Incremental demand response MWH and MW – current year annualized load impacts
- Annual actual demand response MWH and MW – cumulative load impacts
- Incremental potential[19] demand response MWH and MW – cumulative load impacts
- Annual potential demand response MWH and MW – cumulative load impacts
- Information is also available on retail revenues and MWH sold to ultimate customers for each utility service area[20]

[19] Potential impacts reflect the expected load reductions under normal extreme weather conditions as opposed to the actual reductions achieved given the actual weather conditions.
[20] Revenues and sales for utility service areas in deregulated markets require careful handling to ensure a complete picture of revenues and sales.

- Information is also available on state level retail revenues and MWH sold to ultimate customers on EIA Form 826

Data on national inflation and unemployment may be found from numerous sources[21].

Unfortunately, the data collected through the use of EIA Form 861 has several limitations. These limitations include lack of information on the life of the measures in the portfolio of programs, consistency in reporting over time, consistency in treating effects such as free-riders, consistency in reporting program costs versus indirect costs, and impacts due to changes over time in the structure and instructions associated with Form EIA 861.

With respect to measure life, Form EIA 861 seeks data on current year annualized incremental impacts. However, the life expectancy of those impacts is unknown. Impacts from some measures could last 20 years while other associated with behavioral type programs might last just one year and require constant reinforcement to maintain the impacts. For this reason, the analysis conducted here looks at total annual spending relative to the first year impacts. Trying to compute a levelized cost requires knowledge that is just not available. While one might intuit an expected measure life for a portfolio, it is only a guess and could lead to misleading conclusions.
In reviewing the EIA data, it is apparent that the reporting is not consistent. For example, kWh could be reported instead of MWH or dollars instead of thousands of dollars as specified in the instructions to the form. For this reason, this study will focus on the last three years of data for the years 2010 through 2012. Use of the most recent data should provide the best quality of data from the data base.

Regarding cost data, it is unclear what could be included in indirect costs. The categorization of costs across utility service areas will certainly be different, especially with respect

[21] See the website Freelunch.com sponsored by Moody's Analytics for general macroeconomic data including inflation and unemployment.

to treatment of overheads and utility financial incentives. For purposes of this study, only the direct program costs including incentive payments to participants will be considered in the analysis. Finally, to facilitate the research, costs and impact data is aggregated to a state level[22]. This provides a useful data set for the 50 states plus the District of Columbia.

6. Model Development

Using data for the period 2010 to 2012 opens the possibility of taking two approaches to the analysis. In attempting to glean from the data how costs are affected by program size and market penetration, use of multiple approaches can help put a range around an issue afflicted with a lot of uncertainty.

The first approach involves using all the state level data for the 2010 to 2012 time period. This involves estimating a cross-sectional / time-series model. It is cross-sectional given use of data for the 50 states plus the District of Columbia. It is time-series since it covers the period 2010 to 2012. To estimate this model over time with the cross-section requires the use of a fixed-effects panel data modeling approach that captures the underlying relationship between cost and the independent variables while letting the intercept terms capture the inherent underlying differences across the various geographies. The model estimates a separate intercept term for each of the 51 geographic areas while developing estimates for the independent variables that are the same for all the geographic areas. The methodology is designed to uncover the fundamental relationship between cost and the independent variables while differences in the characteristics of each geographic area are captured in the intercept terms.

Algebraically, Model 1, the fixed-effect panel data model, is described as follows:

$$PC_{it} = \alpha_i + \beta 1 \cdot CPR_{it} + \beta 2 \cdot CPT_{it} + \beta 3 \cdot EP_{it} + \beta 4 \cdot UR_t + \varepsilon_{it}) \tag{3}$$

[22] Future research will extend this analysis to an individual utility service area.

where:

PC_{it} = Program costs for geography i during year t

α_i = Constant term for geography i (the fixed-effect)

CPR_{it} = Current kWh impacts as percent of retail sales for geography i during year t

CPT_{it} = Cumulative kWh impacts as percent of retail sales for geography i during year t

EP_{it} = Real electricity price for geography i during year t

UR_t = National unemployment rate for year t

ß = Estimated coefficients for ß1, ß2, ß3, and ß4

ε = Error term for geography i during year t.

The second approach involves using all the data for the most recent year, 2012[23]. This is a traditional cross-sectional approach. Cross-sectional models are extremely useful because they provide a view into the long-run since the data contains multiple points along the continuum of experience. This approach does not require the use of the fixed effects panel data approach. Instead, the model can be estimated using a traditional application of ordinary least squares regression. The model to be estimated is the same as that previous presented by Equation 2.

Algebraically, Model 2, the cross-sectional model, is described as follows:

$$PC_i = \alpha + \beta 1 \cdot CPR_i + \beta 2 \cdot CPT_i + \beta 3 \cdot EP_i + \varepsilon \quad (4)$$

where:

[23] Data for Delaware and Louisiana were deleted since the EIA data indicates essentially zero cumulative impacts for the year 2012.

PC_i = Program cost or spending for geography i

CPR_i = Current kWh impacts as a percent of retail sales for geography i

CPT_i = Cumulative kWh impacts as a percent of retail sales for geography i

EP_i = Real average retail price of electricity for geography i

ε_i = Error term for geography i

The one difference from Equation 2 is that the national variable UR is removed since it would be the same in a given year for all geographic regions.

7. Model Results

Both models were estimated in logarithmic form using the data previously described. The benefit of estimating the model in logarithmic form is that the coefficients represent elasticities that enable one to compute how a percent change in the independent variable results in a coefficient adjusted percent change in the level of program costs. Table 1 below summarizes the results of the statistical analysis for both Model 1 and Model 2.

Table 1			
Model 1			
Variable	Coefficient	t-statistic	Stat Significance
Log (CPR)	0.609	7.761	Yes
Log (CPT)	0.278	3.293	Yes
Log (EP)	-11.980	-1.863	Yes
Log (UR)	2.438	0.769	No
Adjusted R-squared	0.759		Yes
Model 2			
Variable	Coefficient	t-statistic	Stat Significance
Log (CPR)	-0.003	-0.055	No
Log (CPT)	0.897	6.865	Yes
Log (EP)	-0.837	-1.527	Yes at 7% level
Adjusted R-squared	0.543		Yes

For Model 1, the results indicate that strong statistical relationships exist between the level of program cost and program size, market penetration, and real electric price. All three independent variables are statistically significant using a one-tail test given the a priori view of the expected sign for the variables. Only the unemployment rate variable was not statistically significant.

For Model 2, the results indicate that strong statistical relationships exist between the level of program cost and market penetration, and real electric price. The market penetration variable is strongly significant, while the electric price variable is weakly significant. The program size variable is not significant in this model.

These results provide a first insight into the relationship between program costs and program size and market penetration. While the data is aggregate, these results do indicate how these costs can be expected to change. At this point in time, no other study has generated these types of results and insights.

The following section provides an example of how the results can be used to forecast program costs as market penetration increases.

8. Model Application

Often under an Energy Efficiency Resource Standard, there is a requirement to achieve X% cumulative load reduction by a specific year or to reduce load 1% per year for some number of years. Sometimes these values are based upon the results of a market potential study. As an example, let's assume a market potential study concluded that the economic potential over a 20 year period was 20%, or 1% per year. Then, the question becomes: how does the program cost change as one begins to achieve impacts that approach the economic potential, keeping in mind that economic potential implies that 100% of the cost-effective measures are installed?
Given both econometric models previously presented, simulations of the cost impacts can be performed under each model to provide a range on how costs could change as market penetration increases. Another factor to consider is the achievable potential. Data in the EPRI market potential studies[24] indicate that approximately 50% of the economic potential is realistically achievable and that 75% of the economic potential would represent a high achievable potential. Tables 2 and 3 provide examples of how the coefficients from each model can be used to estimate how costs increase as the market penetration increases. Given an economic market potential of 20% of retail sales or 1% per year for 20 years, the achievable potential would be 10% or 0.5% per year, and the high potential would be 15% or .75% per year. The tables depict how average costs change when the market penetration of energy efficiency increases from 50% to 75%.

[24] This applies in the 10 to 20 year time frame. See reference numbers 24 and 25.

Table 2: Impact of Changes in Market Penetration on Program Costs
Simulation of Model 1
Key Assumptions:

Assume the economic market potential is 20% of retail sales.
If the achievable potential is 50% of the market potential, then the achievable potential represents 10% of retail sales.
Increasing achievement from 50% of the market potential to 75% of the market potential impacts the unit cost of EE.
First year cost per kWh saved starts at $.20/kWh
Incremental annual impacts are 1% of retail sales or 100,000,000 kWh per year
The current cumulative market penetration starts at 3% to reflect some existing market presence

EE as % of Retail Sales					Change in Costs
Incremental Impact	Cumulative	Costs (Real $)	Incremental kWh	$/kWh	Due to Change in Cumulative %
1.0%	3.0%	$ 20,000,000	100,000,000	$ 0.2000	
1.0%	4.0%	$ 21,853,333	100,000,000	$ 0.2185	$ 1,853,333
1.0%	5.0%	$ 23,372,140	100,000,000	$ 0.2337	$ 1,518,807
1.0%	6.0%	$ 24,671,631	100,000,000	$ 0.2467	$ 1,299,491
1.0%	7.0%	$ 25,814,750	100,000,000	$ 0.2581	$ 1,143,119
1.0%	8.0%	$ 26,839,964	100,000,000	$ 0.2684	$ 1,025,214
1.0%	9.0%	$ 27,772,653	100,000,000	$ 0.2777	$ 932,689
1.0%	10.0%	$ 28,630,519	100,000,000	$ 0.2863	$ 857,866
1.0%	11.0%	$ 29,426,448	100,000,000	$ 0.2943	$ 795,928
1.0%	12.0%	$ 30,170,134	100,000,000	$ 0.3017	$ 743,687
1.0%	13.0%	$ 30,869,076	100,000,000	$ 0.3087	$ 698,941
1.0%	14.0%	$ 31,529,199	100,000,000	$ 0.3153	$ 660,123
1.0%	15.0%	$ 32,155,279	100,000,000	$ 0.3216	$ 626,080
1.0%	16.0%	$ 32,751,223	100,000,000	$ 0.3275	$ 595,945
1.0%	17.0%	$ 33,320,276	100,000,000	$ 0.3332	$ 569,053
1.0%	18.0%	$ 33,865,161	100,000,000	$ 0.3387	$ 544,885
1.0%	19.0%	$ 34,388,189	100,000,000	$ 0.3439	$ 523,029
1.0%	20.0%	$ 34,891,343	100,000,000	$ 0.3489	$ 503,154
1.0%	21.0%	$ 35,376,332	100,000,000	$ 0.3538	$ 484,990
1.0%	22.0%	$ 35,844,648	100,000,000	$ 0.3584	$ 468,315

	Cost per first year kWh for 50% of economic potential			Cost per first year kWh for next 25% of economic potential	
	Total Cost	$ 198,954,991		Total Cost	$ 154,150,136
	kWh for 50%	800,000,000		kWh for next 25% of retail sales	500,000,000
	Cost per first year kWH	$ 0.249		Cost per first year kWH	$ 0.308
				Percent increase in unt cost	24%
	Model Elasticities				
	Incremental	0.609			
	Cumulative	0.278			

Table 3: Impact of Changes in Market Penetration on Program Costs
Simulation of Model 2
Key Assumptions:

Assume the economic market potential is 20% of retail sales.
If the achievable potential is 50% of the market potential, then the achievable potential represents 10% of retail sales.
Increasing achievement from 50% of the market potential to 75% of the market potential impacts the unit cost of EE.
First year cost per kWh saved starts at $.20/kWh
Incremental annual impacts are 1% of retail sales or 100,000,000 kWh per year
The current cumulative market penetration starts at 3% to reflect some existing market presence

EE as % of Retail Sales					Change in Costs
Incremental Impact	Cumulative	Costs (Real $)	Incremental kWh	$/kWh	Due to Change in Cumulative %
1.0%	3.0%	$ 20,000,000	100,000,000	$ 0.2000	
1.0%	4.0%	$ 25,980,000	100,000,000	$ 0.2598	$ 5,980,000
1.0%	5.0%	$ 31,806,015	100,000,000	$ 0.3181	$ 5,826,015
1.0%	6.0%	$ 37,512,014	100,000,000	$ 0.3751	$ 5,705,999
1.0%	7.0%	$ 43,120,060	100,000,000	$ 0.4312	$ 5,608,046
1.0%	8.0%	$ 48,645,588	100,000,000	$ 0.4865	$ 5,525,528
1.0%	9.0%	$ 54,099,974	100,000,000	$ 0.5410	$ 5,454,387
1.0%	10.0%	$ 59,491,939	100,000,000	$ 0.5949	$ 5,391,964
1.0%	11.0%	$ 64,828,365	100,000,000	$ 0.6483	$ 5,336,427
1.0%	12.0%	$ 70,114,824	100,000,000	$ 0.7011	$ 5,286,459
1.0%	13.0%	$ 75,355,907	100,000,000	$ 0.7536	$ 5,241,083
1.0%	14.0%	$ 80,555,465	100,000,000	$ 0.8056	$ 5,199,558
1.0%	15.0%	$ 85,716,768	100,000,000	$ 0.8572	$ 5,161,304
1.0%	16.0%	$ 90,842,631	100,000,000	$ 0.9084	$ 5,125,863
1.0%	17.0%	$ 95,935,496	100,000,000	$ 0.9594	$ 5,092,865
1.0%	18.0%	$ 100,997,504	100,000,000	$ 1.0100	$ 5,062,008
1.0%	19.0%	$ 106,030,547	100,000,000	$ 1.0603	$ 5,033,042
1.0%	20.0%	$ 111,036,305	100,000,000	$ 1.1104	$ 5,005,758
1.0%	21.0%	$ 116,016,283	100,000,000	$ 1.1602	$ 4,979,978
1.0%	22.0%	$ 120,971,836	100,000,000	$ 1.2097	$ 4,955,553

	Cost per first year kWh for 50% of economic potential			Cost per first year kWh for next 25% of economic potential	
	Total Cost	$ 320,655,590		Total Cost	$ 376,571,330
	kWh for 50%	800,000,000		kWh for next 25% of retail sales	500,000,000
	Cost per first year kWH	$ 0.401		Cost per first year kWH	$ 0.753
				Percent increase in unt cost	88%
	Model Elasticities				
	Incremental	0			
	Cumulative	0.897			

Under Model 1, the average cost increases from \$0.249/kWh to \$0.308/kWh or 24%. Under Model 2, the cost increases from \$0.401/kWh to \$0.753/kWh or 88%. The key point here is not the size of the unit cost numbers, but the percent increase. These values produce a range of average cost increases of 24% to 88% as market penetration increases. This is a wide range, but is based on actual program cost experience. It provides guidance on the expectation that as the market penetration of energy efficiency increases, the unit cost increases.

9. Implications for Future Research

From the review of other studies, it is apparent that little to no evidence exists on the relationship between program costs, program size, and market penetration. But now, the research conducted in this study provides an initial insight into this relationship. While the range of estimated impacts on cost is rather wide, selecting a market penetration driven percent increase in energy efficiency costs in the middle of the range seems appropriate. This percent increase would be applied in estimating costs when the program impacts are expected to exceed the achievable potential. At the same time, efforts to improve targeted marketing can help with cost management.

It should be obvious that further research in this area is warranted. As mentioned, this study is the first to investigate how costs can rise with increases in program size and market penetration. The findings point to the existence of cost efficiencies with respect to program size, but rising costs as market penetration increases. The results developed here are at a very high level. The potential for greater insights may exist by monitoring individual program costs over time. Future research along that direction seems appropriate. The results could vary significantly from one program to the next. Analysis could also be conducted at the portfolio level for individual utility energy efficiency efforts or a cross-section of individual utilities. Only through further research can the range be narrowed and/or confirmed.

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Confidential Attachment 5.4 CHP Market Potential Study
(Not Included in Public Document)

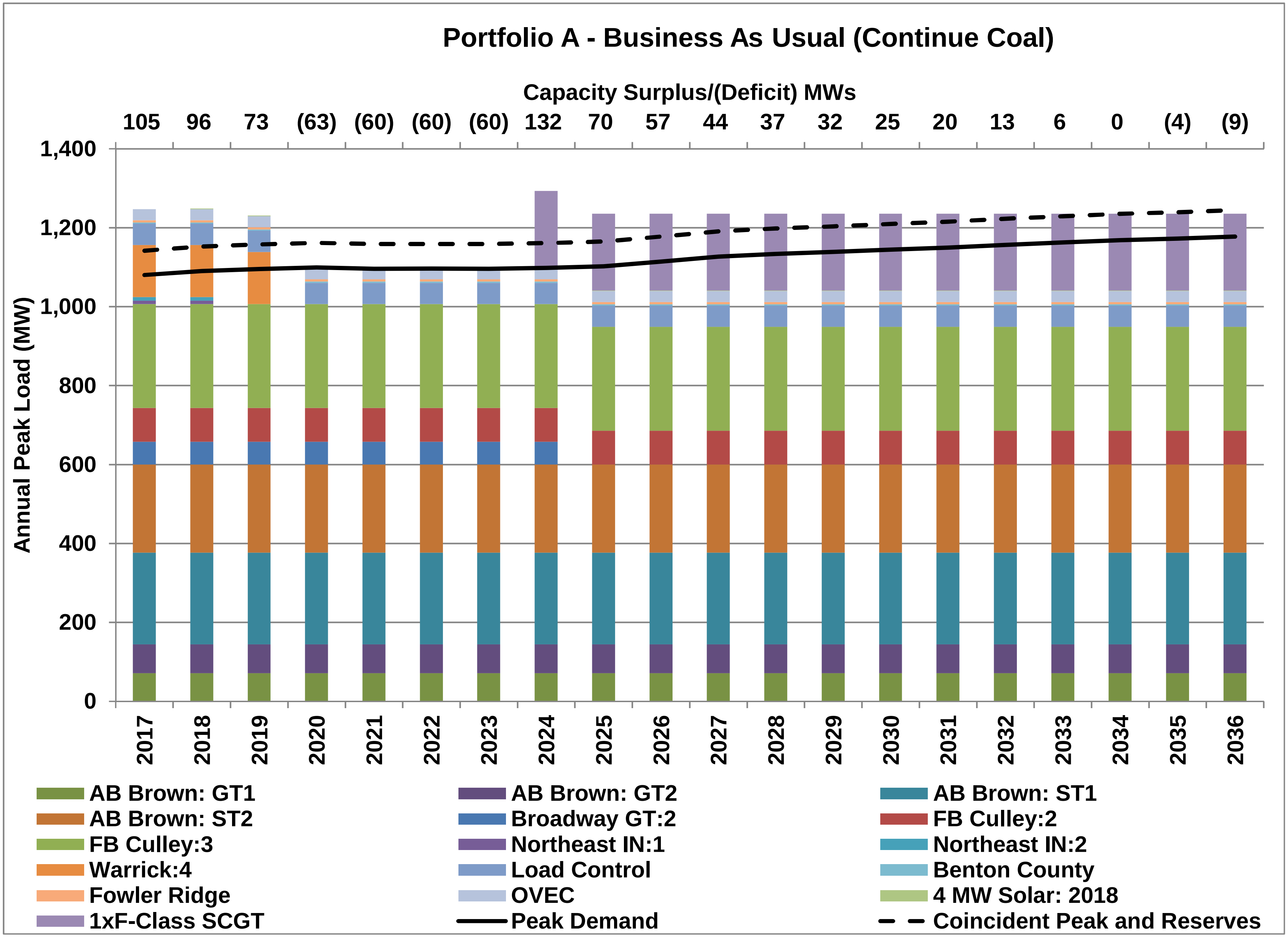
Attachment 7.1 IRP Portfolio Summary Report

Vectren 2016 IRP
Risk Analysis Portfolios

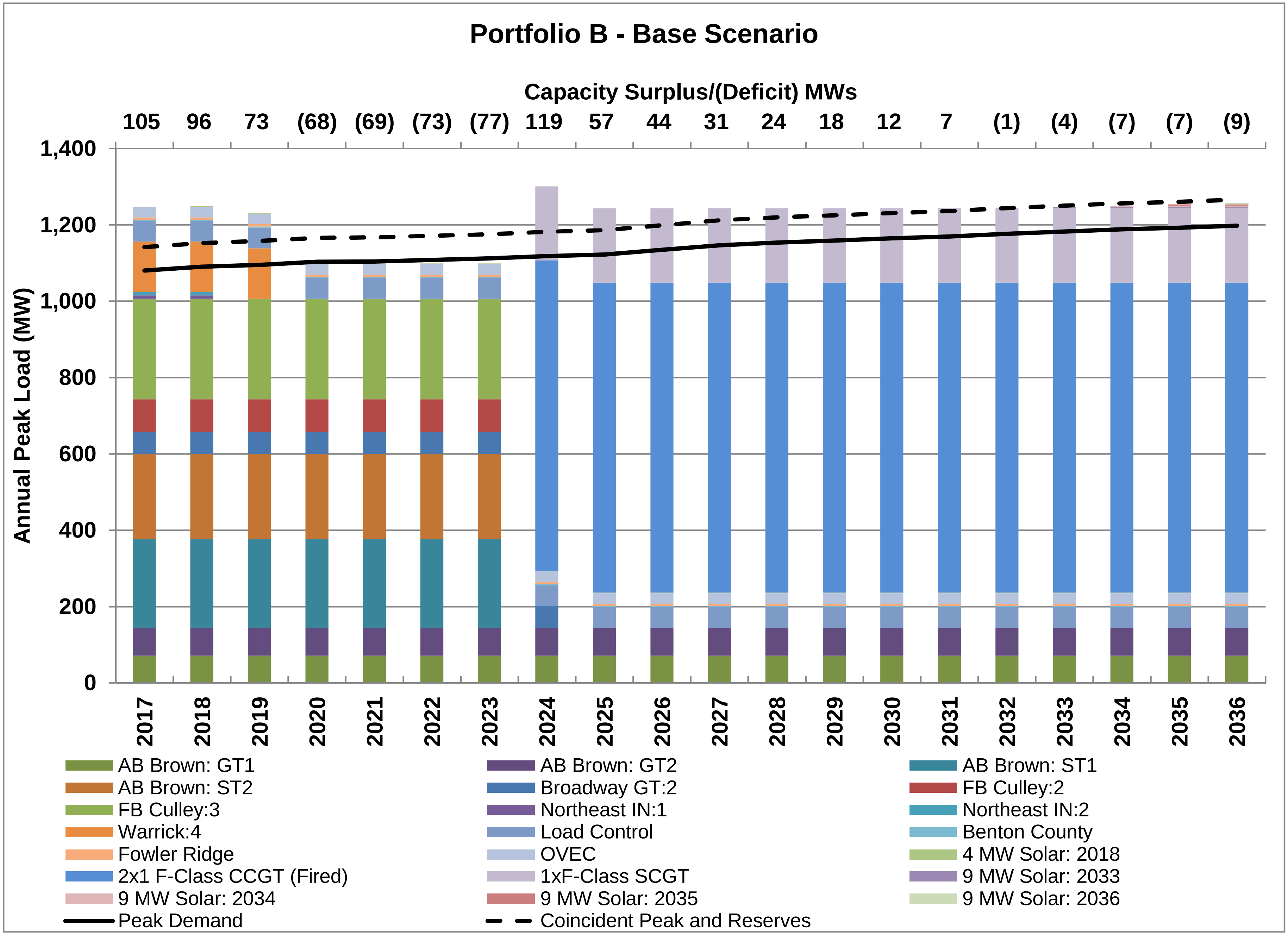
Portfolio ID:	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Portfolio Name:	**Business As Usual (Continue Coal)**	**Base Scenario**	**Base + Alternate Load Scenario**	**High Reg. Scenario**	**Low Reg. Scenario**	**High Economy Scenario**	**Low Economy Scenario**	**High Tech. Scenario**	**Stakeholder Portfolio**	**Stakeholder Portfolio Cease Coal by 2024**	**FB Culley 3, Fired Gas, & Renewables**	**FB Culley 3, Fired Gas, Early Solar, & Energy Efficiency**	**FB Culley 3, Unfired Gas .05, Early Solar, Energy Efficiency, & Renewables**	**Unfired Gas Heavy with 50 MW Solar in 2019**	**Gas Portfolio with Renewables**
2017	DSM Plan 2016-2017	DSM Plan 2016-2017	DSM Plan 2016-2017	DSM Plan 2016-2017	DSM Plan 2016-2017	DSM Plan 2016-2017	DSM Plan 2016-2017	DSM Plan 2016-2017	DSM Plan 2016-2017	DSM Plan 2016-2017	DSM Plan 2016-2017	DSM Plan 2016-2017	DSM Plan 2016-2017	DSM Plan 2016-2017	DSM Plan 2016-2017
2018	4 MW Solar	4 MW Solar	1.0% EE (2018-2036) 4 MW Solar	1.00% EE (2018-2036) 4 MW Solar	1.00% EE (2018-2036) 4 MW Solar	2.00% EE (2018-2036) 4 MW Solar	4 MW Solar	4 MW Solar	2.0% EE (2018-2036) 4 MW Solar	2.0% EE (2018-2036) 4 MW Solar	1.0% EE (2018-2020) 4 MW Solar	1.0% EE (2018-2020) 4 MW Solar	1.0% EE (2018-2020) 4 MW Solar	1.0% EE (2018-2036) 4 MW Solar	1.0% EE (2018-2036) 4 MW Solar
2019	Shutdown NE 1 & 2	Shutdown NE 1 & 2	Shutdown NE 1 & 2	Shutdown NE 1 & 2	Shutdown NE 1 & 2	Shutdown NE 1 & 2	Shutdown NE 1 & 2	Shutdown NE 1 & 2	Shutdown NE 1 & 2	Shutdown NE 1 & 2	Shutdown NE 1 & 2	Shutdown NE 1 & 2 50 MW Solar	Shutdown NE 1 & 2 50 MW Solar	Shutdown NE 1 & 2 50 MW Solar	Shutdown NE 1 & 2 50 MW Solar
2020	Shutdown WAR4 4 MW DR 63 MW Mkt Cap	Shutdown WAR4 68 MW Mkt Cap	Shutdown WAR4 4 MW DR 43 MW Mkt Cap	Shutdown WAR4 47 MW Mkt Cap	Shutdown WAR4 4 MW DR 43 MW Mkt Cap	Shutdown WAR4 27 MW Mkt Cap	Shutdown WAR4 68 MW Mkt Cap	Shutdown WAR4 82 MW Mkt Cap	Shutdown WAR4 4 MW DR 23 MW Mkt Cap	Shutdown WAR4 4 MW DR 23 MW Mkt Cap	Shutdown WAR4 47 MW Mkt Cap	Shutdown WAR4 28 MW Mkt Cap	Shutdown WAR4 4 MW DR 24 MW Mkt Cap	Shutdown WAR4 4 MW DR 24 MW Mkt Cap	Shutdown WAR4 4 MW DR 24 MW Mkt Cap
2021	4 MW DR 60 MW Mkt Cap	69 MW Mkt Cap	4 MW DR 33 MW Mkt Cap	41 MW Mkt Cap	4 MW DR 1xF-Class SCGT	4 MW DR 10 MW Mkt Cap	69 MW Mkt Cap	83 MW Mkt Cap	4 MW DR 6 MW Mkt Cap	4 MW DR 6 MW Mkt Cap	0.75% EE (2021-2026) 43 MW Mkt Cap	0.75% EE (2021-2026) 24 MW Mkt Cap	0.75% EE (2021-2026) 4 MW DR 16 MW Mkt Cap	4 MW DR 14 MW Mkt Cap	4 MW DR 14 MW Mkt Cap
2022	4 MW DR 60 MW Mkt Cap	73 MW Mkt Cap	4 MW DR 26 MW Mkt Cap	39 MW Mkt Cap	4 MW DR	1xF-Class SCGT 4 MW DR	73 MW Mkt Cap	87 MW Mkt Cap	4 MW DR	4 MW DR	42 MW Mkt Cap	23 MW Mkt Cap	4 MW DR 11 MW Mkt Cap	4 MW DR 7 MW Mkt Cap	4 MW DR 3 MW Mkt Cap
2023	4 MW DR 60 MW Mkt Cap	77 MW Mkt Cap	4 MW DR 19 MW Mkt Cap	36 MW Mkt Cap	4 MW DR	4 MW DR	4 MW DR 73 MW Mkt Cap	91 MW Mkt Cap	4 MW DR	4 MW DR	4 MW DR 37 MW Mkt Cap	22 MW Mkt Cap	4 MW DR 5 MW Mkt Cap	4 MW DR	4 MW DR
2024	1xF-Class SCGT 4 MW DR	Shutdown ABB 1 & 2 Shutdown FB 2 & 3 ABB Fired 2x1 CCGT 1xF-Class SCGT	Shutdown ABB 1 & 2 Shutdown FB 2 & 3 ABB Fired 2x1 CCGT .05 1xF-Class SCGT 4 MW DR	Shutdown ABB 1 & 2 Shutdown FB 2 & 3 ABB Fired 2x1 CCGT .05 28 MW Mkt Cap	Shutdown ABB 1 & 2 Shutdown FB 2 & 3 ABB Fired 2x1 CCGT .05 4 MW DR	Shutdown ABB 1 & 2 Shutdown FB 2 & 3 ABB Fired 2x1 CCGT .05 4 MW DR	Shutdown ABB 1 & 2 Shutdown FB 2 & 3 ABB Fired 2x1 CCGT .05 4 MW DR 67 MW Mkt Cap	Shutdown ABB 1 & 2 Shutdown FB 2 & 3 ABB Fired 2x1 CCGT .05 1xF-Class SCGT	Shutdown ABB 1 & 2 Partial Ownership 1x1 CCGT .05 (50%) (5x) 100 MW Solar PV (4x) 200 MW Wind Combined Heat & Power (30 MW) 4 MW DR	Shutdown ABB 1 & 2 Shutdown FB 2 & 3 Partial Ownership 1x1 CCGT .05 (75%) (8x) 100 MW Solar PV (6x) 200 MW Wind Combined Heat & Power (30 MW) (10x) 10MW/40MWh Battery 4 MW DR	Shutdown ABB 1 & 2 Shutdown FB 2 FB 3 Continue Coal ABB Fired 2x1 CCGT .05	Shutdown ABB 1 & 2 Shutdown FB 2 FB 3 Continue Coal ABB Fired 2x1 CCGT .05	Shutdown ABB 1 & 2 Shutdown FB 2 FB 3 Continue Coal ABB Unfired 2x1 CCGT .05 4 MW DR	Shutdown ABB 1 & 2 Shutdown FB 2 & 3 ABB Unfired 2x1 CCGT .05 1xF-Class SCGT 4 MW DR	Shutdown ABB 1 & 2 Shutdown FB 2 & 3 ABB Fired 2x1 CCGT .05 4 MW DR
2025	Shutdown BAGS 2	Shutdown BAGS 2	Shutdown BAGS 2	Shutdown BAGS 2 83 MW Mkt Cap	Shutdown BAGS 2 1xF-Class SCGT	Shutdown BAGS 2 4 MW DR	Shutdown BAGS 2 4 MW DR 125 MW Mkt Cap	Shutdown BAGS 2	Shutdown BAGS 2	Shutdown BAGS 2	Shutdown BAGS 2	Shutdown BAGS 2	Shutdown BAGS 2	Shutdown BAGS 2 50 MW Solar 5 MW Mkt Cap	Shutdown BAGS 2 (2x) 50 MW Solar 4 MW Mkt Cap
2026				88 MW Mkt Cap			4 MW DR 134 MW Mkt Cap							9 MW Solar 7 MW Mkt Cap	9 MW Solar 7 MW Mkt Cap
2027				94 MW Mkt Cap		9 MW Solar	4 MW DR 142 MW Mkt Cap				0.50% EE (2027-2036) 50 MW Wind 9 MW Solar	0.50% EE (2027-2036)	0.50% EE (2027-2036)	9 MW Solar 10 MW Mkt Cap	9 MW Solar 9 MW Mkt Cap
2028				101 MW Mkt Cap			150 MW Mkt Cap							50 MW Solar	50 MW Solar
2029				106 MW Mkt Cap			155 MW Mkt Cap							3 MW Mkt Cap	2 MW Mkt Cap
2030			2 MW Mkt Cap	200 MW Wind 90 MW Mkt Cap		200 MW Wind	161 MW Mkt Cap		(10x) 10MW/40MWh Battery				9 MW Solar 6 MW Mkt Cap	9 MW Mkt Cap	8 MW Mkt Cap
2031			8 MW Mkt Cap	200 MW Wind 72 MW Mkt Cap			167 MW Mkt Cap						9 MW Solar 10 MW Mkt Cap	50 MW Solar	9 MW Solar 10 MW Mkt Cap
2032		1 MW Mkt Cap	50 MW Solar	79 MW Mkt Cap			174 MW Mkt Cap	1 MW Mkt Cap					50 MW Solar	2 MW Mkt Cap	50 MW Solar
2033		9 MW Solar 4 MW Mkt Cap	1 MW Mkt Cap	85 MW Mkt Cap			180 MW Mkt Cap	7 MW Mkt Cap					7 MW Mkt Cap	8 MW Mkt Cap	4 MW Mkt Cap
2034		9 MW Solar 7 MW Mkt Cap	7 MW Mkt Cap	91 MW Mkt Cap		200 MW Wind	187 MW Mkt Cap	10 MW/ 40MWh Battery 3 MW Mkt Cap		(10x) 10MW/40MWh Battery			50 MW Solar	50 MW Solar	10 MW Mkt Cap
2035	4 MW Mkt Cap	9 MW Solar 7 MW Mkt Cap	9 MW Solar 8 MW Mkt Cap	95 MW Mkt Cap			9 MW Solar 188 MW Mkt Cap	8 MW Mkt Cap	Shutdown FB 2 & 3 1x 200 MW Wind 4x 100 MW Solar PV Partial Ownership 1x1 CCGT .05 (25%)				2 MW Mkt Cap		50 MW Solar
2036	9 MW Mkt Cap	9 MW Mkt Cap 9 MW Solar	9 MW Solar 9 MW Mkt Cap	100 MW Mkt Cap			50 MW Solar 174 MW Mkt Cap	9 MW Solar 10 MW Mkt Cap		3 MW Mkt Cap			9 MW Mkt Cap	3 MW Mkt Cap	

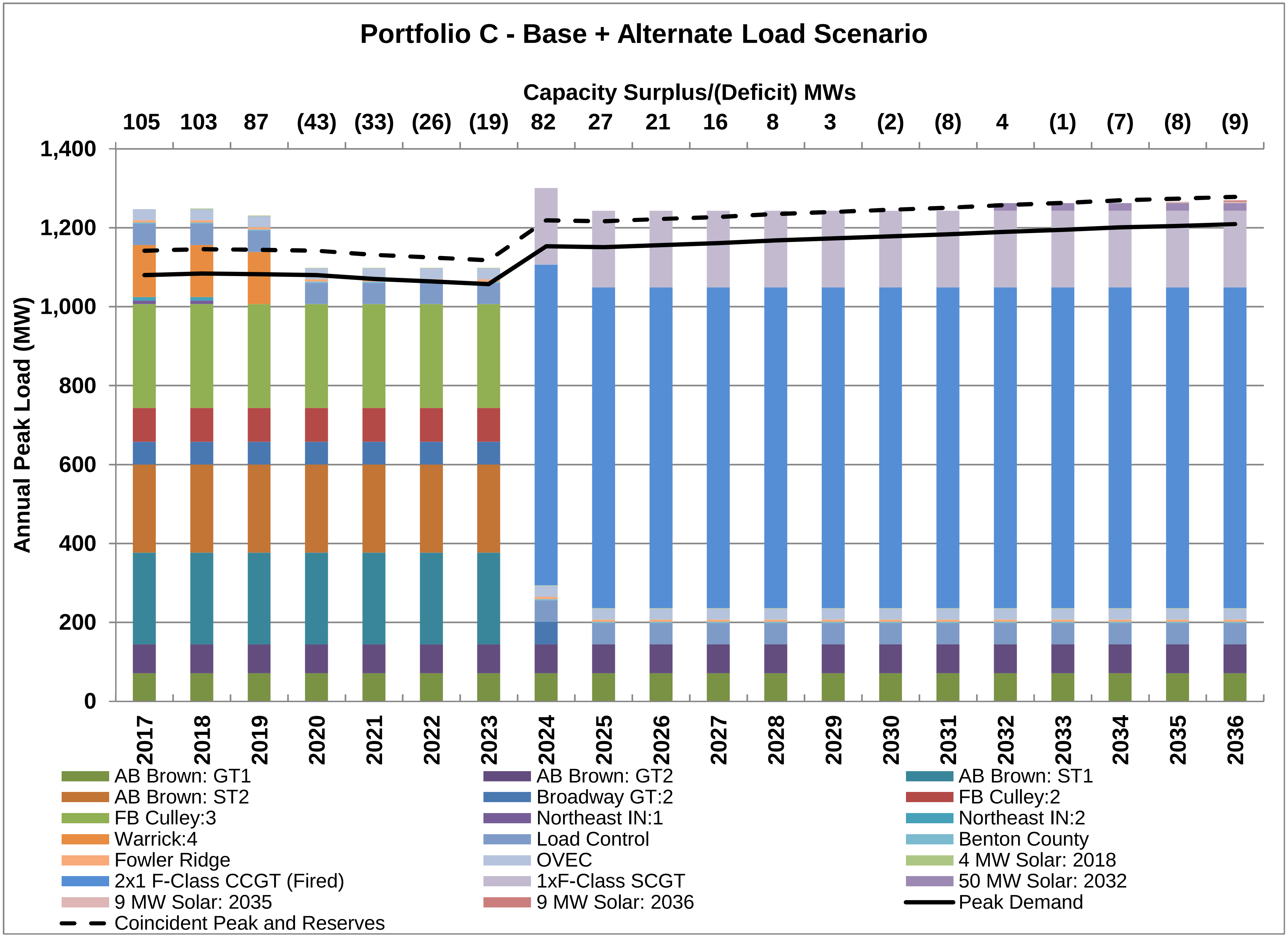
Attachment 7.2 Balance of Loads and Resources

A - Business as Usual (Continue Coal)-BLR.xlsx

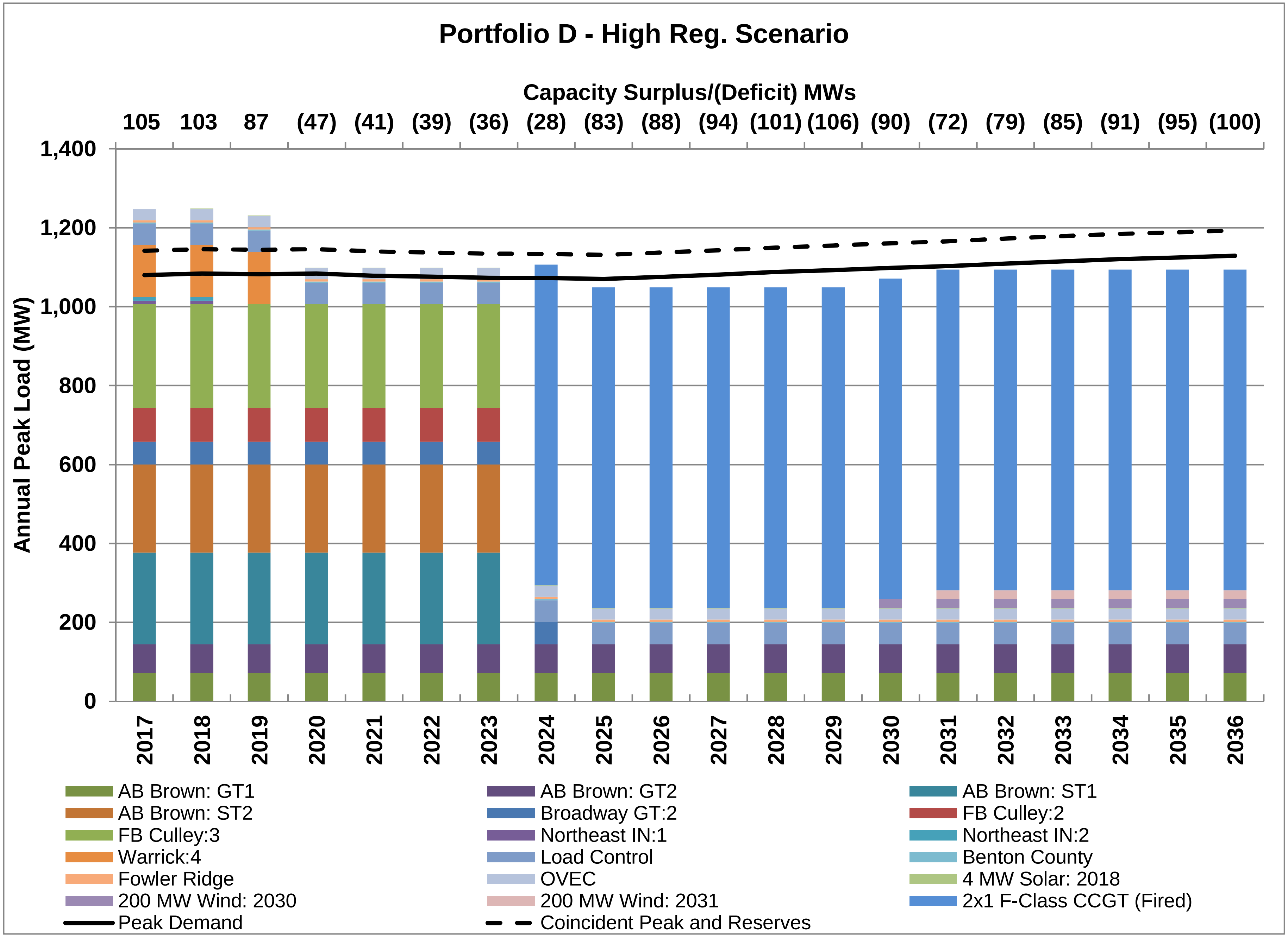


B - Base Scenario- BLR.xlsx

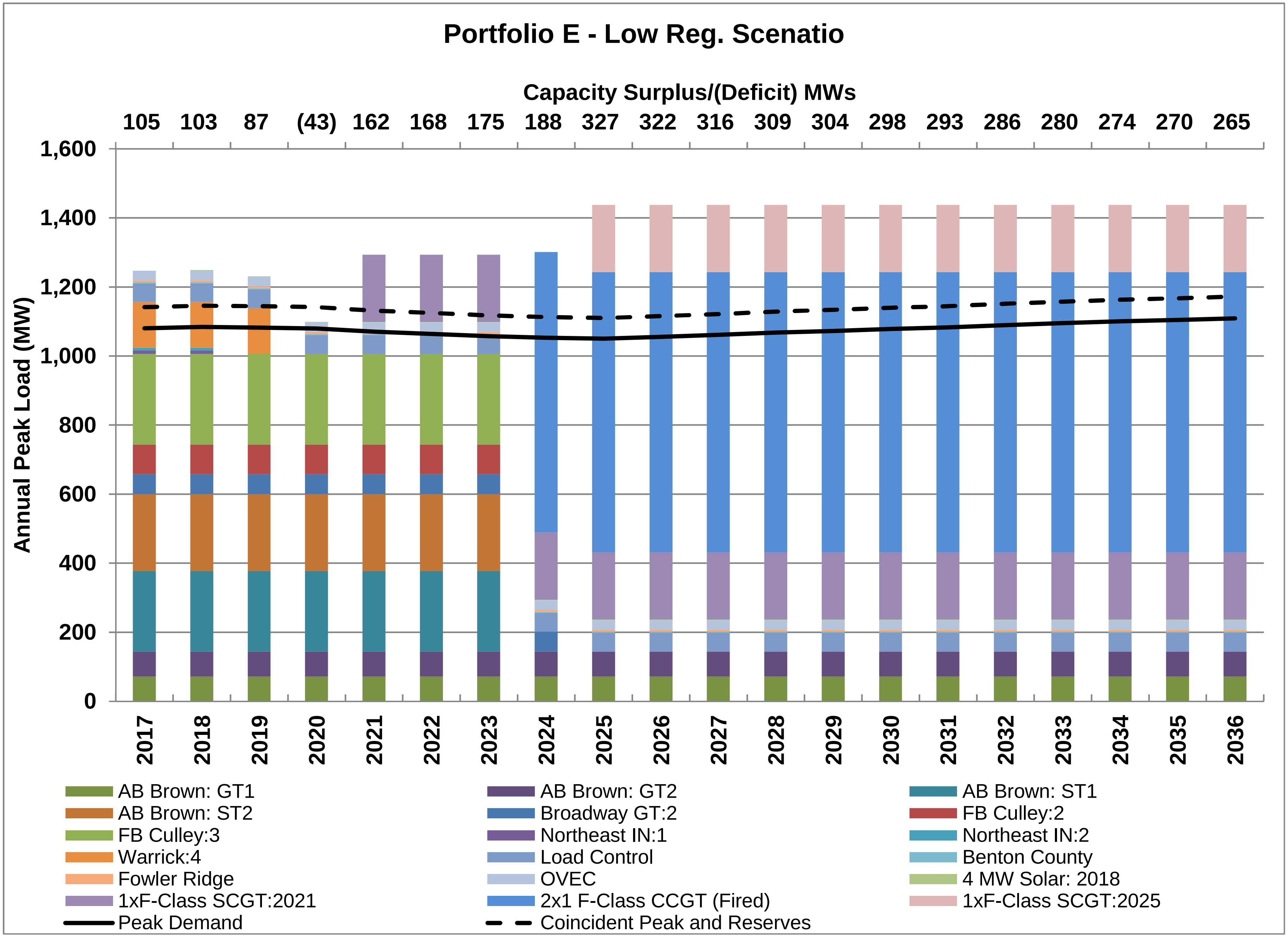



Portfolio C - Base + Alternate Load Scenario
Capacity Surplus/(Deficit) MWs
105 103 87 (43) (33) (26) (19) 82 27 21 16 8 3 (2) (8) 4 (1) (7) (8) (9)
Annual Peak Load (MW)
1,400
1,200
1,000
800
600
400
200
0
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036
AB Brown: GT1
AB Brown: GT2
AB Brown: ST1
AB Brown: ST2
Broadway GT:2
FB Culley:2
FB Culley:3
Northeast IN:1
Northeast IN:2
Warrick:4
Load Control
Benton County
Fowler Ridge
OVEC
4 MW Solar: 2018
2x1 F-Class CCGT (Fired)
1xF-Class SCGT
50 MW Solar: 2032
9 MW Solar: 2035
9 MW Solar: 2036
Peak Demand
Coincident Peak and Reserves

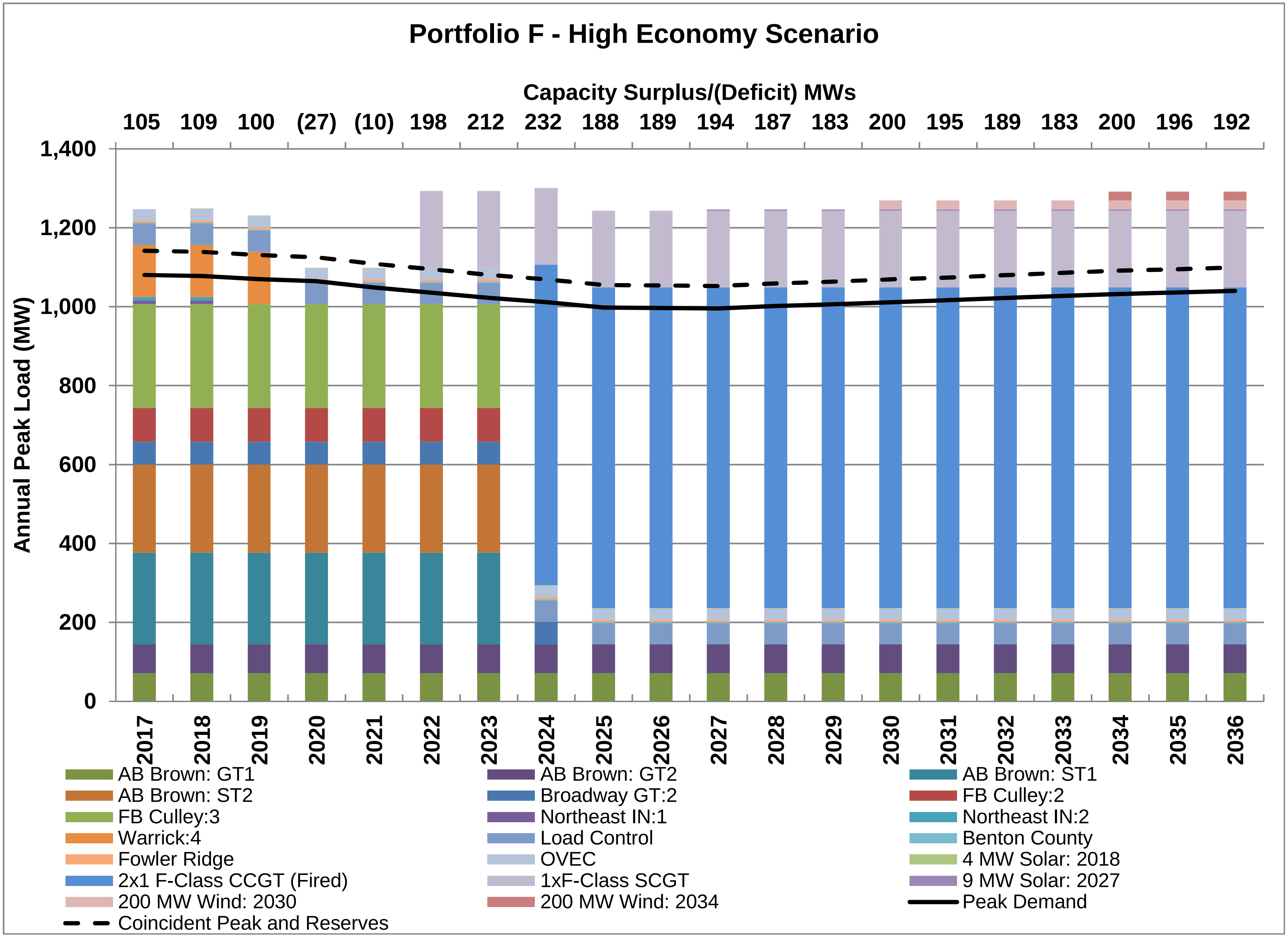
D - High Reg. Scenario-BLR.xlsx

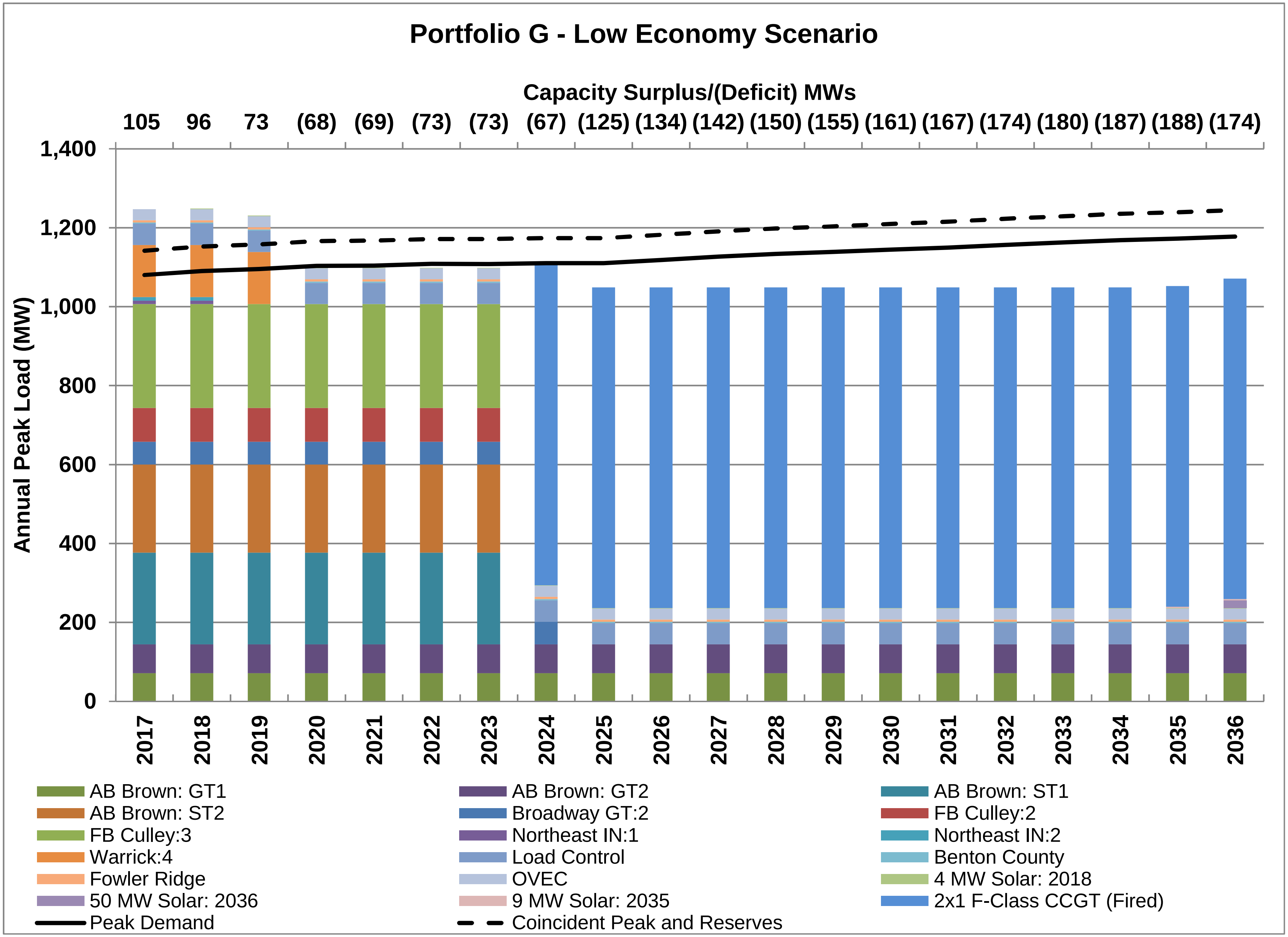


E - Low Reg. Scenario-BLR.xlsx



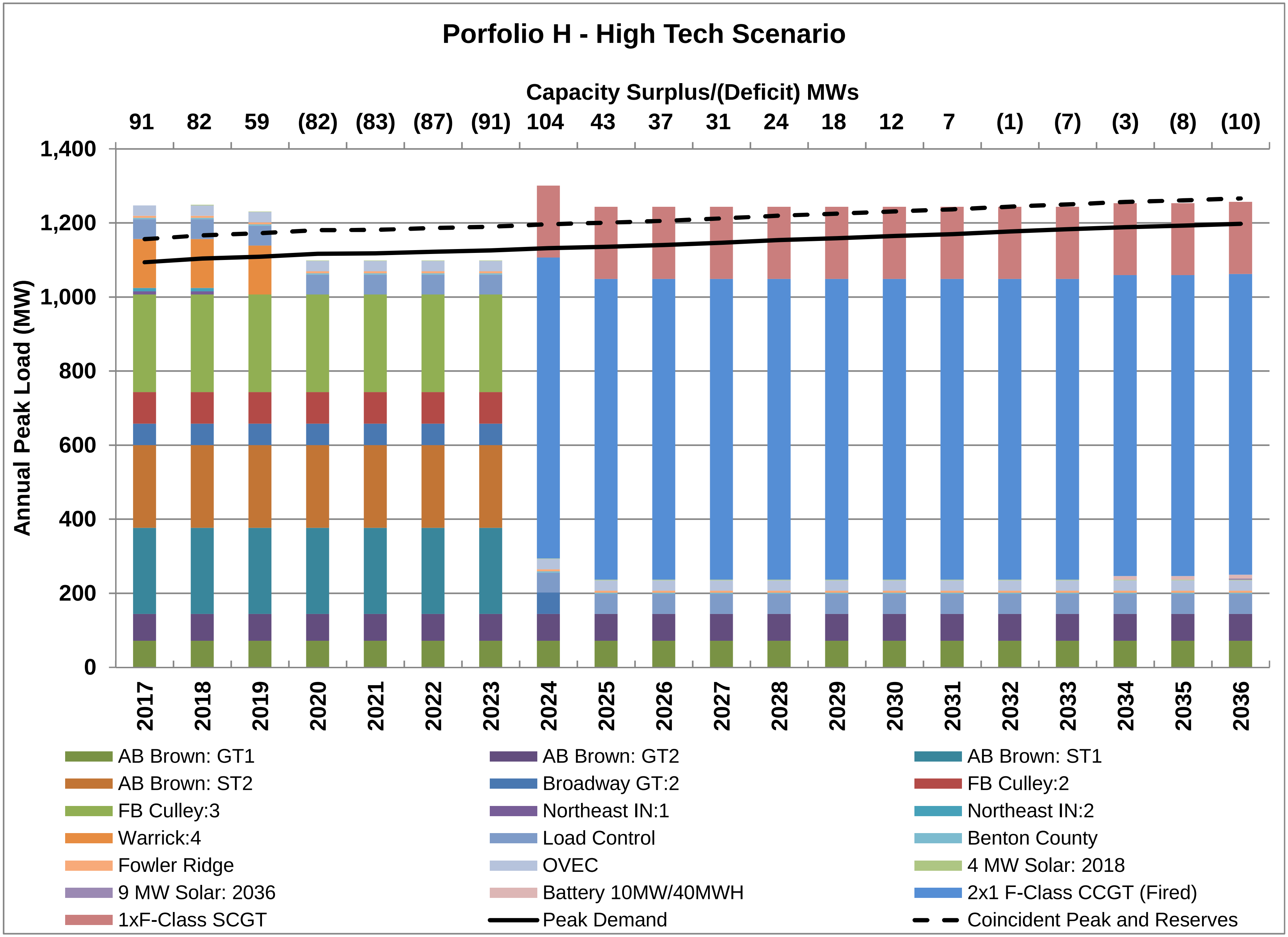
F - High Economy Scenario-BLR.xlsx



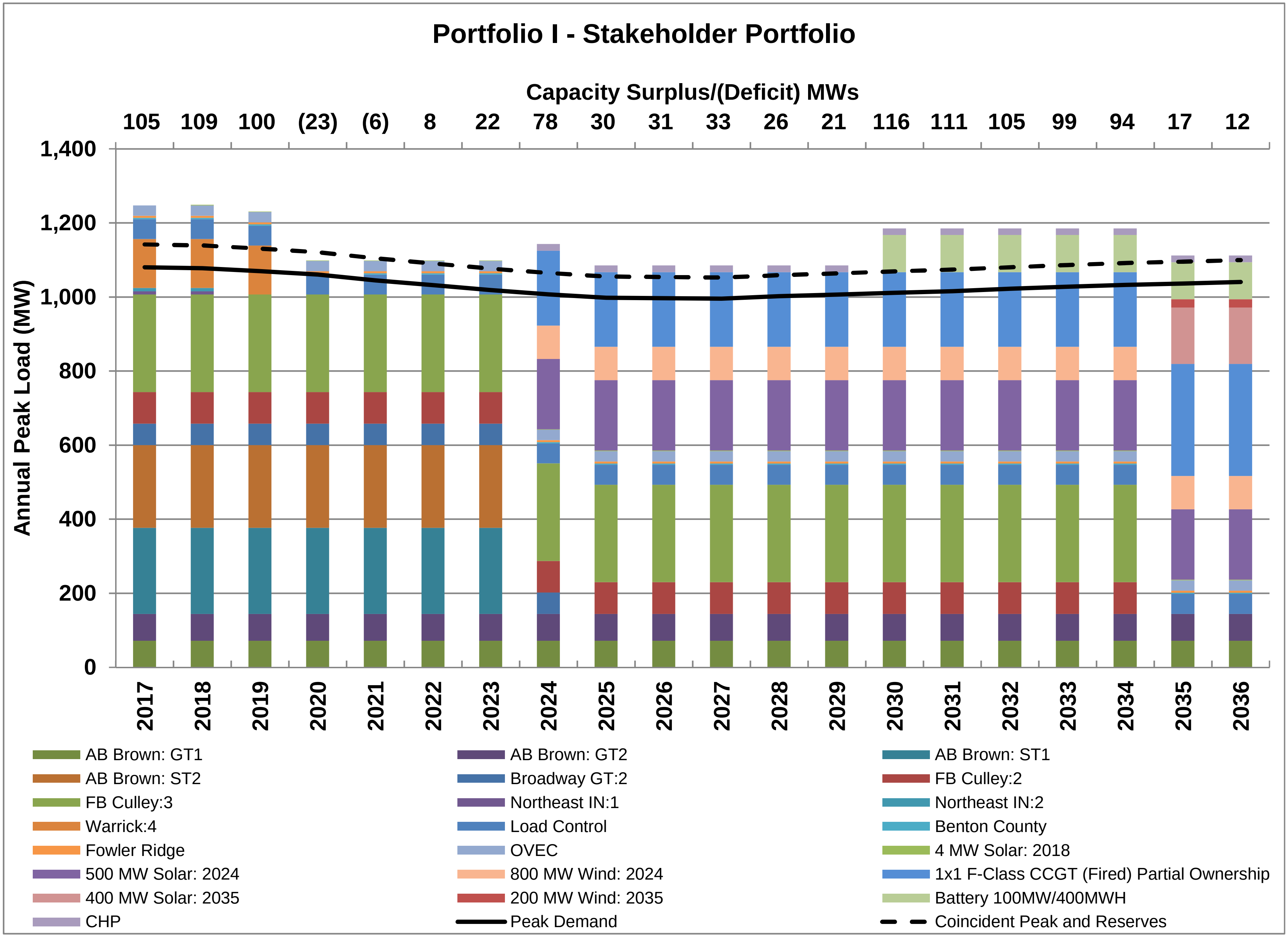


Portfolio G - Low Economy Scenario
Capacity Surplus/(Deficit) MWs
105 96 73 (68) (69) (73) (73) (67) (125) (134) (142) (150) (155) (161) (167) (174) (180) (187) (188) (174)
Annual Peak Load (MW)
1,400
1,200
1,000
800
600
400
200
0
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036
AB Brown: GT1
AB Brown: GT2
AB Brown: ST1
AB Brown: ST2
Broadway GT:2
FB Culley:2
FB Culley:3
Northeast IN:1
Northeast IN:2
Warrick:4
Load Control
Benton County
Fowler Ridge
OVEC
4 MW Solar: 2018
50 MW Solar: 2036
9 MW Solar: 2035
2x1 F-Class CCGT (Fired)
Peak Demand
Coincident Peak and Reserves

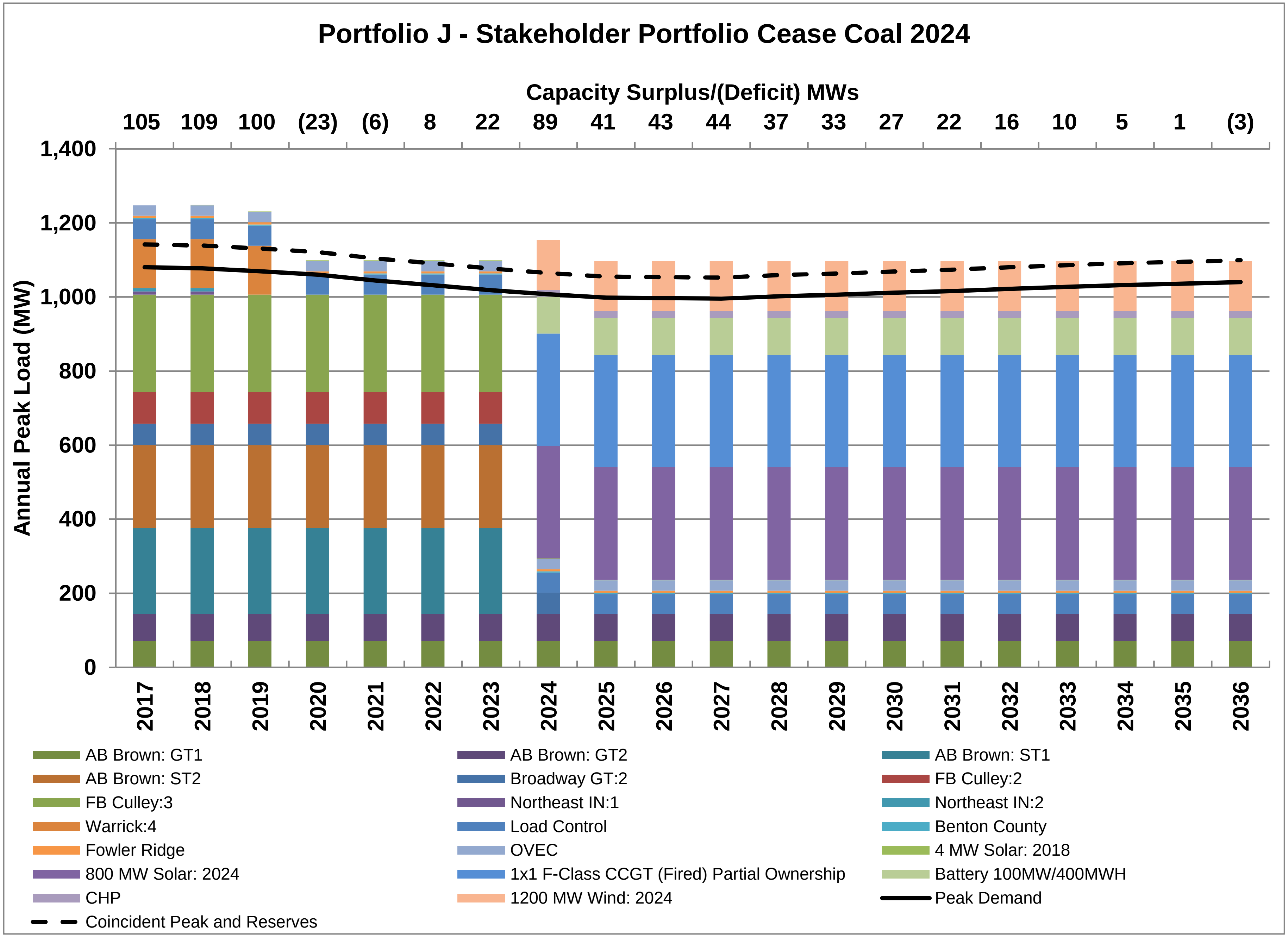
H - High Tech. Scenario-BLR.xlsx

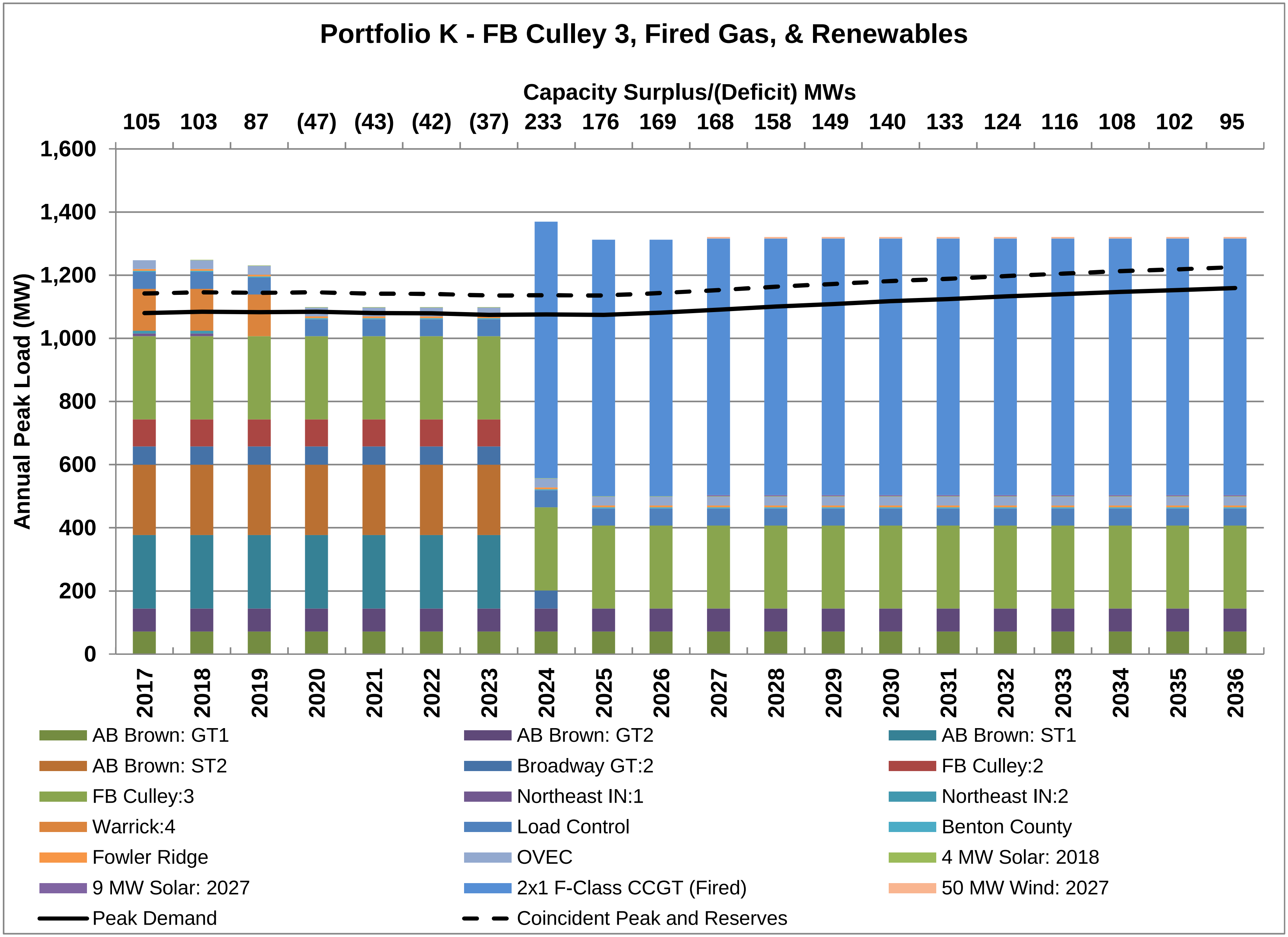


I - Stakeholder Portfolio-BLR.xlsx

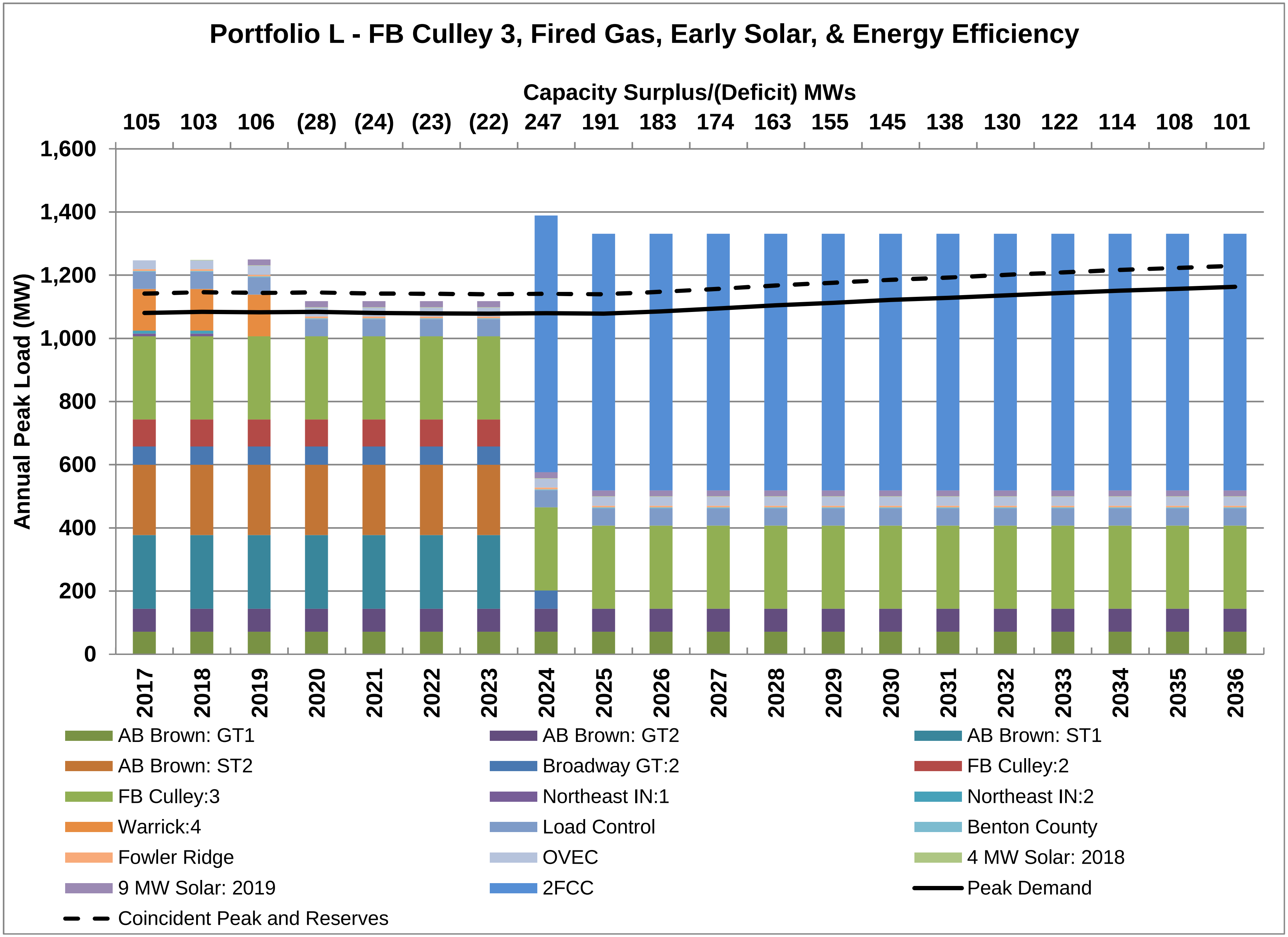


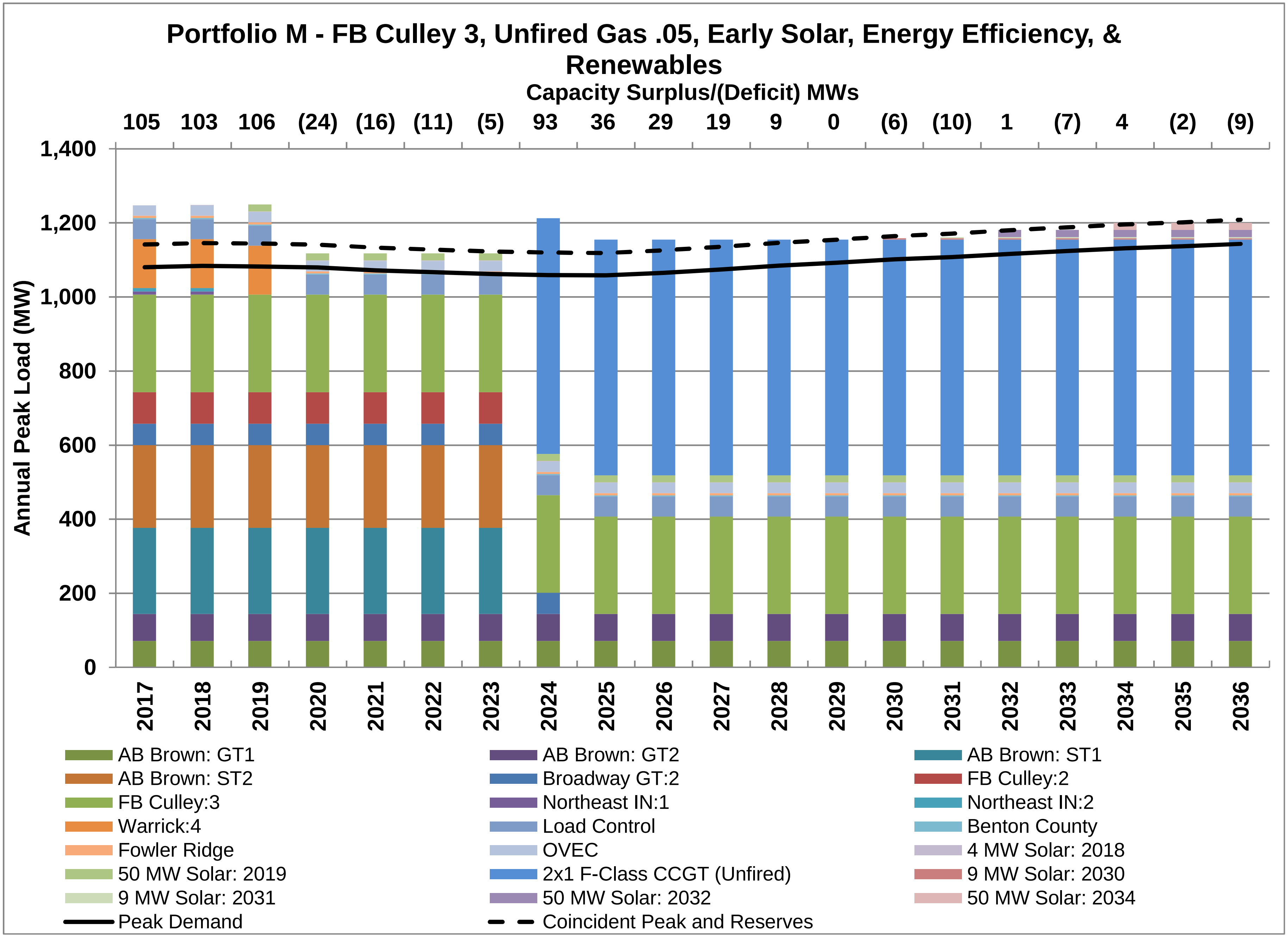
J - Stakeholder Portfolio Cease Coal 2024-BLR.xlsx



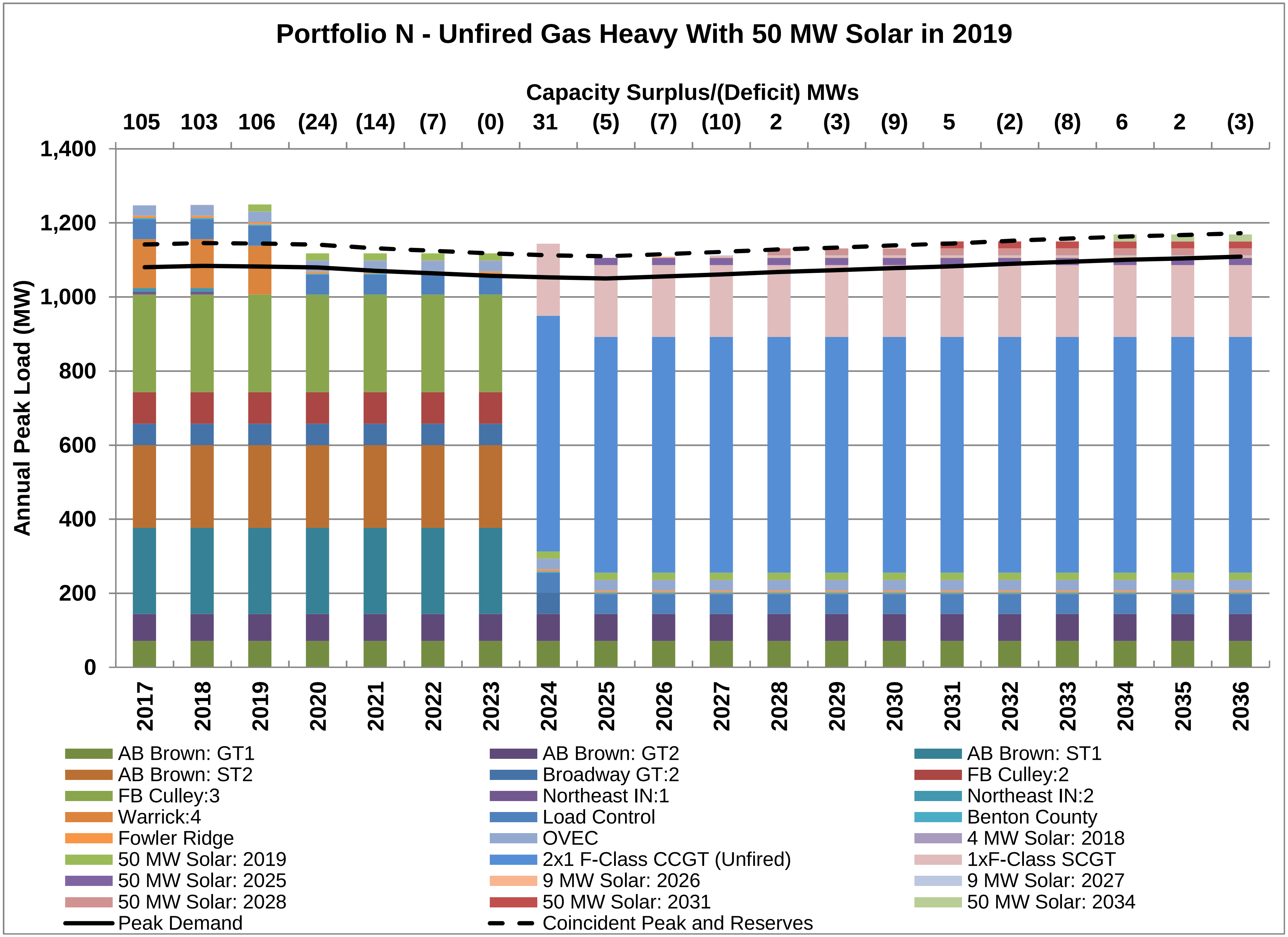

Portfolio K - FB Culley 3, Fired Gas, & Renewables
Capacity Surplus/(Deficit) MWs
105 103 87 (47) (43) (42) (37) 233 176 169 168 158 149 140 133 124 116 108 102 95
Annual Peak Load (MW)
1,600
1,400
1,200
1,000
800
600
400
200
0
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036
AB Brown: GT1
AB Brown: GT2
AB Brown: ST1
AB Brown: ST2
Broadway GT:2
FB Culley:2
FB Culley:3
Northeast IN:1
Northeast IN:2
Warrick:4
Load Control
Benton County
Fowler Ridge
OVEC
4 MW Solar: 2018
9 MW Solar: 2027
2x1 F-Class CCGT (Fired)
50 MW Wind: 2027
Peak Demand
Coincident Peak and Reserves

L - FB Culley 3, Fired Gas, Early Solar, & Energy Efficiency-BLR.xlsx

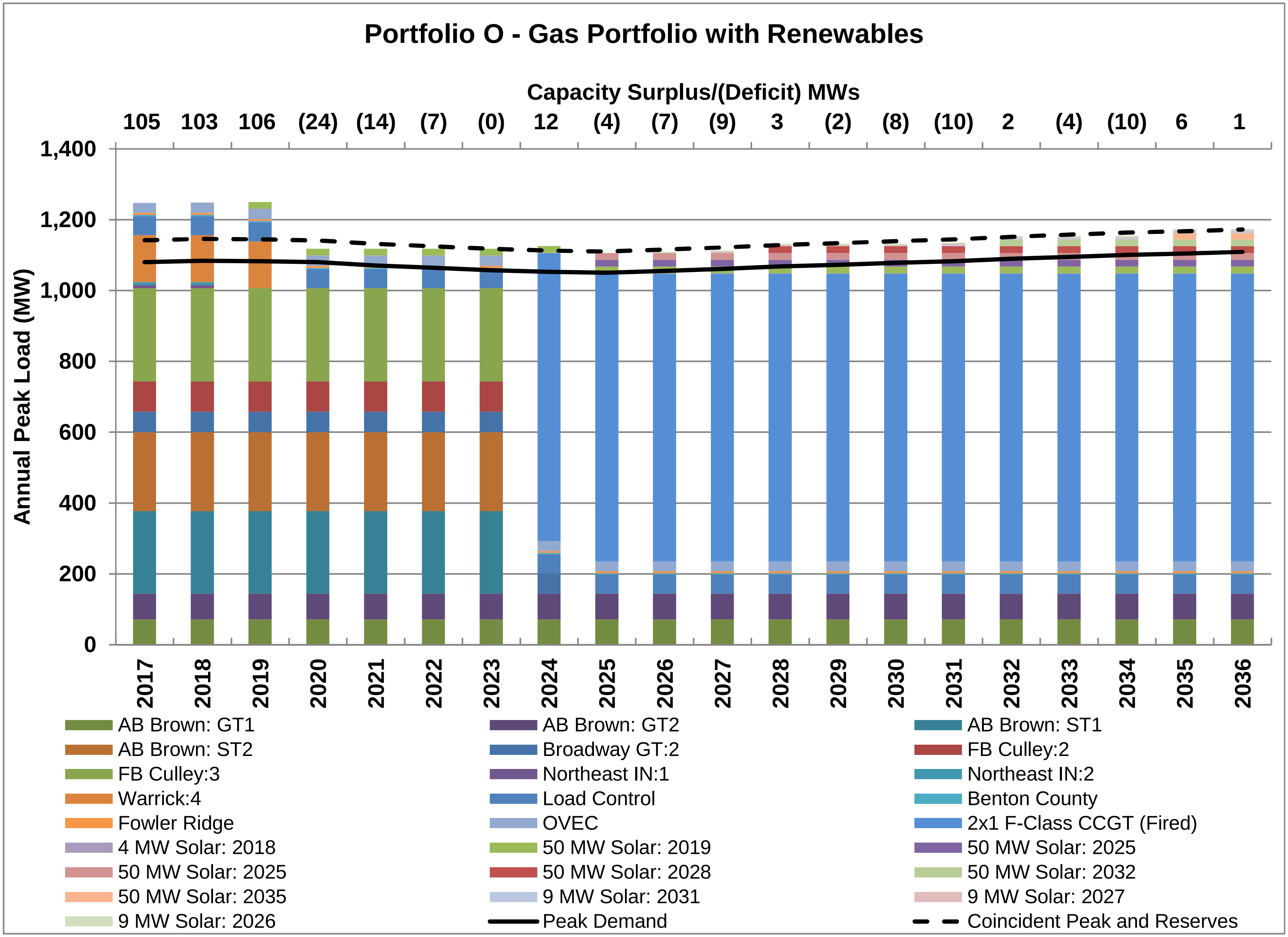



Portfolio M - FB Culley 3, Unfired Gas .05, Early Solar, Energy Efficiency, & Renewables
Capacity Surplus/(Deficit) MWs
105 103 106 (24) (16) (11) (5) 93 36 29 19 9 0 (6) (10) 1 (7) 4 (2) (9)
1,400
1,200
1,000
800
600
400
200
0
Annual Peak Load (MW)
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036
AB Brown: GT1
AB Brown: GT2
AB Brown: ST1
AB Brown: ST2
Broadway GT:2
FB Culley:2
FB Culley:3
Northeast IN:1
Northeast IN:2
Warrick:4
Load Control
Benton County
Fowler Ridge
OVEC
4 MW Solar: 2018
50 MW Solar: 2019
2x1 F-Class CCGT (Unfired)
9 MW Solar: 2030
9 MW Solar: 2031
50 MW Solar: 2032
50 MW Solar: 2034
Peak Demand
Coincident Peak and Reserves

N - Unfired Gas Heavy with 50 MW Solar in 2019-BLR.xlsx



O - Gas Portfolio with Renewables-BLR.xlsx



Confidential Attachment 7.3 Portfolio Input-Output Report
(Not Included in Public Document)

Attachment 7.4 Economic Impact Study – Economic Ripple Effects of Diversifying the Power Generation Portfolio

Economic Impact Study

Economic Ripple Effects of Diversifying the Power Generation Portfolio

Presented by

Yasser Alhenawi, Ph.D.
Associate Professor of Finance
University of Evansville

Omer Bayar, Ph.D.
Associate Professor of Economics
University of Evansville

Presented to

Vectren Corporation
Evansville, IN

November 2, 2016

Background

As an input to the 2016 Integrated Resource Plan, Vectren engaged two University of Evansville professors, Dr. Yasser Alhenawi and Dr. Omer Bayar, to perform an economic impact analysis. The study is intended to independently evaluate major power generation decisions in the near term, which will aide in selecting a preferred portfolio of resource options to serve the customer load over the next 20 years.

The study considers separately the negative impact of retiring coal-fired plants and the positive impact of constructing solar[1] and constructing and operating natural gas capacity. The results show the economic ripple effects including direct, indirect, and induced impacts on jobs, output, and state and local taxes for the following projects.

- Closing Warrick 4 in 2018 (Warrick County)[2]
- Closing Culley 2 in 2024 (Warrick County)
- Closing Culley 3 in 2024 (Warrick County)
- Closing AB Brown 1&2 in 2024 (Posey County)
- Constructing 4MW solar capacity in 2017 (Vanderburgh County)
- Constructing 50MW solar capacity in 2018 (Vanderburgh County)
- Constructing a combined cycle natural gas plant in 2020-2023 (Posey County)
- Operating a combined cycle natural gas plant in 2024 (Posey County)
- Constructing a simple cycle natural gas plant in 2024 (Warrick County)
- Operating a simple cycle natural gas plant in 2024 (Warrick County)

Methodology

The results were produced using IMPLAN (**IM**pact Analysis for **PLAN**ning) data and software. IMPLAN uses standard input-output analysis and regional accounting matrices and multipliers to model the effect on regional and local economies of a given event.

IMPLAN's social accounting system describes transactions that occur between producers and consumers in the economy using a social accounting matrix. This matrix consists of coefficients that capture transfer payments between institutions, including government-to-household transfers such as unemployment benefits and household-to-government transfers such as taxes.

Economic ripple effects considered in this report are three-fold (direct, indirect, and induced) and defined as follows.

- Direct effect is the known or predicted change in the local economy. It takes place only in the industry immediately affected: if XYZ utility plant shuts down, the direct output effect represents the decrease in energy production measured by lost revenues.

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[1] IMPLAN does not have data for industry 44 (solar generation) in Vanderburgh County.

[2] Vectren requested that the economic impact analysis include the possible shutdown of Warrick 4, should this result from Vectren exiting joint operations of the plant.

- Indirect effect captures business-to-business transactions required to satisfy the direct effect, and thus is concerned with inter-industry transactions: because XYZ utility plant is shutting down, it will no longer demand locally-supplied resources to generate electricity. The resulting revenue loss at suppliers is considered an indirect effect.
- Induced effect measures secondary changes due to direct and indirect effects: workers dismissed from XYZ utility plant and affected suppliers will lower expenditures in the local economy: restaurants, stores, etc. These ancillary impacts are considered induced effects.

Input data used in the report were supplied by Vectren. For each project, these data include the expected time frame, change in employee compensation for full-time and contract workers, capital spending, and trade area.

Results

The table below presents a summary of output and tax impacts. Figures in parentheses indicate losses.

Panel A

	Total 1-year Output Impact	***Total 1-year State and Local Tax Impact***	***Reference Project***
Closing Warrick 4 in 2018	($48,431,024)	($2,522,430)	1
Closing Culley 2 in 2024	($22,962,042)	($1,193,208)	2
Closing Culley 3 2024	($142,760,058)	($7,393,373)	3
Closing AB Brown 1&2 2024	($178,778,538)	($9,679,674)	4

Panel B

	Total 1-year Output Impact	***Total 1-year State and Local Tax Impact***	***Reference Project***
Operating a combined cycle natural gas plant 2024	$81,259,433	$4,399,307	8
Operating a simple cycle natural gas plant 2024	$38,206,739	$1,978,571	10

Panel C

	Total Output Impact	*Total State and Local Tax Impact*	*Reference Project*
Constructing 4MW solar capacity in 2017	$13,601,127	$415,914	5
Constructing 50MW solar capacity in 2018	$130,602,671	$3,979,268	6
Constructing a combined cycle natural gas plant in 2020-2023	$953,013,316	$27,067,573	7
Constructing a simple cycle natural gas plant in 2024	$497,801,375	$14,968,977	9

Panel A presents the economic impact of closing existing plants during the year of closure. In this panel, the column titled "Total 1-year Output Impact" reports the value of output lost in the local economy for the year in question. For example, closing Warrick 4 in 2018 will lead to a total output loss of $48,431,024 in Warrick County in the year 2018. This figure is the sum of three components: direct loss measures the decrease in Vectren revenues, which equals the value of output produced by the plant and all resources within (labor, physical capital, etc.) prior to closure; indirect loss measures the decrease in revenues to local suppliers; induced loss measures the decrease in revenues earned by local businesses. On the other hand, the column titled "Total 1-year State and Local Tax Impact" reports tax losses to state and local governments for the year in question, including taxes on employee compensation, proprietor income, production and imports, households, and corporations. For example, the closure of Warrick 4 in 2018 will reduce tax revenues by a total of $2,522,430 in the year 2018.

Panel B represents the economic impact of operating new plants for a given year. The column titled "Total 1-year Output Impact" reports the value of output gained in the local economy for the year in question. For example, operating a combined cycle natural gas power plant in Posey County in 2024 will lead to a total output gain of $81,259,433 in 2024. As before, this figure is the sum of direct revenues to Vectren, indirect revenues to local suppliers, and induced revenues to local businesses. The column titled "Total 1-year State and Local Tax Impact" reports tax gains to state and local governments for the year in question. For example, operating the combined cycle natural gas power plant in Posey County in 2024 will increase tax revenues by a total of $4,399,307 in 2024. Provided that new plants will remain in operation for many years, similar economic impacts can be expected during each year.

Panel C represents the economic impact of building new plants over the construction period. The column titled "Total Output Impact" reports the total value of structures built, which includes the construction budget (payroll and non-payroll) plus any profits and indirect business taxes. For example, constructing 4MW solar capacity in 2017 will raise the value of physical assets held by Vectren by $13,601,127. The column titled "Total State and Local Tax Impact" reports tax gains to state and local governments for the year(s) in question. For example, constructing 4MW solar capacity in 2017 will raise state and local tax revenues by a total of $415,914 in 2017.

The reported impacts cannot simply be added to determine the net effect of multiple decisions, as these projects differ in nature, take place in different trade areas, and create economic impacts over different years. However, there are connections. For instance, the positive impacts of constructing and operating a combined cycle natural gas plant in Posey County (Projects 7 and 8) should offset the adverse impact of closing AB Brown 1&2 located in the same county (Project 4). Similarly, the positive impacts of constructing and operating a simple cycle natural gas plant in Warrick County (Projects 9 and 10) should offset the adverse impact of closing Warrick 4, Culley 2, and Culley 3 in the same county (Projects 1, 2, and 3).

Detailed Analysis

Detailed results for each project are presented below.

Tables 1 through 4 consider plant closures: Warrick 4 (2018), Culley 2 (2024), Culley 3 (2024), and AB Brown 1&2 (2024). These tables show employment and output losses due to dismissing full-time employees and contractors who are currently employed in these plants. Tables also report the projected loss in state and local taxes associated with closures.

Tables 5, 6, 7, and 9 consider construction of new power generation capacity: 4MW solar (2017), 50MW solar (2018), combined cycle natural gas (2020-2023), and simple cycle natural gas (2024). These tables present output gains in addition to state and local tax impacts.

Tables 8 considers employment, output, and tax effects of operating a combined cycle natural gas plant, whereas Table 10 considers the same for a simple cycle natural gas plant. For this analysis, both plants were assumed to begin operations in 2024.

Project 1 - Closing Warrick 4 in 2018

	Full-Time Employees		*Contractors*	
	Employment	*Output*	*Employment*	*Output*
All Industries				
Direct	-20.0	($27,310,038)	-8.5	($12,045,715)
Indirect	-34.2	($4,922,690)	-15.1	($2,171,265)
Induced	-11.4	($1,386,040)	-4.9	($595,275)
Total	-65.5	($33,618,769)	-28.4	($14,812,255)
Total State and Local Tax				
Employee Compensation		($3,671)		($1,573)
Proprietor Income		$0		$0
Tax on Production and Imports		($1,613,929)		($711,053)
Households		($95,502)		($41,026)
Corporations		($38,654)		($17,022)

Results are based on industry 42 (electric power generation: fossil fuel).
Results assume a loss of 20 full-time employees compensated at $2,486,802 per year and a loss of 8.5 contractors compensated at $1,057,056 per year.

Project 2 - Closing Culley 2 in 2024

	Full-Time Employees		***Contractors***	
	Employment	*Output*	*Employment*	*Output*
All Industries				
Direct	-11	($13,437,577)	-4.3	($5,252,871)
Indirect	-16.8	($2,422,151)	-6.6	($946,841)
Induced	-5.5	($667,965)	-1.9	($234,639)
Total	-33.3	($16,527,692)	-12.8	($6,434,350)
Total State and Local Tax				
Employee Compensation		($1,766)		($614)
Proprietor Income		$0		$0
Tax on Production and Imports		($793,410)		($308,821)
Households		($46,034)		($16,188)
Corporations		($18,995)		($7,380)

Results are based on industry 42 (electric power generation: fossil fuel).
Results assume a loss of 11 full-time employees compensated at $1,331,946 per year and a loss of 4.3 contractors compensated at $447,200 per year.

Project 3 - Closing Culley 3 in 2024

	Full-Time Employees		*Contractors*	
	Employment	*Output*	*Employment*	*Output*
All Industries				
Direct	-69	($97,782,869)	-13.2	($18,706,289)
Indirect	-122.3	($17,625,562)	-23.4	($3,371,847)
Induced	-37	($4,517,091)	-6.2	($756,400)
Total	-228.3	($119,925,523)	-42.8	($22,834,535)
Total State and Local Tax				
Employee Compensation		($11,855)		($1,957)
Proprietor Income		$0		$0
Tax on Production and Imports		($5,756,238)		($1,095,780)
Households		($311,523)		($52,240)
Corporations		($137,635)		($26,145)

Results are based on industry 42 (electric power generation: fossil fuel).
Results assume a loss of 69 full-time employees compensated at $8,738,889 per year and a loss of 13.2 contractors compensated at $1,372,800 per year.

Project 4 - Closing AB Brown 1&2 in 2024

	Full-Time Employees		*Contractors*	
	Employment	*Output*	*Employment*	*Output*
All Industries				
Direct	-98	($127,912,993)	-25.2	($32,891,911)
Indirect	-57	($10,440,281)	-14.6	($2,684,644)
Induced	-31	($3,968,723)	-6.9	($879,987)
Total	-186	($142,321,997)	-46.7	($36,456,541)
Total State and Local Tax				
Employee Compensation		($12,283)		($2,711)
Proprietor Income		$0		$0
Tax on Production and Imports		($7,183,469)		($1,839,199)
Households		($365,377)		($81,053)
Corporations		($155,799)		($39,783)

Results are based on industry 42 (electric power generation: fossil fuel).
Results assume a loss of 98 full-time employees compensated at $12,270,357 per year and a loss of 25.2 contractors compensated at $2,620,800 per year.

Project 5 - Constructing 4MW Solar Capacity in 2017

	Output
All Industries	
Direct	$9,261,476
Indirect	$1,440,128
Induced	$2,899,524
Total	$13,601,127
Total State and Local Tax	
Employee Compensation	$3,403
Proprietor Income	$0
Tax on Production and Imports	$258,730
Households	$131,844
Corporations	$21,937

Results are based on industry 54 (construction of new power and communication structures).
Results assume $2,800,000 in contractor labor to construct.

Project 6 - Constructing 50MW Solar Capacity in 2018

	Output
All Industries	
Direct	$89,095,605
Indirect	$13,854,063
Induced	$27,653,003
Total	$130,602,671
Total State and Local Tax	
Employee Compensation	$32,316
Proprietor Income	$0
Tax on Production and Imports	$2,478,452
Households	$1,257,864
Corporations	$210,636

Results are based on industry 54 (construction of new power and communication structures).
Results assume $27,000,000 in contractor labor to construct.

Project 7 - Constructing a Combined Cycle Natural Gas-Fired Plant in 2020-2023

	Output
All Industries	
Direct	$725,237,558
Indirect	$134,468,005
Induced	$93,307,753
Total	$953,013,316
Total State and Local Tax	
Employee Compensation	$194,026
Proprietor Income	$0
Tax on Production and Imports	$16,775,454
Households	$8,874,606
Corporations	$1,223,487

Results are based on industry 54 (construction of new power and communication structures).
Results assume $45,000,000 in 2020, $45,000,000 in 2021, $45,000,000 in 2022, and $45,000,000 in 2023 in contractor labor to construct.

Project 8 - Operating a Combined Cycle Natural Gas-Fired Plant in 2024

	Full-Time Employees		***Contractors***	
	Employment	*Output*	*Employment*	*Output*
All Industries				
Direct	34.0	$44,377,978	22.0	$28,715,163
Indirect	19.8	$3,622,138	12.8	$2,343,737
Induced	11.2	$1,429,765	6.0	$770,652
Total	64.9	$49,429,882	40.8	$31,829,551
Total State and Local Tax				
Employee Compensation		$4,430		$2,374
Proprietor Income		$0		$0
Tax on Production and Imports		$2,495,225		$1,605,787
Households		$131,615		$70,982
Corporations		$54,158		$34,736

Results are based on industry 42 (electric power generation: fossil fuel).
Results assume a gain of 34 full-time employees compensated at $4,458,075 per year and a gain of 22 contractors compensated at $2,297,162 per year.

Project 9 - Constructing a Simple Cycle Natural Gas-Fired Plant in 2024

	Output
All Industries	
Direct	$388,618,653
Indirect	$38,237,963
Induced	$70,944,758
Total	$497,801,375
Total State and Local Tax	
Employee Compensation	$169,277
Proprietor Income	$0
Tax on Production and Imports	$8,991,505
Households	$4,937,371
Corporations	$870,824

Results are based on industry 54 (construction of new power and communication structures).
Results assume $147,269,000 in 2024 in contractor labor to construct.

Project 10 - Operating a Simple Cycle Natural Gas-Fired Plant in 2024

	Full-Time Employees		***Contractors***	
	Employment	*Output*	*Employment*	*Output*
All Industries				
Direct	19	$26,925,716	3	$4,251,429
Indirect	33.7	$4,853,415	5.3	$766,329
Induced	10.2	$1,237,941	1.4	$171,909
Total	62.8	$33,017,072	9.7	$5,189,667
Total State and Local Tax				
Employee Compensation		$3,247		$445
Proprietor Income		$0		$0
Tax on Production and Imports		$1,584,755		$249,041
Households		$85,379		$11,873
Corporations		$37,889		$5,942

Results are based on industry 42 (electric power generation: fossil fuel).
Results assume a gain of 19 full-time employees compensated at $2,390,000 per year and a gain of 3 contractors compensated at $312,000 per year.