2016 Integrated Resource Plan

VECTREN
Live Smart

By
Southern Indiana Gas and Electric Company
d/b/a Vectren Energy Delivery of Indiana, Incorporated

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Rule Reference	**Rule Description**	**Report Reference (Outline Section)**
170 IAC 4-7-4	**Methodology and documentation requirements**	
	(a) The utility shall provide an IRP summary document that communicates core IRP concepts and results to non-technical audiences. (1) The summary shall provide a brief description of the utility's existing resources, preferred resource portfolio, short term action plan, key factors influencing the preferred resource portfolio and short term action plan, and any additional details the commission staff may request as part of a contemporary issues meeting. The summary shall describe, in simple terms, the IRP public advisory process, if applicable, and core IRP concepts, including resource types and load characteristics. (2) The utility shall utilize a simplified format that visually portrays the summary of the IRP in a manner that makes it understandable to a non-technical audience. (3) The utility shall make this document readily accessible on its website.	Executive Summary and a separate document on www.vectren.com/irp
	(b) An IRP must include the following: (1) A discussion of the: (A) inputs; (B) methods; and (C) definitions; used by the utility in the IRP.	Included throughout the IRP

Rule Reference	Rule Description	Report Reference (Outline Section)
170 IAC 4-7-4 Cont.	(2) The data sets, including data sources, used to establish base and alternative forecasts. A third party data source may be referenced. The reference must include the source title, author, publishing address, date, and page number of relevant data. The data sets must include an explanation for adjustments. The data must be provided on electronic media, and may be submitted as a file separate from the IRP, or as specified by the commission.	Included throughout the IRP and Technical Appendix
	(3) A description of the utility's effort to develop and maintain a data base of electricity consumption patterns, by customer class, rate class, NAICS code, and end-use. The data base may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.	10.1.1.1; Technical Appendix Attachment 4.1 2016 Long-Term Electric Energy and Demand Forecast Report
	(4) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.	10.1.2
	(5) A discussion of distributed generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting.	4.4.1; 4.4.2; 4.4.3

Rule Reference	Rule Description	Report Reference (Outline Section)
	(6) A complete discussion of the alternative forecast scenarios developed and analyzed, including a justification of the assumptions and modeling variables used in each scenario.	6.1; 6.2
	(7) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.	8.2.10
	(8) A discussion of how the utility's emission allowance inventory and procurement practices for any air emission regulated through an emission allowance system have been taken into account and influenced the IRP development.	1.3.1.1; 7.3.4; 10.2; 10.2.1
	(9) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	2.2; 7.2.1; 8
170 IAC 4-7-4 Cont.	(10) A brief description and discussion within the body of the IRP focusing on the utility's Indiana jurisdictional facilities with regard to the following components of FERC Form 715: (A) Most current power flow data models, studies, and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The simulation must include the capability of meeting the standards of the North American Electric Reliability Corporation (NERC).	5.4; 10.6

Rule Reference	Rule Description	Report Reference (Outline Section)
	(C) Reliability criteria for transmission planning as well as the assessment practice used. The information and discussion must include the limits set of its transmission use, its assessment practices developed through experience and study, and certain operating restrictions and limitations particular to it. (D) Various aspects of any joint transmission system, ownership, and operations and maintenance responsibilities as prescribed in the terms of the ownership, operation, maintenance, and license agreement.	
	(11) An explanation of the contemporary methods utilized by the utility in developing the IRP, including a description of the following:	
	(A) Model structure and reasoning for use of particular model or models in the utility's IRP.	4.3; 5.2.3.3; 7.1.1.1; 7.2.1.1; 10.5
	(B) The utility's effort to develop and improve the methodology and inputs for its:	1.2.2
	(i) forecast;	4.2; 4.4.2; 6.1; 6.2
	(ii) cost estimates;	5.2
	(iii) treatment of risk and uncertainty; and	2; 6.2; 7; 8.1; 8.2
	(iv) evaluation of a resource (supply-side or demand-side) alternative's contribution to system wide reliability. The measure of system wide reliability must cover the reliability of the entire system, including:	
	(AA) transmission; and	5.4.3; 8.2.7; 10.6
	(BB) generation.	5.1.5.2; 7.3.5; 8.2.3

Rule Reference	Rule Description	Report Reference (Outline Section)
170 IAC 4-7-4 Cont.	(12) An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. Avoided cost shall include, but is not limited to, the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.	10.2.4
	(13) The actual demand for all hours of the most recent historical year available, which shall be submitted electronically and may be a separate file from the IRP. For purposes of comparison, a utility must maintain three (3) years of hourly data.	Technical Appendix Attachment4.2 2015 Vectren Hourly System Load Data
	(14) Publicly owned utilities shall provide a summary of the utility's: (A) most recent public advisory process; (B) key issues discussed; (C) how they were addressed by the utility.	3; Technical Appendix Attachment 3.1 Stakeholder Materials
170 IAC 4-7-5	**Energy and demand forecasts**	
	(a) An electric utility subject to this rule shall prepare an analysis of historical and forecasted levels of peak demand and energy	

Rule Reference	Rule Description	Report Reference (Outline Section)
	usage which includes the following:	
	(1) Historical load shapes, including, but not limited to, the following:	Technical Appendix Attachment 4.1 2016 Long-Term Electric Energy and Demand Forecast Report
	(A) Annual load shapes.	
	(B) Seasonal load shapes.	
	(C) Monthly load shapes.	
	(D) Selected weekly and daily load shapes. Daily load shapes shall include, at a minimum, summer and winter peak days and a typical weekday and weekend day.	
	(2) Historical and projected load shapes shall be disaggregated, to the extent possible, by customer class, interruptible load, and end-use and demand-side management program.	
	(3) Disaggregation of historical data and forecasts by customer class, interruptible load, and end-use where information permits.	Technical Appendix Attachment 4.1 2016 Long-Term Electric Energy and Demand Forecast Report; Technical Appendix Attachment 7.2 Balance of Loads and Resources
	(4) Actual and weather normalized energy and demand levels.	10.1.3
170 IAC 4-7-5 Cont.	(5) A discussion of all methods and processes used to normalize for weather.	10.1.3; 10.1.1.3
	(6) A minimum twenty (20) year period for energy and demand forecasts.	4.5
	(7) An evaluation of the performance of energy and demand forecasts for the previous ten (10) years, including, but not limited to, the following: (A) Total system.	10.1.3

Rule Reference	Rule Description	Report Reference (Outline Section)
	(B) Customer classes or rate classes, or both. (C) Firm wholesale power sales.	
	(8) Justification for the selected forecasting methodology.	Technical Appendix Attachment 4.1 2016 Long Term Electric Energy and Demand Forecast
	(9) For purposes of subdivisions (1) and (2), a utility may use utility specific data or more generic data, such as, but not limited to, the types of data described in section 4(b)(2) of this rule.	
	(b) A utility shall provide at least three (3) alternative forecasts of peak demand and energy usage. At a minimum, the utility shall include high, low, and most probable energy and peak demand forecasts based on alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices. (4) Changes in technology. (5) Behavioral factors affecting customer consumption. (6) State and federal energy policies. (7) State and federal environmental policies.	4.5; 6.2.2.2
170IAC 4-7-6	**Resource Assessment**	
	(a) The utility shall consider continued use of an existing resource as a resource alternative in meeting future electric service requirements. The utility shall provide a description of the utility's existing electric power resources that must include, at a minimum, the following information:	5.1
	(1) The net dependable generating capacity of the system and each generating unit.	5.1

Rule Reference	Rule Description	Report Reference (Outline Section)
	(2) The expected changes to existing generating capacity, including, but not limited to, the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	5.1; 7
	(3) A fuel price forecast by generating unit.	6.1
170IAC 4-7-6 Cont.	(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and (D) subsequent disposal; and (E) water consumption and discharge; at each existing fossil fueled generating unit.	10.2
	(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce transmission losses, congestion, and energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network. (D) An assessment of the transmission component of avoided cost.	10.6
	(6) A discussion of demand-side programs, including existing company-sponsored and government-sponsored or mandated energy conservation or load	5.1.4; 5.1.5; Technical Appendix Attachment 5.1 Vectren South

Rule Reference	Rule Description	Report Reference (Outline Section)
	management programs available in the utility's service area and the estimated impact of those programs on the utility's historical and forecasted peak demand and energy.	Electric 2016-2017 DSM Plan
	The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall also be provided for each year of the planning period.	
	(b) An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers. For a utility-sponsored program identified as a potential demand-side resource, the utility's IRP shall, at a minimum, include the following:	5.1.5; 5.2.3; 5.2.4
	(1) A description of the demand-side program considered.	5.2.3; 5.2.4
	(2) The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to resources under consideration such as project life and seasonal operation.	10.3.4
	(3) The customer class or end-use, or both, affected by the program.	5.1.4; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan

Rule Reference	Rule Description	Report Reference (Outline Section)
	(4) A participant bill reduction projection and participation incentive to be provided in the program.	Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
170IAC 4-7-6 Cont.	(5) A projection of the program cost to be borne by the participant.	Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(6) Estimated energy (kWh) and demand (kW) savings per participant for each program.	Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(7) The estimated program penetration rate and the basis of the estimate.	Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(8) The estimated impact of a program on the utility's load, generating capacity, and transmission and distribution requirements.	5.1.4; 5.2.3; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(c) A utility shall consider a range of supply-side resources including cogeneration and nonutility generation as an alternative in meeting future electric service requirements. This range shall include commercially available resources or resources the director may request as part of a contemporary issues technical conference. The utility's IRP shall include, at a minimum, the following:	5
	(1) Identify and describe the resource considered, including the following:	5; 10.6

Rule Reference	Rule Description	Report Reference (Outline Section)
	(A) Size (MW).	5
	(B) Utilized technology and fuel type.	5
	(C) Additional transmission facilities necessitated by the resource.	5.4.3
	(2) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	9.2.4
	(d) A utility shall consider new or upgraded transmission facilities as a resource in meeting future electric service requirements, including new projects, efficiency improvements, and smart grid resources. The IRP shall, at a minimum, include the following: (1) A description of the timing and types of expansion and alternative options considered. (2) The approximate cost of expected expansion and alteration of the transmission network. (3) A description of how the IRP accounts for the value of new or upgraded transmission facilities for the purposes of increasing needed power transfer capability and increasing the utilization of cost effective resources that are geographically constrained.	5.4.3
170IAC 4-7-6 Cont.	(4) A description of how: (A) IRP data and information are used in the planning and implementation processes of the RTO of which the utility is a member; and (B) RTO planning and implementation processes are used in and affect the IRP.	1.3.7; 4;6.1.3; 10.6.2
170 IAC 4-7-7	**Selection of future resources**	

Rule Reference	Rule Description	Report Reference (Outline Section)
	(a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in sections 6(b) through 6(c) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in, but not limited to, a resource summary table. The following information: (1) Significant environmental effects, including the following: (A) Air emissions. (B) Solid waste disposal. (C) Hazardous waste and subsequent disposal. (D) Water consumption and discharge.	10.2; Technical Appendix Confidential Attachment 1.2 2016 Vectren Technology Assessment Summary Table
	(2) An analysis of how existing and proposed generation facilities conform to the utility-wide plan to comply with existing and reasonably expected future state and federal environmental regulations, including facility-specific and aggregate compliance options and associated performance and cost impacts.	1.3.1; 6.1; 6.2; 7.3.4; 8.2.2; 10; Technical Appendix Attachment 3.1 Stakeholder Materials
	(b) Integrated resource planning includes one (1) or more tests used to evaluate the cost effectiveness of a demand-side resource option. A cost-benefit analysis must be performed using the following tests except as provided under subsection (e): (1) Participant. (2) Ratepayer impact measure (RIM). (3) Utility cost (UC). (4) Total resource cost (TRC). (5) Other reasonable tests accepted by the commission.	5.2.3.7; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan

Rule Reference	Rule Description	Report Reference (Outline Section)
	(c) A utility is not required to express a test result in a specific format. However, a utility must, in all cases, calculate the net present value of the program impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the discount rate used in the test.	5.2.3.7; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(d) A utility is required to:	
	(1) specify the components of the benefit and the cost for each of the major tests; and	5.2.3.7; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(2) identify the equation used to express the result.	5.2.3.7; Technical Appendix Attachment: 5.1 Vectren South Electric 2016-2017 DSM Plan
170 IAC 4-7-7 Cont.	(e) If a reasonable cost-effectiveness analysis for a demand-side management program cannot be performed using the tests in subsection (b), where it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.	5.2.3.7; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(f) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource options.	N/A
170 IAC 4-7-8	**Resource integration**	
	(a) The utility shall develop candidate resource portfolios from the selection of future resources in section 7 and provide a description of its process for developing its candidate resource portfolios.	7.1; 3.2; Technical Appendix Attachment 3.1 Stakeholder Materials

Rule Reference	Rule Description	Report Reference (Outline Section)
	(b) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and provide, at a minimum, the following information:	8.2
	(1) Describe the utility's preferred resource portfolio.	8.2
	(2) Identify the variables, standards of reliability, and other assumptions expected to have the greatest effect on the preferred resource portfolio.	8.2
	(3) Demonstrate that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis.	5; 6; 7; 8.2
	(4) Demonstrate that the preferred resource portfolio utilizes, to the extent practical, all economical load management, demand side management, technology relying on renewable resources, cogeneration, distributed generation, energy storage, transmission, and energy efficiency improvements as sources of new supply.	8.2
	(5) Discuss the utility's evaluation of targeted DSM programs including their impacts, if any, on the utility's transmission and distribution system for the first ten (10) years of the planning period.	5; 8.2; 10.3; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
170 IAC 4-7-8 Cont.	(6) Discuss the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio. The discussion of the preferred resource portfolio shall include, where appropriate, the following: (A) Operating and capital costs. (B) The average cost per kilowatt-hour, which must be consistent with the electricity price assumption used to forecast the utility's	8.2; 9.2.5; 10; Technical Appendix Confidential Attachment 7.3 Portfolio Input-Output Report

Rule Reference	Rule Description	Report Reference (Outline Section)
	expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.	
	(7) Demonstrate how the preferred resource portfolio balances cost minimization with cost effective risk and uncertainty reduction, including the following. (A) Identification and explanation of assumptions. (B) Quantification, where possible, of assumed risks and uncertainties, which may include, but are not limited to: See below. (i) regulatory compliance; (ii) public policy; (iii) fuel prices; (iv) construction costs; (v) resource performance; (vi) load requirements; (vii) wholesale electricity and transmission prices; (viii) RTO requirements; and (ix) technological progress. (C) An analysis of how candidate resource portfolios performed across a wide range of potential futures.	7; 8.2; Technical Appendix Attachment 3.1 Stakeholder Materials
	(D) The results of testing and rank ordering the candidate resource portfolios by the present value of revenue requirement and risk metric(s). The present value of revenue requirement shall be stated in total dollars and in dollars per kilowatt-hour delivered, with the	7.3.1; 10.5.2; Technical Appendix Attachment 3.1 Stakeholder Materials

Rule Reference	Rule Description	Report Reference (Outline Section)
	discount rate specified.	
170 IAC 4-7-8 Cont.	(E) An assessment of how robustness factored into the selection of the preferred resource portfolio.	2; 7; 8
	(8) Demonstrate, to the extent practicable and reasonable, that the preferred resource portfolio incorporates a workable strategy for reacting to unexpected changes. A workable strategy is one that allows the utility to adapt to unexpected circumstances quickly and appropriately. Unexpected changes include, but are not limited to, the following: See below. (A) The demand for electric service. (B) The cost of a new supply-side or demand-side technology. (C) Regulatory compliance requirements and costs. (D) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	7; 8
170 IAC 4-7-9	**Short term action plan**	
	Sec. 9. A short term action plan shall be prepared as part of the utility's IRP, and shall cover each of the three (3) years beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(b)(8), where the utility must take action or incur expenses during the three (3) year period. The short term action plan must include, but is not limited to, the following:	9

Rule Reference	Rule Description	Report Reference (Outline Section)
	(1) A description of each resource in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective. (2) The implementation schedule for the preferred resource portfolio. (3) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts. (4) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually transpired.	

List of Acronyms/Abbreviations

AAB	Advanced Automotive Batteries
ABB	AB Brown Generating Station
AC	Alternating Current
AUPC	Average Use Per Customer
B	Water Heating Service – Closed to new customers
BAGS	Broadway Avenue Generating Station
Bat	Battery
BES	Bulk Electric System
Bn	Billion
BNEF	Bloomberg New Energy Finance
BOS	Balance of System
BTMG	Behind The Meter Generation
Btu	British Thermal Unit
C&I	Commercial and Industrial
CAA	Clean Air Act
CAC	Citizens Action Coalition
CAES	Compressed Air Energy Storage
CAGR	Compound Annual Growth Rate
CAPP	Central Appalachian
CC	Combined Cycle
CC CT	Combined Cycle Combustion Turbine
CC ST	Combined Cycle Steam Turbine
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Day
CEMAC	Clean Energy Manufacturing Analysis
CEMS	Continuous Emissions Monitoring System
CFL	Compact Fluorescent Lighting
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
Comm	Commercial
CPCN	Certificate of Public Need and Necessity
CPP	Clean Power Plan
CSA	Coordinated Seasonal Transmission Assessment
CSAPR	Cross State Air Pollution Rule
CVR	Conservation Voltage Reduction
CWIS	Cooling Water Intake Structures
DB	Deutsche Bank
DC	Direct Current
DG	Distributed Generation
DGS	Demand General Service
DLC	Direct Load Control

List of Acronyms/Abbreviations (Cont.)

DOE	U.S. Department of Energy
DR	Demand Response
DSI	Dry Sorbent Injection
DSM	Demand Side Management
DSMA	Demand Side Management Adjustment
EEFC	Energy Efficiency Funding Component
EERE	Energy Efficiency and Renewable Energy
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines
EM&V	Evaluation, measurement, and Verification
EOP	Emergency Operating Procedure
EPA	U.S. Environmental Protection Agency
EPC	Engineering Procurement and Construction
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
EV	Electric Vehicle
EVA	Energy Ventures Analysis, Inc.
FBC	FB Culley Generating Station
FBC3	FB Culley Unit 3
FDNS	Fixed Slope Decoupled Newton-Raphson
FERC	Federal Energy Regulatory Commission
FF	Fabric Filter
FGD	Flue Gas Desulfurization
GDP	Gross Domestic Product
GE	General Electric
GPCM	Gas Pipeline Competition Model
GPS	Global Positioning System
GS	General Service
GT	Gas Turbine
GTM	Green Tech Media
GW	Gigawatt
GWh	Gigawatt Hour
H_2SO_4	Hydrochloric Acid
HAP	Hazardous Air Pollutants
HCl	Hydrochloric Acid
HDD	Heating Degree Days
Hg	Mercury
HHV	Higher Heating Value
HLF	High Load Factor
HRSG	Heat Recovery Steam Generator
HUM	Humidity

List of Acronyms/Abbreviations (Cont.)

I&M	Indiana Michigan Power
IC	Internal Combustion
ICAP	Installed Capacity
IDEM	Indiana Department of Environmental Management
IGCC	Integrated Gasification Combined Cycle
ILB	Illinois Basin
Ind	Industrial
IPL	Indianapolis Power and Light Company
IPP	Independent Power Producers
IRP	Integrated Resource Plan
ISO	Independent System Operator
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
lb	Pound
LBA	Load Balancing Area
LGE/KU	Louisville Gas and Electric/Kentucky Utilities
LIB	Lithium-ion Battery
Li-ion	Lithium-ion
LMP	Local Marginal Pricing
LMR	Load Modifying Resources
LMR	Load Management Receivers
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LP	Large Power
LRR	Local Reliability Requirement
LRZ	Local Resource Zone
LSE	Load Serving Entity
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
MEP	Market Efficiency Project
MILP	Mixed Integer Linear Programming
MISO	Midcontinent Independent System Operator
MISO Tariff	Open Access Transmission, Energy, and Operating Reserve Markets Tariff
MLA	Municipal Levee Authority
MMBtu	One Million British Thermal Unit
MMWG	Multiregional Modeling Working Group
MPSC	Missouri Public Service Commission
MSA	Metropolitan Statistical Area

List of Acronyms/Abbreviations (Cont.)

MTEP	MISO Transmission Expansion Plan
MVP	Multi Value Project
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standard
NAICS	North American Industry Classification System
NAPP	Northern Appalachia
NEGT	Northeast Gas Turbine
NERC	North American Electric Reliability Council
NERC MOD	NERC Modeling, Data, and Analysis
NIPSCO	Northern Indiana Public Service Company
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NPVRR	Net Present Value Revenue Requirement
NREL	National Renewable Energy Lab
NW Council	Northwest Power and Conservation Council
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
OMS	Organization of MISO States
ORSANCO	Ohio River Valley Sanitation Commission
OSS	Off Season Service
OUCC	Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PI	Personal Income
PIRA	PIRA Energy Group
PJM	Pennsylvania New Jersey Maryland Interconnection LLC
PM	Particulate Matter
PPA	Purchase Power Agreement
PPT	Parts Per Trillion
PRA	Planning Resource Auction
PRB	Powder River Basin
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PSEG	Public Service Electric and Gas
PSIG	Pounds Per Square Inch Gauge
PTI PSS/E	Power Technologies Incorporated's Power System Simulator Program for Engineers
PUC	Public Utility Commission
PV	Photovoltaic

List of Acronyms/Abbreviations (Cont.)

Res	Residential
RF	ReliabilityFirst
RGGI	Regional Greenhouse Gas Initiative
RIM	Ratepayer Impact Measure
RS	Residential Service
RTO	Regional Transmission Operator
SAE	Statistically Adjusted End-use
SB	Senate Bill
SBS	Sodium Bisulfite
SCADA	Supervisory Control and Data Acquisition
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SD	Standard Deviation
SDE	Stochastic Differential Equation
SEA	Senate Enrolled Act
SEIA	Solar Energy Industries Association
SGS	Small General Service
SIGECO	Southern Indiana Gas and Electric Company
SIP	State Implementation Plan
SIS	System Impact Study
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
STD Dev	Standard Deviation
SVC	Static Var Compensator
T&D	Transmission and Distribution
TBtu	One Trillion British Thermal Unit
TRC	Total Resource Cost
TVA	Tennessee Valley Authority
UC	Utility Cost
UCAP	Unforced Capacity
UCT	Utility Cost Test
UE	University of Evansville
UPC	Use Per Customer
V	Volt
VAR	Volt-Amp Reactance
VEDO	Vectren Energy Delivery of Ohio
VOM	Variable Operation and Maintenance
VUHI	Vectren Utility Holdings Inc.
Wdc	Watt Direct Current
WN	Weather Normalized
WTE	Waste To Energy

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Executive Summary (Non-Technical Summary)

I. Introduction

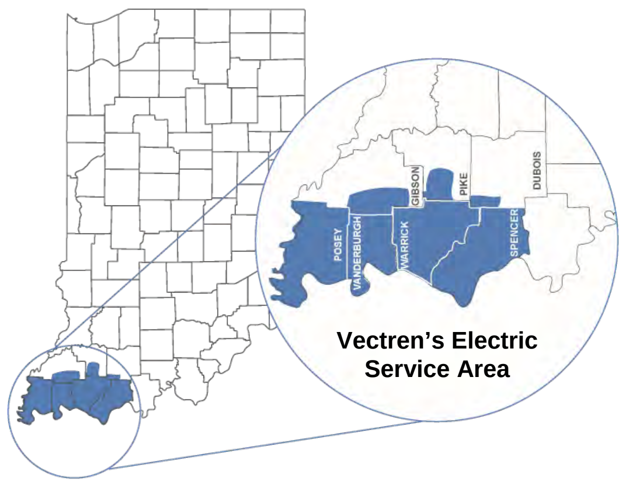
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren") engaged in a planning exercise during 2016 to evaluate its electric supply needs over a 20-year planning horizon. That exercise culminated in this 2016 Integrated Resource Plan ("IRP"). This planning 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

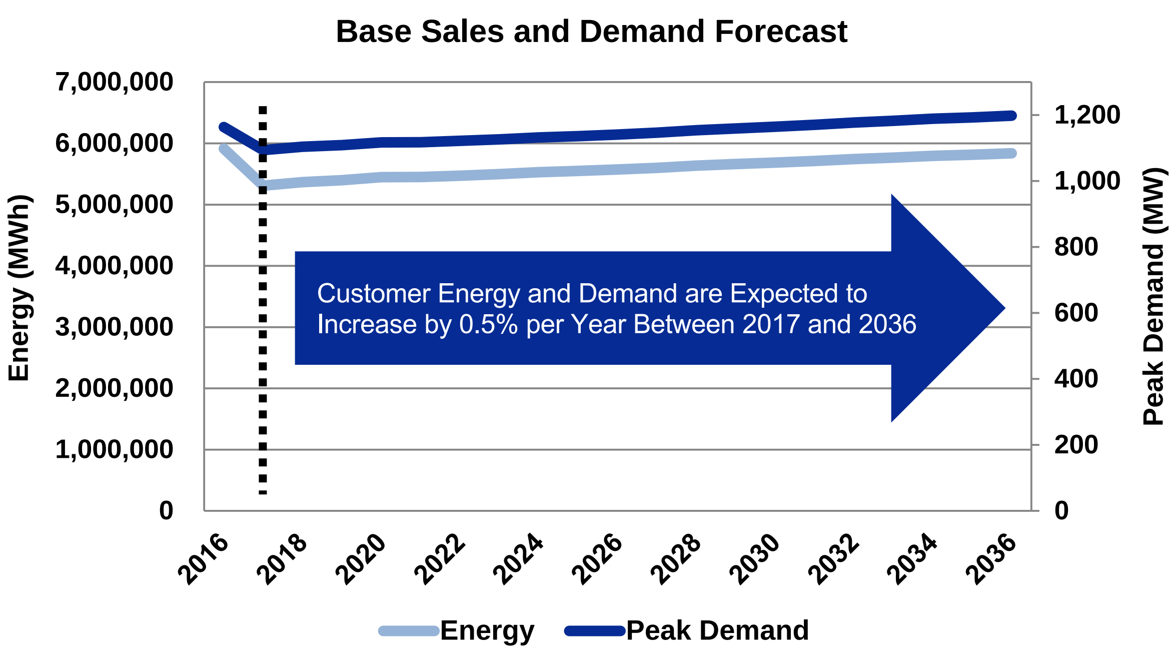
Vectren periodically submits IRPs to the Indiana Utility Regulatory Commission (IURC or Commission) as required by IURC rules. The IRP describes the analysis process used to determine the best mix of generation and energy efficiency resources (resource portfolio) to meet customers' needs for reliable,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

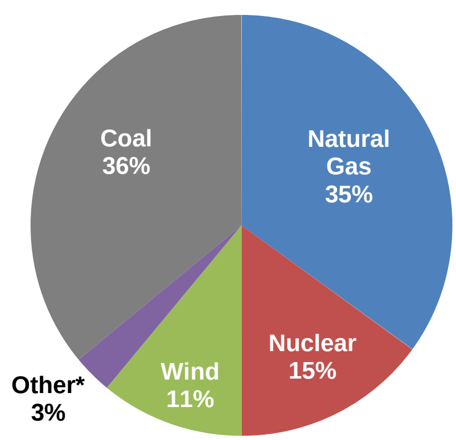
While Vectren's coal plants are controlled to meet or exceed current regulations for Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_x), mercury, and particulate matter (dust), new EPA regulations require Vectren, and other utilities around the country, to make incremental investments in coal-fired generation 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



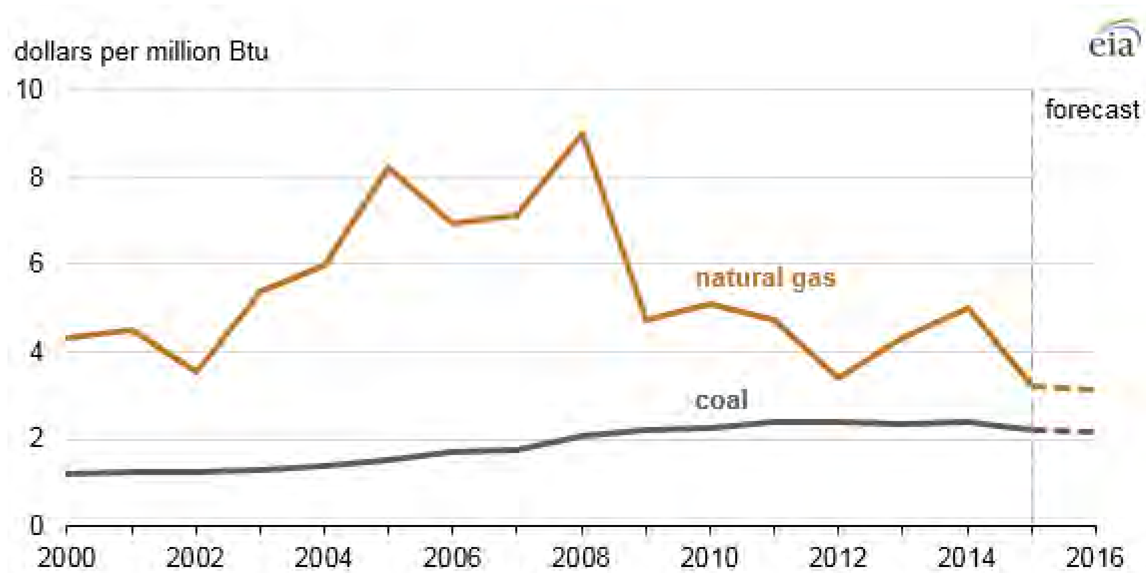
*Other includes hydro, pumped hydro, oil, solar, and others.

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].

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

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

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

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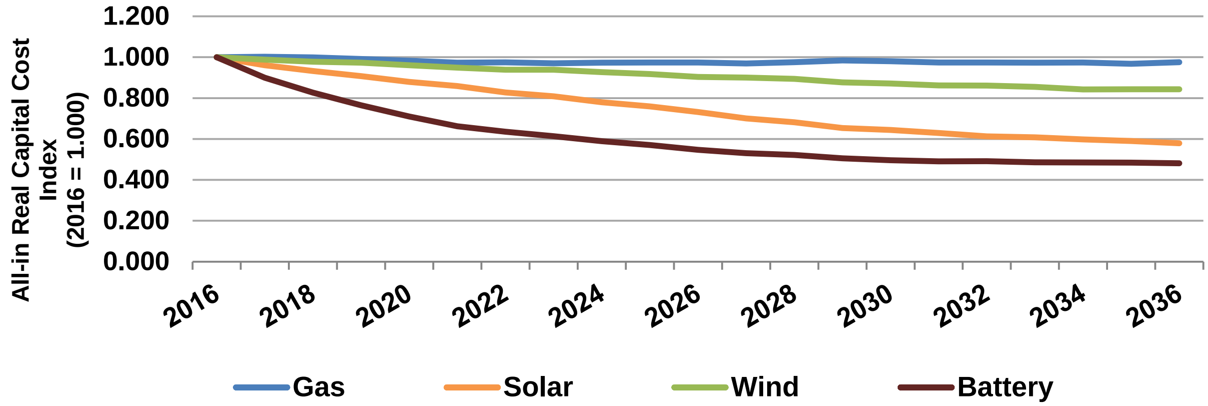
Special%20Meetings/2016/20161031%20Winter%20Readiness%20Workshop/20161031%20Winter%20Readiness%20Workshop%20Presentation.pdf, Slide 64
[4] U.S. Energy Information Administration, *Electric Power Monthly*, and *Short-Term Energy Outlook* (March 2016); http://www.eia.gov/todayinenergy/detail.cfm?id=25392

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

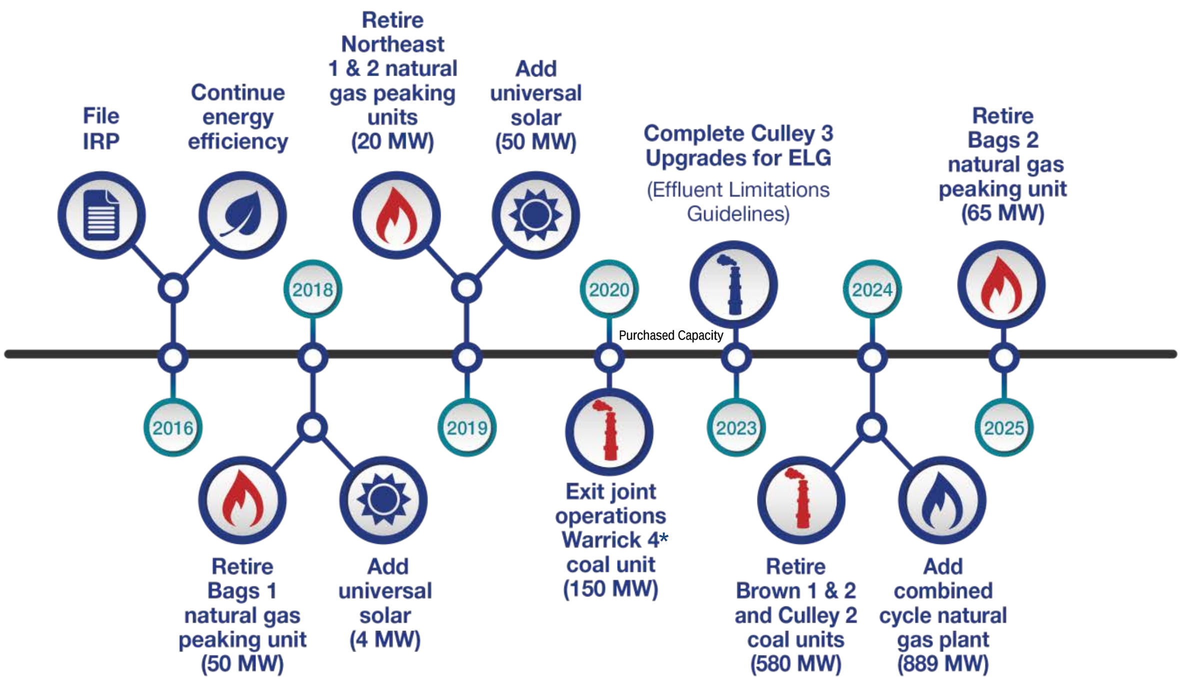
Vectren worked hard to have an open forum for stakeholders to voice questions/concerns and make suggestions on the IRP analysis. Each Vectren stakeholder meeting was opened by Carl Chapman, Chairman, President, and Chief Executive Officer of Vectren. He and other senior management, Vectren subject matter 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



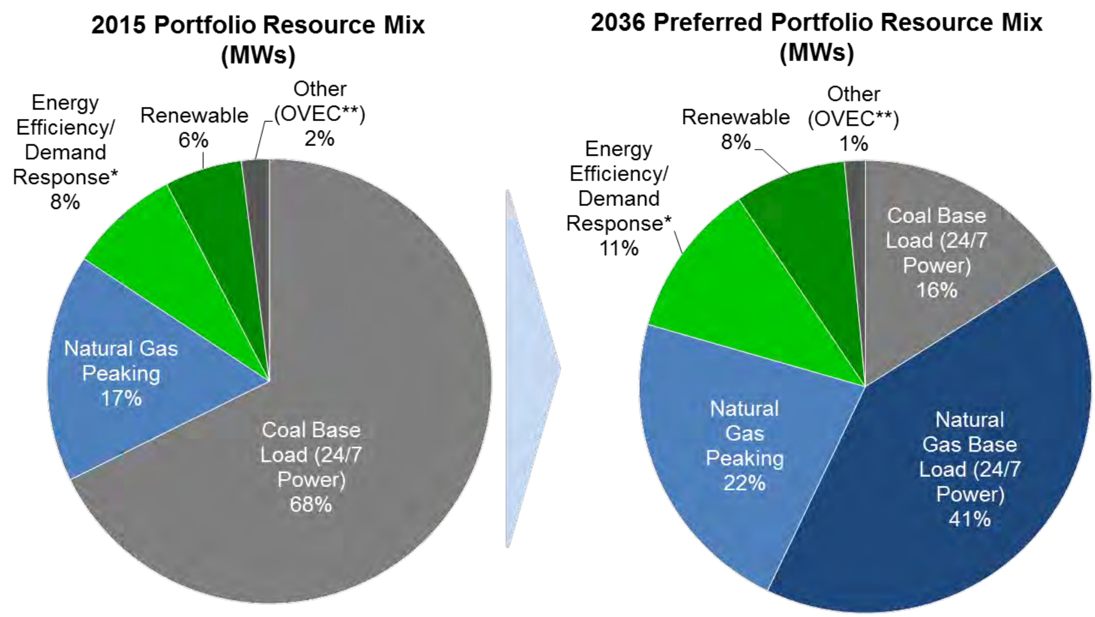
*Warrick 4 jointly owned with Alcoa, which is in the midst of transition. Vectren continues to discuss the future of Warrick 4 with Alcoa.

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.

SECTION 1
OVERVIEW

1.1 COMPANY BACKGROUND

Vectren Corporation is an energy holding company headquartered in Evansville, Indiana. Vectren's wholly owned subsidiary, Vectren Utility Holdings, Inc. (VUHI), is the parent company for three operating utilities: Indiana Gas Company, Inc. (Vectren North), Southern Indiana Gas and Electric Company (Vectren), and Vectren Energy Delivery of Ohio (VEDO).

Vectren North provides energy delivery services to more than 570,000 natural gas customers located in Central and Southern Indiana. Vectren provides energy delivery services to over 144,000 electric customers and approximately 110,000 gas customers located near Evansville in Southwestern Indiana. VEDO provides energy delivery services to approximately 312,000 natural gas customers near Dayton in West Central Ohio.

1.2 INTEGRATED RESOURCE PLANNING

Vectren takes integrated resource planning very seriously. Vectren is required to submit its Integrated Resource Plan (IRP) to the Indiana Utility Regulatory Commission (IURC) every two years (moving to a three year cycle). The IRP begins with a forecast of customer electric needs over a 20-year period and is used as a guide for how Vectren will serve existing and future customers in a reliable and economic manner. The integrated resource plan can be thought of as a compass setting the direction for future generation and demand side management (DSM) options. It is not a turn-by-turn GPS. Future analyses of changing conditions, filings, and subsequent approvals from the IURC are needed to chart the specific course.

The future is uncertain. Several factors have helped to set the stage for this analysis. Environmental Protection Agency (EPA) regulations are putting great pressure on coal resources. Several regulations that were recently finalized are more stringent than originally proposed. Gas prices are low and projected to be stable over the long term.

Shale gas has revolutionized the industry, driving these low gas prices. This has fueled a surge in gas generation investment.

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 will continue to monitor developments related to the high voltage transmission lines still needed to both increase the availability and reduce the cost of wind. Additionally, Vectren will continue to observe developments in Midcontinent Independent System Operator (MISO), Vectren's regional transmission operator. Within Vectren's zone, MISO is projecting a shortfall in generation and demand side options needed to maintain reliability beginning in 2018 for high certainty resources[6]. The shortfall continues to grow through 2021. Regardless of the final plan, reliability needs to be maintained, and customer costs must be a priority.

1.2.1 IRP Objectives

Vectren's IRP objectives are based on the need for a resource strategy that provides value to its customers, communities, and shareholders. Vectren's IRP strategy is designed to accommodate the ongoing changes and uncertainties in the competitive and regulated markets. The main objective is to select a preferred portfolio[7] of supply and demand resources to best meet customers' needs for reliable, reasonably priced, environmentally acceptable power over a wide range of future market and regulatory conditions taking into account risk and uncertainty. Specifically, Vectren's objectives are as follows:

- Maintain reliability
- Minimize rate/cost to customers
- Mitigate risk to Vectren customers and shareholders
- Provide environmentally acceptable power leading to a lower carbon future

[6] High certainty resources are existing resources that have a "High" confidence of being available in the planning year, as determined by utilities in the Organization of MISO States (OMS) survey.
[7] A portfolio is a mix of future supply and demand side resources to meet expected future demand for electricity.

- Include a balanced mix of energy resources
- Minimize negative economic impact to the communities that Vectren serves

1.2.2 IRP Development

Since conducting the 2014 IRP, Vectren has worked diligently to incorporate stakeholder input (direct comments about the 2014 IRP, including the director's report, and indirect comments through suggestions to other utilities) into the 2016 analysis. As a result, the 2016 IRP is much more robust than any Vectren IRP before it.

Vectren made the following commitments, which are incorporated into this IRP analysis:

- construct scenarios (possible future states), which include coordinated data inputs with a well-reasoned narrative,
- conduct a probabilistic risk analysis to explore the outer bounds of probability,
- model future energy company sponsored energy efficiency as a resource (not built into the load forecast),
- evaluate if retirement makes sense for any of Vectren's existing coal generating units within the 20 year time frame under each scenario,
- monitor Combined Heat and Power (CHP) developments and include CHP as a resource option,
- consider conversion or repower of coal units to gas,
- fully consider renewable options, and
- update the IRP document format to be more readable.

Vectren worked closely with industry experts to develop a comprehensive analysis. Pace Global helped with scenario development, modeling inputs, and a comprehensive risk analysis, which included probabilistic modeling. Burns and McDonnell developed a technology assessment which provides resource costs for various types of generation technologies, such as gas, solar, wind, storage, etc. It can be found in Technical Appendix Confidential Attachment 1.2 2016 Vectren Technology Assessment Summary Table. Vectren also engaged Burns and McDonnell in developing a site selection analysis to better understand the ideal location for gas generation, should it be chosen in the preferred portfolio. Additionally, Burns and McDonnell conducted a portfolio screening analysis to help determine the preferred portfolio. Itron developed the base sales and demand forecast, which included a forecast of customer owned solar generation.

1.3 CHANGES THAT HAVE OCCURRED SINCE THE LAST IRP

Several developments have occurred since the last IRP was submitted in 2014, which helps to illustrate the dynamic nature of integrated resource planning. The IRP analysis and subsequent write up represent the best available information for a point in time. The following sections discuss some of the major changes that have occurred over the last two years. The robust risk analysis recognizes that conditions will change. Changes over the last few years provided Vectren with valuable insight on how modeled scenario outcomes can change over time.

1.3.1 Environmental Rules

1.3.1.1 Air

There have been a number of changes in air regulations since the 2014 IRP. The Mercury and Air Toxics Standard (MATS) was published in the Federal Register in February 2012. The rule sets plant-wide emission limits for the following hazardous air pollutants (HAPs): mercury, non-mercury HAPs (e.g. arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride)[8]. Compliance with the new limits was required by April 16, 2015. At the time of the last IRP, Vectren was awaiting approval by the Commission for its MATS Compliance plan (IURC Cause 44446) which included organosulfide injection at the base load units (AB Brown 1, AB Brown 2, FB Culley 3, and Warrick 4). All equipment

[8] MATS Limits: The EPA established stringent plant-wide mercury emission limits (1.2 lb/TBtu for individual unit or 1.0 lb/TBtu for plant average) and set surrogate limits for non-mercury HAPs (total particulate matter limit of .03 lb/MMBtu) and acid gases (HCL limit of .002 lb/MMBtu). The surrogate limits can be used instead of individual limits for each HAP.

has been approved and installed, and Vectren's units are currently in compliance with MATS limits.

In March 2015, EPA entered into a Consent Decree[9] with environmental stakeholders to resolve litigation concerning deadlines for completing 1-hour sulfur dioxide (SO_2) National Ambient Air Quality Standard (NAAQS) designations. EPA identified five sources in Indiana that exceeded a set threshold for SO_2, including the AB Brown plant. In order to ensure that Posey County continued to meet the attainment designation for the new one hour standard, Vectren voluntarily agreed to lower its emission rate for SO_2 at its AB Brown plant. Vectren requested a Commissioner's Order to voluntarily accept a lower SO_2 emission limit that went into effect April 19, 2016. The state will continue to review modeling for additional counties including Warrick County and the FB Culley and Warrick power plants located within that county. A preliminary review indicates that Warrick County is in compliance without additional reductions.

In December 2015, Vectren agreed to a modified Consent Decree to resolve alleged air violations at the FB Culley and AB Brown plants. Based on the negotiated settlement, Vectren eliminated the bypass stack for FB Culley Unit 2 and installed equipment to mitigate incremental sulfur trioxide (SO_3) emissions from the selective catalytic reduction technology installed on AB Brown Units 1 and 2 and FB Culley Unit 3 to control nitrogen oxides (NOx). Each unit is required to maintain a sulfuric acid (H_2SO_4) emission limit to demonstrate compliance.

EPA finalized the Clean Power Plan (CPP) that established carbon dioxide (CO_2) emission standards for a state's electric generating fleet in August 2015. States were given the discretion to set unit specific limits or adopt a mass-based or rate-based allowance trading program. The US Supreme Court issued a stay of the rule, which will remain in place through ultimate Supreme Court review of the opinion of the lower court.

[9] The Consent Decree required EPA to designate as nonattainment, attainment, or unclassifiable certain areas that included sources that emitted more than 16,000 tons of SO_2 in 2012 or emitted more than 2,600 tons of SO_2 with an average emission rate greater than 0.45 lbs/MMBtu.

It is not anticipated that final order on judicial review will come until late 2017 at the earliest. In the event that the CPP is upheld, the state of Indiana will likely develop a State Implementation Plan (SIP). For this analysis, Vectren assumed a two year delay with compliance beginning in 2024.

In addition to the above regulations, on September 7, 2016, EPA finalized the Cross State Air Pollution Rule (CSAPR) Update Rule which established lower ozone season Nitrous Oxide (NOx) allowances for each unit to incorporate the revised Ozone NAAQS. The new limits take effect with the ozone season beginning in May 2017.

1.3.1.2 Water

On September 30, 2015, EPA published the final Effluent Limitations Guidelines rule (ELG). The rule sets strict technology based limits for waste water generated from fossil fuel fired generating facilities and in particular, will force significant operational and technological changes at coal-fired power plants. In the draft proposal, EPA listed eight possible options, with four identified as “preferred.” Within the group of preferred options were exemptions for smaller scrubbers and generating units that could have exempted Vectren’s units from certain requirements. However, in the final regulation EPA chose to bypass the preferred options and went with a hybrid of the most stringent options for fly ash transport water, bottom ash transport water, and flue-gas desulfurization (FGD) waste water.

While the final rule includes reference to multiple waste waters, the key elements applicable to Vectren are FGD waste water and ash transport water. Specifically, FGD waste water must meet new limits for arsenic, mercury, selenium, and nitrate at the end of the wastewater treatment system and prior to mixing with any other process water. Water used to transport bottom ash or fly ash is prohibited from discharge in any quantity which effectively forces the installation of dry or closed loop ash handling systems. The applicability date for the new requirements shall be as soon as possible after November 1, 2018 but no later than December 31, 2023 and established in a schedule outlined in National Pollutant Discharge Elimination System (NPDES) permit renewals. For FGD waste water, alternate, but more restrictive limits can be voluntarily agreed to which would automatically extend the applicability date to December 31, 2023. Technology to meet the more restrictive limits could include the installation of zero liquid discharge equipment that would eliminate all discharge of FGD waste water.

1.3.1.3 Waste

The Coal Combustion Residuals Rule (CCR) was finalized on April 17, 2015. The rule regulates the final disposal of CCRs which include fly ash, bottom ash, boiler slag, and flue gas desulfurization solids. The rule is applicable to all new and existing landfills and surface impoundments used to store or dispose of CCRs at a power plant that was generating electricity on the effective date of the rule (October 2015). The rule establishes operating criteria and assessments as well as closure and post closure care standards. The regulatory deadlines that could trigger the closure of surface impoundments include non-compliance with safety factor assessment standards (April 2017), exceedance of ground water protection standards (April 2018), or failure to demonstrate compliance with location restrictions (April 2019).

1.3.1.4 Post-election Regulations Update

President-elect Trump has indicated that he intends to review environmental regulations. However, at this time 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. In order to rescind and/or modify a final regulation such as the CPP, or the CCR and ELG rules, the new administration would be required to go through a new notice and comment rulemaking process, which could require 18 months to 2 years to complete, and in the case of health and / or technology based standards such as the ELG rule would require a defensible rationale.

With respect to the issue of carbon regulations, President-elect Trump could withdraw from the non-binding Paris carbon reduction goals. However, as indicated above, the

CPP is a final regulation, so it must be rescinded/modified through a supplemental notice and comment rulemaking. Additionally, the previous Endangerment Finding would also need to be rescinded and/or modified. It should also be noted the new Department of Justice may choose to no longer defend the rule; however, the rule would still be defended by some states and environmental groups. While these options are possible, all would require some time. The IRP is a long-term resource plan; future administrations will likely pursue a lower carbon future.

Even if the Trump administration successfully delays/rescinds the CPP, Vectren's decision on continuing operation of its coal-fired fleet is more heavily influenced by the CCR and ELG rules, the primary driver of near-term environmental compliance expenditures modeled in the IRP. These rules require notice and comment rulemaking to rescind and/or modify, which is an 18-24 month process. Rules such as the ELG rule are technology mandates arising under legislation, in this case the Clean Water Act, and are more difficult to set aside. They must be supported by a technological or human health rationale.

1.3.2 Environmental Upgrades for MATS

To comply with the Mercury and Air Toxics Standard (MATS), Vectren installed equipment to inject an organo-sulfide solution into the scrubbers at AB Brown Units 1 and 2, FB Culley combined stack for Units 2 and 3, and Warrick Unit 4. In addition to the treatment technology, MATS also required the installation of new monitoring equipment on the stacks for each of the listed units to assess compliance with the new limits. Continuous emissions monitoring system (CEMS) was installed to monitor filterable particulate (as a surrogate for non-mercury HAPS metals), a separate CEMS to monitor hydrogen chloride, and sorbent traps to measure mercury.

1.3.3 Legislation and IRP Rule Making Process

The Demand Side Management ("DSM") landscape in Indiana has undergone significant changes in recent years, beginning in 2014 with the enactment of Senate

Enrolled Act 340 ("SEA 340"). This not only allowed certain large Commercial & Industrial (C&I) customers to opt-out of participation in Company sponsored energy efficiency ("EE") programs, but also eliminated the savings targets for jurisdictional electric utilities established by the Commission in Cause No. 42396 ("Phase II Order").

Since then, Senate Enrolled Act 412 ("SEA 412") was codified at Ind. Code § 8-1-8.5-10 ("Section 10"), and further impacts how utilities plan for and implement EE programs in Indiana. Beginning not later than calendar year 2017, an electricity supplier, which includes Vectren, is required to petition the Commission at least one time every three years for approval of a plan that includes: (1) energy efficiency goals; (2) energy efficiency programs to achieve the energy efficiency goals; (3) program budgets and program costs; and (4) evaluation, measurement, and verification ("EM&V") procedures that must include independent EM&V (the "Plan").

Once a Plan has been submitted for approval, the Commission must consider the ten factors outlined in Section 10 when determining the overall reasonableness of the Plan. One of the factors that must be considered in this determination is whether the Plan is consistent with the electricity supplier's most recent long range IRP submitted to the Commission. Section 10 requires the Commission to approve an electricity supplier's Plan if, after notice, hearing, and consideration of the ten factors outlined in Section 10, the Commission determines the plan to be reasonable.

Besides the enactment of Section 10, another regulatory development is the pending rulemaking currently underway, known as IURC RM #15-06 that continues to refine the IURC's IRP rules. This is essentially a continuation of the rulemaking from IURC RM #11-07 that resulted in a draft rule dated October 4, 2012, which was never finalized and adopted by the Commission. However, Vectren and other utilities began voluntarily following the 2012 [IRP] draft rule in 2013 and 2014, which outlines the requirements for the IRP process and the IRP report. In crafting the proposed rule, the Commission began with the 2012 draft rule and accepted comments and edits to that draft rule. One significant change from the 2012 draft rule to the proposed rule is the switch from a two year filing requirement to a three year filing requirement, which matches the three year EE Plan filing requirement set forth in Section 10. Vectren continues to actively participate in the rulemaking process and will be prepared to follow the rule once it is finalized and adopted by the Commission. Note that Vectren followed the 2012 draft rule for the 2016 IRP.

1.3.4 Alcoa

In January of this year, Alcoa announced it would permanently cease production of its Warrick Operation smelter in the 1st quarter. Alcoa also communicated that the on-site rolling mill and power plant will continue to operate.

The Warrick power plant consists of four generating units: three 150 Megawatt (MW) industrial units wholly owned by Alcoa and one 300 MW electric generating unit (Warrick 4) that is jointly owned by 50% Alcoa and 50% Vectren. Prior to the smelter closing, the Alcoa power plant provided most of its 600 MW electric generation, if not all, to meet the electric demand of the Warrick Operations facility with the smelter being the majority of that demand. With the smelter closing on March 24, 2016, the electric demand for the Warrick Operations facility is dramatically less. Alcoa has recently split into two (2) separate public companies. Given these operational and organizational changes, Alcoa's interest in continuing to operate the jointly owned Warrick 4 300 MW electric generating unit is unclear.

1.3.5 Co-generation (Combined Heat and Power)

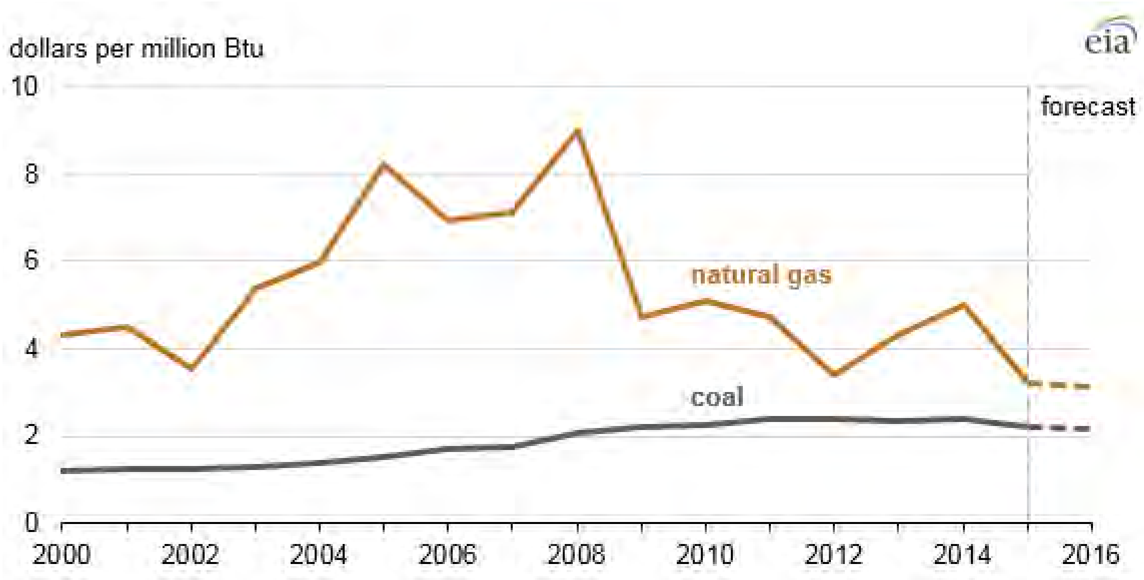
A large industrial customer has installed a natural gas fired co-generation unit that is expected to come on-line by January 2017. The co-generation unit is expected to cover the majority of this customer's load, and Vectren will cover the balance with firm service. The co-generation unit will produce steam and electricity for production processes. This development is reflected in the sales and demand forecast for the IRP.

1.3.6 Increasing Use of Gas-Fired Generation, Regionally and Nationally

There has been a surge of natural gas generation in the United States over the last several years. According to the EIA, electricity net generation from natural gas in the US has increased from approximately 14% in 2000 to approximately 32% in 2015[10]. This has been driven by three primary factors 1) low gas prices, 2) age of existing coal fired generation, and 3) stricter environmental requirements imposed on coal fired generation.

Gas prices are low and projected to remain stable over the long term. Shale gas has revolutionized the industry, driving gas prices down to historically low levels as the supply of natural gas has grown. In recent years, natural gas generation has been competitive with coal generation and therefore has frequently been economically dispatched in place of coal. The table below shows average gas and coal fuel receipt costs at electric generating units between 2000 and 2016[11].

Figure 1.1 – Average Fuel Receipt Costs at Electric Generating Plants (2000-2016)



[10] US Energy Information Administration; August 2016 Monthly Energy Review, Table 7.2b Electricity Net Generation: Electric Power Sector; http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf
[11] U.S. Energy Information Administration, *Electric Power Monthly*, and *Short-Term Energy Outlook* (March 2016); http://www.eia.gov/todayinenergy/detail.cfm?id=25392

Coal has been a long standing fuel for electric generation in the US, as a result a substantial portion of the existing coal fleet is reaching the age when wear and tear, and equipment obsolescence has made their continued operation uneconomic in the long run. Consequently a very sizeable portion of the US coal fleet has, or is expected, to retire due to old age.

In addition, as mentioned in Section 1.3.1, numerous environmental rules have been recently finalized by the EPA, including MATS, ELG, CCR, and CPP. Collectively these rules have helped to retire coal plants across the country, with more closures to come through the early 2020s due to associated compliance costs. Additionally, some politicians and environmental advocacy groups have worked hard to negatively shape public perception of coal fired power plants. Government support for renewables in the form of tax incentives and renewables portfolio standards have also helped to displace coal generation in the market.

1.3.7 MISO

MISO requires Vectren and other member electric utilities to maintain a Planning Reserve Margin (PRM). The PRM is designed to ensure there is enough power capacity throughout the MISO region to meet customer demands during peak periods, including peak periods where some equipment might fail. In recent years, the Planning Reserve Margin (PRM) throughout MISO has dwindled. Because there is less availability of capacity, the price for capacity available in MISO's annual auction has been volatile. The Organization of MISO States (OMS), of which the IURC is a participant, and MISO teamed together to better understand future resource needs. Since June of 2014, MISO and the OMS have compiled Resource Adequacy survey responses from MISO members that indicate the need for more supply and demand side resources to meet expected load. This survey has served as the main vehicle in communicating to the MISO stakeholder community the anticipated PRM for upcoming years and serves as a tool in determining whether additional action is needed.

Since its inaugural survey, MISO has warned that there may be inadequate capacity within the MISO footprint at some future date. OMS-MISO Resource Adequacy survey results have shown projected shortfalls for high certainty resources in the MISO region and Zone 6, which includes most of Indiana and a small portion of Kentucky. The table below illustrates the year-to-year volatility in the survey results and the uncertainty that exists.

Figure 1.2 – OMS-MISO Resource Adequacy Survey Results

OMS-MISO Resource Adequacy Survey Results by Year	Zone 6 Resource Adequacy Shortfall, Earliest Projection	MISO-wide Resource Adequacy Shortfall, Earliest Projection
2014	1.2 GW shortfall in 2016	2.0 GW shortfall in 2016
2015	400 MW shortfall in 2016	1.8 GW shortfall in 2018
2016	800 MW shortfall in 2018	400 MW shortfall in 2018

The projected capacity shortfalls have contributed to volatile capacity prices. MISO's Planning Resource Auction (PRA) is held annually for each of the load zones within the MISO footprint to ensure sufficient capacity resources. The PRA has yielded a wide fluctuation in capacity pricing for Zone 6 since its inaugural year of 2013[12], as shown in the table below. These large swings in prices have made it difficult to forecast forward years.

[12] SNL Financial – Market Prices – ISO Capacity Summary – MISO

Figure 1.3 – MISO Zone 6 Capacity Price History

Planning Year	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/day[13]	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/year	Year-over-Year Price Change
2013-2014	$1.05	$383.25	-
2014-2015	$16.75	$6,113.75	1495% Increase
2015-2016	$3.48	$1,270.20	79% Decrease
2016-2017	$72.00	$26,280.00	1969% Increase

MISO has stated that its role in resource planning is to provide data transparency, markets signals, and assist its stakeholders throughout the resource planning process. To improve its market signals, MISO is currently working on several reforms to its capacity construct. Additionally, in order to ensure data transparency and assist its stakeholders in resource planning, MISO is working with the OMS to refine the results from the survey and continue improving the accuracy and metrics in which the PRM is measured. For more information on MISO, please read Section 4.7, PLANNING RESERVE MARGIN DISCUSSION.

1.3.8 Solar Generation

The Energy Policy Act of 2005 created a 30 percent ITC for residential and commercial solar energy systems placed in service between January 1, 2006 and December 31, 2007. The in service date has been extended several times since then, most recently in 2015 in the Omnibus Appropriations Act (P.L. 114-113). Additionally, the language was updated from “in service” to “commence construction” for projects completed by the end of 2023. 2019 is the last year to commence construction and receive the full 30% benefit (it tapers down from there).

Renewable costs, particularly solar, continue to decline helping to drive demand for more solar energy production. Even with the extension of the ITC, solar panel energy in

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

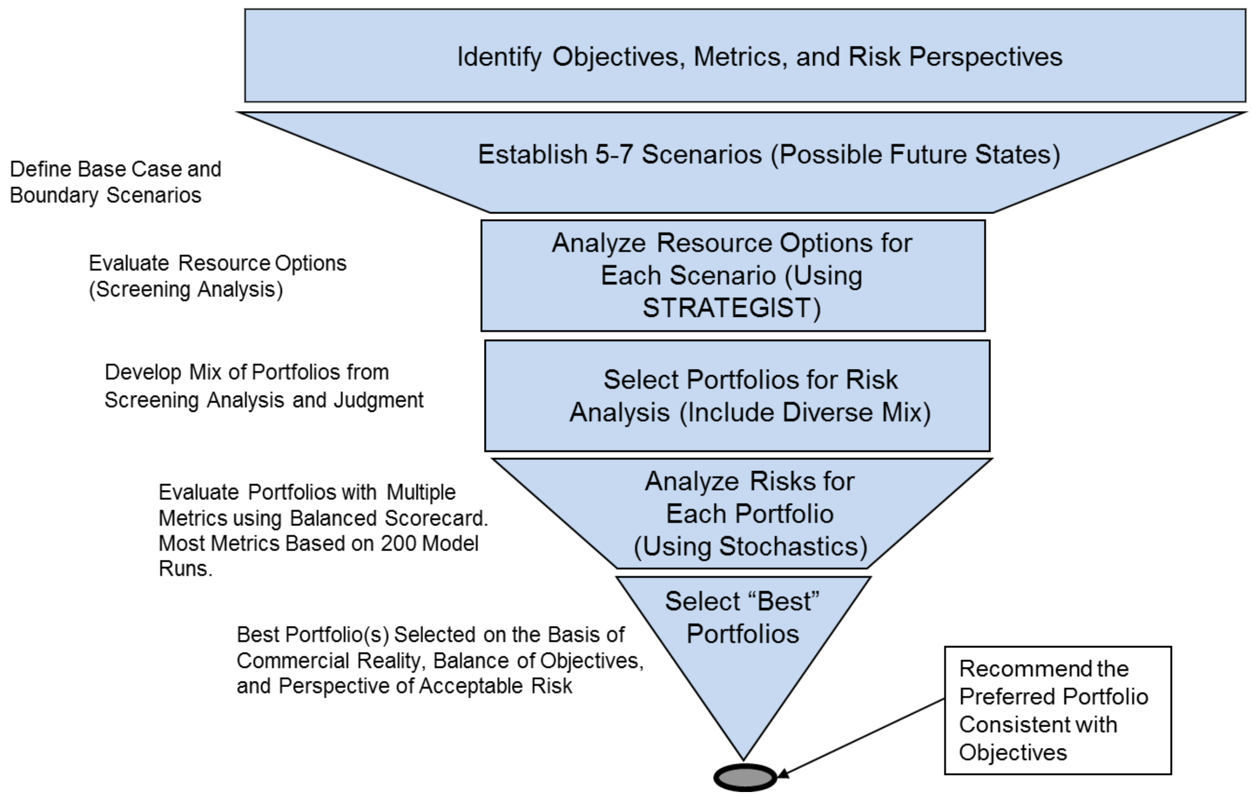
the Midwest is still expected to be more expensive than other alternatives in the next several years. In 2015, solar energy accounted for 1% of total generation in the U.S.

SECTION 2
VECTREN'S IRP PROCESS

2.1 VECTREN'S IRP PROCESS

Vectren's 2016 IRP followed a very structured, comprehensive process over a 15 month period with extensive economic, technical, and risk analyses. This process was designed to ensure that all relevant technologies were screened and evaluated, and the resulting portfolio combinations were subjected to a wide range of future market and regulatory conditions to ensure that the recommended portfolio would best meet its objectives under uncertainty. The process followed is illustrated below.

Figure 2.1 – Vectren IRP Process



The process used to select the recommended portfolio is outlined below:

- Section 2.2 describes how multiple objectives were tracked and measured. These metrics were the key to evaluating how portfolios were judged against each other in the final selection of the best portfolio.

- Section 2.3 describes how the scenarios were developed for screening technologies. Vectren selected six “boundary scenarios” around its consensus base case scenario to ensure that the portfolios selected perform reasonably well across a range of market and regulatory conditions.
- Section 2.4 describes the screening of technologies. Burns and McDonnell used the STRATEGIST model to assess how different technologies and groups of technologies performed across each of the base case and six additional scenarios to help Vectren define which portfolios it wanted to consider for its risk analysis.
- Section 2.5 describes the selection of a group of portfolios for risk analysis. Some of the portfolios came directly out of the screening analysis, considering which group of portfolios performed best under each set of market and regulatory conditions. Others were selected based on the judgment of Vectren and by stakeholders through its stakeholder process. Vectren wanted to ensure that there was due consideration to metrics besides least cost to capture more diverse portfolios, greater penetration of renewables, energy efficiency, and other considerations.
- Section 2.6 describes the input distributions for the risk analysis. This tracks the steps performed in the process, the selection of the distributions, and the use of AURORAxmp to provide carbon prices, power prices, and market retirements and construction of new generation. This section also describes the analysis of the portfolios against the 200 iterations of scenarios that were developed in the previous steps and how resulting metrics are evaluated.
- Section 2.7 describes the selection of the “best” portfolio and provides the basis for eliminating portfolios that do not perform well against target metrics and for selection of a portfolio that performed best.

Vectren evaluated and balanced the expected costs and risks of each portfolio, incorporating environmental goals, to select a portfolio with a good cost-risk combination. Throughout the process, Vectren sought and received input from stakeholders through three public meetings meant to educate and engage all those with an interest in this IRP.

2.2 IDENTIFY OBJECTIVES, METRICS, AND RISK PERSPECTIVES

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

In addition, the IRP process ensures that Vectren meets its environmental regulations and reliability requirements, while reducing its vulnerability to market and regulatory risks, the risk of supply disruptions, and increases the diversification of its supply sources, maintaining the flexibility to take advantage of renewable options and storage when the economic conditions favor it.

One component of resource planning is "least cost" planning, which identifies the portfolio or supply and demand resources that are most likely to result in the lowest expected cost to its customers. While this is certainly an important objective, it is by no means the only objective. Vectren has a number of important objectives, each of which needs to be considered when evaluating the best portfolio for its stakeholders over time. Vectren's IRP strategy is designed to accommodate the ongoing changes and uncertainties in the market. Vectren's IRP objectives are based on the need for a resource strategy that provides long term value to its customers, communities, and shareholders. Specifically, Vectren's IRP objectives are as follows:

- Provide all customers with a reliable supply of energy at the lowest reasonable cost.
- Develop a plan with the flexibility to adapt to market conditions, regulatory and technological change to minimize risk to Vectren customers and shareholders
- Provide environmentally acceptable power, leading to a lower carbon future

- Provide a predictable, balanced mix of energy resources designed to ensure costs do not vary greatly across alternative future market conditions or supply disruptions.
- Minimize the impact of Vectren's past, current, and future operations on the local economy.
- Provide high-quality, customer-oriented services which enhance customer value.

Each objective was given defined and measurable metrics. By testing alternative portfolios against these metrics, Vectren increases the likelihood that the portfolio it ultimately selects will be the best portfolio, in that it meets all of Vectren's objectives better than any other portfolio of assets across a broad range of possible futures. The following metrics were used to select the preferred portfolio:

Figure 2.2 – Vectren Risk Metrics

Objective	Metric
Customer Rate (or utility cost) Metric	• Net Present Value (NPV) of Revenue Requirements
Manage or Minimize Market Risks	• Standard Deviation of NPV Across 200 Future Conditions • Volume of Market Purchases • Volume of Capacity Purchases
Cost Risk-Tradeoff	• NPV against Standard Deviation
Balance and Flexibility	• Net Sales Position • Concentration on One Technology • Number of Technologies • New Remote Resources in Generation Mix
Environmental Requirements	• CO_2 Reductions from 2012 levels • SO_2 and NO_X Reductions from 2012-2015 levels
Local Economic Impacts	• Jobs and Local Economy

Defined metrics are used to evaluate different portfolios and planning strategies in the IRP process. These metrics provide objective assessments of critical factors of each portfolio under different market scenarios. There are natural trade-offs among these objectives; for example, the portfolio with the lowest expected costs may not be the most stable (lowest band of risks), have the most carbon reductions, or provide the needed flexibility to adapt to changing conditions. The objective of the IRP is to find the right balance of these metrics across a wide variety of future conditions to ensure that the ultimate choice of a portfolio performs well, regardless of the circumstances.
A further description of each metric is provided below.

2.2.1 Rate/Cost Metric

2.2.1.1 Lowest Reasonable Customer Cost

The metric typically used for this objective is Net Present Value of Vectren's Revenue Requirements (NPVRR). The NPVRR is a measure of all costs (for each asset, the cost of generation – capital, O&M, fuel, and any ancillary costs, including transmission, plus the cost of power and capacity purchases etc.) associated with the portfolio of assets over time. These costs are adjusted through a discount rate to ensure future costs are reflected in present year dollars, commonly known as a time value of money adjustment. In this way, very different portfolios can be compared on a common metric or value over a long time frame.

2.2.2 Risk Metrics

2.2.2.1 Standard Deviation and the 95th Percentile of Revenue Requirements

In the risk analysis, an assessment of hundreds of scenarios of future market and regulatory conditions were performed on each portfolio. The NPVRR was calculated for each scenario (iteration) and then a frequency distribution of these NPVRRs was calculated. A "standard deviation" is a measure of the variability of the portfolio outcomes. By definition, by taking the mean or average value of the 200 iterations, and then adding and subtracting the value of one standard deviation to the mean value, one captures about 67% of the total observations. Adding or subtracting two standard deviations around the mean captures about 95% of the outcomes. The 95th percentile NPVRR typically represents a plausible worst case outcome of the distribution. Portfolios that have a great deal of uncertainty will have high costs in the worst case outcome. To minimize risk, one would select the portfolio with the lowest measure of dispersion or the lowest standard deviation around the mean value.

2.2.2.2 Market Risk – Reliance on Purchases from the Market

Dispatch modeling informs us of how often units in a given portfolio generate electricity to serve the needs of customers. The balance not met by Vectren's owned generation is supplied by the market. If Vectren relies too much on the market, it subjects Vectren's customers to market price volatility that Vectren would not experience using its own generation assets. Hence, Vectren can measure the percentage reliance on the market as one measure of risk of the portfolio.

2.2.2.3 Capacity Volume Risk

In the base or reference case, the model ensures that adequate capacity purchases are made to meet UCAP reserve margin requirements. When 200 iterations of the model are run, there are high load scenarios where additional capacity purchases may be required to continue to meet the target UCAP requirements. For each portfolio, Vectren calculated on average (across the 200 iterations) how many additional capacity purchases might be required. Since the capacity market is typically more volatile than the energy market, the cost associated with these purchases could be significant.

2.2.3 Environment Improvements Metric

2.2.3.1 Carbon Footprint Reductions from 2012 Levels

Each portfolio was designed to meet existing environmental regulations for carbon dioxide. Some portfolios exceeded the compliance requirements. For example, the Stakeholder Portfolio was designed to achieve a lower carbon footprint than is likely to be required. Vectren tracks the carbon footprint and other emission measures as a measure of environmental compliance and stewardship.

2.2.3.2 SO_2 and NOx Footprint Reductions from 2012-2015 Baseline

Vectren also tracks the sulfur dioxide emission reductions and the nitrous oxide reductions (both regulated by the EPA) over time, which are measured from an average of the 2012-2015 baseline period.

2.2.4 Balance and Flexibility/Diversity Metrics

2.2.4.1 Concentration on One Technology and Number of Technologies Deployed

Vectren must be in a position to be able to quickly adapt to changing market and regulatory conditions. If Vectren relies heavily on the economic performance of any one technology, such as natural gas or coal, higher than anticipated fuel costs for one technology could expose customers to higher prices than a more balanced portfolio. A measure of protection is to have a diverse portfolio that deploys multiple technologies in the resource mix. This approach forms natural hedges in case any single technology becomes obsolete through technological change.

2.2.4.2 Number of Distinct 24/7 Baseload Units

Customers are better off if Vectren has multiple 24/7 baseload facilities to protect against supply disruptions that could impact an individual site, including transmission failures, outages, or other disruptions.

2.2.4.3 Remote Stations

Portfolios that have stations far removed from its load centers are more subject to transmission congestion, transmission failures, or price spikes than local generation.

2.2.4.4 Net Sales

Higher net sale reflects a generation “cushion” created with generation that is available to serve new customers or enable plant retirement. This cushion enables Vectren to satisfy new or growing expected load without exposing customers to wholesale energy market volatilities. In the case of plant retirement, having this cushion allows Vectren to select the optimal time to retire a resource without risking excessive exposure to wholesale energy market volatility.

In addition, duct firing provides economic peaking capacity. Building in duct firing capability during the initial construction of a combined cycle gas fire plant provides savings and reduces future down time compared to adding the capability later. This consideration also justifies adding capacity in advance of expected need.

2.2.5 Cost-Risk Tradeoff

This trade-off combines two often competing objectives (expected costs and standard deviation) to find the portfolios that meet both objectives. The expected costs are derived using the NPVRR method, while the standard deviation risk is a measure of how much volatility is included in the price movements.

2.2.6 Local Economic Impact

Vectren also considered the impact of portfolios on regional jobs and tax base. Professors from the University of Evansville conducted this economic impact analysis, assessing the impact of coal-fired unit closures and constructing/operating replacement generation within the Vectren service territory.

2.3 DEFINE BASE CASE AND BOUNDARY SCENARIOS

2.3.1 Base Case

The base case scenario represents the most likely future conditions. Vectren surveyed and incorporated a wide array of third-party sources to develop its base case assumptions, several of 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
- National carbon (CO_2) prices
- Capital costs and associated cost curves for various supply side (generation) and demand side resource options
- On- and off-peak power prices

The long-term energy and demand forecast for the Vectren service territory was developed for Vectren by Itron, a leading forecasting consultant in the U.S. The forecast is based on historical residential, commercial, and industrial usage and drivers such as appliance saturation and efficiency projections, electric price, long-term weather trends, customer-owned generation, and several demographic and economic factors. More information can be found in Section 4, CUSTOMER ENERGY NEEDS.

For natural gas, coal, and carbon, Vectren used a “consensus” base case view of expected prices by averaging forecasts from several sources. This helps to ensure that reliance on one forecast or forecaster does not occur. For natural gas and coal, 2016 spring forecasts from Ventyx, Wood Mackenzie, EVA, and PIRA are averaged. For carbon, forecasts from Pace Global, PIRA, and Wood Mackenzie are averaged. Note that spring 2016 forecasts were not available from Ventyx or EVA at the time inputs were created.

Burns & McDonnell provided current costs associated with various generation and storage technologies (single cycle gas turbine, combined cycle gas turbine, combined heat and power, solar, wind, and batteries), while projected cost curves were developed by Pace Global.

DSM costs were developed by escalating 2016 costs with the help of Dr. Richard Stevie, Vice President of Forecasting with Integral Analytics. He created two models using EIA data to develop growth rates used to apply to current costs.

On- and off-peak power price forecasts were developed by Pace Global using the base case assumptions described above, together with Pace Global’s view of the greater MISO market, in the AURORAxmp power dispatch model. These key drivers constitute the base case assumptions. More information on modeling inputs can be found in Section 6, SCENARIOS: OPTIMIZATION MODEL INPUTS & ASSUMPTIONS.

2.3.2 Alternative Scenarios

It is important to test technologies against a variety of future market conditions, not just a base or reference case. Hence, Vectren, with the support of Pace Global, selected six alternative scenarios to provide boundary conditions for testing the technologies and portfolios that would be subjected to a full risk assessment (with hundreds of scenarios tested later in the process).

Vectren worked with Pace and also received input from Vectren stakeholders to identify future uncertainties. Major uncertainties were grouped into regulatory risk, technology risk, and market risk.

Using the base case as a starting point, a number of boundary scenarios were developed along three primary axes. The first axis is regulatory, with a high regulatory scenario and a low regulatory scenario. The second axis is technological, with only a high technology scenario (technological innovation is assumed to either continue at the present rate or at an accelerated rate, but not at a "low" rate). The third axis is economic, with a low market/economy scenario and a high market/economy scenario. From these three primary axes come five scenarios that provide a wide range of conditions in which to evaluate various portfolio planning strategies. Additionally, Vectren evaluated a large customer load scenario where Vectren assumes a large load addition of 100 MW in 2024; all else is equal to the base case scenario.

In order to maintain a consistent methodology when crafting the five scenarios[14] from the base case scenario, the forecasting period was divided into short-term (2016-2018), medium-term (2019-2025), and long-term (2026-2036) periods. In the short-term, the market drivers (load, gas, coal, carbon, and capital costs) for all five alternative scenarios are expected to remain the same as the base case scenario. In the medium-term, the market drivers for each alternative scenario (1) stay the same as the base

[14] Also included a scenario where Vectren acquires a 100 MW load addition in 2024; all else is equal to the base scenario.

case scenario, (2) move upward to reach one standard deviation above the base case value by the medium-term timeframe midpoint of 2022, or (3) move downward to reach one standard deviation below the base case value, also by 2022. In the long-term, the market drivers for each alternative scenario maintain their position (same as base case scenario or +/- one standard deviation above/below the base case scenario) or move toward an endpoint in 2036 that is in between +/- one standard deviation. In some cases and for some scenarios, these drivers may push past +/- one standard deviation above/below the base case. For example, in the high regulatory scenario, CO_2 prices push upward past one standard deviation above the base case in order to provide a boundary condition in line with the independent Synapse report[15] forecast for CO_2 prices.

The six scenarios were designed to be consistent with the stochastic distributions (200 iterations) developed for the risk analysis, but on a much more limited scale (six scenarios).

Vectren selected the following scenarios to illustrate the range of potential outcomes:

- Base large load addition;
- A high and a low regulatory case;
- A high and a low economic case; and
- A high technology case.

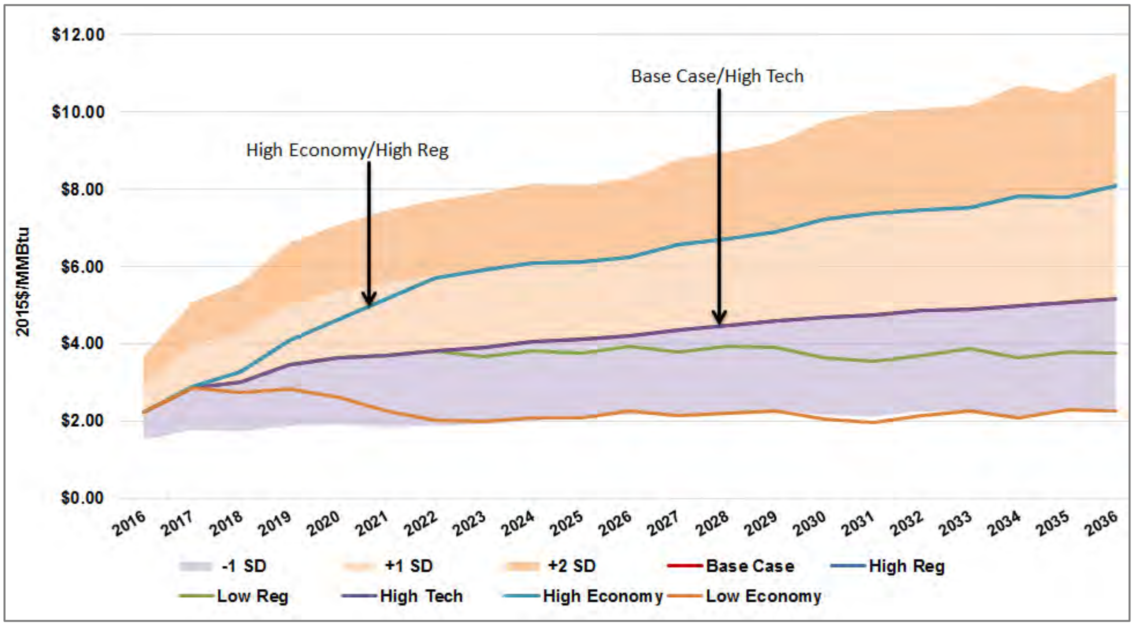
In addition, a consensus between Vectren's staff and its consultants was used to develop directionally whether gas prices, coal prices, load, technology capital costs, retirements and builds, and both carbon emission prices and power prices would move up or down under each of those scenarios. This process was followed more to illustrate what might happen under each of these scenarios in a consistent manner with the risk analysis than to specifically model new regulations or certain technologies.

[15] Synapse Energy Economics, Inc., "Cutting Electric Bills with the Clean Power Plan," March 2016

The six alternate scenarios (described in Section 6 of this document) consist of narrative descriptions of the short-term (2016-2018), medium-term (2019-2025), and long-term (2026-2036) trends in each of the key driver categories described above as well as specific annual or monthly numbers that reflect a shift away from the base case in the medium- to long-term. All scenarios are assumed to mirror the base case in the short-term, though some minor trending apart may begin to occur by 2018. By the middle of the medium-term (2022), each of the drivers will have moved up or down (or stay the same) by one standard deviation relative to the base case, depending on the scenario. By the end of the long-term (2036), each of the drivers will again be one standard deviation above the base case, at the base case, or one standard deviation below the base case.

An illustration of this methodology is given in the graph below for natural gas prices (in constant 2015 dollars). All gas prices begin at $2.23/MMBtu in 2016 and then rise to approximately $2.87/MMBtu in 2017, after which base case gas prices gradually trend upward to $5.13/MMBtu in 2036 while gas prices in the other scenarios either follow the base case or trend higher or lower, depending on the scenario's coordinated input direction. The high technology scenario mirrors that of the base case, while the high economy scenario and high regulatory scenario both move upward to reach +1 standard deviation above the base case in 2022, then remain at +1 standard deviation through the end of the forecast. The low economy scenario sees natural gas prices moving downward to -1 standard deviation below the base case in 2022, and then remains at -1 standard deviation through 2036. Finally, the low regulatory scenario sees natural gas prices trending with the base case through the medium-term, followed by a period of no growth in prices past $4.00/MMBtu.

Figure 2.3 – Natural Gas Price Scenarios, Delivered to Indiana (2015$/MMBtu)



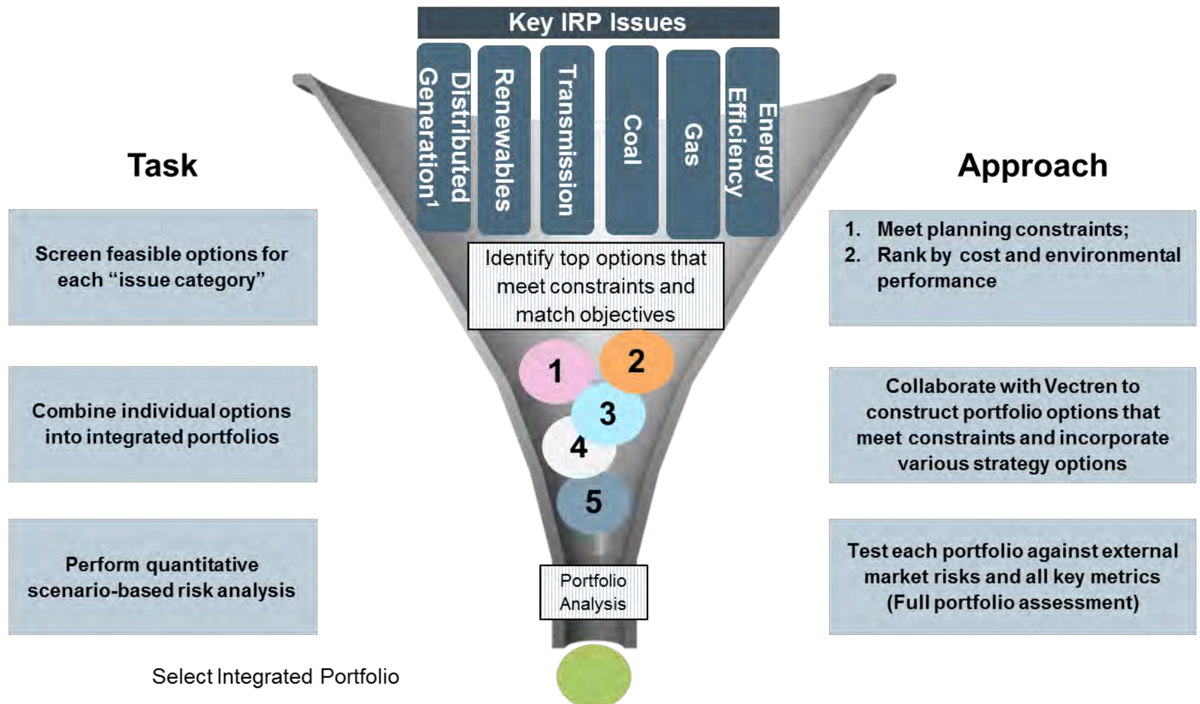
The convention of +/-1 standard deviation is used to maintain a consistent methodology and result when moving key market drivers up or down in each of the scenarios. It should be noted that the historical price distributions differ among the various market drivers and are not necessarily symmetrical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

The graphical descriptions of values for each of the key metrics (e.g. load, gas prices, coal prices, technology costs, carbon prices, and power prices) are shown in Section 6.2.2, Coordinated Forecasts for Alternate Scenarios.

2.4 SCREENING ANALYSIS

Burns & McDonnell performed a technology assessment to look at the multitude of different options for power supply (a total of 36 technologies, including renewables, storage, natural gas (including CHP), and coal). To facilitate efficient and timely modeling, a screening process was developed to filter the technology choices to a smaller data set based on expected operations and levelized cost. The full range of 36 technologies was filtered through this process. The following steps were performed:

Figure 2.4 – Structured Screening Process to Address Issues Efficiently

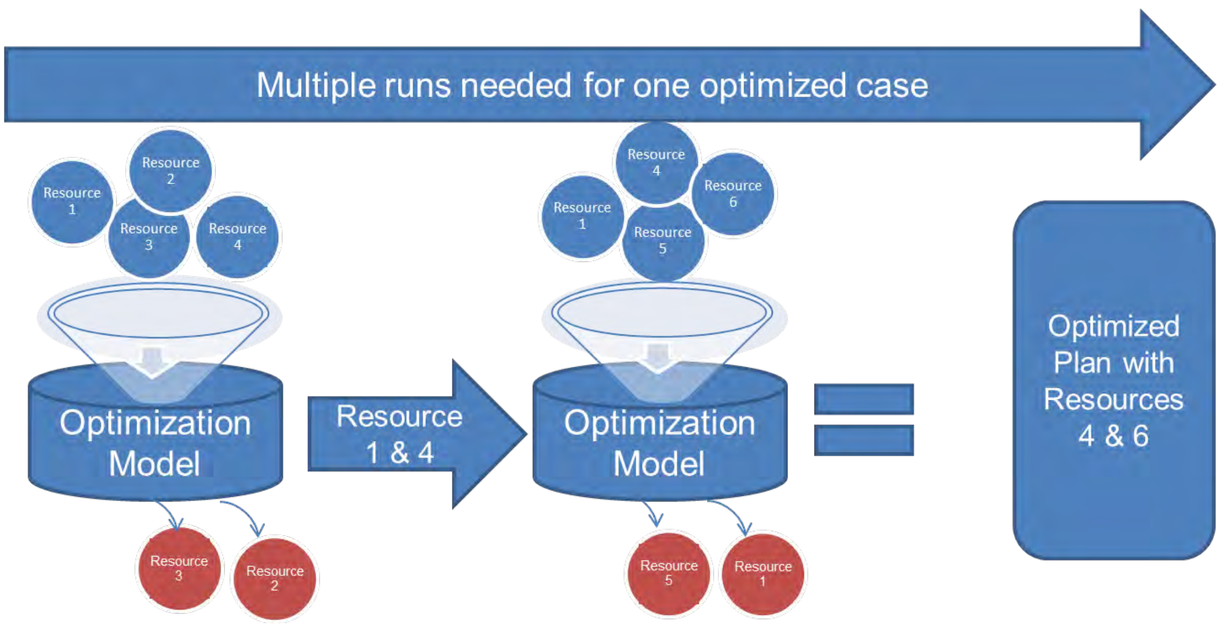


1 Distributed generation may not be controlled by the utility

To assess the alternatives on equal footing, Burns & McDonnell performed a busbar, or levelized cost of electricity comparison, for each of the 36 options, focusing on investment costs, operation and maintenance costs, fuel costs, and emissions costs. This screening process allowed for a direct comparison of the anticipated cost of ownership from base load, intermediate, peaking, renewables, and storage alternatives. This step resulted in the elimination of several technologies that performed poorly on a levelized cost basis.

As a next step, the remaining options along with existing facility and demand side alternatives were screened in the Strategist optimization model for the base case and each of the six scenarios defined in Section 2.3. Due to limitations within the model, not all resource alternatives may be screened in one run. Vectren evaluated more resource alternatives than ever before (coal retirement, existing plant retrofits, multiple blocks of energy efficiency, and demand response, as well as 36 new resource alternatives). In order to accommodate this wide range of options, an iterative process was followed. The model was run with several alternatives. Viable options were kept for the next model run, uneconomic options were screened out, and new options were added in for evaluation. The process was then repeated until all resources were considered and an optimized plan was developed with a small number of resource options for each of the scenarios provided. The illustration below shows the screening process.

Figure 2.5 – Illustrative Example of Strategist Optimization Modeling Process



From this analysis and other objective factors, a list of portfolios was formed in the next stage.

2.5 PORTFOLIO SELECTION

Careful consideration was given to the selection of portfolios in order to address a wide range of objectives, strategies, future market outcomes, and stakeholder concerns; a total of 15 Vectren portfolios were developed for consideration.

First, optimized portfolios were created using Strategist for the base case and each of the six alternate scenarios. The optimized cases produced the least cost portfolio for each of the potential future scenarios, given the modeling inputs. As mentioned above, each scenario represented a possible future state with coordinated inputs for gas, coal, CO_2, market power prices, etc. The intent of this analysis was to produce a wide range of portfolios to test in the risk analysis; however, this modeling produced seven portfolios that looked very similar with a heavy reliance on gas resources and varying levels of energy efficiency. Some included renewables in the late 2020s through the 2030s.

While optimized portfolios are helpful in the analysis process, they may not identify the portfolios that perform well when considering risk and uncertainty. Recognizing this reality and taking stakeholder input into consideration, Vectren worked to develop several diversified portfolios to test in the risk analysis.

During Vectren's public IRP stakeholder meeting on Friday, July 22, 2016, Vectren held a portfolio development workshop to gain input from stakeholders on additional portfolios to be considered within the IRP analysis. 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 used the information gathered from the session to develop two stakeholder portfolios. The first includes some coal, a heavy reliance on renewables and energy efficiency, and some gas in 2024. The second stakeholder portfolio transitions away from coal altogether by 2024, and replaces it with gas, renewables, and storage.

Finally, Vectren worked to develop several alternate portfolios to test. Portfolios can qualitatively be developed in several ways. One can simply consider various portfolio choices, with trial and error, running them through the optimization tool. Another way is futures based, which is how Vectren's optimized portfolios were developed. Each optimization run resulted in a least cost portfolio for each possible future. A third approach is theme based (all coal, all gas, all renewables, diversified, etc.), which is what Vectren focused on when developing several "diversified portfolios." As a benchmark, Vectren developed the business as usual case (nearly all coal to closely align with Vectren's current portfolio). The optimized base case produced another theme (nearly all gas).

Vectren believes there is value in a balanced portfolio as a way to reduce risk. By having a balanced set of resources available to serve customer load (gas, coal, energy efficiency, wind, solar, etc.), Vectren can reduce the reliance on any one resource type. For example, if gas prices spike or rise more quickly than expected, a portfolio that is nearly all gas has more risk of increasing customer bills. Vectren developed and tested five diversified portfolios with various levels of energy efficiency, demand response, gas, coal, solar, and wind. Below are the 15 portfolios that were tested (Business as Usual, 7 optimized portfolios[16], 2 stakeholder portfolios, and 5 diversified portfolios). More information about these portfolios can be found in Section 7, SCREENING ANALYSIS.

A. Business As Usual (Continue Coal) Portfolio
B. Base Scenario (aka Gas Heavy) Portfolio (Optimized)
C. Base + Large Load Scenario Portfolio (Optimized)
D. High Regulatory Scenario Portfolio (Optimized)

[16] Optimized portfolios were created by Strategist modeling, optimizing on least cost for each scenario (possible future state).

E. Low Regulatory Scenario Portfolio (Optimized)
F. High Economy Scenario Portfolio (Optimized)
G. Low Economy Scenario Portfolio (Optimized)
H. High Technology Scenario Portfolio
I. Stakeholder Portfolio
J. Stakeholder Portfolio (Cease Coal 2024)
K. FBC3, Fired Gas, & Renewables Portfolio
L. FBC3, Fired Gas, Early Solar, & EE Portfolio
M. FBC3, Unfired Gas .05, Early Solar, EE, & Renewables Portfolio
N. Unfired Gas Heavy with 50 MW Solar in 2019 Portfolio
O. Gas Portfolio with Renewables Portfolio

2.6 RISK ANALYSIS

The Risk Analysis of each of the portfolios was developed by Pace Global using EPIS' AURORAxmp dispatch model. There were several steps to this process:

- The first step was to develop the input distributions and correlation coefficients for each of the major market and regulatory drivers, including load growth (and shape), gas prices, coal prices, carbon prices, technology capital costs, and power prices. This was done by considering volatility and correlations of each factor in the short term, midterm, and long term.
- The second step was to run a probabilistic model (Monte Carlo) which selected 200 possible future states over the 20 year period. This also formed the basis for the scenario inputs development.
- Portfolios were then run through simulated dispatch for the 200 possible future states using a tool called AURORAxmp. This tool dispatches existing units, builds, and retires units on the basis of least cost optimization for each portfolio combination for each sampled hour over the planning horizon. AURORAxmp will assume that Vectren's portfolio is constant but will allow for economic builds and retirements to occur throughout the region in each scenario based on economic

criteria. Vectren generation, costs, emissions, etc. were tracked for each iteration over time.

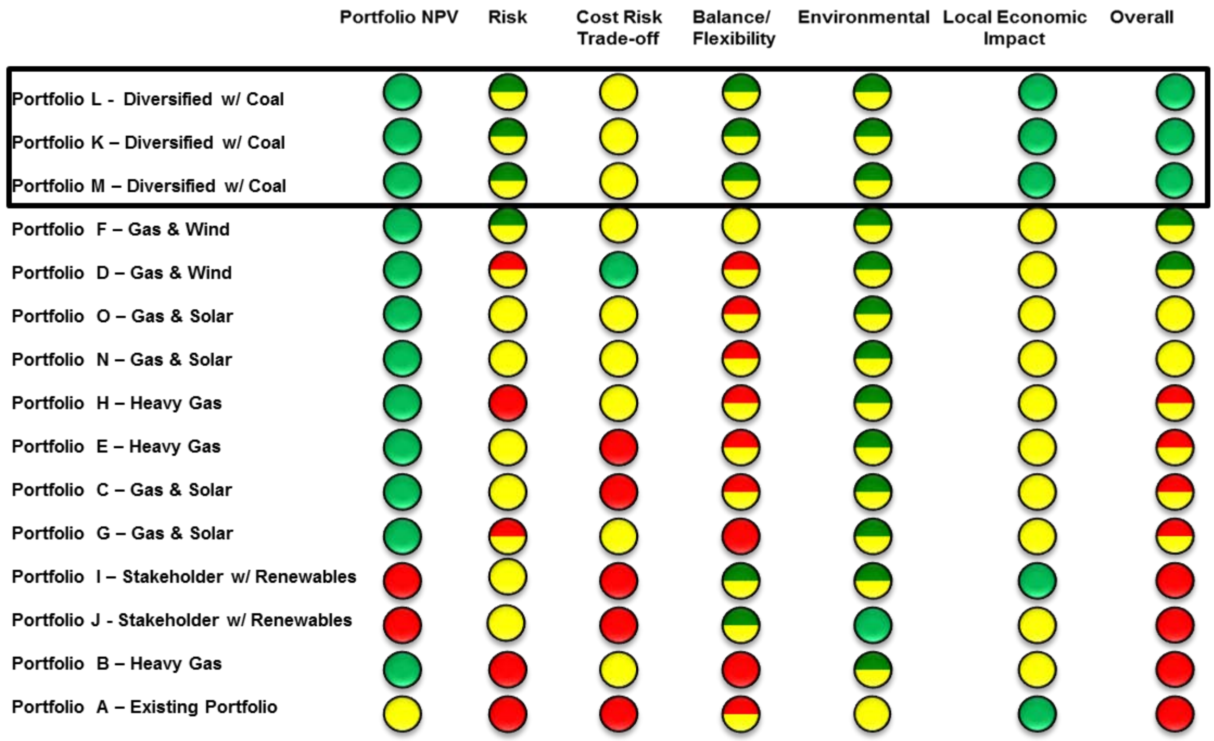
- Next, values for each metric were tracked across all 200 iterations and presented as a distribution with a mean, standard deviation, and other metrics as needed.
- These measures were used as the bases for evaluation in the risk analysis.

More information on the risk analysis can be found in Section 7.2.1, Uncertainty (Risk) Analysis.

2.7 SELECTION OF PREFERRED PORTFOLIO

Selection of the preferred portfolio was based on how well each portfolio met multiple objectives as outlined in Section 2.3, DEFINE BASE CASE AND BOUNDARY SCENARIOS, under 200 iterations representing different, but cohesive and plausible market condition scenarios. The selection process consisted of several comparisons illustrating each portfolio's performance measured against competing objectives. The goal is to create the right balance between satisfying the competing objectives as illustrated below. The preferred portfolio delivered the best balance of performance across all competing metrics when viewed across the full range of 200 iterations. To help illustrate tradeoffs, Vectren utilized a balanced scorecard, as shown below in Figure 2.6 and further discussed in Section 7.2, EVALUATE PORTFOLIO PERFORMANCE.

Figure 2.6 – Identifying and Evaluating Tradeoffs



SECTION 3
PUBLIC PARTICIPATION PROCESS

3.1 PUBLIC PARTICIPATION 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

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

The 2016 IRP analysis was heavily influenced by stakeholder input, beginning with input from stakeholders on Vectren's 2014 IRP and ongoing interaction with other energy company stakeholder processes to glean best practices. Additionally, Vectren utilized the IURC director's report to help guide continuous improvement efforts. As a direct result of these engagements, Vectren publically committed to and incorporated several improvement opportunities for the 2016 IRP, listed below:

- Vectren constructed scenarios (possible future states) with coordinated data inputs with a well-reasoned narrative
- Vectren conducted a probabilistic risk analysis to explore the outer bounds of probability
- Future energy company-sponsored energy efficiency was modeled as a resource (not built into the load forecast)
- Vectren evaluated if retirement made sense for any of Vectren's existing coal generating units within the 20-year time frame under each scenario

- Vectren continues to monitor Combined Heat and Power (CHP) developments and included CHP as a resource option
- Vectren considered conversion of coal units to gas
- Renewable options were fully considered in this analysis
- Updated the IRP document format to be more readable

Another commitment that all Indiana investor-owned utilities, including Vectren, made was to help educate stakeholders on the IRP process. As such, Vectren's 2016 engagement with stakeholders began in February by participation in a joint utilities Integrated Resource Plan Stakeholder Education Session. Duke Energy Indiana, Indiana Michigan Power (I&M), Indianapolis Power & Light Company (IPL), Northern Indiana Public Service Company (NIPSCO), and Vectren jointly presented an educational session to discuss the foundation of the IRP process. This all-day meeting was hosted on February 3, 2016. Topics covered at the meeting included load forecasting, resource options, scenarios & sensitivities, Regional Transmission Operators (RTO), and resource modeling. Recordings and materials were posted to www.vectren.com/irp as a resource for stakeholders who want to know more about the general process.

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

- April 7, 2016
    - 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

  - Environmental Compliance
  - Base Case/Modeling Inputs
  - Busbar Analysis and Optimization Modeling
  - Scenario Development
  - Stakeholder Input to Portfolio Selection
- November 29, 2016
  - Presentation of the Preferred Portfolio
  - Optimization Modeling Results and Portfolio Development
  - Risk Analysis Results

Additionally, Vectren held a DSM Modeling Information Session on October 14, 2016 with the Vectren DSM Oversight Committee, which includes the Office of Utility Consumer Counselor (OUCC) and Citizens Action Coalition (CAC). Additionally, Indiana Utility Regulatory Commission (IURC) staff attended. Other Vectren stakeholders participated via webinar. The main topics discussed were energy efficiency modeling inputs, including energy efficiency pricing and how energy efficiency was modeled on a consistent and comparable basis with supply side options (power generation options).

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

3.2 STAKEHOLDER INPUT

During the course of the 2016 IRP, stakeholders provided their input in several ways: 1) verbal feedback through question/answer sessions during public stakeholder meetings; 2) through participation in Vectren stakeholder workshops; and 3) via written feedback/requests.

Vectren worked diligently to have an open forum for stakeholders to voice questions/concerns and make suggestions on the IRP analysis. Each Vectren stakeholder meeting was opened by 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.

During the first stakeholder workshop on April 7, 2016 Vectren held a session to discuss future uncertainties to be considered in scenario development. The following topics were raised by stakeholders:

- 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 the plan
- Consider distributed generation risk
- Consider diversifying generation
- Consider political/regulatory risk
- Consider additional cogeneration being developed within the Vectren territory

Vectren agrees that these are key uncertainties and included them within scenario development. Please see Section 6.2, DEVELOPMENT OF ALTERNATE SCENARIOS for more information.

During the second public stakeholder meeting on July 22, 2016 Vectren held a workshop to gather input from stakeholders to gain their insight on a preferred resource portfolio. Two stakeholders (Valley Watch and the Sierra Club) made presentations to the audience. Their meeting materials can be found in Technical Appendix Attachment 3.1 Stakeholder Materials. Following these presentations, stakeholders formed several groups and provided feedback on their preferred resource portfolios.

The general consensus among the 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. Several stakeholders expressed concern for the local economic impact if all coal were to be retired in the near to midterm.

Information gathered at this session was used to develop two stakeholder portfolios that were fully tested in the risk analysis. One portfolio kept two coal units through 2035, and the other retired all coal by 2035. For a full description of workshop results, please see Technical Appendix Attachment 3.1 Stakeholder Materials. These portfolios are described in Section 7 Developed Portfolios. Additionally, risk analysis results can be found in Section 8.1, SCORECARD COMPARISON.

On October 14, 2016 Vectren held discussions with stakeholders on EE modeling for the IRP. A stakeholder suggested that breaking the link between EE selected in the near term versus long term as costs increase over time may 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 at the time.

Based on stakeholder feedback, Vectren performed additional analysis which looked at the competitiveness of EE over a 3-year block from 2018-2020 rather than selecting the block for entire study period. The 3-year timeframe was selected in order to provide insights into cost effectiveness of EE programs through the next DSM and IRP filing. The analysis results showed no blocks of EE in the lowest NPV plan under the base scenario. EE Blocks 1-4 represented a cost increase of 0.07% over a 20-year Strategist NPV, while EE Blocks 1-8 resulted in a cost increase of 0.96%. The results indicated that blocks 1-4 in 2018-2020 are relatively similar cost as a plan without any additional blocks of EE.

On November 2, 2016 Vectren received a position paper from Ms. Jean Webb, a residential Vectren customer. Her positions are included in Technical Appendix Attachment 3.1 Stakeholder Materials. Included in the paper was a suggestion to review Lazard's Unsubsidized Levelized Cost of Energy Analysis Version 9.0. In Ms. Webb's paper she mentioned that "Lazard's reported that universal solar ranged from $43 to $70 per MWh, whereas Vectren's levelized numbers were from $190 to $210 per MWh."

Vectren has carefully considered many different technologies to potentially supply customer power, including renewable energy from solar power and would suggest that the numbers Ms. Webb references do not fully capture the cost and potential energy output reflective of a solar project located in southwestern Indiana. The $43 to $70 per MWh levelized cost of solar referenced from the Lazard study – per the footnote included within the paper – "Assumes 30 MW system in high insolation jurisdiction (e.g., Southwest U.S.). Does not account for differences in heat coefficients, balance-of-system costs or other potential factors". Further, the costs presented by Lazard do not include site-specific and owner-specific conditions such as land, permitting, legal fees, and transmission/distribution interconnection. These costs cannot be ignored when considering a solar project compared to other alternatives.

Vectren reviewed and illustrated the impact of different assumptions to the levelized cost of solar at its last public stakeholder meeting (held on November 29, 2016), noting that capacity factor and total cost to build are two of the more impactful assumptions. Vectren believes the costs assumed for a solar project used within this IRP are reasonable.

In the final Vectren IRP Stakeholder meeting held on November 29, 2016 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.

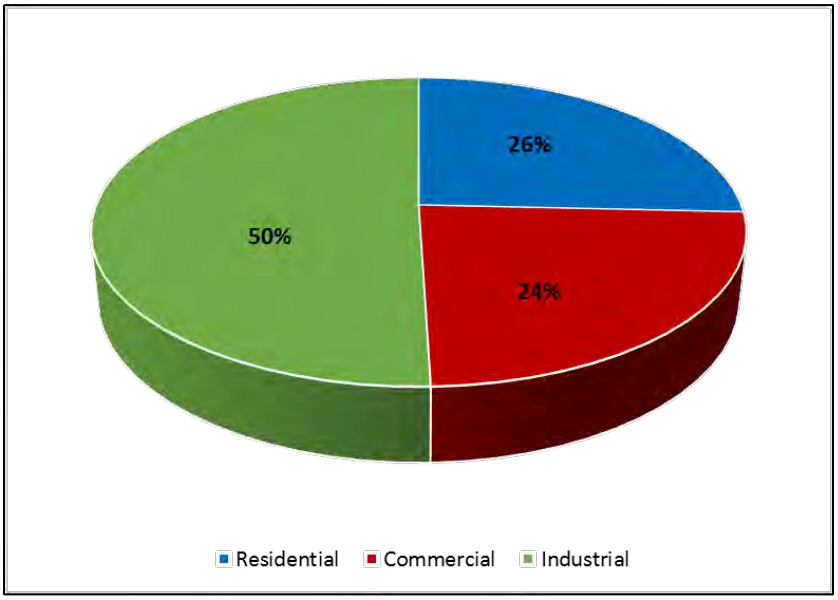
According to EPA, the Clean Air Act (CAA) was designed by Congress to protect public health and welfare from different types of air pollution. The CAA requires EPA to establish national ambient air quality standards for criteria pollutants based upon levels deemed necessary to protect public health, 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 8 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.

SECTION 4
CUSTOMER ENERGY NEEDS

4.1 CUSTOMER TYPES

Vectren 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 with system peak (hour of maximum demand) reaching 1,089 MW. 2015 hourly system load data can be found in Technical Appendix 4.2 2015 Vectren Hourly System Load Data. The weather-normalized peak estimate for 2015 was 1,035 MW. Figure 4.1 shows 2015 class-level sales distribution.

Figure 4.1 – 2015 Vectren Sales Breakdown



4.2 FORECAST DRIVERS AND DATA SOURCES

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

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

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

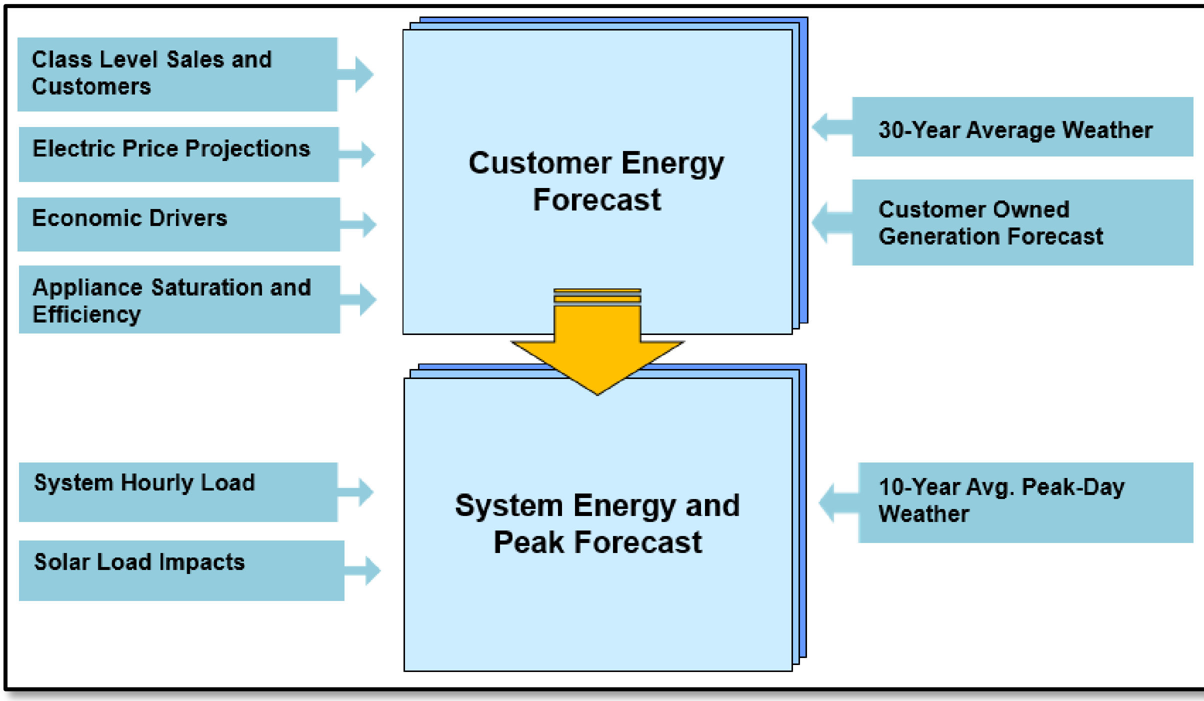
Weather is also a driver of electric consumption. Vectren's peak demand is typically in summer when temperatures are hottest. Air conditioning drives summer usage. Normal weather data is obtained from DTN, a provider of National Oceanic and Atmospheric Administration (NOAA) data. Vectren utilizes data over a 30-year period for the sales forecast and a 10-year period for the demand forecast in order to capture recent weather activity.

Itron, Inc. provides regional Energy Information Administration (EIA) historic and projected data for equipment efficiencies and market shares. This data captures projected changes in equipment efficiencies based on known codes and standards and market share projections over the forecast period, including but not limited to the following: electric furnaces, heat pumps, geothermal, central air conditioning, room air conditioning, electric water heaters, refrigeration, dish washers, dryers, etc. Residential market share data has been adjusted to Vectren's service territory based on the latest appliance saturation survey data.

4.3 MODEL FRAMEWORK

The long-term energy and demand forecast was developed from the customer class total and end-use sales forecast. Customer class (residential, commercial, industrial, and street lighting) sales forecasts were based on monthly sales forecast models that related customer usage to weather conditions, economic activity, price, and end-use ownership and efficiency trends. The relationship was estimated using linear regression models. Energy requirements were then derived by adjusting the sales forecast upwards for line losses. Peak demand was forecasted through a monthly peak-demand linear regression model that related peak demand to peak-day weather conditions and end-use energy requirements (heating, cooling, and other use) derived from the class sales forecasts. Figure 4.2 shows the general framework and model inputs.

Figure 4.2 – Class Build-up Model



In the long-term, both economic growth and structural changes drive energy and demand requirements. Structural changes include the impact of changing appliance ownership trends, end-use efficiency changes, increasing housing square footage, and thermal shell efficiency improvements. Changing structural components are captured in the residential and commercial sales forecast models through a specification that combines economic drivers with end-use energy intensity trends. This type of model is known as a Statistically Adjusted End-Use (SAE) model. The SAE model variables explicitly incorporate end-use saturation and efficiency projections, as well as changes in population, economic conditions, price, and weather. Both residential and commercial sales were forecast using SAE models. Industrial sales were forecast using a generalized econometric model that related industrial sales to seasonal patterns and industrial economic activity. Street light sales were forecast using a simple seasonal trend model. The demand model is an SAE peak model.

4.4 CUSTOMER OWNED DISTRIBUTED GENERATION

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

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

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

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

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

It should be noted that Vectren's forecast of customer owned solar generation is a market based forecast; Vectren did not limit the forecast to 1% of Vectren's installed capacity, consistent with current regulations.

4.4.1 Current DG

As of December 2015, Vectren had approximately 130 residential solar customers and 15 commercial solar customers, with an approximate installed capacity of 1.2 MW. Based on recent solar installation data, the residential average size is 7.8 KW, while the commercial average system size is 16.9 KW. Vectren has incorporated a forecast of customer owned photovoltaic systems into the sales and demand forecast.

Vectren is aware of one large CHP system that is currently being installed within the Vectren service area. A CHP system is projected to be online in 2017. Vectren monitors Combined Heat and Power (CHP) developments in its service area and adjusts the load forecast for any known, future customer owned CHP installations.

4.4.2 Solar DG Forecast

The primary factor driving system adoption is customer economics. Based on analysis of state-level system adoption, Itron has 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. 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, Vectren assumed excess generation is credited to the customer at retail energy rates.

Itron developed a solar adoption model that predicts residential solar saturation by relating historical residential solar saturation to simple payback period. The results of this model were then multiplied by the residential customer forecast to determine the number of residential systems expected to be installed. The installed solar capacity forecast is the product of the solar customer forecast and average system size (measured in kW).

In the commercial sector there have been too few adoptions to estimate a reasonable model; low commercial system adoption is found across the country. Itron believes 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, Itron assumed that there would continue 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, the saturation of residential solar customers was about 0.1% of customers. This is expected to be 4.1% (approximately 5,300) by 2036. Commercial saturation is expected to grow to 2.8% over the same time frame.

By 2036, it is expected that over 50 MW of installed customer owned solar capacity will be in place, generating over 67,000 MWhs of energy. The impact of solar generation on system peak demand is a function of the timing between solar load generation and system hourly demand. For example, system peak is generally around 4:00 pm, while maximum solar output is at noon. Even though solar capacity reaches over 50 MW by 2036, solar load reduces Vectren's system peak demand by only 16 MW. The table below shows the forecast of customer owned solar generation, which has been netted out of Vectren's sales and demand forecast.

Figure 4.3 – Solar Capacity and Generation

Year	Total Generation MWh	Installed Capacity MW	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 2017-2036	11.7%	11.1%	11.1%

4.4.3 Potential Effects on Generation, Transmission, and Distribution

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

- **High voltage mitigation** – With a high penetration of DG, distribution feeder voltage profiles could become unacceptably high when light loading periods coincide with high DG output. A mitigation strategy would need to be developed to control voltage at acceptable levels.

- **Protection system modifications** – Traditionally, electric distribution feeders have been designed as unidirectional from the energy company to the customer. Voltage regulation and feeder protection strategies are designed based on this premise. With high DG penetration under light load with high DG output, power flow could reverse from the customer to the energy company. A mitigation strategy would need to be implemented to correct for the change in the system's operating characteristics.
- **Power quality and harmonics mitigation** – Power quality issues are one of the major impacts of high photovoltaics penetration levels on distribution networks. Power inverters used to interface PV arrays to power grids increase the total harmonic distortion of both voltage and current, which can introduce heating issues in equipment like transformers, conductors, motors, etc. A mitigation strategy would need to be implemented to correct for the change in the system's operating characteristics.
- **Short term load forecast uncertainty** – At higher levels of DG penetration, load forecasting becomes more difficult. DG resources work to offset the customer's load, but their output can be variable depending upon weather conditions. Load forecasting techniques would need to be more granular and would need to incorporate provisions for DG response to short-term weather conditions.
- **Capacitor banks on the distribution feeders** – Capacitor banks are used to improve power factor and also raise voltages along the lines. These are strategically placed based on load/distance from the normal source (substation). Once additional sources (DG) are added to the circuits, the capacitor banks may no longer be in the optimal location for power factor correction or voltage changes. This could negatively impact the power factor and voltage level of the circuit, if a circuit has a high enough DG concentration.

Vectren's electric rates are designed to recover the fixed costs of providing service (transmission, distribution, metering, etc.) via energy and (for large customers) demand charges, along with an associated fixed monthly customer facilities charge. The fixed monthly charge does not reflect the full amount of fixed costs that Vectren incurs to provide retail electric service. DG customers (who generate a portion of their own electricity but still rely on the electric grid) avoid paying the fixed costs of the grid that are included in the energy charge, which leads to Vectren's under recovery of the cost of providing service. Over time, as base rates are updated periodically, these costs shift to non-net metering customers, resulting in a subsidy being paid to net metering customers.

4.5 BASE ENERGY AND DEMAND FORECAST

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% annual growth over the next 20 years. The table below shows Vectren's energy and demand forecast; the forecast includes the impact of customer owned distributed generation and customer EE outside of energy company sponsored programs but excludes future energy company sponsored DSM program savings. For more information on Vectren long-term energy and demand forecasts, including load shapes, see Technical Appendix Attachment 4.1 2016 Vectren Long-Term Electric Energy and Demand Forecast Report.

Figure 4.4 – Energy and Demand Forecast[17]

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 2017-2036		0.5%		0.5%		0.5%

4.6 DISCUSSION OF BASE LOAD, INTERMEDIATE LOAD, AND PEAK LOAD

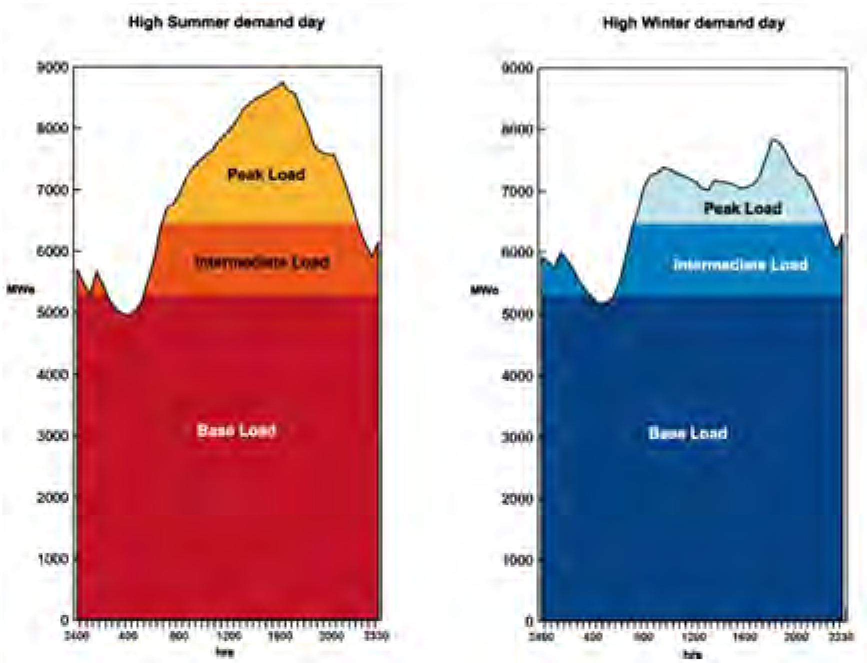
There are three levels of electric load: base load, intermediate load, and peak load. Each level is served by different resource types. Base load is the minimum level of demand on an electrical supply system over 24 hours. Base load is primarily served by power plants which can generate consistent and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

[17] 2016 2016 IRP sales and demand forecast provided to MISO differed slightly in order to match MISO's requirements which necessitated the following two adjustments : 1) incorporated the preferred level of DSM, and 2) adjustment made on the supply and demand side to account for expected customer co-generation unit in 2017.

highest level of demand within a 24-hour period. The annual peak hour is typically between June and September, when weather is hottest. For modeling purposes, Vectren uses August as the peak month. Typically, peak demand is served by units that can be switched on quickly when additional power is needed.

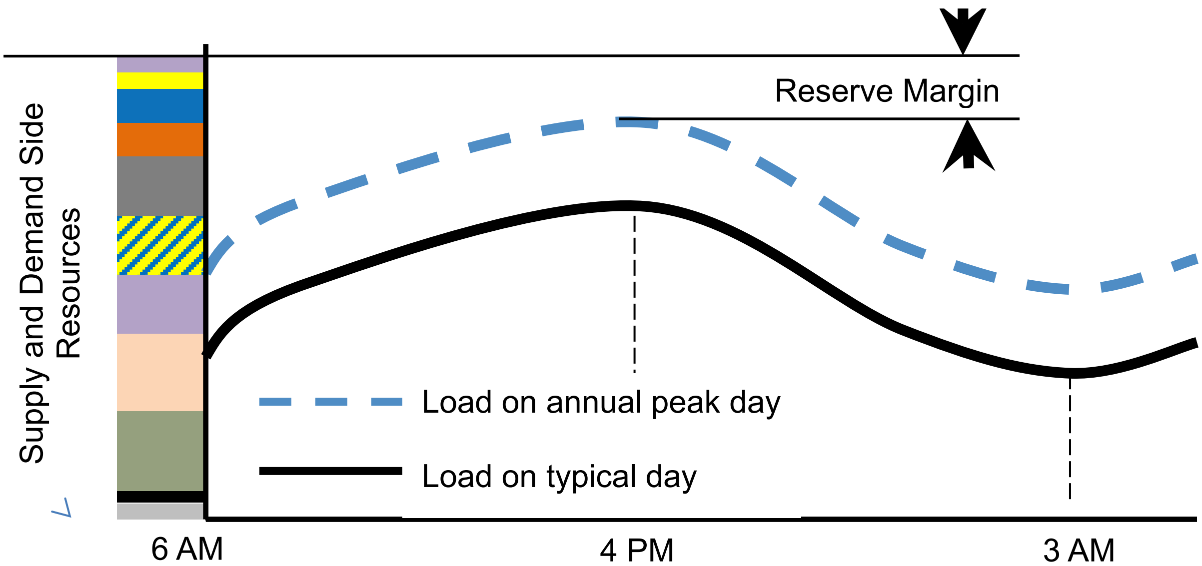
The graphic below shows an illustrative example of summer and winter peak load.

Figure 4.5 – Typical Load Curve Illustrations (Summer and Winter)



Energy companies must have enough resources (supply side generation or demand side energy efficiency & demand response) to meet the annual peak load, plus a reserve margin for reliability purposes, which is required by Vectren's regional transmission operator. The illustration below shows the load on a typical day and load on the peak day with the reserve margin requirement.

Figure 4.6 – Illustration of Load Curve and Planning Reserve Margin



4.7 PLANNING RESERVE MARGIN DISCUSSION

The planning reserve margin requirement is set by MISO (Midcontinent Independent System Operator), which is Vectren's Regional Transmission Operator (RTO).

4.7.1 MISO

MISO, headquartered in Carmel, Indiana, with additional offices in Little Rock, Arkansas, Metairie, Louisiana, and Eagan, Minnesota, was approved as the nation's first Regional Transmission Organization in 2001. Today, MISO manages one of the world's largest energy and operating reserves markets; the market power capacity was 175,600 MW as of June 1, 2016. This market operates in 15 states and 1 Canadian province.

MISO administers its Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff). As a vertically integrated energy company with the responsibility and obligation for serving load within the MISO footprint, Vectren has integrated many functions with the operating procedures of MISO. This integration involves the coordinated operation of its transmission system and generating units, and the functions range from owning and operating generation and transmission to complying with certain reliability standards. These standards include the planning and operation of resources to meet future load needs that are set by the North American Electric Reliability Corporation (NERC) and the regional reliability entity Reliability First Corporation, both of which are overseen by the Federal Energy Regulatory Commission (FERC).

With a native peak load of about 1,160 MW, Vectren is less than 1% of the MISO market footprint and is 1 of 36 local balancing authorities. In addition, the Vectren transmission system supports multiple municipalities. The total control area or Local Balancing Area (LBA) is approximately 1,300 MW.

4.7.2 MISO Planning Reserve Margin Requirement (PRMR)

MISO helps to ensure Resource Adequacy by establishing the Planning Reserve Margin (PRM) with resources at their installed capacity rating at the time of the system-wide MISO coincident peak load. The PRM is a measure of available capacity over and above the capacity needed to meet normal peak demand levels. Reserve margin and reserve capacity are synonymous. For a producer of energy, it refers to the ability of a producer to generate more energy than the system normally requires. Regulatory bodies usually require producers to maintain a constant reserve margin of 10-20% of normal capacity as insurance against breakdowns in part of the system or sudden increases in energy demand. PRMs are needed to cover: planned maintenance, unplanned or forced outages of generating equipment, de-ratings in the capability of generation resources and demand response resources, system effects due to reasonably anticipated variations in weather, and variations in customer demands or forecast demand uncertainty.

4.7.2.1 Mechanics of the PRMR

The PRM calculation is driven by the following: external non-firm support, load forecast uncertainty, load, and generation. External non-firm support refers to the diversity of load between MISO and neighboring systems outside of MISO that allow for limited support and transfer of capacity. An example would be generators in PJM providing capacity to MISO load. Load forecast uncertainty exists due to the variability of economics and weather that impact the demand for energy and increases the uncertainty of forecasts. A robust economy with extreme weather patterns typically leads to higher energy demand. Conversely, a depressed economy with moderate weather tends to lead to reductions in energy demand. Additionally, the ability, or lack there-of, to predict weather and the economy and whether load growth will be positive or negative greatly impacts the amount of reserves needed to reliably meet load needs. The greater the Load Forecast Uncertainty, the greater the PRMR. Finally, generation as it is modeled in terms of capacity and firm imports, impacts the PRM calculation based on the size and outage rate of the generators. A year in which there are a large number of generator outages with long durations will increase the PRM. The chart below is intended to show the impact on the PRMR due to increases in the individual driver (external non-firm support, load forecast uncertainty, load, and generation).

Figure 4.7 – Planning Reserve Margin Drivers

	External Non-Firm Support	Load Forecast Uncertainty	Load (Forecast Demand)	Generation (Size and Outages)
Increase in the Driver	⇧	⇧	⇧	⇧
Impact on the PRM%	⇩	⇧	⇩	⇧

MISO coordinates with stakeholders to determine the appropriate PRM for the applicable planning year based upon the probabilistic analysis of the ability to reliably serve MISO Coincident Peak Demand for that planning year. The probabilistic analysis uses a Loss of Load Expectation (LOLE) study that assumes no internal transmission limitations within the MISO Region. MISO calculates the PRM such that the LOLE for the next planning year is one day in 10 years, or 0.1 days per year. The minimum amount of capacity above Coincident Peak Demand in the MISO Region required to meet the reliability criteria is used to establish the PRM. The PRM is represented as an unforced capacity (PRM UCAP) requirement based upon the weighted average forced outage rate of all Planning Resources in the MISO Region.

The LOLE study sets the Local Reliability Requirement (LRR) for the planning year for each of MISO's zones. MISO's Zone 6[18] in planning year 2016-2017 is required to have a UCAP PRM of 7.6%. This number changes each year based on changes in the factors listed above. Given that the PRM changes from year to year, it is good to have some resources available above the PRM. The full MISO report can be found in Technical Appendix Attachment 4.3 MISO LOLE Study Report.

Since 2013, MISO's Reserve Margin has declined. As MISO starts to operate at or near the Planning Reserve Margin Requirement, it is likely that MISO will begin calling Emergency Operating Procedures more often than in the past to access emergency-only resources, such as Load Modifying Resources (LMR) and Behind the Meter Generation (BTMG). Emergency Operating Procedures (EOPs) guide system operator actions when an event occurs on the electric system that has the potential to, or actually does, negatively impact system reliability.

[18] MISO Zone 6 covers much of Indiana and a small portion of Kentucky.

SECTION 5
RESOURCE OPTIONS

5.1 CURRENT MIX

Generating units are often categorized as either base load, intermediate, or peaking units. This characterization has more to do with the economic dispatch of the units and how much service time they operate rather than unique design characteristics. Base load units generally have the lowest energy costs per kWh and tend to operate most of the time, thereby providing the base of the generating supply stack. The supply stack is the variable cost of production of power by each generating unit, stacked from least cost to most cost. Units that cost less to run are dispatched before units that cost more. Vectren's larger coal units tend to be base load units. Intermediate units may cycle on and off frequently and may sit idle seasonally. Vectren's smallest coal unit sees this type of service. Peaking units have the most expensive energy costs per kWh and are only started when energy demand exceeds 24/7 baseload capacity. Currently, Vectren's gas turbines are dispatched during these peak periods to assure reliability. These peaking units may only run for a few hours and remain idle for long periods of time until called on.

Vectren's current generation mix consists of approximately 1,360 megawatts (MW) of installed capacity. This capacity consists of approximately 1,000 MW of coal fired generation, 245 MW of gas fired generation, 3 MW of landfill gas generation, purchase power agreements (PPA's) totaling 80 MW from wind, and a 1.5% ownership share of Ohio Valley Electric Corporation (OVEC) which equates to 32 MW.

The table below references both installed capacity (ICAP) and unforced capacity (UCAP). Installed capacity is also referred to as nameplate capacity. This is the maximum output that can be expected from a resource. Unforced capacity is the amount of capacity that can be relied upon to meet peak load. MISO uses UCAP for planning purposes. The UCAP accreditation recognizes that all resources are not equally reliable or, in some cases, capable of achieving their design output. MISO uses a three-year reliability history and a weather normalized capability verification to determine the UCAP accreditation of each unit. Vectren used the MISO 2016-2017

UCAP accreditation values along with the MISO UCAP planning reserve margin requirements (7.6% PRM) in the current IRP.

Figure 5.1 – Vectren Generating Units

Unit	Installed Capacity ICAP (MW)	Unforced Capacity UCAP (MW)	Primary Fuel	Unit Age
AB Brown 1	245	238.3	Coal	1979
AB Brown 2	245	223.1	Coal	1986
FB Culley 2	90	85.6	Coal	1966
FB Culley 3	270	263.2	Coal	1973
Warrick 4	150	132.2	Coal	1970
AB Brown 3	80	71.7	Gas	1991
AB Brown 4	80	72.7	Gas	2002
BAGS 2	65	57.6	Gas	1981
Northeast GT 1&2	20	18.9	Gas	1963 / 1964
Blackfoot	3	3 - N/A[19]	Landfill Gas	2009

5.1.1 Coal

The AB Brown Generating Station (ABB), located in Mt. Vernon, IN, consists of two coal fired units, each with an installed capacity of 245 MW. ABB Unit 1 began commercial operation in 1979, while ABB Unit 2 became operational in 1986.

Both AB Brown units are scrubbed for sulfur dioxide (SO_2) emissions, utilizing a dual-alkali flue gas desulfurization (FGD) process. The FGD systems were included as part of the original unit design and construction. Sulfur trioxide (SO_3) is removed via sodium bisulfite (SBS) injection systems installed on both units in 2015. ABB is also scrubbed for nitrogen oxides (NO_x) with selective catalytic reduction (SCR) systems having been installed on Unit 2 in 2004 and on Unit 1 in 2005. Mercury (Hg) removal is accomplished on both units as a co-benefit of SCR and FGD operations as well as through the addition of organosulfide injection systems installed in 2015. Particulate matter (PM) is

[19] The Blackfoot landfill gas generator is connected at the distribution level and is not part of the transmission connected generation network managed by MISO. Therefore, it is not assigned a MISO UCAP value.

captured via an electrostatic precipitator (ESP) on Unit 2. Unit 1 was upgraded to a fabric filter in 2004. The PM that is captured, also known as fly ash, is part of Vectren's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, MO where it is used in the manufacture of cement.

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

The AB Brown plant site also has two natural gas turbine generators which are discussed in Section 5.1.2, Natural Gas.

The FB Culley Generating Station (FBC), located near Newburgh, IN, is a two unit, coal fired facility. FBC Unit 2 has an installed generating capacity of 90 MW and came online in 1966, while FBC Unit 3 has an installed capacity of 270 MW and became operational in 1973.

FBC is scrubbed for sulfur dioxide (SO_2) emissions, utilizing a forced oxidation flue gas desulfurization (FGD) process which is shared by both units and was retrofitted in 1994. The captured SO_2 is converted into synthetic gypsum within the system and, as part of Vectren's beneficial reuse program, is shipped, via barge, to a facility near New Orleans, LA where it is used in the manufacture of drywall. Sulfur trioxide (SO_3) is removed from both units via a dry sorbent injection (DSI) system installed in 2015. FBC Unit 3 is also scrubbed for nitrogen oxides (NO_x) with a selective catalytic reduction (SCR) system that was installed in 2003. NO_x control on FBC Unit 2 is through the use of low NO_x burners. Mercury (Hg) removal is accomplished on both units as a co-benefit of SCR & FGD operation as well as through the addition of organosulfide injection systems installed in 2015. Particulate matter (PM) is captured via an electrostatic precipitator (ESP) retrofitted on Unit 2 in 1972. Unit 3 was upgraded to a fabric filter for PM control in 2006. The PM that is captured, also known as fly ash, is part of Vectren's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, MO where it is used in the manufacture of cement.

The FB Culley units burn Illinois basin bituminous coal, which is mined in Knox County, IN and delivered via truck.

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

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

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

5.1.2 Natural Gas

The AB Brown Generating Station (ABB) located near Mt. Vernon, IN has two natural gas fired simple cycle gas turbine (SCGT) peaking units. Each has an installed capacity of 80 MW. ABB Unit 3 began commercial operation in 1991, while ABB Unit 4 became operational in 2002.

Broadway Avenue Generating Station (BAGS) located in Evansville, IN consists of two gas fired SCGT peaking units. BAGS Unit 1 became operational in 1972 and had an installed capacity rating of 50 MW. This unit has been mothballed and is earmarked for retirement. BAGS Unit 1 is not currently included in Vectren's capacity analysis. BAGS Unit 2 began operation in 1981 and has an installed capacity of 65 MW.

The Northeast Gas Turbine (NEGT 1) facility located in Evansville, IN consists of two natural gas fired peaking units. NEGT 1 began commercial operation in 1963 and has an installed capacity of 10 MW. NEGT 2 became operational in 1964 and also has an installed capacity of 10 MW.

5.1.3 Renewables

The Blackfoot Clean Energy Facility located in Winslow, IN is a base load facility consisting of two internal combustion (IC) landfill methane gas fired units. Blackfoot Units 1 & 2 became operational in 2009 and are capable of producing 1.5 MW each.

5.1.4 DSM

5.1.4.1 INTRODUCTION

Vectren utilizes a portfolio of DSM programs to achieve demand reductions and energy savings, thereby providing reliable electric service to its customers. Vectren's DSM programs have been approved by the Commission and implemented pursuant to various IURC orders over the years.

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

Furthermore, between 2010 and 2015, Vectren's DSM programs reduced demand by approximately 44,000 kW and provided annual incremental gross energy savings of approximately 217,000,000 kWh.

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

Figure 5.2 – Gross Cumulative Savings

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh) - Less Opt Out Savings	Percent of Sales Achieved (Cumulative)
2010	5,616.87	2.52	0.04%
2011	5,594.84	18.30	0.33%
2012	5,464.75	62.29	1.14%
2013	5,459.11	122.06	2.24%
2014[20]	3,498.69	176.74	5.05%
2015	3,223.81	217.25	6.74%

[20] Cumulative savings as a percent of eligible sales saw a higher increase from 2013 to 2014 due to the SB 340's opt-out provision. In 2014, Vectren's eligible sales decreased at a higher rate than achieved savings. For this reason, Vectren achieved higher savings as a percent of eligible sales.

5.1.4.2 2016-2017 Plan Overview

Current Energy Efficiency Programs

On March 23, 2016, the IURC issued an Order approving Vectren's 2016-2017 Energy Efficiency Plan (2016-2017 EE Plan) pursuant to Section 10. Consistent with the 2014 IRP, the framework for the 2016-2017 EE Plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 80% of eligible load. Below is a listing of residential and commercial & industrial programs offered in 2016-2017. For full program descriptions including the customer class, end use of each program, and participant incentives provided by the programs, please refer to the 2016-2017 EE Plan detail found in the Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan.

Residential Programs

- 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
- Residential Smart Thermostat Demand Response

Commercial & Industrial Programs

- Small Business Direct Install
- Commercial & Industrial Prescriptive Rebates
- Commercial & Industrial New Construction
- Commercial & Industrial Custom
- Conservation Voltage Reduction (CVR)

The 2016-2017 plan was included as a resource in the resource optimization model (Strategist) and has an assumed average measure life of 10 years. The table below shows the amount of net savings included in the IRP as a resource (gross savings can be found in Technical Appendix 10.3 DSM Appendix.

Figure 5.3 – 2016-2017 Energy Efficiency Plan Savings

	2016*		2017**	
Sector	Net MWh Energy Savings	Net MW Demand Savings	Net MWh Energy Savings	Net MW Demand Savings
Residential	18,072	4.8	16,332	3.8
Commercial & Industrial	16,474	2.4	15,864	2.4
Total	34,546	7.3	32,196	6.2

*2016 Operating Plan used for 2016
**2016-2017 Filed Plan used for 2017

5.1.5 Demand Response

Vectren's tariff currently includes two active demand response programs: the Direct Load Control and interruptible options for larger customers. Demand response programs allow Vectren to curtail load for reliability purposes. Vectren's tariff also includes a MISO demand response tariff, in which no customers are currently enrolled given the absence of an active demand response program within the MISO market at this time. For purposes of modeling DSM for the IRP, Vectren assumed an active MISO demand response market beginning in 2020.

5.1.5.1 Current DLC (Summer Cycler)

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

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

Cadmus predicts the DLC Program is capable of generating approximately 19.3 MWs of peak demand savings from residential air-conditioning load control and residential water heating load control. As of May 2016, Vectren's DLC Program included over 23,000 customers with a combined total of approximately 31,000 switches. Note that a customer may have more than one switch at a residence or business.

5.1.5.2 Current Interruptible Load

Vectren makes available a credit for qualified commercial and industrial customers to curtail demand under certain conditions. The five customers currently participating provide for a total demand reduction of 35 MW.

5.1.5.3 Smart Thermostats

Pursuant to the IURC approved DSM plan in 2016, Vectren conducted a field study designed to analyze the different approaches of DR that are available through smart thermostats. Between the months of April and May, Vectren installed approximately 2,000 smart thermostats (1,000 Honeywell and 1,000 Nest) in customer homes. Vectren leveraged these thermostats to manage DR events during the summer in an effort to evaluate the reduction in peak system loads. These smart devices, which reside on the customer's side of the electric meter, are connected to Wi-Fi and reside on the customer's side of the electric meter and are used to communicate with customer's air conditioning systems. The program provides Vectren with increased customer contact opportunities and the ability to facilitate customers' shift of their energy usage to reduce peak system loads. In 2017, Vectren will work with an independent evaluator to conduct a billing analysis to measure the effectiveness of the program, including specific performance of the Nest and Honeywell products.

If the program is successful, Vectren will pursue significant expansion in 2018 and beyond, using the technology that best serves its customers' needs. If approved by the Commission, Vectren anticipates replacing DLC switches with smart thermostats over time; indications are the benefits associated with this emerging technology far outweigh the benefits associated with DLC switches.

5.1.5.4 Other Innovative Rate Design

Vectren periodically evaluates alternative rate design and its ability to implement new options as the energy marketplace continues to evolve. Proposals that provide variable energy pricing based on how electric prices change throughout the day (Time of Use rates) and other pricing alternatives may be considered at such time as the required technology upgrades are implemented.

5.2 POTENTIAL FUTURE OPTIONS MODELING ASSUMPTIONS

5.2.1 Coal Technologies

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

Another type of coal technology evaluated was the Integrated Gasification Combined Cycle (IGCC). IGCC produces a low calorific value syngas (synthetic natural gas) from coal or solid waste which can be fired in a combined cycle power plant. The gasification process itself is a proven technology used extensively for chemical production of goods such as ammonia for fertilizer. See Figure 5.4 for further details on the coal technologies evaluated.

Figure 5.4 – Coal Technologies

Coal			
Operating Characteristics and Estimated Costs	**Supercritical Pulverized Coal 500 MW**	**Supercritical Pulverized Coal 750 MW**	**2x1 Integrated Gasification CC**
Base Load Net Output (MW)	425	637.5	525
Base Load Net Heat Rate (HHV Btu/kWh)	10,500	10,200	10,500
Base Project Costs (2015$/kW)	$5,570	$5,080	$3,928
Fixed O&M Costs (2015$/kW-year)	$31.90	$21.20	$36.30

5.2.2 Natural Gas Technologies

5.2.2.1 Simple Cycle Gas Turbines

Simple cycle gas turbines (SCGT) utilize natural gas to produce power. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power or electricity. Typically, SCGTs are used for peaking power due to fast load ramp rates, higher heat rates compared to other technologies, and relatively low capital costs. See Figure 5.5 for further details on the simple cycle gas turbine technologies evaluated.

Figure 5.5 – Simple Cycle Gas Turbine Technologies

Simple Cycle Gas Turbines				
Operating Characteristics and Estimated Costs	**1xLM6000 SCGT**	**1xLMS100 SCGT**	**1xE-Class SCGT**	**1xF-Class SCGT**
Base Load Net Output (MW)	43.4	99.5	90.1	219.8
Base Load Net Heat Rate (HHV Btu/kWh)	9,210	8,840	11,310	9,750
Base Project Costs (2015$/kW)	$1,880	$1,430	$1,230	$650
Fixed O&M Costs (2015$/kW-year)	$26.57	$11.72	$15.83	$7.08

5.2.2.2 Combined Cycle Gas Turbines

Combined cycle gas turbines (CCGT) utilize natural gas to produce power in a gas turbine which can be converted to electric power by a coupled generator, and to also use the hot exhaust gases from the gas turbine to produce steam in a heat recovery steam generator (HRSG). This steam is then used to drive the steam turbine and generator to produce electric power. Using both gas and steam turbine (Brayton and Rankine) cycles in a single plant results in high conversion efficiencies and low emissions.

For this assessment, a 1x1, 2x1, and 3x1 power block, as shown in Figure 5.6, were evaluated with General Electric (GE) 7F-5 turbines as representative CCGT technologies. A 1x1 CCGT has one gas or steam turbine coupled with one HRSG. A 2x1 has two gas or steam turbines coupled with one HRSG. A 3x1 follows the same pattern. The 2x1 CCGT F class technology was considered for both .04 and .05 versions. The .05 technology is GE's most recent F class offering. See Figure 5.6 for further details on the combined cycle gas turbine technologies evaluated.

Figure 5.6 – Combined Cycle Gas Turbine Technologies

Combined Cycle Gas Turbines				
Operating Characteristics and Estimated Costs[21]	**1x1 7FA.05 CCGT (ABB)**	**2x1 7FA.04 CCGT (ABB)**	**2x1 7FA.05 CCGT (ABB)**	**3x1 7FA.05 CCGT (ABB)**
Duct-Firing	Fired	Fired	Fired	Fired
Base Load (24/7 Power) Net Output (MW)	343	579	690	1039
Incremental Duct-Fired (Peaking) Net Output (MW)	99	167	199	298
Base Load Net Heat Rate (HHV Btu/kWh)	6,590	6,650	6,540	6,520
Incremental Duct-Fired Heat Rate (HHV Btu/kWh)	8,460	8,580	8,450	8,460
Base Project Costs (2015$/Fired kW)	$840	$720	$640	$550
Fixed O&M Costs (2015$/Base Load kW-year)	$12.26	$8.89	$7.46	$5.95

A site selection study that examined Greenfield (potential new power plant sites) and compared Brownfield (existing power plant sites) can be found in Technical Appendix Confidential Attachment 5.2 CCGT Site Selection Report.

Vectren initiated studies to evaluate retrofit options that would repurpose existing coal fired generation assets to use natural gas.

[21] Combined cycle gas turbines are shown as fired configuration at AB Brown site for this table. Reference the Technology Assessment for additional details on duct-firing

5.2.2.3 Refuel Option

The conversion of existing coal fired boilers to burn natural gas instead of coal was studied. Detailed site specific studies were performed to determine costs, MW ratings and expected heat rates (efficiency), total natural gas fuel flow requirements, and projected emissions. More information on the refuel option can be found in Technical Appendix Confidential Attachment 1.2 Vectren Technology assessment Summary Table.

5.2.2.4 Repower Option

The conversion of a coal fired unit to a combined cycle gas turbine CCGT was studied. With a unit repower, the existing coal fired boiler and its associated auxiliary equipment would be decommissioned. The steam supply to the legacy steam turbine and electric generator would be accomplished by way of newly constructed heat recovery steam generators capturing heat from the exhaust gas of newly constructed combustion turbines, each of which would have shaft driven electric generators. Detailed site specific studies were performed to determine costs, MW ratings and expected heat rates (efficiency), total natural gas fuel flow requirements, and projected emissions. More information on the repower option can be found in Technical Appendix Confidential Attachment 1.2 2016 Vectren Technology Assessment Summary Table.

5.2.2.5 Combined Heat and Power (CHP)

Combined Heat and Power (CHP), also known as cogeneration, provides both electricity and useful heating or cooling. CHP captures the benefits of heating or cooling, which is created as a byproduct of electricity production, and can be used to create hot water or steam. CHP is typically most efficient when produced close to the end user. See Figure 5.7 for further details on the CHP technologies evaluated.

Figure 5.7 – Combined Heat & Power Technologies

Combined Heat and Power (CHP)					
Operating Characteristics and Estimated Costs	**1 MW Microturbine**	**3 MW Combustion Turbine Generator**	**5 MW Combustion Turbine Generator**	**10 MW Combustion Turbine Generator**	**15 MW Combustion Turbine Generator**
Base Load Net Output (MW)	1.0	3.2	5.1	10.3	13.6
Base Load Net Heat Rate (HHV Btu/kWh)[1]	6,510	4,460	4,400	4,480	4,450
Base Project Costs (2015$/kW)	$4,746	$7,602	$5,637	$3,874	$2,975
Fixed O&M Costs (2015$/kW-year)	$180.30	$227.86	$172.28	$118.77	$99.55

[1]Heat rates are credited for fuel required to produce equivalent steam output.

CHP technical and operating considerations should include the following: customer electric load and thermal requirements inclusive of a detailed engineering and feasibility review. The matching of high load factor thermal load is key to CHP success. In most cases, electricity is considered the byproduct of the process. It is important to understand the variation in heat and electrical demand (demand profiles) as well as the infrastructure modifications within the customer's facility compared to utility connection.

For this screening process it was assumed that Vectren will own and operate a CHP facility. However, it should be noted that a CHP investment may require customers to own and operate internal electric equipment and/or construct significant electric distribution infrastructure. CHP must be mutually beneficial to the customer and Vectren. It is ultimately a customer decision. Upon review of potential customer sites, Vectren identified a market potential of approximately 30 MWs of matching steam and electric load in the Vectren South service territory. The CHP market potential study can be found in Technical Appendix Confidential Attachment 5.4 CHP Market Potential Study.

5.2.3 DSM

5.2.3.1 Background

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

> "An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers."

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

Given that, two questions must be addressed. One, how much DSM should be made available as resource options for selection by the IRP process? And two, how does one project the cost of the DSM resource options over a 20-year horizon and increasing market penetration?

5.2.3.2 DSM Availability

Obviously, at one extreme, one could argue that 100% of retail sales of an energy company could be made available for selection as a DSM resource. However, that is not practical as some energy must be consumed in the course of economic activity. At the other extreme, one could argue that no DSM resource options are required as consumers make their own decisions on the tradeoffs between consumption of energy and investment in more efficient technologies. The result of those decisions would already be reflected in the Company's projection of electric loads.

However, there are barriers to the adoption of more efficient energy using technologies that can be overcome through the implementation of targeted energy company energy efficiency programs. Energy efficiency programs, as marketing programs, encourage customers to adopt higher levels of efficiency earlier than would happen naturally, basically advancing the timing of the energy efficiency. Guidance on the appropriate level of energy efficiency to be made available to the IRP process can be obtained from a market potential study. The Company's market potential study[22] found a Technical Potential of 11%, an Economic Potential of 8.2%, an Achievable High Potential of 6.2%, and an Achievable Low Potential of 3.5%. However, this is only for the years 2015 through 2019.

Another source of information on market potential may be found in a study conducted by the Electric Power Research Institute (EPRI)[23]. This study estimated the potential for the period 2013 through 2035 for the nation as well as selected regions including the Midwest. For the Midwest region, for the full period to the year 2035, the study found a Technical Potential of 23.7%, an Economic Potential of 13.8%, a High Achievable Potential of 11.1%, and an Achievable Potential of 8.9%.

Technical potential is the maximum energy efficiency available, assuming that cost and market adoption of a technology are not a barrier. Economic potential is the amount of energy efficiency that is cost effective, meaning the economic benefit outweighs the cost. The economic potential is measured by the total resource cost test, which

[22] ELECTRIC DEMAND SIDE MANAGEMENT: MARKET POTENTIAL STUDY AND ACTION PLAN, April 2013 prepared by EnerNOC Utility Solutions Consulting.
[23] U.S. Energy Efficiency Potential Through 2035. 1025477 Final Report, April 2014.

compares the lifetime energy and capacity benefits to the incremental cost of the measure. This achievable potential is the amount of energy efficiency that is cost effective and can be achieved given customer preferences. Not all customers will adopt a given technology. For example, CFL light bulbs have been cost effective for many years; however, some people chose not to adopt them for aesthetic reasons. This provides some guidance on the types of potential that the Company could consider for inclusion in its set of DSM resource options.

However, one must consider the impact on these estimates from the fact that larger customers may opt-out of participation in Vectren's energy efficiency programs. As a result of customer opt-outs, 41% of retail sales are not available for consideration in development of DSM resource options. In addition, another adjustment to the available market potential should be taken to capture the level of energy efficiency (EE) impacts expected to be already achieved in the 2013 to 2016 period (when industrial customers were allowed to begin opting out) as represented in the following table.

Figure 5.8 – Vectren Historical Energy Efficiency Impacts

Year	Eligible Retail Sales (GWh)	Gross Incremental Savings (GWh) - Less Opt Out Savings	Gross Cumulative Savings (GWh) - Less Opt Out Savings	Incremental DSM Savings (less opt-out) as a Percent of Eligible Sales	Cumulative DSM Savings (less opt-out) as a Percent of Eligible Sales	Cumulative DSM Savings (less opt-out) as a Percent of Eligible Sales Since 2013
2010	5,616.87	2.52	2.52	0.04%	0.04%	
2011	5,594.84	15.78	18.30	0.28%	0.33%	
2012	5,464.75	43.99	62.29	0.81%	1.14%	
2013	5,479.11	59.77	122.06	1.09%	2.23%	1.09%
2014	3,498.69	54.68	176.74	1.56%	5.05%	3.27%
2015	3,223.81	40.51	217.25	1.26%	6.74%	4.81%
Est2016	3,611.51	42.32	259.57	1.17%	7.19%	5.46%

This implies that the EPRI market potential estimates should be adjusted down to reflect the portion that has already been achieved. Using a conservative estimate of 5% of the potential already achieved, the remaining Technical Potential is estimated to be 18.7%, Economic Potential is 8.8%, High Achievable Potential is 6.1%, and Achievable Potential is 3.9%.

While some may contend that the full technical potential should be provided as the level of DSM options available in the IRP process, this ignores the fact that 100% of the customers would have to participate. This is not realistic. Rather, the potential should reflect some consideration of achievability. This can be estimated by taking the ratio of the achievable percentages to the technical potential percentage and applying that to the remaining estimate of technical potential percentage. This means that 46.8% (11.1%/23.7%) of the technical potential would be considered as the remaining High Achievable Technical Potential or 8.8% of retail sales (e.g., 0.468 x 18.7%). Similarly, 37.6% of the technical potential would be considered as the remaining Achievable Technical Potential or 7.0% of retail sales.

The foregoing provides guidance on the level of DSM resource options that should be considered in the IRP analytical process as well as the maximum levels that seem reasonable at a high level.

For the initial performance of the IRP analysis, Vectren chose to make up to 2% of retail sales as DSM resource options available for selection in the IRP process for each year of the 20 year planning horizon. This represents almost 40% of retail sales, far above any reasonable estimate of even technical market potential. The 2% applies to the level of retail sales after reduction for the level of load that has opted out. To facilitate the IRP resource selection process, the 2% of retail sales was broken into 8 blocks of 0.25% each. Taking this over the 20 year horizon means that over 150 incremental blocks of 0.25% each were available to be selected in the IRP process[24]. From this structure, Vectren expects that the appropriate IRP determined cost-effective level of

[24] For the first two years of the planning horizon, 2016 and 2017, the energy efficiency impacts are based upon the plan approved in Cause No. 44645.

EE would be identified. This process should provide substantial insight on the cost-effective level of energy efficiency. The following table represents the structure and the sizes of the blocks.

Figure 5.9 – DSM Resource Options Net of Free Riders

Year	Eligible GWh Conservation Savings	Percent of Eligible Sales Potential	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8
2016										
2017	3,493									
2018	3,525	2.0%	6.986	6.986	6.986	6.986	6.986	6.986	6.986	6.986
2019	3,545	2.0%	7.050	7.050	7.050	7.050	7.050	7.050	7.050	7.050
2020	3,571	2.0%	7.089	7.089	7.089	7.089	7.089	7.089	7.089	7.089
2021	3,577	2.0%	7.141	7.141	7.141	7.141	7.141	7.141	7.141	7.141
2022	3,594	2.0%	7.154	7.154	7.154	7.154	7.154	7.154	7.154	7.154
2023	3,613	2.0%	7.188	7.188	7.188	7.188	7.188	7.188	7.188	7.188
2024	3,640	2.0%	7.227	7.227	7.227	7.227	7.227	7.227	7.227	7.227
2025	3,654	2.0%	7.281	7.281	7.281	7.281	7.281	7.281	7.281	7.281
2026	3,672	2.0%	7.309	7.309	7.309	7.309	7.309	7.309	7.309	7.309
2027	3,692	2.0%	7.344	7.344	7.344	7.344	7.344	7.344	7.344	7.344
2028	3,721	2.0%	7.384	7.384	7.384	7.384	7.384	7.384	7.384	7.384
2029	3,739	2.0%	7.442	7.442	7.442	7.442	7.442	7.442	7.442	7.442
2030	3,755	2.0%	7.477	7.477	7.477	7.477	7.477	7.477	7.477	7.477
2031	3,772	2.0%	7.511	7.511	7.511	7.511	7.511	7.511	7.511	7.511
2032	3,796	2.0%	7.543	7.543	7.543	7.543	7.543	7.543	7.543	7.543
2033	3,810	2.0%	7.592	7.592	7.592	7.592	7.592	7.592	7.592	7.592
2034	3,831	2.0%	7.620	7.620	7.620	7.620	7.620	7.620	7.620	7.620
2035	3,850	2.0%	7.663	7.663	7.663	7.663	7.663	7.663	7.663	7.663
2036	3,876	2.0%	7.701	7.701	7.701	7.701	7.701	7.701	7.701	7.701

The component programs for the blocks are assumed to initially be those approved in Cause No. 44645 and previously described in Section 5.1.4, DSM. For the first two years of the planning horizon (2016 and 2017), it is assumed that the current set of approved programs are being implemented. However, it is expected that the nature of the programs in the blocks may change over time as energy efficiency technology changes.

No minimum level of energy efficiency impacts have been locked in for the planning process. The table provides 0.25% blocks of net impacts which already reflects a 20% adjustment for free riders. Free riders represent those participants that would have implemented the energy efficiency technology without the energy company program.

5.2.3.3 DSM Resource Cost – Base Case

Projecting the cost of the DSM programs that are expected to achieve a 40% level of energy efficiency (EE) over a long period represents a challenge. As a starting point, the cost of the energy efficiency programs approved in Cause No. 44645 is used for the 2017 DSM resource options. The Company's EE portfolio being implemented in 2016 is designed to achieve approximately 36,000 MWh impacts on a net of free-rider basis at a cost of $0.20 per first year kWh[25] ($.03322 per kWh on a levelized basis). Through 2015, the Company has already achieved a reduction of approximately 7% of available 2017 retail sales (total retail sales reduced for opt-outs)[26]. On a net of free-rider basis, the 2016 plan is designed to achieve an additional 1% of available retail sales.

As discussed above, in an effort to allow the IRP model to inform the Company on the cost-effective level of EE to pursue in the resource plan, the Company has provided the IRP model with the ability to select from 8 blocks of EE impacts each year where each block represents 0.25% of retail sales. This represents a possible additional 2% of available retail sales that could be selected each year from 2018 through 2036.

On a cumulative basis, this means that almost 40% of available retail sales could be selected by the IRP process. This is in addition to the approximate 7% already achieved through past EE efforts. Vectren is not aware of any national or regional EE market potential study with a higher estimate of EE potential. In order to identify the cost-effective level of EE in the IRP process, it is imperative that Vectren develop

[25] This value is estimated using the total cost of the program and dividing by the first year of EE savings.
[26] As previously mentioned, the Company has achieved a 3% reduction in total retail sales over the period 2013 through 2015.

estimates of the cost of EE achievement that reflect how the costs could change as EE market penetration increases.

To this end, Vectren retained Dr. Richard Stevie, VP of Forecasting with Integral Analytics, Inc., to provide insights on how the cost to achieve an increment of EE could change as the cumulative EE market penetration rises. Dr. Stevie's recommendation is based upon his research into the relationship between spending on EE programs and the level of first year impacts achieved through the implementation of the EE programs as well as the cumulative level of EE impacts. The research relies upon EE cost and impact data collected through Form 861 by the Energy Information Administration (EIA). A copy of the research study is provided in Technical Appendix Attachment 5.3 Cost of Energy Efficiency Programs. The study found that EE program costs per kWh increase as the cumulative penetration of EE increases, as measured by the percent of retail sales. The primary focus of the research was to examine if and to what extent the program cost of EE changes as the available supply (i.e., retail sales) of EE is consumed through implementation of EE programs. Based upon this research and Vectren's projected level of EE available for selection by the IRP process, Dr. Stevie developed a projected rate of growth in the cost of EE for the first four blocks which cumulatively represent 1% of eligible retail sales each year. This growth rate was applied to each of the first four 0.25% blocks.

The growth rate was developed from two separate econometric models of the EIA data as described in the study provided in Technical Appendix Attachment 5.3 Cost of Energy Efficiency Programs. 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.

With this first 1% of retail sales, Vectren is planning to achieve an amount of energy efficiency that exceeds an expected high achievable level over the next 20 years. As a result, it is assumed that the second 1% of retail sales must occur at a higher marketing cost than the first 1% of retail sales. In other words, the methodology is that for the first 1%, for the full planning period, Vectren is achieving actually more than what it should reasonably expect to achieve in the market place. The effort being undertaken is as if Vectren were achieving the full 1% for 20 years or 20% of the market at a base level of cost. To get the next 1%, one has to step up to a higher marketing cost that assumes the first 1% has already been achieved. The next 1% is incremental to the first 1%. It is assumed that Vectren will have to dramatically expand its marketing effort to essentially double the annual impact achievement. This would involve expanded advertising and possibly in person contact to get customers to take action. Essentially the second 1% has to be more expensive, not cheaper, than the first 1%.

As a result, the starting cost for the second 1% of blocks is assumed to be the ending cost (in real dollars) for the first 1%. Then, a different growth rate is applied for the remaining set of four 0.25% blocks available each, or the next 1% of retail sales available for selection. The process of computing the applicable growth rate 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. So, this assumes that once the first four blocks have been selected in a year by the IRP, the cost increases first to the cost of the last block of the 1% of retail sales and then by 0.43% per 0.25% block for the 5th to 8th blocks. These growth rates form the basis for projecting how the block costs change for all of the blocks available for selection by the IRP process. The lower growth rate was applied to the second 1% of retail sales (blocks 5 to 8) to allow for economy of operation within a given year, while the higher growth rate was applied to the first 1% of retail sales to try to capture the impact on cost over time. The following table provides the estimated levelized costs used for all of the blocks.

Figure 5.10 – Base Case Cost per kWh[27]

Year	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8
2016	$0.03322	$0.03356	$0.03391	$0.03426	$0.07811	$0.07844	$0.07878	$0.07911
2017	$0.03462	$0.03498	$0.03534	$0.03570	$0.07945	$0.07979	$0.08013	$0.08048
2018	$0.03607	$0.03645	$0.03682	$0.03721	$0.08082	$0.08117	$0.08151	$0.08186
2019	$0.03759	$0.03798	$0.03837	$0.03877	$0.08221	$0.08256	$0.08292	$0.08327
2020	$0.03917	$0.03958	$0.03999	$0.04040	$0.08363	$0.08398	$0.08434	$0.08470
2021	$0.04082	$0.04124	$0.04167	$0.04210	$0.08507	$0.08543	$0.08579	$0.08616
2022	$0.04254	$0.04298	$0.04342	$0.04387	$0.08653	$0.08690	$0.08727	$0.08764
2023	$0.04433	$0.04478	$0.04525	$0.04572	$0.08802	$0.08840	$0.08877	$0.08915
2024	$0.04619	$0.04667	$0.04715	$0.04764	$0.08953	$0.08992	$0.09030	$0.09069
2025	$0.04813	$0.04863	$0.04914	$0.04964	$0.09108	$0.09146	$0.09186	$0.09225
2026	$0.05016	$0.05068	$0.05120	$0.05173	$0.09264	$0.09304	$0.09344	$0.09384
2027	$0.05227	$0.05281	$0.05336	$0.05391	$0.09424	$0.09464	$0.09504	$0.09545
2028	$0.05447	$0.05503	$0.05560	$0.05618	$0.09586	$0.09627	$0.09668	$0.09709
2029	$0.05676	$0.05734	$0.05794	$0.05854	$0.09751	$0.09793	$0.09834	$0.09876
2030	$0.05914	$0.05976	$0.06038	$0.06100	$0.09919	$0.09961	$0.10004	$0.10046
2031	$0.06163	$0.06227	$0.06292	$0.06357	$0.10089	$0.10133	$0.10176	$0.10219
2032	$0.06422	$0.06489	$0.06556	$0.06624	$0.10263	$0.10307	$0.10351	$0.10395
2033	$0.06693	$0.06762	$0.06832	$0.06903	$0.10440	$0.10484	$0.10529	$0.10574
2034	$0.06974	$0.07046	$0.07119	$0.07193	$0.10619	$0.10665	$0.10710	$0.10756
2035	$0.07268	$0.07343	$0.07419	$0.07496	$0.10802	$0.10848	$0.10895	$0.10941
2036	$0.07573	$0.07652	$0.07731	$0.07811	$0.10988	$0.11035	$0.11082	$0.11130

The detailed calculation of the growth rates is provided in Technical Appendix Attachment 5.3 Cost of Energy Efficiency.

5.2.3.4 DSM Resource Cost - Scenario Analysis

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

[27] Costs included in the risk analysis modeling

To that end, high and low DSM resource cost trajectories were developed using the estimated standard errors of the model coefficients used in the development of the Base Case cost projection. These high and low cost trajectories were created by applying plus and minus one standard error to the model coefficients.[28] This produces alternate DSM resource cost growth rates summarized in the following table.

Figure 5.11 – DSM Resource Cost Growth Rates

Sets of Four Blocks	Minus One Standard Deviation	Base Case	Plus One Standard Deviation
First 1%	0.85%	1.04%	1.22%
Second 1%	0.35%	0.43%	0.51%

Applying these alternate growth rates produces the following high and low tables of projected DSM resource costs.

[28] Using the model coefficients and standard errors from the two econometric models referenced in Dr. Stevie's research, the coefficient range is developed by adding the standard error to or subtracting it from the coefficient estimate. For the first model, the coefficient is .278 with a standard error of .084. For the second model, the coefficient is .897 with a standard error of .131.

Figure 5.12 – High Case Cost per kWh: Plus One Standard Deviation

Year	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8
2016	$0.03322	$0.03363	$0.03404	$0.03445	$0.09095	$0.09141	$0.09187	$0.09233
2017	$0.03487	$0.03530	$0.03573	$0.03617	$0.09280	$0.09327	$0.09374	$0.09421
2018	$0.03661	$0.03705	$0.03751	$0.03796	$0.09469	$0.09517	$0.09565	$0.09613
2019	$0.03843	$0.03890	$0.03937	$0.03985	$0.09662	$0.09710	$0.09759	$0.09809
2020	$0.04034	$0.04083	$0.04133	$0.04183	$0.09858	$0.09908	$0.09958	$0.10008
2021	$0.04234	$0.04286	$0.04338	$0.04391	$0.10059	$0.10110	$0.10161	$0.10212
2022	$0.04445	$0.04499	$0.04554	$0.04610	$0.10264	$0.10316	$0.10368	$0.10420
2023	$0.04666	$0.04723	$0.04781	$0.04839	$0.10473	$0.10526	$0.10579	$0.10632
2024	$0.04898	$0.04958	$0.05018	$0.05080	$0.10686	$0.10740	$0.10794	$0.10849
2025	$0.05142	$0.05205	$0.05268	$0.05332	$0.10904	$0.10959	$0.11014	$0.11070
2026	$0.05397	$0.05463	$0.05530	$0.05598	$0.11126	$0.11182	$0.11238	$0.11295
2027	$0.05666	$0.05735	$0.05805	$0.05876	$0.11352	$0.11409	$0.11467	$0.11525
2028	$0.05948	$0.06020	$0.06094	$0.06168	$0.11583	$0.11642	$0.11700	$0.11760
2029	$0.06243	$0.06320	$0.06397	$0.06475	$0.11819	$0.11879	$0.11939	$0.11999
2030	$0.06554	$0.06634	$0.06715	$0.06797	$0.12060	$0.12121	$0.12182	$0.12243
2031	$0.06880	$0.06964	$0.07049	$0.07135	$0.12305	$0.12367	$0.12430	$0.12493
2032	$0.07222	$0.07310	$0.07400	$0.07490	$0.12556	$0.12619	$0.12683	$0.12747
2033	$0.07581	$0.07674	$0.07768	$0.07862	$0.12811	$0.12876	$0.12941	$0.13006
2034	$0.07958	$0.08055	$0.08154	$0.08253	$0.13072	$0.13138	$0.13205	$0.13271
2035	$0.08354	$0.08456	$0.08559	$0.08664	$0.13338	$0.13406	$0.13473	$0.13541
2036	$0.08770	$0.08877	$0.08985	$0.09095	$0.13610	$0.13679	$0.13748	$0.13817

Figure 5.13 – Low Case Cost Per kWh: Minus One Standard Deviation

Year	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8
2016	$0.03322	$0.03350	$0.03379	$0.03407	$0.06700	$0.06723	$0.06747	$0.06770
2017	$0.03436	$0.03465	$0.03495	$0.03524	$0.06794	$0.06818	$0.06841	$0.06865
2018	$0.03554	$0.03585	$0.03615	$0.03646	$0.06889	$0.06913	$0.06938	$0.06962
2019	$0.03677	$0.03708	$0.03739	$0.03771	$0.06986	$0.07011	$0.07035	$0.07060
2020	$0.03803	$0.03835	$0.03868	$0.03901	$0.07084	$0.07109	$0.07134	$0.07159
2021	$0.03934	$0.03967	$0.04001	$0.04035	$0.07184	$0.07209	$0.07234	$0.07260
2022	$0.04069	$0.04104	$0.04138	$0.04174	$0.07285	$0.07311	$0.07336	$0.07362
2023	$0.04209	$0.04245	$0.04281	$0.04317	$0.07388	$0.07413	$0.07439	$0.07465
2024	$0.04354	$0.04391	$0.04428	$0.04465	$0.07491	$0.07518	$0.07544	$0.07570
2025	$0.04503	$0.04542	$0.04580	$0.04619	$0.07597	$0.07623	$0.07650	$0.07677
2026	$0.04658	$0.04698	$0.04738	$0.04778	$0.07704	$0.07731	$0.07758	$0.07785
2027	$0.04818	$0.04859	$0.04901	$0.04942	$0.07812	$0.07839	$0.07867	$0.07894
2028	$0.04984	$0.05026	$0.05069	$0.05112	$0.07922	$0.07950	$0.07977	$0.08005
2029	$0.05155	$0.05199	$0.05243	$0.05288	$0.08033	$0.08061	$0.08089	$0.08118
2030	$0.05333	$0.05378	$0.05424	$0.05470	$0.08146	$0.08175	$0.08203	$0.08232
2031	$0.05516	$0.05563	$0.05610	$0.05658	$0.08261	$0.08290	$0.08319	$0.08348
2032	$0.05706	$0.05754	$0.05803	$0.05852	$0.08377	$0.08406	$0.08436	$0.08465
2033	$0.05902	$0.05952	$0.06003	$0.06053	$0.08495	$0.08524	$0.08554	$0.08584
2034	$0.06105	$0.06157	$0.06209	$0.06262	$0.08614	$0.08644	$0.08675	$0.08705
2035	$0.06315	$0.06368	$0.06422	$0.06477	$0.08735	$0.08766	$0.08796	$0.08827
2036	$0.06532	$0.06587	$0.06643	$0.06700	$0.08858	$0.08889	$0.08920	$0.08951

These cost projections were incorporated into the scenario analyses. The selection of a high or low cost projection depends upon the nature or characteristics of each scenario. Expected direction of power costs is assumed to be one of the key drivers in deciding which of the cost projections should be used in a given scenario.

Scenario 1, The High Regulatory Scenario, is characterized by a heavier reliance on regulations such as the Clean Power Plan (CPP) as well as other potential future regulations focused on reducing carbon emissions. In conjunction with these regulations, it is expected that more stringent codes and standards would be implemented to promote installation of more energy efficient equipment. The stricter efficiency codes and standards will likely shrink the available market potential for energy company DSM programs, which could make it more difficult to market DSM resources. As a result, the high DSM resource cost projection is employed for this scenario.

Under the Low Regulatory Scenario, it is expected that with a reduced regulatory environment, there would be greater economic growth and thus a larger market for offering DSM programs. The lower regulatory environment could make it easier to market DSM resources. As a result, the low DSM resource cost projection is employed in this scenario.

The High Technology Scenario is characterized by significant advances in solar, wind, and energy storage technologies as well as advances in EE technologies. In addition, it is expected that newer technologies could improve marketing efficiency that makes it easier to attract DSM program participants. As a result, the low DSM resource cost projection is employed for this scenario.

The High Economy/Market Scenario sees faster economic growth which leads to higher growth in energy usage, in the absence of faster technology development. The growth in energy usage will make DSM resources more attractive and cost-effective for program participants. As a result, the low DSM resource cost projection is employed for this scenario.

Under the Low Economy/Market Scenario, the economy is sluggish which keeps load growth low. It is expected that power prices would increase at a slower rate which could make it more difficult to market DSM resources. As a result, the high DSM resource cost projection is employed in this scenario.

Incorporating alternate views of DSM resource costs into the IRP planning process provides a better view on the robustness of the final DSM resource selection.

5.2.3.5 Summary

This DSM Resource process provides EE savings and cost values for over 150 blocks of DSM resources representing almost 40% of available retail sales for potential selection by the IRP analytical model. This level of DSM resource options, exceeding estimates of Technical Potential, provides enough flexibility to the IRP model for identifying and selecting a DSM plan consistent with the IURC and legislative objectives. However, given that there is a potential to exceed the estimate of Technical Potential, adjusted for past impacts already obtained and for achievability, the results of the IRP analytical process need to be checked to ensure that the resulting level of DSM selected is ultimately and practically viable.

5.2.3.6 DSM Planning Process

One of the key objectives of the IRP is to "provide all customers with a reliable supply of energy at the lowest reasonable cost." The level of DSM to be offered in Vectren's service territory is an important outcome of the IRP process. The IRP should determine the appropriate level of DSM to include in the preferred resource plan. However, for Vectren, the IRP is not the appropriate tool to determine which specific programs to include in a DSM plan. Instead, every 2-3 years Vectren engages in a multi-step planning process designed to select programs that meet the level of savings established in the preferred resource portfolio. Once the level of DSM to be offered has been established by the IRP and a portfolio of programs to meet the savings levels has been designed, the last step in the planning process is to test the cost effectiveness of the programs.

5.2.3.7 Cost Benefit Analysis

Utilizing the DSMore cost/benefit model, the measures and programs were analyzed for cost effectiveness. The model includes a full range of economic perspectives typically used in EE and DSM analytics. Inputs into the model include the following: participation rates, incentives paid, energy 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 considers the results of each test and ensures that the portfolio passes the Total Resource Cost (TRC) test as it includes the total costs and benefits to both the energy company and the consumer. The outputs include all the California Standard Practice Manual results:

- Participant Cost Test
- Ratepayer Impact Measure Test
- Utility Cost Test ("UCT")
- Total Resource Cost Test ("TRC")

The cost effectiveness analysis produces two types of resulting metrics:

- Net Benefits (dollars) = NPV ∑ benefits – NPV ∑ costs
- Benefit Cost Ratio = NPV ∑ benefits ÷ NPV ∑ costs

Figure 5.14 – Vectren Cost Effectiveness Tests Benefits & Costs Summary

Test	Benefits	Costs
Participant Cost Test	• Incentive payments • Annual bill savings • Applicable tax credits	• Incremental technology/equipment costs • Incremental installation costs
Rate Impact Measure Test	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs • Lost revenue due to reduced energy bills
Utility Cost Test (Program Administrator Cost Test)	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs
Total Resource Cost Test	• Avoided energy costs • Avoided capacity costs • Applicable participant tax credits	• All program costs (not including incentive costs) • Incremental technology/equipment costs (whether paid by the participant or the utility)

The Participant Cost Test shows the value of the program from the perspective of the energy company's customer participating in the program. The test compares the participant's bill savings over the life of the DSM program to the participant's cost of participation.

The Utility Cost Test shows the value of the program 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 energy company and the participating customers. This test compares the level of benefits associated with the reduced energy supply costs to energy company programs and participant costs. In completing the tests listed above, Vectren used 10.09% as the weighted average cost of capital, which is the weighted cost of capital that was approved by the IURC on April 27, 2011 in Cause No. 43839.

5.2.4 Demand Response

Demand Response (DR) represents curtailment or reduction to end user electrical consumption based on market or operator feedback. Feedback is typically driven by economic incentives or reliability concerns due to imbalances in supply and demand of electricity. DR is a broad category that can apply to a variety of both consumption technologies (i.e. air conditioner, irrigation, etc.) and customer classes (i.e. industrial, commercial, residential). DR is typically more cost effective with larger individual customer loads. See Figure 5.15 for further details on the DR technologies evaluated.

Figure 5.15 – Demand Response

Operating Characteristics and Estimated Costs	Demand Response
Base Load Net Output (MW)	4.0
Base Project Costs (2015$/kW)	$14.00
Fixed O&M Costs (2015$/kW-year)	$57.07

5.2.5 Renewables Technologies

5.2.5.1 Wind

Three renewable technologies were evaluated in the IRP. Those technologies were wind energy, solar photovoltaic, and hydroelectric.

Wind turbines convert the kinetic energy of wind into mechanical energy. Typically, wind turbines are used to pump water or generate electrical energy which is supplied to the grid. See Figure 5.16 for further details on the variety of wind technologies evaluated.

Figure 5.16 – Wind Renewables

Operating Characteristics and Estimated Costs	50 MW Wind (Indiana)	200 MW Wind (Indiana)
Base Load Net Output (MW)	50	200
Base Project Costs (2015$/kW)	$1,940	$1,680
Fixed O&M Costs (2015$/kW-year)	$45.00	$42.00

The production tax credit (PTC) is a tax credit per-kilowatt-hour (kWh) for electricity generated by qualified energy resources. The duration of the credit is 10 years after the in-service date for all facilities placed in service after August 8, 2005. The tax credit is $0.015 per kWh in 1993 adjusted by inflation adjustment factor provided by the IRS and rounded to the nearest 0.1 cents. Vectren assumed 1.6% past 2016 IRS values, which was the general inflation used throughout the IRP. The tax credit is phased down by 20 percent per year for wind facilities commencing construction after December 31, 2016. The tax credit reduces from 100 percent for wind facilities commencing construction in 2016 and before, down to 40 percent for wind facilities commencing construction in 2019. See Figure 5.17 below for the percent of production tax credit. For purposes of the IRP, Vectren applied the PTC as if the commence construction was one year prior to the commercial operation date.

Figure 5.17 – Wind Production Tax Credit by Year

Commence Construction (Prior to)	Production Tax Credit (%)
2017	100%
2018	80%
2019	60%
2020	40%

5.2.5.2 Solar

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

Photovoltaic (PV) cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively and negatively charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other. See Figure 5.17 for further details on the solar PV technologies evaluated.

Figure 5.18 – Solar Photovoltaic

Operating Characteristics and Estimated Costs	3 MW Solar PV	6 MW Solar PV	9 MW Solar PV	50 MW Solar PV	100 MW Solar PV
Base Load Net Output (MW)	3	6	9	50	100
Base Project Costs (2015$/kW)	$3,420	$2,700	$2,540	$2,260	$2,230
Fixed O&M Costs (2015$/kW-year)	$19.50	$19.50	$19.50	$19.50	$19.50

As discussed in Section 1.3.8, Solar Generation, the Investment Tax Credit (ITC) is a federal tax credit as a percent of basis invested in eligible properly. Investment tax credit percentage depends on the commencement of construction as shown below in Figure 5.19. For modeling purposes, Vectren assumed commercial operation date and commence construction to be the same year for solar projects. The eligible investment was assumed to be the total invested project costs to build. The Investment Tax Credit was normalized over the book life of the asset, which evenly distributes the tax credit out over the asset book life.

Figure 5.19 – Solar Investment Tax Credit by Year

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

5.2.5.3 Hydroelectric

Low-head hydroelectric power generation facilities are designed to produce electricity by utilizing water resources with low pressure differences, typically less than 5 feet head but up to 130 feet. This allows the technology to be implemented with a smaller impact to wildlife and environmental surroundings than conventional hydropower. However, power supply is dependent on water supply flow and quality, which are sensitive to adverse environmental conditions like dense vegetation or algae growth, sediment levels, and drought. Additionally, low-head hydropower is relatively new and undeveloped, thus resulting in a high capital cost for the relatively small generation output. See Figure 5.20 for further details on the hydroelectric technology evaluated.

Figure 5.20 – Hydroelectric

Operating Characteristics and Estimated Costs	50 MW Low-head Hydroelectric
Base Load Net Output (MW)	50
Base Project Costs (2015$/kW)	$3,760
Fixed O&M Costs (2015$/kW-year)	$75.00

5.2.5.4 Waste-to-Energy

Two waste-to-energy (WTE) technologies were included within the analysis. Stoker boiler technology, or biomass, is the most commonly used WTE technology. Waste fuel is combusted directly in the same way fossil fuels are consumed in other combustion technologies. The heat resulting from the burning of waste fuel converts water to steam, which then drives a steam turbine generator for the production of electricity. The two fuel types evaluated in the IRP were wood and landfill gas, which are represented in Figure 5.21.

Figure 5.21 – Waste to Energy Technologies

Operating Characteristics and Estimated Costs	Wood Stoker Fired	Landfill Gas IC Engine
Base Load Net Output (MW)	50	5
Base Load Net Heat Rate (HHV Btu/kWh)	13,500	10,500
Base Project Costs (2015$/kW)	$4,720	$4,250
Fixed O&M Costs (2015$/kW-year)	$93.00	$180.00

5.2.5.5 Renewable Cost Curve Discussion

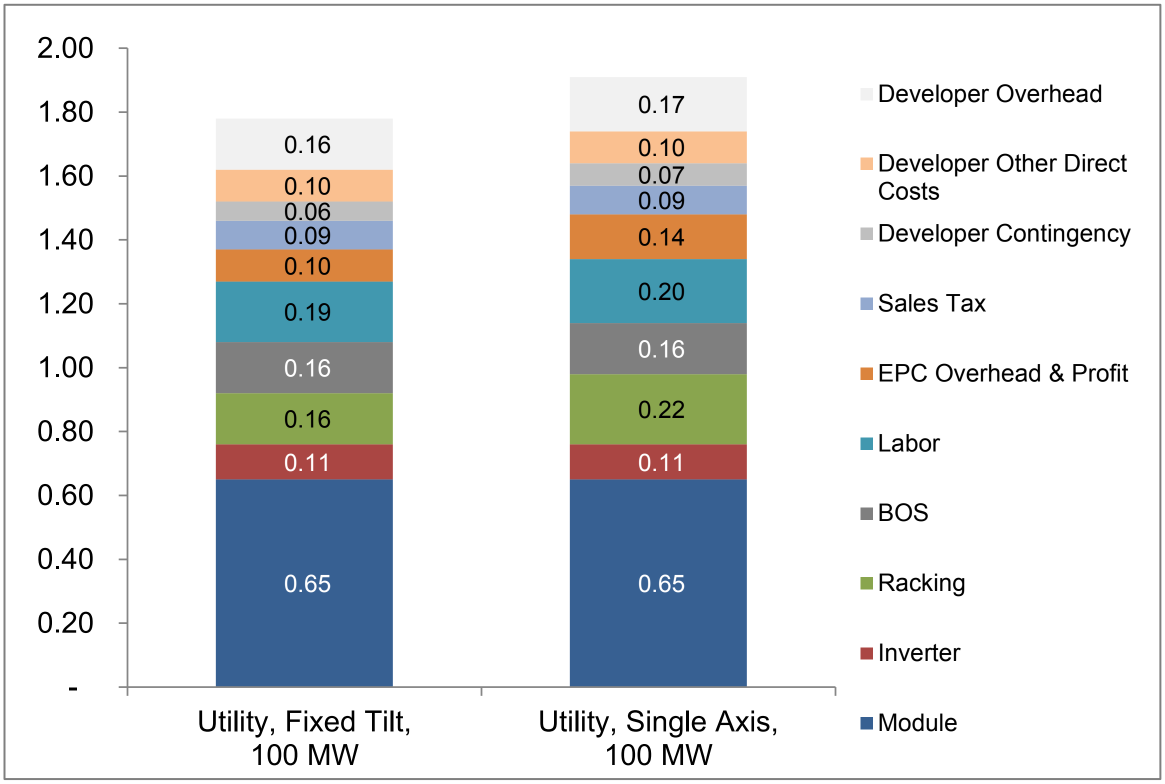
5.2.5.5.1 Solar

Current overnight capital cost estimates for solar technology were developed by Burns & McDonnell as part of the technology assessment. Pace Global then developed a long-term view of solar capital costs by reviewing public reputable studies and other IRPs. As a result, Pace Global's estimates are derived from several quality references supplemented with analysis and expert judgment.

In the case of solar photovoltaics (PV), the National Renewable Energy Lab (NREL) provides a rich data set from which to explain current costs and trends. According to NREL, universal solar PV pricing has continued to decline over the last several years. While costs have declined in the past three years, the rate of decline has slowed significantly in the past two to three years as production scale and global competition has driven equipment pricing down[29]. Though some continued improvement in equipment cost is expected, NREL and other experts now expect most cost reductions will come from solar PV project soft costs. Soft costs generally include cost items such as Installation Labor, EPC Overhead & Profit, Developer Contingency, Developer Other Direct Costs, and Developer Overhead. For fixed tilt and single axis systems, soft costs comprise $0.60/Wdc and $0.68/Wdc (dollars per watt direct current), respectively.

[29] Sunshot report - Photovoltaic System Pricing Trends, Historical, Recent, and Near-Term Projections 2015 Edition", DOE Sunshot, Aug 2015, page 19, https://emp.lbl.gov/sites/all/files/pv_system_pricing_trends_presentation_0.pdf

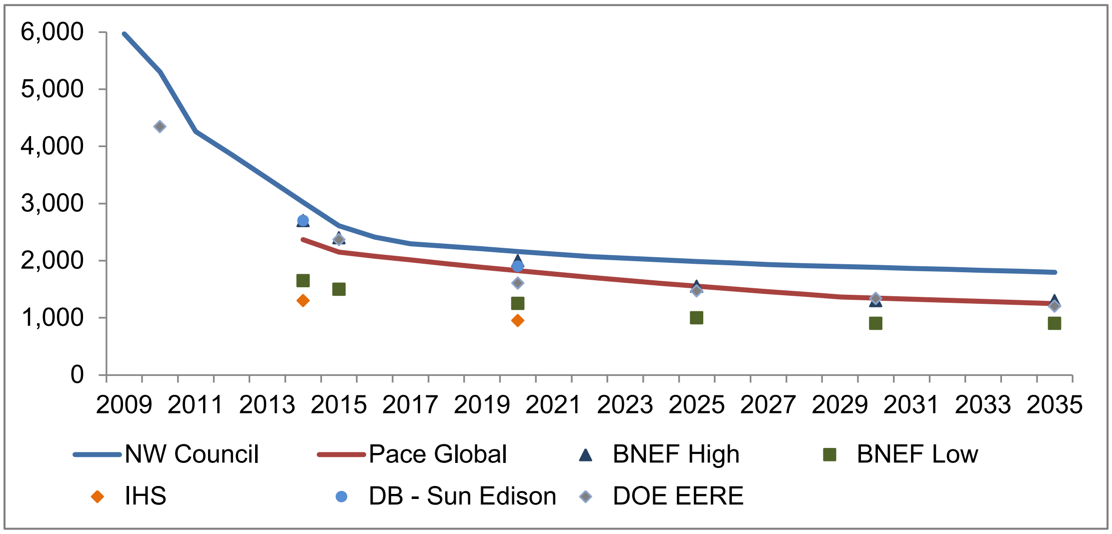
Figure 5.22 – Q1 2015 Universal Solar PV Cost Breakdown, 100 MW U.S. National Average, 2015$/Wdc[30]



To forecast capital cost for solar power generation technology, Pace Global reviewed numerous public sources regarding industry issues, trends, and predictions. Equipment, material, labor, and developer costs were considered to project the rate of cost change. This estimate was then compared with independent forecasts to ensure consistency. Pace Global expects solar capital costs to decline at a compound annual growth rate of 2.7% per year through 2036, which is in-line with other expert forecasts presented in the graph below.

[30] U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2015 Benchmarks for Residential, Commercial, and Utility-Scale Systems; NREL, September 2015

Figure 5.23 – U.S. National Average Overnight Solar PV Capital Costs, 2015$/kW[31]



By combining the 2015 Indiana capital cost estimate with the anticipated decline rate in solar power generation technology costs, a specific forecast for solar PV costs in Indiana is derived.

5.2.5.5.2 Wind

Onshore wind-powered electrical generating technologies are becoming a mature technology. While wind project capital costs are expected to continue declining for several years as wind turbine pricing declines, the rate of decline is expected to slow.

Turbine nameplate capacity, hub height, and rotor diameter have all increased significantly over the long term. Though trends in the average nameplate capacity, hub height, and rotor diameter of turbines have been notable, the growth in the swept area of the rotor has been particularly rapid. All else being equal, increased swept rotor area results in greater energy capture for each watt of rated turbine capacity, meaning that

[31] The sources used to develop the above forecast are as follows: Photovoltaic System Pricing Trends, Historical, Recent, and Near-Term Projections 2015 Edition, DOE Sunshot, Aug 2015; U.S. Solar Market Insight Report, GTM Research and SEIA; Annual Technology Baseline and Standard Scenarios, NREL, July 2015; NW Council 2015 IRP; H1 2015 North American PV Outlook, Bloomberg New Energy Finance 01/16/15; Deutsche Bank, 02/19/15, 02/25/15, 05/04/15, 05/13/15; Solar Market Intelligence, IHS, 07/07/15; WindVision: A New Era for Wind Power in the United States, DOE EERE, Mar 2015; Pace Global client confidential data.

the generator is likely to run closer to or at its rated capacity and more often. The expected growth in capacity factors resulting from improved turbine designs is being held back by curtailments and inter-year wind resource variability. The strength of the wind resource varies from year to year, partly in response to significant persistent weather patterns such as El Niño/La Niña. A relatively strong El Niño in 2015 led to lower than expected wind speeds in the first two quarters, which reduced turbine output.

Based on these trends and observations, Pace Global estimates that 2016 overnight capital costs for an Indiana-based 50 MW wind farm are expected to decline by an average of one percent per year through 2030, with a lower decline rate of 0.3% per year thereafter.[32]

5.2.5.6 Out-of-State Wind

5.2.5.6.1 Contracted Wind Prices

Recent energy trade publications have touted the cheap energy production costs and increased capacity factors (the average power generated, in relation to the rated peak output of the wind turbine) of wind rich areas located in various parts of the MISO footprint, all of which are outside of Indiana. Combined with certain geographic locations being greater in wind output, technological innovation, production tax incentives, and various other factors, the contracted price of wind energy has decreased over time. Based on data from the U.S. Department of Energy, wind output in the plains states of Iowa, Oklahoma, and Kansas yields more megawatt hours and therefore a lower cost per MWh than Indiana wind resources[33]. The differences in cost per MWh are as much

[32] Pace Global used the following sources in developing this capital cost decline curve: 2015 Wind Technologies Market Report, August 2015, EERE; EIA AEO 2016 Assumptions; Lazard Levelized Cost of Generation Study, version 9.0, NOV 17 2015; The Cost Landscape of Solar and Wind, America's Insight, Jan 2015, BNEF; WindVision: A New Era for Wind Power in the United States, DOE EERE, Mar 2015; RE Map 2030, IRENA, May 2015; Most recent IRPs from Entergy Arkansas, NW Power Council, TVA, and Pacificorp.

[33] U.S. Department of Energy, National Renewable Energy Laboratory http://www.c2es.org/technology/factsheet/wind

as $20 and place wind energy from the plains states at prices competitive with conventional electric power generation.

Growth of wind resources moderated in 2015 due in part to the uncertainty regarding the renewal of the federal tax credits. However, in December Congress extended the investment and production tax credits of $23/MWh and allowed for wind resources under construction by 2016 to receive the full credit for the first 10 years of operation. The credit decreases 20 percent per year for units that begin construction each year from 2017 through 2019. Additional wind growth may also occur in the coming years as Multi Value [Transmission] Projects ("MVP") are completed, which include 17 transmission projects with regional benefits expected to significantly exceed the estimated $6.3 billion cost[34].

5.2.5.6.2 Total Cost of Delivered Wind

Aware of this generation shift and growth in wind generation, Vectren has monitored these developments and researched the current total cost of delivered wind. The total cost of delivered wind, as with any generation, that is accredited towards Vectren's planning reserve margin is comprised of three main factors: the cost of energy (the wind itself), the cost of delivering the energy (through transmission lines), and any transmission congestion charges (charges that are added to the energy component as a result of overloads on the system). In addition to cost consideration, other factors include timing, certainty, and access.

5.2.5.6.3 Delivering the Wind

Vectren has three options for delivered wind to serve load: 1) build a transmission line, 2) pay for use of existing MISO transmission through tariff rates, or 3) contract for

[34] 2015 State of the Market Report for the MISO Electricity Markets, By Potomac Economics, June 2016 https://www.misoenergy.org/Library/Repository/Report/IMM/2015%20State%20of%20the%20Market%20Report.pdf

subscriber-based transmission projects that charge a per MW rate for capacity (usage) of the line.

Building a specific transmission line for the sole purpose of delivering wind to Vectren load is an option that presents several challenges. The most obvious hurdle is cost. The cost of building high-voltage (138 kV and above) transmission to transport wind from the turbine to its desired load ranges from $1 million to $3 million per mile. For reference, MISO's most recent Market Efficiency [Transmission] Project "Duff to Coleman" is a 345 kV single circuit line that MISO has estimated to cost approximately $2,104,209 per mile[35]. Wind that would be accredited to Vectren load would have to be connected from the turbine to a MISO load zone. Wind located within Iowa, for example, would require less mileage to connect since Iowa is located within MISO, while wind in Kansas would require considerable spans of transmission to connect to MISO. In addition to the cost of connecting wind into MISO via constructing a new line, there is the coordination and increased requirements dictated by the system in which the wind generator is physically located. This would include additional study costs and possible upgrades to that system's transmission facilities. Building a transmission line to deliver wind would only be viable if the wind is located within or near a MISO load zone.

Part of the benefit of being a member of MISO is the open access it provides to MISO transmission and the avoidance of pancaking, paying a separate rate to each transmission owner to pass energy through its line, of transmission rates. Wind that is connected to existing MISO transmission would pay defined tariff rates for usage of the path. These tariff rates vary for each Load Serving Entity (LSE), but in most instances for Vectren, add $1-$5 of cost per MWh. However, before a generator can tie-in to the MISO system, a System Impact Study (SIS) must be performed that will analyze the impact that generator will have on the entire system and identify any transmission

[35] MISO 2015 MEP Bid Summary
https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2015/20150729/20150729%20PAC%20Item%2004%20Duff%20Coleman%20Project%20Estimate.pdf

upgrades needed as result of the additional generation onto the system. This cost is borne solely by the generator. The timing for the study results is approximately 12-18 months, and the cost is between $60,000 and $600,000 depending on the size of the unit.

The final option is subscribing to a transmission project and paying for transmission "capacity", or defined usage of the line, to deliver wind. The predominant subscriber-based developer of transmission lines in North America is Clean Line Energy, which currently has three proposed transmission projects that would bring wind from the west into the Midwest region. One of those projects, Grain Belt Express, would bring upwards of 3,500 MWs of wind into Sullivan, IN. This project would source wind energy from southwest Kansas, which has some of the highest capacity factor (the average power generated, in relation to the rated peak output of the wind turbine) wind in North America. All three of the projects are dependent upon a sufficient amount of subscribers to economically justify the construction of the lines and the regulatory approval process for the lines to traverse multi-state regions.

The Grain Belt Express transmission project has been delayed while Clean Line Energy Partners, the developer of the project, seeks regulatory approval from the Missouri Public Service Commission (MPSC). The MPSC has been the lone state to deny the approval of the project. Clean Line filed its third application with the MPSC on September 5, 2016. Representatives of the Block Grain Belt Express, the grass-roots organization that led to the project's rejection last summer, remain in opposition of the project as it cites health concerns and reductions in financial benefit as the main deterrents. The construction and right-of-way acquisition timeline could take 5-7 years if the MPSC approves the project.

5.2.5.6.4 Congestion Charges

Transmission congestion charges are the final element for consideration when analyzing the true cost of delivered wind and are the most difficult to estimate.

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

5.2.5.6.5 Analysis

MISO's current transmission system is not designed to support a large influx of variable resources, such as wind, and is undergoing a paradigm shift that involves further build-out of its system to accommodate the unique properties of wind. Currently during periods of high wind, MISO has to curtail individual wind units due to overloading of the MISO transmission system.

While wind resources account for less than 10% of both energy and capacity within MISO, they still set negative LMPs in the local areas they are located in almost half of the time. A negative LMP means that MISO must be paid for each MWh put on the grid. Typically MISO pays producers to put power on the MISO grid. Negative LMPs are intended to signal generators that their power is not needed. This is due to the frequent curtailment of wind generation to manage congestion. As wind continues to increase its makeup of MISO capacity, additional transmission build-out may be needed to deliver the wind from wind rich areas to large load bases[36].

[36] MISO's Analysis of EPA's Final Clean Power Plan Study – June 2016 page 6 https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2016/20160615/20160615%20PAC%20Item%2002a%20MISO's%20Analysis%20of%20EPA's%20Final%20Clean%20Power%20Plan%20Study%20Report%20Draft%202_Highlighted%20Changes.pdf

Additionally, although wind is more than 9% of MISO's installed capacity (ICAP), it is less than 2% of MISO's unforced capacity (UCAP), which means that for planning purposes, its capacity credit is approximately 15% of its stated generation capability and can only be relied upon for that amount. For the 2016-2017 planning year, MISO's system-wide wind capacity credit is 15.6%[37]. Wind located in MISO's Zone 1 (Montana, North Dakota, South Dakota, Wisconsin, and Michigan) receives a UCAP value, or Effective Load Carrying Capability (ELCC) of 18.8% of installed capacity, while wind in Zone 6 (Indiana and Kentucky) receives virtually half that amount at an estimated 9.6%. Essentially, utilities in Zone 6 only get to approximately 10 MW out of every 100 MW, depending on location and performance, to meet the MISO's planning reserve margin requirement. This calculation is based mainly on historical output of each wind resource, while also considering the wind resource's location. Given the uncertainty around out-of-state wind costs, Vectren utilized an estimate of in-state wind for this analysis. As projections of out-of-state wind costs become more certain, Vectren will re-evaluate out-of-state wind in future IRPs.

5.2.6 Energy Storage

Two energy storage technologies were evaluated in the IRP –batteries and compressed air energy storage (CAES). These are shown in Figure 5.24.

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

To utilize CAES, a suitable storage site is needed, either above or below ground, as well as availability of transmission and fuel source. CAES facilities use electricity to

[37] MISO's Planning Year 2016-2017 Wind Capacity Credit Report – December 2015 https://www.misoenergy.org/Library/Repository/Report/2016%20Wind%20Capacity%20Report.pdf

power a compressor train that compresses air into an underground reservoir at approximately 850 pounds per square inch (psig). Energy is then recaptured by releasing the compressed air, heating it (typically) with natural gas firing, and generating power as the heated air travels through an expander. The expander is essentially a turbine that spins as the compressed air is released from storage.

Both battery and CAES technology offer a way of storing low-priced, off-peak generation that can be discharged during higher-priced, peak demand hours.

Figure 5.24 – Energy Storage Technologies

Operating Characteristics and Estimated Costs	Lithium Ion 10 MW / 40 MWh	Lithium Ion 1 MW / 1 MWh	Commercial 100 kW / 250 kWh	Residential 2 kW / 7 kWh	CAES
Base Load Net Output (MW)	10	1	0.1	0.002	100
Round-Trip Cycle Efficiency	90%	90%	90%	90%	75%
Base Project Costs (2015$/kW)	$3,050	$2,430	$3,080	$3,480	$1,490
Fixed O&M Costs (2015$/kW-year)	$16.20	$40.80	$50.40	$60.00	$7.00

5.2.6.1 Energy Storage Cost Curve Discussion

Current overnight capital cost estimates for battery technologies (residential, commercial, and universal) were developed by Burns & McDonnell as part of the technology assessment. Pace Global then developed a long-term view of battery capital costs by class from the expected volumetric growth in lithium-ion battery sales for automotive and grid support applications and anticipated technology learning rates. Data supporting this analysis was sourced from public independent expert studies and available IRPs. The approach is tried and tested, frequently applied during the early stages of new technology adoption to estimate demand and pricing when measured market data is limited.

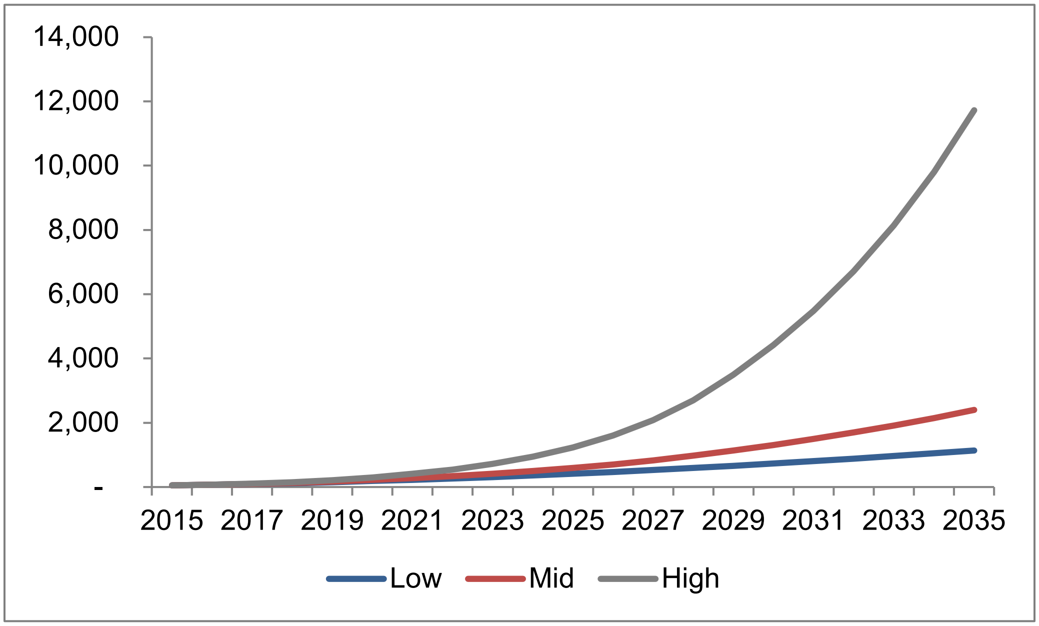
A single deterministic price forecast may introduce bias that skews the forecast path. To counter this, Pace Global sought to develop a reasonable range of price expectations to support the stochastic market analysis. The selected approach is founded on the principle that as greater numbers of similar sizes and types of batteries are manufactured, economies of scale and learning effects from manufacturing engineers will result in reduced unit production costs. Such a belief is well-supported in literature.

Pace Global developed a forecasted range of lithium-ion battery sales for similar applications, specifically automotive and grid support, but not consumer electronics. A June 2015 report to the National Renewable Energy Lab (NREL)[38] provided a forecast of demand for lithium-ion batteries used in several applications, as well as forecast growth rates from several leading experts[39] ranging from 22% to 41% through 2020. By combining these outlooks, several lithium-ion battery sales forecasts were derived for the period 2016-2036.

[38] Automotive Lithium-ion Battery (LIB) Supply Chain and U.S. Competitiveness Considerations, Clean Energy Manufacturing Analysis Center, June 2015

[39] Roland Berger, Navigant Consulting, AAB, Avicenne, and CEMAC

Figure 5.25 – Global Lithium-Ion Battery Sales Forecast, Automotive & Grid Applications, 2015-2036 GWh



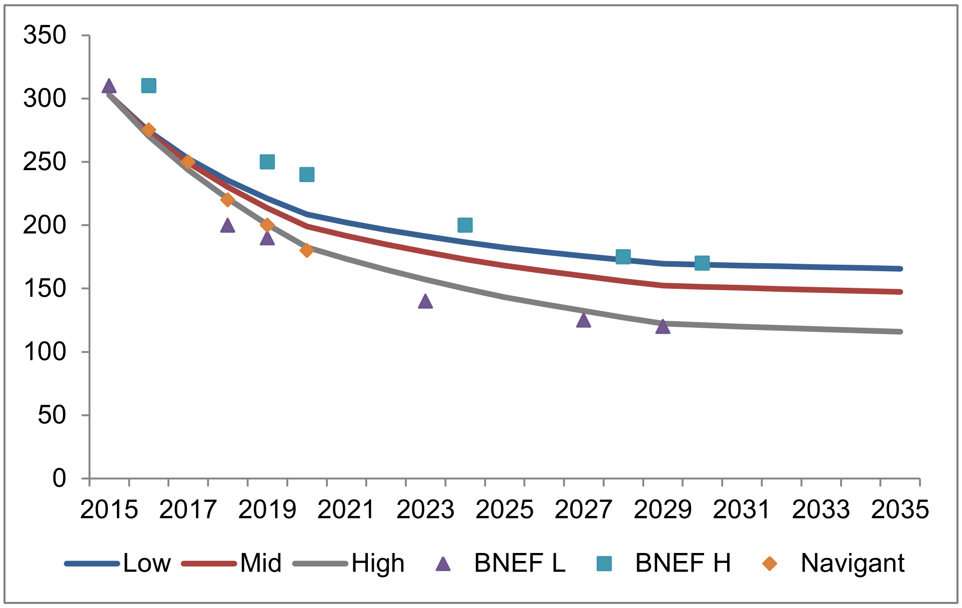
Pace Global then researched publically available literature to determine recently reported progress and learning rates for lithium-ion battery development and other power generation technologies. A nonlinear learning function and a progress ratio formula are developed to estimate the speed of learning (i.e. how much costs decline for every doubling of capacity). To apply this approach, three large format lithium-ion battery sales growth and learning development scenarios were developed with growth rates applied in each of four stages of market development. This resulted in three unique sales forecasts to which the aforementioned learning model was applied. Four different learning rates were developed to align with the four stages of market and technology development. When applied, three independent lithium-ion battery price paths were estimated based on market growth and learning expectations. The results of these derivations were compared with other publically available projections[40,41] to

[40] Bloomberg New Energy Finance Summit 2015, April 2015

41 The Lithium Ion Battery Market, Navigant, Jan 2014

assess the reasonableness of the results. The results and comparison against other available sources are presented in the graph below[42].

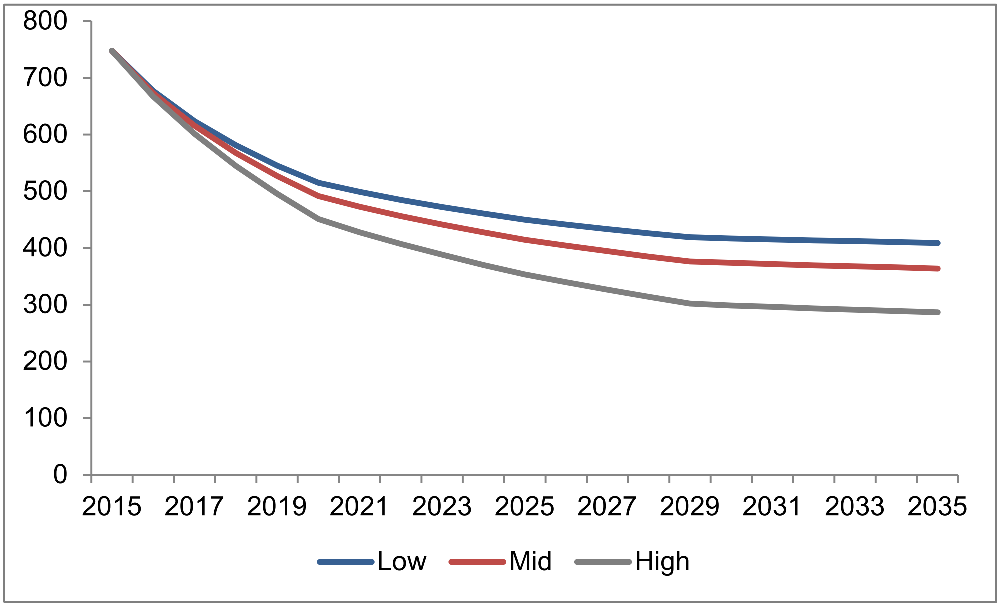
Figure 5.26 – Lithium-Ion Battery Storage Cost, $kWh



A lithium-ion battery-based bulk energy storage system requires more than batteries to deliver energy to the grid on demand. To estimate the overnight cost of the battery storage system, Pace Global estimated the additional balance of plant costs that a utility would require to complete the system. To finalize the all-in cost estimate, a financing charge (IDC/AFUDC) appropriate to the expected loan was added. The all-in utility scale lithium-ion battery storage cost estimates for the different market growth and learning expectations are displayed in the graph below.

[42] The sources used to develop the above forecast are as follows: The Cost Landscape of Solar and Wind, America's Insight, Jan 2015, BNEF; Bloomberg New Energy Finance Summit 2015, New York, April 2015; Energy Storage, EV's and the Grid, Tesla Motors, 2015 EIA Conference, June 15, 2015; Batteries Charge Up For the Electric Grid, Moody's, 24 SEPTEMBER 2015; The Economics of Load Defection, Rocky Mountain Institute, April 2015; U.S. Electric Utilities & IPPs, Storage Deep Dive Highlights Supply Chain Risks, 18 September 2015; Batteries and Energy Storage, NY Battery and Energy Storage, June 2015; Lazard's Levelized Cost of Storage Analysis – Version 1.0, November 2015; U.S. Energy Storage Monitor, Q1 2015, May 2015, GTM Research; Pace Global proprietary Li-ion production cost model; Pace Global client confidential data.

Figure 5.27 – All-In Utility Scale Lithium-Ion Battery Storage Cost, $/kWh



5.3 MISO CAPACITY CREDIT

Each resource option receives varying amounts of capacity credit within MISO based on their ability to reliably contribute capacity at the peak demand hour. Combined cycle gas turbines are considered base load (24/7 power) and can produce an expected level of output when called upon. For this reason, utilities are able to count nearly the full installed capacity for CCGTs (less their historical outage rate). A new combined cycle facility can count 96 MWs out of every 100 MWs of installed capacity towards meeting the MISO's planning reserve margin requirement. Renewable wind and solar resources are variable sources of power (available when the wind blows or the sun shines), which means they are not always available to meet peak demand. Neither wind nor solar resources tend to reliably provide their full installed capacity at the peak demand hour, as such, they receive less capacity credit.

Typically, renewable wind resources do not produce much energy during hot summer days when Vectren normally sees peak demand. Vectren's receives approximately 11% capacity credit towards meeting planning reserve margin for its wind resources.

While renewable wind resources produce a lot of renewable energy, they cannot be counted on for capacity. A solar power plant in Southern Indiana is expected to receive 38% capacity credit. For every 100 MW of installed capacity, Vectren would receive 38 MWs of capacity credit from MISO. The tradeoff between renewable wind and solar resources is energy need vs capacity need. Within optimization modeling, solar tends to be selected as a resource before wind when there is a capacity need.

Figure 5.28 – MISO Capacity Credit

Accredited Capacity	CCGT	GT	Wind[43]	Solar[44]
% of Summer output	96%	76-94%	11%	38%

5.4 TRANSMISSION CONSIDERATIONS

5.4.1 Description of Existing Transmission System

Vectren's transmission system is comprised of 64 miles of 345 kV lines, 374 miles of 138 kV lines and 565 miles of 69 kV lines. It has interconnections with Duke Energy (345 kV-138 kV-69 kV), Hoosier Energy (161 kV-69 kV), Indianapolis Power and Light Co. (138 kV), Big Rivers Electric Company (138 kV), and LGE/KU (138 kV). Key interconnection points include three 345 kV interconnections to Duke Energy's system in the area of Duke's Gibson Generation Station, a 345 kV interconnection to Big Rivers' Reid EHV Substation, a 138 kV interconnection at IPL's Petersburg Generation Station, and 138 kV interconnections to Hoosier Energy, LGE/KU, and Big Rivers at Vectren's Newtonville Substation.

[43] For wind, 11.25% (based on actual performance of Benton County and Fowler Ridge units) was used to calculate the amount of UCAP available for modeling.
[44] For solar PV, 38% was used to calculate the amount of UCAP available. This number closely aligns with the PJM capacity credit for solar and NREL expectations for the Vectren service territory.

5.4.2 Discussion on Resources Outside of Area

As mentioned above, Vectren's transmission system interconnects with neighboring systems, which provides wholesale import and export capability. Transmission planning studies indicate the existing transmission system provides a maximum import capability of approximately 900 MWs (or approximately 75% of peak demand). Although Vectren has the capability to offset internal generation with imported capacity, this is not a long term solution; several factors would influence that capability, including:

- MISO resource adequacy requirements
- Availability of firm capacity
- Transmission path availability
- Operating concerns (post-contingent voltage and line flow)

5.4.3 Evaluation of Various Resource Configurations as an Input to the Optimization Model

Vectren performed an analysis of its transmission system's performance in an effort to understand the high-level impact of building a combined cycle gas turbine plant to replace the existing AB Brown 1 and 2 coal units. Transmission enhancement cost estimates were developed for this scenario and used as an input to the optimization model.

The following outlines the basic assumptions used in this analysis:

Figure 5.29 – Transmission Input Analysis Assumptions

Generator Retirements:	**Vectren Generators Available:**
Culley Unit 2 – 90 MW BAGS Unit 1 – 60 MW Northeast Units 1 and 2 – 20 MW Warrick Unit 4 - 300 MW[45]	AB Brown Unit 3 – 80 MW AB Brown Unit 4 – 70 MW BAGS Unit 2 – 60 MW New AB Brown CC ST – 422 MW New AB Brown CC CT – 211 MW New AB Brown CC CT – 211 MW Culley 3 – 270 MW
Generator Modeling Notes: Coal unit retirements occur at the end of 2023. On January 1, 2024, a new 844 MW[46] A.B. Brown combined cycle adds two new 211 MW combustion turbines and a 422 MW steam turbine (output based on summer temperature of 90F).	

In this scenario, west to east power transfer becomes an issue due to the increased output of the AB Brown plant. This problem would be magnified should ALCOA-Warrick generating facility (units 1-4) shut down. Additionally, voltage performs poorly on the east side of the transmission system due to the loss of reactive power support from the Warrick power plant.

Several projects were modeled to mitigate the west to east power transfer issue. A new 138 kV line from the AB Brown power plant to Pigeon Creek substation to the Culley power plant along with miscellaneous 69 kV upgrades mitigated all of the issues. In order to provide sufficient reactive support, a synchronous condenser was modeled. The estimated cost for these projects is listed below.

[45] There is still uncertainty with respect to the ALCOA-Warrick generation facility following the retirement of ALCOA's aluminum smelter. A conservative planning approach was taken in this analysis and all four Warrick generating units were modeled as retired with Vectren serving the remaining ALCOA load.
[46] 889 MW is expected output at 59 degrees (average annual temperature)

Figure 5.30 – Estimated Cost of Transmission Modeling Input

New 138 kV Line	$31,840,000[47]
138 kV Terminal Upgrades	$1,150,000
138 kV Terminal Relocation	$250,000
Misc. 69 kV Upgrades	$2,179,500
Synchronous Condenser Conversion	$6,000,000
Total	**$41,419,500**

Cost Estimate Notes:

- The cost for the 138 kV line was based on 12 miles through suburban terrain ($800k per mile), followed by 12 miles double circuited with a 69 kV line through Evansville metro ($1,000k per mile), and then followed by 12.8 miles through suburban terrain ($800k per mile). The distances are based on a preliminary route developed by Vectren transmission engineering.
- The 138 kV terminals were based on estimates of $150k per breaker (one installed at AB Brown, two at Pigeon Creek, and two at Culley) plus $100k per dead-end terminal (four total). These costs are based on actual costs from several recent projects.
- The $250k for the terminal relocation is for AB Brown. There is an open bay for a new 138 kV terminal; however, it shares a common breaker with Z93 AB Brown – Northwest. A fault on this breaker outages both the new line and Z93, causing an overload on Z99 AB Brown – Northwest. Z93, Z99, and the new line need to be on different rungs to prevent a breaker fault overloads. The cost for this was based on a recent project to relocate 138 kV line terminals at another substation, escalated due to the more complex nature of this relocation. Also, this cost is a high-level budget number because the design for this relocation has the potential to be very complex and there are currently too many unknowns.
- The 69 kV upgrades include 1.83 miles of conductor upgrade through Evansville metro ($650k per mile), 12 switches to be replaced ($37k each), and 0.21 miles of underground conductor to be replaced ($2,600k per mile).

[47] Vectren engaged a third-party consultant to verify the cost estimate for the new 138 kV line. The third-party estimate was approximately $37M, or $6M higher than the original cost estimate.

- A synchronous condenser was modeled to provide reactive support, with a cost provided by GE. However, it is possible that an SVC or STATCOM device would also provide sufficient support. These devices could be studied more in depth if this scenario moves forward.

5.5 BUSBAR SCREENING

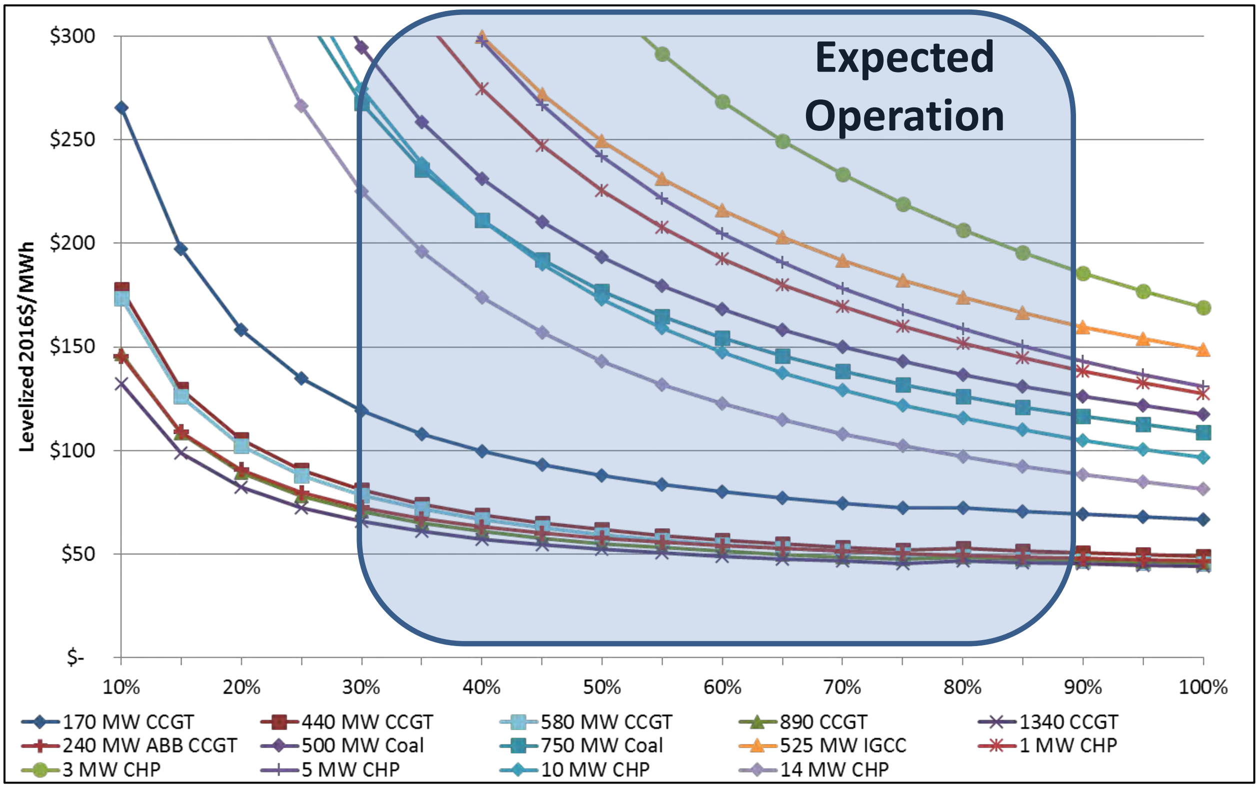
Vectren considered a wide variety of power supply alternatives including 24/7 baseload, intermediate, and peaking options, as well as renewable generation, energy storage, distributed generation, and demand side management. These power supply alternatives were screened using a busbar levelized cost of electricity analysis. Levelized cost of electricity is the net present value of costs to install and operate an energy system divided by its expected energy output over a defined time period. The busbar analysis was done in order to reduce the number of alternatives that would be simultaneously evaluated within Strategist, the planning model.

The screening analysis was performed by developing and comparing the levelized cost of electricity for each resource over the same 20 year period. This simple approach is used to identify and limit the number of higher-cost generation alternatives that would otherwise be expected to operate in a similar nature to lower-cost alternatives. For screening purposes, estimated costs included emissions (CO_2), fuel, operation & maintenance, and capital costs. Resources were then compared across various capacity factors in order to compare resource costs across all dispatch levels. Variable resources were compared at their respective output levels.

Using the calculated busbar levelized cost of electricity analysis, technology alternatives were screened for Strategist optimization modeling based on: cost effectiveness, feasibility, and capacity size. The alternatives screened using the busbar levelized cost of electricity calculations are shown in Figure 5.31. Note that in the following Figures 5.31-5.32 the x axis is capacity factor and the y axis is Levelized 2016 $/MWh.

Demand side management (DSM) was not considered in the busbar analysis, but was included as one of the alternatives within the IRP modeling.

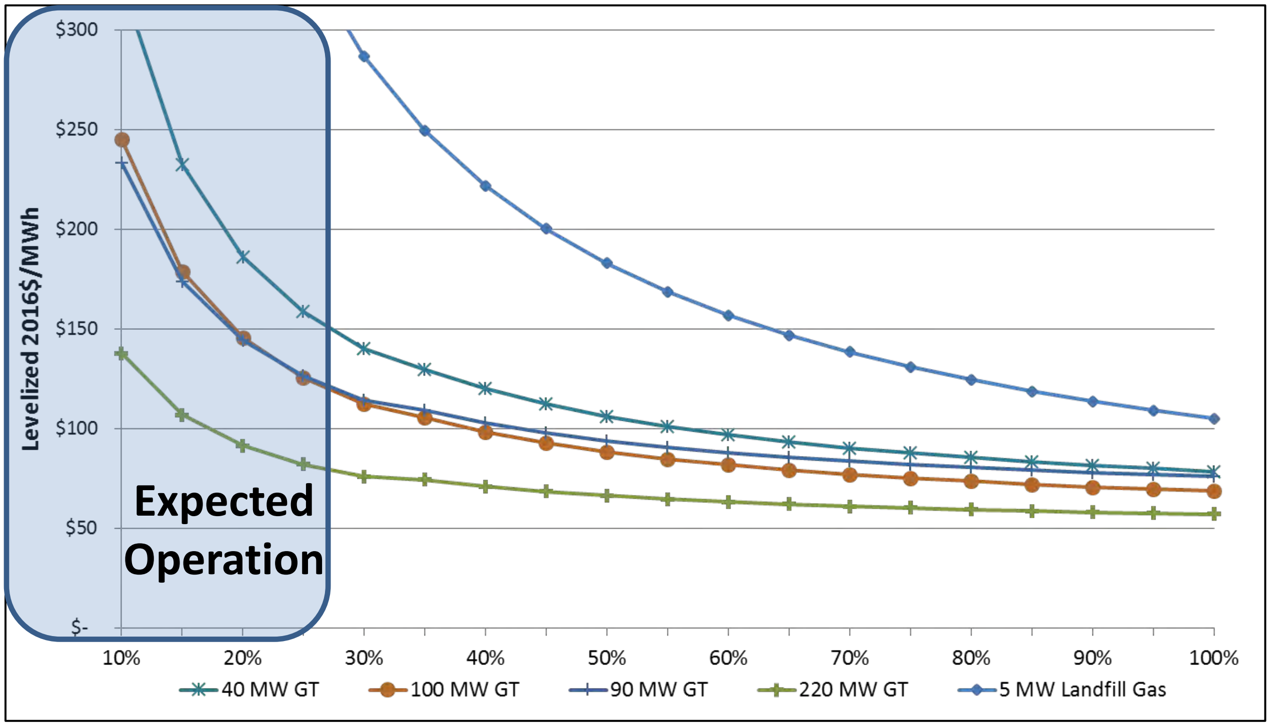
Figure 5.31 – 20-Year Levelized Cost of Electricity: Base and Intermediate Load Resources



The F-class combined cycle gas turbines show the lowest levelized busbar cost across all capacity factors. Due to 3x1 7FA.05 (1,340 MW) exceeding Vectren's forecasted planning reserve margin requirements, this alternative was eliminated from further analysis. Based on the screening results of the base and intermediate resources, the 1x1 7FA.05 (440 MW), 2x1 7FA.04 (750 MW), and 2x1 7FA.05 (890 MW) combined cycles were considered for further analysis within Strategist.

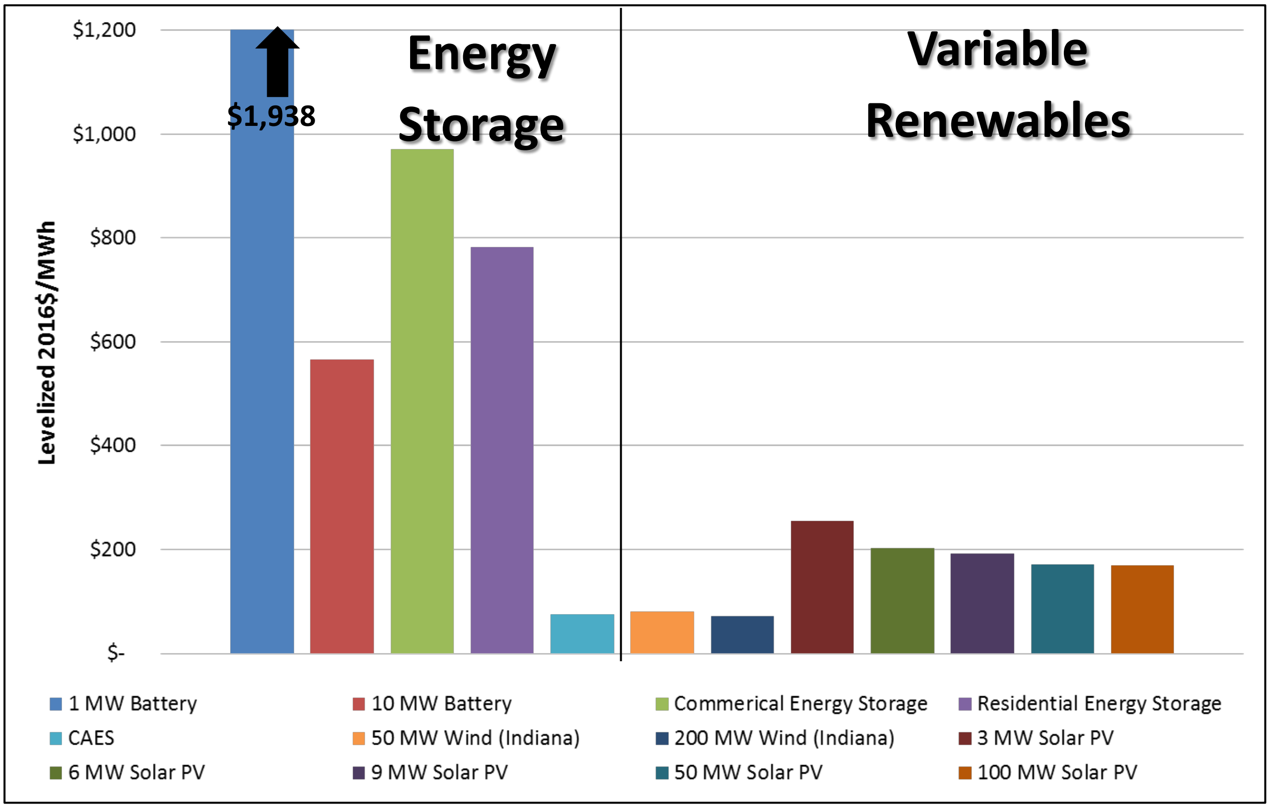
For combined heat and power, the 14 MW option was the lowest cost option evaluated. The 14 MW CHP was included in the Strategist modeling due to the size flexibility and being the most economical CHP option considered.

Figure 5.32 – 20-Year Levelized Cost of Electricity: Peaking Load Resources



The F-class simple cycle gas turbines show the lowest levelized busbar cost across all capacity factors. Due to the smaller project size available with the LMS100 (100 MW), this presented a smaller simple cycle option. The F-Class SCGT (220 MW) and LMS100 (100 MW) technologies were considered for further analysis within Strategist.

Figure 5.33 – 20-Year Levelized Cost of Electricity: Energy Storage & Renewable Load Resources



Two types of renewable resources were included in the final integration analysis. The renewable resources were modeled in various size blocks to be evaluated against the other new construction alternative options. The renewable technologies that were selected by the busbar cost analysis included wind and solar photovoltaic (PV).

Compressed air energy storage was the lowest cost storage option, but was eliminated due to limited feasibility (likely not available) in Vectren's service territory. Suitable underground storage would need to be identified. The 10 MW/40 MWh Lithium Ion represented the next lowest cost storage. Based on the levelized cost of electricity results, the 10 MW/40 MWh battery was carried forward as an alternative in Strategist for the high tech scenario.

SECTION 6
SCENARIOS: OPTIMIZATION MODEL INPUTS & ASSUMPTIONS

6.1 BASE CASE

Vectren developed a base case forecast of key market drivers as inputs into this IRP process that collectively represent the expected path most likely to occur. For many of these assumptions, including natural gas prices, coal prices, and carbon prices, a wide range of views were incorporated into a consensus forecast. For load growth, Vectren developed a bottom-up, forward looking view that incorporates energy, customers, prices, economic drivers, appliance saturation and efficiency, long-term weather, customer owned generation, hourly system load, and 10-year average peak-day weather. The following sections detail these base case assumptions.

The base case scenario is a consensus forecast. Hence, it is impossible to describe specifics regarding the assumptions driving the forecast. However, the base case can be described in more general terms based upon consistency in general trends among the individual forecasts that comprise the consensus forecast. Generally, the forecast is characterized by reasonable and balanced levels of growth and drivers that lead to moderate market price increases over time. Power market participants under base case conditions are able to adapt and adjust in a timely manner to changing market forces.

Short Term: In the short-term (2016-2018), the base case generally assumes positive sales growth as the economy continues to improve and as Vectren adds new customers to its base. Residential customer growth remains positive, albeit lower, than pre-recession levels, but this is partially offset by moderately declining average use per customer. Similarly, the customer base for small and large commercial and industrial (C&I) customers continues to grow, but with a partial offset of this growth by increasing efficiency. As a result, energy sales grow at a moderate pace.

Natural gas prices remain low through 2016 and 2017 as the current oversupply situation continues to dominate gas market dynamics. However, low prices eventually result in restricted production and reduced gas supply. Coupled with new LNG export terminals and new heavy industrial facilities, demand rises and gas markets begin to tighten. This is especially true in the premium Gulf Coast market, where much of the demand is materializing, pushing prices incrementally higher in 2018 and beyond. Gas prices in the Utica/Marcellus also recover in 2018 and 2019 as several pipeline projects that provide takeaway capacity enter into service.

Meanwhile, coal prices remain depressed in the near short-term as domestic markets remain soft, with a modest price recovery beginning in 2018.

Market power prices for residential and commercial customers historically have declined since the 2008 recession, but both are expected to experience slight upward price increases over the next few years, based on rising future operating costs and associated revenue requirements. Increased revenue requirements are due to rising replacement and retrofit costs imposed by EPA's ELG regulation as well as by declining reserve margins that compel new builds. Capital costs are generally expected to increase at a moderate pace, reflecting increased costs for labor as the unemployment rate remains at a relatively competitive five percent and higher borrowing costs from rising interest rates, but tempered by lower costs for material as commodity prices remain broadly lower.

Coal plant retirements were high in 2015 driven by regulation including MATS, but continue at a comparatively much more moderate pace in the next few years. Meanwhile, capacity additions in the form of efficient combined cycle gas turbine plants continues at a healthy pace as merchant plants and utilities continue to take advantage of actual and expected low gas prices.

Medium Term: In the medium-term (2019-2025), the base case consensus forecast reflects the assumption that most states, including Indiana, will opt for a mass-based Clean Power Plan (CPP) compliance approach due to the expected broader trading opportunities, albeit with a two year delay of the beginning of the compliance period (from 2022 to 2024) due to the legal uncertainty following the U.S. Supreme Court stay.

Mass-based is seen as a more optimal compliance approach for coal heavy states relative to the rate-based approach alternative. Specifically:

- It is considered simpler and easier to administer than a rate-based plan.
- Retirements of older inefficient plants that are occurring primarily due to economics.
- States will feel pressure to join together to create the most liquid market and largest possible pool of trading partners for emissions reductions.

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

Natural gas prices at the Henry Hub do increase to $4/MMBtu and above as markets tighten significantly on the Gulf Coast. Midwest gas prices continue to benefit from proximity to the Utica and Marcellus shale plays, helping to keep regional gas price growth to a more moderate level.

Coal prices recover most strongly in the Illinois Basin to 2020, with a modest recovery in the Powder River Basin and very limited recovery in the Appalachian region, due to consolidation among producers, lowered production that tightens supply, and a modest export market.

CO_2 prices in California and in Northeast states participating in RGGI harmonize with the broader U.S. market as the CPP compliance period begins in 2024. Given that the CPP allows for interim goals for compliance, CO_2 prices are expected to increase moderately as states adapt to the compliance regime and carbon markets have time to adjust.

Market power prices continue to move upward moderately as the CPP compliance period begins. Fuel costs increase incrementally with new export demand markets. As the customer base continues to grow, energy company operating costs continue to rise. Commodity markets recover in the medium-term, pushing up material costs and consequently capital costs. In addition, as the overall economy continues to make improvements and the unemployment rate remains around five percent, capital costs rise as competitive upward pressure remains on labor costs.

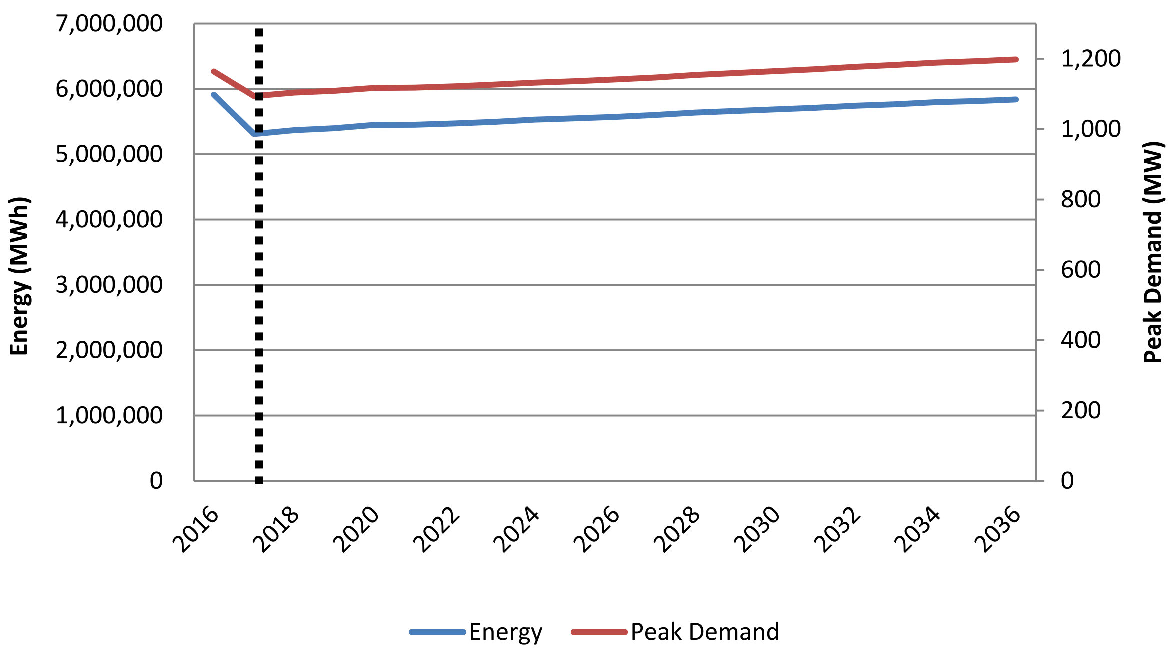
Coal-plant retirements mean no emissions from retired plants, which contribute to lowering total emissions under a mass-based approach. Through the years after the CPP goes into effect in 2024, coal plant retirements will continue to be driven by plant-specific going-forward economics. Meanwhile, capacity additions largely come from natural gas combined cycle turbines, solar, and wind facilities.

Long Term: In the long-term (2026-2036), the suite of market outcomes and drivers in the base case settles into a pattern of moderate growth based on a well-balanced market. Markets have sufficient time to adapt and adjust as the final CPP goal in 2030 nears and as regulation is expected to be extended to 2036 and beyond, helping keep CO_2 prices reasonable if growing. Energy demand grows as electric car sales take hold but is offset by continued gains in distributed generation and energy efficiency measures. Domestic shale gas and coal resources help to keep fuel cost growth to a moderate level. Capital costs increase at a measured pace as the GDP growth rate averages two percent or more. Capacity additions and retirements continue at a reasonable rate as the fleet of power plants maintains a healthy rate of turnover.

6.1.1 Input Forecasts

The long-term energy and demand forecast for the Vectren service territory was developed for Vectren by Itron. For more information, please see Section 4 Customer Energy Needs. The forecast is based on a combination of historical usage trends and a bottoms-up approach to drivers such as residential and commercial demand, industrial load, appliance saturation, energy efficiency, long-term weather trends, customer-owned generation, and an outlook for economic factors.

Figure 6.1 – Base Case Vectren Load Forecast (MWh and MW)



For natural gas, coal, and carbon, Vectren used a “consensus” base case view of expected prices by averaging forecasts from several sources. For natural gas, forecasts from Ventyx, Wood Mackenzie, EVA, and PIRA were averaged. For carbon, forecasts from Pace Global, PIRA, and Wood Mackenzie were averaged. This helps to ensure that reliance on one forecast or forecaster does not occur.

Figure 6.2 – Base Case Natural Gas Price Forecast (2015$/MMBtu)

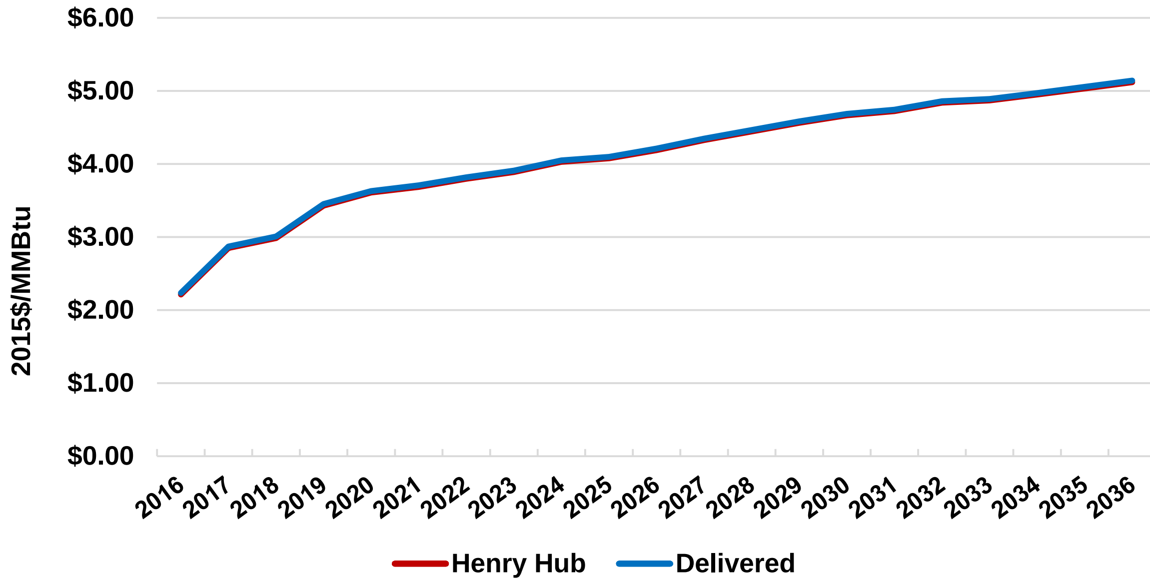


Figure 6.3 – Base Case Coal Price Forecast (2015$/MMBtu)

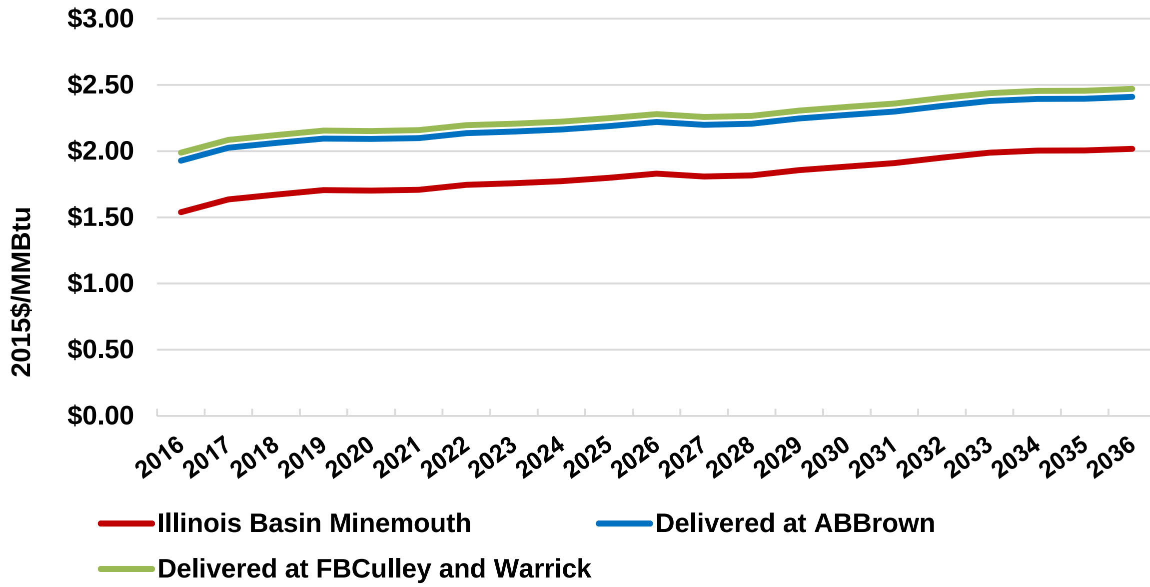
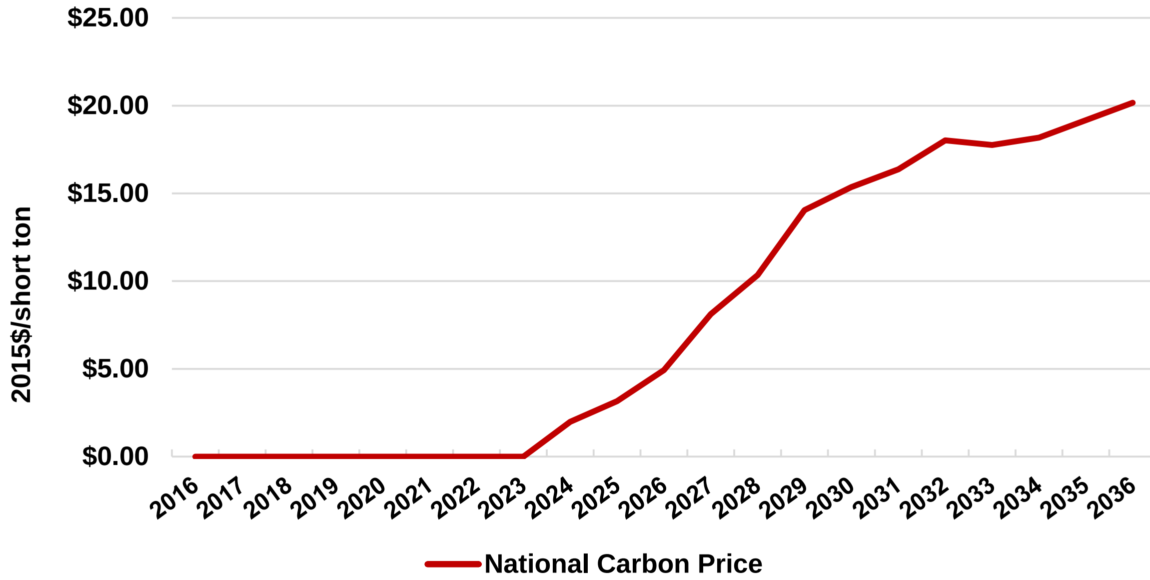
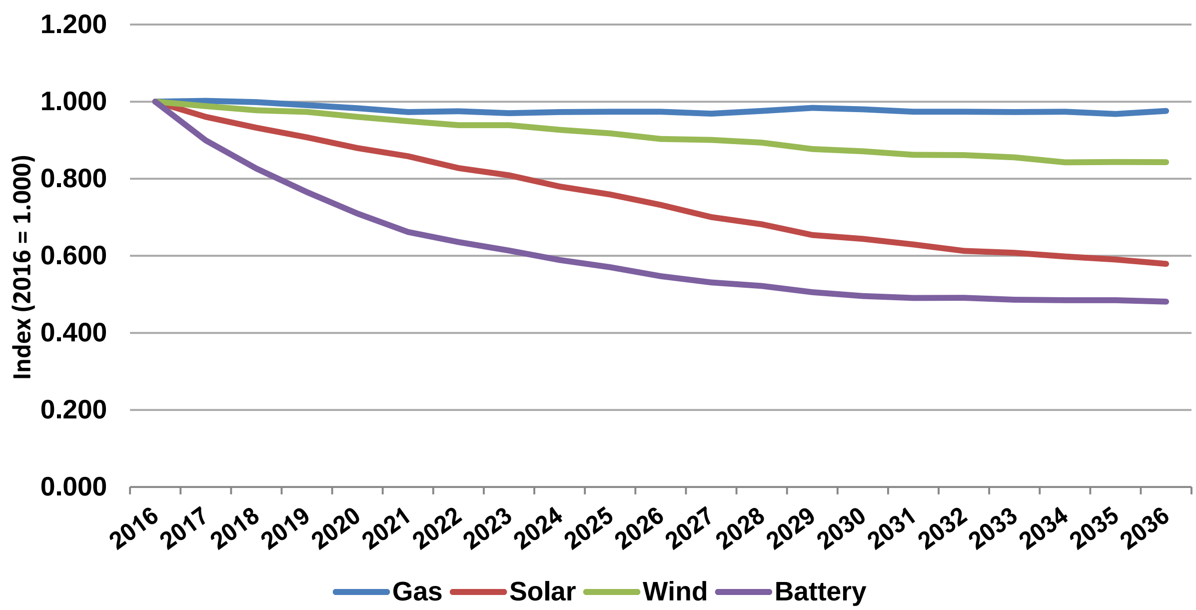


Figure 6.4 – Base Case Carbon Price Forecast (2015$/short ton)



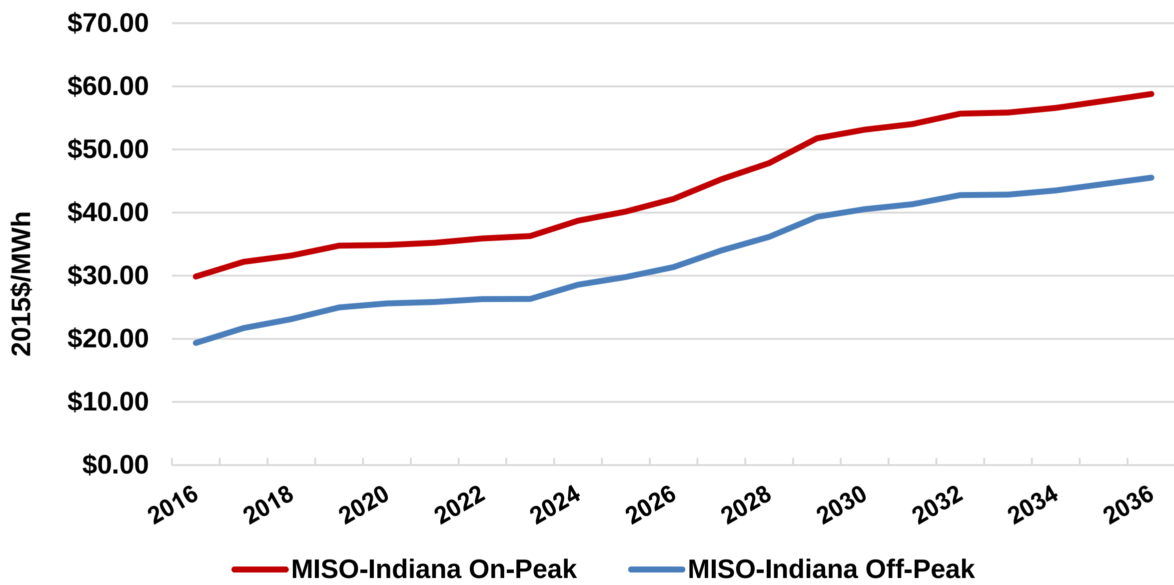
Current capital costs were developed by Burns & McDonnell, with a decline rate for each capital cost category (single cycle gas turbine, combined cycle gas turbine, solar, wind, and batteries) developed by Pace Global.

Figure 6.5 – Base Case Capital Cost Price Index Forecast (2016 = 1.000)



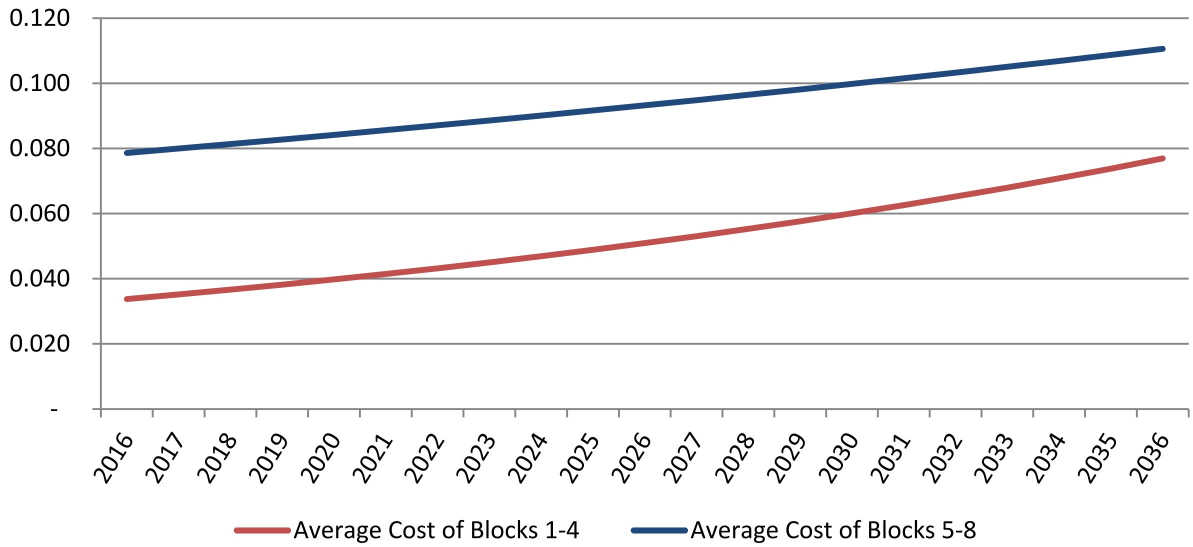
On- and off-peak power price forecasts were developed by Pace Global using the base case assumptions described above, together with Pace Global' s view of the greater MISO market, in the AURORAxmp power dispatch model.

Figure 6.6 – Base Case Power Price Forecast (2015$/MWh)



Levelized DSM costs were developed by Dr. Richard Stevie and described in detail in Section 5.2.3 DSM.

Figure 6.7 – Base Levelized Cost of DSM



6.1.2 Environmental Regulations

6.1.2.1 Effluent Limitations Guidelines (ELG)

On September 30, 2015, EPA published the final Effluent Limitations Guidelines rule (ELG). The rule sets strict technology-based limits for waste water generated from fossil fuel fired generating facilities and in particular, will force significant operational and technological changes at coal fired power plants. Below are the estimates used for IRP modeling.

AB Brown: ELG related changes include conversion to dry bottom ash, upgrades to the dry fly ash system, a new landfill that can handle scrubber product and ash, and a new lined pond to handle process water (~$115M).

FB Culley: Required plant upgrades include conversion to dry bottom ash, FGD waste water treatment, and access to a landfill that can handle small quantities of dry bottom ash (~$75M).

Warrick U4: The exact ELG status of the Warrick plant will not be determined until the next NPDES permit renewal in 2018. For purposes of the IRP only, Vectren has assumed required upgrades and costs similar to FB Culley since the units are of similar design and size (~$40M, Vectren's portion of the total $80M estimate).

6.1.2.2 Coal Combustion Residuals (CCR)

The Coal Combustion Residuals Rule (CCR) was finalized on April 17, 2015. The rule regulates the final disposal of CCRs which include fly ash, bottom ash, boiler slag, and flue gas desulfurization solids. The rule is applicable to all new and existing landfills and surface impoundments used to store or dispose of CCRs at a power plant that was generating electricity on the effective date of the rule (October 2015). The rule establishes operating criteria and assessments as well as closure and post closure care standards.

For AB Brown and FB Culley, it was assumed that ash ponds would be closed in place at the end of their useful life. The timing of the closures is dependent on continued need for the pond. For instance, if ELG related changes are made, such that the pond is no longer being used for ash storage, pond closure is then triggered. The base cost for the closures does not change regardless of future generation, and only the timing of the spend is affected in the modeling. Vectren has not historically utilized the ponds at the Warrick power plant for its share of the CCR generated by Warrick 4, and therefore is not liable for pond closure costs.

6.1.2.3 Clean Power Plan (CPP)

EPA finalized the Clean Power Plan that established carbon dioxide (CO_2) emission standards for a state's electric generating fleet in August 2015. States were given the discretion to set unit specific limits or adopt a mass-based or rate-based allowance trading program. The US Supreme Court issued a stay of the rule. It is not anticipated that final order on judicial review will come until 2017. After which, the state will develop the State Implementation Plan (SIP).

Vectren assumed the CPP would be upheld by the US Supreme Court, but the compliance would be delayed two years to 2024 due to the implementation delay caused by the stay. An average of currently available carbon costs was used for base case modeling. Note that the start dates for forecasts were adjusted to 2024 prior to averaging. More details can be found in Section 2.3, DEFINE BASE CASE AND BOUNDARY SCENARIOS.

To consider carbon (CO_2) emissions, Vectren assumed an emission allowance trading system with costs per short ton of emissions under all scenarios except the low regulatory scenario. Allowances were allocated based on Vectren's historical portion of CO_2 emissions relative to the state of Indiana totals for 2012. Allowances were based on the final Clean Power Plan (CPP) mass-based state targets. Vectren decreased the mass-based targets over time to reflect the interim and final targets of the rule. In all except the high regulatory scenario, the CPP interim period and final targets were delayed two years from the original start year (2022) in order to factor in delays associated with resolution of legal challenges pending before the United States Supreme Court.

6.1.2.4 316(b)

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

This requirement applies to both FB Culley and Warrick 4. Standard fine mesh, fish friendly screens, and fish return systems were estimated to be $12-14M at FB Culley and $5-6M at Warrick 4 (Vectren's share).

6.1.3 Capacity Prices

The MISO capacity price has been difficult to predict as indicated by the volatile price history shown in Section 1.3.7, MISO. However, it is necessary for analysis purposes to have a capacity market price assumption to be included in the IRP modeling process. Some capacity will be bought or sold in practically every year due to the fact that load and planning reserve margin requirements vary incrementally from year to year while most supply side resources, such as generating units, come in large blocks with 30 to 55 year expected lifetimes. Vectren elected to use the Ventyx fall 2015 reference case MISO Indiana capacity price forecast for modeling purposes.

Figure 6.8 – Confidential Forecast Capacity Market Value (2015$/kW-yr)

[redacted]

6.1.4 Assumptions

Broadway Avenue Generating Station (BAGS) Unit 1 (as mentioned in Section 5.1.2, Natural Gas) has been mothballed and is earmarked for retirement in 2018. (47 years)

Broadway Avenue Generating Station (BAGS) Unit 2 (as mentioned in Section 5.1.2, Natural Gas) is earmarked for age related retirement in 2025. (44 years)

The Northeast Gas Turbine generating facility, NEGT 1 and NEGT 2, with capacities of 10 MW each, are currently scheduled to be retired from commercial operation in 2019. (55 years)

6.2 DEVELOPMENT OF ALTERNATE SCENARIOS

In order to develop several alternative scenarios for its IRP process, Vectren created a base case and several additional qualitative scenarios in its initial formulation. These scenarios were evaluated by a panel to estimate how key uncertainties (e.g., energy sales, gas prices) might fall relative to the base case. These estimates were quantified, averaged, and compared to Pace Global's independent estimates, which were closely aligned. Additionally, stakeholders provided Vectren with their list of possible uncertainties in a workshop held on April 7, 2016. Their inputs were considered and incorporated into the development of each alternate scenario.

These initial scenarios (base case plus 10 alternate scenarios) were then consolidated and reduced by Pace Global to a base case plus 6 alternate scenarios. The alternative scenarios were developed along three primary axes: regulatory, technological, and economic. Each axis is dichotomous, either being high or low, although there is only one technology scenario as technological innovation is assumed to either continue at the present rate or at an accelerated rate, but not at a "low" rate. From these three primary axes come five scenarios that provide a wide range of conditions in which to evaluate various portfolio planning strategies.

6.2.1 Description of Alternate Scenarios

As described in Section 2.3, DEFINE BASE CASE AND BOUNDARY SCENARIOS, the purpose of developing these "boundary" scenarios were to test a relevant range for each of the key market drivers on how various technologies are selected under boundary conditions. The specific conditions described in the following section are illustrative of the kinds of conditions that might generate values shown in the following graphics. Values for the market drivers were based on an adjustment from the mean of a distribution and not a calculated value from that scenario.

6.2.1.1 High Regulatory

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

- A much higher cost for compliance with the CPP, which begins on schedule in 2022, in part from less coordination among states that results in a mix of rate-based and mass-based compliance, but with many states not opting in to a national EPA backed program and in general more state-by-state command and control efforts for CO_2 emissions;
- More renewable adoption pushed through via mandates;
- Additional regulations on carbon on the horizon after 2030 that are higher than in the base case;
- Greater adoption of distributed generation in the form of solar and combined heat and power;
- Restrictions on fracking and fugitive methane emissions that limit gas supply growth, drive up gas prices, and result in an additional push and economic case for renewable energy; and
- Low economic growth that provides justification and room for greater regulation.

In the short-term (2016-2018), markets will not yet be characterized as “high regulatory” and will largely resemble the drivers in the base case. However, over the intermediate term some combination of the following might occur that results in the price trajectories shown below:

- The U.S. economy will continue to expand, albeit with signs that mid-term economic growth may be slower than in the base case. The customer base continues to grow, including among large C&I customers, with some initial attention being paid to the contribution from large-scale industrial facilities to carbon emissions.

- Natural gas prices remain relatively low in the short-term, forcing operators to innovate rapidly to drive up efficiencies and drive down production costs or face bankruptcy. An ever greater share of U.S. gas production comes from shale gas, which is highly concentrated in Ohio, Pennsylvania, and West Virginia. This concentration of production renders U.S. supply more susceptible to short-term curtailments (freeze-offs) and longer-term economic downswings (and thus lower gas production out of this region).
- Coal prices remain depressed as in the base case, but with an economic outlook for coal-fired generation in the mid-term that appears to be increasingly regulated.
- Meanwhile, CO_2 prices in the California and RGGI markets begin to move upward in anticipation that these programs will be CPP compliant after 2022.
- Market penetration of solar and wind generation continues to grow at a fast rate, albeit still from a relatively small base, with state- and federal-level mandates supporting their implementation through relatively inefficient and costly market mechanisms. As a result, a full recovery of costs to maintain national transmission and distribution grids remains difficult, and underinvestment continues in modernizing the underlying power grid infrastructure.
- In the short-term, these market forces do not indicate an overly heavy interventionist hand from the state. However, they do presage a higher regulatory level to come in the medium- to long-term as the economy grows relatively weakly, market power prices rise, and the state intervenes in an attempt to stabilize markets.

In the medium-term (2019-2025), the following is representative of the high regulatory projections:

- At the beginning of the CPP compliance period in 2022, little progress has been made among states to opt into efficient national trading mechanisms. States seek compliance individually or on a regional basis that results in the need for higher cost emission reductions and increases the overall compliance cost of the program.

- Further, the EPA could issue additional CPP reduction goals for the 2031 and beyond time period, which are significantly stricter than the current CPP. All of these developments lead to increased costs for CPP compliance that in turn lead to higher market power prices and a lower level of load growth as compared to the base case.
- Power markets are also constrained by higher gas costs stemming from increased regulation on natural gas fracking and fugitive methane emissions from distribution pipelines and drilling operations.
- Environmental concerns over fracked gas (e.g. induced seismicity, contaminated well sites) and a sustained public affairs campaign lead to national restrictions, higher production costs, and a lower supply base for natural gas.
- Coal-fired generation is highly disfavored due to ever-tightening restrictions on plant emissions, leading to lower coal prices than in the base case based on lax demand, but higher costs for coal-fired generation that lead to higher coal-fired plant retirements. Export restrictions on oil, gas, and coal are reinstated or increased.
- The U.S. economy undergoes another major market correction and resulting recession, leading to sweeping market interventions that include reforms such as mandated improvements to energy infrastructure whose costs are passed along to consumers. This leads to a high rate of retirement of coal plants, replaced by costly renewables that require commensurate and costly investment in energy storage. It also includes costly upgrades to transmission and distribution (T&D) infrastructure to guard against cyberattacks. Strong targets for distributed generation penetration, energy conservation, demand-side management, and energy efficiency lead to increased costs and higher electricity rates for existing energy company customers.

In the long-term (2026-2036), the high regulatory scenario enters into the 2030s at the same time as efforts to reduce carbon footprint become ever more intensified and target all areas of the traditional energy market.

- A new round of global climate talks is successful and includes binding targets, which precipitates an ever increasing regulatory role of the government in the energy sector, that help to keep CO_2 and power prices high.
- Toward the end of the forecast period, the scale of renewable penetration is such that costs begin to move downward once again as fuel costs become less important, and capital costs decline with massive economies of scale for renewable production and an efficient labor force experienced in distributed generation. The U.S. market experiences a period of moderate and sustained growth, which allows some breathing room in terms of new regulatory restriction, but not enough incentive to roll back existing restrictions, which continue to push high levels of coal retirements and renewable additions.

6.2.1.2 Low Regulatory

The low regulatory scenario was developed to establish a lower boundary condition on regulatory reform. Relative to the base case, this scenario is characterized by free market attitude in which few new regulatory restrictions are put forward and many of those that are currently in motion (e.g. CPP) are shelved. Regulations that do enter into force are implemented at lower cost than expected.

In the short-term (2016-2018):

- Political leaders shelve the national carbon regulatory scheme (the CPP).
- The U.S. economy continues to improve (as it does in the base case), which in turn leads to the beginnings of rising energy sales.
- Natural gas costs remain relatively low, as do coal prices, which help to constrain market power prices to the same moderate level as in the base case. Capital costs remain moderate as the commodity price rout continues and as wages grow only slowly.

The main difference between the outlook in this scenario and the recent past is that economic or forced retirements are expected to be lower than in the base case (in the medium-term). A strong economy, low fuel costs, and robust load growth help to sustain the existing generation fleet that includes coal plants. This period of efficient market operations helps to keep power prices on the lower side and stave off new regulatory interventions.

In the medium-term (2019-2025):

- The U.S. market continues to improve and grow which limits economic plant retirements and encourages additional deployment of advanced gas-fired generation to meet load growth.
- Although absolute emissions begin to rise again as the economy grows, per capita energy intensity declines, and as a result the CPP remains the only significant piece of regulation to move forward during this timeframe. Fuel prices remain moderate (gas) to high (coal).
- Commodity costs begin to rise once again as the global economy picks up steam, though not enough to move capital costs away from the base case forecast. Overall, the strength of the economy helps to limit the desire to intervene with any potential market corrections and new regulatory regimes.

In the long-term (2026-2036):

- Few new power market interventions are sought or required. Energy markets continue to work well, providing affordable electricity and fueling a sustained period of economic growth.
- However, this economic growth reverts to a more moderate level in the long-term, similarly moving load growth to a moderate level.
- Capital costs rise steadily in the healthy economy as interest rates are pushed higher by federal monetary policy makers. Retirements move to a more moderate level as older plants are forced to retire and capacity additions rev up to handle

these retirements as well as the continued economic growth (despite higher capital costs).

6.2.1.3 High Technology

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

In the short-term (2016-2018):

- The recent high pace of coal plant retirements continues (mostly due to MATS regulation but also for economic reasons), driven largely by initially low gas prices that create difficult economic conditions for coal-fired generation.
- The pace of economic expansion continues to grow as the U.S. economy becomes the lead driver of global economic health. However, this also begins to push interest rates higher with potential impact on future capital costs.
- Because fuel costs remain low initially (shale gas oversupply continues while coal demand remains soft), market power prices also remain muted despite moderate energy sales growth in an increasingly healthy U.S. economy.
- Low natural gas prices begin to have an effect on production, reducing the growth rate for new supplies, while the strong uptick in gas demand from LNG exports and other sectors helps to tighten the market and push gas prices higher in 2018.

In the medium-term (2019-2025):

- The main characteristic of the high technology scenario is that in the early 2020s timeframe a technology breakthrough occurs in the renewables market and possibly also in the storage market, such that the cost for renewables declines dramatically, which in turn encourages a faster shift to renewables from fossil fuels.

- This breakthrough results in an incremental reduction in natural gas demand, in the latter half of the medium-term, as compared to the base case. Coal plant retirements continue at a relatively high rate. Whereas previously these retirements were driven primarily by competition with existing natural gas-fired generation, they are increasingly being replaced with renewables and high efficiency combined cycle gas turbine (CCGT) plants.
- Accordingly, the high rate of retirements and capacity additions/replacements continues into the medium-term. Many of the expected costs that are associated with CPP compliance are mitigated by advances in generation (gas and renewables), distribution, and storage technologies. Gas prices remain low despite somewhat tighter supply/demand dynamics, which prompts another wave of improvements in drilling and fracking technology and helps to keep gas prices at relatively low levels.
- The low gas prices are coupled with lower gas demand in the medium-term as renewables growth begins to pick up steam. Interest rates continue to move higher, which in turn pushes capital costs higher than in the base case.
- Distributed generation plays a much greater role in the high technology scenario, given advances in battery technology, gains in photovoltaic costs and efficiencies, and a more coordinated approach to managing variable wind generation across regional transmission organizations (RTO) and independent system operators (ISO).
- Given advances in battery technologies, there is a higher penetration rate of electric vehicles than in the base case. This increases load growth, but also allows for a more efficient distribution of resources as the growing fleet of vehicle batteries help to manage peak power load and power price volatility.

In the long-term (2026-2036):

- A well-functioning and expanding U.S. market helps to keep regulatory interventions beyond the CPP at a minimum.
- Fuel costs continue to remain relatively low.
- The pace of retirements and capacity additions continues in the high technology scenario, albeit slightly lower than otherwise would be with lower capital costs (as a result of interest rates that remain high). Most of the retirements would come from older gas plants (including single cycle gas turbine peakers) while most of the additions would come from residential and commercial solar, wind, CHP, and combined cycle gas turbine facilities. There are fewer feedback mechanisms at play in this scenario, as the technology improvements over time help to maintain low fuel and capital costs and keep the energy sector on a steady path of moderate growth.

6.2.1.4 High Economy

The high economy/market scenario was constructed to be indicative of a market that has a robust and growing U.S. economy keeping 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. 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 beneficial to keeping prices and costs in check. Regulations are similar to those in the base case.

In the short-term (2016-2018):

- The U.S. economy makes substantial gains in reducing the unemployment level while creating new jobs that bring discouraged workers back into the work force. The housing market continues to improve, as do the C&I sectors.

- Commodity costs remain low in the short-term, helping to fuel this period of continued economic expansion. All planned capacity additions move forward in a timely manner, while somewhat fewer coal plants announce a planned retirement due to economic or regulatory conditions. In the short-term, regulation continues in a business-as-usual manner.

In the medium-term (2019-2025):

- Outlook in this scenario begins with many positive indicators that continue into the medium-term. However, the expansion of the economy becomes a partial victim of its own success.
- Strong economic growth in the U.S. market helps to push energy sales higher, which in turn pushes underlying fuel and capital costs higher. A relatively strong feedback mechanism begins to assert itself under these circumstances, in which technology does not play as great a role in this scenario as it does in the high technology scenario. Accordingly, what began as very strong growth begins to become more restrained toward the end of the medium-term.
- Existing technology remains important in maintaining the high rate of load growth because technology does not necessarily play as large a role in this scenario. Accordingly, very few coal, gas, or other plants are retired for economic or regulatory reasons, while new plants are added on a relatively consistent basis.
- The CPP proceeds along the lines of the base case, with CO_2 costs at a similar level. Gas costs are incrementally higher, as are the costs for renewables.

In the long-term (2026-2036):

- Global economic activity begins to increase as developing markets such as India move to the forefront and drive growth.
- Global growth begins to apply upward pressure to global LNG and coal costs as well as commodity costs for materials, which in turn drives up market power prices here in the United States.

- Energy sales growth remains strong, as do capacity additions, but tighter global markets put upward pressure on several of the other market outcomes.
- Long-term outlook in the high economy/market scenario begins to push toward an era of high prices, high costs, high capacity additions, and high load growth. Given that the economy is doing well in this scenario in the long-term, market regulators feel they have greater latitude to implement additional regulations. This provides a modest feedback loop to slightly dampen U.S. GDP growth over time.

6.2.1.5 Low Economy

The low economy/market scenario is characterized by sluggish economic growth both domestically and globally, including (in the short-term) important growth markets like China, Europe, and Brazil. 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. Moderate CO_2 prices and low load growth help to keep market power prices on the low end of the scale, which in turn keep capacity additions low. Market regulators have less latitude to implement new regulations, as the economy cannot afford them in this low economy scenario.

In the short-term (2016-2018):

- The U.S. economy begins this period at a relatively good growth rate, but the rest of the world does not fare as well, which begins to weigh on the U.S. economy.
- As a result, load growth begins to slow gradually as U.S. manufacturers and exporters curtail operations, which in turn leads to low market power prices.
- Low gas prices remain low as demand dries up (incrementally) even while supply remains healthy.

In the medium-term (2019-2025):

- As the global economy continues to stagnate or degrade, the U.S. economy also begins to be affected negatively. GDP growth is less than half a percent, which particularly hurts the power sector given the strong role that energy plays in fueling economic growth (though efficiency gains have been muting this role of late).

- With little to no growth in energy sales, few new plants are built and plants continue to retire as they reach the end of their technical and economic lives. Fuel costs remain relatively low, given the lack of demand.
- Capital costs remain moderate as interest rates maintain a modest level, as the policy makers are reluctant to return to an era of artificially low interest rates.

In the long-term (2026-2036):

- By the 2030's, the world market is slowly coming out of its slump, but recovery is slow as progress is held back by strong global adherence to emissions targets set forth in climate negotiations.
- Low fuel prices continue, albeit slightly higher as demand eventually responds to sustained low prices. Overall, in the long-term the low economy/market scenario begins to revert back to resemble, in part, the base case with more moderate levels of market outcomes and drivers.

6.2.1.6 Base Large Load Addition

This scenario adds 100 MWs of load beginning in 2024 to the base forecast. All else is equal to the base scenario.

6.2.2 Coordinated Forecasts for Alternate Scenarios

6.2.2.1 Methodology

A very structured and coordinated approach for developing alternate scenarios was undertaken as part of this IRP process. It has been observed that future markets are driven principally by economic forecasts, regulations, and technological change. Accordingly, a set of alternate scenarios was developed around the base case that include a "low and a high regulatory" case, a "low and a high" economic case, and a "high technology" case. Each of these scenarios has an internally consistent narrative. For example, the "high regulatory" case is associated with both a more strict Clean Power Plan case, plus fracking restrictions, or other water usage issues that would limit shale gas development, and more stringent regulations on coal.

This methodology provides a useful starting point for integrated forecasts that are fully developed and consistently applied. Under each of these scenarios, a perspective was developed on how key variables such as load growth, fuel prices (e.g. coal and gas prices), emission prices, and capital costs for different technologies, retirements, and new builds are expected to move relative to the base case forecasts in the short term, medium term, and long term. These narratives were converted to a directional change for each variable, and then actual values were developed in a consistent manner.

These alternate scenarios were developed to be plausible, not necessarily highly probable. They are intended to provide boundary conditions against which to test each portfolio or investment strategy. A description of the development of these integrated forecasts for each of the key variables is provided in this document. For the development of these scenarios, stochastic distributions of each of the key variables (e.g. load, gas prices, technology costs, etc.) were developed, with select values that are either one standard deviation above or below the base case values for that variable. In this way, a consistent methodology was applied across each of the integrated scenarios, by creating both a directional variable movement and a consistent quantified value for the variable that is consistent with the description of that alternate scenario.

A hybrid approach that combines a deterministic forecast for key market drivers together with probabilistic stochastics was used to inform the characterization of uncertainty. Stochastic distributions that reflect a combination of historical data and informed judgment tend to capture "black swan events" that are impossible to forecast, but tend to occur quite frequently. Some variables, like carbon regulations, have no historical data and others, like gas prices, have had fundamental market changes that will influence the future differently from the past. Accordingly, a hybrid approach combined with expert judgment by market consultants was used to develop and inform the alternate scenarios.

6.2.2.2 Model Inputs

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

Figure 6.9 – Vectren Total Load (GWh) and Peak Load (MW) Alternate Scenarios

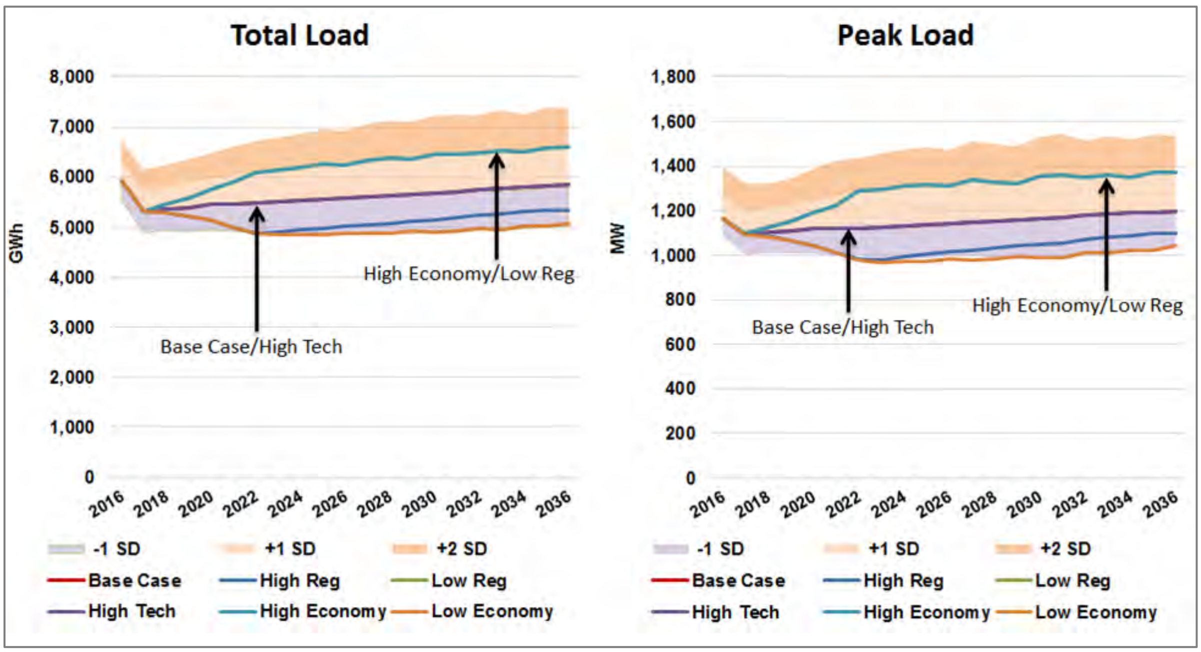


Figure 6.10 – Coal Alternate Scenarios (2015$/MMBtu)

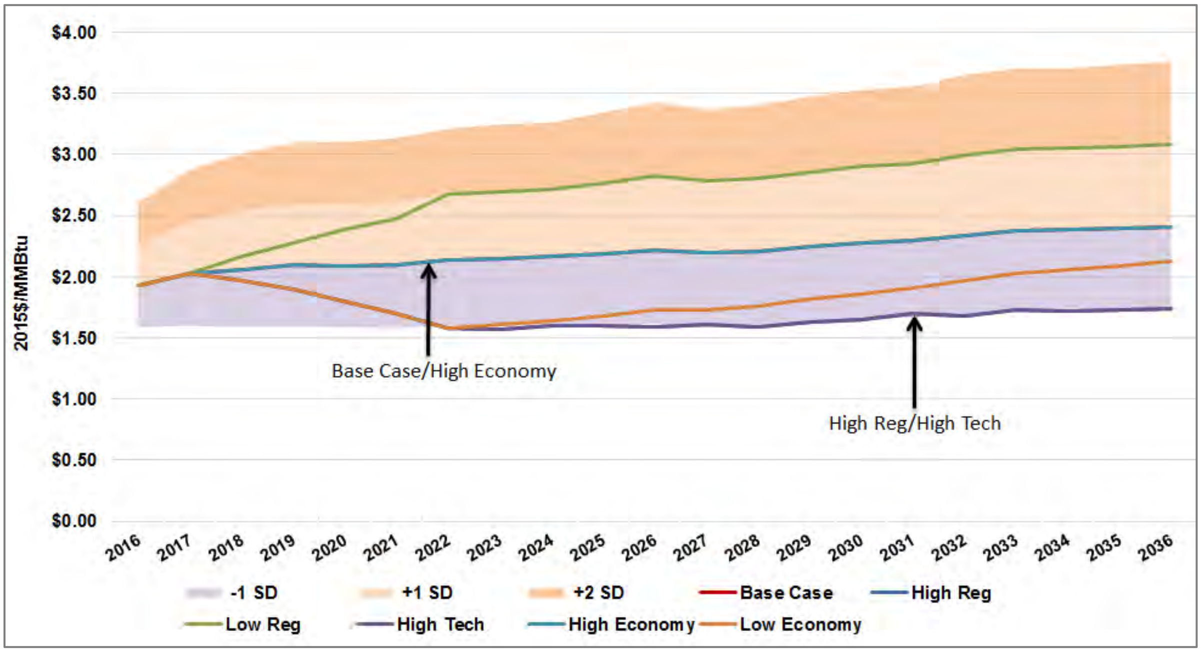
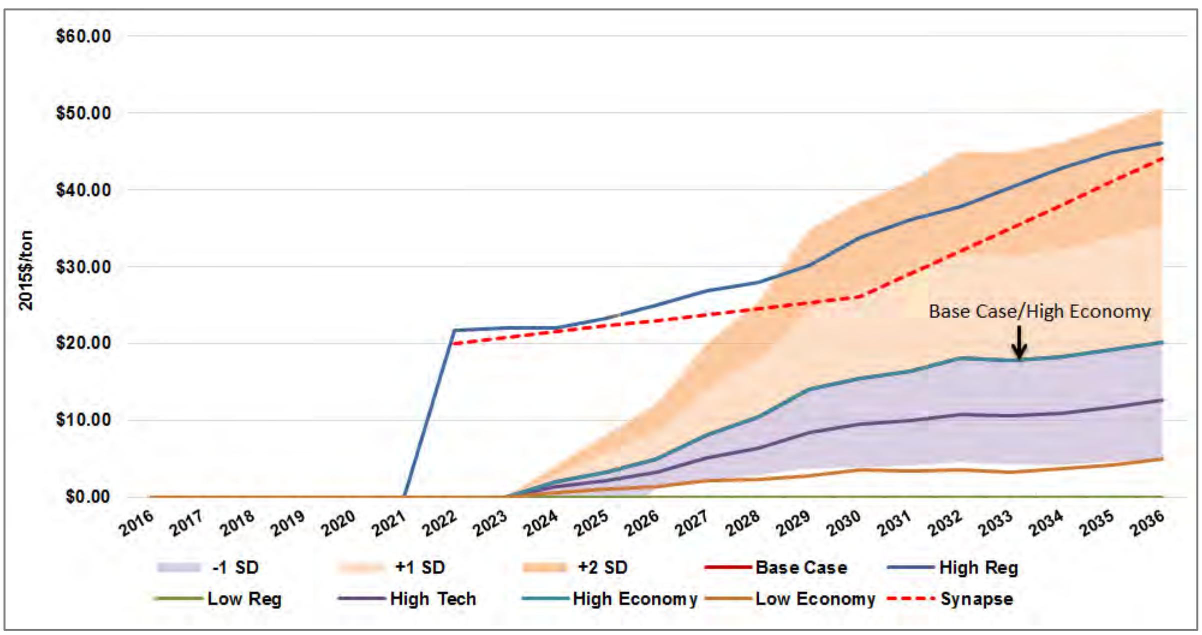


Figure 6.11 – Carbon Alternate Scenarios (2015$/ton)[48]



[48] Note that Synapse refers to the Mid Case on page 8 (adjusted for 2024 start date) from Spring 2016 National Carbon Dioxide Price Forecast, Updated March 16, 2016, Synapse Economics Inc., http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008.pdf

Figure 6.12 – Natural Gas (delivered to Indiana) Alternate Scenarios (2015$/MMBtu)

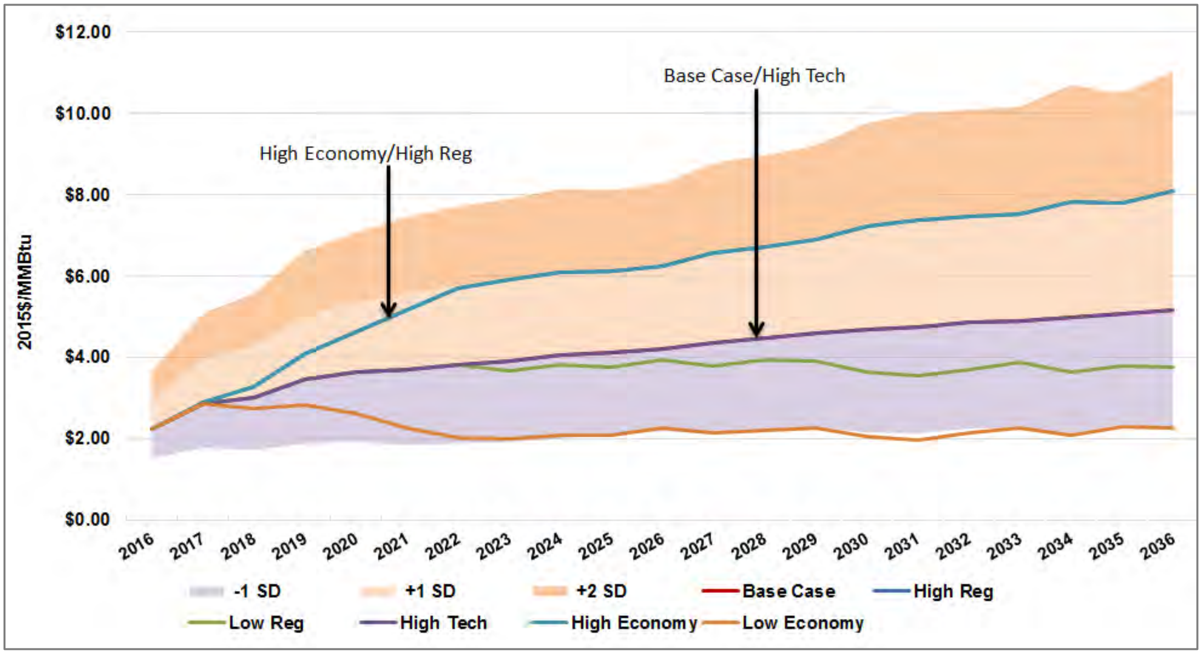


Figure 6.13 – Indiana Hub On- and Off-Peak Power Prices Alternate Scenarios (2015$/MWh)

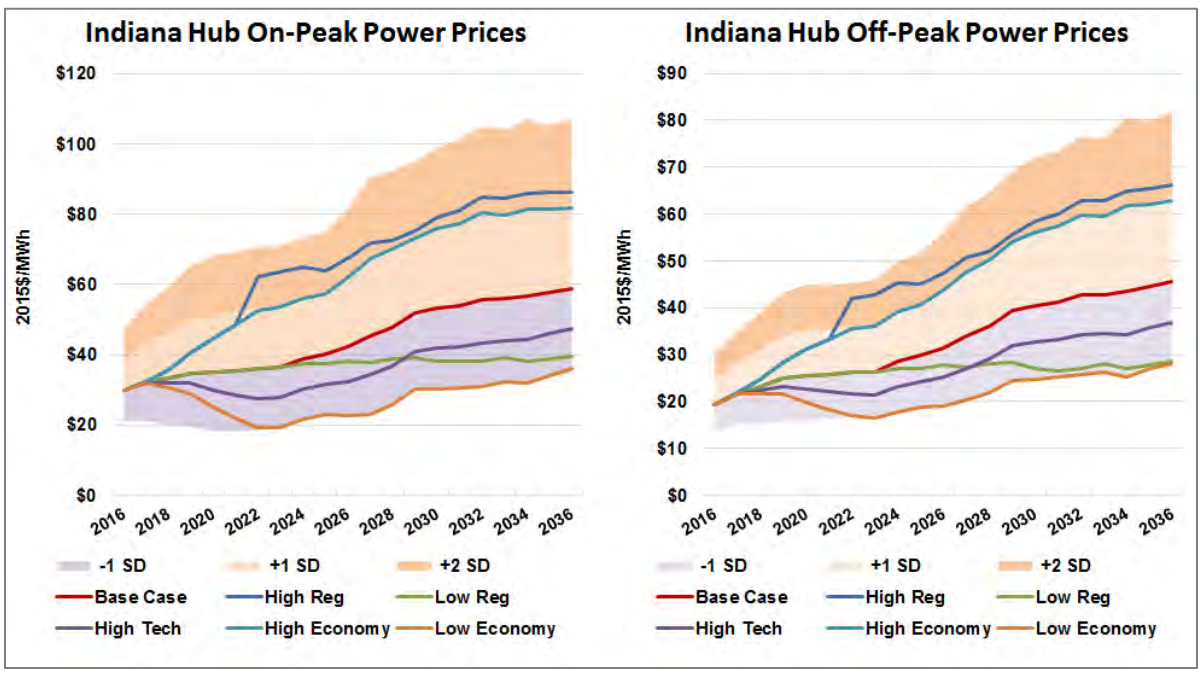


Figure 6.14 – Gas-Fired Capital Costs Alternate Scenarios (Index, 2016 = 1.000)

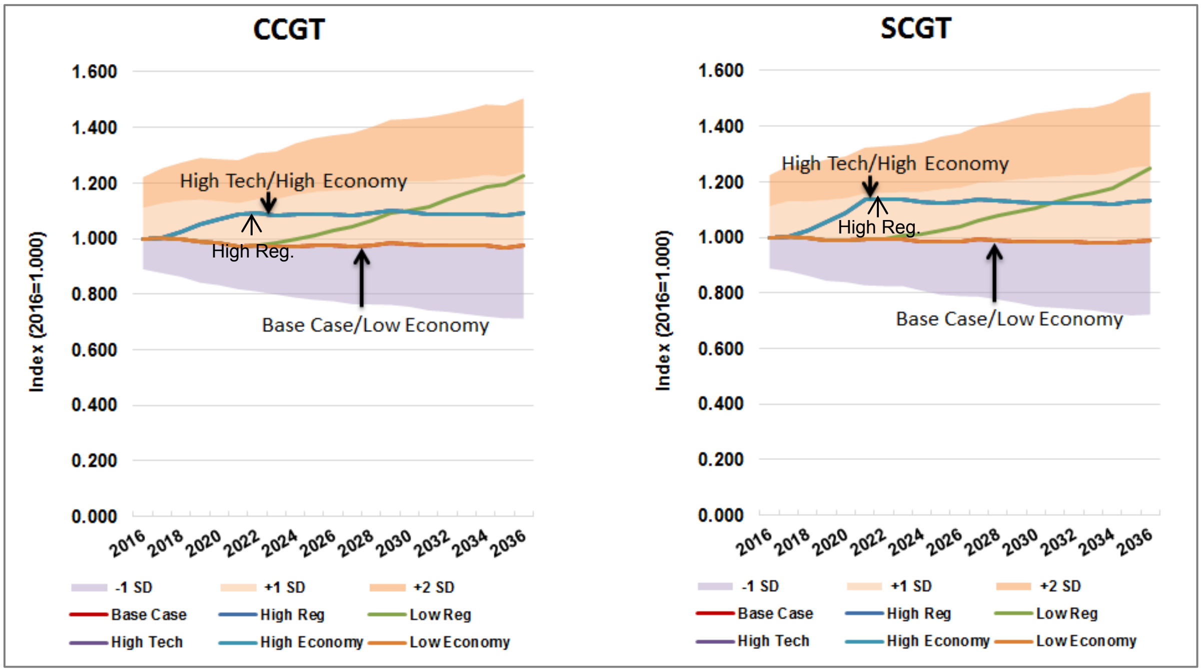


Figure 6.15 – Solar and Wind Capital Costs Alternate Scenarios (Index, 2016 = 1.000)

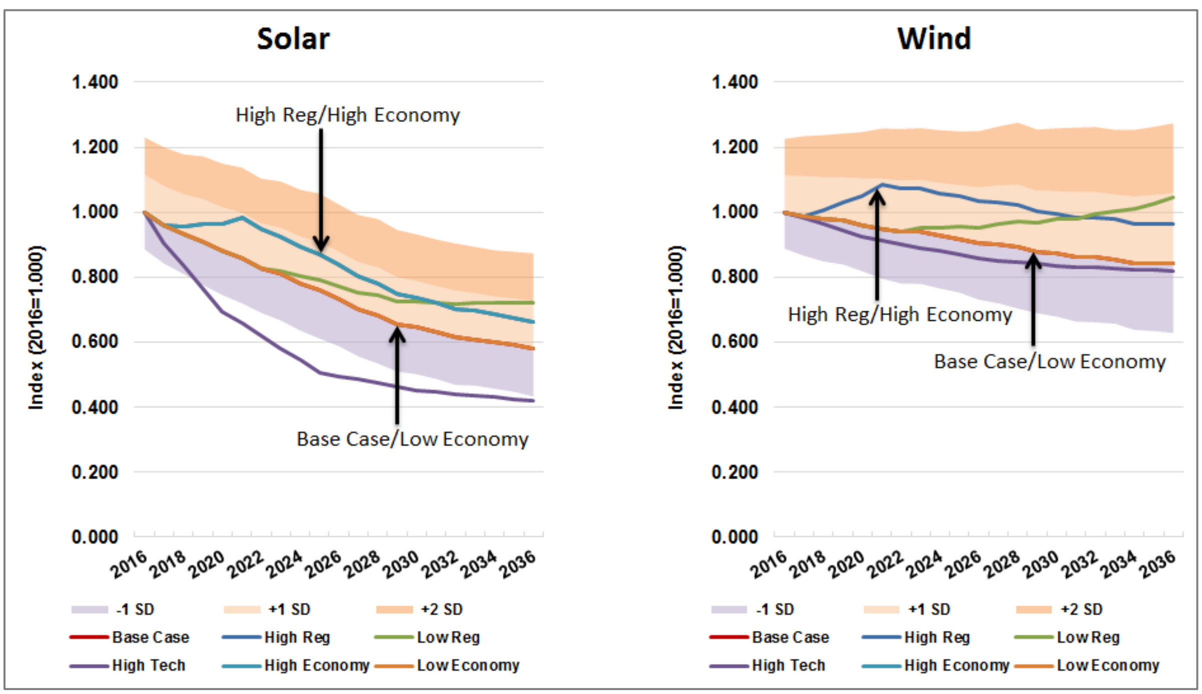
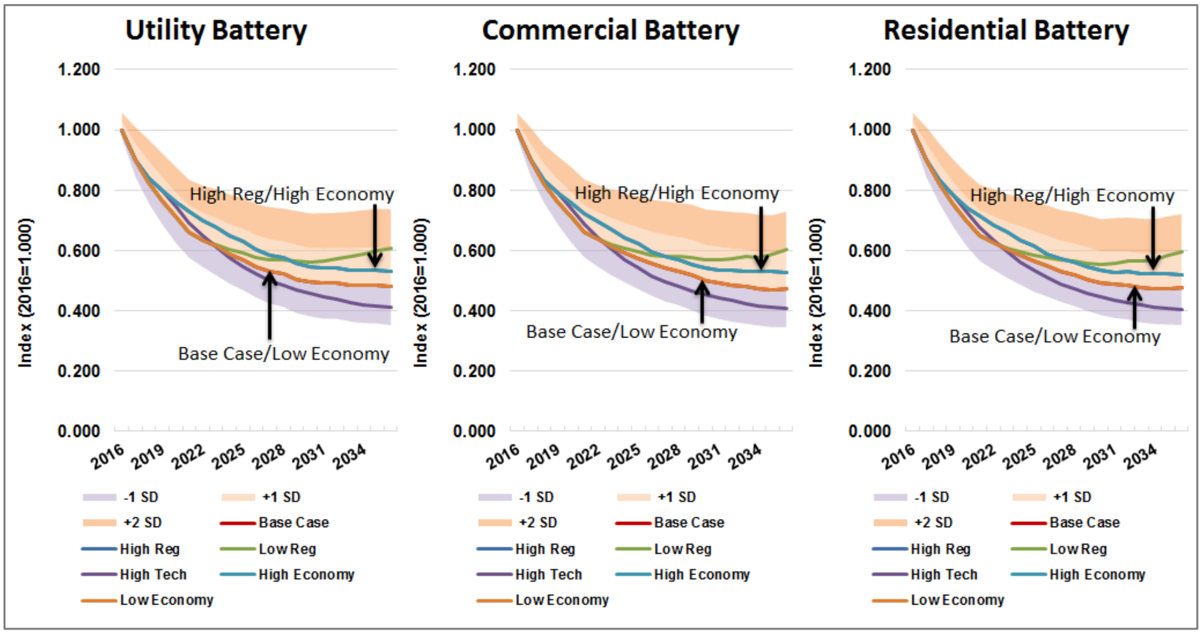


Figure 6.16 – Battery Capital Costs Alternate Scenarios (Index, 2016 = 1.000)



SECTION 7
SCREENING ANALYSIS

7.1 DEVELOP PORTFOLIOS

7.1.1 Optimized Portfolios

7.1.1.1 Model Description

Vectren continues to use the Strategist modeling software from ABB Group (formerly Ventyx), as it has in its last several IRP studies. This software has traditionally been used by some of the other Indiana utilities as well as utilities in other states. The modeling performed by Vectren provides important information to evaluate potential future resource needs.

Strategist is a strategic planning system that integrates financial, resource, marketing, and customer information. Strategist is able to simultaneously consider all aspects of integrated planning at the level of detail required for informed decision making. Strategist handles production costing, capital expenditures and recovery, financial and tax implications, and optimization all within one software system.

An optimization method has three elements: an objective, constraints, and alternatives. For the electric integration process, the three elements can be summarized as follows:

7.1.1.2 Objective

The objective of the analysis was to determine the optimal resource plan by minimizing the net present value (NPV) of customer costs. For the purposes of this discussion, the planning period NPV is defined as the net present value of operating costs including fuel, related emissions, and capital costs. Power purchases and sales are also included in the NPV analysis for the 20 year period, 2017 through 2036. NPV numbers were developed by integrating the various scenario assumptions into the optimization model. The generation options within the scenarios, along with unit retirements, additional DSM, and purchasing capacity from the market were compared against the capacity needs of the scenario yielding seven optimized low cost NPV plans.

7.1.1.3 Constraints

The primary constraint was to maintain a minimum planning reserve margin (PRM). MISO has moved to an unforced capacity (UCAP) PRM in the last couple of years. The UCAP accounts for the amount of installed capacity (ICAP) or nameplate capacity available at system's megawatt peak hour of the peak day after discounting for the time that the generating facility is not available due to historical outages such as maintenance and repairs. The UCAP PRM is subject to change each year depending on MISO's projected need and based on annual system reliability studies. For the planning year 2016/2017, MISO set forth a UCAP PRM of 7.6%. This means that Vectren must maintain at least 7.6% over the peak demand of its customers on a UCAP basis coincident to the MISO system peak. The goal is to determine the minimum planning reserve margin that would result in the MISO system experiencing a loss of load event less than one day every ten years. Other constraints include the project development and build times for new construction alternatives, transmission import constraints, reliability considerations, and the characteristics of existing resources and demand.

7.1.1.4 Alternatives

A broad array of alternative generation and DSM was included within the optimization analysis. The full range of supply-side resource alternatives were identified and discussed in Section 5, RESOURCE OPTIONS.

7.1.1.5 Results

There were a number of non-optimized portfolio shutdown decisions that were fixed due to age or other related issues including the following:

- End Warrick 4 joint operations mid-2020 (132 MW UCAP)
- Northeast 1 and 2 by end of 2018 (18 MW UCAP)
- BAGS 2 by end of 2024 (58 MW UCAP)

Additionally, a 4 MW solar plant is assumed to be operational by 2018. This is representative of 4-6 MWs of several energy company owned solar projects that are expected to be in place by this time, including:

- 2 MW universal solar power plant with a 1 MWh battery storage system
- solar plant with the City of Evansville, details of which are expected to be finalized in the first quarter 2017, and
- other potential project discussions (on-going).

Under all scenarios, additional resources were not selected until joint operations cease at Warrick 4, causing a planning reserve margin shortfall. At the end of 2023, economic shutdown of coal units occurred under each scenario. A 2x1 combined cycle gas turbine was selected to replace the retiring coal capacity. Certain portfolios selected a simple cycle gas turbine in addition to the combined cycle gas turbine. See the optimized and deterministic portfolio tables in Technical Appendix Attachment 7.1 IRP Portfolio Summary Report for more details. For a graphical representation of each portfolio see Technical Appendix 7.2 Balance of Loads and Resources. Detailed Strategist model information can be found in Confidential Attachment 7.3 Portfolio Input-Output Report.

In the **Base Scenario (aka Gas Heavy) Portfolio**, market capacity purchases occur through 2023. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking) and a 1xF-class SCGT with an annual base load capacity of 220 MWs. Some market capacity purchases and solar capacity installations begin in 2032 and continue through 2036.

Figure 7.1 – Base Scenario (aka Gas Heavy) Portfolio

	(B) Base Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2022 (68-73 MW Market Capacity)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 2023 (77 MW Market Capacity) Combined Cycle Gas Turbine (889 MW) Simple Cycle Gas Turbine (220 MW)
2030-2036	**New** 2032-2036 (1-9 MW Market Capacity) 36 MW Solar

In the **Base + Large Load Scenario Portfolio**, there is 1% EE (2018-2036), market capacity purchases through 2023, and 4 MW of DR each year through 2024. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and are replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking) and a 1xF-class SCGT with an annual base load capacity of 220 MWs. Market capacity purchases begin again in 2030, with 50 MW of solar in 2032 and 9 MW solar in 2035 and 2036.

Figure 7.2 – Base + Large Load Scenario Portfolio

	(C) Base + Alternate Load Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4MW Solar 2020-2022 (26-43 MW Market Capacity) 2018-2022 (1.0% Energy Efficiency) 12 MW Demand Response
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 8 MW Demand Response 2023 (19 MW Market Capacity) Combined Cycle Gas Turbine (889 MW) Simple Cycle Gas Turbine (220 MW) 2023-2029 1.0% Energy Efficiency
2030-2036	**New** 2030-2036 (1-9 MW Market Capacity) 68 MW Solar 2030-2036 1.0% Energy Efficiency

The **High Regulatory Scenario Portfolio** is characterized by 1% EE (2018-2036), 4 MW solar in 2018, and market capacity purchases beginning in 2020. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). 200 MW of wind come online in both 2030 and 2031, with significant market capacity purchases in 2030 through 2036.

Figure 7.3 – High Regulatory Scenario Portfolio

	(D) High Reg. Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2022 (39-47 MW Market Capacity) 2018-2022 (1.0% Energy Efficiency)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** Combined Cycle Gas Turbine (889 MW) 2023-2029 (28-106 MW Market Capacity) 2023-2029 1.0% Energy Efficiency
2030-2036	**New** 2030-2036 (72-100 MW Market Capacity) 400 MW Wind 2030-2036 1.0% Energy Efficiency

The **Low Regulatory Scenario Portfolio** has a market capacity purchase of 43 MW in 2020, 1% EE (2018-2036), and the installation in 2021 of a 1xF-class SCGT with an annual base load capacity of 220 MW. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). A second 1xF-class SCGT with an annual base load capacity of 220 MW is installed in 2025.

Figure 7.4 – Low Regulatory Scenario Portfolio

	(E) Low Reg. Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020 (43 MW Market Capacity) 2018-2022 (1.0% Energy Efficiency) Simple Cycle Gas Turbine (220 MW) 12 MW Demand Response
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 8 MW Demand Response Combined Cycle Gas Turbine (889 MW) Simple Cycle Gas Turbine (220 MW) 2023-2029 1.0% Energy Efficiency
2030-2036	2030-2036 1.0% Energy Efficiency

The **High Economy Scenario Portfolio** includes a market capacity purchases beginning in 2020, 2% EE (2018-2036), and the installation in 2022 of a 1xF-class SCGT with an annual base load capacity of 220 MW. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down, replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). 9 MW solar come online in 2027 and substantial wind is built 2030-2036.

Figure 7.5 – High Economy Scenario Portfolio

	(F) High Economy Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 8 MW Demand Response 2020-2021 (10-27 MW Market Capacity) 2018-2022 (2.0% Energy Efficiency) Simple Cycle Gas Turbine (220 MW)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 12 MW Demand Response Combined Cycle Gas Turbine (889 MW) 9 MW Solar 2023-2029 2.0% Energy Efficiency
2030-2036	**New** 400 MW Wind 2030-2036 2.0% Energy Efficiency

The **Low Economy Scenario Portfolio** shows market capacity purchases 2020 through 2036. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). 9 MW and 50 MW of solar come online in 2035 and 2036, respectively.

Figure 7.6 – Low Economy Scenario Portfolio

	(G) Low Economy Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2022 (68-73 MW Market Capacity)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 2023-2029 (67-155 MW Market Capacity) 20 MW Demand Response Combined Cycle Gas Turbine (889 MW)
2030-2036	**New** 2030-2036 (161-188 MW Market Capacity) 59 MW Solar

Finally, the **High Technology Scenario Portfolio** includes up to 91 MW of market capacity purchases through 2023. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking), as well as a 1xF-class SCGT with an annual base load capacity of 220 MW. Minimal market capacity purchases occur in 2035 and 2036.

Figure 7.7 – High Technology Scenario Portfolio

	(H) High Tech. Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2022 (82-87 MW Market Capacity)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 2023 (91 MW Market Capacity) Combined Cycle Gas Turbine (889 MW) Simple Cycle Gas Turbine (220 MW)
2030-2036	**New** 2032-2036 (1-10 MW Market Capacity) Battery 10 MW / 40 MWh 9 MW Solar

7.1.2 Stakeholder Suggested Portfolios

In addition to the scenario optimized portfolios, Vectren solicited input from public stakeholder attendees during the second public stakeholder meeting for two additional portfolios. These stakeholder portfolios include less combined cycle gas capacity additions (331 MW) compared to the other portfolios, 1,000-1,200 MW of wind capacity additions, 804-904 MW of solar capacity additions, 100-200 MW of battery storage capacity, and 30 MW of CHP capacity. Both stakeholder portfolios see 1,061 MW of coal capacity retirement, similar to the other portfolios, but fewer capacity market purchases. Energy efficiency plays a relatively larger role in the two stakeholder portfolios.

The **Stakeholder Portfolio** was developed with input from attendees during the second stakeholder meeting. It is characterized by 2% EE (2018-2036), market capacity purchases through 2021, and 4 MW of DR each year 2020 through 2024. In 2024, AB Brown Units 1 & 2 are shut down, there is partial ownership of a 1x1 CCGT F.05 (50%), 500 MW solar PV and 800 MW wind are installed, and 30 MW of combined heat & power is installed. Ten (10) 10MW/40MWh batteries come online in 2030. In 2035, FB Culley Units 2 & 3 are shut down, 200 MW wind and 400 MW solar PV comes online, and there is partial ownership of a 1x1 CCGT F.05 (25%).

Figure 7.8 – Stakeholder Portfolio

	(I) Stakeholder Portfolio
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2021 (6-23 MW Market Capacity) 2018-2022 (2% Energy Efficiency) 12 MW Demand Response
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire Broadway Avenue Gas (65 MW) **New** Combined Cycle Gas Turbine (50%) – 220 MW 8 MW Demand Response 2% Energy Efficiency 500 MW Solar PV 800 MW Wind Combined Heat & Power (30 MW)
2030-2036	**Retirement** Retire FB Culley 2 & 3 (360 MW) **New** Combined Cycle Gas Turbine (25%) - 110 MW 2% Energy Efficiency 400 MW Solar PV 200 MW Wind 100 MW Battery

The second stakeholder portfolio [**Stakeholder Portfolio (Cease Coal 2024)**] is similar to the previous stakeholder portfolio, except that in 2024 FB Culley Units 2 & 3 are shut down rather than in 2035. In addition in 2024, there is partial ownership of a 1x1 CCGT .05 (75%), 8x100 MW solar PV and 6x200 MW wind are installed, 30 MW of combined heat & power is installed, and ten (10) 10 MW/40 MWh batteries come online.

Figure 7.9 – Stakeholder Portfolio (Cease Coal 2024)

	(J) Stakeholder Portfolio Cease Coal 2024
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2021 (6-23 MW Market Capacity) 2018-2022 (2% Energy Efficiency) 12 MW Demand Response
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** Combined Cycle Gas Turbine (75%) - 330 MW 8 MW Demand Response 2% Energy Efficiency 800 MW Solar PV 1,200 MW Wind Combined Heat & Power (30 MW) 100 MW Battery
2030-2036	**New** 2% Energy Efficiency 100 MW Battery 2036 (3 MW Market Capacity)

7.1.3 Balanced Energy Portfolios

Economic modeling considers a wide range of theoretical possibilities, but does not necessarily account for all potential possibilities or real world outcomes, and therefore judgment must also be included in developing portfolios. In other words, an optimized portfolio may not be the best solution given future risks and uncertainties. In order to test a wide range of possible portfolios, Vectren included a business as usual portfolio and developed several balanced energy mix portfolios to be tested in the risk analysis.

The **Business as Usual Portfolio** represents a continuation of the current configuration of Vectren coal generating assets supplemented by market capacity purchases and a small measure of demand response (4 MW) 2020-2024. In 2024, a 1xF-class SCGT with an annual base load capacity of 220 MW comes online. Apart from small market capacity purchases in 2035-2036, the portfolio sees only minimal changes after the SCGT capacity comes online.

Figure 7.10 – Business as Usual Portfolio

	(A) Business as Usual (Continue Coal)
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4MW Solar 2020-2022 (60-63 MW Market Capacity) 12 MW Demand Response CCR Compliance at Brown & Culley
2023-2029	**Retirement** Retire Broadway Avenue Gas (65 MW) **New** 8 MW Demand Response 2023 (60 MW Market Capacity) Simple Cycle Gas Turbine (220 MW) **Upgrade** ELG Compliance at Brown & Culley
2030-2036	**New** 2035-2036 (4-9 MW Market Capacity)

The **FBC3, Fired Gas, & Renewables Portfolio** is characterized by market capacity purchases that occur 2020-2023, as well as blocks of energy efficiency at 1% (2018-2020), 0.75% (2021-2026), and 0.5% (2027-2036). AB Brown Units 1 & 2 as well as FB Culley Unit 2 are shut down (FB Culley Unit 3 continues) and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). 50 MW of wind and 9 MW of solar come online in 2027.

Figure 7.11 – FBC3, Fired Gas, & Renewables Portfolio

	(K) FB Culley 3, Fired Gas, & Renewables
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2022 (42-47 MW Market Capacity) 2018-2020 (1.0% Energy Efficiency) 2021-2022 (0.75% Energy Efficiency) **Upgrade** CCR Compliance for Culley 3
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 Retire Broadway Avenue Gas (65 MW) **New** 4 MW Demand Response Combined Cycle Gas Turbine (889 MW) 2023 (37 MW Mkt Capacity) 50 MW Wind 9 MW Solar 2023-2026 (0.75% Energy Efficiency) 2027-2029 (0.50% Energy Efficiency) **Upgrade** ELG Compliance for Culley 3
2030-2036	**New** 0.50% Energy Efficiency

The **FBC3, Fired Gas, Early Solar, & EE Portfolio** is similar to the previous portfolio, except that market capacity purchases are lower through 2023 and 50 MW of solar comes online in 2019. AB Brown Units 1 & 2 as well as FB Culley Unit 2 are shut down (FB Culley Unit 3 continues) and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). In addition, there are no renewable additions in 2027 as in the previous portfolio.

Figure 7.12 – FBC3, Fired Gas, Early Solar, & EE Portfolio

	(L) FB Culley 3, Fired Gas, Early Solar, & Energy Efficiency
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 54 MW Solar 2020-2022 (23-28 MW Market Capacity) 2018-2020 (1.0% Energy Efficiency) 2021-2022 (0.75% Energy Efficiency) **Upgrade** CCR Compliance for Culley 3
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 Retire Broadway Avenue Gas (65 MW) **New** Combined Cycle Gas Turbine (889 MW) 2023-2026 (0.75% Energy Efficiency) 2027-2029 (0.50% Energy Efficiency) 22 MW Market Capacity **Upgrade** ELG Compliance for Culley 3
2030-2036	**New** 0.50% Energy Efficiency

The **FBC3, Unfired Gas .05, Early Solar, EE, & Renewables Portfolio** is similar to the previous portfolio, except that market capacity purchases are lower through 2023 and 4 MW of demand response is seen through 2024. AB Brown Units 1 & 2 as well as FB Culley Unit 2 are shut down (FB Culley Unit 3 continues) and replaced by a 2x1 F-class CCGT at AB Brown with an unfired annual base load capacity of 700 MW. Beginning in 2030, market capacity purchases and solar power plants help to meet future demand requirements.

Figure 7.13 – FBC3, Unfired Gas .05, Early Solar, EE, & Renewables Portfolio

	(M) FB Culley 3, Unfired Gas .05, Early Solar, Energy Efficiency, & Renewables
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** 12 MW Demand Response Energy Efficiency Plan 2016-2017 54 MW Solar 2020-2022 (11-24 MW Market Capacity) 2018-2020 (1.0% Energy Efficiency) 2021-2022 (0.75% Energy Efficiency) **Upgrade** CCR Compliance for Culley 3
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 (90 MW) Retire Broadway Avenue Gas (65 MW) **New** 8 MW Demand Response 2023 (5 MW Market Capacity) Combined Cycle Gas Turbine (700 MW) 2023-2026 (0.75% Energy Efficiency) 2027-2029 (0.50% Energy Efficiency) **Upgrade** ELG Compliance for Culley 3
2030-2036	**New** 118 MW Solar 2030-2036 (2-10 MW Market Capacity) 0.50% Energy Efficiency

The **Unfired Gas Heavy with 50 MW Solar in 2019 Portfolio** includes market capacity purchases 2020-2022, 4 MW of DR each year 2020-2024, and blocks of energy efficiency at 1% (2018-2036). 50 MW of solar comes online in 2019. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by a 2x1 F-class CCGT at AB Brown with an unfired annual base load capacity of 700 MW and a 1xF-class SCGT with an annual base load capacity of 220 MW. Some market capacity purchases and a significant amount of solar capacity installations begin in 2025 and continue through 2036. Total solar capacity through 2036 equals 272 MW.

Figure 7.14 – Unfired Gas Heavy with 50 MW Solar in 2019 Portfolio

	(N) Unfired Gas Heavy with 50 MW Solar in 2019
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** 12 MW Demand Response Energy Efficiency Plan 2016-2017 54 MW Solar 2020-2022 (7-24 MW Market Capacity) 2018-2022 (1.0% Energy Efficiency)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 2025-2029 (3-10 MW Market Capacity) 8 MW Demand Response Combined Cycle Gas Turbine (700 MW) Simple Cycle Gas Turbine (220 MW) 118 MW Solar 1.0% Energy Efficiency
2030-2036	**New** 2030-2036 (3-9 MW Market Capacity) 100 MW Solar 1.0% Energy Efficiency

The **Gas with Renewables Portfolio** is similar to the previous portfolio, except that in 2024 an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking) comes online. 331 MW of solar capacity is installed throughout the forecast period.

Figure 7.15 – Gas with Renewables Portfolio

	(O) Gas Portfolio with Renewables
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** 12 MW Demand Response Energy Efficiency Plan 2016-2017 54 MW Solar 2020-2022 (3-24 MW Market Capacity) 2018-2022 (1.0% Energy Efficiency)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 2025-2029 (2-9 MW Market Capacity) 8 MW Demand Response Combined Cycle Gas Turbine (889 MW) 168 MW Solar 1.0% Energy Efficiency
2030-2036	**New** 2030-2034 (4-10 MW Market Capacity) 109 MW Solar 1.0% Energy Efficiency

7.2 EVALUATE PORTFOLIO PERFORMANCE

7.2.1 Uncertainty (Risk) Analysis

The process for addressing uncertainty in long-term resource planning studies requires an integrated framework that takes into account markets for natural gas, coal, oil, and other fuels as well as capital costs for new generation (both fossil-fuel units and renewables) and supply/demand dynamics affected by environmental regulations and uncertainties around these regulations. To capture this variability of market conditions, Pace Global employed a stochastic analysis that provides a wide range of potential market outcomes for the study-period. These outcomes include variables such as energy prices, portfolio costs, and revenues from specific generation assets.

7.2.1.1 Model Description

AURORAxmp was used as the primary tool for conducting Vectren's risk assessment. AURORAxmp is an industrial standard chronological unit commitment and dispatch model with extensive presence throughout the electric power industry. The model uses a state of the art, mixed integer linear programing approach (MILP) to capture details of power plant and transmission network operations while observing real world constraints, such as emission reduction targets, transmission and plant operation limitations, renewable energy availability and mandatory portfolio targets. It is widely used by electric utilities, consulting agencies, and other stakeholders to forecast generator performance and economics, develop Integrated Resource Plans (IRP), forecast power market prices, and assess detailed impact of regulations and market changes affecting the electric power industry. Key inputs to the model include load forecasts, power plant costs and operating characteristics (e.g. heat rates), fuel costs, fixed and variable operating costs, outage rates, emission rates as well as capital costs. The model is able to assess the potential performance and capital cost of existing and perspective generation technologies and resources, and make resource addition and retirement decisions for economic, system reliability, and policy compliance reasons on a utility system, regional or nationwide scale as needed. Outputs of the model include plant generation, gross margin, emissions, and a variety of other metrics as needed.

Pace Global has used AURORA for well over 15 years as its primary model for asset valuation, power market forecast, and IRPs. The model is able to analyze portfolio risks by assessing portfolio performance across 200 different future market outlooks. Pace Global has developed a sophisticated stochastic framework to ensure that these future market outlooks reflect both relevant historic volatility in key market drivers and cross relationships between different market drivers. Pace Global has also developed modules to simulate the different operating characteristics of ISOs across the country. For this reason it is one of the most comprehensive, reliable and flexible tools in the market for conducting IRPs. Pace Global has successfully conducted numerous IRPs for many utilities across the country, it has gained wide acceptance before energy company managements, stakeholder groups and PUCs.

In order to perform the stochastic analysis, a set of probability distributions are required for key market driver variables. These include probabilistic distributions for demand growth (load), fuel costs (natural gas and coal), environmental compliance costs (carbon), and capital costs.

7.2.1.1.1 Load Stochastics

To account for variations in electricity demand stemming from economic growth, weather, and energy efficiency and demand side management measures, Pace Global developed stochastics around the load growth expectations for the Vectren control area and the neighboring ISO zones. Pace Global's long-term load forecasting process is a two-step process that captures both the impact of historical load drivers such as economic growth and variability of weather (parametric step) and the possible disruptive impacts of energy efficiency penetration (quantum step) in constructing the average and peak demand outlook. This process is explained in detail in the Technical Appendix 10.5 Risk Appendix. Pace Global benchmarked the projections against MISO-sponsored load forecasting studies that are conducted by independent consultants and institutions and then released into the public domain.

7.2.1.1.2 Gas Stochastics

Pace Global developed natural gas stochastic distributions for Henry Hub and other basis points in MISO and elsewhere. These stochastic distributions are based on the base case view of natural gas prices with probability bands developed based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility. To estimate future volatility, the volatility of the last 30 months is applied to 2016-2018, the volatility from 2011-2015 is applied to 2016-2025, and the volatility from 2005-2015 is applied to 2026-2035. This allows gas price volatility to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility. The 95th percentile probability bands are driven by increased gas demand (most likely due to coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization down as well as little to no environmental legislation around power plant emissions.

7.2.1.1.3 Coal Stochastics

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

7.2.1.1.4 Emissions Stochastics

Pace Global developed uncertainty distributions around carbon compliance costs, which were used in the power dispatch modeling to capture the inherent risk associated with regulatory compliance requirements. The technique to develop carbon costs distributions, unlike the previous variables, is based on “expert-opinion”-based projections, as there are no historical data sets to estimate the parameters for developing carbon costs distributions.

7.2.1.1.5 Capital Cost Stochastics

Pace developed the uncertainty distributions for the cost of new entry units by technology types, which was used in the Aurora dispatch model for determining the economic new builds based on market signals. The methodology of developing the capital cost distributions is a two-step process: (1) a parametric distribution based on a base case view of future all-in capital costs, historical costs and volatilities, and a sampling of results to develop probability bands around the base case; and (2) a quantum distribution that captures the additional uncertainty with each technology that factors in learning curve effects, improvements in technology over time, and other uncertain events.

7.2.1.1.6 Cross-Commodity Stochastics

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

7.2.1.2 Results

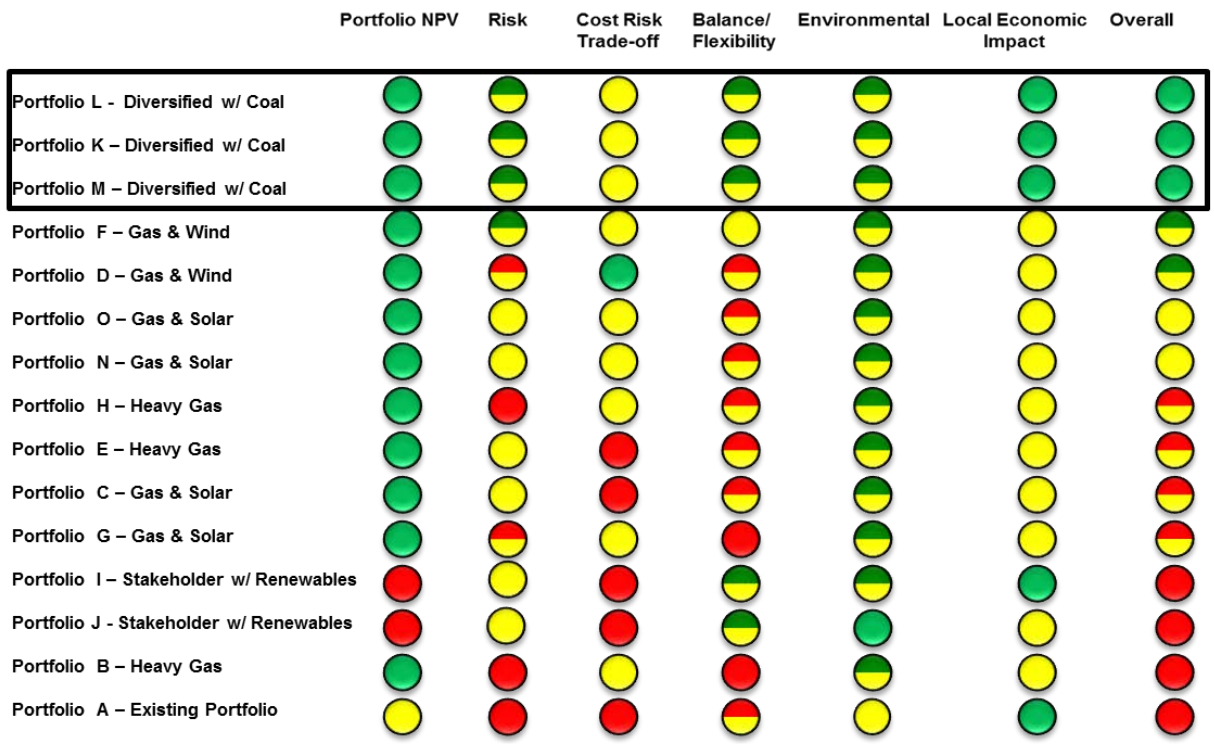
7.3 RISK ANALYSIS SUMMARY OF RESULTS

As summarized in an earlier section, Pace Global conducted a risk analysis on 15 portfolios. The analysis subjects each portfolio to 200 iterations (future market and regulatory outcomes). Then portfolios were ranked by each group of key criteria and associated metrics. The best performers in each metric were given a green color and the worst were given a red color; yellow was also shown as caution within a given metric.

Figure 7.16 summarizes the rankings for each metric. This figure shows that the diversified portfolios with coal resources performed better than the other portfolios across all of the metrics.

The recommended portfolio (Portfolio L) adopted renewables earlier than the other diversified portfolios with coal in them.

Figure 7.16 – IRP Portfolio Balanced Scorecard

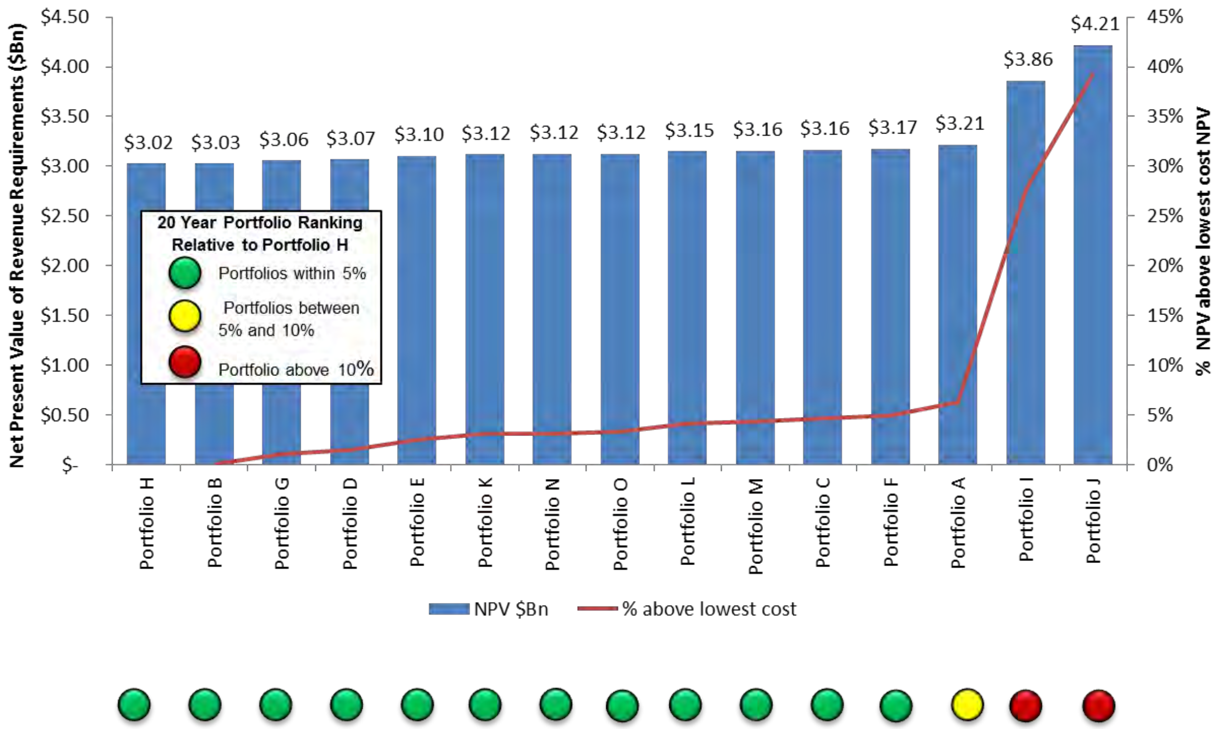


The sections below build up the metrics one at a time.

7.3.1 Customer Rates

The portfolio with the lowest mean or average costs across all 200 iterations will facilitate lower customer rates than other portfolios. The portfolios that were within 5% of the portfolio with the lowest expected cost (the net present value of revenue requirements) were given a green color, and the portfolios that were 10% or more expensive than the lowest cost portfolio were given a red color.

Figure 7.17 – IRP Modeling – 20-Year NPV Ranking



7.3.2 Risks

Four different risks were considered as part of the "Risk" metric.

One measure of risk is the volatility of the portfolio cost across the 200 iterations. The most commonly used measure of volatility is the standard deviation of the mean. The portfolios whose standard deviations of the mean were within 10% of the least volatile portfolio were given a green color. The portfolios that had standard deviations 15% or more than the lowest portfolio were given a red color. The recommended portfolio (Portfolio L) received a green color. Please see slide 50 from the November 29th Public Stakeholder meeting found in Attachment 3.1 Stakeholder Materials for more information.

The second measure of risk is exposure to volatilities in the wholesale energy market prices. The portfolio with the lowest average purchases from the market is less subject to market price volatility. When looking at the range of market purchases, those with less than 800 GWhs per year on average were given a green color and those above 1,200 GWhs were given a red color. Again, Portfolio L received a green color rating. Please see slide 52 from the November 29th Public Stakeholder meeting found in Attachment 3.1 Stakeholder Materials for more information.

The third measure assesses the potential exposure to MISO capacity markets. Although each portfolio is designed to meet MISO reserve margin targets under reference case conditions, they each may fall short if demand growth is higher than expected. The average number of additional capacity purchases across all 200 iterations was computed to see which needed the most incremental capacity purchases. Portfolios purchasing less than 20 MW per year on average received a green color and those above 35 MW per year received a red color. The recommended portfolio received a yellow color. Please see slide 51 from the November 29th Public Stakeholder meeting found in Attachment 3.1 Stakeholder Materials for more information.

The fourth and final risk measure was remote generation risk. Portfolios with generation assets located away from Vectren's service territory are exposed to greater risk of transmission congestion and outages. Portfolio L has limited susceptibility to remote generation risk.

The overall risk measure is the average of the four colors. All three of the diversified with coal portfolios (K, L, and M) were at the top of the group on the four risk measures.

Figure 7.18 – 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

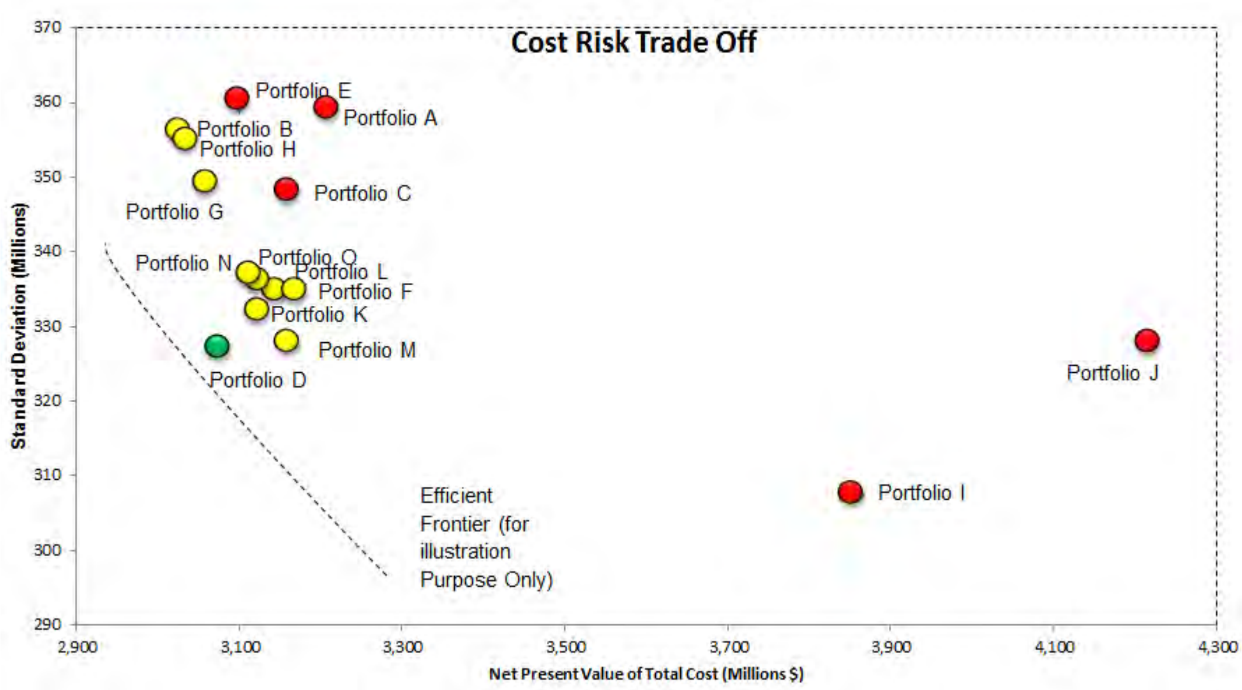
Market Purchase Ranking
Portfolios less than 800 GWh
Portfolios between 801 and 1,200 GWh
Portfolio above 1,200 GWh

Remote Generation Risk
Portfolios less than 50 MW of new remote generation
Portfolios greater than 50 MW of new remote generation

7.3.3 Cost-Risk Tradeoff

Cost and Risk tradeoff relates two variables, expected costs and the standard deviation of cost, to provide a metric of whether a portfolio hedges risk in a cost effective manner. The following graph shows some portfolios have both higher expected costs and higher standard deviations than other portfolios (receiving a red color). Others, like the two stakeholder portfolios, have very high expected costs, so high that they far exceeded the benefit of these portfolios' lower standard deviation. The recommended portfolio (Portfolio L) was given a yellow color.

Figure 7.19 – Portfolio Standard Deviation Risk (vertical axis) vs. Expected Cost (horizontal axis) Tradeoff



7.3.4 Environmental Issues

All of the portfolios will easily meet the requirements of the Clean Power Plan. Nearly all portfolios are approximately 15% or more below the required level of carbon reductions. Portfolio L will reduce carbon levels by over 45%. Moreover, nearly all the portfolios will reduce both SO_2 and NO_X levels by over 80%. While the stakeholder portfolios have the greatest reductions, all other Portfolios received a yellow/green color. Please see slides 63-65 from the November 29th Public Stakeholder meeting found in Attachment 3.1 Stakeholder Materials for more information.

7.3.5 Balance and Flexibility

Balance and flexibility are important objectives to ensure that Vectren has a diverse generation mix that does not rely too heavily on the economics and viability of one technology or one site. In addition, portfolios with the greatest number of technologies are ranked higher than those with fewer numbers. Finally portfolios with more net sales have the flexibility to adapt to unexpected breakthroughs in technology.

The recommended portfolio (Portfolio L) is among the best portfolios considering the number of technologies (five) relied upon. It also has one of the higher net sales levels.

Figure 7.20 – 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%

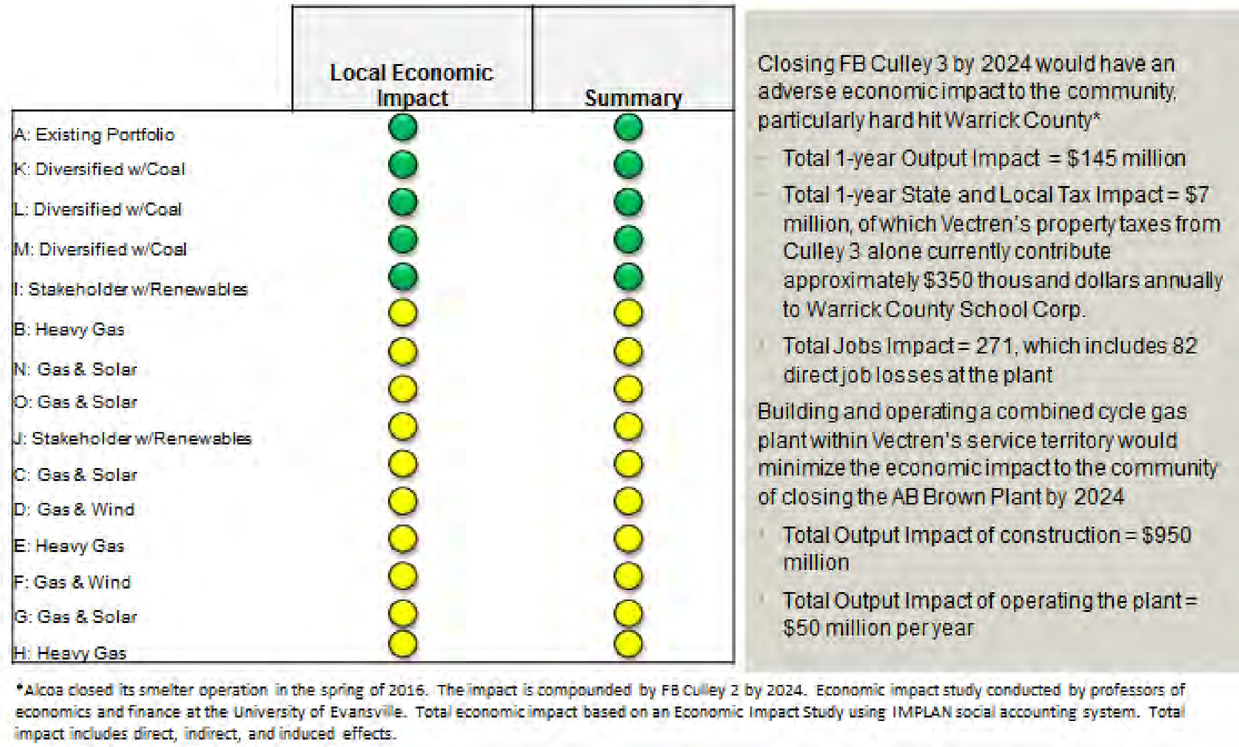
Balanced Energy Metric
- Portfolios = 5 technologies
- Portfolios = 4 technologies
- Portfolios = 3 or less technologies

Market Flexibility Ranking
- Portfolios > 10%
- Portfolios between 0% and 10%
- Portfolios < 0%

7.3.6 Local Economic Impact

The last metric is local economic impact to the community. This includes local output reductions and tax losses if local generation is closed. In addition, construction additions and operation of replacement generation was considered. Portfolio L has the lowest negative impact among portfolios. The full economic impact report can be found in Technical Appendix Attachment 7.4 Economic Impact Study – Economic Ripple Effects of Diversifying Power Generation Portfolio.

Figure 7.21 – Local Economic Impact

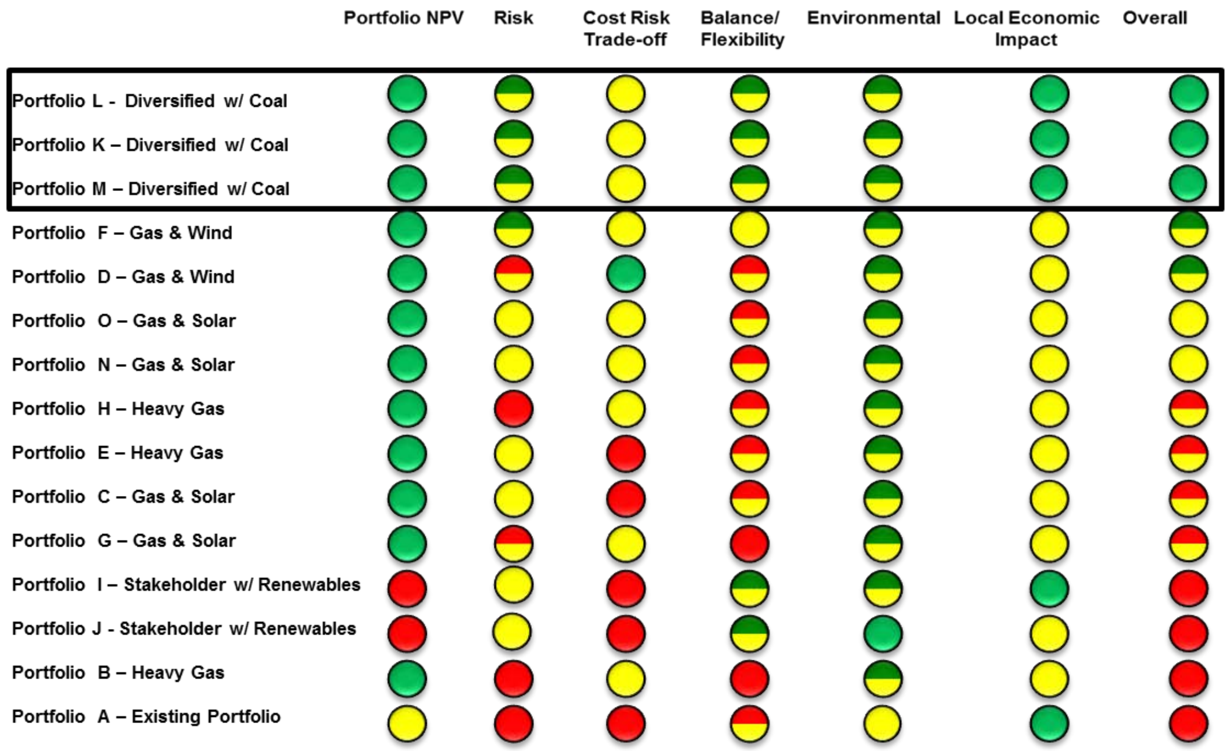


SECTION 8
IRP RESULTS AND RECOMMENDATION

8.1 SCORECARD COMPARISON

Balanced portfolios L, K, and M, the Diversified with Coal Portfolios, perform best across all metrics, as shown below in Figure 8.1. Of the three diversified portfolios, Portfolio L has early renewables and low cost, highly efficient peaking capacity to back up variable renewable resources, mitigate capacity market risk, and allow for economic development opportunities.

Figure 8.1 – IRP Portfolio Balanced Scorecard



8.2 PREFERRED PORTFOLIO RECOMMENDATION

The preferred portfolio L provides a number of 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% 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 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

8.2.1 Description of the Portfolio

8.2.1.1 Retirements

Vectren will be replacing a large portion of its aging generating fleet under the preferred plan. The preferred portfolio retires a significant amount of coal generation, including: Brown Units 1 & 2 and FB Culley Unit 2. While the Brown units are newer than FB

Culley 3, they have more expensive scrubber technology used to scrub SO_2 from the air. Vectren invested early in this clean coal technology on Brown units 1 and 2 in 1979 and 1986, respectively. The AB Brown SO_2 scrubbers are of a design known as dual alkali scrubbers. The FB Culley forced oxidation SO_2 scrubber was retrofitted years later and has better SO_2 removal efficiency with significantly lower operating costs when compared to the AB Brown dual alkali scrubbers. It should be noted that the boiler and turbine generator actually represent only a portion of the equipment required for a modern environmentally compliant coal plant. Successful coal unit operation relies heavily on extensive pollution control equipment. In short, environmental compliance is projected to be less expensive at Culley than Brown.

Additionally, the preferred plan has additional benefits in regard to having generation located on both sides of the Evansville load. If all generation were retired on one side of the system, voltage regulation issues would arise on the side of the system that was without generation. Should the combined cycle plant be built on the west side of the system, Culley 3 can help provide this support for the east side of the system.

The preferred portfolio also retires several small, inefficient gas peaking units due to age, including: Broadway Avenue Gas Generating Station 1 (BAGS 1) in 2019, Northeast 1 & 2 gas peaking units in 2019, and BAGS 2 in 2025. The preferred plan calls for the new combined cycle gas turbine to be duct-fired, which will replace older, inefficient peaking capacity with much more efficient peaking capability. 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. This technology is about half of the cost of a comparable simple cycle gas turbine.

8.2.1.2 Existing

The preferred portfolio continues use of FB Culley 3, which is Vectren's most efficient coal unit. This 270 MW unit is controlled for NO_X with an SCR. It is controlled for SO_2 with an FGD. Additionally, it has a fabric filter to remove particulate matter and is controlled for mercury and SO_3. It should also be noted that the FB Culley SO_2 FGD is a different design than the FGDs on the AB Brown coal units. The FB Culley FGD achieves more efficient SO_2 removal at significantly lower operating costs than the FGD at AB Brown. Further, most of the FGD byproduct at FB Culley is beneficially reused in the manufacture of drywall, which also reduces costs when compared to landfilling the AB Brown FGD byproduct. Vectren studies say that the going forward environmental compliance costs at FB Culley are expected to be lower than at AB Brown. And lastly, maintaining generating facilities on both sides of Evansville is desirable from a reliability and voltage regulation perspective.

8.2.1.3 Renewables

Solar photovoltaic (PV) technology is key to providing future, clean energy as part of a balanced, economical portfolio. However, PV is relatively new as a source of utility-scale generation. Each potential project poses unique challenges including site-selection and land-use competition, the amount of solar irradiance available for conversion to electricity, transmission and interconnection design, and component-level configuration of the plant. Due to the complexity of these projects, energy companies take an incremental approach to solar plant development, gaining proficiencies in these resource options along the way and unlocking the greatest value from future renewable energy installations for the communities in which they serve.

Vectren plans to explore a variety of solar PV arrangements while providing universal solar power for its customers from installations in rural as well as rooftop settings. The preferred portfolio calls for a 4 MW solar plant by 2018. This is representative of several, smaller, energy company-owned and operated projects that are expected to be in place by this time, including a 2 MW solar power plant with a 1 MWh battery storage system. Additionally, Vectren is in talks with the City of Evansville on joint projects to be finalized in the first quarter 2017, and Vectren is in on-going discussions to develop other potential projects.

Vectren's plans to integrate up to 54 MWs of solar power before tax incentives expire in 2020. The solar projects are designed to afford Vectren South and its customers an opportunity to make a meaningful step to integrating solar power into Vectren South's integrated resource portfolio. Vectren plans 50 MW of solar in 2019, which corresponds with clean energy tax incentives. Projects meeting the ITC Requirements by December 31, 2019 are eligible for 30% tax credit, helping to offset comparatively higher cost of solar generation to other resources. Timing of this plant may change should these incentives not be available. After 2020, the sustained growth rate of solar power penetration is uncertain due to policy, technological, economic, and a variety of other factors. However, in the recent release of its 2016 Standard Scenarios Report, the National Renewable Energy Laboratory cited solar PV, especially universal solar power plants, as a growing contributor of renewable energy generation. Vectren's preferred portfolio positions the company to efficiently adapt to the evolving energy mix while passing the benefits of current tax incentives on to its customers.

8.2.1.4 Energy Efficiency

The preferred portfolio continues energy efficiency programs throughout the next 20 years to help cost effectively serve Vectren customers, providing them with tools to help manage their energy bills. The preferred portfolio includes energy efficiency equivalent to 1% of eligible sales annually for years 2018 through 2020. Vectren will file its 2018-2020 energy efficiency plan in the spring of 2017, which is consistent with this level.

Vectren ran several scenarios with varying future states. Three of the seven model runs selected 1% energy efficiency throughout the 20-year period, and one selected 2% energy efficiency over this time period. These alternate scenario runs helped to inform the preferred level of energy efficiency; however, judgment for reasonableness is still necessary. Vectren included energy efficiency resources in the preferred plan that is viable and can confidently be achieved over the 20 year period (0.75% of eligible sales between 2021-2026 and 0.50% thereafter to cover incremental expected energy and demand growth). The level of energy efficiency selected in the next IRP will inform the 2021-2023 DSM filing.

8.2.2 Environmental Benefits

Vectren has reduced carbon emissions by 31% between 2005 and 2015. The preferred portfolio leads to a lower carbon future by reducing CO_2 by 46% from 2012 levels, which exceeds the Clean Power Plan requirements. Additionally, the preferred portfolio is expected to reduce SO_2 and NO_X by over 80% compared to the average of 2012-2015 levels.

A new CCGT will yield a significant reduction in air, water, and waste emissions for Vectren's generation portfolio. The ability for rapid ramp-up will allow effective back up power to renewable generation sources such as the new proposed solar projects. Additionally, a new CCGT is more efficient (requires less fuel per kilowatt hour) than a coal unit.

The preferred portfolio keeps FB Culley 3, which is controlled for multiple air pollutants. This 270 MW unit is controlled for NO_X with an SCR. It is controlled for SO_2 with an FGD. Additionally, it has a fabric filter to remove particulate matter and is controlled for mercury and SO_3. The unit has dry fly ash handling which allows for the recycling of the fly ash at a cement kiln in addition to the synthetic gypsum (FGD solids) which goes to a wallboard manufacturer.

8.2.3 Reliability

Each of the portfolios were required to meet all of the planning (PRM) and operational (UCAP) requirements set out by the Regional Transmission Operator (MISO) under each of the screening analyses. In the case of renewable builds, the ability of Vectren to support variable resources limited the total capacity of renewables built into any one portfolio in the near term.

In addition, too much reliance on one site or on one technology or fuel source, or too much reliance on remote sources, can expose Vectren to the risk of weather, transmission, or other risks that can at least temporarily impact reliability. These factors were carefully considered in the Energy Balance metric. The recommended Portfolio L meets all of the MISO reserve requirements, had five technologies in the capacity mix, two 24/7 baseload technologies, and no additional remote sources (beyond its existing contracts), which provides a relatively secure, reliable portfolio.

8.2.4 Cost

Expected costs over the planning horizon are one of the most important metrics that were evaluated in the risk analysis. Over 200 different scenarios (future conditions) were evaluated to fully test each of the 15 portfolios. While the selection of a combined cycle plant with duct-firing was consistently selected as part of the most economic portfolios, the majority of the 15 portfolios evaluated were within 5% of the lowest cost portfolio. The lowest cost scenarios were “heavy gas” portfolios which provided less diversity and less flexibility than the other portfolios. The recommended Portfolio L exhibited costs 4.1% higher than the lowest portfolio. Compared to this, the highest cost portfolios were the Stakeholder Portfolios, which were both over 25% higher cost than the lowest cost portfolios.

8.2.5 Benefits of a Balanced Energy Mix

In a world where the rate of technological advance is creating greater and greater levels of uncertainty, the benefits of a balanced energy mix cannot be understated. Five years ago, few predicted that the shale boom would result in low and relatively stable gas prices for the past five years. While renewable costs continue to decline, it is impossible to predict when battery storage technologies will become economic or whether it will fundamentally change the economics of base load generation. The best way to plan in this environment is to provide a diverse portfolio, which provides natural hedges against unforeseen changes in regulations, technologies and markets. Placing too large a bet on one and only one technology with no flexibility to adapt would leave Vectren subject to unexpected changes that could result in significant stranded assets.

The recommended Portfolio L takes a balanced approach towards capturing the current promises of combined cycle plant afforded by the mainstream low gas price outlook, and retaining a hedge against new gas capital investment becoming stranded later in the relatively unlikely event of dramatic storage technology breakthrough or unexpected severe gas extraction regulation, which is diminished by retaining a modest amount of existing coal. Portfolio L further reduces exposure to the risk of relying heavily on any single technology by incorporating three additional sources of energy generation, from solar, wind, and through energy efficiency measures.

8.2.6 Flexibility

Flexibility is another important objective for Vectren's future portfolio. Prior to the 2016 presidential election, greater regulations on natural gas, tighter carbon controls, and more regulations were commonly expected. With President-Elect Trump's election, even the current regulations on the Clean Power Plan could be in jeopardy. It is clear that with the new administration, and the rate of technological advance, Vectren must position itself to be as flexible as possible. With that in mind, Vectren needs to be able to react quickly should such factors as renewable tax provisions and the regulations on coal call for changes to its portfolio composition, such as by closing its coal plants or accelerating/delaying adding renewable generation. Whether Vectren has the agility to react in a timely manner depends in part on whether Vectren's portfolio has sufficient reserve capacity to avoid excessive exposure to market volatility during the transition, when some established market hedges (plants) retire, and before new ones (plant builds) can be completed. This reserve capacity is reflected in the amount of economic generation a portfolio has available for export into the wholesale market under normal circumstances.

8.2.7 Transmission/Distribution

An assessment of Vectren's transmission system was conducted to ensure that the preferred portfolio would support continued system reliability. The analysis indicated that the system would perform well; however, certain transmission enhancements will be required to support continued reliability. A new west to east 138 kV line from the AB Brown power plant to Pigeon Creek substation to the Culley power plant will need to be constructed. Also, additional dynamic reactive power support is needed in the eastern part of system, which will require a synchronous condenser, Static Var Compensator (SVC), or an alternative reactive power source.

8.2.8 Risk

A number of risks were considered in selecting the recommended portfolio. The first risk measured was the stability of the portfolio over the 200 scenarios run. The "standard deviation" measures the variability of portfolio cost around the mean value, with a lower standard deviation representing a relatively stable portfolio considering uncertainties in load, fuel prices, capital costs, and emissions. Another risk is exposure to the market. Owned generation is a hedge against market price fluctuations, so lower market purchases reduce Vectren's exposure to market fluctuations. A third risk is tied to incremental capacity purchases that would be required to meet on-going UCAP reserve requirements. These incremental purchases are not explicitly captured in the risk metrics. The fourth metric is the risk of remote sources, which subjects capacity to greater levels of transmission and site related risks, simply by being remote to its service territory.

The recommended Portfolio L belongs to the low-to-mid group of portfolios in terms of cost standard deviation, which indicates its expected costs are relatively stable over a wide range of market conditions. It requires some of the lowest levels of energy market purchases among the portfolios examined, which further reduces Vectren's exposure to market heat rate risk. While Portfolio L has some transmission congestion risk resulting from reliance on existing remote wind contracts, it controls this risk by calling for no further wind generation. Only in potential requirements for further capacity purchases does Portfolio L fall to the middle tier amongst all portfolios examined. But when examined together, Portfolio L is one of the best among the portfolios examined.

8.2.9 Economic Impact Analysis Results

The preferred portfolio 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 seven million dollars annually. Currently, taxes from FB Culley 3 alone contribute approximately $350 thousand annually to the Warrick County School Corp. The total output impact of FB Culley 3 is $145 million annually.

Additionally, 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. The construction of the plant is expected to produce $950 million in total economic output. Once operational, the plant is expected to have total output of $50 million annually.

8.2.10 Fuel Inventory and Procurement Planning

It is impossible to predict price fluctuations in commodity prices such as coal and natural gas. Vectren uses coal contract strategies intended to even out short term price fluctuations, such as locking in prices for various overlapping time horizons. Normally these contract renewals are staggered in time in order to even out short term price fluctuations. Coal suppliers and transportation providers generally require firm commitments in regard to quantities; however, Vectren coal contracts include optionality to adjust tonnage up or down to help manage operational variability which impacts inventory levels. Currently Vectren utilizes non-firm pipeline delivery and gas storage for the existing peaking units. It is planned that the future combined cycle gas fired 24x7 generator will utilize firm pipeline supply contracts.

SECTION 9
SHORT TERM ACTION PLAN

9.1 DIFFERENCES BETWEEN THE LAST SHORT TERM ACTION PLAN FROM WHAT TRANSPIRED

Consistent with its commitment in the 2014 Short Term Action Plan, Vectren has continued monitoring changes in inputs to its integrated resource planning. The 2016 IRP accounts for changes that have occurred and, as a result, changes the recommended short-term action plan.

The 2014 IRP called for no additional supply side resources to meet customer needs based on reasonable assumptions made in that IRP. Accordingly, Vectren did not pursue any new supply side resources in 2014 or 2015.

The 2014 IRP did support continued energy efficiency programs designed to save 1% of eligible retail sales. Vectren proposed the 2016-2017 Electric DSM Plan to obtain approval of programs to achieve this level of savings. The Commission approved this plan on March 23, 2016 in Cause No. 44645. Consistent with the 2014 IRP, the framework for the 2016-2017 filed plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 80% eligible load.

Since 2014 gas prices have dropped and are projected to remain low and 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. Projected gas prices were a major driver in this analysis.

Vectren's planning efforts for the 2016 IRP identified changes from the 2014 assumptions that drive different conclusions. In the ensuing two years, environmental rules (the CPP, ELG, and CCR) were finalized. The final ELG and CCR were more stringent than originally proposed by the EPA. The stricter standards impacted the cost of continuing to rely on our coal fired power plants in our 2016 IRP analysis.

Change impacting Vectren's modeling also resulted from actions of industrial operations in its service territory. In January of this year, Alcoa announced it would permanently cease production of its Warrick Operation smelter in the 1st quarter. Alcoa also communicated that the on-site rolling mill and power plant will continue to operate. Of Alcoa's generating units, Warrick 4 is jointly owned by Alcoa and Vectren. Alcoa is in the midst of operational and organizational changes. It is uncertain whether Alcoa will continue to run the jointly owned Warrick 4 electric generating unit. Vectren will continue talks with Alcoa as to the best course of action for Warrick 4. Also, one of Vectren's large customers brought on-line a large cogeneration facility that impacted Vectren's load forecast.

Other changes arose from efforts to continue to refine the IRP process. Vectren developed a more robust risk modeling approach for the 2016 IRP. Studies of potential customer-owned combined heat and power generation facilities were analyzed.

9.2 DISCUSSION OF PLANS FOR NEXT 3 YEARS

9.2.1 DSM

Vectren will seek Commission-approval for its 2018-2020 electric demand side management (DSM) plan in 2017. The 2018-2020 energy efficiency savings will be guided by the 2016 IRP process. Once approved by the Commission, the Vectren Oversight Board, including the Office of Consumers Counselor (OUCC), Citizens Action Coalition (CAC), and Vectren, will oversee the implementation of energy efficiency programs.

9.2.2 Solar Projects

Vectren will seek Commission approval to own and construct 4-6 MWs of energy company owned solar projects in its service territory, including:

- 2 MW universal solar power plant with a 1 MWh battery storage system

- a project to develop a solar power plant with the City of Evansville, details of which are expected to be finalized in the first quarter 2017, and
- other potential project discussions (on-going).

Additionally, Vectren plans to file and seek approval for 50 MW of solar. The timing of this project was advanced to enable Vectren to reap benefits of clean energy tax incentives for its customers. Timing of this solar power plant may change based on the availability of these incentives.

9.2.3 Environmental Permits for ELG/CCR

Vectren has timely NPDES permit renewals pending for Brown and Culley. As part of this permit renewal process Vectren will establish a compliance schedule for constructing new water pollution control equipment at FB Culley and list retirement dates for units that will not be upgraded. Vectren will seek Commission-approval to recover costs associated with the new pollution control equipment at FB Culley.

9.2.4 Generation Transition

In early 2017 Vectren will continue to evaluate several options as it pertains to building a new CCGT; building a CCGT at the AB Brown site (currently modeled in this IRP) or partnering with another energy company on a large CCGT build. While Vectren feels that the AB Brown site is attractive to maintain reliable, on-system generation (good water supply, access to 345kv electric transmission line, limits economic impact to the community, etc.), additional analysis is needed to ensure that that Vectren is pursuing the best option for customers.

Vectren will use the coming months to develop a generation transition case, complete with timelines and costs, which will be filed with the Commission for approval. The filing is expected to seek a Certificate of Public Convenience and Necessity (CPCN) to construct a new, fully fired combined cycle gas unit.

As Vectren works to replace much of its existing coal fleet with a new Combined Cycle Gas Turbine, Vectren will enter MISO's Generator Interconnection Queue process. During this process, MISO studies the impacts of new generation on the MISO transmission system and identifies any needed transmission facility upgrades. The process takes approximately 18 months and upon completion of satisfying any identified upgrades, Vectren will obtain a signed Generator Interconnection Agreement that will allow the new Combined Cycle Gas Turbine to connect to MISO's transmission system and participate in the MISO energy markets.

9.2.5 Ability to Finance the Preferred Portfolio

The Company has access to a $350 million revolving credit facility through its parent company Vectren Utility Holdings, Inc. ("VUHI"), internal cash flows, and transfers of cash flow from nonutility businesses. Additionally, Vectren and its subsidiary companies have strong investment grade ratings from both Moody's and Standard and Poor's, which affords access to the capital markets at attractive rates. This flexibility and ample access to funds will allow for the funds to be obtained in a manner consistent with the timing of the capital expenditures.

SECTION 10
TECHNICAL APPENDIX

10.1 CUSTOMER POWER NEEDS APPENDIX

10.1.1 Forecast Inputs

10.1.1.1 Energy Data

Historical Vectren sales and revenues data were obtained through an internal database. The internal database contains detailed customer information including rate, service, North American Industrial Classification System (NAICS) codes (if applicable), usage, and billing records for all customer classes (more than 15 different rate and customer classes). These consumption records were exported out of the database and compiled in a spreadsheet on a monthly basis. The data was then organized by rate code and imported into the load forecasting software.

10.1.1.2 Economic and Demographic Data

Economic and demographic data was provided by Moody's Economy.com for the nation, the state of Indiana, and the Evansville Metropolitan Statistical Area (MSA). Moody's Economy.com, a division of Moody's Analytics, is a trusted source for economic data that is commonly utilized by utilities for forecasting electric sales. The monthly data provided to Vectren contains both historical results and projected data throughout the IRP forecast period. This information is input into the load forecasting software and used to project residential, commercial (GS), and industrial (large) sales.

10.1.1.3 Weather Data

The daily maximum and minimum temperatures for Evansville, IN were obtained from DTN, a provider of National Oceanic and Atmospheric Administration (NOAA) data. NOAA data is used to calculate monthly heating degree days (HDD) and cooling degree days (CDD). HDDs are defined as the number of degrees below the base temperature of 65 degrees Fahrenheit for a given day. CDDs are defined as the number of degrees above the base temperature of 65 degrees Fahrenheit for a given day. HDDs and CDDs are averaged on a monthly basis. Normal degree days, as obtained from NOAA, are based on a thirty year period. Historical weather data is imported into the load forecasting software and is used to normalize the past usage of residential and GS customers. Similarly, the projected normal weather data is used to help forecast the future weather normalized loads of these customers.

10.1.1.4 Equipment Efficiencies and Market Shares Data

Itron Inc. provides regional Energy Information Administration (EIA) historic and projected data for equipment efficiencies and market shares. This information is used in the residential average use model and GS sales model. Note that in 2013 an appliance survey of Vectren's residential customers was conducted to compare its territory market share data with the regional EIA data. In order to increase the accuracy of the residential average use model, regional equipment market shares were altered to reflect those of Vectren's actual territory.

10.1.2 Appliance Saturation Survey and Continuous Improvement

Vectren surveys residential customers as needed. A residential appliance saturation survey was conducted in the summer of 2013. The survey was completed by a representative sample of customers. Results from this survey were used to reflect market shares of actual residential customers. The residential average use model statistics were improved by calibrating East South Central Census regional statistics with the appliance saturation of Vectren's customers. Note that Vectren's service area is technically in the southern most point of the East North Central Census region, bordering the Ease South Central region. Model results were improved by calibrating to the East South Central region.

At this time, Vectren does not conduct routine appliance saturation studies of GS and large customers. These customers are surveyed when needed for special programs. However, Vectren's large and GS marketing representatives maintain close contact with its largest customers. This allows Vectren to stay abreast of pending changes in demand and consumption of this customer group.

Vectren continually works to improve the load forecasting process in a variety of ways. First, Vectren is a member of Itron's Energy Forecasting Group. The Energy Forecasting Group contains a vast network of forecasters from around the country that share ideas and study results on various forecasting topics. Vectren forecasters attend an annual meeting that includes relevant topic discussions along with keynote speakers from the EIA and other energy forecasting professionals. The meeting is an excellent source for end-use forecasting directions and initiatives, as well as a networking opportunity. Vectren forecasters periodically attend continuing education workshops and webinars on various forecasting topics to help improve skills and learn new techniques. Additionally, Vectren discusses forecasts with the State Utility Forecasting Group and other Indiana utilities to better understand their forecasts. Vectren compares and contrasts Vectren model assumptions and results to these groups to gain a better understanding of how they interpret and use model inputs.

10.1.3 Overview of Past Forecasts

The following tables outline the performance of Vectren's energy and demand forecasts over the last several IRPs by comparing Weather Normalized (WN) sales and demand figurers to IRP forecasts from 2006-2014.

Weather-normalization is performed each month by importing customer count, meter read schedule, billing month sales, and daily temperature into Vectren's Electric AUPC Estimation system. Underlying the Electric AUPC Estimation System is a set of MetrixND (Itron's statistical modeling software) average use models. Separate models have been estimated for residential and general service customer classes. These models have been estimated from historical billed sales and customer data, and daily system delivery data. On execution, the Use per Customer (UPC) project files read actual weather data from the Access weather database and generate daily use per customer estimates for the revenue classes. The results are exported back to the AUPC system database where the predicted daily use estimates are used to allocate billed monthly sales to the calendar-month period. The models are also executed using normal daily temperatures. Results are written back to the AUPC system database. Weather-normalized sales are then exported from the Electric AUPC Estimation system.

The following tables show the WN[49] and forecasted values for:

- Total Peak Demand
- Total Energy
- Residential Energy
- GS Energy
- Large Energy

Figure 10.1 – Total Peak Demand Requirements (MW) , Including Losses and Street Lighting

Year	2005 Total Demand Forecast (MW)	2007 Total Demand Forecast (MW)	2009 Total Demand Forecast (MW)	2011 Total Demand Forecast (MW)	2014 Total Demand Forecast (MW)	WN 2016 Total Demand (MW)[50]	2005 % Diff.	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.
2006	1,326					1,325	-0.1%				
2007	1,268					1,341	5.4%				
2008	1,237	1,184				1,166	-6.1%	-1.5%			
2009	1,257	1,216				1,066	-17.9%	-14.1%			
2010	1,275	1,237	1,153			1,154	-10.5%	-7.2%	0.1%		
2011	1,294	1,252	1,179			1,132	-14.3%	-10.6%	-4.2%		
2012	1,314	1,258	1,118	1,156		1,158	-13.5%	-8.6%	3.5%	0.2%	
2013	1,333	1,265	1,115	1,156		1,144	-16.5%	-10.5%	2.6%	-1.0%	
2014	1,350	1,272	1,107	1,165		1,133	-19.2%	-12.3%	2.3%	-2.8%	
2015	1,366	1,281	1,100	1,164	1,155	1,134	-20.5%	-13.0%	3.0%	-2.6%	-1.8%
Mean Absolute Error							12.4%	9.7%	2.6%	1.7%	1.8%

[49] 2009-2014 forecastd incorporates DSM into the class level forecasts and does not include wholesale energy. Note that large sales are not significantly influenced by weather and are therefore not weather normalized. The 2005-2007 Forecasts were before the Great Recession and do not include a significant amount of DSM.
[50] 2006-2009 peak not weather normalized

Figure 10.2 – Total Energy Requirements (GWh), Including Losses and Street Lighting

Year	2005 Total Energy IRP Forecast (GWh)	2007 Total Energy IRP Forecast (GWh)	2009 Total Energy IRP Forecast (GWh)	2011 Total Energy IRP Forecast (GWh)	2014 Total Energy IRP Forecast (GWh)	WN Total Energy Results (GWh)[51]	2005 % Diff.	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.
2006	5,875					5,772	-1.8%				
2007	6,393					5,763	-10.9%				
2008	6,531	5,846				5,568	-17.3%	-5.0%			
2009	6,640	6,090				5,387	-23.3%	-13.0%			
2010	6,743	6,230	5,306			5,739	-17.5%	-8.6%	7.5%		
2011	6,846	6,329	5,460			5,857	-16.9%	-8.1%	6.8%		
2012	6,955	6,369	5,456	5,837		5,691	-22.2%	-11.9%	4.1%	-2.6%	
2013	7,060	6,422	5,434	5,807		5,768	-22.4%	-11.3%	5.8%	-0.7%	
2014	7,159	6,476	5,403	5,803		5,867	-22.0%	-10.4%	7.9%	1.1%	
2015	7,252	6,527	5,365	5,772	5,914	5,794	-25.2%	-12.6%	7.4%	0.4%	-2.1%
Mean Absolute Error							17.9%	10.1%	6.6%	1.2%	2.1%

Figure 10.3 – Residential Energy (GWh)

Year	2005 Res. IRP Forecast (GWh)	2007 Res. IRP Forecast (GWh)	2009 Res. IRP Forecast (GWh)	2011 Res. IRP Forecast (GWh)	2014 Res. IRP Forecast (GWh)	WN Res. Results (GWh)	2005 % Diff.	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.
2006	1,584					1,554	-1.9%				
2007	1,609					1,550	-3.8%				
2008	1,633	1,581				1,520	-7.5%	-4.0%			
2009	1,660	1,595				1,520	-9.2%	-4.9%			
2010	1,687	1,620	1,467			1,483	-13.8%	-9.2%	1.1%		
2011	1,716	1,645	1,440			1,483	-15.7%	-10.9%	2.9%		
2012	1,745	1,663	1,421	1,462		1,411	-23.7%	-17.9%	-0.7%	-3.6%	
2013	1,774	1,683	1,391	1,419		1,429	-24.1%	-17.7%	2.7%	0.7%	
2014	1,801	1,703	1,365	1,399		1,439	-25.2%	-18.3%	5.1%	2.8%	
2015	1,830	1,722	1,332	1,371	1,404	1,444	-26.7%	-19.2%	7.8%	5.0%	2.8%
Mean Absolute Error							15.1%	12.8%	3.4%	3.0%	2.8%

[51] Assumes 5.2% losses

Figure 10.4 – Commercial (GS) Energy (GWh)

Year	2005 Comm. (GS) IRP Forecast (GWh)	2007 Comm. (GS) IRP Forecast (GWh)	2009 Comm. (GS) IRP Forecast (GWh)	2011 Comm. (GS) IRP Forecast (GWh)	2014 Comm. (GS) IRP Forecast (GWh)	WN Comm. (GS) Results (GWh)	2005 % Diff.	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.
2006	1,566					1,342	-16.7%				
2007	1,594					1,371	-16.3%				
2008	1,625	1,380				1,346	-20.7%	-2.5%			
2009	1,660	1,384				1,324	-25.4%	-4.6%			
2010	1,694	1,404	1,275			1,321	-28.3%	-6.3%	3.4%		
2011	1,727	1,426	1,284			1,318	-31.0%	-8.2%	2.6%		
2012	1,764	1,438	1,296	1,375		1,266	-39.3%	-13.6%	-2.3%	-8.6%	
2013	1,800	1,455	1,304	1,383		1,298	-38.7%	-12.1%	-0.4%	-6.6%	
2014	1,834	1,472	1,307	1,399		1,312	-39.8%	-12.2%	0.4%	-6.6%	
2015	1,863	1,490	1,306	1,402	1,304	1,321	-41.1%	-12.8%	1.1%	-6.2%	1.3%
Mean Absolute Error							29.7%	9.0%	1.7%	7.0%	1.3%

Figure 10.5 – Industrial (Large) Energy (GWh)

Year	2005 Ind. (Large) IRP Forecast (GWh)	2007 Ind. (Large) IRP Forecast (GWh)	2009 Ind. (Large) IRP Forecast (GWh)	2011 Ind. (Large) IRP Forecast (GWh)	2014 Ind. (Large) IRP Forecast (GWh)	WN Ind. (Large) Results (GWh)	2005 % Diff.	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.
2006	2,379					2,570	7.4%				
2007	2,422					2,538	4.6%				
2008	2,461	2,591				2,409	-2.2%	-7.5%			
2009	2,498	2,820				2,259	-10.6%	-24.9%			
2010	2,530	2,921	2,281			2,630	3.8%	-11.0%	13.3%		
2011	2,561	2,980	2,445			2,745	6.7%	-8.6%	10.9%		
2012	2,594	2,999	2,449	2,687		2,711	4.3%	-10.6%	9.7%	0.9%	
2013	2,624	3,014	2,449	2,693		2,735	4.1%	-10.2%	10.4%	1.5%	
2014	2,650	3,028	2,446	2,693		2,805	5.5%	-8.0%	12.8%	4.0%	
2015	2,674	3,040	2,445	2,688	2,916	2,722	1.7%	-11.7%	10.1%	1.2%	-7.1%
Mean Absolute Error							5.1%	11.6%	11.2%	1.9%	7.1%

Figure 10.6 – Historic Energy and Demand

	Res.	Comm. (GS) Sales	Ind. (Large)	Other	Total Energy[52]	Total Demand[53]
2006	1,469	1,321	2,570	20	5,660	1,165
2007	1,631	1,412	2,538	19	5,892	1,182
2008	1,514	1,337	2,409	18	5,552	1,097
2009	1,452	1,309	2,259	19	5,300	1,076
2010	1,604	1,361	2,630	21	5,908	1,204
2011	1,499	1,329	2,745	21	5,884	1,152
2012	1,434	1,297	2,711	21	5,748	1,192
2013	1,415	1,287	2,735	21	5,742	1,091
2014	1,455	1,307	2,805	21	5,879	1,084
2015	1,408	1,307	2,722	21	5,737	1,089

10.2 ENVIRONMENTAL APPENDIX

10.2.1 Air Emissions

It was assumed that current or future generation resources would not exceed Vectren's allocated SO_2 and NOx emission allowances. Vectren's fleet of existing power generation facilities meet all rules and regulations related to SO_2 and NOx emissions while the cost of emission control equipment for SO_2 and NOx is factored into any new facilities that would be selected as part of a portfolio.

Figure 10.7 – Air Pollution Control Devices Installed

	FB Culley 2	FB Culley 3	Warrick 4	AB Brown 1	AB Brown 2
Vintage	1966	1973	1970	1979	1986
MW (net)	90	270	150	245	245
NO_X	Low NO_X Burner	SCR	SCR	SCR	SCR
SO_2	FGD	FGD	FGD	FGD	FGD
PM	ESP	FF	ESP	FF	ESP
MATs	Shared w/ U3	Injection	Injection	Injection	Injection
SO_3		Injection	Injection	Injection	injection

[52] Assumes 5.2% Losses
[53] Does not include municipal demand

Figure 10.8 – CSAPR SO_2 Allowances Current through 11/15/2014 & Seasonal NO_X Allowances Current through 11/24/2014

SO_2				
	AB Brown	FB Culley	SIGECO W4	Total
2016	7,894	4,411	2,892	15,197
2017	4,423	3,890	1,620	9,933
2018	4,423	3,890	1,620	9,933
2019	4,423	3,890	1,620	9,933

NOx					
	AB Brown	BAGS	FB Culley	SIGECO W4	Total
2016	1,214	21	1,060	445	2,740
2017	1,195	21	1,044	437	2,697
2018	1,195	21	1,044		2,698
2019	1,195	21	1,044	437	2,697

Figure 10.9 – CSAPR Seasonal NOx Allowances Current through 9/16/2016

	AB Brown	BAGS	FB Culley	SIGECO W4	Total
2016	1,214	21	1,060	445	2,740
2017	658	6	465	227	1,356
2018	658	6	465	227	1,356
2019	658	6	465	227	1,356

10.2.2 Solid Waste Disposal

Scrubber by-products from AB Brown are sent to an on-site landfill permitted by Indiana Department of Environmental Management (IDEM). During the fall of 2009, Vectren finalized construction of a dry fly ash silo and barge loading facility that would allow for the beneficial reuse of Vectren-generated fly ash. Since February 2010, the majority of AB Brown fly ash is diverted to the new dry ash handling system and sent for beneficial reuse to a cement processing plant in St. Genevieve, Missouri via a river barge loader and conveyor system. This major sustainability project serves to mitigate negative impacts from the imposition of a more stringent regulatory scheme for ash disposal, as the majority of Vectren's coal combustion materials are now being diverted from the existing ash pond structures and surface coal mine backfill operations and transported offsite for recycling into a cement application.

Fly ash from the FB Culley facility is similarly transported off-site for beneficial reuse in cement. In May 2009, Culley began trucking fly ash to the St. Genevieve cement plant. Upon completion of the barge loading facility at the AB Brown facility in late 2009, FB Culley's fly ash is now transported to the AB Brown loading facility and shipped to the cement plant via river barge. The FB Culley facility sends its bottom ash to the East ash pond via wet sluicing. The pond is approximately 10 acres in size. The West pond (27 acres) no longer receives bottom ash, but continues to accept coal pile run-off and general storm water from the west side of the plant, including the plant entrance road. Scrubber by-product generated by the FB Culley facility is also used for beneficial reuse and shipped by river barge from FB Culley to a wallboard manufacturer. In summary, the majority of Vectren's coal combustion material is no longer handled on site, but is being recycled and shipped off-site for beneficial reuse.

10.2.3 Hazardous Waste Disposal

Vectren's AB Brown and FB Culley plants are episodic producers of hazardous waste that may include paints, parts washer fluids, or other excess or outdated chemicals. Both facilities are typically classified as Conditionally Exempt Small Quantity Generators.

10.2.4 Water Consumption and Discharge

AB Brown and FB Culley currently discharge process and cooling water to the Ohio River under National Pollutant Discharge Elimination System (NPDES) water discharge permits issued by the Indiana Department of Environmental Management (IDEM). AB Brown utilizes cooling towers while FB Culley has a once through cooling water system. In fall 2014, both plants installed chemical precipitation water treatment systems to meet Ohio River Valley Sanitation Commission (ORSANCO) regional water quality standards mercury limit of 12 ppt monthly average.

10.3 DSM APPENDIX

10.3.1 Gross Savings 2016-2017 Plan

Figure 10.10 – 2016-2017 Plan Gross kWh Energy Savings

	2016*		2017**	
Sector	Gross kWh Energy Savings	kW Demand Savings	Gross kWh Energy Savings	kW Demand Savings
Residential	23,528,418	6,400	20,362,245	4,439
Commercial & Industrial	18,796,505	2,800	17,428,270	2,669
Total	42,324,923	9,200	37,790,515	7,108

*2016 Operating Plan used for 2016

**2016-2017 Filed Plan used for 2017

10.3.2 DSM Programs

Vectren has offered tariff based DSM resource options to customers for a number of years. Consistent with a settlement approved in 2007 in Cause No. 43111, the Demand Side Management Adjustment ("DSMA") was created to specifically recover all of Vectren's Commission approved DSM costs, including (at that time) a DLC Component. The Commission, in its order in Cause No. 43427, authorized Vectren to include both Core and Core-Plus DSM Program Costs and related incentives in an Energy Efficiency Funding Component ("EEFC") of the DSMA. The EEFC supports the Company's efforts to help customers reduce their consumption of electricity and related impacts on peak demand. It is designed to recover the costs of Commission-approved DSM programs from all customers receiving the benefit of these programs. In Cause Nos. 43427, 43938, and 44318, the Commission approved recovery of the cost of Conservation Programs via the EEFC. This rider is applicable to customers receiving service pursuant to Rate Schedules RS, B, SGS, DGS, MLA, OSS, LP, and HLF.

10.3.3 Impacts

The table below demonstrates estimated energy (kWh) and demand (kW) savings per participant for each program.

Figure 10.11 – 2016 Electric DSM Operating Plan Program Savings

Program	Residential/ Commercial	Particicpants	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross KW/ Participant	Net KW
Residential Lighting	Residential	314,618	67%	7,923,516	25	5,308,756	1,167	0.004	782
Home Energy Assessments	Residential	1,500	98%	2,048,260	1,366	2,007,295	262	0.17	257
Income Qualified Weatherization	Residential	485	100%	1,103,043	2,274	1,103,043	240	0.49	240
Appliance Recycling	Residential	950	54%	-	-	-	152	0.19	82
Energy Efficient Schools	Residential	2,400	100%	739,963	308	739,963	115	0.05	115
Residential Efficient Products	Residential	4,643	52%	1,997,855	430	1,038,885	918	0.20	477
Residential New Construction	Residential	103	50%	260,756	2,532	130,378	168	1.63	84
Residential Behavioral Savings	Residential	49,751	100%	8,200,000	165	8,200,000	1,400	0.03	1,400
Multi-Family CFL's	Residential	985	100%	326,240		326,240	29	0.03	29
Conservation Voltage Reduction	Residential		100%	-		-	-		-
Nest Demand Response Pilot	Residential	1,000	80%	429,000	429	343,200	900	0.90	720
Honeywell Demand Response Pilot	Residential	1,000	80%	429,000	429	343,200	900	0.90	720
Nest On-Line	Residential	165	100%	70,785	429	70,785	149	0.90	149
Small Business Direct Install	Commercial	26,037	95%	6,619,675	254	6,288,691	878	0.03	834
Commercial & Industrial Prescriptive	Commercial	12,540	87%	6,911,630	551	6,013,119	1,303	0.10	1,134
Commercial & Industrial New Construction	Commercial	15	100%	519,000	34,600	519,000	94	6.27	94
Commercial & Industrial Custom	Commercial	25	100%	4,296,200	171,848	4,296,200	525	21.01	525
Building Tune-Up	Commercial	9	100%	450,000	50,000	450,000	-	-	-
Conservation Voltage Reduction	Commercial		0%	-					
Total		416,226	88%	42,324,923	102	37,178,754	9,200	0.02	7,642

Figure 10.12 – 2017 Electric DSM Filed Planned Savings

Program	Residential/ Commercial	Participants	NTG	Gross kWh	Gross kWh per Participant	Net kWh	Gross KW	Gross kWh per Participant	Net KW
Residential Lighting	Residential	233,899	67%	6,831,909	29	4,577,379	865	0.004	580
Home Energy Assessments	Residential	2,125	98%	1,935,719	911	1,897,004	290	0.14	284
Income Qualified Weatherization	Residential	564	100%	1,282,577	2,274	1,282,577	254	0.45	254
Appliance Recycling	Residential	952	54%	1,020,544	1,072	551,094	152	0.16	82
Energy Efficient Schools	Residential	2,400	100%	675,508	281	675,508	106	0.04	106
Residential Efficient Products	Residential	2,216	52%	1,075,888	486	559,462	623	0.28	324
Residential New Construction	Residential	103	50%	146,775	1,425	73,388	68	0.66	34
Residential Behavioral Savings	Residential	43,500	100%	5,576,656	128	5,576,656	1,553	0.04	1,553
Multi-Family CFL's	Residential	5,500	100%	335,000	61	335,000	20	0.00	20
Conservation Voltage Reduction	Residential	5,324	100%	1,481,669	278	1,481,669	508	0.10	508
Nest Demand Response Pilot	Residential		80%	-		-	-		-
Honeywell Demand Response Pilot	Residential		80%	-		-	-		-
Nest On-Line	Residential		100%	-		-	-		-
Small Business Direct Install	Commercial	17,235	95%	6,000,810	348	5,700,770	906	0.05	861
Commercial & Industrial Prescriptive	Commercial	12,222	87%	6,910,197	565	6,011,871	1,088	0.09	947
Commercial & Industrial New Construction	Commercial	15	100%	534,135	35,609	534,135	94	6.27	94
Commercial & Industrial Custom	Commercial	25	100%	2,906,300	116,252	2,906,300	385	15.40	385
Multi Family Retrofit Pilot Program	Commercial	100	100%	201,785	2,018	201,785	33	0.330	33
Conservation Voltage Reduction	Commercial	558	100%	875,044	1,568	875,044	163	0	163
Total		326,738	87%	37,790,515	116	33,239,641	7,075	0.02	6,227

10.3.4 Avoided Costs

The avoided power capacity costs are reflective of the estimated replacement capital and fixed operations and maintenance cost. For this avoided cost analysis, a 1x F-class simple cycle gas turbine was used as the comparison due to the low capital and fixed O&M costs. The operating and capital costs are assumed to escalate with inflation throughout the study period. Transmission and distribution capacity are accounted for within the transmission and distribution avoided cost. Avoided capacity costs should only be considered avoidable when there is a planning reserve margin deficit that would otherwise need to be met through a new capacity resource.

The marginal operating energy costs were based off the modeled Vectren system marginal energy cost from the base optimized scenario under base assumptions. This included emission cost for CO_2 starting in 2024, estimated capital, variable operation and maintenance, and fuel costs. The marginal system cost reflects the modeled spinning reserve requirement and adjusted sales forecasts accounting for transmission and distribution losses. The table below shows avoided costs.

Figure 10.13 – Avoided Costs[54]

	Natural Gas Forecast $/MMBTu	CO_2 Forecast $/Short Ton	Economic Carrying Charge[55] $/kW	Transmission/ Distribution Avoided Cost $/kW (10% of Carrying Charge)	Total Capacity Avoided Cost $/kW	System Marginal Cost $/MWh	System Marginal Cost $/kWh
2017	$2.94		$91.82	$9.18	$101.00	$28.62	$0.02862
2018	$3.13		$92.55	$9.25	$101.80	$30.93	$0.03093
2019	$3.65		$93.41	$9.34	$102.76	$33.95	$0.03395
2020	$3.90		$94.99	$9.50	$104.49	$35.90	$0.03590
2021	$4.05		$96.77	$9.68	$106.45	$36.09	$0.03609
2022	$4.23		$98.30	$9.83	$108.13	$36.61	$0.03661
2023	$4.40		$100.00	$10.00	$110.00	$36.73	$0.03673
2024	$4.63	$2.29	$100.85	$10.09	$110.94	$40.78	$0.04078
2025	$4.77	$3.70	$102.19	$10.22	$112.41	$42.19	$0.04219
2026	$4.97	$5.87	$103.89	$10.39	$114.27	$44.98	$0.04498
2027	$5.22	$9.83	$106.32	$10.63	$116.95	$49.09	$0.04909
2028	$5.45	$12.71	$107.73	$10.77	$118.51	$52.58	$0.05258
2029	$5.68	$17.54	$109.23	$10.92	$120.15	$57.65	$0.05765
2030	$5.90	$19.50	$110.56	$11.06	$121.62	$60.23	$0.06023
2031	$6.07	$21.11	$112.38	$11.24	$123.62	$62.27	$0.06227
2032	$6.32	$23.60	$114.21	$11.42	$125.64	$65.42	$0.06542
2033	$6.46	$23.63	$115.76	$11.58	$127.33	$66.61	$0.06661
2034	$6.67	$24.58	$117.42	$11.74	$129.17	$68.66	$0.06866
2035	$6.89	$26.34	$119.98	$12.00	$131.98	$71.30	$0.07130
2036	$7.13	$28.14	$122.37	$12.24	$134.60	$73.90	$0.07390

10.4 RESOURCE SCREENING APPENDIX

10.4.1 Busbar Analysis

[54] Reflective of the 2016 IRP Base Scenario Optimized Case B as of September 20, 2016
[55] Economic Carrying Charge is not an avoidable cost if there is no capacity requirement

Figure 10.14 – New Construction Alternatives

Resource[56]	Net Operating Capacity (MW)	Fuel Type	Accepted or Rejected as Resource Alternative	Reason to Accept or Reject
LM6000 Simple Cycle Gas Turbine	43.4	Natural Gas	Rejected	Not cost effective compared to alternatives
LMS100 Simple Cycle Gas Turbine	99.5	Natural Gas	Rejected	Not cost effective compared to alternatives
E-Class Simple Cycle Gas Turbine	90.1	Natural Gas	Rejected	Not cost effective compared to alternatives
F-Class Simple Cycle Gas Turbine	**220**	**Natural Gas**	**Accepted**	**Cost effective**
1x1 7EA CCGT	170	Natural Gas	Rejected	Not cost effective compared to alternatives
1x1 7FA.05 CCGT	**442**	**Natural Gas**	**Accepted**	**Cost effective for size**
2x1 7FA.04	**745**	**Natural Gas**	**Accepted (select scenarios)**	**Not cost effective compared to alternatives**
2x1 7FA.05	**889**	**Natural Gas**	**Accepted**	**Cost effective for size**
3x1 7FA.05	1337	Natural Gas	Rejected	Exceeds capacity needs
1 MW Microturbine	1.0	CHP-Natural Gas	Rejected	Not cost effective compared to alternatives
3 MW Combustion Turbine	3.2	CHP-Natural Gas	Rejected	Not cost effective compared to alternatives
5 MW Combustion Turbine	5.1	CHP-Natural Gas	Rejected	Not cost effective compared to alternatives
10 MW Combustion Turbine	10.3	CHP-Natural Gas	Rejected	Not cost effective compared to alternatives
14 MW Combustion Turbine	**13.6**	**CHP-Natural Gas**	**Accepted**	**Cost effective CHP**
Supercritical Pulverized Coal 500 MW with Carbon Capture	430	Coal	Rejected	Not cost effective compared to alternatives
Supercritical Pulverized Coal 750 MW with Carbon Capture	640	Coal	Rejected	Not cost effective compared to alternatives
2x1 Integrated Gasification Combined Cycle with Carbon Capture	480	Coal	Rejected	Not cost effective compared to alternatives
Wood Stoker Fired	50	Wood Biomass	Rejected	Not cost effective

[56] Combined cycle gas turbines are shown as duct fired configuration for this table.

Resource[56]	Net Operating Capacity (MW)	Fuel Type	Accepted or Rejected as Resource Alternative	Reason to Accept or Reject
				compared to alternatives
Landfill Gas IC Engine	5	Landfill Gas	Rejected	Not cost effective compared to alternatives
Lithium Ion (10 MW/40 MWh)	**10**	**Battery Storage**	**Accepted (select scenarios)**	**Cost effective battery**
Lithium Ion (1 MW/4 MWh)	1	Battery Storage	Rejected	Not cost effective compared to alternatives
Commercial Battery (0.1 MW/0.25 MWh)	0.1	Battery Storage	Rejected	Not cost effective compared to alternatives
Residential Battery (0.002 MW/ 0.007 MWh)	.002	Battery Storage	Rejected	Not cost effective compared to alternatives
Compressed Air Energy Storage	100	Storage	Rejected	Not feasible in Vectren's service territory
Wind (North Dakota 50 MW)	50	Renewables	Rejected	Transmission costs are cost prohibitive
Wind (North Dakota 200 MW)	200	Renewables	Rejected	Transmission costs are cost prohibitive
Wind (Indiana 50 MW)	**50**	**Renewables**	**Accepted**	**Low cost renewable energy for size**
Wind (Indiana 200 MW)	**200**	**Renewables**	**Accepted**	**Low cost renewable energy for size**
Solar Photovoltaic (3 MW)	3	Renewables	Rejected	Not cost effective compared to alternatives
Solar Photovoltaic (6 MW)	6	Renewables	Rejected	Not cost effective compared to alternatives
Solar Photovoltaic (9 MW)	**9**	**Renewables**	**Accepted**	**Low cost renewable capacity for size**
Solar Photovoltaic (50 MW)	**50**	**Renewables**	**Accepted**	**Low cost renewable capacity for size**
Solar Photovoltaic (100 MW)	100	Renewables	Rejected	Acreage required may be difficult to find in Vectren's service territory
Hydroelectric	50	Hydroelectric	Rejected	Not cost effective compared to alternatives

10.5 RISK APPENDIX

As described further below, uncertainty is addressed in two different ways: first, by subjecting technologies to a variety of market outcomes in the screening analysis to ensure that Vectren has selected technologies in its portfolios that will perform well in a variety of future conditions, and second, in a more comprehensive risk analysis where the range of future conditions on the selected portfolios is more fully captured.

Key to this more comprehensive risk analysis is a stochastic risk assessment that bounds the uncertainty, captures the variability, and identifies the risk exposure inherent in long-term power generation planning. Variability results from supply and demand disruptions, market conditions, technology improvements, economic cycles, and weather, all of which are captured in Vectren's Risk Integrated IRP approach. To capture this variability, a Monte Carlo simulation is used to evaluate the range of possible futures as well as their likelihoods. The stochastic model estimates probability distributions of potential outcomes by allowing for simultaneous random-walking yet inter-correlated variation in many inputs over time, including gas prices, coal prices, carbon prices, capital costs, and load growth. These boundary conditions and probability bands then help to inform decision making on each portfolio's overall benefit-risk profile.

10.5.1 Stochastics

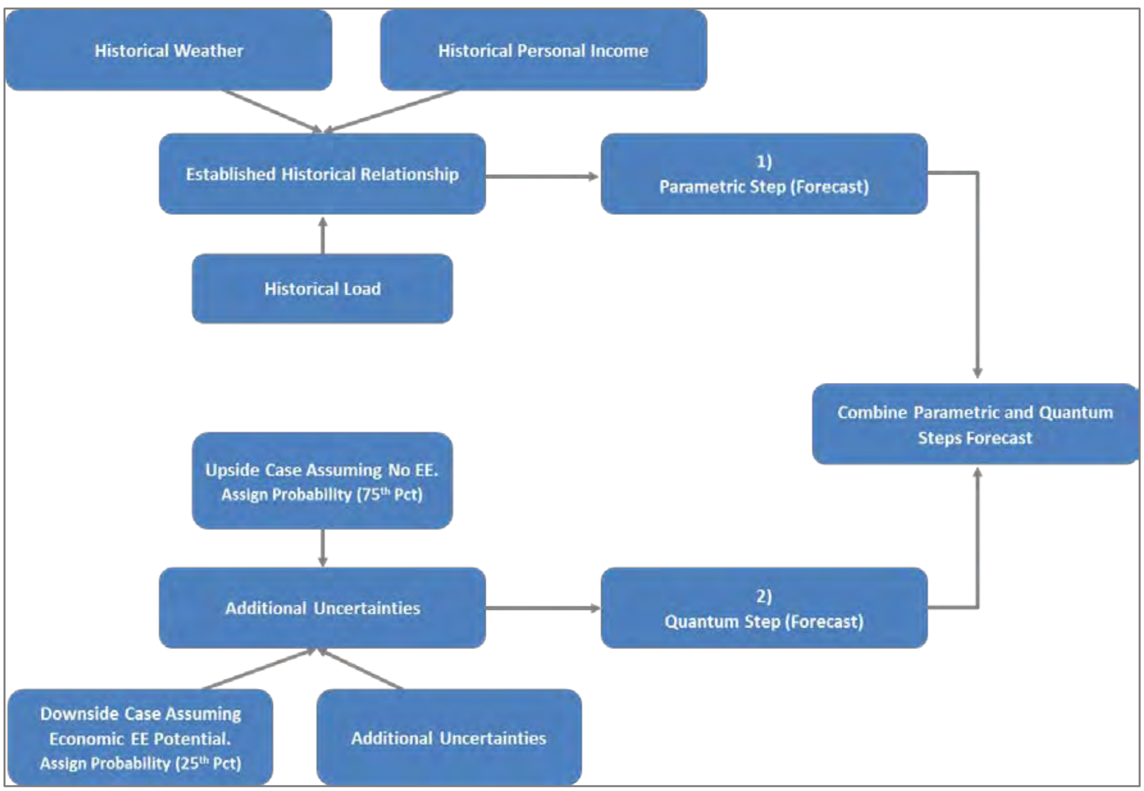
10.5.1.1 Load Stochastics

To account for variations in electricity demand stemming from economic growth, weather, and energy efficiency and demand side management measures, Pace Global developed stochastics around the load growth expectations for the Vectren control area and the neighboring ISO zones. While values in the 95th percentile are driven by strong economic growth, values in the 5th percentile are driven by economic stagnation as well as energy efficiency and demand-side management implementation.

Pace Global' s long-term load forecasting process is a two-step process that captures both the impact of historical load drivers such as economic growth and variability of weather (parametric step) and the possible disruptive impacts of energy efficiency penetration (quantum step) in constructing the average and peak demand outlook.

Pace Global benchmarked the projections against MISO-sponsored load forecasting studies that are conducted by independent consultants and institutions and then released into the public domain. The process to benchmark the load to MISO's forecasts was undertaken during the quantum step, which is described below.

Figure 10.15 – Pace Global's Load Forecast Process



The parametric step separately employs a unique econometric model for each MISO Local Resource Zone (LRZ) based on the historical relationships between average and peak load, and key driver variables, including temperature data (HDD, CDD, and humidity) and an economic factor variable (personal income for the geographical area).

Pace Global used the historical personal income drift rates and volatility and a sampling from 17 years of historical data for each region to assess the distribution of overall load growth conditions for each year of the forecast. The base average and demand forecast were based on the average of the peak and average demand forecasts.

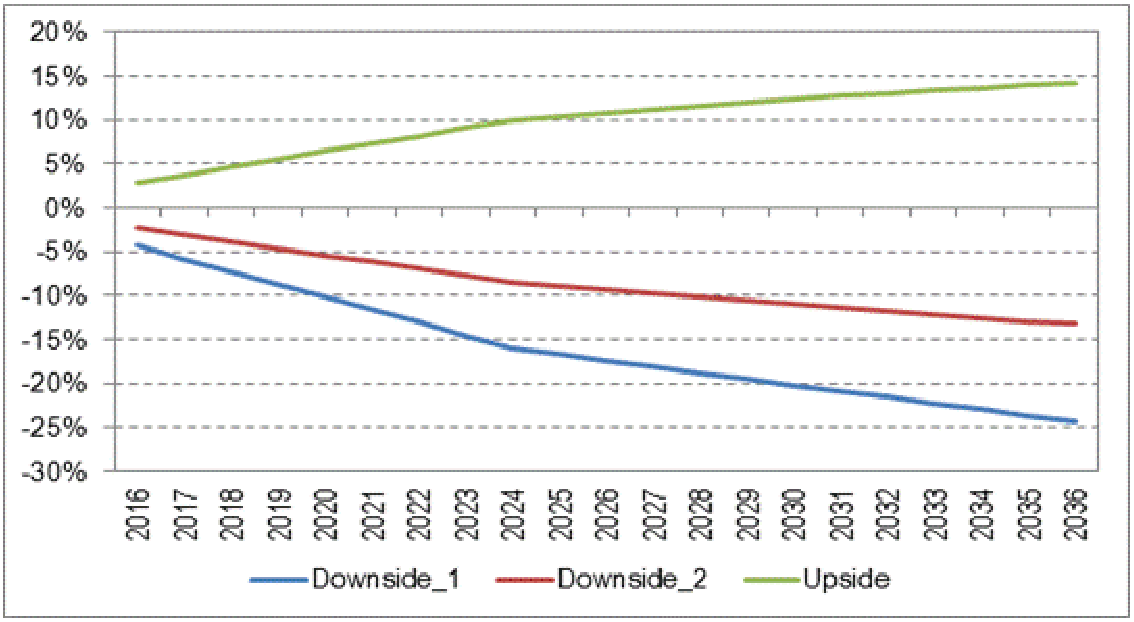
The quantum step assessed the possible disruptive impacts of energy efficiency on the average and peak loads in MISO. Pace constructed three energy efficiency scenarios using publically available FERC and NERC reports data:

1. Upside scenario: No significant savings from efficiency programs
2. Downside scenario 2: Energy efficiency penetration dictated by current economic value
3. Downside scenario 1: Additional energy efficiency penetration driven by federal and state programs to achieve energy efficiency technical potential

In addition, Pace Global used the most recent historical average and peak load for each MISO LRZ and the forecasted compounded annual growth rate (CAGR) of peak and average demand from MISO-sponsored 10 year independent load forecasts to benchmark and formulate a reference.

With this information, Pace Global constructed synthetic distributions for energy efficiency by assigning the upside scenario as the 75th percentile case, the base case scenario as the 50th percentile case, the economic energy efficiency potential as the low 25th percentile, and the technical energy efficiency potential as the 5th percentile. The following graph shows an illustration of the impact of three scenarios on the average demand growth rate. The average impact derived from the synthetic distribution was applied to base demand forecast obtained in the parametric step.

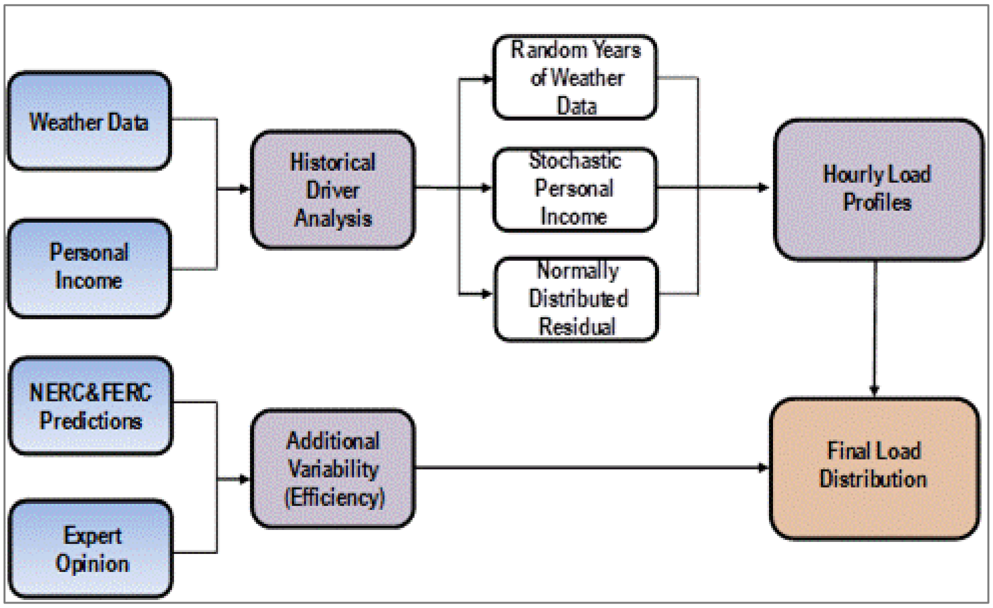
Figure 10.16 – Illustrative Impact of Three Scenarios on Energy Efficiency



Pace Global benchmarked its outlook against the latest MISO-sponsored load forecasting study, which shows the CAGR for the next 10 year study period. The study report has a CAGR value for each of the nine LRZs. Pace Global applied the CAGR value to the actual 2015 historical load, which is the starting value, and determined a projection of the load forecast. This load forecast was considered as the base case (50th percentile) reference. The previous graph shows the high and two low percentiles as percentage increase/reductions to the reference load. For example, the 5th percentile case has a value of -16% by 2025. The base case reference load for 2025 was reduced by 16%, which corresponds to the technical potential for EE penetration. The same steps were repeated for the 25th percentile and 75th percentile cases for each year, which created a distribution of projections depicting the various "market events" that can happen in the future. For the deterministic case, the average impact from this synthetic distribution was imposed on the load forecast from the parametric step, to obtain the final load forecasts.

To address demand uncertainty in modeling and capture the risk associated with demand growth, Pace Global produced a distribution of monthly average and peak loads using the methodology described below and summarized in the following flow chart.

Figure 10.17 – Flow Chart to Address Load Uncertainty



With respect to the historical driver analysis, Pace Global finds that historical monthly weather data and personal income explain fairly well the changes in monthly average and peak load. This relationship forms the basis for Pace Global's load uncertainty analysis. The basic premise of the model is that load can be expressed as a function of HDDs, CDDs, humidity, and personal income.

$$Load\_t=\alpha+ \beta\_1*HDD\_t+ \beta\_2*CDD\_t+ \beta\_3*HUM\_t+ \beta\_4*PI\_t+ \xi\_t$$

Where:

- HDD (Heating Degree Days): 65 - Average daily temperature in degrees Fahrenheit or zero (HDD is never negative)
- CDD (Cooling Degree Days): Average daily temperature -65 in degrees Fahrenheit or zero. (CDD is never negative)
- HUM (Humidity): Average daily percent humidity
- PI: Personal Income

- ξ: A normally distributed variable with mean 0 and constant variance
- α: A constant derived from the regression analysis
- β_n: Coefficients derived from the regression analysis

A stepwise regression then calibrated this model to historic data.

The load stochastics propagation was conducted in a two-step process.

Step 1: Weather and Economic Variability

To produce load stochastics, Pace Global propagated three independent random paths: weather data, personal income, and a residual. Weather data includes HDDs, CDDs, and humidity. To produce reasonable weather data projections, Pace Global sampled actual yearly paths from history. On average, Pace uses 17 years of historical data to perform the weather projections for the forward study period. Personal income is assumed to follow Geometric Brownian Motion. This means that there exists a normal distribution with constant mean and variance that describes how the return on personal income will behave at any time. Historical personal income data produces a best estimate for the relevant monthly mean and variance of this process going forward. Finally, to account for unexplained variation in the observed data, Pace Global added a normally distributed residual with mean zero and standard deviation equal to the root mean squared error of the previously mentioned stepwise regression.

Step 2: Additional Variability

Pace Global believes that future power demand may differ substantially from past power demand. To accommodate for this possibility, an additional "efficiency distribution" was added to the empirically derived distribution. The distribution is log-normally distributed. The 5th percentile of this distribution is taken primarily from NERC and FERC projections (or other relevant data sources) for statewide potential for load reduction from efficiency or other DSM measures. For example, these measures may include smart meter infrastructure, appliance energy efficiency standards, or other direct load control programs. The upper tail of this distribution was weighted to match Pace

Global's analysis of historical high periods of load growth and Pace Global's expert opinion. Note that the "efficiency distribution" incorporates the potential for limited or no penetration of the expected increases in the energy efficiency of the economy embedded in the base case. Examples include increasing residential plug load or high energy consumption technology breakthroughs. Pace Global expects that changes attributable to the efficiency distribution will affect load growth on a large geographic scale. Accordingly, concurrent energy efficiency changes are highly correlated across regions. Additionally, Pace Global expects that incremental efficiency changes will persist over time. Accordingly, the propagations have a high level of serial correlation.

10.5.1.2 Gas Stochastics

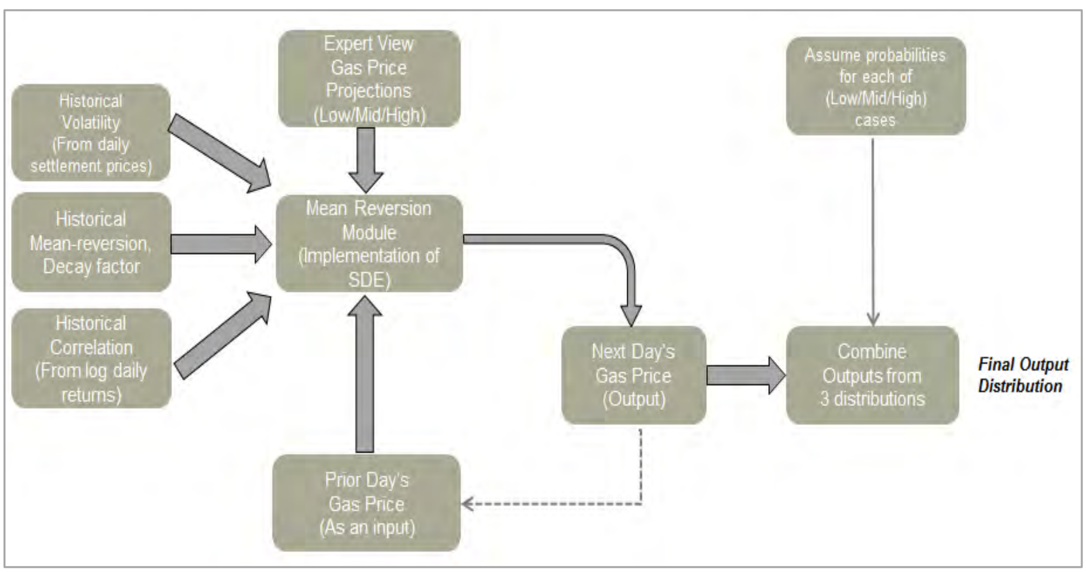
Pace Global developed natural gas stochastic distributions for Henry Hub and other basis points, including points relevant to Indiana. These stochastic distributions are based on a base case view of natural gas prices with probability bands developed based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility.

Pace Global developed stochastics around the price at the Henry Hub and other hubs based, including points relevant to Indiana, on historical volatility, current market forwards, and a long-term term fundamental view that takes into account the expected supply-demand balance. To estimate future volatility, the volatility of the last 30 months is applied to 2016-2018, the volatility from 2011-2015 is applied to 2019-2025, and the volatility from 2005-2015 is applied to 2026-2035. This allows gas price volatility to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility. The 95th percentile probability bands are driven by increased gas demand (most likely due to coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization down as well as little to no environmental legislation around power plant emissions.

The steps involved in the development of gas stochastics are as follows:

- As the first step, Pace developed the long-term fundamental forecast of Henry Hub and many other North American gas hub bases to the Henry Hub (using the Gas Pipeline Competition Model or GPCM). The probability distributions were developed around this fundamental forecast.
- From historical data sets, the volatility parameter was calculated using the daily settled prices. Volatilities for different historical time periods were calculated (such as past 10-years, past 5 years, recent 2.5 years etc.)
- The daily gas prices were modeled as a single-factor continuous mean-reverting process. The mean reversion parameter was also calculated from the historical daily settled prices.
- For several gas hub bases that are deemed to be correlated, the appropriate correlations were calculated from the historical data.
- The entire process to develop the gas stochastics is described in the exhibit below:

Figure 10.18 – Pace Global's Gas Stochastics Process



- The volatilities tend to vary for different time periods. In order to capture this for the forecast time period, different volatility values from different historical time periods were considered. For example, for the first three forecast years (2016-2018), volatility calculated from the past 30 months price data is used. For years 4-10 (2019-2025), volatility calculated from the past five years (2011-2015) is used. Beyond that time period (2026-2035), the past 10-year historical volatility (2005-2015) is used.

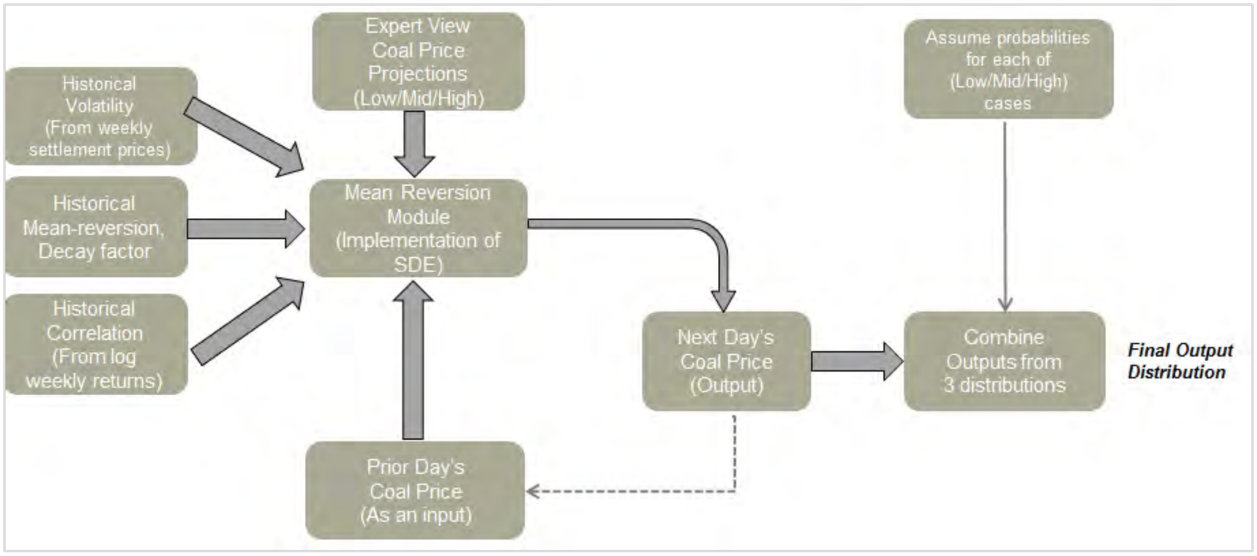
- The long-term fundamental forecast for each month in the forecast time period was treated as the mean-reverting level in this process.

10.5.1.3 Coal Stochastics

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

The methodology involved in the distribution of stochastic coal prices is exactly the same as that used for natural gas stochastics.

Figure 10.19 – Pace Global's Coal Stochastics Process



The steps involved in the development of coal basin price stochastics are as follows:

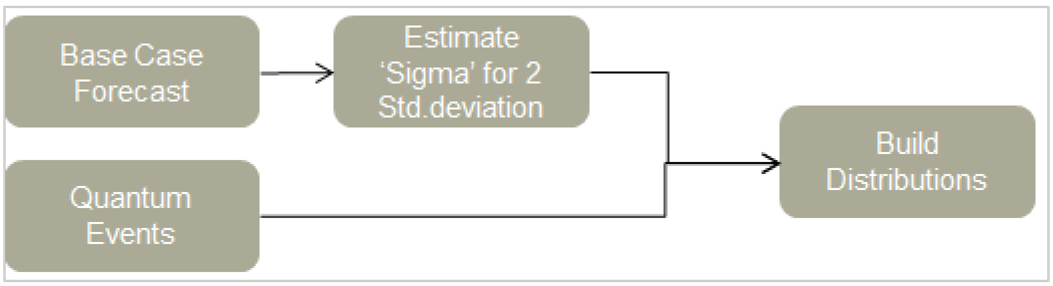
- As the first step, Pace developed the long-term fundamental forecast of each of the coal basins. The probability distributions were developed around these fundamental forecasts.
- From historical data sets, the volatility parameter was calculated using weekly prices. Volatilities for different historical time periods were calculated (such as past 10-years, past 5 years, recent 2.5 years etc.)
- The coal prices were modeled as a single-factor continuous mean-reverting process. The mean reversion parameter was also calculated from the historical prices.
- For the four coal basin prices, the appropriate correlations were calculated from the historical data.

10.5.1.4 Emissions Stochastics

Pace Global developed uncertainty distributions around carbon compliance costs, which were used in the power dispatch modeling to capture the inherent risk associated with regulatory compliance requirements.

The technique to develop carbon costs distributions, unlike the previous variables, is based on Pace Global' expert opinion based projections. There are no historical data sets to estimate the parameters for developing carbon costs distributions. Accordingly, the views of Pace Global's subject matter experts are taken into consideration. The exhibit below shows the high level methodology for developing stochastic distributions, when the historical data is not available.

Figure 10.20 – Pace Global's Emissions Stochastics Process



Given below are the steps involved in this process:

- Pace's environmental team developed a base case forecast, and an associated high and low case. In addition to the high and low cases, the probability values for the high and low cases were developed.
- These three cases are treated as 16th, 50th and 84th percentiles. Using these percentiles and statistical techniques, the standard deviation values were calculated.
- The base case is treated as the mid-case (median).
- Using the standard deviation values and a sampling from an underlying standard normal distribution (which has a mean zero and variance one), the probability bands were constructed around the reference projections. This underlying distribution captures the quantum events that can happen in the market.
- The distributions were then adjusted to incorporate probabilities such as "*the probability of a CO_2 program not taking effect*" and "*a greater chance of a nation-wide CO_2 regime starting in 2022,*" etc.

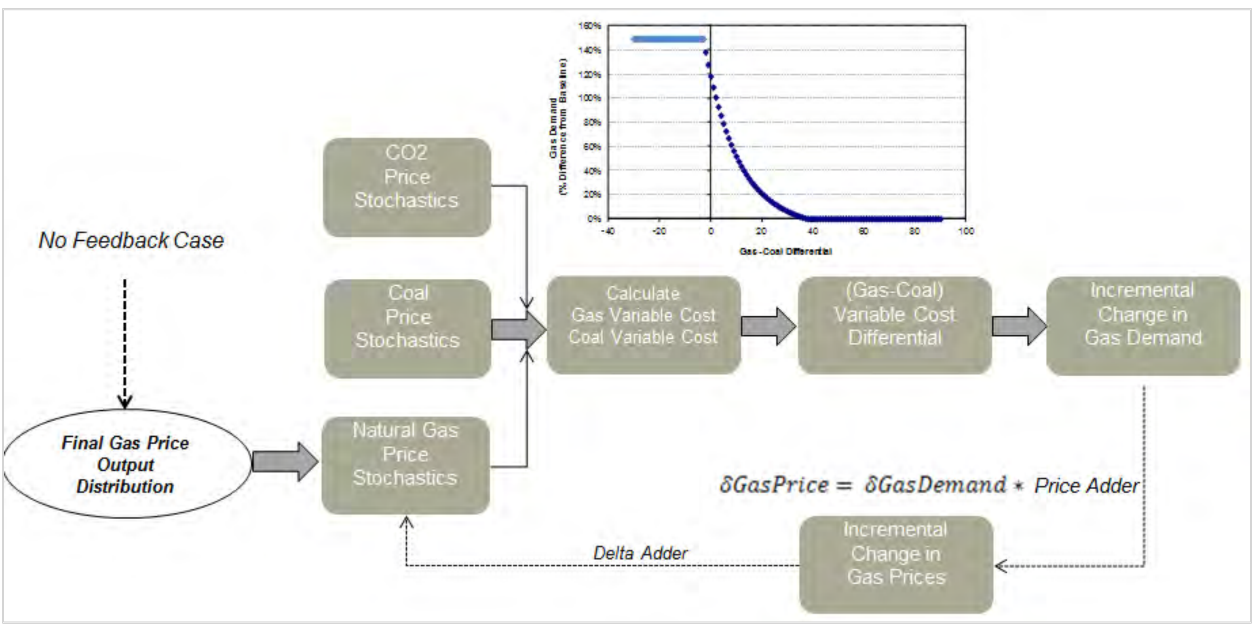
- Separate distributions were developed for national carbon costs, California carbon costs, and RGGI prices, which were then applied to the respective states.

10.5.1.5 Gas-Coal-CO_2 Prices Feedback (Cross-Commodity Correlations) Stochastics

Pace Global has implemented a distinct process to capture the cross-commodity correlations into the stochastic processes. This is a separate process which is implemented after modeling the gas, coal, and CO2 processes discussed above.

The exhibit below describes the coal and CO_2 feedback loops that affect gas prices. At a high level, the feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators.

Figure 10.21 – Pace Global's Cross-Commodity Correlation Stochastics Process



- Pace performed fundamental analysis to define the relationship between gas-coal dispatch cost and demand; incremental gas demand curve as a function of the gas-coal differential was calibrated.

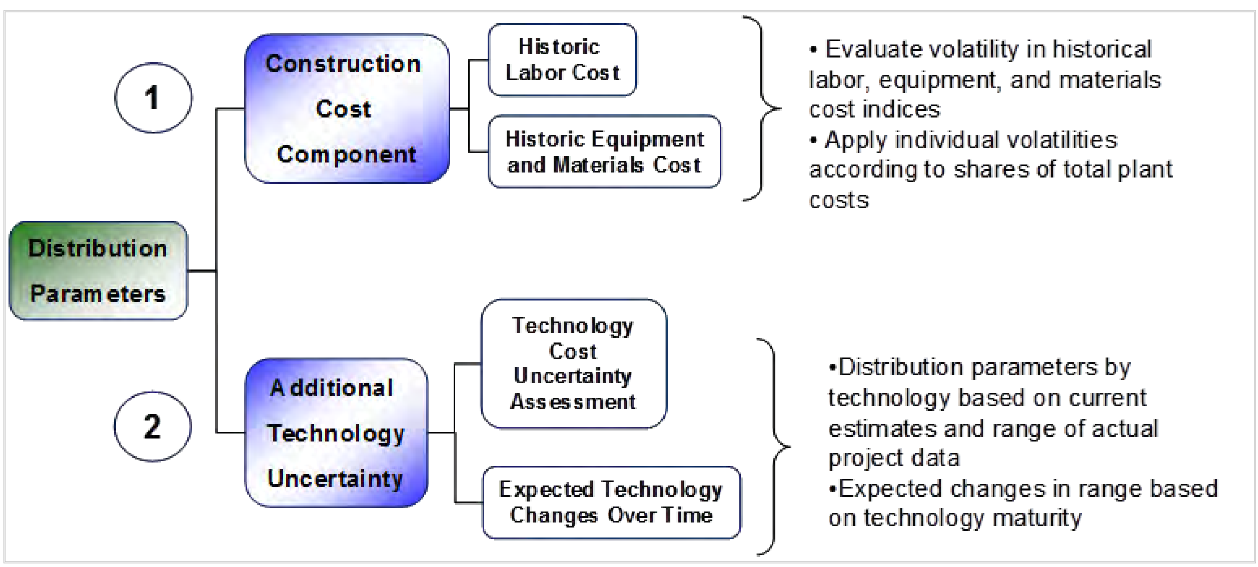
- For each iteration, the dispatch cost of gas and coal was calculated from the fuel stochastics and CO_2 stochastics, along with generic assumptions for VOM.
- If the gas-coal dispatch differential changes significantly enough to affect demand, the gas demand from the previous year was adjusted to reflect the corresponding change in demand.
    - Adjustment can happen in both directions
- A gas price delta was then calculated based on the defined gas demand – price relationship developed.

This gas price delta is added to the gas stochastic path developed from historic volatility to calculate an integrated CO_2 and natural gas stochastic price.

10.5.1.6 Capital Cost Stochastics

Pace developed the uncertainty distributions for the cost of new entry units by technology types, which were used in the Aurora dispatch model for determining the economic new builds based on market signals. The exhibit below describes the methodology at a high level:

Figure 10.22 – Pace Global's Capital Cost Stochastics Process



The methodology of develop the capital cost distributions is a two-step process:

Step 1:

Parametric Distribution:
Pace Global's subject matter experts provided a reference case forecast of $/KW all-in capital costs for different technology types. Along with it, high and low case forecasts were also developed.

The plant costs were broken down into four categories: Equipment, Materials, Labor, and Other. Historical data (from the Handy-Whitman Index) was used to estimate mean price changes and volatilities in these cost categories.

Suitable weights were allocated to each of these four categories. The weighted average of the historical mean and volatilities were then estimated.

Using the mean and volatility values, and sampling from an underlying standard normal distribution (which has a mean zero and variance one), the probability bands were constructed around the base case forecast.

Step 2:

Quantum Distribution:
This step captured the additional uncertainty associated with each technology. It also factored in the learning curve effects, improvements in technology over time, and other uncertain events.

The expert opinion based high and low cases were treated as one standard deviation from the mean. With this assumption, the variance values were calculated.

To determine the probability distributions, a log-normal distribution was assumed. This distribution was combined with the parametric distribution obtained in the previous step, to come up with the final set of distributions.

10.5.2 Rate Metric Ranking

Figure 10.23 – Aurora 20-Year Mean NPV $ Billion

Portfolio	20 Year NPV[57]	% above lowest cost
H: Heavy Gas	$ 3.02	
B: Heavy Gas	$ 3.03	0.0%
G: Gas & Solar	$ 3.06	1.0%
D: Gas & Wind	$ 3.07	1.4%
E: Heavy Gas	$ 3.10	2.5%
K: Diversified w/ Coal	$ 3.12	3.1%
N: Gas & Solar	$ 3.12	3.1%
O: Gas & Solar	$ 3.12	3.3%
L: Diversified w/ Coal	$ 3.15	4.1%
M: Diversified w/ Coal	$ 3.16	4.3%
C: Gas & Solar	$ 3.16	4.6%
F: Gas & Wind	$ 3.17	4.9%
A: Existing Portfolio	$ 3.21	6.3%
I: Stakeholder w/ Renewables	$ 3.86	27.6%
J: Stakeholder w/ Renewables	$ 4.21	39.3%

[57] The NPV of energy procurement is an indicative component of rates

Figure 10.24 – Aurora 20-Year Weighted Energy Procurement Cost[58]

Portfolio	20 Year $/kWh	% above lowest cost
H: Heavy Gas	0.064	
B: Heavy Gas	0.064	0.0%
G: Gas & Solar	0.065	1.0%
D: Gas & Wind	0.065	1.4%
E: Heavy Gas	0.066	2.5%
K: Diversified w/ Coal	0.066	3.1%
N: Gas & Solar	0.066	3.1%
O: Gas & Solar	0.066	3.3%
L: Diversified w/ Coal	0.067	4.1%
M: Diversified w/ Coal	0.067	4.3%
C: Gas & Solar	0.067	4.6%
F: Gas & Wind	0.067	4.9%
A: Existing Portfolio	0.068	6.3%
I: Stakeholder w/ Renewables	0.082	27.6%
J: Stakeholder w/ Renewables	0.089	39.3%

10.6 TRANSMISSION APPENDIX

10.6.1 Transmission and Distribution Planning Criteria

Vectren continually assesses the performance of its electric transmission and distribution systems to ensure safe and reliable service for its customers. The primary goals of Vectren's planning process can be summarized as follows:

a) Developing a transmission system capable of delivering voltage of constant magnitude, duration and frequency at levels which meet Vectren customers' needs during normal conditions and during a system contingency or set of contingencies;

[58] The NPV of energy procurement is an indicative component of rates

b) Minimizing thermal loadings on transmission facilities to be within operating limits during normal conditions and to be within emergency limits during contingency conditions;
c) Analyzing the dynamic stability of the transmission system under various contingency conditions;
d) Ensuring the fault current duty imposed on circuit breakers does not exceed the interrupting capability established by the equipment manufacturer;
e) Optimizing the system configuration such that costs (capital and operating) are minimized while maintaining reliability and providing a plan for system upgrades to meet performance requirements;
f) Coordinating transmission planning activities in broader regional evaluations with the Midcontinent Independent System Operator (MISO), ReliabilityFirst (RF), and neighboring transmission owners;
g) Performing an annual assessment of the electric transmission system over a ten-year planning horizon;
h) Performing analysis of reactive power resources to ensure adequate reserves exist and are available to meet system performance criteria;
i) Analyzing the performance of its distribution system to ensure reliability, adequacy to meet future load growth, and to address age and condition of existing facilities; and
j) Ensuring compliance with Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC) and RF Reliability Standards for transmission planning.

10.6.2 MISO Regional Transmission Planning

The Midcontinent Independent System Operator (MISO) performs the North American Electric Reliability Corporation (NERC) functional role of Planning Coordinator on behalf of Vectren. In its NERC functional role of Transmission Planner, Vectren supports MISO's regional transmission planning processes.

MISO develops regional transmission models that are used for a variety of near-term and long-term planning studies. On an annual basis, MISO builds models to represent a 10-year planning horizon. The modeling process begins in September and concludes the following August. Vectren is responsible for submitting the required modeling data to MISO pursuant to NERC MOD-032.

Vectren participates in MISO coordinated seasonal transmission assessments (CSAs) for spring, summer, fall and winter peak loads. MISO's Seasonal Assessments review projected demand and resources for the MISO footprint and assess adequacies and risks for upcoming seasons. The CSAs consider planned and unplanned generation and transmission outages. Vectren also participates in MISO Generator Interconnection and Transmission Service Requests planning processes as required.

Vectren participates in MISO's regional Transmission Expansion Plan (MTEP). The system expansion plans produced through the MTEP process ensure the reliable operation of the transmission system, support achievement of state and federal energy policy requirements, and enable a competitive electricity market to benefit all customers. The planning process, in conjunction with an inclusive, transparent stakeholder process, identifies and supports development of transmission infrastructure that is sufficiently robust to meet local and regional reliability standards, enables competition among wholesale capacity and energy suppliers in the MISO markets, and allows for competition among transmission developers in the assignment of transmission projects.

MISO approved a 345kV Market Efficiency Project between Vectren's Duff substation and Big Rivers Electric Corporation's Coleman EHV substation during the MTEP 2015 planning cycle. The project is expected to be in-service by the beginning of 2021. Pursuant to FERC Order 1000, MISO solicited competitive bids to construct the 345kV line. Vectren partnered with PSEG in submitting a proposal to MISO to construct the line. Vectren, as the incumbent transmission owner, will be responsible for the Duff substation modifications required for the project. The overall project cost is shared according to MISO's Tariff. The project not only provides regional economic benefits, but also enhances grid reliability in the area of Vectren's Newtonville substation.

10.6.3 Annual Transmission Assessment

Vectren's most recent transmission assessment was completed in 2015. The study used the final NERC Multiregional Modeling Working Group (MMWG) 2014 Series Models, which includes the Vectren full detailed model. The MMWG is responsible for developing a library of solved power flow models and associated dynamics simulation models of the Eastern Interconnection. The models are used by the NERC Regions and their member systems in planning future performance and evaluating current operating conditions of the interconnected bulk electric systems. Siemens PTI PSS/E version 33.6.0 software was used to conduct the assessment.

Vectren's internal planning procedures direct the specific tasks and methods for conducting this study. The internal procedures also define the ratings methodology used for the existing and proposed facilities. All simulations were performed using Steady State Power Flow models using AC analysis. Models were solved using the Fixed Slope Decoupled Newton-Raphson (FDNS) solution method with stepping transformer tap adjustments, switched shunts enabled, area interchange control enabled for tie lines and loads, DC taps disabled, and VAR limits applied automatically. Dynamic simulations were not completed in 2015, as previous dynamic studies were still deemed valid. Dynamic simulations were completed with MTEP-14 and the RF MMWG Seasonal Assessments.

The Vectren Bulk Electrical System (100kV and above) is expected to be stable and perform well over the next 10 years. Normal system conditions do not result in any voltage problems or thermally overloaded facilities. Some facility outage contingencies create thermal overloads and voltage violations. When these violations cannot be effectively mitigated by operational guides, Vectren plans projects to mitigate the violations.

The loss of the two 138kV lines into Toyota substation results in the loss of service to the facility. A new 138kV line from Toyota substation to Scott Township substation is proposed. This line will also provide a second line into Scott Township substation, which is on a radial 138kV line. Scott Township substation provides voltage support for most of the load along the Highway 41 North corridor. This proposed line will also become a parallel path to the Francisco to Elliott 138kV line and increases post-contingent import capability.

Other notable contingencies (N-1-1) include the loss of load in the Mt. Vernon, IN area. The area is served by three 138kV lines. The outage of any two feeds causes voltage issues in the area and potential thermal overloads on the remaining line. The proposed customer-owned Co-Generation facility has the potential to reduce this large customer's load and eliminate this potential issue. Additional capacitor banks and upgrades could mitigate this issue as well. The only mentionable extreme contingency is also for the Mt. Vernon area for the complete loss of the A.B. Brown 138kV substation. This substation loss has the potential to cause voltage loss to the Mt. Vernon area and numerous large industrial customers. NERC requirements do not require that Vectren prevent this event. The standards only require that extreme contingencies not cause cascading outage and impair the Bulk Electric System (BES). The electric transmission system outside of Mt. Vernon is not affected; however, an outage of this magnitude would require a notification to NERC.

Several 69kV lines are proposed as alternate feeds to reduce outage times.

- A new 69kV line to be installed between Mohr Rd and St. Wendell substations (scheduled in-service date of 12/31/2016).
- A new 69kV line to be installed between Boonville and Boonville Pioneer Substation (scheduled in-service date of 12/31/2018).
- Extend an existing 69kV line to provide a third source into the Jasper area from Dubois substation (scheduled in-service date of 12/31/2017).

These are not NERC reliability driven projects, but should reduce outage durations to customers caused by transmission outages in these areas and should improve reliability indices and metrics.

Toyota South, Roesner Road and Adam Street are new distribution substations currently proposed to meet load growth. The Adams Street substation project also facilitates 4kV to 12kV conversion projects.

SECTION 11
TECHNICAL APPENDIX ATTACHMENTS

Attachment 1.1 Non-Technical Summary

Confidential Attachment 1.2 2016 Vectren Technology Assessment Summary Table

Attachment 3.1 Stakeholder Materials

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

Attachment 4.2 2015 Vectren Hourly System Load Data

Attachment 4.3 2016 MISO LOLE Study Report

Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan

Confidential Attachment 5.2 CCGT Site Selection Report

Attachment 5.3 Cost of Energy Efficiency Programs

Confidential Attachment 5.4 CHP Market Potential Study

Attachment 7.1 IRP Portfolio Summary Report

Attachment 7.2 Balance of Loads and Resources

Confidential Attachment 7.3 Portfolio Input-Output Report

Attachment 7.4 Economic Impact Study - Economic Ripple Effects of Diversifying the Power Generation Portfolio