Vectren Corporation
2014 Integrated Resource Plan

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

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IRP Proposed Draft Rule Requirements Cross Reference Table

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
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.	Technical Appendix J and 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 (As Page # or Attachment)
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.	72, 190-191, Technical Appendix sections: A, B, D, E, F, I
	(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.	72
	(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.	92
	(5) A discussion of distributed generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting.	84-85
	(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.	66-89, 186-200
	(7) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.	190
	(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.	51-55
	(9) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	186-192

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
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). (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.	175-183
	(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.	66-67, 186-187
	(B) The utility's effort to develop and improve the methodology and inputs for its:	32, 186
	(i) forecast;	32, 93
	(ii) cost estimates;	32, 99, 190-191
	(iii) treatment of risk and uncertainty; and	32, 190
	(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:	32
	(AA) transmission; and	176-177
	(BB) generation.	32

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
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.	139, Technical Appendix B
	(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 G
	(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.	20-21, Technical Appendix A
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 usage which includes the following:	
	(1) Historical load shapes, including, but not limited to, the following:	90-92, Technical Appendix C
	(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.	28, 69
	(4) Actual and weather normalized energy and demand levels.	90

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-5 Cont.	(5) A discussion of all methods and processes used to normalize for weather.	72-73
	(6) A minimum twenty (20) year period for energy and demand forecasts.	67-71
	(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. (B) Customer classes or rate classes, or both. (C) Firm wholesale power sales.	94-96
	(8) Justification for the selected forecasting methodology.	66-67, 76-77
	(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.	89
	(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.	70-71
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:	189
	(1) The net dependable generating capacity of the system and each generating unit.	189
	(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.	28
	(3) A fuel price forecast by generating unit.	190-191

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
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.	51-58
	(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.	175-183
	(6) A discussion of demand-side programs, including existing company-sponsored and government-sponsored or mandated energy conservation or load 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.	69, 121-131, 152-171
	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:	122-129
	(1) A description of the demand-side program considered.	153-171
	(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.	140
	(3) The customer class or end-use, or both, affected by the program.	153-171
	(4) A participant bill reduction projection and participation incentive to be provided in the program.	153-171

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170IAC 4-7-6 Cont.	(5) A projection of the program cost to be borne by the participant.	153-171
	(6) Estimated energy (kWh) and demand (kW) savings per participant for each program.	153-171
	(7) The estimated program penetration rate and the basis of the estimate.	153-171
	(8) The estimated impact of a program on the utility's load, generating capacity, and transmission and distribution requirements.	153-171
	(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:	109, 112
	(1) Identify and describe the resource considered, including the following:	109
	(A) Size (MW).	109
	(B) Utilized technology and fuel type.	109
	(C) Additional transmission facilities necessitated by the resource.	180-182
	(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.	N/A
	(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.	175-183

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
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.	38-48
170 IAC 4-7-7	**Selection of future resources**	
	(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.	109
	(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.	188
	(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.	137-151
	(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.	138, 153-154
	(d) A utility is required to:	
	(1) specify the components of the benefit and the cost for each of the major tests; and	137-138
	(2) identify the equation used to express the result.	137

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
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.	137-151
	(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.	186-187
	(b) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and provide, at a minimum, the following information:	193-201
	(1) Describe the utility's preferred resource portfolio.	193-194, 201
	(2) Identify the variables, standards of reliability, and other assumptions expected to have the greatest effect on the preferred resource portfolio.	202-211
	(3) Demonstrate that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis.	171-172
	(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.	84-89, 109, 112, 122-132, 171-172
	(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.	179, 137-140

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
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 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.	N/A
	(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.	201-212
	(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 discount rate specified.	Technical Appendix H

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-8 Cont.	(E) An assessment of how robustness factored into the selection of the preferred resource portfolio.	201-212
	(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.	201-212
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: (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.	215-216

List of Acronyms/Abbreviations

AC	Air Conditioning
ACS	American Community Survey
AMI	Advanced Metering Infrastructure
APWR	Advanced Pressurized Water Reactor
ARRA	American Recovery and Reinvestment Act
ASPEN-OneLiner	Advanced Systems for Power Engineering, Incorporated
AUPC	Average Use Per Customer
B	Water Heating Service – Closed to new customers
BAGS	Broadway Avenue Gas Turbines
BPJ	Best Professional Judgment
BPM	MISO's Business Practice Manual
BTU	British Thermal Unit
CAA	Clean Air Act
CAC	Citizens Action Coalition
CAES	Compressed Air Energy Storage
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Days
CEII	Critical Electric Infrastructure Information
CFL	Compact Fluorescent Lighting
CHP	Combined Heat and Power
CIL	Capacity Import Limit
CO_2	Carbon Dioxide
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CVR	Conservation Voltage Reduction
CWA	Clean Water Act
DA	Distribution Automation
DGS	Demand General Service
DLC	Direct Load Control
DOE	United States Department of Energy
DR	Demand Response
DRR-1	Demand Response Resource Type 1
DSM	Demand-side Management
DSMA	Demand Side Management Adjustment
EAP	Energy Assistance Program
ECM	Electronically Commutated Motor
EDR	Emergency Demand Response
EEFC	Energy Efficiency Funding Component
EGU	Electric Generating Units
EIA	Energy Information Administration
EISA	Energy Independence and Security Act
ELGS	Effluent Limit Guidelines and Standards
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
EVA	Energy Ventures Analysis, Inc.
FERC	Federal Energy Regulatory Commission
FF	Fabric Filter
FGD	Flue Gas Desulfurization
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GS	General Service
GWH	Gigawatt Hour
HAP	Hazardous Air Pollutants
HCi	Hydrochloric Acid

List of Acronyms/Abbreviations (continued)

HDD	Heating Degree Days
HHV	Higher Heating Value
HLF	High Load Factor
HRSG	Heat Recovery Steam Generator
HSPF	Heating Seasonal Performance Factor
HVAC	Heating, Ventilation, and Air Conditioning
ICAP	Interconnection Installed Capacity
IDEM	Indiana Department of Environmental Management
IGCC	Integrated Gasification Combined Cycle
IPP	Independent Power Producers
IRP	Integrated Resource Plan
IOU	Investor-Owned Utility
IURC	Indiana Utility Regulatory Commission
kV	Kilovolt
kVA	Kilovolt-Ampere
kWh	Kilowatt Hour
LBA	Load Balancing Area
LCR	Local Clearing Requirement
LMR	Load Management Receivers
LP	Large Power
LRZ	Local Resource Zone
LOLE	Loss of Load Expectation
LSE	Load Serving Entity
MACT	Maximum Achievable Control Technology Standards
MAPE	Mean Absolute Percentage Error
MARS	Multi-Area Reliability Simulation
MATS	mercury and Air Toxics Standards
MECT	Module E Capacity Tracking
MGD	Millions of Gallons per Day
MISO	Midcontinent Independent System Operator
MLA	Municipal Levee Authority
MMBTU	One million British Thermal Unit
MSA	Metropolitan Statistical Area
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt Hour
NAICS	North American Industry Classification System
NDC	Net Dependable Capacity
NERC	North American Electric Reliability Council
NERC MOD	NERC Modeling, Data, and Analysis
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrous Oxide
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NSPS	New Source Performance Standards
O&M	Operation and Maintenance
ORSANCO	Ohio River Valley Sanitation Commission
OSS	Off Season Service
OUCC	Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PJM	Pennsylvania New Jersey Maryland Interconnection LLC
PM	Particulate Matter
PRM	Planning Reserve Margin
PTI-PSS/E	Power Technologies Incorporated's Power System Simulator Program for Engineers
PV	Photovoltaic
PVRR	Present Value of Revenue Requirements
RBS	Residential Behavioral Savings

List of Acronyms/Abbreviations (continued)

RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
RECB	Regional Expansion Criteria and Benefits
RFC	Reliability First Corporation
RIM	Ratepayer Impact Measure
RPS	Renewable Portfolio Standard
RS	Residential Service
SAE	Statistically Adjusted End-use
SCADA	Supervisory Control and Data Acquisition
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SEER	Seasonal Energy Efficiency Ratio
SGS	Small General Service
SGT	Steam Turbine Generator
SIP	System Integration Plan
SMR	Small Modular Reactors
SO_2	Sulfur Dioxide
TPA	Third Party Administrator
TRC	Total Resource Cost
TVA	Tennessee Valley Authority
UCAP	Unforced Capacity Rating
VUHI	Vectren Utility Holdings Inc.
ZRC	Zone Resource Credit

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CHAPTER 1
EXECUTIVE SUMMARY

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 142,000 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.

Vectren's company-owned generation fleet represents 1,158 megawatts (MW)[1] of unforced capacity (UCAP) as shown in Table 1-1.

Table 1-1 Generating Units

Unit	UCAP (MW)	Primary fuel	Commercial Date
Northeast 1	9 MW	Gas	1963
Northeast 2	9 MW	Gas	1964
FB Culley 2	83 MW	Coal	1966
Warrick 4	135 MW	Coal	1970
FB Culley 3	257 MW	Coal	1973
AB Brown 1	228 MW	Coal	1979
BAGS 2	59 MW	Gas	1981
AB Brown 2	233 MW	Coal	1986
AB Brown 3	73 MW	Gas	1991
AB Brown 4	69 MW	Gas	2002
Blackfoot	3 MW	Landfill Gas	2009

[1] Blackfoot landfill gas project is considered behind-the-meter and is therefore currently accounted for as a reduction to load and is omitted from the capacity total

In addition to company owned generating resources, Vectren has access to an additional 30 MW of capacity as a result of its 1.5% ownership interest in Ohio Valley Electric Corporation (OVEC). Vectren is also contracted to receive 80 MW of nominal capacity wind energy through two separate long-term purchase power agreements. The total firm capacity credit for the MISO 2014-2015 planning year for these wind resources is 7.3 MW. Vectren is interconnected with other utilities at both 345 kV and 138 kV and is able to exchange capacity and energy through the market mechanisms of the Midcontinent Independent System Operator (MISO).

THE IRP PROCESS

The Integrated Resource Plan (IRP) process was developed to assure a systematic and comprehensive planning process that produces a reliable, efficient approach to securing future resources to meet the energy needs of the utility and its customers. The IRP process encompasses an assessment of a range of feasible supply-side and demand-side alternatives to establish a diverse portfolio of options to effectively meet future generation needs.

In Indiana, the IRP is also guided by rules of the Indiana Utility Regulatory Commission (IURC). Those rules, found in the Indiana Administrative Code at 170 I.A.C. 4-7-4 through 4-7-9, provide specific guidelines for plan contents and filing with the Commission. On October 14, 2010, the IURC issued an order to commence rulemaking to revise/update the current Indiana IRP rule. The following summer, Vectren participated in a stakeholder process to provide input on updating the rule. The proposed draft rule was sent to stakeholders on October 4, 2012. Although not finalized, Vectren voluntarily followed the proposed draft rule, which is found in the IRP Proposed Draft Rule Requirements Cross Reference Table of this IRP.

Vectren modified its processes to meet the proposed draft rule. Most notably, Vectren incorporated a stakeholder process to gather input from stakeholders and answer stakeholder questions in an open, transparent process. The proposed rule requires at least 2 meetings with stakeholders. On March 20, 2014, Vectren met with stakeholders to discuss the base inputs of the plan, educate stakeholders on IRP related topics, and review the Vectren process. Based on feedback from stakeholders, Vectren added an additional meeting on August 5, 2014 to further discuss major assumptions and data inputs prior to modeling. Finally, on September 24, 2014 Vectren presented a preview of the plan. A summary of the stakeholder meetings can be found in Chapter 2 Planning Process, and the meeting presentations and Q&A summaries are found in the Technical Appendix, section A.

Details of the process used by Vectren to develop the recommended plan in this IRP are found in chapters 2 through 11 of this report. Chapter 11 Action Plan sets forth the action plan for Vectren over the next three years to achieve the long-term resource objectives described in this IRP.

Included in the process is an updated demand and energy forecast (detailed in Chapter 5 Sales and Demand Forecast). Table 1–2, shows a summary of the demand and energy forecast.

VECTREN'S QUANTITATIVE AND QUALITATIVE IRP PROCESS

Historically, Vectren has used modeling to perform the evaluations, screenings, and assessments of various potential scenarios to arrive at a single plan that represented its "Resource Plan Additions." Vectren continues to use the Strategist modeling software from 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. The submitted plan was the result of a process that was primarily a quantitative evaluation performed using an industry standard planning model.

The modeling performed by Vectren provides important information to evaluate future resource needs. However, Vectren will also continue to monitor developments that could impact future resource needs. Three developments that Vectren is focusing on for impacts on the near term are:

1. The Clean Power Plan from the Environmental Protection Agency (EPA) and Indiana's approach to implementing this rule.
2. MISO capacity market constraints resulting from the early retirements of coal units as a response to the EPAs MATS rule.
3. The impacts on Vectren's load due to the addition of or loss of large customer load.

While Vectren's models attempt to evaluate the impact those issues may have on its future load, significant uncertainty remains. Vectren must maintain flexibility to adjust its plans based on the outcome of these and other unknown factors. In the case of Vectren, one of the smallest investor-owned electric utilities in the nation, the ramifications of major capacity decisions are particularly important.

Equally important, Vectren believes one of the major objectives of the Commission's reporting and filing requirements regarding the IRP process is to communicate with the IURC regarding the decision processes, evaluations, and judgments that Vectren uses to assist in making the resource planning decisions that are in the long-term best interest of Vectren's customers and the communities it serves. Vectren understands that the action plan which results from the IRP process is to be used as a guide by the Company and the IURC in addressing long-term resource needs, as both attempt to carry out their respective responsibilities in the most effective manner possible.

CHANGES SINCE LAST IRP

While a number of changes have occurred since Vectren's last IRP, four specific changes have had a significant impact on this IRP. First, the IURC's proposed draft IRP rules were released after Vectren's last IRP. Vectren is voluntarily following the new proposed draft IRP rule, which includes a stakeholder process, non-technical summary, more robust risk analysis, and attending an annual contemporary issues meeting in Indianapolis. The IRP Proposed Draft Rule Requirements Cross Reference Table on page three shows the new proposed draft rule and where Vectren addresses each part in this IRP.

Second, Vectren engaged a third party consultant with significant experience conducting IRPs for other parties, Burns & McDonnell, one of the leading engineering design experts in the United States, to aid its preparation of this IRP. For the 2014 IRP, Vectren worked closely with Burns and McDonnell to perform Strategist modeling (including additional DSM modeling). Burns and McDonnell has a great deal of experience in working with companies across the country on resource modeling. They also performed the Technology Assessment, detailing costs for potential resource options. The Technology Assessment can be found in the Technical Appendix, section B.

Third, the EPA has finalized various federal mandates with respect to further environmental regulation of Vectren's generating units and proposed a sweeping greenhouse gas regulation for existing coal-fired generating sources since Vectren's last IRP. As will be discussed in more detail in Chapter 4 Environmental, the EPA finalized its Mercury and Air Toxics Standard (MATS) in 2012, which set first ever plant-wide emission limits for mercury and other hazardous air pollutants and has a compliance deadline of April 2015. MATS has resulted in many announcements of coal plant retirements across the US. As a result, MISO, Vectren's Regional Transmission Operator (RTO), is predicting potential capacity shortfalls in the next few years. In the next two years Vectren intends to spend \$70- \$90 million on its environmental compliance program to meet not only the MATS rule, but also recent water discharge limits for mercury contained in water discharge permit renewals and mitigate incremental sulfur trioxide (SO_3) emissions resulting from the installation of Vectren's selective catalytic reduction technology under an agreement with the EPA. However, Vectren is projecting to defer recovery of these federally mandated costs until approximately 2020. The assumptions in the IRP are consistent with Vectren's environmental compliance filing.

In addition to the federal mandates referenced above, the EPA released its final rule regulating cooling water structures under Section 316(b) of the Clean Water Act (CWA) on August 15, 2014. Section 316(b) requires that intake structures that withdraw > 2 Million Gallons per Day (MGD) of water, including most electric generating units, use the "Best Technology Available" to prevent and / or mitigate adverse environmental impacts to shellfish, fish, and wildlife in a water body. This rule applies only to the FB Culley plant, as the AB Brown plant already utilizes cooling water towers.

Finally, on June 2, 2014, the EPA issued the Clean Air Act Section 111(d) Greenhouse Gas (GHG) New Source Performance Standards (NSPS) for existing sources, known as the Clean Power Plan (CPP). The CPP sets state-specific carbon reduction goals based on a state's existing generation mix based upon a building block approach and provides guidelines for the development, submission and implementation of state plans to achieve the state goals. As yet, there is little clarity on how the state of Indiana will choose to implement this rule. However, this IRP considers several of the potential building blocks in its assumptions: Demand Side Management (DSM), a potential renewables portfolio standard, and a price for carbon price beginning in 2020.

Fourth, the Indiana General Assembly passed legislation in March of 2014 that modified DSM requirements in Indiana. Senate Enrolled Act No. 340 ("SEA 340") removed requirements for mandatory statewide "Core" DSM programs and energy savings goals effective December 31, 2014. SEA 340 also allows large Commercial and Industrial (C&I) customers who meet certain criteria to opt-out of participating in utility sponsored DSM programs.

Vectren continues to support DSM related energy efficiency efforts as a fundamental part of the services that are provided to customers in order to help them manage their energy bills. Vectren believes that a cost effective level of DSM energy efficiency may be supported by policy considerations beyond the IRP's focus on planning for future resources. Consistent with this belief, Vectren's base sales forecast includes a base level of DSM at a targeted level of 1% eligible annual savings for 2015 – 2019 and 0.5% annually thereafter for customer load that has not opted-out of DSM programs.

Vectren also modeled whether incremental DSM energy efficiency programs would be selected as a resource when competing with supply side options, to meet future electric requirements. Vectren's approach attempts to balance its commitment to a level of cost-effective DSM to help customers manage their energy bills, while evaluating additional DSM resources consistent with least cost planning.

Note that since the last IRP was performed, Broadway Unit 1 (BAGS 1) has quit performing up to specifications. The unit has been on a long-term outage. Therefore, Vectren currently does not get credit for the unforced capacity (UCAP) amount, and it was not included in the analysis as shown in Table 1-1. BAGS 1 is a natural gas peaking unit, and in the past was typically good for approximately 40 MW on a UCAP basis.

PLAN RESULTS / RECOMMENDATIONS

The IRP indicates that Vectren does not need any incremental generation resources or purchase power agreements during the planning horizon. Although the IRP does not project incremental resource needs, Vectren proposes to continue offering DSM programs to help customers use less energy, thus lowering their total bill. The IRP forecasts that there may be some marginal economic benefit to retiring FB Culley 2 in 2020 under certain scenarios. This retirement evaluation is influenced by Vectren's load forecast, carbon costs, and fuel costs. Vectren will continue to evaluate the impact of these components on Culley Unit 2 in successive IRPs to evaluate the optimal time to retire Culley Unit 2.

As mentioned above and discussed in further detail in this IRP, the decision to retire FB Culley 2 will not be made until major near term uncertainties become more clear, most notably how the state of Indiana will implement the EPA's Clean Power Plan (if the plan survives legal challenges). Additionally, Vectren is actively working to attract new industrial customers through economic development activities in southwestern Indiana. If a large customer chooses to locate within the Vectren electric service area, Culley 2 will be required to operate at least in the short term to provide the resources necessary to serve such a customer. Leaving Culley Unit 2 in operation at this time provides Vectren maximum flexibility to adapt to such future developments. Economic modeling does not necessarily account for all such developments that are very possible, and therefore, judgment must also be part of the analysis. Table 1-2 shows the peak and energy forecast. Table 1-3 shows that no capacity additions are currently deemed necessary.

Vectren's base case scenario assumptions are detailed in Chapter 10 Generation Planning. In summary, Vectren assumed a minimum planning margin of 7.3%[1] for each year of the study. Energy savings goals of 1% of eligible customer load were incorporated into the load forecast through 2019. Additionally, incremental energy savings of .5% per year were assumed beginning in 2020 and were carried throughout the rest of the planning period. All assumptions are discussed in depth throughout this IRP.

Sensitivity risk analyses were performed around coal, gas, energy, and carbon pricing, capital costs, and high environmental regulation cost. These results are shown in Chapter 10 Generation Planning.

CONCLUSION

Vectren recognizes that the electric utility industry is experiencing a fast-changing time in terms of potential regulations, environmental mandates, and technology advances. Given the significant impact of any resource decision on both customers and other stakeholders, Vectren will continue to actively monitor developments in the regulatory,

[1] MISO unforced capacity (UCAP) requirement, further discussed in Chapter 3 MISO

environmental, and technology arenas for both their impact on future generation needs and existing facilities. Open communication with the IURC and other parties including the OUCC will be key to Vectren's ability to make the best decisions for all stakeholders.

Table 1-2 Peak and Energy Forecast

Year	Peak (MW)[1]	Annual Energy (GWh)
2014 Proj.	1,145	5,782
2015	1,155	5,914
2016	1,156	5,936
2017	1,113	5,514
2018	1,109	5,503
2019	1,106	5,494
2020	1,106	5,497
2021	1,106	5,492
2022	1,107	5,494
2023	1,107	5,494
2024	1,107	5,496
2025	1,106	5,487
2026	1,106	5,487
2027	1,107	5,492
2028	1,109	5,507
2029	1,110	5,509
2030	1,111	5,517
2031	1,111	5,523
2032	1,113	5,540
2033	1,114	5,548
2034	1,115	5,560
Compound Annual Growth Rate, 2014-2034	-0.1%	-0.2%

[1] Includes wholesale contract sales for 2014

Table 1-3 Base Case Resource Plan

Year	Firm Peak Demand[1] (MW)	UCAP Company Owned Generation (MW)	DLC (MW)	Interruptible (MW)	UCAP Committed Purchases (MW)	Capacity Additions (MW)	Total Resources (MW)	Reserve Margin (%)[2]
2015	1,155	1,155	17	50	38		1,260	9.1%
2016	1,156	1,155	17	50	38		1,260	9.0%
2017	1,113	1,155	18	27	38		1,238	11.2%
2018	1,109	1,155	18	27	38		1,238	11.6%
2019	1,106	1,155	17	28	38		1,238	11.9%
2020	1,106	1,155	17	28	38		1,238	11.9%
2021	1,106	1,155	17	28	38		1,238	11.9%
2022	1,107	1,155	17	28	38		1,238	11.8%
2023	1,107	1,155	17	28	38		1,238	11.8%
2024	1,107	1,155	17	28	38		1,238	11.8%
2025	1,106	1,155	17	28	38		1,238	11.9%
2026	1,106	1,155	17	28	38		1,238	11.9%
2027	1,107	1,155	17	28	38		1,238	11.8%
2028	1,109	1,155	17	28	38		1,238	11.6%
2029	1,110	1,155	17	28	38		1,238	11.5%
2030	1,111	1,155	17	28	38		1,238	11.4%
2031	1,111	1,155	17	28	38		1,238	11.4%
2032	1,113	1,155	17	28	38		1,238	11.2%
2033	1,114	1,155	17	28	38		1,238	11.1%
2034	1,115	1,155	17	28	38		1,238	11.0%

[1] Vectren is not forecasting firm wholesale contracts throughout this forecast.
[2] MISO requires a 7.3% Planning Reserve

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CHAPTER 2

PLANNING PROCESS

INTRODUCTION

Vectren's IRP objectives are based on the need for a resource strategy that provides value to its customers, communities, and shareholders. In addition, this strategy must accommodate the ongoing changes and uncertainties in the competitive and regulated markets. Specifically, Vectren's IRP objectives are as follows:

- Provide all customers with a reliable supply of energy at the least cost reasonably possible
- Develop a plan with the flexibility to rapidly adapt to changes in the market while minimizing risks
- Provide high-quality, customer-oriented services which enhance customer value
- Minimize impacts of Vectren's past and current operations on local environments

PLANNING PROCESS

The planning process is driven by the characteristics of Vectren's markets and the needs of its customers. These elements serve to define the utility's objectives and help establish a long-term forecast of energy and demand.

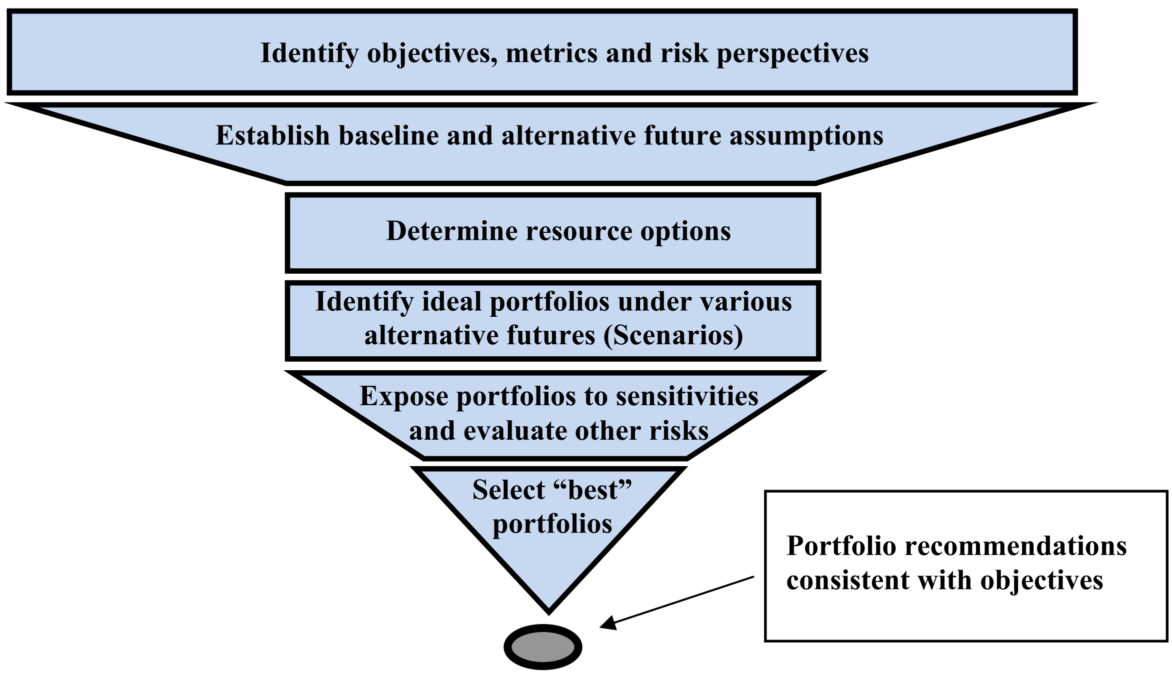
Using the forecast as a baseline, the IRP process entails evaluation of both supply-side and demand-side options designed to address the forecast. These options serve as input into a formal integration process that determines the benefits and costs of various combinations of supply-side and demand-side resources. Because the IRP modeling process requires significant amounts of data and assumptions from a variety of sources, a process is needed to develop appropriate inputs to the models.

The process criteria for inputs include:

- Maintain consistency in developing key assumptions across all IRP components
- Incorporate realistic estimates based on up-to-date documentation with appropriate vendors and available market information, as well as internal departments

- Consideration of impacts and experiences gained in prior IRP processes and demand-side program efforts

Vectren follows an integrated resource plan process that is very similar to other utilities throughout the country. In order to stay current with IRP methodologies and techniques, Vectren works with consultants, attends integrated resource planning conferences, and attends the annual contemporary issues meeting (hosted by the IURC). The diagram below illustrates the general process.



Vectren's objective is to serve customers as reliably and economically as possible, while weighing future risks and uncertainties. Vectren begins the process by forecasting customers' electric demand for 20 years. The electric demand forecast considers historical electric demand, economics, weather, appliance efficiency trends (driven by Federal codes and standards), population growth, adoption of customer owned generation (such as solar panels), and Vectren DSM energy efficiency programs (such as appliance rebates). A base, low, and two high peak load forecasts were developed.

The next step in the process is to determine possible alternative futures (scenarios) and determine how to reliably and economically meet customers' future electric demand. Vectren has adequate resource options (power plants, on-going energy efficiency and demand response options) to meet customers' need. The base scenario assumes customer need will be met with existing resources. The second scenario examines the potential impact of retiring FB Culley 2, Vectren's oldest, smallest (83 MW), and most inefficient coal generating unit. Additionally, it is not controlled for NO_x. The final scenario included a possible future where the government enacts a Renewable Portfolio Standard (RPS), requiring 20% of electricity to be produced with renewable resources, such as wind, solar, customer-owned renewable distributed generation, and utility sponsored DSM energy efficiency programs.

Each electric demand forecast is exposed to the base and two alternate futures to determine the most economical way to meet customer needs, resulting in 12 possible plans. The diagram below illustrates each alternative.

		A	B	C
		Base	FB Culley 2 Unit Retirement	RPS
1	Base Demand Forecast	Plan A1	Plan B1	Plan C1
2	Low Demand Forecast	Plan A2	Plan B2	Plan C2
3	High (modeled) Demand Forecast	Plan A3	Plan B3	Plan C3
4	High (large load) Forecast[1]	Plan A4	Plan B4	Plan C4

[1] The base demand forecast with a 100 MW firm load addition in 2018

Each plan represents the lowest-cost option to meet customer demand. Several resource options were considered in the analysis to meet customer demand, including various (types and sizes) natural gas powered generation options, additional energy efficiency programs beyond what is already included in the electric demand forecasts, renewables (wind and solar generation), and short-term market capacity purchases.

All model inputs and assumptions are loaded into a modeling tool called Strategist, which is used by many utilities throughout the country. The modeling tool optimizes for the lowest-cost plan to meet customer demand, plus a 7.3% UCAP planning reserve margin.

Each plan was then subjected to additional risk sensitivities to determine which plan is the lowest cost over a wide range of possible future risks. As previously mentioned, resource modeling requires a large number on inputs and assumptions: forecasts for natural gas prices, coal prices, market energy prices, CO_2 prices, costs of resource options, and potential costs for regulations. If the costs of any of these risk factors vary significantly from the base forecasts, the results of the analysis could potentially be different. Each plan (A1-C4) was subjected to varying costs (most often +/- 20%) for the risk factors mentioned above to determine the impact to each plan from the possible future sensitivities.

The remainder of this IRP is organized as follows:

MISO
Chapter 3 - Discusses Vectren's participation in MISO and the implications for resource planning

Environmental
Chapter 4 - Discusses current and pending environmental issues and regulations and the potential considerations for resource decisions

Forecast
Chapter 5 - Contains the electric sales and demand forecast

Supply-Side
Chapter 6 - Describes the electric supply analysis including a review and screening of the various electric supply options
Chapter 7 - Describes the viability and application of renewable and clean energy technologies and renewable energy credits (RECs)
Chapter 9 - Contains a discussion of Vectren's transmission and distribution expansion plan forecast

Demand-Side
Chapter 8 - Presents a discussion of DSM resources including screening results and program concept development

Integration
Chapter 10 - Details the formal integration process which includes conducting sensitivity analyses and obtaining the final resource plan

Short term Action Plan
Chapter 11 - Contains action plans designed to implement the resource plan over the next three years

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CHAPTER 3

MISO

INTRODUCTION

Vectren was an original signer of the Transmission Owners Agreement, which organized the Midwest Independent Transmission System Operator, now known as the Midcontinent Independent System Operator (MISO) and under which authority the MISO administers its Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff). As a vertically integrated utility 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 planning and operation of resources to meet the needs of loads in the future and 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).

MISO OVERVIEW

MISO, headquartered in Carmel, Indiana, with additional offices in Egan, 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 generation capacity was 175,436 MW as of May 1, 2014. This market operates in 15 states and one Canadian province.

Key Dates

- February 1, 2002 - Transmission service began under MISO Open-Access Transmission Tariff with Vectren as a full Transmission Owning Member
- April 1, 2005 - Midwest markets launch
- April 16, 2008 - NERC certified MISO as Balancing Authority
- January 6, 2009 - Ancillary Services Markets began and MISO became the region's Balancing Authority
- December 19, 2013 – Added South Region

Vectren in Relation to MISO Footprint

With a native peak load of about 1,150 MW, Vectren is approximately 1.4% of the MISO market footprint and is one of 36 local balancing authorities. In addition, the Vectren transmission system supports multiple municipals and a large industrial smelter. The total control area or Local Balancing Area (LBA) is approximately 1,900 MW.

Figure 3-1 below is a drawing of the entire MISO market footprint, and Figure 3-2 shows the MISO Reliability Coordination Area.

Figure 3-1 MISO Market Area

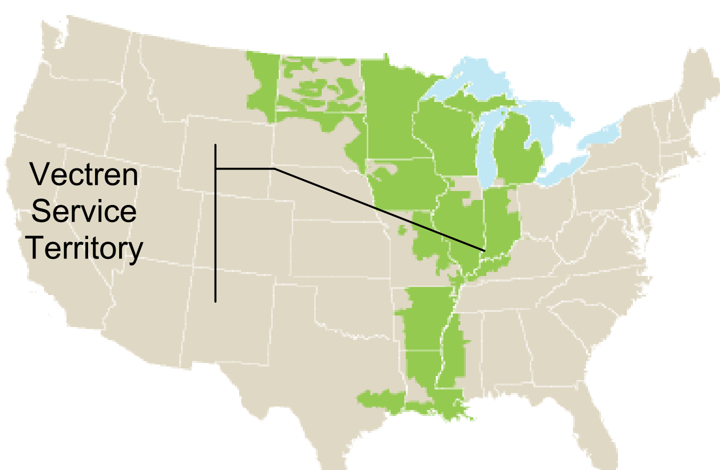
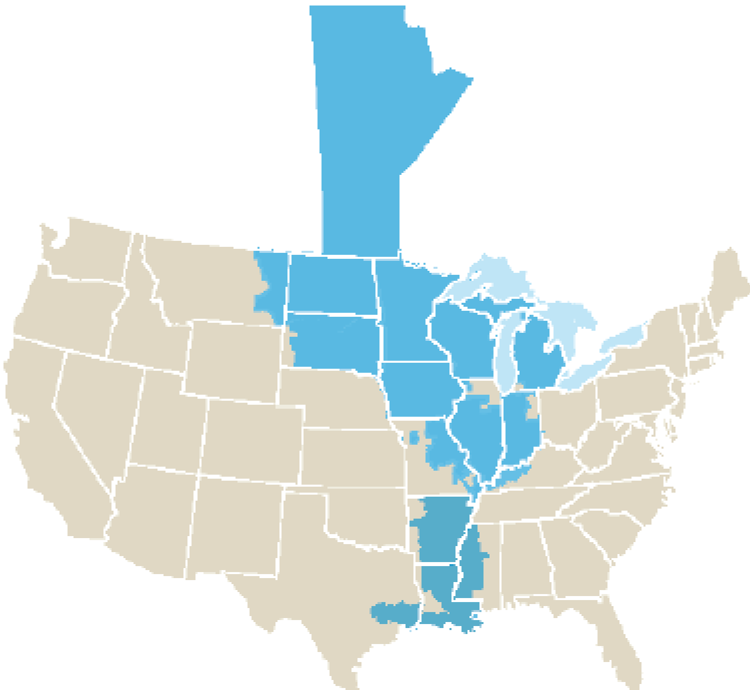


Figure 3-2 MISO Reliability Coordination Area



MISO's GOALS

The goal of MISO's regional transmission planning process is the development of a comprehensive expansion plan that meets both reliability and economic expansion needs. This process identifies solutions for reliability issues that arise from the expected dispatch of network resources. These solutions include evaluating alternative costs between capital expenditures for transmission expansion projects and increased operating expenses from redispatching network resources or other operational actions.

The MISO Board of Directors has adopted six planning principles to guide the MISO regional plan:

1. Make the benefits of an economically efficient energy market available to customers by identifying transmission projects which provide access to electricity at the lowest total electric system costs.
2. Provide a transmission infrastructure that upholds all applicable NERC and Transmission Owner planning criteria and safeguards local and regional reliability through identification of transmission projects to meet those needs.
3. Support state and federal energy policy requirements by planning for access to a changing resource mix.

4. Provide an appropriate cost allocation mechanism that ensures the costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects.
5. Analyze system scenarios and make the results available to state and federal energy policymakers and other stakeholders to provide context and to inform choices they face.
6. Coordinate transmission planning with neighboring planning regions to seek more efficient and cost-effective solutions.[1]

MISO is designated as Vectren's Planning Authority, under the NERC reliability standards, and in FERC Order 1000, MISO has additional regional planning responsibilities.

MISO PLANNING PROCESS

MISO Transmission Planning Process

MISO's transmission planning process begins with the models for the current planning cycle and includes opportunities for stakeholder input on the integration of transmission service requests, generator interconnection requests, and other studies to contribute to the development of an annual MISO Transmission Expansion Plan (MTEP) report.

The 2013 MTEP recommended $1.48 billion in 317 new projects across the MISO footprint through the year 2023. MISO MTEP process has recommended $17.9 billion total investment since its 2003 inception through the first 10 years.

[1] These Guiding Principles were initially adopted by the Board of Directors, pursuant to the recommendation of the System Planning Committee, on August 18, 2005, and reaffirmed by the System Planning Committee in February 2007, August 2009, May 2011, and March 2013.

MISO's role in meeting Vectren's requirements as a member of ReliabilityFirst for a Planning Reserve Margin

As a result of the Energy Policy Act of 2005, regional entities were delegated authority by FERC to establish standards to provide for reliable operation of the bulk-power system. Vectren is a member of regional entity ReliabilityFirst, and so must comply with regional entity Reliability First standards, including the Planning Resource Adequacy Analysis and the Assessment and Documentation Standard BAL-502-RFC-02. This assessment and documentation standard requires planning coordinators to perform annual resource adequacy analyses. This includes calculating a planning reserve margin (PRM) that will result in the sum of the probabilities for loss of load for the integrated peak hour for all days of each planning year equal to a one day in 10 year criterion. This PRM requirement also includes documenting the projected load, resource capability, and PRM for the years under study, and other particular criteria.

The first planning year the Reliability First Planning Reserve Standard was in effect (June 2008-May 2009), Vectren complied with the ReliabilityFirst Planning Resource Adequacy standard by participating in the Midwest Planning Reserve Sharing Group. The calculated required PRM for Vectren was 14.3% on an installed capacity basis. For planning year June 2009-May 2010 and beyond, Vectren and all other MISO utilities have delegated their tasks assigned to the Load Serving Entities (LSEs) under BAL-502-RFC-02 to MISO. The specific section of the MISO Tariff that addresses planning reserves is Module E-1 Resource Adequacy. Vectren is complying with the ReliabilityFirst Planning Resource Adequacy standard by meeting the MISO Module E individual LSE required PRM. This PRM (UCAP) is 7.3% for planning year June 2014 - May 2015.

MISO's Module E-1

As previously mentioned, Module E-1- Resource Adequacy is the portion of the MISO Tariff which requires MISO to determine the Planning Reserve Margin Requirement, on an unforced capacity (UCAP) basis, that would result in 1 day in 10 Loss of Load Event reliability standard. Module E-1 and its associated business practice manual lays out the mandatory requirements to ensure access to deliverable, reliable and adequate planning resources to meet peak demand requirements on the transmission system. To perform these calculations, MISO requires entities to utilize their Module E Capacity Tracking Tool (MECT) to submit a forecast of demand and list their qualified resources. This same tool is then leveraged to accept offers into MISO's annual Planning Resource Auction (PRA).

Loss of Load Expectation and Determination of Planning Reserve Margins

MISO used a Loss of Load Expectation[1] (LOLE) of 1 day in 10 years as the probabilistic method to determine expected number of days per year for which available generating capacity is insufficient to serve the daily peak demand (load). This LOLE, along with other LSE-specific data, is used to perform a technical analysis on an annual basis to establish the PRM UCAP for each LSE. The PRM analysis considers other factors such as generator forced outage rates of capacity resources, generator planned outages, expected performance of load modifying resources, forecasting uncertainty, and system operating reserve requirements.

For this year, an unforced capacity planning reserve margin of 7.3% applied to the MISO system Coincident Peak Demand has been established for the planning year of June 2014 through May 2015. This value was determined by MISO through the use of the GE Multi-Area Reliability Simulation (MARS) software for Loss of Load analysis.

Effect of Load Diversity

Within Module E-1, individual LSEs maintain reserves based on their Coincident Peak Demand, which is the LSE's demand at the time of the MISO peak. MISO no longer calculates a Load Diversity Factor for LSE's, as this would be different for each LSE. However, each LSE peaks at a different time, and for reference, an LSE can determine

[1] Included in the Technical Appendix, section I

what the PRM UCAP would be when accounting for load diversity by multiplying the PRM UCAP times the ratio of LSE Coincident Peak Demand divided by LSE peak Demand.

Forecast LSE Requirements

LSEs must demonstrate that sufficient planning resources are allocated to meet the LSE Coincident Peak Demand multiplied by one plus the PRM and one plus transmission losses. The submission of this forecast follows MISO's prescribed processes.

LSEs must report their peak demand forecasts for each month of the next two planning years and for each summer period (May-October) and winter period (November-April) for an additional eight (8) planning years for the NERC MOD standards.

Forecasted demand in MISO reflects the expected "50/50" LSE Coincident Peak Demand and includes the effect of all distribution and transmission losses. This means there is a 50% chance that actual demand will be higher and a 50% chance that actual demand will be lower than the forecasted level.

LSEs must also report their Net Energy for Forecasted Demand for the same time periods: monthly for the next two planning years and for each summer period (May-October) and winter period (November-April) for an additional eight (8) planning years for the NERC MOD standards.

LSEs register demand side management into the MECT tool separate from their demand forecasts. These resources are explicitly modeled on the supply side in determination of the PRM.

Resource Plan Requirements

LSEs are obligated to provide MISO with resource plans demonstrating that Zonal Resource Credits (ZRC) will be available to meet their resource adequacy requirements. Generally, the Planning Reserve Margin Requirement (PRMR) is the forecast LSE Peak Demand multiplied by one plus MISO PRM UCAP and one plus transmission losses, unless the state utility commission establishes a PRM that is different from MISO's. Additionally LSEs must meet a Local Clearing Requirement (LCR) for the Local Resource Zone (LRZ) for which the LSE resides, Vectren is in LRZ six. The LCR is equal to the Local Reliability Requirement (LRR) less the Capacity Import Limit (CIL) into that zone. The LRR is established so that the LRZ can also meet the 1 day in 10 LOLE reliability standard by clearing the necessary resources within the LRZ.

If a state utility commission establishes a minimum PRM for the LSEs under their jurisdiction, that state-set PRM will be adopted by MISO for affected LSEs in such state. If a state utility commission establishes a PRM that is higher than the MISO established PRM, the affected LSE's must meet the state-set PRM.[1] Indiana does not have a stated minimum planning reserve margin; therefore, Vectren must meet the PRM of MISO.

Qualification of Resources, Including Unforced Capacity Ratings (UCAP), Conversion of UCAP MW to Zonal Resource Credits

To comply with MISO Resource Adequacy provisions, LSEs must submit data for their eligible resources for MISO to determine the total installed capacity that the resource can reliably provide, called Unforced Capacity Rating (UCAP).

[1] From MISO BPM-011-r13 Resource Adequacy Section 3.5.5 State Authority to set PRM

MISO will calculate unforced capacity for all generation resources interconnected to the MISO Transmission System while respecting the interconnection study results and the results of the aggregate deliverability analysis.

The first step is to compare a Generation Resource Net Dependable Capacity (NDC) to the tested capacity from the interconnection process to determine the total installed capacity that the generation resource can reliably provide, which is the Total Interconnection Installed Capacity (ICAP). A unit's NDC for the Planning Year is determined by averaging the NDC data that is entered into MISO's Generating Availability Data System (GADS) database. The UCAP rating represents the MW's that are eligible to be converted into ZRCs.

Evaluation and Reporting

MISO will maintain databases and will "..provide to states, upon request, with relevant resource adequacy information as available…" per section 69 of the MISO Tariff during relevant time periods, subject to the data confidentiality provisions in section 38.9 of the MISO Tariff.

Vectren's approach to the Voluntary Capacity Auction

Due to the long lead time generally required to build capacity resources, Vectren does not consider MISO's annual Planning Resource Auction an appropriate means to meet the needs of the 20 year Integrated Resource Plan and continues to pursue more traditional means of ensuring adequate resources.

Future of MISO's Module E

<u>MISO proposed Capacity Market</u>

MISO is currently evaluating whether the annual summer based resource adequacy construct contains gaps that prevent it from achieving resource adequacy during all periods of the year. MISO is working to identify seasonal or other changes that will close any identified gaps.

Footprint Changes

On Dec. 19, 2013 MISO began coordinating all RTO activities in the newly combined footprint consisting of all or parts of 15 states with the integration of the MISO south entities which include the LBAs of Entergy Arkansas, Inc., Entergy Texas, Inc., Entergy Mississippi, Inc., Entergy Louisiana, LLC, Entergy Gulf States Louisiana, L.L.C., Entergy New Orleans, Inc., Cleco Power LLC, Lafayette Utilities System, Louisiana Energy & Power Authority, South Mississippi Electric Power Authority and Louisiana Generating, LLC.

DEMAND RESPONSE

Demand response is an integral part of a utility's system, operations, and planning, and helps Vectren meet the obligation to serve all customers. Effective July 1, 2011 and pursuant to Commission order in Cause 34566 MISO 4, Vectren filed Rider DR, which provides qualifying customers the optional opportunity to reduce their electric costs by participating in the MISO wholesale energy market. This rider helps the Company's efforts to preserve reliable electric service through customer provision of a load reduction during MISO high price periods and declared emergency events. This initial Rider DR offers two programs, Emergency Demand Response (EDR) and Demand Response Resource Type 1 ("DRR-1") energy programs.

MISO FORECAST

Based on analysis of load forecasts and planned resources derived from survey responses provided by the load serving entities in its footprint, MISO has created several iterations of resource adequacy forecasts that indicate beginning in 2016, several zones within the footprint may lack the capacity required to meet reserve requirements. MISO continues to assess the accuracy of this analysis and appears to concede that state regulatory commissions remain confident that adequate reserves exist in the near term. However, such studies do highlight the potential reliability issues created by the EPA emissions restrictions, and in particular, the potential for numerous base load coal plant retirements driven by the EPA's Clean Power Plan. Questions regarding available capacity, as well as local reliability concerns will be factored into the Company's planning processes.

Vectren's Approach to Resource Adequacy

Vectren will continue to comply with MISO's Module E requirements, which includes the possibility for varying amounts of planning reserves.

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Chapter 4

ENVIRONMENTAL

INTRODUCTION

Compliance planning associated with existing and anticipated environmental laws and regulations in each of the three media (air, water and waste) is discussed in this chapter.

CURRENT ENVIRONMENTAL COMPLIANCE PROGRAMS:

AIR

Acid Rain Program

Vectren's Acid Rain compliance program was approved by the IURC in Cause No. 39347, which authorized the construction of a combined sulfur dioxide (SO_2) scrubber for FB Culley Units 2 and 3. As AB Brown Units 1 and 2 were newer vintage units, the units' original construction included scrubber technology. Vectren relies upon its existing scrubber technology for compliance with acid rain requirements and has sufficient allowance allocations to meet its future acid rain obligations. See, Table 4-1, a listing of current air pollution control devices for each Vectren unit, Table 4-2, a listing of emission rates for each Vectren unit, and Table 4-3 a listing of the acid rain allowances allocated to Vectren units.

Table 4-1 Air Pollution Control Devices Installed

	FB Culley 2	FB Culley 3	Warrick 4	AB Brown 1	AB Brown 2
Commercial Date	1966	1973	1970	1979	1986
MW (UCAP)	83	257	135	228	233
NO_X	Low NO_X Burner	SCR[1]	SCR	SCR	SCR
SO_2	FGD[2]	FGD	FGD	FGD	FGD
PM[3]	ESP[4]	FF[5]	ESP	FF	ESP

[1] Selective Catalytic Reduction
[2] Flue Gas Desulfurization
[3] Particulate Matter
[4] Electrostatic Precipitator
[5] Fabric Filter

Table 4-2 Current (2013) Emission Rates (lbs./mm Btu)

Units	SO_2	Annual NO_X	Ozone Season NO_X
AB Brown 1	0.6400	0.1510	0.1464
AB Brown 2	0.3610	0.1160	0.1091
AB Brown 3	0.0006	0.1800	0.1710
AB Brown 4	0.0006	0.0310	0.0214
FB Culley 2/3	0.1700	0.1190	0.1312
Warrick 4	0.1800	0.2400	0.2740
BAGS 2	0.0006	0.2226	0.2111

Table 4-3 SO2 Acid Rain Allowances Allocated to Vectren Units (per year)

Plant Name	Percent Ownership	2013	2014-2041
AB Brown	100%	10,546	10,546
FB Culley	100%	9,922	9,922
Warrick 4[1]	50%	5,122	5,122

For purposes of compliance year 2014, acid rain allowances will continue to be used for compliance with the SO_2 emission reductions requirements of the Clean Air Interstate Rule (CAIR). As detailed more fully below, the Cross-State Air Pollution Rule (CSAPR) which was originally slated to become effective in two phases during 2012 and 2014, was stayed by the Court in December 2011 and vacated in August 2012. Through a series of appeals, it was reviewed by the US Supreme Court who issued judgment on April 29, 2014 to reverse the lower Court decision and upheld CSAPR. The stay was lifted on October 23, 2014 but an implementation schedule and reallocation of allowances has not been determined at this time. Due to the timing of this recent decision, Vectren is unable to state when CSAPR will go into effect and what the final allowance levels will be for each of its units. Neither the CAIR rule nor CSAPR supersedes the Acid Rain program. Facilities will still be required to annually surrender acid rain allowances to cover emissions of SO_2 under the existing Acid Rain program.

[1] Number of allowances shown are for Vectren's portion of Warrick 4

NO_x SIP Call

Vectren's NO_x SIP Call compliance plan was approved by the IURC in Cause Nos. 41864 and 42248, which authorized Vectren to retrofit selective catalytic reduction (SCR) technology on Culley Unit 3, Warrick Unit 4, and Brown Units 1 and 2. Vectren relies upon its existing SCR technology for compliance with the seasonal NO_x reductions required in the NO_x SIP Call. When CAIR was finalized in March of 2005, the EPA included a seasonal NO_x emission reduction requirement, which incorporated, and in most cases, went beyond the seasonal NO_x emission reductions required under the NO_x SIP Call. For purposes of compliance year 2014, CAIR NO_x seasonal allowances will continue to be used for compliance with the seasonal NO_x emission reductions requirement under the current CAIR rule. CAIR and CSAPR are discussed more fully below.

CAIR and CSAPR

On March 10, 2005, the US Environmental Protection Agency (EPA) finalized its determination in the CAIR rule that emissions from coal-burning Electric Generating Units (EGUs) in certain upwind states result in the transport of fine particles ($PM_{2.5}$) and ozone that significantly contribute to nonattainment of the applicable ambient air quality standards for those pollutants in downwind states. The CAIR rule required revisions to state implementation plans in twenty eight states, including Indiana, requiring further reductions of NO_x and SO_2 from EGUs beyond those required in the NO_x SIP Call and Acid Rain programs. Emissions reductions under the CAIR rule were to be implemented in two phases, with requirements for first phase reductions in 2009 (NO_x) and 2010 (SO_2), and second phase reductions starting in 2015. The Warrick 4 scrubber was constructed to comply with the CAIR regulation and approved in Cause No. 42861. The CAIR rule provided a federal framework for a regional cap and trade system, and those allowances allocated to the Vectren units under the CAIR rule are being used for compliance in 2014 and until the EPA reinstates CSAPR (see below).

On July 6, 2010, the EPA proposed its Clean Air Transport Rule ("Transport Rule") in response to the court's remand of CAIR. In an effort to address the court's finding that CAIR did not adequately ensure attainment of ozone and $PM_{2.5}$ air quality standards in certain Eastern states due to unlimited trading and banking of allowances, the Transport Rule proposal dramatically reduced the ability of facilities to meet the required emission reductions through interstate allowance trading. Like CAIR, the Transport Rule proposal set individual state caps for SO_2 and NO_x; however, unlike CAIR, individual unit allowance allocations were set out directly in the Transport Rule proposal. Interstate allowance trading was severely restricted and limited to trading within a zonal group. On July 7, 2011, the EPA finalized the Transport Rule proposal and renamed the program the Cross State Air Pollution Rule (CSAPR). CSAPR sets individual allowance allocations for Vectren's units directly in the rule. Table 4-4 shows a listing of individual unit allowance allocations under the original CSAPR. Under the original version of CSAPR, any excess CAIR allowances (vintage 2011 or older) that were not needed for compliance in 2011 could not be used for compliance with CSAPR, which was scheduled to become effective January 1, 2012. It is not yet known how, or when, the EPA will revise the effective dates in the reinstated version of the rule. Given the stringent state emission caps, the limited allowance trading available under the CSAPR, and the unknown implementation timing due to the recent lifting of the court ordered stay on October 23, 2014 it is virtually impossible to predict with any certainty the availability of excess allowances for compliance and the costs of those allowances under a reinstated CSAPR.

Table 4-4 CSAPR Allowances Allocated to Vectren Units

	SO_2 Allocation		Annual NO_X		Seasonal NO_X	
	2012	**2014**	**2012**	**2014**	**2012**	**2014**
AB Brown 1	3,761	2,080	1,393	1,376	595	586
AB Brown 2	3,889	2,151	1,440	1,422	601	591
AB Brown 3	1	1	19	19	14	14
AB Brown 4	0	0	6	6	4	4
BAGS 2	0	0	26	26	18	8
FB Culley 2	1,488	925	619	612	268	264
FB Culley 3	2,923	2,799	1,874	1,851	792	780
Warrick 4	2,802	1,550	1,037	1,025	444	437

Vectren's original multi-pollutant compliance plan was approved under IURC Cause No. 42861. While Vectren's original multi-pollutant planning focused on compliance with the CAIR regulation which was in place at the time, the successful execution of the approved multi-pollutant plan would enable Vectren to comply with the SO_2 and NO_x emission caps in the original CSAPR allocation without further significant capital investment; however, while currently well controlled, Vectren will incur increased Operating and Maintenance (O&M) costs attributable to a new regulation, such as an increase in chemical costs to achieve the lower emission targets. With the completion of the Warrick 4 scrubber pursuant to the approved order in Vectren's multi-pollutant proceeding, Vectren's generating system is 100% scrubbed for SO_2 and has selective catalytic reduction technology on all but one unit (FB Culley Unit 2). See Table 4-1. As such, Vectren will be well-positioned to comply with the new, more stringent SO_2 and NO_x caps that are required by a re-instated CSAPR, without reliance on a highly uncertain allowance market or further significant capital expenditures. It is important to note that CSAPR stay was just recently lifted on October 23, 2014, and final implementation dates are still unknown.

Mercury and Air Toxics Rule

The 1990 Amendments to the Clean Air Act (CAA or Act) required that the EPA determine whether EGUs should be required to reduce hazardous air pollutants, including mercury, under § 112 of the Act. In December of 2000, the EPA officially listed coal-fired EGUs as subject to CAA § 112 Maximum Achievable Control Technology (MACT) Standards for mercury, thus lifting a previous exemption from the air toxics requirements. On March 15, 2005, the EPA finalized its Clean Air Mercury Rule (CAMR) which set "standards of performance" under CAA §111 for new and existing coal-fired EGUs and created a nation-wide mercury emission allowance cap and trade system for existing EGUs which sought to reduce utility emissions of mercury in two phases. The first phase cap would have started in 2010, except the CAMR rule was similarly vacated by a reviewing court in March of 2008. Thus, like the CAIR rule, utilities were preparing for compliance with a finalized CAMR regulation that was ultimately found to be deficient by a reviewing court. The reviewing court directed the EPA to proceed with a MACT rulemaking under CAA § 112 which would impose more stringent individual plant-wide limits on mercury emissions and not provide for allowance trading.

On March 16, 2011, the EPA released its proposed MACT for utility boilers. The final rule, known as the Mercury and Air Toxics Standards (MATS) was published in the Federal Register on February 16, 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). 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. Compliance with the new limits will be required by April 16, 2015. The Indiana Department of Environmental Management (IDEM), the state permitting authority, has the discretion to grant a compliance extension of up to one year on a case by case basis if a source is unable to install emission controls or make fuel conversions prior to the April 2015 deadline. Vectren was granted a 1-year extension for the AB Brown Unit 2, contingent upon the need for injection of a secondary mercury treatment chemical. The need for the secondary chemical will not be known until after the primary system is operational at the end of 2014. Vectren currently has a MATS Compliance plan before the Commission (IURC Cause 44446) for approval that includes organo sulfide injection at the baseload units (AB Brown 1, AB Brown 2, FB Culley 3, and Warrick 4) with the possibility of an additional HBr injection at AB Brown 2 if needed.

SOLID WASTE DISPOSAL

Scrubber by-products from AB Brown are sent to an on-site landfill permitted by 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 has been 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. The remainder of the A B Brown fly ash and bottom ash is sluiced to an on-site pond. This major sustainability project will serve to mitigate negative impacts from the imposition of a more stringent regulatory scheme for ash disposal. 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. Until mid-2009, fly ash from the FB Culley facility was sent to the Cypress Creek Mine for backfill pursuant to the mine's surface coal mine permit. In May 2009, FB 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 one of two on-site ponds via wet sluicing. The ponds are seven and eighteen acres in size. 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.

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 and other excess or outdated chemicals. Both facilities are typically classified as Conditionally Exempt Small Quantity Generators.

WATER

AB Brown and FB Culley currently discharges process and cooling water to the Ohio River under National Pollutant Discharge Elimination System (NPDES) water discharge permits issued by the IDEM. AB Brown utilizes cooling towers while FB Culley has a once through cooling water system.

The Ohio River Valley Sanitation Commission (ORSANCO) regional water quality standards were most recently revised in 2012 and are more restrictive than current EPA standards. ORSANCO is a regional state compact focused on water quality issues for the Ohio River and governs water discharges that enter the Ohio River. Under Vectren’s most recent NPDES permits issued in late 2011, Vectren must meet more restrictive mercury limits at its river outfall to comply with the ORSANCO mercury limit of 12 ppt monthly average. To meet the limits, Vectren chose to install two chemical-precipitation water treatment systems at AB Brown and one at FB Culley. The new water treatment systems are included in the pending environmental compliance proceeding before the IURC (Cause No. 44446), and began operation in third quarter 2014.

FUTURE ENVIRONMENTAL REGULATIONS

CARBON REGULATION

On June 2, 2014, the EPA issued the CAA Section 111(d) Greenhouse Gas (GHG) New Source Performance Standards (NSPS) for existing sources, known as the Clean Power Plan (CPP). The CPP sets state-specific carbon reduction goals based on a state's existing generation mix and provides guidelines for the development, submission and implementation of state plans to achieve the state goals. The EPA asserts that the state reduction goals will result in a 30% decrease in CO_2 emissions from 2005 levels by 2030. To insure each state is making adequate progress towards the 2030 goal, an interim emission rate goal for 2020-2029 has also been established.

Indiana's state specific emission rate goals are 1,607 lb CO_2/MWh for the interim period and 1,531 lb CO_2/MWh for a final goal. This equates to a 20% reduction in CO_2 emission rates from 2012 levels. The EPA determined the state specific goals through a portfolio approach that includes improving power plant heat rates, dispatching lower emitting fuel sources more frequently and increasing utilization of renewable energy sources and energy efficiency programs. Specifically, each state's goals were set by taking 2012 emissions data and applying four "building blocks" of emission rate improvements that the EPA has determined are achievable by that state.

The four building blocks used by the EPA to calculate state goals are as follows:

1) Coal fleet heat rate improvement of 6%.
2) Increased dispatch of existing baseload natural gas generation sources to 70%. For Indiana this also includes announced new natural gas combined cycle plants.
3) Renewable energy portfolio of 5% in the interim and 7% in the final stage.
4) Energy efficiency reductions of 1.5% annually starting in 2020.

While individual state goals were based on the EPA's application of the building blocks to 2012 emission rates, states have flexibility through their state implementation plan to implement the building blocks in part or not at all to reach the listed goal, or enter a regional trading program. Since the state plan may include a variety of options, many of which are outside the fence line and control of a power plant, the interim and final CO_2 emission rates will not necessarily apply to individual generating plants or companies within the state. It is yet to be determined how the CPP will directly affect Vectren's generating units.

The final rule is scheduled for June 2015, with individual state implementation plans due by June 2016. States have the option to seek a one year extension, or up to two years if part of a regional or multi-state plan. After the submittal of the state or regional plan, the first annual reporting begins in 2022. This timeline represents the earliest emission reductions will be required, as it is almost certain that this rule will be heavily litigated. Vectren will continue to work with the state of Indiana to ensure that the State's compliance plan is the least cost to Indiana consumers.

WASTE DISPOSAL

Over the course of the last twenty years the EPA has conducted numerous studies and issued two reports to Congress on the management of coal combustion by-products (primarily fly ash, bottom ash, and scrubber by-product), concluding both times that these materials generally do not exhibit hazardous waste characteristics and can be managed properly under state solid waste regulations. In response to the Tennessee Valley Authority's (TVA's) catastrophic ash pond spill in December of 2008, the EPA revisited its regulatory options for the management of coal combustion by-products. On June 21, 2010, the EPA published three options for a proposed rule covering Coal Combustion Residuals (CCRs). Two options would regulate combustion by-products as solid waste under the Resource Conservation and Recovery Act (RCRA) Subtitle D, with the only significant difference being whether existing ponds are retrofitted or closed within five years, or whether utilities will be permitted to continue to use an existing pond for its remaining useful life. The third option would regulate combustion by-products as hazardous waste under RCRA Subtitle C. Under all three options, certain beneficial reuses of coal combustion residuals, such as cement and wallboard applications, will continue to be allowed. The EPA has set December 19, 2014 as the deadline for issuing the final rule.

Uncertainties remain until the rule is finalized. For example, under the Subtitle D proposed rule, unlined ash ponds would have to be closed within five years and groundwater monitoring installed within one year. The proposal, however, did not define whether the term “close” means to cease receiving new material or to have the site completely capped and grass covered within five years. The proposal also failed to take into account site specific circumstances such as size of the pond and the percentage filled when establishing the five year closure timeframe. A majority of the final closure obligation and compliance costs will be focused on historic material that is already in the ponds so a change in future generation will not negate the obligation to comply with the CCR regulation when it is issued. However, as a result of Vectren’s previous investments in dry fly ash handling and beneficial reuse activities, the volume of new material added to the ponds since 2009 has been significantly decreased.

As a direct result of the TVA spill referenced above, the EPA undertook to inspect all surface impoundments and dams holding combustion by-products. The EPA conducted site assessments at Vectren's AB Brown and FB Culley facilities and found the facilities' surface impoundments to be satisfactory and not posing a high hazard.

WATER

There are multiple regulatory rulemakings that could, when finalized, require more stringent limits for power plant discharges.

The EPA is developing new Effluent Limit Guidelines and Standards (ELGS) for the Steam Electric Power Generating Point Source Category. A draft was issued June 7, 2013, with a final rule scheduled for September 2015. The draft rule requested comment on 8 different options for treatment standards and compliance locations that ranged from no change of current standards to a requirement for full zero liquid discharge. Of the eight options, the EPA identified four “preferred” options. For the preferred options, the size of Vectren’s units would drop the plants out of the requirement for specific treatment and discharge limits for Flue Gas Desulfurization (FGD) waste water or bottom ash transport water in 2 of the 4 options. Instead, IDEM would apply Best Professional Judgment (BPJ) which takes into consideration site specific factors. While Vectren acknowledges that the EPA’s final ELGs could further alter discharge parameters and limits, it is not possible at this time to predict the outcome of the final rule. Vectren believes its chosen treatment systems are the most cost effective option for meeting its current permits while limiting potential stranded costs when new regulations take effect.

The EPA released its final rule regulating cooling water structures under Section 316(b) of the Clean Water Act (CWA) on August 15, 2014. Section 316(b) requires that intake structures that withdraw > 2 MGD of water, including most electric generating units, use the "Best Technology Available" to prevent and / or mitigate adverse environmental impacts to shellfish, fish, and wildlife in a water body. The rule lists separate sampling and study programs to minimize entrainment (pulling small organisms into the intake structure) and impingement (trapping or pinning fish against the exterior of the intake structure). In addition, three additional studies are required that look at technical feasibility and treatment costs, cost benefits evaluation, and non-water quality environmental impacts of the potential treatment option. These studies, combined with the results of the in-river fish sampling will help determine potential treatment options.

Seven options were identified as pre-approved methods for complying with impingement mortality standards. While cooling towers are listed as an option, they are not mandated for existing facilities. Vectren does not believe cooling tower retrofits will be required at FB Culley due to its size and location on the Ohio River. The EPA acknowledges that for many facilities, the process of conducting the studies, determining the best treatment option, constructing the selected option, and confirming the adequacy of the treatment may take a minimum of 8 years from the time the rule becomes effective. Vectren's FB Culley units currently use a "once through" cooling water intake system and are affected by this proposed regulation. Vectren's AB Brown units use a closed cooling water system. However, under the final rule Vectren would still be required to submit documentation and study reports to confirm the existing cooling water tower mitigates impingement and entrainment.

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CHAPTER 5

SALES & DEMAND FORECAST

INTRODUCTION

The electric energy and demand forecasts provide the basis for evaluation of supply-side and demand-side options to meet the electric needs of Vectren's customers. These forecasts reflect local and regional economic impacts, the effects of past, present, and proposed Demand Side Management / Demand Response (DSM/DR) programs, mandated efficiency standards, and the effects of normal market forces on electricity sales.

Overview of Vectren's Customers

Vectren provides delivery services to approximately 142,000 electric residential, general service (commercial), and large (primarily industrial) customers with electricity in southwestern Indiana. A high proportion of Vectren's sales are made to electric-intensive general service and large customers. In 2013, about 29% of Vectren's annual retail electric energy sales were consumed by residential customers, 23% of sales were consumed by General Service (GS), and 48% of sales were consumed by more than 100 large customers. Less than 1% served other load (street lights). Significant general service and large load creates complexity in load forecasting. These customers have the ability to significantly impact Vectren's demand for electricity, as economic factors affect their businesses' success.

ELECTRIC LOAD FORECAST OVERVIEW

Vectren developed low, base, and high forecasts of annual energy sales and requirements (e.g. sales plus related delivery losses) and peak loads (e.g. demand plus losses) for the purposes of its IRP. These forecasts, and the activities undertaken to develop them, are described in this section.

Development of the Vectren system-wide long-term electric load forecast involves the aggregation of multiple models. Vectren uses statistically adjusted end use (SAE) modeling and econometric modeling to forecast customer needs for the future. Vectren has investigated the use of pure end-use modeling for forecasting purposes but believes that a combination of statistically adjusted end-use and econometric modeling best accommodates its forecasting needs. End-use modeling involves building and maintaining a detailed end-use database to capture appliance and thermal shell characteristics, as well as end-use consumption information. The basic structure of an end-use model is households multiplied by appliance saturation and unit energy consumption. Each component of the end-use model is modeled separately. For these reasons, end-use modeling is very expensive to develop and maintain. It is meant primarily for long-term modeling (5-20 years). Often, a separate short term forecast is necessary, which is hard to integrate with the long-term forecast. Vectren utilizes statistically adjusted end-use models to forecast residential and general service loads. Large customer needs are forecasted with an econometric linear regression model, while street lighting load is forecasted with a simple trend model. The detail of Vectren's forecasting methodology is discussed later in this chapter.

FORECAST RESULTS

The base case forecasts of annual energy requirements and peak loads for the 2014 - 2034 planning period are provided in Tables 5-1 and 5-2. Annual energy requirements are projected to have a -.2% compound annual growth rate over the twenty year planning period. Peak requirements are projected to have a compound annual growth rate of -.1% over the twenty year planning period.

Table 5-1 Base Case Energy and Demand Forecast

Year	Peak (MW)[1]	Annual Energy (GWh)
2014 Proj.	1,145	5,782
2015	1,155	5,914
2016	1,156	5,936
2017	1,113	5,514
2018	1,109	5,503
2019	1,106	5,494
2020	1,106	5,497
2021	1,106	5,492
2022	1,107	5,494
2023	1,107	5,494
2024	1,107	5,496
2025	1,106	5,487
2026	1,106	5,487
2027	1,107	5,492
2028	1,109	5,507
2029	1,110	5,509
2030	1,111	5,517
2031	1,111	5,523
2032	1,113	5,540
2033	1,114	5,548
2034	1,115	5,560
Compound Annual Growth Rate, 2014-2034 Including Wholesale	-0.1%	-0.2%

[1] Includes wholesale contract sales for 2014

Table 5-2 Base Case Energy Forecast by Customer Class

Year	Residential (GWh)	General Service (GWh)	Large (GWh)	Other (GWh)	Net DSM (GWh)	DG (GWh)	Wholesale (GWh)	Losses (GWh)	Total Requirements (GWh)
2013 Calendar	1,435	1,294	2,744	21			61	267	5,822
2014 Proj.	1,444	1,300	2,739	20	(47)	(1)	61	265	5,782
2015	1,444	1,327	2,926	20	(72)	(1)	0	271	5,914
2016	1,448	1,351	2,945	20	(98)	(2)	0	272	5,936
2017	1,451	1,354	2,563	19	(123)	(3)	0	253	5,514
2018	1,458	1,357	2,567	19	(148)	(3)	0	252	5,503
2019	1,469	1,363	2,569	19	(173)	(5)	0	252	5,494
2020	1,475	1,370	2,574	19	(186)	(7)	0	252	5,497
2021	1,480	1,373	2,577	19	(199)	(9)	0	252	5,492
2022	1,490	1,380	2,579	19	(211)	(12)	0	252	5,494
2023	1,500	1,386	2,579	18	(224)	(17)	0	252	5,494
2024	1,514	1,395	2,578	18	(237)	(23)	0	252	5,496
2025	1,523	1,398	2,579	18	(250)	(32)	0	251	5,487
2026	1,534	1,404	2,579	18	(263)	(37)	0	251	5,487
2027	1,547	1,413	2,581	18	(276)	(42)	0	252	5,492
2028	1,562	1,427	2,584	18	(289)	(48)	0	252	5,507
2029	1,572	1,436	2,588	18	(302)	(55)	0	252	5,509
2030	1,586	1,445	2,593	18	(316)	(62)	0	253	5,517
2031	1,599	1,455	2,598	18	(329)	(71)	0	253	5,523
2032	1,616	1,473	2,604	18	(343)	(81)	0	254	5,540
2033	1,628	1,486	2,611	18	(356)	(93)	0	254	5,548
2034	1,644	1,501	2,619	18	(370)	(106)	0	255	5,560
Compound Annual Growth Rate for (2014-2034)	0.6%	0.7%	-0.2%	-0.7%					-0.2%

Low and high energy and demand forecasts were developed by modifying the assumptions around conservation, distributed generation adoption, economic drivers, population projections, and large customer additions. The difference between the two high growth cases is slow steady growth or a large step up. In the high growth (modeled) forecast, economic growth was increased from approximately 1% to 2%, and population growth was increased from about .3% to .5%. The high growth (large load) case is the same as the base case, with the addition of a large customer in 2018. The results are shown in Table 5-3 and 5-4.

Table 5-3 Base, Low, and High Case Energy Forecasts

Year	Base Annual Requirements		Low Growth Annual Requirements		High Growth (modeled) Annual Requirements		High Growth (large load) Annual Requirements	
	GWh	Growth,%	GWh	Growth,%	GWh	Growth,%	GWh	Growth,%
2014 Proj.	5,782		5,782		5,799		5,782	
2015	5,914	2.3%	5,907	2.2%	5,947	2.6%	5,914	2.3%
2016	5,936	0.4%	5,922	0.3%	5,990	0.7%	5,936	0.4%
2017	5,514	-7.1%	5,320	-10.2%	5,609	-6.4%	5,514	-7.1%
2018	5,503	-0.2%	5,302	-0.3%	5,645	0.6%	6,098	10.6%
2019	5,494	-0.2%	5,287	-0.3%	5,681	0.6%	6,088	-0.2%
2020	5,497	0.1%	5,290	0.1%	5,712	0.5%	6,090	0.0%
2021	5,492	-0.1%	5,285	-0.1%	5,734	0.4%	6,085	-0.1%
2022	5,494	0.0%	5,286	0.0%	5,764	0.5%	6,087	0.0%
2023	5,494	0.0%	5,284	0.0%	5,799	0.6%	6,085	0.0%
2024	5,496	0.1%	5,285	0.0%	5,841	0.7%	6,088	0.0%
2025	5,487	-0.2%	5,273	-0.2%	5,870	0.5%	6,077	-0.2%
2026	5,487	0.0%	5,272	0.0%	5,909	0.7%	6,077	0.0%
2027	5,492	0.1%	5,276	0.1%	5,950	0.7%	6,081	0.1%
2028	5,507	0.3%	5,288	0.2%	5,997	0.8%	6,095	0.2%
2029	5,509	0.1%	5,289	0.0%	6,028	0.5%	6,097	0.0%
2030	5,517	0.1%	5,293	0.1%	6,060	0.5%	6,104	0.1%
2031	5,523	0.1%	5,296	0.0%	6,094	0.6%	6,109	0.1%
2032	5,540	0.3%	5,310	0.3%	6,132	0.6%	6,127	0.3%
2033	5,548	0.1%	5,312	0.0%	6,157	0.4%	6,133	0.1%
2034	5,560	0.2%	5,320	0.1%	6,188	0.5%	6,145	0.2%
Compound Annual Growth Rate for (2014-2034)		-0.2%		-0.4%		0.3%		0.3%

Table 5-4 Base, Low, and High Case Demand Forecasts

Year	Base Annual Requirements		Low Growth Annual Requirements		High Growth (modeled) Annual Requirements		High Growth (large load) Annual Requirements	
	MW	Growth,%	MW	Growth,%	MW	Growth,%	MW	Growth,%
2014 Proj.	1,145		1,145		1,148		1,145	
2015	1,155	0.8%	1,153	0.7%	1,160	1.0%	1,155	0.8%
2016	1,156	0.1%	1,153	-0.1%	1,164	0.3%	1,156	0.1%
2017	1,113	-3.7%	1,088	-5.6%	1,127	-3.2%	1,113	-3.7%
2018	1,109	-0.3%	1,083	-0.5%	1,130	0.3%	1,208	8.6%
2019	1,106	-0.3%	1,079	-0.4%	1,133	0.3%	1,205	-0.3%
2020	1,106	0.0%	1,079	0.0%	1,136	0.3%	1,206	0.0%
2021	1,106	0.0%	1,079	0.0%	1,139	0.3%	1,206	0.0%
2022	1,107	0.1%	1,080	0.0%	1,143	0.3%	1,206	0.0%
2023	1,107	0.0%	1,079	0.0%	1,147	0.4%	1,206	0.0%
2024	1,107	0.0%	1,079	0.0%	1,152	0.4%	1,206	0.0%
2025	1,106	-0.1%	1,077	-0.2%	1,155	0.3%	1,205	-0.1%
2026	1,106	0.0%	1,077	0.0%	1,160	0.4%	1,205	0.0%
2027	1,107	0.1%	1,078	0.1%	1,165	0.4%	1,206	0.1%
2028	1,109	0.2%	1,079	0.1%	1,171	0.5%	1,207	0.1%
2029	1,110	0.1%	1,079	0.0%	1,175	0.3%	1,208	0.0%
2030	1,111	0.1%	1,080	0.0%	1,179	0.3%	1,209	0.1%
2031	1,111	0.0%	1,080	0.0%	1,183	0.3%	1,209	0.0%
2032	1,113	0.2%	1,081	0.1%	1,187	0.4%	1,211	0.1%
2033	1,114	0.1%	1,081	0.0%	1,190	0.2%	1,211	0.1%
2034	1,115	0.1%	1,081	0.0%	1,193	0.3%	1,212	0.1%
Compound Annual Growth Rate for (2014-2034)		-0.1%		-0.3%		0.2%		0.3%

FORECAST INPUTS & METHODOLOGY

Forecast Inputs

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.

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, GS, and large sales.

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[1] 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.

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.

Model Overview

Changes in economic conditions, prices, weather conditions, as well as appliance saturation and efficiency trends drive energy deliveries and demand through a set of monthly customer class sales forecast models. Monthly regression models are estimated for each of the following primary revenue classes:

- Residential (residential average usage and customer models)
- General Service
- Large
- Street Lighting

In the long-term, both economics and structural changes drive energy and demand growth. Structural changes are captured in the residential average use and general service sales forecast models through Statistically Adjusted End-Use (SAE) model specifications. The SAE model variables explicitly incorporate end-use saturation and

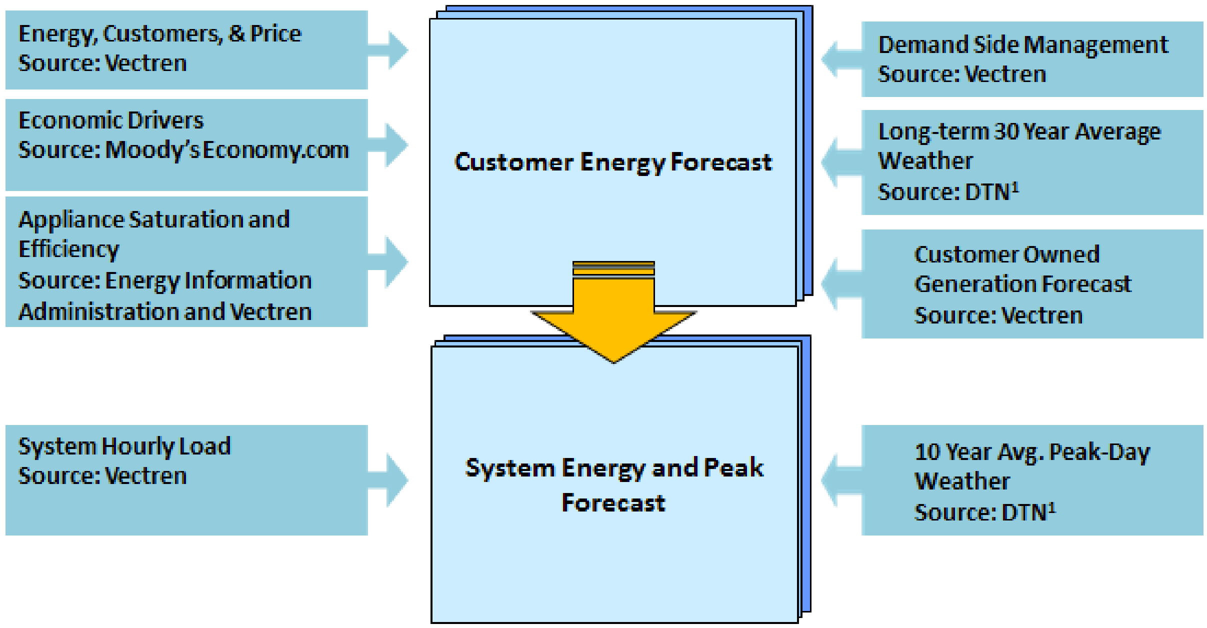
[1] The large sales model also includes CDDs.

efficiency projections, as well as changes in population, economic conditions, price, and weather. End-use efficiency projections include the expected impact of new end-use standards and naturally occurring efficiency gains. The large sales forecast is derived using an econometric model that relates large sales mostly to regional manufacturing Gross Domestic Product (GDP) growth. Street light sales are forecasted using a simple trend and seasonal model. The results of the sales forecast modes are imported into the demand forecast model.

The long-term demand forecast is developed using a “build-up” approach. This approach entails first estimating class and end-use energy requirements and then using class and end-use sales projections to drive system peak demand. The forecast models capture not only economic activity and population projections, but also expected weather conditions, the impact of improving end-use efficiency and standards, and electricity prices.

The long-term system peak forecast is derived through a monthly peak linear regression model that relates monthly peak demand to heating, cooling, and base load requirements. The model variables incorporate changes in heating, cooling, and base-use energy requirements derived from the class sales forecast models as well as peak-day weather conditions. Note that the forecast is adjusted to reflect future Vectren sponsored DSM impacts, expected adoption of customer owned distributed generation, and expected large customer additions. Figure 5-1 shows the general approach.

Figure 5-1: Forecast Approach



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

Analytic Methodology Used in Forecast

Residential Average Use Model

Residential customer usage is a product of heating, cooling, and other load. Both heating and cooling are weather sensitive and must be weather normalized in a model to remove weather noise from projections. Other major drivers of load are historical and projected market saturation of electronics, appliances, and equipment and their respective efficiencies. Vectren's service territory has a high saturation rate of central air conditioning equipment that is growing at a very slow pace, which helps to minimize average use growth. As equipment wears out and is replaced with newer, more efficient equipment, the average energy use per customer (AUPC) is reduced. Although there is increasing use of household electronics and appliances, this is balanced by increasing efficiencies in these areas. High tech devices like televisions, computers, and set-top boxes will see improving efficiencies, driven by innovation, competition, and voluntary agreements like the Energy Star program. Changes in lighting standards are having a large impact on energy consumption and will continue to impact residential customer usage in the years to come.

Even before Vectren sponsored DSM program savings, use per customer is largely flat, increasing only by 0.2% annually through 2024. This is largely due to the continuing phase-out of the most common types of incandescent light bulbs mandated by the Energy Independence and Security Act (EISA) and new end-use efficiency standards recently put in place by the Department of Energy (DOE). Average use begins to increase at a slightly faster rate in the later years, as the Energy Information Administration (EIA) baseline intensity projections only include those end-use standards that are currently law. Note that DOE continues to propose new energy efficiency standards.

The price of electricity and household income also influence average customer energy use. In general, there is a positive correlation between household income and usage. As household income rises, total usage rises. Conversely, there is a negative correlation between price and usage. As price goes up, average use goes down. Finally, the size of the home (number of inhabitants and square footage) and the thermal integrity of the structure affect residential consumption.

The residential average use model is a statistically adjusted end-use (SAE) model that addresses each of the previously discussed drivers of residential usage. SAE models incorporate many of the benefits of econometric models and traditional end-use models, while minimizing the disadvantages of each.

SAE models are ideal for identifying sales trends for short-term and long-term forecasting. They capture a wide variety of relevant data, including economic trends, equipment saturations and efficiencies, weather, and housing characteristics. Additionally, SAE models are cost effective and are easy to maintain and update. In the SAE model, use is defined by three primary end uses: heating (XHeat), cooling (XCool), and other (XOther). XHeat, XCool, and XOther are explanatory variables in the model that explain customer usage. By design, the SAE model calibrates results into actual sales.

$$ResAvgUse_m = B_0 + (B_1 \times XHeat_m) + (B_2 \times XCool_m) + (B_3 \times XOther_m) + e_m$$

The end-use variables incorporate both a variable that captures short-term utilization (Use) and a variable that captures changes in end-use efficiency and saturation trends (Index). The heating variable is calculated as:

$$XHeat = HeatUse \times HeatIndex$$

Where

$$HeatUse = f(HDD, Household\ Income, Household\ Size, Price)$$

$$HeatIndex = g(Heating\ Saturation, Efficiency, Shell\ Integrity, Square\ Footage)$$

The cooling variable is defined as:

$$XCool = CoolUse \times CoolIndex$$

Where

$$CoolUse = f(CDD, Household\ Income, Household\ Size, Price)$$

$$CoolIndex = g(Cooling\ Saturation, Efficiency, Shell\ Integrity, Square\ Footage)$$

XOther captures non-weather sensitive end-uses:

$$XOther = OtherUse \times OtherIndex$$

Where

$$OtherUse = f(Seasonal\ Use\ Pattern, Household\ Income, Household\ Size, Price)$$

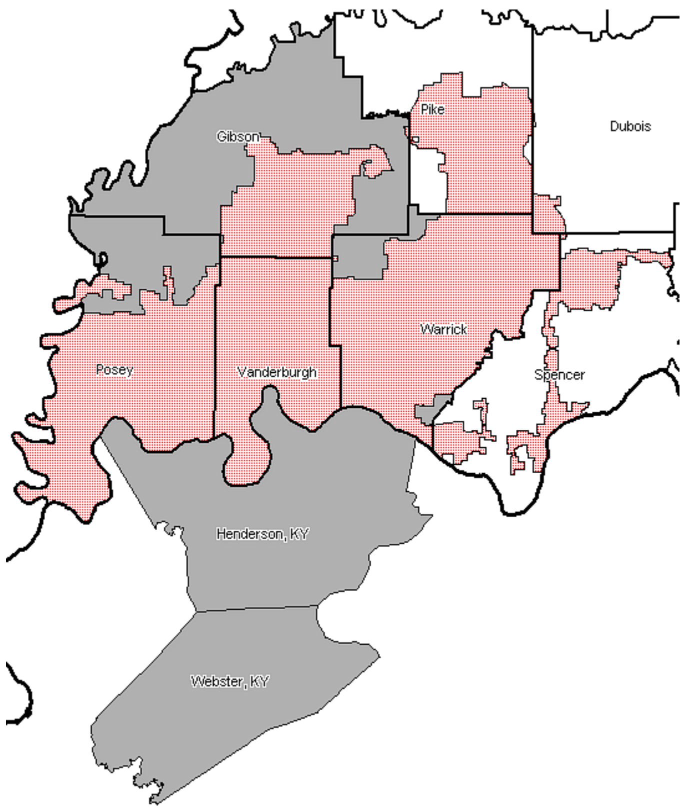
$$OtherIndex = g(Other\ Appliance\ Saturation\ and\ Efficiency\ Trends)$$

Monthly residential usage was regressed on the XHeat, XCool, and XOther variables. The average use model is estimated over the period January 2003 through December 2013. The model explains historical average use well with an Adjusted R^2 of 0.95 and in-sample MAPE of 3.3%.

Residential Customers Model

A simple linear regression model was used to predict the number of residential customers. The number of residential customers was forecasted as a function of population projections for the Evansville Metropolitan Statistical Area (MSA) from Moody's Economy.com. There is a strong correlation between the number of customers and population.

Figure 5-2 Vectren Service Territory Map



The Evansville MSA is a good proxy for the Vectren service territory. Figure 5-2 shows Vectren's service territory (in red) and the Evansville MSA in gray. The number of residential customers is projected to grow an average of .27% per year throughout the planning period. The adjusted R^2 for this model was .992, while the MAPE was .09%.

General Service (GS) Sales Model

Like the residential model, the general service (commercial) SAE sales model expresses monthly sales as a function of XHeat, XCool, and XOther. The end-use variables are constructed by interacting annual end-use intensity projections (EI) that capture end-use efficiency improvements, with non-manufacturing output (GDP) and employment (ComVarm), real price (Pricem), and monthly HDD and CDD:

$$XHeat_m = EI_{heat} \times Price_m^{-0.10} \times ComVar_m \times HDD_m$$

$$XCool_m = EI_{cool} \times Price_m^{-0.10} \times ComVar_m \times CDD_m$$

$$XOther_m = EI_{other} \times Price_m^{-0.10} \times ComVar_m$$

The coefficients on price are imposed short-term price elasticities. A monthly forecast sales model is then estimated as:

$$ComSales_m = B_0 + B_1 XHeat_m + B_2 XCool_m + B_3 XOther_m + e_m$$

Commercial Economic Driver

Output and employment are combined through a weighted economic variable where ComVar is defined as:

$$ComVar_m = (ComEmploy_m^{0.5}) \times (ComOutput_m^{0.5})$$

Employment and nonmanufacturing output are weighted equally. The weights were determined by evaluating the in-sample and out-of-sample model statistics for different sets of employment and output weights.

The resulting commercial sales model performs well with an Adjusted R^2 of 0.95 and an in-sample MAPE of 2.2%.

Commercial sales growth averages 1.9% per year through 2016, as economic growth projections are relatively strong through this period. Real output is projected to increase at 2.2% with employment increasing 1.9%. After 2016, both output and employment growth slow with output averaging 0.5% growth and employment largely flat through 2024. Commercial sales, in turn, slow averaging 0.4% annually between 2016 and 2024.

Large Sales Model

The industrial sales forecast is based on a generalized monthly regression model where industrial sales are specified as a function of manufacturing employment, output, monthly CDD, and monthly binaries to capture seasonal load variation and shifts in the data. The economic driver is a weighted combination of real manufacturing output and manufacturing employment. The industrial economic (IndVar) variable is defined as:

$$IndVar_m = (ManufEmploy_m^{0.3}) \times (ManufOutput_m^{0.7})$$

The imposed weights are determined by evaluating in-sample and out-of-sample statistics for alternative weighting schemes. The final model's Adjusted R^2 is 0.65 with in-sample MAPE of 6.7%. The relatively low Adjusted R^2 and relatively high MAPE are due to the "noisy" nature of industrial monthly billing data.

There are many variables that impact large customer consumption that are not easily forecasted. These unforeseeable impacts make forecasting GS and large customers' usage with a high degree of certainty very difficult, as these customers' usage is extremely sensitive to economic conditions.

Lighting Sales Model

Street light sales are fitted with a simple seasonal exponential smoothing model with a trend term. Street lighting sales have been declining and are expected to continue to decline through the forecast period as increasing lamp efficiency outpaces installation of new street lights. The model yielded an adjusted R^2 of .769 and a MAPE of 5.34%.

Vectren's total energy requirements include forecasted sales for the four sectors described above, wholesale contracts, DSM savings, impact of customer owned distributed generation (DG) and delivery losses. Losses were estimated to be approximately 4.8 percent of requirements. DSM savings and a forecast of customer owned DG are highlighted separately in the sales forecast, and the DSM programs are discussed in detail in Chapter 8 DSM Resources.

Peak Demand Forecast

The Vectren energy forecast is derived directly from the sales forecast by applying a monthly energy adjustment factor to the monthly calendarized sales forecast. The energy adjustment factor includes line losses and any differences in timing between monthly sales estimates and delivered energy (unaccounted for energy). Monthly adjustment factors are calculated as the average monthly ratio of energy to sales.

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

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

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

Heating and Cooling Model Variables

Heating and cooling requirements are driven by customer growth, economic activity, changes in end-use saturation, and improving end-use efficiency. These factors are captured in the class sales forecast models. The composition of the models allows historical and forecasted heating and cooling load requirement to be estimated.

The estimated model coefficients for the heating (XHeat) and cooling variables (XCool) combined with heating and cooling variable for normal weather conditions (NrmXHeat and NrmXCool) gives an estimate of the monthly heating and cooling load requirements. Heating requirements are calculated as:

$$HeatLoad_m = B_1 \times ResNrmXHeat_m + C_1 \times ComNrmXheat_m$$

B1 and C1 are the coefficients on XHeat in the residential and commercial models.

Cooling requirements are estimated in a similar manner. As there is a small amount of cooling in the industrial sector, industrial cooling is included by multiplying the industrial model coefficient for the CDD variable by normal monthly CDD. Cooling requirements are calculated as:

$$CoolLoad_m = B_2 \times ResNrmXCool_m + C_2 \times ComNrmXCool_m + D_2 \times NrmCDD_m$$

B2 and C2 are the coefficients on XCool in the residential and commercial models and D2 is the coefficient on CDD in the industrial sales model.

The impact of peak-day weather conditions is captured by interacting peak-day HDD and CDD with monthly heating and cooling load requirements indexed to a base year (2005). The peak model heating and cooling variables are calculated as:

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

Base Load Variable

The peak model base load variable (BaseVarm) derived from the sales forecast models is an estimate of the non-weather sensitive load at the time of the monthly system peak demand. The base load variable is defined as:

$$BaseVar_m = ResOtherCP_m \times ComOtherCP_m + IndOtherCP_m + StLightingCP_m$$

Base load requirements are derived for each revenue class by subtracting out heating and cooling load requirements from total load requirements. Using the SAE modeling framework, class annual base load requirements are then allocated to end-uses at the time of monthly peak demand. For example, the residential water heating coincident peak load estimate is derived as:

$$ResWaterCP_m = ResBaseLoad_m \times \left({ResWaterEI_a}/{ResBaseEI_a} \right) \times ResWaterFrac_m$$

Where

ResWaterEI = Annual water heating intensity (water use per household)

ResBaseEI = Annual base-use intensity (non-weather sensitive use per household)

ResWaterFrac = Monthly fraction of usage on at peak (estimates are based on Itron's hourly end-use load profile database)

End-use load estimates are aggregated by end-use and then revenue class resulting in the base load variable.

Model Results

The model explains monthly peak variation well with an adjusted R^2 of 0.97 and an in-sample MAPE of 2.5%.

CUSTOMER OWNED DISTRIBUTED GENERATION FORECAST

Vectren has been monitoring national and regional distributed generation trends since the 2011 IRP. While a number of technologies continue to influence the electric utility industry, the primary focus is on distributed solar. The present IRP considers the potential for future customer-owned DG growth, specifically in the area of net metered distributed solar photovoltaic (PV) adoption. For modeling purposes, distributed PV is treated as a decrease in demand. A distributed solar forecast was developed using Vectren and Indiana historical net metering information and 3rd party data and assumptions. This forecast is presented below in Table 5-5.

Table 5-5 Distributed Solar Growth Forecast

Year Ending	Historic Peak Planning Capacity (MW)	Distributed Solar Adoption Forecasts: Contribution to Peak Planning Capacity[1] (MW)		
		LOW CASE	HIGH CASE	BASE CASE
2006	0.002			
2007	0.002			
2008	0.003			
2009	0.012			
2010	0.029			
2011	0.051			
2012	0.106			
2013	0.162			
2014		0.2	0.2	0.2
2015		0.3	0.3	0.3
2016		0.4	0.4	0.4
2017		0.5	0.6	0.6
2018		0.7	0.9	0.8
2019		0.9	1.2	1.1
2020		1.3	1.7	1.5
2021		1.7	2.4	2.0
2022		2.3	3.3	2.8
2023		3.0	4.7	3.9
2024		4.1	6.6	5.3
2025		5.5	9.2	7.3
2026		6.2	10.6	8.4
2027		7.0	12.1	9.6
2028		7.8	14.0	10.9
2029		8.9	16.1	12.5
2030		10.0	18.5	14.2
2031		11.3	21.2	16.3
2032		12.7	24.4	18.6
2033		14.3	28.1	21.2
2034		16.2	32.3	24.2

[1] Peak planning capacity is 38% of installed capacity.

Because the IRP is concerned with meeting the annual peak demand, the data presented in Table 5-5 are expressed in terms of megawatts of peak planning capacity, rather than total direct current (DC) gross capacity or total alternating current (AC) inverter capacity. The summer peak typically occurs in late afternoon in mid-to-late summer, whereas maximum solar output is generally at noon in late spring or early summer. Because optimal solar output does not coincide with the summer peak, a factor must be applied to estimate the useful solar capacity from a given PV system at the summer peak. A wide range of peak planning capacity factors have been reported for distributed solar resources.[1] Although MISO has not formally adopted a peak planning capacity factor, PJM, a regional transmission operator, has recommended a factor of 38%.[2] Because of this PJM reference, Vectren has chosen to use this value. There may be further refinements on this going forward as the utility & solar industry further evaluate methodologies for developing this factor, and Vectren may revise this number in future IRPs.

The historical data column reflects the summer peaking capacity of Vectren's reported net metered customer accounts.[3] The High, Low, and Base Case forecasts for the 2014 – 2034 planning horizon are derived from the following information & data sets:

- Vectren historical growth in net metered inverter-rated capacity,
- Indiana historical growth in net metered inverter-rated capacity, and
- Navigant Consulting solar capacity future growth rate assumptions for Indiana.[4]

High Case (applied to the low energy and demand forecast) calculation methodology is as follows:

- Vectren year-end 2013 inverter-rated capacity (426 kW) grows each year in a compounding manner using Navigant's Indiana predicted growth rates as follows:

[1] Sterling, John, and J. McLaren, M. Taylor, K. Cory. Treatment of Solar Resource Generation in Electric Utility Resource Planning. NREL/TP-6A20-60047. October, 2013.
[2] PJM Manual 21: Rules and Procedures for Determination of Generating Capability, revision 11. PJM System Planning Department. March 5, 2014.
[3] Vectren's Customer-Generator Interconnection and Net Metering Report for year ended 12/13/2013.
[4] Navigant Consulting, 5/2/2014.

    - 2014 – 2025: 40% per year
    - 2025 – 2034: 15% per year
- Each year's result is then multiplied by the factor 0.38 to arrive at the peak planning contribution for distributed solar.

Low Case (applied to the high (modeled) energy and demand forecast) calculation methodology is as follows:

- Vectren year-end 2013 inverter-rated capacity (426 kW) grows each year in a compounding manner using slower growth rates as follows:
    - 2014 – 2025: 34.1% per year
    - 2025 – 2034: 12.8% per year
    - These growth rates are a modified version of the High Case's Navigant Indiana rates based on a derived factor.
        - This growth "adjustment" factor is derived by taking historical net metered capacity growth in Vectren territory versus Indiana as a whole.
        - Specifically, this adjustment factor takes the simple average growth rate for Vectren for the years 2010 through 2012 and divides this result by the simple average growth rate for Indiana over the same period.
        - This adjustment factor is 0.852 (or 85.2%). Applying this factor to Navigant's Indiana growth rates yields the 34.1% and 12.8% values given above.
- Each year's result is then multiplied by the factor 0.38 to arrive at the peak planning contribution for distributed solar.

Base Case (applied the base case and high (large load) energy and demand forecasts) calculation methodology is as follows:

- Takes the simple average of the High and Low cases in each year.

- Each year's result is then multiplied by the factor 0.38 to arrive at the peak planning contribution for distributed solar.

The overall approach for the High, Low, and Base cases is a reflection of the difference in the overall net-metered distributed generation customer adoption rates between Vectren and Indiana. It takes a very high level view of how solar adoption may evolve over a relatively long planning horizon. Vectren believes that the long term nature of the IRP process calls for a high level macro approach, and the Navigant assumptions, while very general in nature, represent the results of expert analysis and therefore are an appropriate basis for making this forecast. Navigant did suggest an "adjustment factor" for the Vectren territory because the Vectren service territory is growing at a slower rate than the state of Indiana, resulting in the use of this in the Low case (and indirect use in the Base Case). The High Case utilizes the unadjusted, original Navigant growth rates (where the Vectren growth rate matches the overall state growth rate).

While distributed solar PV, is the most prominent form of distributed generation anticipated in terms of total numbers of customers, it is not the only DG technology to be considered. Cogeneration, or Combined Heat and Power (CHP), is also a key technology category in the context of the IRP. However, because of the case-by-case nature of these potential resources, and the fact that some could be large enough to be modeled as a generation and/or capacity resource, these are covered outside this section on distributed generation.

Additional future technologies in the distributed generation space include:

- Small wind turbines
- Energy storage
- Fuel cells
- Micro turbines
- Other Micro-CHP (e.g. small advanced engine technologies)

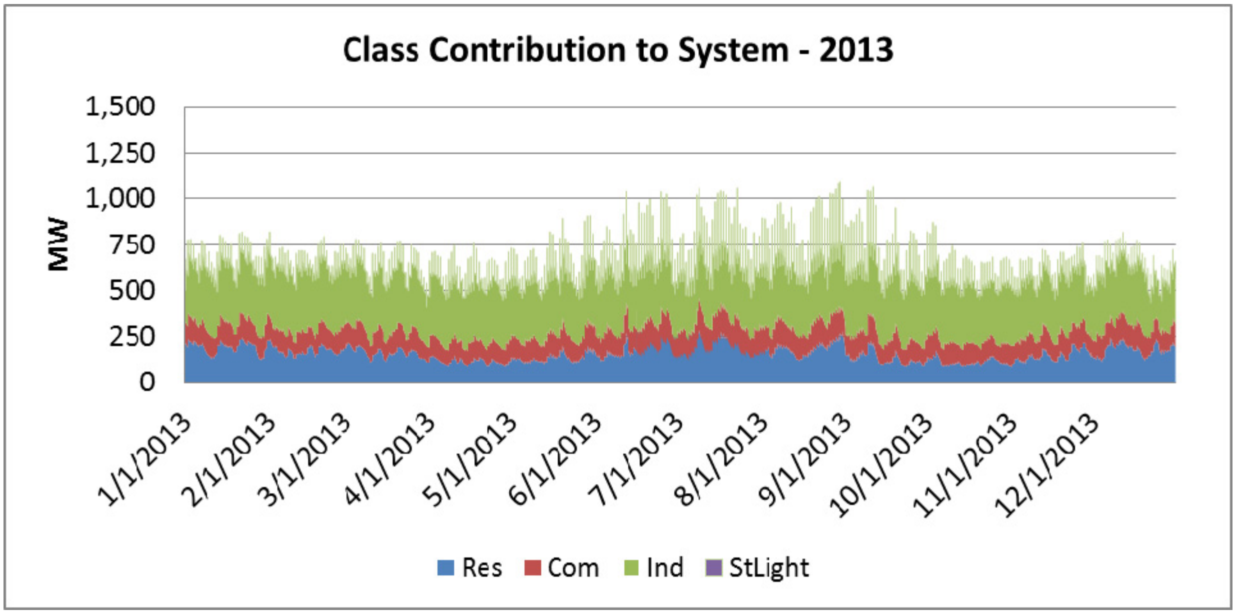
- Micro grids (i.e. customer-sited distribution systems that may include generation and storage technologies)

Each of these technologies will be an important area for the industry to consider in coming years. At this time, none of these are significant enough (or certain enough) to be forecasted as customer-sited DG resources in the present IRP. However, Vectren will continue to monitor and consider how these technologies play into generation planning going forward.

OVERVIEW OF LOAD RESEARCH ACTIVITIES

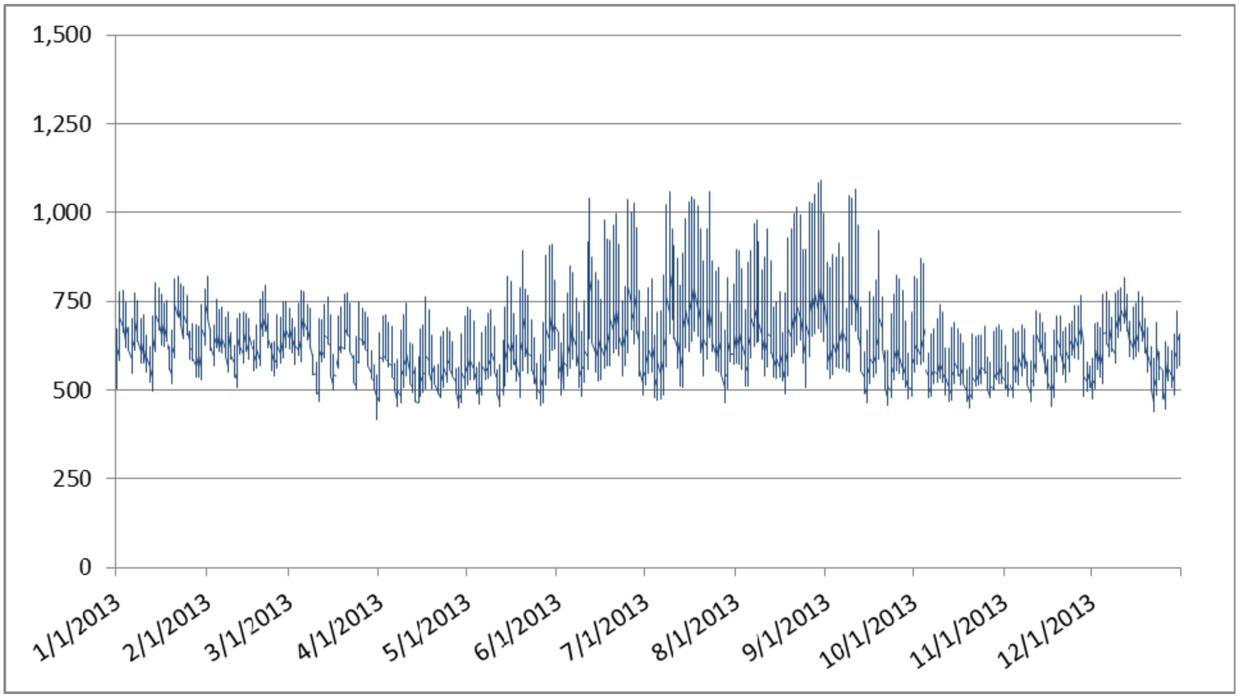
Vectren has interval meters installed on a sample of residential and GS customers. Large customers who have a monthly minimum demand obligation of 300kVA are required to have interval meters installed. Vectren collects and stores this information for analysis as needed. Detailed load shapes are used to better understand customers' usage, primarily for cost of service studies. For this IRP, class load shapes were borrowed from Itron's Indiana library to break down Vectren's hourly load profile by class. The load shapes were applied to historical peak demand. Graph 5-1 shows daily class contribution to peak for 2013.

Graph 5-1 Daily Class Contribution to Peak for 2013 (MW)

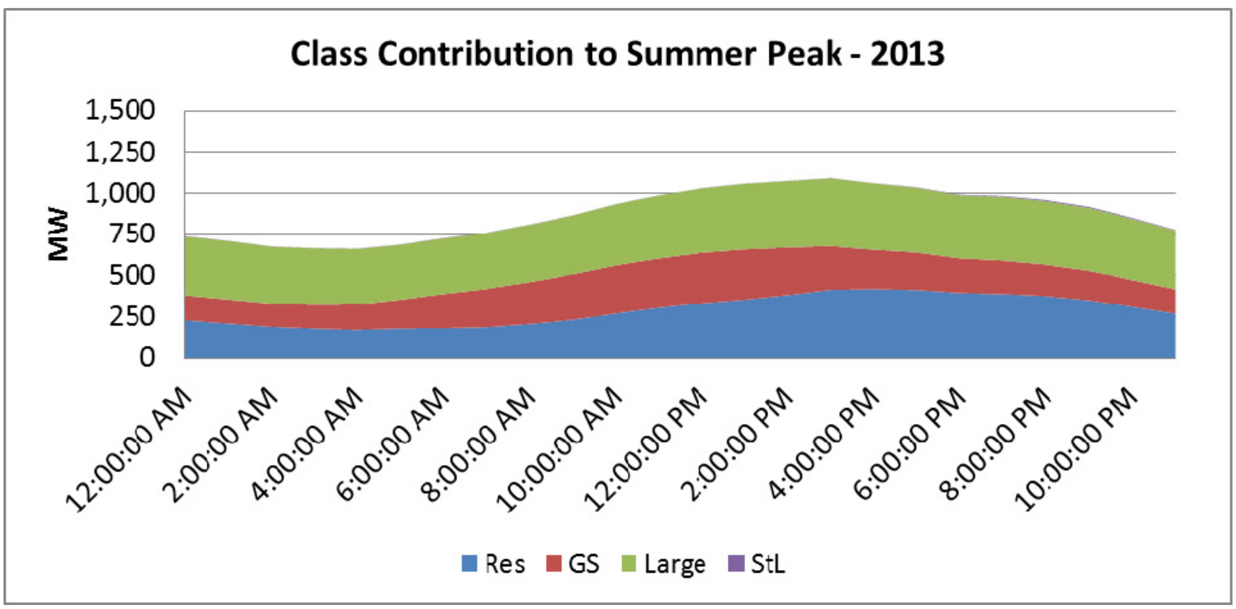


The following graphs (5-2 through 5-4) show the actual system load by day for 2013, the actual summer peak day for 2013 by hour, and the winter peak day for 2013 by hour. Note that these graphs do not include wholesale contract sales. Also additional load shapes are included in the Technical Appendix, section C.

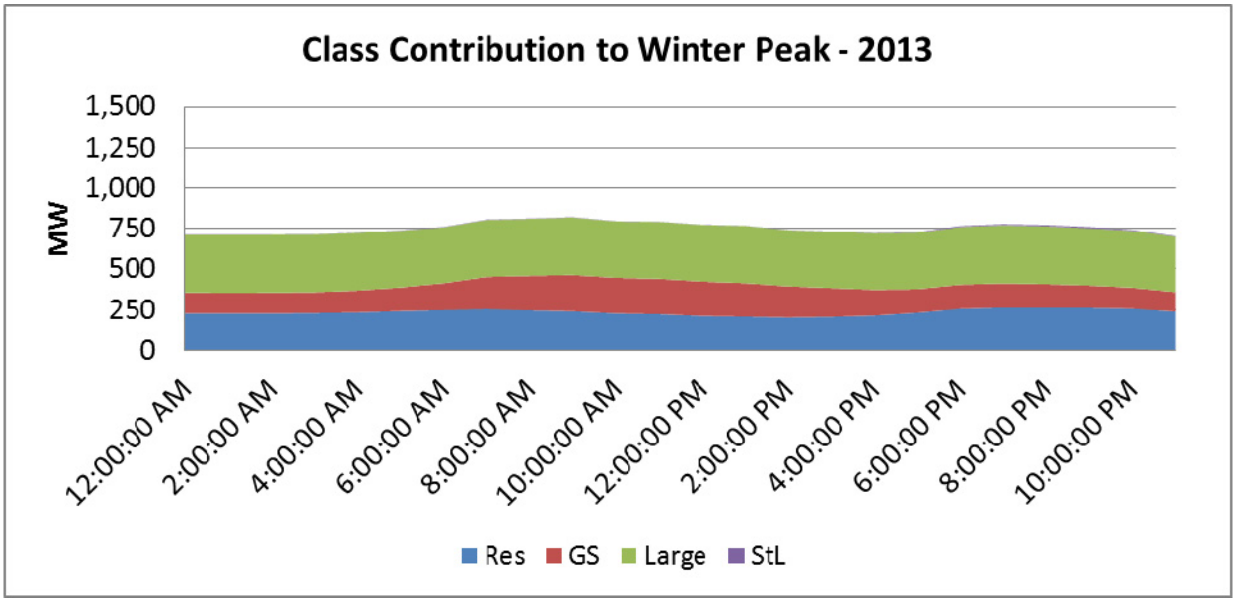
Graph 5-2 Total System Load for 2013 (MW)



Graph 5-3 Summer Peak 2013 (MW)



Graph 5-4 Winter Peak 2013 (MW)



APPLIANCE SATURATION SURVEY AND CONTINUOUS IMPROVEMENT

Vectren typically surveys residential customers every other year. 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 our 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. We compare and contrast our model assumptions and results to these groups to gain a better understanding of how they interpret and use model inputs.

OVERVIEW OF PAST FORECASTS

The following tables outline the performance of Vectren's energy and demand forecasts. Forecasts from previous IRP filings from 2004 through 2013 were compared to actual values in order to evaluate the reliability of Vectren's past energy and demand forecasts. The following tables show the actual and forecasted values for:

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

Tables 5-6 through 5-10 present comparisons of actual values versus forecasted values from previous IRP filings. The percentage deviation of the actual values from the most recent forecast is shown in the last column of each table. The deviations of the total energy and total peak forecasts are better than for the individual classes, which is to be expected. <u>Note that all of the forecasted values are weather-normalized, but the actual</u>

loads are not. This comparison would show much closer correlation if the actual loads were normalized to match the forecasts. This is particularly true when predicting the peak hour of the year. For example, weather in 2012 was abnormally hot, with multiple 100 degree days in a row, causing the peak demand to be high. 2013 was much milder and, therefore had a lower peak demand. Another factor affecting forecasts is the economic forecast. The recovery from the Great Recession has been much slower than expected. Another source of potential error is the use of the direct load control program, which reduces the peak demand on hot days by cycling off customer appliances to reduce system load. Note that Vectren is not forecasting any firm wholesale contracts after 2014.

Table 5-6 Total Peak Requirements (MW)

		Forecasts						
Year	Actual	2011	2009	2007	2005	2004	2001	Deviation from most recent forecast, %
2004	1,222						1,325	-8.4%
2005	1,316					1,313		0.2%
2006	1,325				1,326			-0.1%
2007	1,341				1,346			-0.4%
2008	1,166			1,184				-1.6%
2009	1,143			1,216				-6.4%
2010	1,275		1,153					9.6%
2011	1,221		1,179					3.4%
2012	1,205	1,168						-3.1%
2013	1,102	1,168						6.0%
Compound Annual Growth Rate, 2004-2013	-1.15%							

Table 5-7 Total Energy Requirements (GWh)

		Forecasts						Deviation from prior IRP forecast,
Year	Actual	2011	2009	2007	2005	2004	2001	%
2004	6,303						6,437	-2.1%
2005	6,508					6,624		-1.8%
2006	6,352				6,543			-3.0%
2007	6,527				6,210			4.9%
2008	5,931			6,160*				-3.9%
2009	5,598			6,068				-8.4%
2010	6,221		5,608					9.9%
2011	6,244		5,762					7.7%
2012	5,861	5,896						0.6%
2013	5,822	5,867						0.8%
Compound Annual Growth Rate, 2004-2013	-0.88%							

*Adjusted to include wholesale sales

Table 5-8 Residential Energy Sales (GWh)

		Forecasts						Deviation from prior IRP forecast,
Year	Actual	2011	2009	2007	2005	2004	2001	%
2004	1,502						1,553	-3.4%
2005	1,571					1,546		1.6%
2006	1,475				1,584			-7.4%
2007	1,631				1,609			1.3%
2008	1,435			1,581				-10.1%
2009	1,449			1,595				-10.0%
2010	1,598		1,467					8.2%
2011	1,515		1,451					4.2%
2012	1,456	1,501						-3.1%
2013	1,427	1,483						-3.9%
Compound Annual Growth Rate, 2004-2013	- 0.57%							

Table 5-9 General Service Energy Sales (GWh)

Year	Actual	Forecasts (GS) 2011	2009	2007	2005	2004	2001	Deviation from prior IRP forecast, %
2004	1,502						1,408	6.3%
2005	1,556					1,500		3.6%
2006	1,515				1,566			-3.4%
2007	1,412				1,594			-12.9%
2008	1,294			1,380				-6.6%
2009	1,299			1,384				-6.5%
2010	1,361		1,275					6.3%
2011	1,335		1,285					3.8%
2012	1,315	1,387						-5.5%
2013	1,303	1,409						-8.2%
Compound Annual Growth Rate, 2004-2013	-1.57%							

Table 5-10 Large Energy Sales (GWh)

Year	Actual	Forecasts (Large) 2011	2009	2007	2005	2004	2001	Deviation from prior IRP forecast, %
2004	2,346						2,570	-9.5%
2005	2,389					2,619		-9.6%
2006	2,376				2,379			-0.1%
2007	2,538				2,422			4.6%
2008	2,744			2,591				5.6%
2009	2,251			2,598				-15.4%
2010	2,601		2,281					12.3%
2011	2,744		2,445					10.9%
2012	2,714	2,696						0.7%
2013	2,744	2,714						1.1%
Compound Annual Growth Rate, 2004-2013	1.76%							

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CHAPTER 6

ELECTRIC SUPPLY ANALYSIS

INTRODUCTION

The purpose of the electric supply analysis is to determine the best available technologies for meeting the potential future supply-side resource needs of Vectren. A very broad range of supply alternatives were identified in a Technology Assessment described below. These supply alternatives were screened, and a smaller subset of alternatives were chosen for the final planning and integration analysis. Demand side alternatives play a major role in the integrated plan and are discussed in Chapter 8 DSM Resources. The supply-side alternatives which are discussed here fall into two basic categories:

- construction of new generating facilities and
- energy and capacity purchases.

Note that additional DSM energy efficiency programs beyond what was included in the base case energy and demand forecasts were modeled competed with supply-side options to meet future load requirements. This is discussed further in Chapter 8 DSM Resources.

TECHNOLOGY ASSESSMENT

For the 2014 Electric IRP process, Vectren retained the services of Burns & McDonnell, one of the leading engineering design experts in the United States, to assist in performing a Technology Assessment for generation technologies. The Technology Assessment can be found in the Technical Appendix, section B. Below are descriptions of the technologies that were considered from the Technology Assessment.

Natural Gas Technologies

The simple cycle gas turbines (SCGT) utilize natural gas to produce power in a gas turbine generator. The gas turbine 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 their fast load ramp rates and relatively low capital costs.

However, the units have high heat rates compared to other technologies. The different classes of SCGTs are shown below in Table 6-1. Please note that for new natural gas fired units, the capital costs shown in the table above are higher than the overnight costs shown in the Technology Assessment document. A 30% contingency for gas infrastructure siting costs and owner's costs was added for final modeling purposes.

Table 6-1 SGCT Classes

Simple Cycle Gas Turbine				
	LM6000	**LMS100**	**E-Class**	**F-Class**
Base Load Net Output (MW)	49.1	106.4	87.5	212.8
Base Load Net Heat Rate (HHV Btu/kWh)	9,570	8,860	11,480	9,940
Base Project Costs (2014$/kW)	$2,047	$1,440	$1,704	$1,228
Fixed O & M Costs (2014$/kW-yr.)	$23.98	$11.18	$16.56	$7.42

The 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 a steam turbine and generator to produce electric power. The use of both gas and steam turbine cycles in a single plant to produce electricity results in high conversion efficiencies and low emissions. For this assessment, a 1x1, 2x1, and 3x1 power block, as shown in Table 6-2, was evaluated with General Electric (GE) 7F-5 turbines as representative CCGT technology. A 1x1 means one gas or steam turbine is coupled with one HRSG. A 2x1 means two gas or steam turbines are coupled with one HRSG. A 3x1 follows the same pattern, meaning that there are three gas or steam turbines coupled with one HRSG.

Table 6-2 CCGT Classes

Combined Cycle Gas Turbine			
	1x1 F-Class Unfired	2x1 F-Class Unfired	3x1 F-Class Unfired
Base Load Net Output (MW)	405.5	815.5	1227.1
Base Load Net Heat Rate (HHV Btu/kWh)	6,610	6,530	6,500
Base Project Costs (2014$/kW)	$1,400	$1,083	$925
Fixed O & M Costs (2014$/kW-yr)	$13.51	$7.62	$5.79

The reciprocating engine is the last of the natural gas alternative technologies evaluated. The reciprocating, or piston, engine operates on the conversion of pressure into rotational energy that will fire on natural gas. Fuel and air are injected into a combustion chamber prior to its compression by the piston assembly of the engine. A spark ignites the compressed fuel and air mixture causing a rapid pressure increase that drives the piston downward. The piston is connected to an offset crankshaft, thereby converting the linear motion of the piston into rotational motion that is used to turn a generator for power production. The reciprocating engine is shown in Table 6-3.

Table 6-3 Reciprocating Engine

Reciprocating Engine	
Base Load Net Output (MW)	100.2
Base Load Net Heat Rate (HHV Btu/kWh)	8,470
Base Project Costs (2014$/kW)	$1,677
Fixed O & M Costs (2014$/kW-yr)	$11.79

Coal Technologies

Pulverized coal steam generators are characterized by the fine processing of the coal for combustion in a suspended fireball. Coal is supplied to the boiler from bunkers that direct coal into pulverizers, which crush and grind the coal into fine particles. The primary air system transfers the pulverized coal from the pulverizers to the steam generator's low NO_x burners for combustion. The steam generator produces high-pressure steam for throttle steam to the steam turbine generator. The steam expansion provides the energy required by the steam turbine generator to produce electricity.

Another type of coal technology that was evaluated was the Integrated Gasification Combined Cycle (IGCC) technology. IGCC technology produces a low calorific value syngas from coal or solid waste that can be fired in a combined cycle power plant. The gasification process itself is a proven technology used extensively for chemical production of products such as ammonia for fertilizer.

See Table 6-4 for further details on the coal technologies evaluated.

Table 6-4 Coal Technologies

Coal			
	Supercritical Pulverized Coal 1	**Supercritical Pulverized Coal 2**	**2x1 Integrated Gasification CC**
Base Load Net Output (MW)	425	637.5	482
Base Load Net Heat Rate (HHV Btu/kWh)	10,500	10,200	11,470
Base Project Costs (2014$/kW)	$5,568	$5,080	$10,698
Fixed O & M Costs (2014$/kW-yr)	$32.41	$21.54	$36.88

Waste to Energy Technologies

Stoker boiler technology is the most commonly used waste to energy (WTE) or biomass 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 was wood and landfill gas which are represented in Table 6-5.

Table 6-5 Waste to Energy Technologies

Biomass		
	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 (2014$/kW)	$4,542	$3,261
Fixed O & M Costs (2014$/kW-yr)	$94.49	$182.88

Renewable Technologies

Four renewable technologies were evaluated in the IRP. Those technologies were wind energy, solar photovoltaic, solar thermal, and hydroelectric. Most of the data evaluated was taken from the Technology Assessment, but some data used was from updated studies or real-life examples which will be further discussed below.

Wind turbines convert the kinetic energy of wind into mechanical energy, and are typically used to pump water or generate electrical energy that is supplied to the grid. Subsystems for either configuration typically include a blade or rotor to convert the energy in the wind to rotational shaft energy, a drive train, usually including a gearbox and a generator, a tower that supports the rotor and drive train, and other equipment, including controls, electrical cables, ground support equipment and interconnection equipment. All the data evaluated for wind energy came from the Technology Assessment.

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 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, and Solar Thermal technology, which converts the radiant heat of the solar energy to electricity through an intermediary fluid.

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.

Solar Thermal technology transfers solar energy to an intermediary liquid (typically mineral oil or molten sodium and potassium nitrate salts) in the form of heat, which is then used to boil water and produce steam. That steam is sent to a Steam Turbine Generator (STG) for the production of electricity. The life expectancy of a solar thermal power plant is similar to that of any fossil fueled thermal plant as long as preventative and routing maintenance programs are undertaken.

Vectren recognized that utility scale solar costs are expected to decline over the next few years and decided to have Burns & McDonnell revisit the solar portion of this Technology Assessment, which had a static cost for solar. Burns & McDonnell's

Phoenix office, which has extensive knowledge of the solar industry, developed an asymptotic curve, beginning at $1,880 per KWac in 2014, and declining to $1,500 per KWac in 2020 and staying flat in real terms for the remainder of the planning horizon. The declining cost curve was used for Vectren's IRP modeling. The costs are represented in Table 6-6.

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. Specially designed low-head hydro turbines are often current driven, and therefore operate at low speeds of 100 to 500 rpm in various configurations and orientations. Since they do not require a large head loss, low-head hydroelectric facilities can be incorporated in a variety of different applications, including rivers, canals, aqueducts, pipelines, and irrigation ditches. This allows the technology to be implemented much more easily than conventional hydropower, with a much smaller impact to wildlife and environmental surroundings. However, power supply is dependent on water supply flow and quality, which are sensitive to adverse environmental conditions such as dense vegetation or algae growth, sediment levels, and drought. Additionally, low-head hydropower is relatively new and undeveloped, resulting in a high capital cost for the relatively small generation output.

Vectren utilized a previously performed study that included dams in and around Vectren's electric service territory to help provide guidance for this IRP. The study was titled *Hydropower Resource Assessment at Non-Powered USACE Sites* and was prepared by the Hydropower Analysis Center for U. S. Army Corps of Engineers. The study was finalized in July 2013.[1] Since there were no costs in the study, Vectren used a real-life example from a hydroelectric construction project in the area to gather the project costs. This data is represented in table 6-6.

[1] Vectren referenced page 28 of this analysis.

Table 6-6 Renewable Technologies

Renewable				
	Wind	**Solar PV**	**Solar Thermal**	**Hydroelectric**
Base Load Net Output (MW)	50	50	50	50
Capacity Factor (energy annual output)	Intermittent (27%)	Intermittent (19%)	Intermittent (19%)	44%
Base Project Costs (2014$/kW)	$2,296	$1,880[1]	$5,740	$4,966
Fixed O & M Costs (2014$/kW-yr)	$25.40	$17.27	$35.56	$76.20

Energy Storage Technologies

Two energy storage technologies were evaluated in the IRP. The technologies were batteries and Compressed Air Energy Storage (CAES). These are shown in Table 6-7.

Electrochemical energy storage systems 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.

CAES offers a way of storing off-peak generation that can be dispatched during peak demand hours. To utilize CAES, the project needs a suitable storage site, either above ground or below ground, and availability of transmission and fuel source. CAES facilities use off-peak electricity to power a compressor train that compresses air into an underground reservoir at approximately 850 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.

[1] $1,880 per KWac in 2014, and declining to $1,500 per KWac in 2020 and staying flat in real terms for the remainder of the planning horizon.

Table 6-7 Energy Storage Technologies

Energy Storage		
	Advanced Battery Energy Storage	**Compressed Air Energy Storage**
Base Load Net Output (MW)	10	135
Base Project Costs (2014$/kW)	$4,135	$1,240
Fixed O & M Costs (2014$/kW-yr)	$60.96	$7.11

Nuclear Technologies

Manufacturers have begun designing Small Modular Reactors (SMRs) to create a smaller scale, completely modular nuclear reactor. These modular reactors are on the order of 30 feet in diameter and 300 feet high. The conceptual technologies are similar to Advanced Pressurized Water Reactors (APWR), and the entire process and steam generation is contained in one modular vessel. The steam generated in this vessel is then tied to a steam turbine for electric generation. The benefit of these SMRs is two-fold; the smaller unit size will allow more resource generation flexibility and the modular design will reduce overall project costs while providing increased benefits in the areas of safety and concern, waste management, and the utilization of resources. The 225 MW SMR facility is shown in Table 6-8.

Table 6-8 Nuclear SMR Technology

Nuclear	
	Small Modular Reactor
Base Load Net Output (MW)	225
Base Load Net Heat Rate (HHV Btu/kWh)	10,300
Base Project Costs (2014$/kW)	$5,415
Fixed O & M Costs (2014$/kW-yr)	$90.42

NEW CONSTRUCTION ALTERNATIVE SCREENING

The first step in the analysis of new construction alternatives was to survey the available list of technologies and to perform a preliminary screening of each of the options, eliminating those options that were determined to be unfeasible or marginal. The power supply alternatives Vectren considered include 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 bus bar cost analysis. This was done in order to reduce the number of alternatives that were evaluated to a manageable level within Strategist, the planning model.

The screening analysis was performed by developing and comparing levelized cost of each resource over a 20 year period. This simple approach is used to identify and limit the number of higher-cost generation alternatives. For screening purposes, estimated costs included fuel, operation & maintenance, and capital costs. Resources were then compared across various capacity factors in order to compare resource costs across all dispatch levels. Intermittent resources were compared at their respective output levels. Demand side management (DSM) and distributed generation (DG) were not considered in the bus bar analysis, but were considered alternatives within the IRP. See Chapter 5 Sales and Demand Forecast and Chapter 8 DSM Resources for more details.

The set of new construction alternatives that was selected for further assessment as a result of the screening process are presented in Table 6-9. The capital cost and O&M characteristics of these selected alternatives were assessed and developed in detail.

Table 6-9 New Construction Alternatives

Resource[1]	Net Operating Capacity (MW)	Fuel Type	Accepted or Rejected as Resource Alternative	Reason to Accept or Reject
7FA CCGT 1x1	405.5	Natural Gas	Accept	Cost Effective Option
7FA CCGT 2x1	815.5	Natural Gas	Reject	Exceeds capacity needs. If pursuit of a Combined Cycle was needed, would consider coordinating with another utility in order to reduce costs.
7FA CCGT 3x1	1227.1	Natural Gas	Reject	Exceeds capacity needs. If pursuit of a Combined Cycle was needed, would consider coordinating with another utility in order to reduce costs.
1xLM6000	49.1	Natural Gas	Accept	Cost Effective for 50 MW or less
1xLMS100	106.4	Natural Gas	Reject	Not Cost Effective compared to alternatives
1xE-Class SCGT	87.5	Natural Gas	Reject	Not Cost Effective compared to alternatives
1xF-Class SCGT	212.8	Natural Gas	Accept	Cost Effective for low capacity factors
100 MW Recips	100.2	Natural Gas	Accept	Cost Effective for 100 MW or less
500 MW Supercritical Pulverized Coal	425	Coal	Reject	Not Cost Effective compared to alternatives
750 MW Supercritical Pulverized Coal	637.5	Coal	Reject	Not Cost Effective compared to alternatives
2x1 Integrated Gasification Combined Cycle	482	Coal	Reject	Not Cost Effective compared to alternatives
Wood Stoker Fired	50	Biomass	Reject	Not Cost Effective compared to alternatives
Landfill Gas IC Engine	5	Biomass	Reject	Not Cost Effective compared to alternatives
10 MW Adv. Battery Energy Storage	10	Energy Storage	Reject	Not Cost Effective compared to alternatives
135 MW Compressed Air Energy Storage	135	Energy Storage	Reject	Not Cost Effective compared to alternatives
50 MW Wind Energy Conversion	50	Renewables	Accept	Cost Effective Renewable Source
50 MW Solar PV	50	Renewables	Accept	Cost Effective Renewable Source
50 MW Solar Thermal	50	Renewables	Reject	Not Cost Effective compared to PV
50 MW Low-head Hydro	50	Renewables	Reject	Not Cost Effective compared to alternatives
Small Modular Nuclear	225	Uranium	Reject	Not Cost Effective compared to alternatives

[1] Resource options could be structured as a PPA or be utility owned

Gas-Fueled Technologies

Two major types of gas-fired power generation technology, representing six alternatives, were selected for the detailed assessment. These were either simple cycle or combined cycle technology.

- Simple cycle gas turbine (SCGT) technology was evaluated for four levels of generating capability.
- Combined cycle gas turbine (CCGT) technology was evaluated for two levels of generating capabilities.

Simple cycle alternatives were included in the final integration analysis. With respect to the combined cycle alternatives, this assumption was made on the basis of capturing economies of scale and high efficiencies while satisfying the reserve margin and capital investment constraints.

Renewable Technologies

Two renewable resources were included in the final integration analysis. The renewable resources were modeled in 50 MW blocks to be evaluated against the other new construction alternative options. The 50 MW blocks are an installed capacity (ICAP) or generation nameplate designation. The renewable technologies that were selected by the bus bar cost analysis included wind and solar photovoltaic (PV). These renewable resources are intermittent resources, meaning that they are not continuously available due to some factor outside direct control. Given that this analysis is based on unforced capacity (UCAP), the resources are converted from the installed capacity to the unforced capacity based on the percentage of the designated resource. For wind, 9.125% was used to calculate the amount of UCAP available. This effectively makes every 50 MW block of wind worth 4.56 MW towards meeting the UCAP requirement. For solar PV, 38% was used to calculate the amount of UCAP available. This makes every 50 MW block of solar PV worth 19 MW towards meeting the UCAP requirement. See Chapter 5 Sales and Demand Forecast for more details.

PURCHASED POWER ALTERNATIVES

Another set of options available for assisting in meeting future supply-side resource requirements is purchased power from the wholesale electric market for both capacity and/or energy needs. Vectren is a participant in the wholesale electric power market and is a member of the ReliabilityFirst (RF), a regional reliability organization operating within the framework of the North American Electric Reliability Council (NERC). Vectren is also a member of MISO, the independent transmission system operator that serves much of the Midwest and Canada.

Estimating the future market price for electric energy available for purchase is difficult. In general, forward market information for "standard" products is available from brokers, counterparties, and published price indices. However, the liquidity and price transparency of the forward market is inversely proportional to the proximity of the delivery date of the product. The forward market becomes much less liquid (less trade volume) as the delivery date of the product moves further out into the future. Price discovery is more difficult as the more forward products are traded less and therefore less transparent.

Capacity prices within MISO are on an upward trend that may last for several years. Vectren does not foresee a near term need for capacity. In the long run, regional reserve margins will approach equilibrium due to a combination of load growth and generation retirements. Capacity prices may converge with replacement build prices as surplus legacy capacity diminishes through unit retirements and market growth. If at some future point in time Vectren foresees a projected need for capacity, purchased power options will be fully and explicitly considered at that time.

CUSTOMER SELF- GENERATION

Customer self-generation or behind the meter generation is likely to increase in the future. As discussed in in Chapter 5 Sales and Demand Forecast, a future trend of distributed rooftop solar has been projected and included in all scenarios. Somewhat more difficult to predict is the industrial adoption of behind the meter generation. One such facility is planned by a large industrial customer with a proposed implementation in 2017. As these types of projects become known they are incorporated into Vectren's forecasts. They are not however a typical trend, and therefore, are not projected beyond the known projects.

Some large electric customers may be candidates for cogeneration opportunities. Vectren's marketing department is in periodic discussions with customers most likely to participate in such a project. Should such a scenario develop, Vectren would work with that customer to see if they would benefit Vectren's customers to participate in such a project by possibly increasing the output of the cogeneration plant and thus supplying the Vectren system with the excess. Such a project can only be evaluated on a case by case basis.

RENEWABLE TECHNOLOGIES

Wind

As will be discussed further in Chapter 7 Renewables and Clean Energy, Vectren has two separate long-term purchase power agreements for a total of 80 MW of wind name plate capacity. These agreements were included in all integration analysis cases for the entire 20 year study period.

Other

Landfill gas projects and biomass are viable renewable sources of energy. However, due to their typically small relative size and unique site situations required for development, they weren't considered explicitly in the Technology Assessment or included in the integration analysis of this IRP. Vectren believes these technologies may be considered for viable projects in the future, primarily in the context of distributed generation as discussed in the following section, and that such projects will be duly evaluated as they develop.

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CHAPTER 7

RENEWABLES

and

CLEAN ENERGY

CURRENT PROJECTS

Vectren currently receives renewable energy from three projects: two purchase power contracts from Indiana wind projects and one landfill methane gas project.

Benton County Wind Farm

The Benton County Wind Farm, located in Benton County, Indiana, began providing electricity to Vectren in May 2007 under a 20 year purchase power agreement. The nominal nameplate rating for this contract is 30 MW, and the expected annual energy to Vectren from this project is 76,500 MWh.

Fowler Ridge II Wind Farm

Vectren began receiving energy from the Fowler Ridge II wind farm, also located in Benton County, Indiana in December of 2009 under a 20 year purchase power agreement. The nominal nameplate rating for this contract is 50 MW, and the expected annual energy to Vectren from this project is 130,500 MWh.

Blackfoot Landfill Gas Project

Vectren owns the Blackfoot Landfill Clean Energy Project located in Pike County, Indiana. Vectren officially took over ownership of this project on June 22, 2009. This facility consists of 2 internal combustion engine-generator sets that burn methane gas collected from the adjacent Blackfoot Landfill. Total nameplate capacity is 3.2 MW gross combined for the two machines. Vectren projects to produce approximately 15,000 MWh per year from this facility. Pending future expansion of the Blackfoot landfill and corresponding development of a viable gas field, Vectren may consider adding an additional generator set to this facility at some point in the future.

RENEWABLE ENERGY CREDITS

In addition to participation in actual renewable energy projects, both through ownership and purchase power agreements, Vectren will also consider purchasing renewable energy credits (RECs) to meet future renewable mandates. Vectren will monitor the market development for RECs over the next several years to determine the soundness of such a strategy.

ADDITIONAL RENEWABLE AND CLEAN ENERGY CONSIDERATIONS

Vectren modeled generation characteristics for output at time of peak load and capacity factor based on its geographic footprint. Additional wind generation with characteristics similar to Vectren's existing wind PPA's was also considered. Demand side management programs were considered as clean energy resource options and competed directly with other supply side options in the model.

Table 7-1 Clean Energy Projections

		Clean Energy Source					
	Retail Sales before conservation programs	Wind Generation	Landfill Gas Generation	Conservation Programs	Year-Over-Year Conservation Increase	Customer-Owned DG	Vectren Clean Energy
Year	GWh	GWh	GWh	GWh	GWh	GWh	% of sales
2014	5,832	207.0	15	157		1	7%
2015	5,991	207.0	15	182	26	1	7%
2016	6,040	207.0	15	208	26	2	8%
2017	5,645	207.0	15	233	25	3	9%
2018	5,661	207.0	15	258	25	3	9%
2019	5,680	207.0	15	283	25	5	9%
2020	5,699	207.0	15	296	13	7	9%
2021	5,710	207.0	15	309	13	9	10%
2022	5,729	207.0	15	321	13	12	10%
2023	5,746	207.0	15	334	13	17	10%
2024	5,769	207.0	15	347	13	23	10%
2025	5,782	207.0	15	360	13	32	11%
2026	5,801	207.0	15	373	13	37	11%
2027	5,825	207.0	15	386	13	42	11%
2028	5,860	207.0	15	399	13	48	12%
2029	5,884	207.0	15	412	13	55	12%
2030	5,913	207.0	15	426	13	62	12%
2031	5,942	207.0	15	439	13	71	13%
2032	5,985	207.0	15	453	14	81	13%
2033	6,018	207.0	15	466	14	93	13%
2034	6,060	207.0	15	480	14	106	14%

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CHAPTER 8

DSM RESOURCES

INTRODUCTION

The demand-side resource assessment process is based on a sequential series of steps designed to accurately reflect Vectren's markets and identify the options which are most reasonable, relevant, and cost-effective. It is also designed to incorporate the guidelines from the IURC. This chapter presents a discussion of the planning and screening process, identification of the program concepts, and a listing of the demand-side management (DSM) options passed for integration. Additionally, IRP DSM modeling is discussed.

HISTORICAL PERFORMANCE

Since 1992, Vectren has utilized DSM as a means of reducing customer load and thereby providing reliable electric service to its customers. Historically, DSM programs provided both peak demand and energy reductions. DSM programs were approved by the Commission and implemented pursuant to IURC orders. These programs were implemented, modified, and discontinued when necessary based on program evaluations. Vectren has managed the programs in an efficient and cost effective manner, and the load reductions and energy savings from the programs have been significant. Between 2010 and 2013, Vectren DSM programs reduced demand by over 25,000 kW and provided annual incremental energy savings of over 130,000,000 kWh. It is anticipated that in 2014, Vectren will save an incremental 58,000,000 kWh of gross energy savings and approximately 15,000 kW in demand savings.

Vectren also operates a Direct Load Control (DLC) program that reduces residential and small commercial air-conditioning and water heating electricity loads during summer peak hours. This demand response program commenced in 1992 and over 27,000 customers are enrolled with approximately 17 MW of peak reduction capacity.

EXISTING DSM RESOURCES and PROGRAMS

Tariff Based Resources

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 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 available to rate schedule RS, B, SGS, DGS, MLA, OSS, LP, and HLF customers.

Interruptible Rates

In addition to the DSM programs described in this chapter, Vectren has offered interruptible rate programs for commercial and industrial customers. Vectren currently has approximately 47 MW of interruptible load under contract, not including the DLC Program. In addition to the riders listed below, Vectren has one customer on a special contract interruptible rate (as approved by the IURC), that makes up approximately 20 MW of the total 47 MW of interruptible load.

<u>Rider IP – 2 Interruptible Power Service</u>

This rider is available to rate schedule DGS, OSS, LP, and HLF customers with an interruptible demand of at least 200 kW who were taking service under this rider during September 1997. This rider is closed to new participants. This rider currently has two customers that represent approximately 6 MW of the total interruptible load.

Rider IC Interruptible Contract Rider

This rider is available to any rate schedule LP or HLF customer electric who can provide for not less than 1,000 kVa of interruptible demand during peak periods. This rider currently has two customers that represent approximately 21MW of the total interruptible load.

Rider IO Interruptible Option Rider

This rider is available to any rate schedule DGS, MLA, OSS, LP, or HLF customer who will interrupt a portion of their normal electrical load during periods of request from Vectren. A Customer's estimated load interruption capability must exceed 250 kW to be eligible. This rider is not applicable to service that is otherwise interruptible or subject to displacement under rate schedules or riders of Vectren. Customers currently taking service under Vectren's rider IP – 2, which is closed to new business, may apply for service under this rider, if eligible, for the balance or renewal of the existing contracts.

Direct Load Control (DLC)

The DLC program provides remote dispatch control for residential and small commercial air conditioning, electric water heating and pool pumps (on existing units only) through radio controlled load management receivers (LMR). The DLC program was implemented in April 1992 by Vectren, with the objective of reducing summer peak demand by direct, temporary cycling of participating central air conditioners and heat pumps and by shedding connected water heating and pool pump loads. Participating customers receive credits on their bills during the months of June through September based on the number and type of equipment participating in the program. The DLC program was identified, in 2007, as part of Vectren's DSM Market Assessment study, prepared by Forefront Economics Inc. and H. Gil Peach & Associates LLC, as "…of high quality and notable for its participation and program longevity." Vectren's customers have achieved significant benefits from the existing DLC program.

The program consists of the remote dispatch and control of a DLC switch installed on participating customers' central cooling units (central air conditioners and heat pumps), as well as electric water heating units where a DLC switch is also installed on the central cooling unit. Vectren can 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), the regional electricity transmission grid authority. The control of central cooling units is typically a 50% cycling strategy and involves cycling the compressor off for 15 minutes out of every half hour during the cycling period. The direct load control of water heating equipment utilizes a shedding strategy. This involves shutting off these units for the duration of the cycling period. Cycling periods can range between two and six hours in duration.

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.

The DLC system has the capability to obtain approximately 17 MW of peak reduction capacity from the DLC system. Over time, the operability of the DLC switches can decline for a variety of reasons, including mechanical failure, contractor or customer disconnection, and lack of re-installation when customer equipment is replaced. In order to continue to obtain the peak demand response benefits from the DLC system, Vectren requested and received Commission approval of a multi-year DLC Inspection & Maintenance Program in Cause No. 43839. This inspection process began in 2011 with approximately 25% of the DLC switches inspected annually and this process will be completed early in 2015. Vectren has proposed in Cause No. 43405 DSMA 12 to continue ongoing maintenance of DLC switches on a five (5) year cycle with approximately 20% inspected annually. The work will continue to be conducted by trained vendors for both the inspection and replacement components of the program. By investing in the inspection and maintenance of the DLC system, Vectren can continue its ability to rely on this demand reduction resource as part of its resource planning.

As of May 2014, Vectren's DLC Program had approximately 27,040 residential customers and 530 commercial customers with a combined total of over 36,000 switches. Note that a customer may have more than one switch at a residence or business.

Cause No. 43839 – Rate Design

In Cause No. 43839, approved by the IURC on May 3, 2011, specific structural rate modifications were proposed by Vectren to better align Vectren's rate design to encourage conservation. These structural changes include:

- For all rate schedules, Vectren separated its variable costs from its fixed costs. These changes are intended, among other things, to provide more clarity and transparency in the rate schedules as to the variable costs that Vectren customers can avoid as customers reduce usage.
- Combined the customers under Rate A (the "Standard" customers) and Rate EH (the "Transitional" customers) into a single rate schedule, called Rate RS - Residential Service. The results of these changes resulted in the elimination of the Rate A declining block rate design in favor of a single block rate design for the Rate RS - Standard customer group versus the previous declining block rates. The transition from a declining block rate design to a flat block rate design has been recognized as a method to encourage energy conservation.
- The availability of Rate RS-Transitional was closed to new customers on May 3, 2012 in order to eliminate the promotion of all-electric space heating. A transition

plan to gradually move the existing Rate RS-Transitional customers to RS-Standard was to be filed for the Commission's consideration within two years of Vectren's most recent electric rate case on May 3, 2011. Vectren filed with the Commission a report on the Transition Plan on April 23, 2013 and recommended that any transition plan be considered in the next base rate case. The Commission has not yet ruled on this matter.

- The availability of the commercial Rate OSS (Off Season Service) was also closed to new customers on May 3, 2012 in order to eliminate the promotion of all-electric space heating. A transition plan to gradually move the existing Rate OSS customers to a comparable Rate DGS was to be filed for the Commission's consideration within two years of Vectren's most recent electric rate case on May 3, 2011. Vectren filed with the Commission a report on the Transition Plan on April 23, 2013 and recommended that any transition plan be considered in the next base rate case. The Commission has not yet ruled on this matter.

In Vectren's last electric base rate case, the Company proposed a decoupling mechanism that would break the link between recovery of fixed costs and energy sales in order to eliminate the financial harm to the Company caused when customers reduce their electric usage, thereby supporting the Company's ability to aggressively promote energy conservation. The Commission ultimately denied this request in their April 27, 2011 Order.

The rate structure listed above is reflected in the long term sales and demand forecast.

MISO DR Program

Vectren rider DR provides qualifying customers the optional opportunity to reduce their electric costs through customer provision of a load reduction during MISO high price periods and declared emergency events. Rider DR currently offers two programs, emergency demand response ("EDR") and demand response resource Type 1 ("DRR-1") energy programs.

Rider DR is applicable to any customer served under rates DGS or OSS with prior year maximum demand greater than 70 kW, MLA, LP, or HLF. A customer may participate in the rider DR only with kVa or kW curtailment load not under obligation pursuant to rider IC or IO or special contract. Customers must offer Vectren a minimum of one (1) MW of load reduction, or the greater minimum load reduction requirement that may be specified by the applicable MISO BPM for the type of resource offered by customer. A customer may participate in an aggregation as described in the Rider DR in order to meet the minimum requirement.

Vectren currently does not have any customers participating in rider DR.

Net Metering – Rider NM

Rider NM allows certain customers to install renewable generation facilities and return any energy not used by the customer from such facilities to the grid. On July 13, 2011 the Commission published an amended net metering rule, which included additional modifications to the rules, including eligibility to all customer classes, increase to the size of net metering facilities (1 MW) and an increase in the amount of net metering allowed (1% of most recent summer peak load or approximately 11.5 MW). The new rules also required that at least forty percent (40%) of the amount of net metering allowed would be reserved solely for participation by residential customers.

Vectren has worked with customers over the past several years to facilitate the implementation of net metering installations. As of July 1st, 2014, Vectren had 69 net metering customers with a total nameplate capacity of 474 kW.

Smart Grid Resources

Smart Grid technology has the potential to enable higher levels of reliability, energy efficiency and demand response, as well as improved evaluation, measurement, and verification of energy efficiency and demand response efforts. Reliability can be improved through distribution automation (DA) enhancements. These enhancements can provide operators with real-time information that allows them to make operational decisions more quickly to restore customers following an outage or possibly avoiding the outage completely. Additionally the enhancements can provide automation that can identify fault location, isolate and restore the customers quickly without operator intervention. The advanced metering infrastructure (AMI) portion of a Smart Grid project, as well as new dynamic pricing offerings, enable those customers who decide to actively manage their energy consumption to have access to significantly more information via enhanced communication. This provides those customers a better understanding and more control of their energy consumption decisions and the resulting energy bills. These improvements can provide benefits toward carbon foot print reduction as a result of the overall lowered energy consumption. The potential DSM benefits related to Smart Grid include:

- Peak reductions resulting from enabling Vectren customers to actively participate in demand response programs via dynamic pricing programs,
- Enhanced load and usage data to the customer to foster increased customer conservation, and
- Conservation voltage and line loss reductions due to the improved operating efficiency of the system.

In 2009, as part of the funding available from the United States Department of Energy (DOE) pursuant to American Recovery and Reinvestment Act (ARRA), Vectren conducted a business case analysis of the broad benefits of a Smart Grid implementation. According to the October 27, 2009 DOE announcement, Vectren did not receive a grant award for the Smart Grid project. Vectren re-evaluated the business case and determined that it would not be prudent to proceed with a broad Smart Grid project at this time due to net costs to customers. As part of this initiative Vectren completed the development of an initial Smart Grid strategy where it identified the need to invest in some foundational communication and information gathering technology in order to support future demand response and load management technology. The initial focus of the strategy is to build out a communication network that will support current and future Smart Grid technology, such as distribution Supervisory Control and Data Acquisition (SCADA), AMI, conservation voltage reduction (CVR), and system automation. Vectren has implemented a fiber optic communication path across its transmission network, connecting at both primary generating stations. Additional fiber installations are in progress across the transmission grid. The build out of the communication system has allowed Vectren to install and monitor additional SCADA points from its distribution substations. These SCADA installations are fundamental to the potential implementation of future conservation and voltage management programs, such as CVR, on the distribution network. Vectren will continue to monitor and evaluate Smart Grid technologies and customer acceptance of Smart Grid enabled energy efficiency and demand response.

Vectren recognizes the potential benefits Smart Grid technology programs offer. While a comprehensive Smart Grid deployment is likely several years in the future, the goal of any Vectren Smart Grid project will be to improve reliability, reduce outage restoration times, and increase energy conservation capabilities. The foundational investments currently being made and those planned over the next few years will enhance Vectren's ability to achieve these benefits.

The potential impacts of a robust Smart Grid implementation that would include dynamic pricing, improved information or conservation voltage reduction have not been explicitly quantified in this IRP because no specific project of this magnitude has been proposed by Vectren. We continue to monitor these technologies for potential future implementation as they become cost effective for our customers.

FEDERAL AND STATE ENERGY EFFICIENCY DEVELOPMENTS

Federal – Codes, Standards and Legislation

Energy efficiency policies are gaining momentum at both the state and Federal level. Although there are numerous activities going on at the state and Federal level the following are components of significant legislation that are approaching implementation, as well as new codes, standards and legislation being considered that will likely have an impact on energy efficiency in the planning horizon.

- On June 2, 2014, the EPA released its Clean Power Plan proposal that, if implemented, will for the first time regulate carbon dioxide (CO_2) emissions from existing power plants at the U.S. federal level. The rule is designed to cut carbon pollution from power plants nationwide by 30 percent from 2005 levels. State compliance includes several paths, one of which is end use energy efficiency. While dependent on the actual state implementation plan, the proposed plan would require reductions of 0.57% starting in 2017 and ramping up to 1.5% annually from 2022-2036. By 2030, the EPA is looking for usage reductions in Indiana of 11.6% in cumulative savings and that number increases to 12.9% in cumulative savings by 2036. As this rule is developed and finalized, it is likely to have potential significant impacts on energy efficiency planning.
- The U.S. Department of Energy's Appliances and Equipment Standards Program develops test procedures and minimum efficiency standards for residential appliances and commercial equipment. On June 27, 2011, amended standards were issued for residential central air conditioners and heat pumps. Central air conditioners and central air conditioning heat pumps manufactured on or after January 1, 2015 will have minimum requirements for Seasonal Energy Efficiency Ratios (SEER) and Heating Seasonal Performance Factors (HSPF).

State – Codes, Standards and Legislation

Since 2009, Indiana has taken several significant steps to enhance energy efficiency policy in the state.

- In 2009, the IURC released the Phase II Generic DSM order. The order established statewide electric savings goals for utilities starting in 2010 at

0.3% of average sales and ramping to 2% per year by 2019, The Phase II order also defined a list of five (5) Core DSM programs to be offered by a statewide Third Party Administrator (TPA) and allowed utilities the option to offer Core Plus programs in an effort to reach the 2% goal.

- As a result, since 2012, a statewide TPA has been running Core DSM Programs in Indiana. In March 2014, the Indiana General Assembly passed legislation which modified DSM requirements in Indiana. Senate Enrolled Act No. 340 (“SEA 340”) removed requirements for mandatory statewide ”Core’ DSM programs and savings requirements established in the Phase II Order. SEA 340 also allows large C&I customers who meet certain criteria to opt-out of participation in utility sponsored DSM programs. Furthermore, the statute goes on to prohibit the Commission from requiring jurisdictional electric utilities to meet the Phase II Order energy savings targets after December 31, 2014 and prohibits jurisdictional electric utilities from renewing or extending an existing contract or entering into a new contract with a statewide third party administrator for an energy efficiency program as established in the Phase II Order.
- As a result of SEA 340, Vectren filed and received approval for a one year DSM plan for 2015 under Cause No. 44495 with a savings target of 1% of eligible customer sales.

VECTREN DSM STRATEGY

Vectren has adopted a cultural change that encourages conservation and efficiency for both its gas and electric customers. Vectren has embraced energy efficiency and actively promotes the benefits of energy efficiency to its employees and customers. Vectren has taken serious steps to implement this cultural change starting with its employees. Vectren encourages each employee, especially those with direct customer contact, to promote conservation. Internal communications and presentations, conservation flyers and handouts, meetings with community leaders, and formal training have all promoted this shift. This cultural shift was a motivating factor in launching a new Vectren motto of "Live Smart" in order to further emphasize efficiency. Vectren's purpose statement is the foundation of the Vectren Strategy related to DSM:

> *Purpose*
> With a focus on the need to conserve natural resources, we provide energy and related solutions that make our customers productive, comfortable and secure.

Customers are a key component of Vectren's values, and Vectren knows success comes from understanding its customers and actively helping them to use energy efficiently.

Vectren will continue to offer cost-effective DSM to assist customers in managing their energy bills and meet future energy requirements. Vectren will include an on-going level of Vectren sponsored DSM in the load forecast and will also consider additional DSM as a source of new supply in meeting future electric service requirements (discussed further in the IRP DSM modeling section of this chapter). DSM savings levels in the load forecast include DSM energy efficiency programs available to all customer classes and a 1% annual savings targets for 2015-2019 and .5% annually thereafter. The 1% of eligible annual savings target assumes that 70% of eligible large customer load will opt-out of DSM programs using the provision provided in SEA340.[1] The load forecast also includes an ongoing level of energy efficiency related to codes and standards embedded in the load forecast projections. Ongoing DSM is also important given the integration of Vectren's gas and electric efficiency programs.

DSM PLANNING PROCESS

The following outlines Vectren's planning process in support of Vectren's strategy to identify cost effective energy efficiency resources. In 2006, as a result of a settlement in

[1] Vectren assumes that 80% of large customers will opt out of Vectren sponsored DSM programs; however, 70% was selected for large sales modeling to capture large customer energy efficiency projects outside of Vectren sponsored programs.

Cause No. 42861, the DSM Collaborative was formed, including Vectren and the Indiana Office of Utility Consumer Counselor ("OUCC") as voting members. The Collaborative provided input in the planning of Vectren's proposed DSM programs. The Oversight Board was formed as a result of Cause No. 43427 and was given authority to govern Vectren'sElectric DSM Programs. When formed, the Oversight Board included Vectren and the OUCC as voting members. The Citizens Action Coalition ("CAC") was added as a voting member of the Oversight Board in 2013 as a result of Cause No. 44318.

The IURC Phase II Order in Cause No. 42693 issued on December 9, 2009 established energy saving goals for all jurisdictional utilities in Indiana. The Phase II Order required all jurisdictional utilities to implement five specified programs, which the Commission termed Core Programs. The Core Programs were administered by a third party administrator (TPA) selected through a process involving the Demand Side Coordination Committee composed of jurisdictional Investor-Owned Utilities (IOU's) and other pertinent key stakeholders.

Additionally, the Commission recognized that achieving the goals set out in the Phase II Order would not be possible with Core Programs alone and encouraged the utilities to implement Core Plus Programs to assist in reaching the annual savings goals. Core Plus programs are those programs implemented by the jurisdictional electric utilities in Indiana designed to fill the gap between savings achieved by the Core programs and the savings targets established by the Commission in the Phase II Order. To develop its own set of Core Plus programs, Vectren modified existing programs approved in Cause No. 43427 and added new programs, which were approved on August 31, 2011 in Cause No. 43938. During this period, Vectren also proceeded to integrate some of its electric programs with existing gas DSM programs.

However, with the passage of SEA 340, mandatory statewide "Core" DSM programs and savings requirements established in the Phase II Order have been removed as of

December 31, 2014 and large C&I customers who meet certain criteria ("Qualifying Customers") are allowed to opt-out of participation in Company sponsored energy efficiency programs. As a result, Vectren has implemented an opt-out process as defined in IURC Cause No. 44441 to allow Qualifying Customers to opt-out. This process includes defined annual opt-out and opt-in periods. The plan that Vectren initially filed for 2015 in IURC Cause No. 44495 on May 31, 2014 assumed a 50% level of opt-out. During the initial opt-out period effective July 1, 2014, approximately 71% of eligible large C&I retail sales opted out of participation in Company sponsored DSM. The higher than anticipated opt-out required Vectren to adjust the 2015 Plan to reflect lower spending and lower available savings potential because of the additional portion of the load that is no longer participating in DSM programs. There is an additional opt-out period in the fall of 2014 effective January 1, 2015. As a result, Vectren revised the 2015 Plan to adjust for an 80% opt-out level effective January 1, 2015. The revised plan was approved by the Oversight Board and is still pending Commission approval as part of Cause No. 44495.

The 2015 Plan was developed during an IRP planning period; therefore, the 2014 IRP could not serve as a key input into the 2015 Plan. As a result, the avoided cost basis from the 2011 IRP was used to develop the 2015 Plan. The framework for the 2015 Plan is a continuation of programs offered in 2014, at a savings level of 1.2% of sales (adjusted for the assumption that 80% of Qualifying Customers will opt-out of the programs). However, there were many steps involved in developing the 2015 Plan. The objective of these steps was to develop a plan based on market-specific information for Vectren, which could be successfully implemented utilizing realistic assessments of achievable market potential.

The first step in the process was retaining EnerNOC to complete a Market Potential Study[1] (MPS), included in the Technical Appendix, section D. At the end of 2012,

[1] Electric Demand Side Management: Market Potential Study and Action Plan, EnerNOC Utility Solutions Consulting, April 22, 2013

Vectren, with guidance from the Vectren Electric Oversight Board, engaged EnerNOC, Inc. to study its DSM market potential and develop an Action Plan. EnerNOC conducted a detailed, bottom-up assessment of the Vectren market in the Evansville metropolitan area to deliver a projection of baseline electric energy use, forecasts of the energy savings achievable through efficiency measures, and program designs and strategies to optimally deliver those savings. The study developed technical, economic and achievable potential estimates by sector, customer type and measure. According to the MPS, EnerNOC performed the following tasks in completing the study:

1. Conducted onsite energy consumption surveys with 30 of Vectren's largest commercial and industrial customers in order to provide data and guidance for these market sectors that had not formerly received focused DSM program efforts.
2. Performed a market characterization to describe sector-level electricity use for the residential, commercial, and industrial sectors for the base year, 2011. This included using existing information contained in prior Vectren and Indiana studies, new information from the aforementioned onsite surveys with large customers, EnerNOC's own databases and tools, and other secondary data sources such as the American Community Survey (ACS) and the Energy Information Administration (EIA).
3. Developed a baseline electricity forecast by sector, segment, and end use for 2011 through 2023. Results presented in this volume focus on the upcoming implementation years of 2015 through 2019.
4. Identified several hundred measures and estimated their effects in five tiers of measure-level energy efficiency potential: Technical, Economic, Achievable High, Achievable Recommended and Achievable Low.
5. Reviewed the current programs offered by Vectren in light of the study findings to make strategic program recommendations for achieving savings.
6. Created recommended program designs and action plans through 2019 representing the program potential for Vectren, basing them on the potential analysis and strategic recommendations developed in the previous steps.

The EnerNOC MPS and other study information were used to help guide the plan design. Study analysis and results details can be found in the MPS and its appendices. For planning purposes Vectren used the “Recommended Achievable” scenario as a guide for developing the 2015 Plan.

The second primary step in the planning process was to hire outside expertise to assist with the plan design and development. Vectren retained Morgan Marketing Partners to assist with designing the 2015 Plan. Rick Morgan, President of Morgan Marketing Partners, was the primary planner working with the Vectren team.

The third primary step in the planning process was to obtain input from various sources to help develop and refine a workable plan. The first group providing input was Vectren’s DSM Program Managers who have been overseeing current Vectren programs. In addition, vendors and other implementation partners who operate the current programs were very involved in the process as well. They provided suggestions for program changes and enhancements. The vendors and partners also provided technical information about measures to include recommended incentives, estimates of participation and estimated implementation costs. These data provided a foundation for the 2015 Plan based on actual experience within Vectren’s territory. These companies also bring their experience operating programs for other utilities.

Other sources of program information were also considered. Current evaluations were used for adjustments to inputs. In addition, best practices were researched and reviewed to gain insights into the program design of successful DSM programs implemented at other utilities. Once the plan was developed, Vectren obtained feedback and approval from the Oversight Board before finalizing.

DSM SCREENING RESULTS

The last step of the planning process was the cost benefit analysis. Utilizing a cost / benefit model, the measures and programs were analyzed for cost effectiveness. The outputs include all the California Standard Practice Manual results including Total Resource Cost (TRC), Utility Cost Test (UCT), Participant and Ratepayer Impact Measure (RIM) tests. Inputs into the model include the following: participation rates, incentives paid, energy savings of the measure, life of the measure, implementation costs, administrative costs, incremental costs to the participant of the high efficiency measure, escalation rates and discount rates. Vectren considers the following tests and ensures that the portfolio passes the TRC test as this test includes the total costs and benefits to both the utility and the consumer. Table 8-4 below outlines the results of all tests.

The model includes a full range of economic perspectives typically used in energy efficiency and DSM analytics. The perspectives include:

- Participant Test
- Utility Cost Test
- Ratepayer Impact Measure Test
- Total Resource Cost Test

The cost effectiveness analysis produces two types of resulting metrics:

1. Net Benefits (dollars) = NPV ∑ benefits – NPV ∑ costs
2. Benefit Cost Ratio = NPV ∑ benefits ÷ NPV ∑ costs

As stated above, the cost effectiveness analysis reflects four primary tests. Each reflects a distinct perspective and has a separate set of inputs reflecting the treatment of costs and benefits. A summary of benefits and costs included in each cost effectiveness test is shown below in Table 8-1.

Table 8-1 Vectren Cost Effectiveness Tests Benefits & Costs Summary

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

The Participant Cost Test shows the value of the program from the perspective of the utility's customer participating in the program. The test compares the participant's bill savings over the life of the 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 utility and the participating customers. This test compares the level of benefits associated with the reduced energy supply costs to utility programs and participant costs.

In completing the tests listed above, Vectren used 7.29% 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. For the 2015 Plan, Vectren utilized the avoided costs from Table 8-4 in the 2011 IRP. The avoided costs listed below in Table 8-2 were not yet available when the 2015 Plan was developed and filed with the Commission. As the 2015 Action Plan is finalized in late 2014, Vectren will use the avoided costs from the table below and also for any future modeling of DSM programs for 2016 and beyond. Vectren conducts IRPs every two years. Note that The avoided generating capacity costs are reflective of the estimated replacement capital and fixed operations and maintenance cost for an F-class simple cycle gas turbine, as discussed in Table 6-1 SGCT Classes. The operating and capital costs are assumed to escalate with inflation throughout the study period. The cost assumptions can be found in the Technical Appendix, section B. Transmission and distribution capacity are accounted for within the transmission and distribution avoided cost. Vectren's planning reserve margin position is not factored into the avoided capacity cost as presented. Under the base sales forecast, Vectren does not require additional capacity to meet the planning reserve margin requirement throughout the study period.

The marginal energy cost are reflective of the modeled Vectren system marginal cost of energy from the base scenario under base assumptions. This included variable transaction purchase, emission costs for CO_2 starting in 2020, 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 variable system costs reflected in this calculation can be found in the Technical Appendix, section B.

Table 8-2 Vectren Avoided Costs

	Capacity Surplus / (Deficit)	Generation Avoided Cost	Transmission / Distribution Avoided Cost	Total Capacity Avoided Cost	Marginal Energy Cost	Marginal Energy Cost
	MW	$/kW	$/kW	$/kW	$/MWh	$/kWh
2015	81	$104.01	$10.40	$114.41	$36.94	$0.0369
2016	80	$105.67	$10.57	$116.24	$43.32	$0.0433
2017	102	$107.36	$10.74	$118.10	$45.01	$0.0450
2018	106	$109.08	$10.91	$119.99	$47.58	$0.0476
2019	109	$110.82	$11.08	$121.91	$49.42	$0.0494
2020	109	$112.60	$11.26	$123.86	$63.16	$0.0632
2021	109	$114.40	$11.44	$125.84	$65.23	$0.0652
2022	108	$116.23	$11.62	$127.85	$67.44	$0.0674
2023	108	$118.09	$11.81	$129.90	$69.84	$0.0698
2024	108	$119.98	$12.00	$131.98	$73.54	$0.0735
2025	109	$121.90	$12.19	$134.09	$76.04	$0.0760
2026	109	$123.85	$12.38	$136.23	$79.06	$0.0791
2027	108	$125.83	$12.58	$138.41	$81.84	$0.0818
2028	106	$127.84	$12.78	$140.63	$85.11	$0.0851
2029	105	$129.89	$12.99	$142.88	$89.11	$0.0891
2030	104	$131.97	$13.20	$145.16	$92.79	$0.0928
2031	104	$134.08	$13.41	$147.49	$96.21	$0.0962
2032	102	$136.22	$13.62	$149.85	$100.77	$0.1008
2033	101	$138.40	$13.84	$152.24	$105.98	$0.1060
2034	100	$140.62	$14.06	$154.68	$110.93	$0.1109

A review of the benefit/cost results for each of the technologies considered in the screening analysis is detailed in Table 8-3. Note that measures with a benefit-cost ration of 0.00 indicates no direct technology costs are applied.

Table 8-3 Vectren DSM Technology Screening Results

Residential Technology Analysis Results

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
1	30% Infil. Reduction Electric Furnace no CAC V IQW109	$458	N/A	$118	1.11	$785	3.17	$785	3.17
2	30% Infil. Reduction Electric Furnace w/ CAC V IQW107	$55,076	N/A	$15,424	1.13	$95,634	3.23	$95,634	3.23
3	30% Infil. Reduction Gas Furnace no CAC V IQW111	$55	N/A	($558)	0.18	($478)	0.21	($478)	0.21
4	30% Infil. Reduction Gas Furnace w/ CAC	$19,901	N/A	($58,161)		($29,178)		($29,178)	

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
	V IQW110				0.44		0.61		0.61
5	30% Infil. Reduction Heat Pump V IQW108	$6,012	N/A	$226	1.02	$8,981	2.63	$8,981	2.63
6	5th Grade Kit- Air Filter Alarm V RES113	$16,471	N/A	$8,159	1.29	$31,187	7.34	$31,187	7.34
7	5th Grade Kit- Bathroom Aerator 1.0 gpm V RES110	$5,758	N/A	$671	1.07	$7,862	3.52	$7,862	3.52
8	5th Grade Kit- CFL - 13 W V RES111	$40,416	N/A	($28,761)	0.61	$15,287	1.51	$15,287	1.51
9	5th Grade Kit- CFL - 23 W V RES112	$65,788	N/A	($43,510)	0.63	$28,191	1.63	$28,191	1.63
10	5th Grade Kit- Kitchen Flip Aerator 1.5 gpm V RES109	$2,879	N/A	($1,431)	0.79	$2,165	1.65	$2,165	1.65
11	5th Grade Kit- LED Nightlight V RES114	$16,172	N/A	($15,326)	0.50	$4,874	1.46	$4,874	1.46
12	5th Grade Kit- Low Flow Showerhead 1.5 gpm V RES108	$35,128	N/A	($7,034)	0.89	$31,250	2.29	$31,250	2.29
13	Air Source Heat Pump 16 SEER - no gas available REP113	($7,347)	0.57	($2,518)	0.77	($2,546)	0.77	$1,427	1.20
14	Air Source Heat Pump 16 SEER -gas available REP127	($8,537)	0.50	($1,328)	0.87	($2,546)	0.77	$2,617	1.44
15	Air Source Heat Pump 18 SEER - gas available REP129	($2,249)	0.46	$127	1.05	($1,032)	0.73	$1,450	2.04
16	Air Source Heat Pump 18 SEER - no gas available REP115	($2,074)	0.51	($48)	0.98	($1,032)	0.73	$1,275	1.81
17	Appliance Recycling Freezers ARC102	$84,943	5.32	($298)	1.00	$63,369	2.69	$63,612	2.71
18	Appliance Recycling Refrigerators ARC101	$385,674	5.90	($3,125)	0.99	$269,452	2.67	$268,064	2.64
19	Attic Insulation V IQW112	$3,288	N/A	($13,850)	0.35	($9,061)	0.46	($9,061)	0.46
20	Audit Recommendations IQW V IQW114	$11,374	N/A	($40,699)	0.29	($29,325)	0.36	($29,325)	0.36
21	Audit Recommendations V HEA116	$28,561	N/A	($69,232)	0.35	($44,098)	0.45	($44,098)	0.45
22	Bathroom Aerator IQW V IQW103	$2,874	N/A	($615)	0.90	$3,125	2.21	$3,125	2.21
23	Bathroom Aerator V HEA112	$37,299	N/A	$3,890	1.06	$46,598	3.48	$46,598	3.48
24	Central Air Conditioner 16 SEER REP 116	($21,517)	0.75	($19,160)	0.73	($4,056)	0.93	$3,801	1.08
25	Central Air Conditioner 18 SEER REP 117	($40,415)	0.68	($11,391)	0.89	($19,244)	0.83	$28,384	1.43
26	CFL 0-15W RLT104	$611,084	3.01	($105,148)	0.84	$300,024	2.27	$347,738	2.85
27	CFL 16-20W RLT105	$619,795	3.46	($77,706)	0.87	$320,977	2.55	$360,400	3.15
28	CFL 21W or Greater RLT106	$591,307	4.09	($55,275)	0.90	$314,606	2.85	$344,554	3.46
29	Compact Fluorescent Lamps V HEA101	$309,769	N/A	($390,021)	0.45	($80,547)	0.80	($80,547)	0.80
30	Compact Fluorescent Lamps IQW V IQW101	$69,004	N/A	($127,952)	0.38	($49,613)	0.62	($49,613)	0.62
31	Dual Fuel Air Sourc Heat Pump 16 SEER REP128	($8,537)	0.50	($1,328)	0.87	($2,546)	0.77	$2,617	1.44
32	Duct Sealing Electric Heat Pump REP108	$20,945	1.89	$5,993	1.10	$38,174	2.27	$36,074	2.13
33	Duct Sealing Electric Resistive Furnace REP109	$10,758	4.42	($1,045)	0.95	$13,411	2.65	$13,131	2.56
34	Duct Sealing Gas Heating with A/C REP107	$1,482	1.02	$49,405	1.46	$77,922	1.99	$101,547	2.84
35	Ductless Heat Pump 17 SEER 9.5 HSPF REP123	$2,469	2.84	($1,590)	0.73	$1,603	1.61	$1,628	1.63
36	Ductless Heat Pump 19 SEER 9.5 HSPF REP124	$1,819	1.90	($1,508)	0.74	$1,174	1.37	$1,735	1.67
37	Ductless Heat Pump 21 SEER 10.0 HSPF REP125	$790	1.59	($904)	0.71	$391	1.21	$765	1.51
38	Ductless Heat Pump 23 SEER 10.0 HSPF REP126	$461	1.27	($869)	0.73	$165	1.08	$808	1.54

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
39	Duel Fuel Air Source Heat Pump 18 SEER REP130	($2,249)	0.46	$127	1.05	($1,032)	0.73	$1,450	2.04
40	ECM HVAC Motor REP118	$9,831	1.11	($49,672)	0.56	($17,936)	0.78	($8,311)	0.88
41	Energy Star Ceiling Fans RLT112	($165)	0.74	($59)	0.84	($29)	0.91	$172	2.26
42	Energy Star Fixtures RLT111	$4,481	1.15	($3,400)	0.88	$8,869	1.54	$15,622	2.63
43	Energy Star Reflector CFL V RLT102	$4,738	1.14	($10,011)	0.65	($1,997)	0.90	$8,065	1.78
44	Energy Star Reflector LED V RLT103	$4,345	1.72	($1,530)	0.87	$5,336	2.01	$7,749	3.70
45	Energy Star Specialty CFL V RLT101	$4,738	1.14	($10,011)	0.65	($1,997)	0.90	$8,065	1.78
46	Furnace Filter Whistle IQW V IQW106	$20,061	N/A	$3,847	1.09	$33,063	3.59	$33,063	3.59
47	Gold Star HERS =<67 All Electric RNC105	$524	1.04	($8,690)	0.71	($1,425)	0.94	$7,088	1.49
48	Gold Star HERS =<67 Electric RNC102	$25,046	2.59	($19,160)	0.78	$24,432	1.55	$26,821	1.64
49	Heat Pump Water Heater REP103	$19,345	1.72	($19,604)	0.74	$8,378	1.18	$21,083	1.62
50	Kitchen Aerator IQW V IQW102	$1,848	N/A	($592)	0.86	$1,812	1.97	$1,812	1.97
51	Kitchen Aerator V HEA111	$37,299	N/A	$3,140	1.05	$45,848	3.35	$45,848	3.35
52	LED 13W RLT109	($1,754)	0.95	($5,037)	0.87	$4,357	1.14	$21,940	2.68
53	LED 22W RLT110	$8,841	1.38	$485	1.01	$18,092	1.90	$29,324	4.29
54	LED 7W RLT107	($2,968)	0.78	($2,138)	0.82	($1,314)	0.88	$5,270	2.11
55	LED 9W RLT108	($5,610)	0.75	($4,383)	0.77	($3,977)	0.78	$6,693	1.87
56	LF Showerhead (Whole House) IQW V IQW104	$18,274	N/A	($10,072)	0.75	$10,674	1.53	$10,674	1.53
57	LF Showerhead (Whole House) V HEA113	$99,709	N/A	($36,798)	0.80	$62,816	1.76	$62,816	1.76
58	Opower OPO101	$487,718	N/A	($188,368)	0.79	$299,349	1.73	$299,349	1.73
59	Pipe Wrap (10', 3/4" Wall) IQW V IQW105	$12,656	N/A	$1,510	1.05	$19,942	3.21	$19,942	3.21
60	Pipe Wrap (5', 3/4" Wall) V HEA114	$28,728	N/A	($6,586)	0.90	$30,232	2.10	$30,232	2.10
61	Platinum Star- EPAct Tax Credit All Electric RNC106	$591	1.13	($3,351)	0.71	($165)	0.98	$2,776	1.50
62	Platinum Star- EPAct Tax Credit Electric RNC103	$10,104	1.60	($12,332)	0.78	$9,998	1.29	$17,159	1.62
63	Pool Heater REP111	$9,209	1.31	($3,752)	0.93	$12,595	1.37	$27,184	2.40
64	programmable thermostat REP104	$37,956	4.10	$30,849	1.41	$78,387	3.90	$81,187	4.36
65	Refrigerator Replacement IQW V IQW113	$195,980	N/A	($51,141)	0.91	$245,594	1.98	$245,594	1.98
66	Siver Star HERS =<75 All Electric RNC104	$3,935	2.61	($4,059)	0.72	$2,951	1.40	$3,588	1.53
67	Siver Star HERS =<75 Electric RNC101	$10,658	3.15	($7,321)	0.79	$10,766	1.65	$11,274	1.71
68	Smart programmable thermostat REP120	$54,240	2.55	$62,384	1.46	$135,466	3.19	$145,966	3.83
69	Variable Speed Pool Pump REP110	$6,147	1.12	$48,252	1.58	$66,439	2.02	$87,439	2.99
70	Water Heater Tank Wrap HEA117	$31,284	N/A	($35,875)	0.56	($4,620)	0.91	($4,620)	0.91

Measures with a benefit-cost ration of 0.00 indicates no direct technology costs are applied.

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
1	Anti Sweat - Cooler V CDI101	$53,689	2.18	($39,109)	0.70	$34,169	1.61	$34,169	1.61
2	Anti Sweat - Freezer V CDI102	$33,647	3.96	($7,383)	0.88	$38,540	3.14	$38,540	3.14
3	Barrel Wraps (Inj Mold Only) CIP202	$5,727	6.73	$206	1.03	$5,561	4.57	$5,861	5.65
4	CFL 16-20W Fixture 1 Lamp CIE142	$5,798	2.43	$678	1.06	$8,088	3.09	$10,178	6.69
5	CFL 16-20W Fixture 2 Lamp CIE145	$15,079	4.25	$1,355	1.06	$18,962	4.81	$20,355	6.69
6	CFL 21W+ Fixture 1 Lamp CIE143	$4,265	3.10	$487	1.07	$5,672	3.79	$6,601	7.00
7	CFL 21W+ Fixture 2 Lamp CIE146	$10,271	5.42	$974	1.07	$12,738	5.78	$13,202	7.00
8	CFL Fixture, Direct Install, 18 Watt, Exterior V CDI103	$3,376	N/A	($1,047)	0.86	$3,561	2.35	$3,561	2.35
9	CFL Fixture, Direct Install, 36 Watt, Interior V CDI104	$17,933	N/A	($931)	0.97	$23,544	3.51	$23,544	3.51
10	CFL screw-in: <30W V CDI105	$38,152	N/A	($15,939)	0.76	$24,794	1.94	$24,794	1.94
11	CFL <15W Fixture 1 Lamp CIE141	$2,655	1.65	$295	1.04	$4,295	2.17	$6,617	5.91
12	CFL <15W Fixture 2 Lamp CIE144	$8,794	2.89	$590	1.04	$11,376	3.50	$13,234	5.91
13	Clothes Washer CEE Tier 2 CIP244	($139)	0.71	($21)	0.94	($53)	0.87	$267	4.22
14	Clothes Washer CEE Tier 3 CIP245	($258)	0.57	($31)	0.92	($157)	0.69	$257	3.76
15	Clothes Washer ENERGY STAR/CEE Tier 1 CIP243	($10)	0.94	($5)	0.97	$25	1.16	$138	4.80
16	Cooler - Glass Door 15-30 vol CIP224	$297	3.39	$3	1.01	$361	3.79	$433	8.54
17	Cooler - Glass Door 30-50 vol CIP225	$435	6.30	$7	1.01	$503	5.91	$539	9.05
18	Cooler - Glass Door <15 vol CIP223	$220	4.07	($5)	0.99	$254	4.28	$286	7.32
19	Cooler - Glass Door >50 vol CIP226	$753	10.18	$26	1.03	$869	7.88	$900	10.39
20	Cooler - Reach-In Electronically Commutated (EC) Motor CIP238	$1,773	4.55	($118)	0.96	$2,081	4.87	$2,181	5.99
21	Cooler - Solid Door 15-30 vol CIP220	$149	1.60	($29)	0.94	$202	1.90	$346	5.27
22	Cooler - Solid Door 30-50 vol CIP221	$361	5.40	$2	1.00	$417	5.30	$452	8.37
23	Cooler - Solid Door <15 vol CIP219	$91	2.28	($14)	0.92	$104	2.54	$136	4.84
24	Cooler - Solid Door >50 vol CIP222	$576	8.03	$13	1.02	$663	6.87	$693	9.42
25	Cooler - Walk-In Electronically Commutated (EC) Motor CIP235	$1,462	4.90	($100)	0.96	$1,703	5.13	$1,778	6.27
26	Cooler Anti-Sweat Heater Controls - Conductivity-Based CIP216	$239	2.19	$19	1.04	$334	2.76	$444	6.58
27	Cooler Anti-Sweat Heater Controls - Humidity-Based CIP215	$28	1.19	$2	1.01	$74	1.56	$169	5.62
28	Cooler Controller - occupancy sensor V CDI106	$16,843	6.91	($1,002)	0.97	$21,128	4.18	$21,840	4.68
29	Delamping, T12 to T8, 4' V CDI108	$59,889	N/A	$16,927	1.18	$98,666	9.71	$98,666	9.71
30	Delamping, T12 to T8, 8' V CDI109	$24,811	N/A	$7,020	1.18	$40,883	9.71	$40,883	9.71
31	Delamping, >=400 Watt Fixture V CDI107	$48,989	N/A	$13,958	1.18	$80,821	9.71	$80,821	9.71
32	Demand Controlled Ventilation - CO CIP165	$961	4.34	$383	1.25	$1,589	6.14	$1,704	9.79
33	Demand Controlled Ventilation - CO2 CIP164	$1,922	4.34	$766	1.25	$3,177	6.14	$3,407	9.79
34	Door Closers for Cooler CDI142	$16,426	2.07	($16,277)	0.61	$2,205	1.09	$6,033	1.31

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
35	Door Closers for Freezer CDI143	$45,048	3.94	($23,049)	0.73	$26,959	1.78	$30,788	2.00
36	EC Motor Reach-in V CDI110	$8,130	2.14	($3,488)	0.84	$9,163	2.03	$10,939	2.53
37	EC Motor Walk-in V CDI111	$8,309	1.70	($6,787)	0.75	$6,664	1.48	$9,624	1.88
38	EDA - Lighting Power Density Reduction CNC101	$41,883	1.24	$3,144	1.01	$124,901	1.54	$260,146	3.76
39	EDA - Non Lighting Measures CNC102	($41,916)	0.73	($49,757)	0.72	($61,110)	0.68	$69,363	2.18
40	Electric Chiller - Air cooled, with condenser CIP156	$150	2.81	$125	1.42	$347	5.40	$383	9.92
41	Electric Chiller - Air cooled, without condenser CIP157	($25)	0.40	$14	1.66	$0	1.01	$28	5.96
42	Electric Chiller - Water Cooled, Centrifugal 150-300 tons CIP162	$28	1.60	$30	1.32	$83	3.04	$105	6.59
43	Electric Chiller - Water Cooled, Centrifugal <150 tons CIP161	$24	1.39	$37	1.34	$94	2.73	$129	7.59
44	Electric Chiller - Water Cooled, Centrifugal >300 tons CIP163	$76	2.10	$54	1.29	$175	3.80	$201	6.38
45	Electric Chiller - Water Cooled, Rotary Screw 150-300 tons CIP159	$45	2.51	($13)	0.87	$55	2.98	$64	4.38
46	Electric Chiller - Water Cooled, Rotary Screw <150 tons CIP158	$29	1.69	$41	1.46	$94	3.54	$112	7.05
47	Electric Chiller - Water Cooled, Rotary Screw >300 tons CIP160	$53	3.52	$31	1.33	$104	6.07	$106	6.64
48	Electric Chiller Tune-up - Air cooled, with condenser CIP172	$24	3.17	$7	1.18	$30	3.34	$35	5.36
49	Electric Chiller Tune-up - Water Cooled, Centrifugal 150-300 tons CIP178	$9	1.82	$1	1.06	$11	2.01	$16	3.76
50	Electric Chiller Tune-up - Water Cooled, Centrifugal >300 tons CIP179	$8	1.70	$1	1.04	$9	1.88	$14	9.92
51	Electric Chiller Tune-up - Water Cooled, Rotary Screw 150-300 tons CIP175	$10	1.89	$1	1.03	$11	2.02	$16	5.96
52	Electric Chiller Tune-up - Water Cooled, Rotary Screw >300 tons CIP176	$8	1.76	$1	1.07	$11	1.98	$15	7.59
53	ENERGY STAR CEE Tier 1 Window\Sleeve\Room AC < 14,000 BTUH CIP118	$6	1.15	$33	1.63	$51	2.45	$75	7.87
54	ENERGY STAR CEE Tier 2 Window\Sleeve\Room AC < 14,000 BTUH CIP170	($82)	0.34	$54	2.12	($0)	1.00	$75	8.19
55	ENERGY STAR CEE Tier 2 Window\Sleeve\Room AC >= 14,000 BTUH CIP171	($181)	0.27	$101	2.29	($25)	0.88	$75	11.68
56	ENERGY STAR Commercial Dishwasher - Door Type, High Temp CIP249	$4,292	18.17	$501	1.09	$5,552	12.13	$5,502	11.03
57	ENERGY STAR Commercial Dishwasher - Multi-Tank Conveyor, Low Temp CIP252	$5,646	12.64	$884	1.11	$8,216	11.86	$8,229	12.06
58	ENERGY STAR Commercial Dishwasher - Under Counter, High Temp CIP247	$1,580	4.16	$12	1.00	$1,769	4.17	$1,994	6.99
59	ENERGY STAR Commercial Dishwasher - Under Counter, Low Temp CIP246	$119	1.45	($45)	0.89	$140	1.59	$277	3.75
60	ENERGY STAR Commercial Fryer CIP103	$78	1.31	$22	1.06	$175	1.79	$325	5.60
61	ENERGY STAR Commercial Hot Holding Cabinets Full Size CIP104	$1,195	3.15	($1)	1.00	$1,443	3.60	$1,637	5.53
62	ENERGY STAR Commercial Hot Holding Cabinets Half Size CIP105	$101	1.18	($34)	0.95	$227	1.47	$546	4.32
63	ENERGY STAR Commercial Hot Holding Cabinets Three Quarter Size CIP106	$432	1.78	($37)	0.97	$581	2.15	$850	4.61

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
64	ENERGY STAR Commercial Ice Machine < 500 lb/day harvest rate CIP114	($123)	0.54	($42)	0.73	($110)	0.51	$55	1.94
65	ENERGY STAR Commercial Ice Machine >=1000 lb/day harvest rate CIP116	($471)	0.53	($91)	0.84	($355)	0.58	$323	3.01
66	ENERGY STAR Commercial Ice Machine >=500 and <1000 lb/day harvest rate CIP115	($4,241)	0.43	($685)	0.80	($3,406)	0.45	$1,659	2.54
67	ENERGY STAR Commercial Steam Cookers 3 Pan CIP107	$1,123	1.32	$36	1.01	$2,215	1.72	$4,265	5.14
68	ENERGY STAR Commercial Steam Cookers 4 Pan CIP108	$2,419	1.69	$4	1.00	$3,575	2.13	$5,375	4.96
69	ENERGY STAR Commercial Steam Cookers 5 Pan CIP109	$2,214	2.27	$64	1.01	$2,934	2.79	$3,709	5.28
70	ENERGY STAR Commercial Steam Cookers 6 Pan CIP110	$2,957	2.69	$72	1.01	$3,743	3.22	$4,393	5.23
71	ENERGY STAR Convection Oven CIP111	$564	2.01	$16	1.01	$779	2.52	$1,049	5.31
72	ENERGY STAR Griddles CIP112	$1,348	2.29	$65	1.02	$1,810	2.84	$2,296	5.61
73	ENERGY STAR Window\Sleeve\Room AC < 14,000 BTUH CIP117	$24	2.20	$35	1.70	$67	4.53	$77	9.64
74	ENERGY STAR Window\Sleeve\Room AC >= 14,000 BTUH CIP119	$47	3.35	$58	1.75	$114	6.57	$123	11.69
75	Faucet Aerators-electric V CDI112	$2,777	N/A	($235)	0.95	$3,378	4.33	$3,378	4.33
76	Fluorescent Exit Sign To LED Exit Sign CIE135	$40,257	2.47	($10,427)	0.87	$44,602	2.78	$48,247	3.25
77	Freezer - Glass Door 15-30 vol CIP232	$611	8.36	($28)	0.97	$657	6.79	$648	6.31
78	Freezer - Glass Door 30-50 vol CIP233	$1,242	15.97	($6)	1.00	$1,366	9.56	$1,332	7.90
79	Freezer - Glass Door <15 vol CIP231	$351	5.94	($21)	0.96	$378	5.44	$385	5.92
80	Freezer - Glass Door >50 vol CIP234	$2,357	12.58	$8	1.00	$2,625	8.63	$2,612	8.33
81	Freezer - Reach-In Electronically Commutated (EC) Motor CIP237	$228	5.57	($13)	0.96	$266	5.65	$276	6.84
82	Freezer - Solid Door 15-30 vol CIP228	$665	9.01	($23)	0.97	$720	7.12	$711	6.64
83	Freezer - Solid Door 30-50 vol CIP229	$872	11.50	($34)	0.97	$932	8.10	$899	6.45
84	Freezer - Solid Door <15 vol CIP227	$262	4.68	($28)	0.93	$273	4.49	$280	4.92
85	Freezer - Solid Door >50 vol CIP230	$1,497	8.36	($58)	0.97	$1,620	6.81	$1,608	6.53
86	Freezer - Walk-In Electronically Commutated (EC) Motor CIP236	$916	8.33	($76)	0.94	$1,020	7.16	$1,020	7.16
87	Freezer Anti-Sweat Heater Controls - Conductivity-Based CIP218	$362	4.62	$23	1.04	$443	4.98	$473	6.82
88	Freezer Anti-Sweat Heater Controls - Humidity-Based CIP217	$249	2.66	($17)	0.96	$291	3.01	$336	4.37
89	Halogen 120W x3 To CMH 150W - Retrofit CIE134	$14,364	6.00	$2,071	1.10	$19,539	6.90	$19,923	7.80
90	Halogen 120W x3 To CMH 150W - Turnover CIE115	$15,464	5.77	$3,054	1.13	$22,016	6.90	$23,168	9.97
91	Halogen 50W x2 To CMH 20W - Retrofit CIE129	$2,561	1.62	$539	1.07	$4,881	2.32	$7,245	6.41
92	Halogen 50W x2 To CMH 20W - Turnover CIE110	$2,706	1.58	$787	1.09	$5,500	2.32	$8,344	7.28
93	Halogen 50W x2 To MH 20W Track - Retrofit CIE126	$618	1.40	$186	1.07	$1,418	2.05	$2,348	6.59
94	Halogen 50W x2 To MH 20W Track - Turnover CIE107	$3,036	1.40	$912	1.07	$6,959	2.05	$11,527	6.59
95	Halogen 65W x3 To CMH 50W - Retrofit CIE131	$9,293	4.06	$1,395	1.09	$13,093	5.16	$14,083	7.53

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
96	Halogen 65W x3 To CMH 50W - Turnover CIE112	$9,930	3.90	$2,112	1.13	$14,752	5.16	$16,408	9.68
97	Halogen 75W x2 To CMH 39W - Retrofit CIE130	$4,622	2.27	$739	1.07	$7,264	3.15	$9,049	6.70
98	Halogen 75W x2 To CMH 39W - Turnover CIE111	$5,963	2.27	$954	1.07	$9,372	3.15	$11,676	6.70
99	Halogen 75W x2 To MH 39W Track - Retrofit CIE127	$1,441	1.94	$275	1.08	$2,448	2.75	$3,280	6.79
100	Halogen 75W x2 To MH 39W Track - Turnover CIE108	$8,513	1.94	$1,624	1.08	$14,466	2.75	$19,380	6.79
101	Halogen 75W x3 To CMH 70W - Retrofit CIE132	$8,661	4.27	$1,185	1.09	$12,014	5.33	$12,739	7.21
102	Halogen 75W x3 To CMH 70W - Turnover CIE113	$10,456	4.06	$2,249	1.13	$15,502	5.33	$17,158	9.91
103	Halogen 75W x3 To MH 70W Track - Retrofit CIE128	$2,627	2.83	$433	1.09	$3,936	3.84	$4,589	7.28
104	Halogen 75W x3 To MH 70W Track - Turnover CIE109	$15,521	2.83	$2,559	1.09	$23,256	3.84	$27,117	7.28
105	Halogen 90W x3 To CMH 100W - Retrofit CIE133	$11,327	4.94	$1,481	1.09	$15,438	5.94	$15,981	7.19
106	Halogen 90W x3 To CMH 100W - Turnover CIE114	$12,043	4.72	$2,389	1.13	$17,394	5.94	$18,726	9.56
107	Heat Pump Water Heater 10-50 MBH CIP255	$27,103	3.71	$2,908	1.07	$37,311	4.65	$40,311	6.57
108	HID 101W-175W To T5 Garage 2 Lamp CIE159	($6,247)	0.73	($8,549)	0.52	($10,409)	0.47	($1,040)	0.90
109	HID 176W+ To T5 Garage 3 Lamp CIE160	$834	1.07	($6,812)	0.47	($3,827)	0.61	($1,792)	0.77
110	HID 75W-100W To T5 Garage 1 Lamp CIE158	($12,753)	0.46	($4,919)	0.55	($13,185)	0.31	$87	1.01
111	HID To Induction Lamp and Fixture 55-100W CIE204	($616)	0.47	$55	1.08	($245)	0.75	$574	4.95
112	HID To Induction Lamp and Fixture >100W CIE205	($27,147)	0.36	$3,072	1.16	($13,089)	0.62	$18,771	7.30
113	HID >400W to Exterior LED or Induction CIP199	$17	2.10	$5	1.13	$30	3.15	$38	7.61
114	HID >400W to Garage LED or Induction CIP200	$4	2.10	$1	1.13	$8	3.15	$10	7.61
115	High Efficiency Pumps - 1.5hp CIP203	$103	1.29	$45	1.08	$283	1.93	$503	6.85
116	High Efficiency Pumps - 10hp CIP208	$1,846	12.12	$395	1.16	$2,586	11.00	$2,599	11.58
117	High Efficiency Pumps - 15hp CIP209	$2,339	9.00	$541	1.17	$3,350	9.38	$3,444	12.26
118	High Efficiency Pumps - 20hp CIP210	$4,073	5.79	$942	1.16	$5,945	7.03	$6,305	11.07
119	High Efficiency Pumps - 2hp CIP204	$162	1.92	$27	1.07	$271	2.70	$361	6.23
120	High Efficiency Pumps - 3hp CIP205	$471	3.69	$99	1.13	$701	4.92	$781	8.90
121	High Efficiency Pumps - 5hp CIP206	$1,031	7.05	$226	1.15	$1,477	8.00	$1,533	10.92
122	High Efficiency Pumps - 7.5hp CIP207	$1,579	7.34	$370	1.17	$2,284	8.27	$2,384	12.09
123	Incandescent To CFL 16-20W Screw-In CIE139	$5,023	10.61	($532)	0.91	$3,837	3.82	$3,906	4.03
124	Incandescent To CFL 21W+ Screw-In CIE140	$2,230	8.68	($369)	0.86	$1,593	3.50	$1,535	3.21
125	Incandescent To CFL <15W Screw-In CIE138	$7,100	7.80	($960)	0.89	$5,262	3.41	$5,402	3.64
126	Incandescent Traffic Signal To LED Traffic Signal Pedestrian 12" CIE137	$21,726	2.79	($3,430)	0.91	$21,988	2.81	$28,671	6.25
127	Incandescent Traffic Signal To LED Traffic Signal Round 8" Red CIE136	$4,272	1.59	($1,197)	0.91	$4,931	1.75	$8,940	4.45
128	Industrial Request for Proposals - Elec CUS109	$8,218	1.75	($2,373)	0.91	$10,428	1.75	$17,627	3.63
129	Industrial Staffing Grants - Elec CUS108	$8,218	1.75	($2,373)	0.91	$10,428	1.75	$17,627	3.63
130	Large Industrial Custom Measure - Non	$116,770		($30,687)		$145,242		$227,929	

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
	Lighting CUS101		1.89		0.91		1.86		3.63
131	LED A-Line 8-12W CIE162	$10,449	1.99	($2,431)	0.89	$9,009	1.87	$13,755	3.47
132	LED Decoratives 2-4W CIE161	$140	1.23	($172)	0.78	$56	1.10	$335	2.24
133	LED Exterior Wall-Pack 30W-75W CIE174	$2,902	1.36	$366	1.03	$5,720	1.81	$10,512	5.63
134	LED Exterior Wall-Pack 75W+ CIE175	$7,841	1.65	$1,290	1.06	$13,129	2.21	$20,318	6.56
135	LED Exterior Wall-Pack <30W CIE173	$6,377	2.21	$415	1.03	$8,766	2.77	$11,304	5.69
136	LED Fixture <250W, Replacing 400W HID, HighBay V CDI113	$13,142	1.59	($9,928)	0.79	$11,749	1.46	$17,309	1.87
137	LED for Walk in Cooler V CDI114	$10,734	1.19	($33,049)	0.61	($10,205)	0.83	$4,003	1.09
138	LED for Walk in Freezer V CDI115	$5,749	1.20	($16,378)	0.62	($4,388)	0.86	$2,716	1.12
139	LED MR16 4-7W CIE166	$473	1.22	($560)	0.80	$317	1.17	$1,220	2.27
140	LED Open Sign V CDI116	$27,587	4.88	$3,027	1.06	$41,327	4.26	$43,103	4.96
141	LED Outdoor Decorative Post 30W-75W CIE168	$2,902	1.36	$366	1.03	$5,720	1.81	$10,512	5.63
142	LED Outdoor Decorative Post 75W+ CIE169	$7,841	1.65	$1,290	1.06	$13,129	2.21	$20,318	6.56
143	LED Outdoor Decorative Post <30W CIE167	$6,377	2.21	$415	1.03	$8,766	2.77	$11,304	5.69
144	LED PAR 20 7-9W CIE163	$928	1.44	($200)	0.94	$1,123	1.58	$2,292	4.03
145	LED PAR 30 10-13W CIE164	$5,141	1.61	($611)	0.96	$6,093	1.78	$10,756	4.42
146	LED PAR 38 10-21W CIE165	$21,522	2.23	($2,793)	0.93	$21,858	2.30	$28,851	3.93
147	LED Parking Garage/Canopy 30W-75W CIE171	$1,921	1.36	$243	1.03	$3,786	1.81	$6,959	5.63
148	LED Parking Garage/Canopy 75W+ CIE172	$5,191	1.65	$854	1.06	$8,691	2.21	$13,450	6.56
149	LED Parking Garage/Canopy <30W CIE170	$4,274	2.21	$278	1.03	$5,875	2.77	$7,576	5.69
150	LED Recessed Downlight V CDI117	$19,708	2.46	($1,564)	0.97	$28,759	2.64	$32,311	3.31
151	LED, Exit Sign, Retrofit V CDI118	$13,304	N/A	($7,931)	0.74	$11,833	2.13	$11,833	2.13
152	LED, Refrigerated Case, Replaces T12 or T8 V CDI119	$29,418	1.30	($74,323)	0.55	($18,547)	0.83	$6,317	1.07
153	LEDs: 8-12W V CDI122	$30,516	N/A	($7,788)	0.86	$29,919	2.54	$29,919	2.54
154	LEDs: 8-12W V CDI123	$17,175	N/A	($4,383)	0.86	$16,840	2.54	$16,840	2.54
155	LEDs: MR16 track V CDI124	$36,993	N/A	($6,825)	0.90	$38,887	2.86	$38,887	2.86
156	LEDs: MR16 track V CDI125	$20,821	N/A	($3,841)	0.90	$21,887	2.86	$21,887	2.86
157	LEDs: >12W Flood V CDI120	$51,786	N/A	($7,940)	0.91	$56,050	3.02	$56,050	3.02
158	LEDs: >12W Flood V CDI121	$19,420	N/A	($2,978)	0.91	$21,019	3.02	$21,019	3.02
159	Low Flow Pre-Rinse Sprayer - Electric CIP242	$3,052	35.87	($52)	0.98	$2,735	6.90	$2,742	7.01
160	Market Segment Programs - Elec CUS105	$8,218	1.75	($2,373)	0.91	$10,428	1.75	$17,627	3.63
161	MH 1000W Pulse Start To T5 46" 10 Lamp HO - Turnover CIE105	$132,715	8.86	$21,253	1.12	$179,716	9.00	$179,153	8.78
162	MH 1000W Pulse Start To T5 46" 12 Lamp HO - Turnover CIE106	$84,985	6.97	$10,884	1.09	$113,138	7.59	$112,663	7.38
163	MH 1000W To T5 46" 10 Lamp HO - Retrofit CIE124	$132,715	8.86	$21,253	1.12	$179,716	9.00	$179,153	8.78
164	MH 1000W To T5 46" 12 Lamp HO -	$56,388		$7,222		$75,068		$74,753	

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
	Retrofit CIE125		6.97		1.09		7.59		7.38
165	MH 1000W To T8VHO 48" 8 Lamp (2 fixtures) CIP187	$4,072	6.43	($183)	0.96	$3,880	4.86	$3,855	4.74
166	MH 150W Pulse Start To T5 46" 2 Lamp HO - Turnover CIE101	$5,637	1.24	$2,653	1.08	$17,219	1.83	$32,224	6.73
167	MH 175W To T5 46" 2 Lamp HO - Retrofit CIE120	$17,621	1.74	$2,785	1.06	$30,921	2.45	$43,557	6.05
168	MH 175W To T5 46" 3 Lamp HO - Retrofit CIE121	($6,991)	0.70	($3,617)	0.81	($4,156)	0.79	$8,480	2.21
169	MH 200W Pulse Start To T5 46" 3 Lamp HO - Turnover CIE102	($131)	0.99	$1,153	1.04	$8,998	1.44	$24,003	5.58
170	MH 200W To LED High Bay 139W CIE118	$317	1.04	($694)	0.92	$1,096	1.16	$5,740	3.70
171	MH 250W To LED High Bay 175W CIE119	$12,997	1.34	($4,175)	0.92	$16,097	1.46	$37,432	3.78
172	MH 250W To LED Low Bay 85 W3 CIE116	$10,051	2.30	($1,166)	0.94	$10,264	2.37	$13,360	4.03
173	MH 250W To T8VHO 48" 4 Lamp CIP184	$2,799	1.93	($496)	0.92	$2,720	1.95	$4,120	3.82
174	MH 320W Pulse Start To T5 46" 4 Lamp HO - Turnover CIE103	$47,012	2.39	$9,667	1.10	$75,276	3.37	$93,276	7.79
175	MH 350W Pulse Start To T5 46" 6 Lamp HO - Turnover CIE104	$1,046	1.06	($1,009)	0.95	$5,628	1.39	$14,628	3.72
176	MH 400W To T5 46" 4 Lamp HO - Retrofit CIE122	$108,061	4.20	$12,814	1.08	$147,878	5.21	$155,753	6.72
177	MH 400W To T5 46" 6 Lamp HO - Retrofit CIE123	$36,116	2.07	$3,997	1.05	$56,539	2.83	$72,289	5.78
178	MH 400W To T8VHO 48" 6 Lamp CIP185	$5,930	2.98	($387)	0.96	$5,849	2.86	$7,049	4.62
179	MH 400W To T8VHO 48" 8 Lamp CIP186	$966	2.29	($151)	0.92	$911	2.24	$1,211	3.77
180	Network PC Power Management Software CIP214	$306	3.55	($97)	0.78	$186	2.21	$252	3.89
181	Night Covers V CDI126	$5,769	1.73	($6,168)	0.64	$651	1.06	$2,640	1.31
182	No controls To Ceiling-Mounted Occupancy Sensors CIE180	$50,987	4.48	($10,188)	0.85	$43,051	3.54	$48,110	5.04
183	No controls To Ceiling-Mounted Occupancy Sensors >500W Connected CIP190	$5,164	8.82	($724)	0.88	$4,510	5.46	$4,638	6.25
184	No controls To Central Lighting Controls (Timeclocks) CIE185	$119	1.10	($395)	0.71	($55)	0.95	$591	2.60
185	No controls To Central Lighting Controls (Timeclocks) >500W Connected CIP195	$49	1.95	($20)	0.81	$38	1.77	$69	4.83
186	No controls To Fixture Mounted Daylight Dimming Sensors CIE183	$916	1.66	($20)	0.99	$1,153	1.90	$1,850	4.15
187	No controls To Fixture Mounted Daylight Dimming Sensors >500W Connected CIP193	$10,648	11.65	$1,487	1.12	$12,210	7.91	$12,210	7.91
188	No controls To Fixture Mounted Occupancy Sensors CIE181	($1,238)	0.70	($801)	0.74	($1,233)	0.65	$1,431	2.65
189	No controls To Fixture Mounted Occupancy Sensors >500W Connected CIP191	$9,148	4.66	($1,448)	0.88	$8,075	3.72	$9,275	6.25
190	No controls To LED Case Lighting Sensor Controls CIP196	$2,123	2.63	$99	1.03	$2,446	2.85	$3,186	6.44
191	No controls To Remote-Mounted Daylight Dimming Sensors CIE182	$2,597	4.55	$292	1.08	$3,001	4.53	$3,249	6.38
192	No controls To Remote-Mounted Daylight Dimming Sensors >500W Connected CIP192	$1,293	8.96	$186	1.12	$1,496	6.97	$1,526	7.91
193	No controls To Switching Controls for Multi-Level Lighting CIE184	($5,195)	0.32	($248)	0.90	($3,936)	0.37	$1,622	3.23
194	No controls To Switching Controls for Multi-Level Lighting >500W Connected CIP194	$771	2.13	$122	1.08	$1,015	2.52	$1,463	7.63

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
195	No controls To Wall-Mounted Occupancy Sensors CIE179	$25,210	3.71	($6,241)	0.83	$20,488	3.02	$23,505	4.30
196	No controls To Wall-Mounted Occupancy Sensors >500W Connected CIP189	$5,404	13.87	($724)	0.88	$4,702	6.74	$4,638	6.25
197	Occupancy Sensor, Wall Mount, >200 Watts V CDI128	$46,730	3.19	($16,159)	0.83	$42,841	2.26	$48,172	2.68
198	Occupancy Sensor, Wall Mount, <=200 Watts V CDI127	$6,114	2.15	($4,027)	0.73	$3,842	1.54	$5,176	1.89
199	Outside Air Economizer with Dual-Enthalpy Sensors CIP167	($172)	0.57	($25)	0.90	($109)	0.67	$161	3.49
200	Packaged Terminal Air Conditioner (PTAC) 65,000-135,000 BtuH CIP141	($326)	0.97	$8,588	1.74	$11,611	2.36	$18,111	9.76
201	Packaged Terminal Air Conditioner (PTAC) <65,000 BtuH CIP140	($346)	0.97	$9,198	1.80	$12,198	2.42	$18,698	10.05
202	Packaged Terminal Heat Pump (PTHP) 65,000-135,000 BtuH CIP143	($363)	0.96	$7,591	1.66	$10,572	2.23	$17,072	9.26
203	Packaged Terminal Heat Pump (PTHP) <65,000 BtuH CIP142	($382)	0.96	$8,204	1.71	$11,162	2.30	$17,662	9.55
204	Pellet Dryer Duct Insulation 3in -8in dia CIP201	$839	2.29	($307)	0.80	$553	1.83	$773	2.73
205	Performance Based Industrial Assessments - Elec CUS106	$8,218	1.75	($2,373)	0.91	$10,428	1.75	$17,627	3.63
206	Plug Load Occupancy Sensors CIP212	$262	1.37	($306)	0.70	$87	1.14	$447	2.65
207	Pre-Rinse Spray Valves - ele V CDI129	$6,301	N/A	($1,263)	0.87	$5,890	3.56	$5,890	3.56
208	Programmable Thermostat CDI137	$647,200	N/A	($113,077)	0.91	$621,676	2.28	$621,676	2.28
209	PSMH 1000W To T8VHO 48" 8 Lamp (2 fixtures) CIP197	$5,683	8.58	$1,298	1.17	$8,143	9.10	$8,443	12.96
210	Refrigerated Case Covers CIP239	$250	1.60	($262)	0.62	$24	1.06	$210	1.97
211	Self-Generation Efficiency Improvements - Elec CUS107	$8,218	1.75	($2,373)	0.91	$10,428	1.75	$17,627	3.63
212	Showerheads-electric V CDI130	$3,016	N/A	($231)	0.95	$3,693	4.42	$3,693	4.42
213	Smart Strip Plug Outlet CIP211	($4)	0.98	($29)	0.81	($4)	0.97	$76	2.52
214	Smart Strips CDI138	$11,467	N/A	($35,603)	0.32	($21,432)	0.44	($21,432)	0.44
215	Snack Machine Controller (Non-refrigerated vending) CIP213	$351	1.32	($296)	0.80	$167	1.17	$731	2.64
216	Specialty CFLs: Reflectors V CDI131	$10,774	N/A	($11,491)	0.55	($353)	0.98	($353)	0.98
217	Split System Heat Pump 135,000-240,000 BtuH CIP149	($228)	0.96	$4,336	1.63	$6,096	2.19	$9,896	8.43
218	Split System Heat Pump 240,000-760,000 BtuH CIP150	($4,412)	0.51	$3,369	1.62	$1,382	1.19	$7,782	8.32
219	Split System Heat Pump 65,000-135,000 BtuH CIP148	($127)	0.96	$2,657	1.66	$3,700	2.23	$5,975	9.26
220	Split System Heat Pump <65,000 BtuH CIP147	($19)	0.96	$410	1.71	$558	2.30	$883	9.55
221	Split System Unitary Air Conditioner 135,000-240,000 BtuH CIP153	($129)	0.97	$3,075	1.71	$4,191	2.31	$6,566	8.89
222	Split System Unitary Air Conditioner 240,000-760,000 BtuH CIP154	($5,494)	0.51	$4,791	1.70	$2,332	1.25	$10,332	8.77
223	Split System Unitary Air Conditioner 65,000-135,000 BtuH CIP152	($245)	0.97	$6,441	1.74	$8,708	2.36	$13,583	9.76
224	Split System Unitary Air Conditioner <65,000 BtuH CIP151	($260)	0.97	$6,899	1.80	$9,149	2.42	$14,024	10.05
225	Split System Unitary Air Conditioner >760,000 BtuH CIP155	($14,058)	0.38	$6,711	1.65	($1,651)	0.91	$14,799	7.63
226	Strip Curtains Cooler CDI144	$656	1.01	($36,333)	0.29	($34,476)	0.30	($23,298)	0.39
227	Strip Curtains Freezer CDI145	$86,941	2.62	($64,121)	0.66	$33,008	1.35	$46,464	1.58

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
228	System Study CUS102	$47,415	7.16	($6,819)	0.91	$53,528	4.27	$50,651	3.63
229	T12 18" 1 Lamp To Delamp CIE147	$1,061	N/A	$42	1.04	$1,141	16.44	$1,019	6.19
230	T12 24" 1 Lamp To Delamp CIE148	$6,891	N/A	$482	1.06	$7,630	16.44	$7,016	7.33
231	T12 36" 1 Lamp To Delamp CIE149	$2,000	N/A	$205	1.09	$2,282	16.44	$2,160	8.99
232	T12 46" 1 Lamp To T5 46" 1 Lamp CIE154	$342	1.22	($106)	0.95	$606	1.45	$1,469	4.00
233	T12 46" 2 Lamp To T5 46" 2 Lamp CIE155	$6,104	2.32	($79)	0.99	$7,318	2.66	$9,348	4.94
234	T12 46" 3 Lamp To T5 46" 3 Lamp CIE156	$7,448	3.43	$105	1.01	$8,538	3.69	$9,521	5.35
235	T12 46" 4 Lamp To T5 46" 4 Lamp CIE157	$22,669	4.69	$702	1.02	$25,627	4.72	$26,856	5.74
236	T12 48" 1 Lamp To Delamp CIE150	$71,597	N/A	$7,541	1.09	$81,894	16.44	$77,671	9.15
237	T12 6' To Refrigerated Display Case Lighting 6' LED - Cooler CIP181	($2,341)	0.63	($568)	0.86	($1,692)	0.68	$2,308	2.82
238	T12 6' To Refrigerated Display Case Lighting 6' LED - Freezer CIP183	($1,873)	0.63	($454)	0.86	($1,354)	0.68	$1,846	2.82
239	T12 60" 1 Lamp To Delamp CIE151	$3,282	N/A	$393	1.11	$3,804	16.44	$3,651	10.14
240	T12 72" 1 Lamp To Delamp CIE152	$7,243	N/A	$903	1.11	$8,430	16.44	$8,121	10.51
241	T12 96" 1 Lamp To Delamp CIE153	$60,800	N/A	$8,362	1.12	$71,570	16.44	$69,651	11.63
242	T8 2 Lamp 4' To LED 1 Lamp Linear 4' CIE178	($5,043)	0.80	($1,837)	0.92	($524)	0.98	$14,434	3.38
243	T8 2L 4', 28W, CEE V CDI132	$16,306	1.18	($55,730)	0.56	($25,373)	0.74	($3,171)	0.96
244	T8 3 Lamp 4' To LED 2 Lamp Linear 4' CIE177	($2,105)	0.85	($1,588)	0.88	($1)	1.00	$8,063	2.97
245	T8 3L 4', 28W, CEE V CDI133	$6,935	1.33	($12,528)	0.64	($1,118)	0.95	$4,214	1.23
246	T8 4L 4', 28W, CEE V CDI134	$16,613	1.25	($40,353)	0.60	($11,630)	0.84	$4,946	1.09
247	T8 5' To Refrigerated Display Case Lighting 5' LED - Cooler CIP180	($790)	0.37	($75)	0.85	($619)	0.40	$256	2.64
248	T8 5' To Refrigerated Display Case Lighting 5' LED - Freezer CIP182	($790)	0.37	($75)	0.85	($619)	0.40	$256	2.64
249	T8 6L or T5HO 4L Replacing 400-999 W HID V CDI135	$418,460	2.96	($25,775)	0.97	$564,806	2.87	$618,086	3.48
250	T8 HO 96" 2 Lamp To LED Low Bay 85 W3 CIE117	($1,674)	0.93	($3,754)	0.84	($947)	0.95	$11,873	2.64
251	T8 To 21" Tubular Skylight/Light Tube CIP188	($513)	0.59	$7	1.01	($231)	0.78	$644	4.82
252	T8 U-Tube 2 Lamp 2' To LED U-Tube CIE176	($466)	0.68	($143)	0.87	($255)	0.79	$615	2.81
253	Typical Custom Measure - Lighting CUS103	$167,953	1.52	$16,810	1.02	$368,488	1.96	$605,926	5.11
254	Typical Custom Measure - Non-Lighting CUS104	$102,880	1.26	($88,493)	0.87	$134,708	1.29	$431,727	3.48
255	Vending Machine Occ Sensor - Refrigerated Glass Front Cooler CIE187	$1,682	2.08	($350)	0.90	$1,379	1.86	$2,260	4.11
256	Vending Machine Occ Sensor - Refrigerated Beverage CIE186	$7,920	2.70	($1,040)	0.92	$6,757	2.30	$9,401	4.69
257	Vending Miser V CDI136	$16,535	2.75	($10,318)	0.70	$8,774	1.56	$11,142	1.83
258	VFD CHW Pump 20-100hp - Hospital CIP129	$120,238	37.83	$12,528	1.08	$153,600	14.81	$154,962	16.88
259	VFD CHW Pump 20-100hp - Hotel CIP123	$121,367	38.17	$8,185	1.05	$150,572	14.44	$151,934	16.44
260	VFD CHW Pump 20-100hp - Large Office CIP135	$68,869	22.09	$9,241	1.10	$90,464	12.99	$91,826	15.85
261	VFD CHW Pump <20hp - Hospital	$28,808		$2,407		$36,345		$36,591	

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
	CIE190		21.11		1.06		12.40		13.44
262	VFD CHW Pump <20hp - Hotel CIE195	$14,539	21.30	$682	1.04	$17,809	12.11	$17,932	13.11
263	VFD CHW Pump <20hp - Large Office CIE200	$16,479	12.50	$1,618	1.07	$21,192	10.09	$21,438	11.29
264	VFD Compressor CIE203	$7,653	2.26	($346)	0.98	$10,538	2.86	$13,879	6.97
265	VFD CW Pump 20-100hp - Hospital CIP131	$34,533	11.58	$5,744	1.12	$47,071	10.07	$49,083	16.45
266	VFD CW Pump 20-100hp - Hotel CIP125	($1,330)	0.59	$283	1.13	($173)	0.94	$1,839	3.66
267	VFD CW Pump 20-100hp - Large Office CIP137	$16,492	6.05	$3,448	1.14	$23,755	7.03	$25,767	14.37
268	VFD CW Pump <20hp - Hospital CIE192	$3,405	6.43	$540	1.11	$4,715	7.11	$5,091	13.84
269	VFD CW Pump <20hp - Hotel CIE197	($155)	0.42	($14)	0.89	($105)	0.52	$56	1.96
270	VFD CW Pump <20hp - Large Office CIE202	$1,511	3.41	$299	1.11	$2,267	4.54	$2,643	10.96
271	VFD HW Pump 20-100hp - Hospital CIP130	$101,456	32.07	$15,040	1.12	$134,271	14.66	$135,883	17.53
272	VFD HW Pump 20-100hp - Hotel CIP124	$128,158	40.25	$11,016	1.07	$161,357	14.80	$162,969	17.17
273	VFD HW Pump 20-100hp - Large Office CIP136	$67,034	21.53	$19,781	1.23	$98,908	14.30	$100,520	18.26
274	VFD HW Pump <20hp - Hospital CIE191	$10,579	17.88	$1,369	1.10	$13,871	12.01	$14,058	14.10
275	VFD HW Pump <20hp - Hotel CIE196	$5,735	22.35	$406	1.05	$7,164	12.49	$7,244	14.33
276	VFD HW Pump <20hp - Large Office CIE201	$6,965	12.11	$1,867	1.20	$10,158	11.08	$10,345	13.59
277	VFD Return Fan 20-100hp - Hospital CIP127	$31,961	10.79	$4,648	1.11	$42,994	9.55	$45,106	16.46
278	VFD Return Fan 20-100hp - Hotel CIP121	($34)	0.99	$113	1.03	$1,184	1.42	$3,296	5.78
279	VFD Return Fan 20-100hp - Large Office CIP133	$22,492	7.89	$4,703	1.15	$32,017	8.33	$34,129	16.12
280	VFD Return Fan <20hp - Hospital CIE188	$7,189	6.02	$947	1.09	$9,799	6.68	$10,657	13.28
281	VFD Return Fan <20hp - Hotel CIE193	($245)	0.66	($70)	0.87	($118)	0.80	$311	2.87
282	VFD Return Fan <20hp - Large Office CIE198	$4,917	4.43	$961	1.12	$7,165	5.57	$8,023	12.30
283	VFD Supply Fan <100hp - Hospital CIP132	$37,387	12.45	$5,784	1.12	$50,452	10.33	$52,564	16.95
284	VFD Supply Fan <100hp - Hotel CIP126	($1,691)	0.48	($451)	0.75	($1,312)	0.51	$800	2.39
285	VFD Supply Fan <100hp - Large Office CIP138	$29,684	10.09	$5,903	1.15	$41,597	9.54	$43,709	16.85
286	VFD Tower Fan 20-100hp - Hospital CIP128	$12,755	4.91	$9,977	1.51	$25,967	8.03	$28,204	20.33
287	VFD Tower Fan 20-100hp - Hotel CIP122	$18,620	6.70	$13,857	1.51	$36,682	9.94	$38,919	21.86
288	VFD Tower Fan 20-100hp - Large Office CIP134	($1,762)	0.46	$371	1.21	($552)	0.79	$1,685	4.72
289	VFD Tower Fan <20hp - Hospital CIE189	$2,538	2.77	$2,268	1.47	$5,713	5.06	$6,643	14.95
290	VFD Tower Fan <20hp - Hotel CIE194	$3,946	3.75	$3,200	1.49	$8,284	6.51	$9,214	17.06
291	VFD Tower Fan <20hp - Large Office CIE199	($946)	0.34	($37)	0.93	($652)	0.44	$279	2.19
292	Water Heater Pipe Insulation - 6' CDI139	$286,572	N/A	($43,293)	0.92	$374,055	4.44	$374,055	4.44
293	Water Heater Setback (manual adj) CDI140	$50,942	N/A	($52,784)	0.51	($122)	1.00	($122)	1.00
294	Window Film CIP139	$14	1.21	($9)	0.89	$20	1.35	$47	2.50

2015 ELECTRIC DSM PLAN – CAUSE NO. 44495

Energy efficiency measures considered for the programs were developed using existing Indiana utility program measures (whenever possible) and measures used in other programs in the region. It should be noted that in any plan measures within programs will change and adapt to changing technology and markets. The 2015 Plan shows a framework of measures and programs that can meet the savings goals; however, it is expected that new measures and opportunities will become available during this period and that some measures will phase out as standards change and they are no longer cost effective.

The technologies listed above were developed as a result of the EnerNOC MPS data and other study information in order to guide the plan design. Vectren then hired outside expertise to assist with plan design and development in order to refine the technologies above into a workable plan. Additionally, input into the plan design was obtained from various sources, such as current program managers and implementation partners, in order to establish a solid foundation for the 2015 Plan that is based on actual experience in Vectren's territory. Other program information, such as current evaluations and best practices of other successful DSM programs, was used for adjustments to inputs. Lastly, Vectren received feedback and approval from the Oversight Board before finalizing. The result of these efforts, listed in Table 8-4 below, shows the DSM Programs benefit/cost data per the portfolio of programs filed under Cause No. 44495.

Table 8-4 Program Benefit/Cost Results for 2015 DSM Plan[1]

Commercial	TRC	UCT	RIM	Participant
Small Business Direct Install	2.00	2.21	0.83	3.66
Commercial & Industrial Prescriptive	3.75	5.44	1.02	3.25
Commercial & Industrial New Construction	1.09	2.72	0.87	1.00
Commercial & Industrial Custom	1.64	3.82	0.93	1.52
Commercial Sector Portfolio	**2.17**	**3.08**	**0.90**	**2.63**

Residential	TRC	UCT	RIM	Participant
Residential Lighting	2.18	2.88	0.85	2.94
Home Energy Assessments	1.02	1.02	0.56	NA
Income Qualified Weatherization	1.14	1.14	0.66	NA
Appliance Recycling	2.52	2.51	0.97	5.79
Residential Schools	1.89	1.89	0.72	NA
Efficient Products	1.51	2.02	1.05	1.13
Residential New Construction	1.28	1.52	0.75	1.89
Residential Behavior Savings	1.64	1.64	0.77	NA
Residential Sector Portfolio	**1.49**	**1.64**	**0.77**	**3.36**

Total Portfolio	**1.86**	**2.34**	**0.85**	**2.89**

Table 8-4 Program Benefit/Cost Results for 2015 DSM Plan Cont.[2]

Commercial	Lifetime Cost/ kWh	1st Year Cost/ kWh
Small Business Direct Install	$0.04	$0.32
Commercial & Industrial Prescriptive	$0.01	$0.15
Commercial & Industrial New Construction	$0.03	$0.36
Commercial & Industrial Custom	$0.02	$0.23
Commercial Sector Portfolio	**$0.03**	**$0.26**

[1] Commercial sector includes outreach costs for benefit/cost runs, and residential sector includes outreach and tracking costs for benefit/cost runs
[2] Commercial sector includes outreach costs for benefit/cost runs, and residential sector includes outreach and tracking costs for benefit/cost runs

Residential	Lifetime Cost/kWh	1st Year Cost/kWh
Residential Lighting	$0.03	$0.07
Home Energy Assessments	$0.08	$0.35
Income Qualified Weatherization	$0.07	$0.78
Appliance Recycling	$0.04	$0.16
Residential Schools	$0.04	$0.23
Efficient Products	$0.06	$0.67
Residential New Construction	$0.04	$0.92
Residential Behavior Savings	$0.06	$0.07
Residential Sector Portfolio	**$0.05**	**$0.18**
Total Portfolio	**$0.03**	**$0.21**

Commercial	TRC NPV $	UCT NPV $	Participant NPV $	RIM NPV $
Small Business Direct Install	$2,116,270	$2,319,485	$2,311,703	($888,566)
Commercial & Industrial Prescriptive	$3,072,637	$3,419,025	$2,406,007	$76,945
Commercial & Industrial New Construction	$40,071	$305,069	($32)	($71,053)
Commercial & Industrial Custom	$726,468	$1,376,727	($26,798)	$695,808
Commercial Sector Portfolio	**$5,805,446**	**$7,270,305**	**$5,193,787**	**($1,181,366)**

Residential	TRC NPV $	UCT NPV $	Participant NPV $	RIM NPV $
Residential Lighting	$929,179	$1,121,826	$1,838,832	($307,982)
Home Energy Assessments	$15,690	$15,690	$572,651	($572,019)
Income Qualified Weatherization	$115,688	$115,688	$416,861	($468,781)
Appliance Recycling	$320,800	$319,656	$470,616	($15,444)
Residential Schools	$113,569	$113,569	$182,611	($94,479)
Efficient Products	$352,915	$524,039	$82,526	$53,200
Residential New Construction	$39,816	$61,965	$50,858	($61,654)
Residential Behavior Savings	$274,885	$274,885	$487,718	($212,832)
Residential Sector Portfolio	**$1,992,542**	**$2,377,317**	**$4,102,673**	**($1,849,991)**
Total Portfolio	**$7,797,988**	**$9,647,622**	**$9,296,460**	**($3,031,357)**

The following programs were filed in the 2015 Plan in Cause No. 44495.

School Energy Efficiency Program

Program

The Energy Efficient Schools Program is designed to impact students by teaching them how to conserve energy and to produce cost effective electric savings by influencing students and their families to focus on conservation and the efficient use of electricity.

The program consists of a school education program for 5^{th} grade students attending schools served by Vectren. To help in this effort, each child that participates will receive a take-home energy kit with various energy saving measures for their parents to install in the home. The kits, along with the in-school teaching materials, are designed to make a lasting impression on the students and help them learn ways to conserve energy.

Eligible Customers

The program will be available to selected 5^{th} grade students/schools in the Vectren electric service territory.

Energy/Demand Savings

The proposed savings are attributed to the take-home kits provided to the elementary school children for parents to install. For modeling purposes, the energy savings estimate is 216 kWh per participant and .020 kW.

Table 8-5 School Energy Efficiency Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Residential Schools				
	2015	2,600	560,786	52	$ 128,033
Per Participant Avg Energy Savings (kWh)					216
Per Participant Avg Demand Savings (kW)					0.020
Participant Incremental Cost					$ -
Weighted Avg Measure Life					7
Net To Gross Ratio					96%

Residential Lighting Program

Program

The Residential Lighting Program is a market-based residential DSM program designed to reach residential customers through retail outlets. The program design consists of a buy-down strategy to provide the incentive to consumers to facilitate their purchase of energy-efficient lighting products. This program is justified based on direct energy savings targets, but also has a significant market transformation opportunity.

The program not only empowers customers to take advantage of new lighting technologies and accelerate the adoption of proven energy efficient technologies, but also allows the customers to experience the benefits of energy efficiency and decrease their energy consumption.

Eligible Customers

Any residential customer who receives electric service from Vectren is eligible.

Energy/Demand Savings

The program is designed to provide an incentive for the purchase and installation of CFL bulbs. For modeling purposes, the savings estimates per bulb are 32 kWh annually with demand savings of 0.004 kW.

Table 8-6 Residential Lighting Program Data

Market	Program	Number of Measures	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Residential Lighting				
	2015	261,316	8,334,008	978	$ 596,567
Per Participant Avg Energy Savings (kWh)					32
Per Participant Avg Demand Savings (kW)					0.004
Participant Incremental Cost					$ 3.63
Weighted Avg Measure Life					6
Net To Gross Ratio					49%

Home Energy Assessments

Program

The Home Energy Assessment Program targets a hybrid approach that combines helping customers analyze and understand their energy use via an on-site energy assessment, as well as providing direct installation of energy efficiency measures including efficient low-flow water fixtures and CFL bulbs.

Collaboration and coordination between electric and gas conservation programs will be explored and, to the extent possible, implemented for greatest efficiencies.

Eligible Customers

Any residential customer who receives electric service from Vectren at a single-family residence is eligible, provided the home:

- Was built prior to 1/1/2010;
- Has not had an audit within the last three years; and,
- Is owner occupied or non-owner occupied where occupants have the electric service in their name.

Energy/Demand Savings

For modeling purposes, the energy savings estimate is 1,036 kWh and .164 kW per participant.

Table 8-7 Home Energy Assessments Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Home Energy Assessments				
	2015	2,000	2,072,900	328	$ 716,163
Per Participant Avg Energy Savings (kWh)					1,036
Per Participant Avg Demand Savings (kW)					0.164
Participant Incremental Cost					$ -
Weighted Avg Measure Life					6
Net To Gross Ratio					88%

Income Qualified Weatherization

Program

The Low Income Weatherization program is designed to produce long-term energy and demand savings in the residential market. The program will provide weatherization upgrades to low income homes that otherwise would not have been able to afford the energy saving measures. The program will provide direct installation of energy saving measures, educate consumers on ways to reduce energy consumption, and identify opportunities for additional weatherization measures.

Collaboration and coordination between gas and electric low income programs along with state and federal funding, is recommended to provide the greatest efficiencies among all programs.

Eligible Customers

The Residential Low Income Weatherization Program targets single-family homeowners and tenants, who have electric service in their name with Vectren and with a total household income up to 200% of the federally-established poverty level. Priority will be given to:

a. Single parent households with children under 18 years of age living in dwelling.
b. Households headed by occupants over 65 years of age.
c. Disabled homeowners as defined by the Energy Assistance Program (EAP).
d. Households with high energy intensity usage levels.

Energy/Demand Savings

For modeling purposes, the energy savings estimate is 1,822 kWh per participant annually with demand savings of 0.453 kW.

Table 8-8 Income Qualified Weatherization Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Income Qualified Weatherization				
	2015	564	1,027,651	256	$ 798,474
Per Participant Avg Energy Savings (kWh)					1,822
Per Participant Avg Demand Savings (kW)					0.453
Participant Incremental Cost					$ -
Weighted Avg Measure Life					15
Net To Gross Ratio					100%

Appliance Recycling

Program

The Residential Appliance Recycling program encourages customers to recycle their old inefficient refrigerators and freezers in an environmentally safe manner. The program recycles operable refrigerators or freezers so the appliance no longer uses electricity and is recycled instead of being disposed of in a landfill. An older refrigerator can use as much as twice the amount of energy as new efficient refrigerators. An incentive of $50 will be provided to the customer for each operational unit picked up.

Eligible Customers

Any residential customer with an operable secondary refrigerator or freezer receiving electric service from Vectren is eligible.

Incentive

The program offers customers free pick-up of working refrigerators or freezers and a $50 cash incentive.

Energy/Demand Savings

The program is designed to remove the old, secondary refrigerator or freezer. The savings estimate is 1,230 kWh per measure annually, with a summer demand savings of 0.397 kW.

Table 8-9 Residential Appliance Recycling Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Appliance Recycling				
	2015	1,058	1,301,338	420	$ 212,366
Per Participant Avg Energy Savings (kWh)					1,230
Per Participant Avg Demand Savings (kW)					0.397
Participant Incremental Cost					$ 92.96
Weighted Avg Measure Life					8
Net To Gross Ratio					53%

Residential Efficient Products

Program

To assist customers with the purchase of energy efficient products, prescriptive incentives will be provided on efficient electric measures and equipment (qualifying air conditioning units, heat pumps, thermostats, etc.) above the standard baseline. The program will be promoted through trade allies and appropriate retail outlets.

Eligible Customers

Any residential customer located in the Vectren electric service territory is eligible.

Incentive

Incentives are provided to customers to reduce the difference in first cost between the lower efficient technology and the high efficient option.

Energy/Demand Savings

For modeling purposes, the energy/demand savings estimates are 514 kWh annually per participant (measure) and demand savings of .403 kW.

Table 8-10 Residential Efficient Products Data

Market	Program	Number of Measures	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Efficient Products				
	2015	1,500	771,461	605	$ 516,189
Per Participant Avg Energy Savings (kWh)					514
Per Participant Avg Demand Savings (kW)					0.403
Participant Incremental Cost					$ 421.53
Weighted Avg Measure Life					15
Net To Gross Ratio					73%

Residential Behavioral Savings Program

Program

The Residential Behavioral Savings (RBS) program motivates behavior change and provides relevant, targeted information to the consumer through regularly scheduled direct contact via mailed and emailed home energy reports. The report and web portal include a comparison against a group of similarly sized and equipped homes in the area, usage history comparisons, goal setting tools, and progress trackers. The Home Energy Report program anonymously compares customers' energy use with that of their neighbors of similar home size and demographics. Customers can view the past twelve months of their energy usage and compare and contrast their energy consumption/ costs with others in the same neighborhood. Once a consumer better understands how they use energy, they can then start conserving energy.

Program data and design was provided by OPower, the implementation vendor for the program. OPower provides energy usage insight that drives customers to take action by selecting the most relevant information for each particular household, which ensures maximum relevancy and high response rate to recommendations.

Eligible Customers

Residential customers who receive electric service from Vectren are eligible.

Energy/Demand Savings

To identify the measurable savings, Vectren proposes to have a set of customers who receive the letter with energy tips and suggestions and a set of control customers who do not receive the letter. The energy consumption of the 2 groups will be compared to determine the measurable savings. For modeling purposes, the annual energy savings was estimated at 126 kWh per participant with demand savings of .041 kW.

Table 8-11 Residential Behavioral Savings Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	**Behavioral Savings**				
	2015	50,400	6,350,400	2,051	$ 432,202
Per Participant Avg Energy Savings (kWh)					126
Per Participant Avg Demand Savings (kW)					0.041
Participant Incremental Cost					$ -
Weighted Avg Measure Life					1
Net To Gross Ratio					100%

Residential New Construction

Program

The Residential New Construction Program will provide incentives and encourage home builders to construct homes that are more efficient than current building codes. The Residential New Construction Program will work closely with builders, educating them on the benefits of energy efficient new homes. Homes may feature additional insulation, better windows, and higher efficiency appliances. The homes should also be more efficient and comfortable than standard homes constructed to current building codes.

Program incentives are designed to be paid to both all-electric and combination homes that have natural gas heating and water heating. It is important to note that the program is structured such that an incentive will not be paid for an all-electric home that has natural gas available to the home site.

The Residential New Construction Program will address the lost opportunities in this customer segment by promoting energy efficiency at the time the initial decisions are being made. This will ensure efficient results for the life of the home.

Eligible Customers

Any home builder constructing a home to the program specifications in the Vectren electric service territory is eligible.

Incentives

Incentives will be based on a rating tier qualification and are designed to be paid to both all-electric and combination homes that have natural gas space heating.

Energy/ Demand Savings

For modeling purposes, the savings estimates per home are calculated at 1,898 kWh and .309 kW, based upon the blended savings estimate of all participating homes. The specific energy and demand impacts will vary by size and composition of the home and will be characterized through follow-up evaluation and verification procedures.

Table 8-12 Residential New Construction Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Residential New Construction				
	2015	68	129,048	21	$ 119,092
Per Participant Avg Energy Savings (kWh)					1,898
Per Participant Avg Demand Savings (kW)					0.309
Participant Incremental Cost					$ 844.56
Weighted Avg Measure Life					25
Net To Gross Ratio					95%

Commercial and Industrial Prescriptive Program

Program

The Commercial and Industrial (C&I) Prescriptive Program is designed to provide financial incentives on qualifying products to produce greater energy savings in the C&I market. The rebates are designed to promote lower electric energy consumption, assist customers in managing their energy costs and built a sustainable market around energy efficiency. Program participation is achieved by offering incentives structured to cover a portion of the customer's incremental cost of installing prescriptive efficiency measures.

Eligible Customers

Any participating commercial or industrial customer receiving electric service from Vectren is eligible.

Incentive

Incentives are provided to customers to reduce the difference in first cost between the lower efficient technology and the high efficient option.

Energy/Demand Savings

For modeling purposes, the energy savings estimate is 487 kWh per participant (measure) and demand savings of .089 kW.

Table 8-13 Commercial and Industrial Prescriptive Program Data

Market	Program	Number of Measures	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Commercial & Industrial	Commercial & Industrial Prescriptive				
	2015	10,470	5,103,942	935	$ 769,573
Per Participant Avg Energy Savings (kWh)					487
Per Participant Avg Demand Savings (kW)					0.089
Participant Incremental Cost					$ 102.29
Weighted Avg Measure Life					14
Net To Gross Ratio					80%

Commercial and Industrial Audit and Custom Efficiency Program

Program

The Commercial and Industrial Custom Program promote the implementation of customized energy saving measures at qualifying customer facilities. Incentives promoted through this program serve to reduce the cost of implementing energy reducing projects and upgrading to high-efficiency equipment. Due to the nature of a custom energy efficiency program, a wide variety of projects are eligible.

The technical audit or compressed air system study offers an assessment to systematically identify energy saving opportunities for customers and provides a mechanism to prioritize and phase-in projects that best meet customer needs. In turn, the opportunities identified from the audit can be turned in for the customized efficiency program. These two components work hand in hand to deliver energy savings to Vectren commercial and industrial customers.

Eligible Customers

Any participating commercial or industrial customer receiving electric service from Vectren is eligible.

Incentive

Vectren will provide a customer incentive based on the estimated kWh savings at a modeled rate of .12 cents per kWh, and is paid based on the first year annual savings reduction.

Energy/Demand Savings

The custom nature of the program makes it difficult to develop a prototypical example. Each building will have very site specific projects and impacts. For modeling purposes the energy/demand savings estimates are 95,248 kWh per participant (measure) and demand savings of 15.455 kW.

Table 8-14 Commercial and Industrial Audit & Custom Efficiency Program Data

Market	Program	Number of Projects	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Commercial & Industrial	Commercial & Industrial Custom				
	2015	22	2,095,450	340	$ 488,274
Per Participant Avg Energy Savings (kWh)					95,248
Per Participant Avg Demand Savings (kW)					15.455
Participant Incremental Cost					$ 41,400.96
Weighted Avg Measure Life					12
Net To Gross Ratio					99%

Commercial and Industrial New Construction Program

Program

The Commercial and Industrial New Construction Program provides value by promoting energy efficient designs with the goal of developing projects that are more energy efficient than current Indiana building code. Incentives promoted through this program serve to reduce the incremental cost to upgrade to high-efficiency equipment over standard efficiency options for Vectren customers. The program includes equipment with easily calculated savings and provides straightforward and easy participation for customers.

Eligible Customers

Any participating commercial or industrial customer receiving electric service from Vectren is eligible.

Incentive

The program is designed to pay .12 cents per kWh saved up to $100,000 based on the first year energy savings determined in the final energy model.

Energy/Demand Savings

For modeling purposes the estimated energy/demand savings per participant are 35,100 kWh and 6.286 kW.

Table 8-15 Commercial and Industrial New Construction Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Commercial & Industrial	Commercial & Industrial New Construction				
	2015	14	491,400	88	$ 177,373
Per Participant Avg Energy Savings (kWh)					35,100
Per Participant Avg Demand Savings (kW)					6.286
Participant Incremental Cost					$ 24,517.34
Weighted Avg Measure Life					14
Net To Gross Ratio					95%

Small Business Direct Install

Program

The program provides value by directly installing energy efficient products such as high efficiency lighting, low flow water saving measures and vending machine controls. The program helps businesses identify and install cost effective energy saving measures by providing an on-site energy assessment customized for their business.

Eligible Customers

Any participating Vectren small business customer with a maximum peak energy demand of less than 300 kW is eligible.

Incentive

In addition to the low cost measures installed during the audit, the program will also pay a cash incentive of up to 75% of the cost of any recommended improvements identified through the audit.

Energy/Demand Savings

For modeling purposes the estimated energy/demand savings per participant are 6,001 kWh and 1.622 kW.

Table 8-16 Small Business Direct Install Program Data

Market	Program	Number of Projects	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Commercial	**Small Business Direct Install**				
	2015	1,000	6,001,171	1,622	$ 1,909,188
Per Participant Avg Energy Savings (kWh)					6,001
Per Participant Avg Demand Savings (kW)					1.622
Participant Incremental Cost					$ 868.98
Weighted Avg Measure Life					10
Net To Gross Ratio					100%

DSM Portfolio Objective and Impacts

Vectren plans to reduce residential and commercial/industrial customer usage by 34,240 MWh in 2015. Vectren also projects to achieve a reduction in summer peak demand of 7.69 MW in 2015. In implementing these programs, consideration will be given to utilizing small businesses when feasible. Table 8-17 outlines the portfolio and the associated programs, as well as the projected energy/demand impacts, program costs, and customer participation of DSM programs offered under Cause No. 44495.

Table 8-17 Projected Energy and Peak Savings – Cause No. 44495

COMMERCIAL	2015 kWh Total	2015 kW
Small Business Direct Install	6,001,171	1,622
Commercial & Industrial Prescriptive	5,103,942	935
Commercial & Industrial New Construction	491,400	88
Commercial & Industrial Custom	2,095,450	340
Commercial Total	**13,691,963**	**2,985**
RESIDENTIAL	**2015 kWh Total**	**2015 kW**
Residential Lighting	8,334,008	978
Home Energy Assessments	2,072,900	328
Income Qualified Weatherization	1,027,651	256
Appliance Recycling	1,301,338	420
Residential Schools	560,786	52
Efficient Products	771,461	605
Residential New Construction	129,048	21
Behavior Savings	6,350,400	2,051
Residential Total	**20,547,593**	**4,711**

While Vectren believes this level of savings is achievable, it will require robust programs for all classes of retail customers.

Given the market assessment, collaborative process, portfolio cost/benefit modeling efforts, and DSM program portfolio proposal, Vectren used the projected demand-side reductions from the programs as an input into the IRP process, rather than allowing the integration modeling to independently select some level of DSM to meet customer requirements. With respect to DSM, the programs that pass cost effectiveness testing are input into the integration analysis as a resource. IRP DSM modeling is discussed later in this chapter.

Customer Outreach and Education

Program

This program will raise awareness and drive customer participation as well as educate customers on how to manage their energy bills. The program will include the following goals as objectives:

- Build awareness;
- Educate consumers on how to conserve energy and reduce demand;
- Educate customers on how to manage their energy costs and reduce their bill;
- Communicate Vectren's support of customer energy efficiency needs; and
- Drive participation in the DSM programs.

This annual program will include paid media, web-based tools to analyze bills, energy audit tools, and energy efficiency and DSM program education and information. Informational guides and sales promotion materials for specific programs will also be included.

Vectren will oversee the outreach and education programs for the DSM programs. Vectren will utilize the services of communication and energy efficiency experts to deliver the demand and energy efficiency message.

Eligible Customers

Any Vectren electric customer will be eligible.

Energy/Demand Savings

This communications effort differs from typical DSM programs in that there are no direct estimates of participants, savings, costs, and cost-effectiveness tests. Such estimates are considered impractical for these types of overarching efforts to educate consumers and drive participation in other DSM programs. The California Standard Practice Manual (p. 5) addresses this issue as follows:

"For generalized information programs (e.g., when customers are provided generic information on means of reducing utility bills without the benefit of on-site evaluations or customer billing data), cost-effectiveness tests are not expected because of the extreme difficulty in establishing meaningful estimates of load impacts."

This effort is the key to achieving greater energy savings by convincing the families and businesses making housing/facility, appliance and equipment investments to opt for greater energy efficiency. The first step in convincing the public and businesses to invest in energy efficiency is to raise their awareness. It is essential that a broad public education and outreach campaign not only raise awareness of what consumers can do to save energy and control their energy bills, but to prime them for participation in the various DSM programs. The budget is $150,000 each for Residential and Commercial programs, for a total of $300,000.

Table 8-18 DSM Outreach & Education Program Budget

Customer Outreach	Residential	Business	Total Program Costs
Outreach	$150,000	$150,000	$300,000

IRP DSM MODELING

Vectren continues to support DSM related energy efficiency efforts as a fundamental part of the services that are provided to customers in order to help them manage their energy bills. The Market Potential study, developed by EnerNoc on behalf of the Vectren Oversight Board, illustrated a level of ongoing DSM energy efficiency is cost effective and Vectren believes the inclusion of the described level of ongoing DSM energy efficiency is best reflected in the base case sales forecast. DSM energy efficiency programs included in the base sales forecast are available to all customer classes at a targeted level of 1% eligible annual savings for 2015 – 2019 and 0.5%

annually thereafter for customer load that has not opted-out of DSM programs. Vectren believes that a cost effective level of DSM energy efficiency may be supported by policy considerations beyond capacity planning which are not always captured in the IRP modeling process.

Vectren did model the option of offering DSM energy efficiency programs designed to achieve more than the level reflected in the base case sales forecast to determine if it is selected as a resource to meet future electric requirements. Vectren's approach attempts to balance its commitment to a level of cost-effective DSM, while evaluating additional DSM resources consistent with least cost planning. Below is a list of major assumptions included in Vectren's IRP DSM modeling.

Vectren began by creating savings blocks based on 0.5% of eligible sales based on a projection that 80% of large customers will opt out of Vectren sponsored DSM programs. The maximum amount of possible additional DSM that could be selected was 2% (embedded savings + additional modeled blocks) in 2018-2019. Beyond 2019, the model was limited to selecting 1.5% (embedded + additional modeled blocks) of total eligible sales, consistent with the proposed Clean Power Plan (111d). Levelized costs were based on the Market Potential study and Vectren's 2015 Plan. Consistent with the Market Potential study, each block cost more than the last and increased over time. Levelized costs of energy saved began at approximately 3 cents per kWh for the first available block in 2015 and increased to approximately 6.4 cents for the last available block in 2034. In order to minimize ramping costs, DSM programs were required to run for at least 3 consecutive years.

Based on these assumptions, DSM successfully competed with resource alternatives within the planning model to help meet future load requirements. DSM was selected in several resource plans as discussed further in Chapter 10 Generation Planning.

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CHAPTER 9

TRANSMISSION AND DISTRIBUTION PLANNING

INTRODUCTION

In accordance with IURC Rule 170 IAC, Vectren analyzed its transmission and distribution system's ability to meet future electric service requirements reliably and economically through the year 2034. This chapter describes the criteria applied in the analysis and the system conditions studied. The study was conducted to maintain compliance with the requirements of the Midcontinent Independent System Operator (MISO), the *Reliability* First (RF) in conjunction with NERC requirements, as well as Vectren’s internal planning criteria. Internal Long Range Plans are completed annually. In addition, Vectren has worked closely with MISO Transmission Expansion Plans (MTEP) and RF in performing regional studies, which include proposed projects identified in Vectren studies.

Modeling of the transmission system was conducted with steady-state conditions using the Power Technologies Inc.’s Power System Simulator Program for Engineers (PTI-PSS/E). The models and the studies and assessment on these models comply with all NERC, RF, MISO and IURC requirements, and they include real and reactive flows, voltages, generation dispatch, load, and facilities appropriate for the time period studied. The primary criteria for assessing the adequacy of the internal Vectren transmission system were (1) single contingency outages of transmission lines and transformers during peak conditions, and (2) selected double and multiple contingencies. Interconnections were also assessed by examining single, double, and other multiple contingencies.

In addition, short circuit models were developed and analyzed through the use of Advanced Systems for Power Engineering, Inc.’s short circuit program (ASPEN-OneLiner).

Dynamic simulation was also performed using PTI-PSS/E to examine the performance of the interconnected transmission system to various electrical faults. The Vectren system remains stable for a variety of faulted conditions.

METHODOLOGY

The distribution system review covers native load as described in previous chapters in this IRP. The Transmission system review also covers loads connected to Vectren's transmission system such as municipals and Independent Power Producers (IPP's) that Vectren is not obligated to serve or include in its generation resources. The primary reason is to determine impacts or limitations in the transmission capacity to serve the Vectren native load. Vectren adheres to the transmission planning criteria developed and published by MISO in its document MISO *Transmission Expansion Planning*; (MTEP) and by RF through NERC in its *Reliability Standards* under *Transmission Planning (TPL-001 through TPL-004)*.

The basis for the selection of RF reliability criteria offers five points for member recognition.

1. The need to plan bulk electric systems that will withstand adverse credible disturbances without experiencing uncontrolled interruptions.

2. The importance of providing a high degree of reliability for local power supply but the impossibility of providing 100 percent reliability to every customer or every local area.

3. The importance of considering local conditions and requirements in establishing transmission reliability criteria for the local area power supply and the need, therefore, to view reliability in local areas primarily as the responsibility of the individual RFC members. However, local area

disturbances must not jeopardize the overall integrity of the Bulk Electric System.

4. The importance of mitigating the frequency, duration and extent of major Bulk Electric System outages.

5. The importance of mitigating the effect of conditions that might result from events such as national emergencies, strikes, or major outages on other regional networks.

SYSTEM INTEGRITY ANALYSIS – 2013 (SEASONAL ANNUAL, INCLUDES SPRING, SUMMER, FALL, AND WINTER)

Based on initial conditions for load, generation, and system topology the following tests were conducted.

1. Single contingency:
   - Outage of any line
   - Outage of any transformer
   - Outage of any generator
2. Multiple contingencies:
   - Double outage of any combination of generators, lines and transformers
   - Double outages of generators
   - Sensitivity outages: two lines or transformers under different Generation dispatch scenarios
3. Extreme Contingencies:
   - Loss of all generation at a plant site
   - Loss of entire switchyard with associated load, generation and line connectivity where three or more 100kV or higher voltage lines are connected

As a result of these tests, various system operational or construction improvements have been postulated. These improvements may be either operator action, (such as shifting generation or switching lines), or the installation of actual substations, the construction of transmission lines, or the upgrading of facilities. Required construction improvements have been prioritized by where they fall in the contingency spectrum. Improvements that must be made in response to a single line outage have higher priority than improvements resulting from a more unlikely occurrence.

SYSTEM INTEGRITY ANALYSIS – 2018 (NEAR TERM – WITHIN 1-5 YEARS)

Using updated load and generation forecasts and included planned upgrades, the same analysis is performed for the 2013 system. Contingency analysis is also the same as for the 2013 system.

SYSTEM INTEGRITY ANALYSIS – 2022 (LONG TERM – 6-10 YEARS)

Using updated load and generation forecasts and included planned upgrades, the same analysis is performed for the 2013 system. Contingency analysis is the same as for the 2013 system.

TRANSMISSION ADEQUACY SUMMARY TABLE

Table 9-1 shows the Vectren generation and load resources, as summarized from previous chapters, as well as the generation and load resources expected to be served from the transmission system for the entire Vectren Local Balancing Authority (LBA) as coordinated by MISO.

Table 9-1 Transmission Import Adequacy/Shortfall Assessment

Year	Vectren Available Gen (MW)[1]	IPP's & other Gen (MW)	Vectren Firm Peak Demand (MW)[2]	Muni's & Other Load (MW)	Proj. Inter-Change (MW)	Trans. System Import Cap (MW)
2014	1,155	596	1,145	690	-84	728
2015	1,155	680	1,155	690	-10	802
2016	1,155	680	1,156	690	-11	801
2017	1,155	680	1,113	690	32	844
2018	1,155	680	1,109	690	36	848
2019	1,155	680	1,106	690	39	851
2020	1,155	680	1,106	690	39	851
2021	1,155	680	1,106	690	39	851
2022	1,155	680	1,107	690	38	850
2023	1,155	680	1,107	690	38	850
2024	1,155	680	1,107	690	38	850
2025	1,155	680	1,106	690	39	851
2026	1,155	680	1,106	690	39	851
2027	1,155	680	1,107	690	38	850
2028	1,155	680	1,109	690	36	848
2029	1,155	680	1,110	690	35	847
2030	1,155	680	1,111	690	34	846
2031	1,155	680	1,111	690	34	846
2032	1,155	680	1,113	690	32	844
2033	1,155	680	1,114	690	31	843
2034	1,155	680	1,115	690	30	842

The table reflects that if all available internal generation is on line the expected net interchange would be negative for years 2014 through 2016 and positive or exporting for all years beyond 2017. This reliability measure indicates that additional import transmission capacity is not needed for our generation to serve our load. However, the table does not reflect several other factors such as potential purchases and sales. The

[1] Values from Table 10-1 Characteristics of Existing Generation Resources
[2] Values from Table 5-4 Base Case Demand Forecast

table reflects total generation capability and not a reasonable economic dispatch under all conditions. It is likely that renewable energy resources may be imported using the transmission system in lieu of running local generation. It is assumed that the gas peaking turbines would likely not be dispatched during some near peak summer conditions, in which it is not only possible, but likely that the expected interchange could be importing 300-400 MW. These values are also supported by actual historical interchange. In any event, MISO will dispatch the available resources to serve the load based on N-1 contingency analysis and economics and losses. With the largest generation resource on the Vectren system at 300 MW, the transmission system capacity is adequate under reasonable expected resource dispatches and contingencies and additional growth. Within each PSS/E case, the actual load, generation dispatch, firm purchases and sales, and expected interchange is appropriate for the time period.

RECOMMENDATIONS: 2014 - 2034

No transmission facilities were identified specifically due to proposed generation interconnections, transmission service requests or energy resources in this IRP process. Since the projected load growth is essentially flat and no new generation resources or retirements are planned, no new transmission facilities have been identified. In addition, significant upgrades were constructed in 2012 as a result of the MISO Regional Expansion Criteria and Benefits (RECB) process. The completed projects include the construction of a new 345 kV line from the Duke Gibson Station to the Vectren AB Brown Station to the BREC Reid Station. The Duke Gibson to Vectren AB Brown to BREC Reid EHV Substation is complete and energized. This project also included the construction of a 345/138 kV substation at Vectren's AB Brown Station which is also complete. A new 138kV line (Z77) from FB Culley Substation to Oak Grove Substation to Northeast Substation is complete. This facility allows for better generation dispatch diversity with lower congestion costs under contingencies. However, recent generation and load changes in the Commonwealth of Kentucky are expected to impact the Vectren system due to flow through congestion. MISO is considering Market Congestion Projects for mitigation of the projected congestion costs, and a project will only move forward if the benefits exceed the costs metric. Multiple distribution substation upgrades were completed to include Bergdolt and Libbert Substations. Leonard Rd 69kV Switching substation should be complete in 2014 and will support a greater number of contingencies for substransmission on Evansville's west side. Demand side management and energy conservation is expected to provide some load reduction on the Vectren system.

Local load growth areas have been identified for potential new business loads. Near term projections indicate the need for at least 2 more distribution substations tentatively identified as Roesner Road and Princeton South areas, as well as potentially a new plant.

The specific projects to be completed in the future years will depend on the load growth, the location of generation facilities, and/or on the source of purchased power. General recommendations are as follows:

1. A number of 69 kV transmission upgrades will be needed. An engineering evaluation will be conducted for upgrading the identified lines to higher operating temperature and for reconductoring some lines.
2. A number of substations will need to be modified.
3. Several new 138 and 69 kV lines and substations are planned to be added in this timeframe.
4. New high voltage interconnections with neighboring utilities are being investigated, including 345 kV facilities, to improve import capability and improve regional reliability.
5. If new generation capacity is added within the Vectren system, transmission facilities would also be planned to incorporate the new power source.

6. If new generation capacity were acquired outside the Vectren system, additional new interconnections may be needed. These projects would be investigated and would require involvement of other utilities.

All of these potential transmission projects would be planned with and coordinated through the MISO.

COST PROJECTIONS:

Vectren is projecting its annual transmission, substation, and distribution expenditures to remain flat to slightly decrease over the next five years. The primary factors are that there is not a recommendation to add new generation sources in this IRP that causes new construction and the existing transmission system is adequate for full deliverability of the existing generation sources. A reason for part of the decrease is the 345kV project was completed in 2012 and spending in following years are expected to be lower. However, the Federal Stimulus Plan funding is expected to force some transmission and distribution relocations increasing in some areas due to roadway improvements. Approximately half of these are expected to be reimbursable with the remaining cost incurred by Vectren. Also, increasing demands for Smart Grid technology and infrastructure are resulting in some additional expenditure. New business and load growth forecast is expected to stay relatively flat. The need for import capability due to generation additions and retirements are expected to remain mostly unchanged as well. Tables 9-2 and 9-3 reflect both previous annual costs and projected annual spend:

Table 9-2 Actual Expenditures

	Dist. Feeder	Dist. Substation	Trans. Lines	Trans. Substation
2009	$27.3M	$5.2M	$27.2M	$20.2M
2010	$15.4M	$5.2M	$40.6M	$10.5M
2011	$26.6M	$6.5M	$24.8M	$1.4M
2012	$19.2M	$4.6M	$33.5M	$4.7M
2013	$23.8M	$2.8M	$14.9M	$4.8M

Table 9-3 Planned Expenditures

	Dist. Lines	Dist. Substation	Trans. Lines	Trans. Substation
2014	$28.9M	$4.3M	$8.5M	$4.5M
2015	$27.0M	$5.8M	$7.4M	$4.8M
2016	$27.0M	$7.9M	$5.2M	$4.8M
2017	$27.5M	$6.7M	$8.8M	$2.3M
2018	$27.6M	$4.5M	$8.6M	$4.3M

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CHAPTER 10

GENERATION PLANNING

INTRODUCTION

The purpose of the generation plan is to develop the optimal strategy for adding the resources as necessary to reliably meet the future demand requirements of Vectren's electric customers. The plan is integrated in that both supply-side and demand-side alternatives were considered and evaluated. The optimal plan is defined as the best possible combination of resource additions that result in reliable service at the lowest cost to customers over the twenty year planning horizon. The optimal resource plan is determined by evaluating all of the possible resource combinations and choosing the plan that minimizes the Net Present Value (NPV).

APPROACH

The process of determining the best resource plan was approached as an optimization problem. Vectren's consultant, Burns and McDonnell, utilized the Strategist software tool developed and supported by Ventyx of Atlanta, GA. Strategist is a strategic planning system that integrates financial, resource, marketing, and customer information. Strategist allows for addressing all aspects of integrated planning at the level of detail required for informed decision making. Strategist handles production costing, capital expenditure 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:

Objective

The objective of the integration analysis was to determine the optimal resource plan by minimizing the NPV. For the purposes of this discussion, the planning period NPV is defined as the net present value of operating costs including fuel plus capital costs. Power purchases and sales are also included in the NPV analysis for the 20 year period, 2015 – 2034. NPV numbers were developed by integrating three scenarios with four different energy forecasts. The generation options within the scenarios, along with the alternative generation (discussed in Chapter 6 Electric Supply Analysis and Chapter 7 Renewables and Clean Energy), additional DSM (discussed in Chapter 8 DSM Resources) and purchasing capacity from the market were compared against the capacity needs of the four energy forecasts yielding twelve plans of the least cost NPV. These twelve plans were then vetted against multiple sensitivities to see which plan would be the most versatile given a wide range of possible outcomes.

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 mega-watt 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. For the year 2014, MISO set forth a UCAP PRM of 7.3%. This means that Vectren must maintain at least 7.3% over the peak demand of its customers on a UCAP basis. The goal is to determine the minimum planning reserve margin that would result in the MISO system experiencing less than one loss of load event 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.

Alternatives

A broad array of alternative generation and DSM was included in the optimization analysis. The full range of supply-side resource alternatives were identified and discussed in Chapter 6 Electric Supply Analysis. Likewise, the demand-side alternatives were covered in Chapter 8 DSM Resources.

DISCUSSION OF KEY INPUTS AND ASSUMPTIONS

The NPVs were determined by evaluating all of the pertinent costs that could impact future resource additions. The NPVs include the operating and maintenance (O&M) costs of existing and new facilities and the financial costs associated with capital investments. O&M costs include both fixed and variable expenses such as fuel, production labor, maintenance expenses, and chemical costs for environmental controls.

Please note that this analysis does not explicitly include all of Vectren's Power Supply and Energy Delivery costs related to serving retail electric customers. Costs that would be common to all of the potential resource plans (e.g., allocated admin and general costs, transmission and distribution costs, other embedded costs, etc.) were not included because they had no impact on the comparative economic analysis. The considered costs were primarily related to O&M and new capital associated with power generation activities. Therefore, comparisons between the base case and alternate scenarios should be viewed within this context.

Electric Demand Forecast

As mentioned in the prior section, the electric peak and energy forecast is discussed in detail in Chapter 5 Sales & Demand Forecast. The four demand forecast results used in the optimization analysis are summarized in Table 5-3. The four forecasts consist of a base, a low, and two separate high demand forecasts.

Characteristics of Existing Generating Resources

The operating characteristics of existing Vectren owned electric generating resources, as they were simulated for the purposes of the integration analysis are summarized in Table 10-1. These characteristics were applied to all years of the study period.

Table 10-1 Characteristics of Existing Generating Resources

Resource Name	UCAP (MW)	Primary Fuel	Resource type	EFOR (%)	Estimated Full Load Heat Rate (Btu/kwhn)
AB Brown 1	228	coal	steam	4.9	10,800
AB Brown 2	233	coal	steam	3.6	10,700
FB Culley 2	83	coal	steam	7.4	11,700
FB Culley 3	257	coal	steam	4.3	10,400
Warrick 4	135	coal	steam	10.2	10,200
AB Brown 3	73	gas	combustion turbine	0.0	12,000
AB Brown 4	69	gas	combustion turbine	3.6	11,700
BAGS 2	59	gas	combustion turbine	3.6	13,000
Northeast 1	9	gas	combustion turbine	2.7	15,000
Northeast 2	9	gas	combustion turbine	2.7	15,000
Blackfoot[1]	3	landfill gas	IC engine	5.0	9,000

Existing Purchased Power

Vectren has an existing and ongoing firm purchased capacity and energy commitment with the Ohio Valley Electric Corporation (OVEC). The UCAP of this commitment equals 30 MW. It was also assumed that this resource would be present throughout the 20-year study period.

Finally, as discussed in Chapter 7 Renewables and Clean Energy, Vectren has two long-term purchase power agreements for wind energy. These purchases were assumed to be in place for the entire IRP study period. The UCAP for Vectren's wind capacity is approximately 9.1% or 7.3 MW of the 80 MW of wind.

[1] Blackfoot is "behind the meter" and is accounted for as a credit to load

Fuel Prices

The cost of fuel is one of the largest cost components of the analysis. Therefore, the assumptions that are made regarding future fuel prices are a very important variable for developing a least cost resource plan.

Vectren utilized data from three sources to develop the fuel price forecasts for this IRP. The natural gas price forecast is an average of U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2014 Reference case[1], Wood Mackenzie long term forecast[2], and Black & Veatch's natural gas forecast[3]. Basis assumptions were applied to simulate the delivered burner tip gas cost to Vectren generators. To develop the coal price forecast; Vectren utilized the same three sources and averaged their coal forecasts together to develop the IRP forecast.

An important factor to consider when developing or analyzing long-term fuel price forecasts is the impact that the Clean Power Plan (discussed in Chapter 4 Environmental) may have on the forecasts. Another factor to consider is the uncertainty of markets in the future. The further out the forecast goes the more uncertain the projection becomes. Market conditions and customer demand are continually evaluated when procuring fuel for use in Vectren's electric generation units. Vectren maintains an adequate supply of coal in physical inventory on the ground at each of plant location to ensure reliable service to customers as a prudent contingency in the event of unforeseen supply interruptions due to weather, labor, etc. Table 10-2 shows the average annual delivered base case fuel price forecasts for coal and natural gas.

[1] Included in the Technical Appendix, section E

[2] Wood Mackenzie long term forecasts are subscription based and proprietary.

[3] Black and Veatch's long term forecasts are subscription based and proprietary.

Table 10-2 Base Fuel Price Projection

IRP Base Case Delivered Forecasts		
	Real 2014$/MMBtu	
Year	Coal	Natural Gas
2015	2.57	4.65
2016	2.54	4.86
2017	2.54	5.03
2018	2.59	5.31
2019	2.62	5.46
2020	2.60	5.66
2021	2.61	5.71
2022	2.64	5.72
2023	2.63	5.82
2024	2.67	6.06
2025	2.65	6.15
2026	2.65	6.28
2027	2.67	6.33
2028	2.68	6.43
2029	2.71	6.59
2030	2.71	6.72
2031	2.71	6.82
2032	2.74	6.99
2033	2.80	7.16
2034	2.81	7.35

Environmental Considerations

Chapter 4 Environmental discusses environmental issues in detail. Variable cost impacts associated with running FGD, SCR and other environmental equipment were included in the revenue requirement calculations as part of the integration analysis.

Financial Assumptions

The financial assumptions with respect to capital investments required to add new construction resource alternatives are summarized in Chapter 6 Electric Supply Analysis. Additional information can be found in the Technology Assessment in the Technical Appendix, section B. Additional information regarding the projected costs energy efficiency programs can be found in Chapter 8 DSM Resources. The declining costs of utility scale solar (50 MW blocks) were modeled as an asymptotic curve beginning at $1,880 per KWac in 2014 and declining to $1,500 per KWac in 2020 and staying flat in real terms for the remainder of the planning horizon.

General Inflation Forecast

The general inflation forecast used in the assumptions is 1.6%. This inflation rate comes from the Federal Reserve Bank of St. Louis. This is also very close to the compound annual growth rate used in the EIA AEO 2014 for the years that are covered in the IRP.

Additional Considerations

The energy industry landscape has been changing at a fast pace, affecting both electric utilities and their customers. Although there is little clarity on how the state of Indiana will choose to implement the EPA's Clean Power Plan, it could drive substantial changes to the mix of resources available to meet customer electric demand. The EPA's MATS rule has resulted in numerous announcements of coal plant retirements across the US. As a result, MISO is predicting potential capacity shortfalls in the next few years. With low natural gas prices, some large industrial customers are considering generating their own electricity, which could affect future energy forecasts. Additionally, the proportion of residential and commercial customers installing solar panels to generate electricity continues to rise, which will effectively lower future demand for energy from the system.

Vectren has taken all of these factors into consideration in the 2014 IRP by either modeling assumed inputs, as is the case with customer-owned solar panels, or outside of modeling in the risk analysis. The combination of these factors makes the future very uncertain. Vectren continues to evaluate these developments and plan for the future with an emphasis on keeping costs as low and fair as possible for all customers, while maintaining reliability and meeting regulations.

INTEGRATION ANALYSIS RESULTS

Base Demand Forecast (Growth Scenario 1)

Plans A-1 B-1 and C-1 represent the base demand forecast in combination with the three basic portfolio themes of “A”- Base (serve customers with existing resources & DSM), “B” – FB Culley 2 Unit Retirement Scenario and “C” – Renewable Portfolio Standard. It should be noted that no new capacity is required under this load forecast. Therefore, the resource additions in plan C-1 are driven by the renewable energy constraints unique to the renewable portfolio scenario.

This case represents the base set of assumptions and inputs as presented in the preceding sections of this chapter. For this analysis, no additional constraints were introduced that would prevent the planning model from selecting the set of future supply-side or demand side resources that resulted in the lowest NPV.

Table 10-3 shows the resource plan for the base demand forecast and the associated NPV’s. Plans A-1 and B-1 are essentially the same with only about 0.5 % difference in the NPV’s. Plan C-1 which is 2.4% higher reflects the capital expense of additional renewable resources. All three plans are the same through 2019 where a DSM block is selected in the more expensive plan C-1. This will be re-evaluated in future IRP cycles as various uncertainty factors are resolved over time.

Table 10-3 Base Demand Forecast (Growth Scenario 1)

Energy Sales Case :	Base Demand Forecast		
Scenario :	Base	FB Culley 2 Unit Retirement	RPS[1]
Plan ID :	Plan A1	Plan B1	Plan C1
2015			
2016			
2017			
2018			
2019			0.5% DSM[2] Block (2019-2034)
2020		Shutdown FB Culley 2	0.5% DSM Block (2020-2034)
2021			
2022			
2023			
2024			Solar PV (1x50 MW)
2025			Solar PV[3] (4x50 MW)
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
NPV[4]	$4,874,614	$4,848,213	$4,991,616
% Difference	0.0%	-0.5%	2.4%

[1] RPS = Renewable Portfolio Standard
[2] DSM = Demand Side Management
[3] PV = Photovoltaic
[4] Net Present Value inclusive of wholesale adjustment (2014 $)

Low Demand Forecast (Growth Scenario 2)

Plans A-2, B-2 and C-2 represent the low demand forecast in combination with the three basic portfolio themes of “A”- Base (serve customers with existing resources & DSM), “B” – FB Culley 2 Unit Retirement Scenario and “C” – Renewable Portfolio Standard. It should be noted that no new capacity is required under this load forecast. Therefore, the resource additions in plan C-2 are driven by the renewable energy constraints unique to the renewable portfolio scenario.

This case represents the base set of assumptions and inputs as presented in the preceding sections of this chapter. For this analysis, no additional constraints were introduced that would prevent the planning model from selecting the set of future supply-side or additional demand side resources that resulted in the lowest NPV.

Table 10-4 shows the resource plan for the base demand forecast and the associated NPV’s. Plans A-2 and B-2 are essentially the same with only about 0.7 % difference in the NPV’s. Plan C-2 which is 2.1% higher reflects the capital expense of additional renewable resources. All three plans are the same through 2017 where a DSM block is selected in the more expensive plan C-2.

Table 10-4 Low Demand Forecast (Growth Scenario 2)

Energy Sales Case :	Low Demand Forecast		
Scenario :	Base	FB Culley 2 Unit Retirement	RPS[1]
Plan ID :	Plan A2	Plan B2	Plan C2
2015			
2016			
2017			0.5% DSM[2] Block (2017-2034)
2018			
2019			
2020		Shutdown FB Culley 2	0.5% DSM Block (2020-2034)
2021			
2022			
2023			
2024			
2025			Solar PV[3] (4x50 MW)
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
NPV[4]	$4,771,789	$4,739,585	$4,871,859
% Difference	0.0%	-0.7%	2.1%

[1] RPS = Renewable Portfolio Standard
[2] DSM = Demand Side Management
[3] PV = Photovoltaic
[4] Net Present Value inclusive of wholesale adjustment (2014 $)

High (modeled) Demand Forecast (Growth Scenario 3)

Plans A-3, B-3 and C-3 represent the High (modeled) demand forecast in combination with the three basic portfolio themes of "A"- Base (serve customers with existing resources & DSM), "B" – FB Culley 2 Unit Retirement Scenario and "C" – Renewable Portfolio Standard. It should be noted that no new capacity is required under this load forecast as can be seen in case A-3. However, the assumed retirement of Culley unit 2 in 2020 in conjunction with the increase in load drives some capacity additions in case B-3. The resource additions in plan C-3 are driven by the renewable energy constraints unique to the renewable portfolio scenario. However, the timing of the resources is slightly different due to interim renewable constraint in the renewable portfolio scenario.

This case represents the base set of assumptions and inputs as presented in the preceding sections of this chapter. For this analysis, no additional constraints were introduced that would prevent the planning model from selecting the set of future supply-side or additional demand side resources that resulted in the lowest NPV.

Table 10-5 shows the resource plan for the high (modeled) demand forecast and the associated NPV's. Plans A-3 and B-3 are essentially the same with only about 0.3% difference in the NPV's. Plan C-3 which is 2.1% higher reflects the capital expense of additional renewable resources. The higher load growth in combination with the assumed retirement of Culley 2 suggests that more energy efficiency measures should be implemented soon if that combination of were to occur. However, a mere 0.2% difference in the NPV's between plan A-3 and B-3 is not enough to drive such a major change.

Table 10-5 High (modeled) Demand Forecast (Growth Scenario 3)

Energy Sales Case :	**High (modeled) Demand Forecast**		
Scenario :	**Base**	**FB Culley 2 Unit Retirement**	**RPS[1]**
Plan ID :	**Plan A3**	**Plan B3**	**Plan C3**
2015		0.5% DSM[2] Block (2015-2034)	
2016			
2017			
2018			
2019			
2020		0.5% DSM Block ('20-'34) Shutdown FB Culley 2	1.0% DSM Block (2020-2034)
2021			
2022			
2023			
2024			Solar PV[3] (1x50 MW)
2025			Solar PV (4x50 MW)
2026			
2027			
2028			
2029			
2030			
2031		Mkt Cap[4] (2MW)	
2032		Mkt Cap (6MW)	
2033		Mkt Cap (8MW)	
2034		Solar PV (1x50 MW)	
NPV[5]	$5,064,159	$5,049,163	$5,168,352
% Difference	0.0%	-0.3%	2.1%

1 RPS = Renewable Portfolio Standard
2 DSM = Demand Side Management
3 PV = Photovoltaic
4 Mkt Cap = Market Capacity Purchase
5 Net Present Value inclusive of wholesale adjustment (2014 $)

High (large load) Demand Forecast (Growth Scenario 4)

Plans A-4, B-4 and C-4 represent the high (large load) demand forecast in combination with the three basic portfolio themes of "A"- Base (serve customers with existing resources & DSM), "B" – FB Culley 2 Unit Retirement Scenario and "C" – Renewable Portfolio Standard. It should be noted that no new capacity is required under this load forecast as can be seen in case A-4. However, the assumed retirement of Culley unit 2 in 2020 in conjunction with the increase in load drives a capacity addition in case B-4. The resource additions in plan C-4 are driven by the renewable energy constraints unique to the renewable portfolio scenario. However, the timing of the resources is slightly different due to interim renewable constraint in the renewable portfolio scenario.

This case represents the base set of assumptions and inputs as presented in the preceding sections of this chapter. For this analysis, no additional constraints were introduced that would prevent the planning model from selecting the set of future supply-side resources that resulted in the lowest NPV.

Table 10-6 shows the resource plan for the high (large load) demand forecast and the associated NPV's. Plan A-4 is the lowest cost plan under this load growth scenario, beating plans B-4 and C-4 by 1.9% and 2.5% respectively. Plans B-4 and C-4 reflect the capital expense of additional resources. These scenarios are significantly higher than plan A-4 in the near term. Note that all three plans are the same through 2018 where a DSM block is selected in the more expensive plan C-1.

Table 10-6 High (large load) Demand Forecast (Growth Scenario 4)

Energy Sales Case :	**High (large load) Demand Forecast**		
Scenario :	**Base**	**FB Culley 2 Unit Retirement**	**RPS[1]**
Plan ID :	**Plan A4**	**Plan B4**	**Plan C4**
2015			
2016			
2017			
2018			0.5% DSM[2] Block (2018-2034)
2019			
2020		Block of CCGT[3] (200 MW) Shutdown F.B Culley 2	0.5% DSM Block (2020-2034)
2021			
2022			
2023			
2024			Solar PV[4] (2x50 MW)
2025			Solar PV (4x50 MW)
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
NPV[5]	$5,156,487	$5,254,385	$5,283,860
% Difference	0.0%	1.9%	2.5%

[1] RPS = Renewable Portfolio Standard
[2] DSM = Demand Side Management
[3] CCGT = Combined Cycle Gas Turbine
[4] PV = Photovoltaic
[5] Net Present Value inclusive of wholesale adjustment (2014 $)

Integration Analysis Results Summary

As mentioned previously, the Strategist output is the lowest-cost plan for customers. The plan summary table 10-7 shows the costs for each plan A1-C4. Note that the costs represent the total present day value of serving Vectren customers under various portfolio mixes to meet customer demand for each scenario. The costs include capital for new resources, operating and maintenance costs, etc. for each plan over the 20-year forecast. Renewable Portfolio Standard (RPS) scenario plans were all the most expensive because they require new generation to be built and additional energy efficiency programs, which are paid for by customers, to meet the renewables requirement. Although no fuel is consumed by renewable resources, there are still costs associated with building and maintaining facilities. Renewables are intermittent resources, making them generally more expensive to help meet capacity requirements. Additionally, retiring FB Culley 2 prematurely, in the event of a large customer addition, could be very costly to customers. The cost of serving customers with existing resources, compared to retiring FB Culley 2 in 2020, were essentially the same under the low, base and high electric forecasts. Due to the risks associated with prematurely retiring FB Culley 2, discussed below in the Sensitivity and Risk Analysis section of this report, Vectren plans to serve customers with existing generation, plan A1 (Base electric forecast and Base scenario) in the near term. Vectren will conduct IRPs in 2016 and 2018. The plans are very similar or identical during the first few years. Therefore, no immediate action is required. The plans will be re-evaluated in future IRP cycles as various uncertainty factors are resolved over time.

Table 10-7 Plan Summary Table

		A	B	C
		Base Scenario	FB Culley 2 Unit Retirement Scenario	RPS Scenario
1	Base Demand Forecast	$4,874,614 0.0%	*$4,848,213 -0.5%*	$4,991,616 2.4%
2	Low Demand Forecast	$4,771,789 0.0%	*$4,739,585 -0.7%*	$4,871,859 2.1%
3	High (modeled) Demand Forecast	$5,064,159 0.0%	*$5,049,163 -0.3%*	$5,168,352 2.1%
4	High (large load) Demand Forecast	*$5,156,487 0.0%*	$5,254,385 1.9%	$5,283,860 2.5%

Note: Percent difference is reported on the same sales forecast basis
NPV = 2014 $000's @ 5.6%

SENSITIVITY AND RISK ANALYSIS

Each plan was subjected to additional risk sensitivities to determine which plan is the lowest cost over a wide range of possible future risks. As previously mentioned, resource modeling requires a large number of inputs and assumptions over a 20-year timeframe. It is impossible to precisely predict future prices of commodities such as fuel and other assumed economic factors such as carbon prices. Therefore, several future possibilities were considered. The 12 expansion plan scenarios were stress tested in regard to their sensitivity to variation in natural gas prices, coal prices, electric energy market prices, carbon prices, and capital costs of new resources. One additional stress test was added for a high regulation cost uncertainty. The parameters for these stress tests can be seen in table 10-8. The range of cost sensitivities for natural gas, coal and electric energy were stressed +/- 20%, which is consistent with the sensitivity percentages used in the MISO Transmission Expansion Plan 15 (MTEP 15). The large MISO stakeholder constituency reaches consensus on these ranges; therefore, Vectren believes that these are reasonable ranges. At the suggestion of some stakeholders, Vectren used the Synapse 2013 mid case CO_2 pricing as the high sensitivity and the MTEP 15 CO_2 mid case as the low sensitivity. Capital costs for new resources were stressed +30/-10 percent as it is much more common throughout the industry to see cost underestimates than cost overestimates upon actual project completions. The high regulation cost was a stress test of adding the capital for a cooling tower at FB Culley in 2022.[1]

[1] [1] While Vectren continues to believe that it is unlikely that the state will require a cooling water tower retrofit at Culley under regulations recently finalized implementing Clean Water Act §316b, Vectren included this as a high cost sensitivity. Construction costs would commence starting in 2022, after the required ecological and technological study feasibility period.

Table 10-8 Sensitivity Summary Table (Used For Stress Tests)

Sensitivities	High	Low	Potential Sources
Natural Gas Forecasts	+20%	-20%	MTEP 15
Coal Forecast	+20%	-20%	MTEP 15
Market Energy Forecast	+20%	-20%	MTEP 15
CO_2 Forecast	$15.5/Ton	$10.3/Ton	Synapse, MTEP 15
Capital Cost	+30%	-10%	Burns and McDonnell Tech Assessment
High Regulation Cost*	$40m	-	Future Regulatory Scenario[1]

[1] While Vectren continues to believe that it is unlikely that the state will require a cooling water tower retrofit at Culley under regulations recently finalized implementing Clean Water Act §316b, Vectren included this as a high cost sensitivity. Construction costs would commence starting in 2022, after the required ecological and technological study feasibility period.

Stress Test of Base Demand Forecast (Growth Scenario 1)

Plan A-1 B-1 and C-1 stress test results are shown in table 10-9. Similarly to the results shows in table 10-3, plans A1 and B1 are essentially the same over a wide variety of possible future sensitivities. Plan C1 remains the most expensive.

Table 10-9 Stress Tests Results for Base Demand Forecast (Growth Scenario 1)

	Base (Plan A1)	FB Culley 2 Unit Retirement (Plan B1)	RPS (Plan C1)
Base	$4,874,614	$4,848,213	$4,991,616
High Gas	$4,908,570	$4,883,867	$5,024,377
Low Gas	$4,826,209	$4,797,668	$4,944,615
High Coal	$5,268,181	$5,221,310	$5,381,876
Low Coal	$4,471,184	$4,466,032	$4,591,643
High Market	$4,727,528	$4,737,505	$4,821,102
Low Market	$4,957,322	$4,895,134	$5,099,072
Low Carbon Price	$4,704,763	$4,681,858	$4,836,921
High Carbon Price	$5,336,590	$5,302,147	$5,415,470
High Capital Cost	$4,874,614	$4,848,213	$5,047,790
Low Capital Cost	$4,874,614	$4,848,213	$4,972,892
High Regulation Cost	$4,900,481	$4,867,614	$5,017,484

Stress Test of Low Demand Forecast (Growth Scenario 2)

Plan A-2 B-2 and C-2 stress test results are shown in table 10-10. Similarly to the results shows in table 10-4, plans A2 and B2 are essentially the same over a wide variety of possible future sensitivities. Plan C2 remains the most expensive.

Table 10-10 Stress Tests Results for Low Demand Forecast (Growth Scenario 2)

	Base (Plan A2)	FB Culley 2 Unit Retirement (Plan B2)	RPS (Plan C2)
Base	$4,771,789	$4,739,585	$4,871,859
High Gas	$4,804,936	$4,774,367	$4,904,004
Low Gas	$4,724,382	$4,690,021	$4,825,580
High Coal	$5,162,681	$5,110,118	$5,259,798
Low Coal	$4,371,289	$4,360,256	$4,474,450
High Market	$4,610,079	$4,613,296	$4,689,627
Low Market	$4,870,385	$4,803,750	$4,992,076
Low Carbon Price	$4,608,762	$4,579,376	$4,722,725
High Carbon Price	$5,215,962	$5,175,885	$5,282,560
High Capital Cost	$4,771,789	$4,739,585	$4,915,631
Low Capital Cost	$4,771,789	$4,739,585	$4,857,268
High Regulation Cost	$4,797,656	$4,758,986	$4,897,726

Stress Test of High (modeled) Demand Forecast (Growth Scenario 3)

Plan A-3 B-3 and C-3 stress test results are shown in table 10-11. Similarly to the results shows in table 10-5, plans A3 and B3 are essentially the same over a wide variety of possible future sensitivities. Plan C3 remains the most expensive.

Table 10-11 Stress Tests Results for High (modeled) Demand Forecast (Growth Scenario 3)

	Base (Plan A3)	FB Culley 2 Unit Retirement (Plan B3)	RPS (Plan C3)
Base	$5,064,159	$5,049,163	$5,168,352
High Gas	$5,099,475	$5,086,180	$5,202,306
Low Gas	$5,014,048	$4,997,322	$5,119,822
High Coal	$5,462,101	$5,425,041	$5,562,663
Low Coal	$4,655,886	$4,663,907	$4,763,874
High Market	$4,943,471	$4,956,522	$5,022,702
Low Market	$5,116,818	$5,076,415	$5,248,386
Low Carbon Price	$4,881,866	$4,876,097	$4,999,192
High Carbon Price	$5,563,573	$5,525,040	$5,628,969
High Capital Cost	$5,064,159	$5,050,009	$5,224,526
Low Capital Cost	$5,064,159	$5,048,881	$5,149,626
High Regulation Cost	$5,090,027	$5,068,564	$5,194,219

Stress Test of High (large load) Demand Forecast (Growth Scenario 4)

Plan A-4 B-4 and C-4 stress test results are shown in table 10-12. Similarly to the results shows in table 10-6, plan A4 is significantly less expensive in the near term than plans B4 and C4.

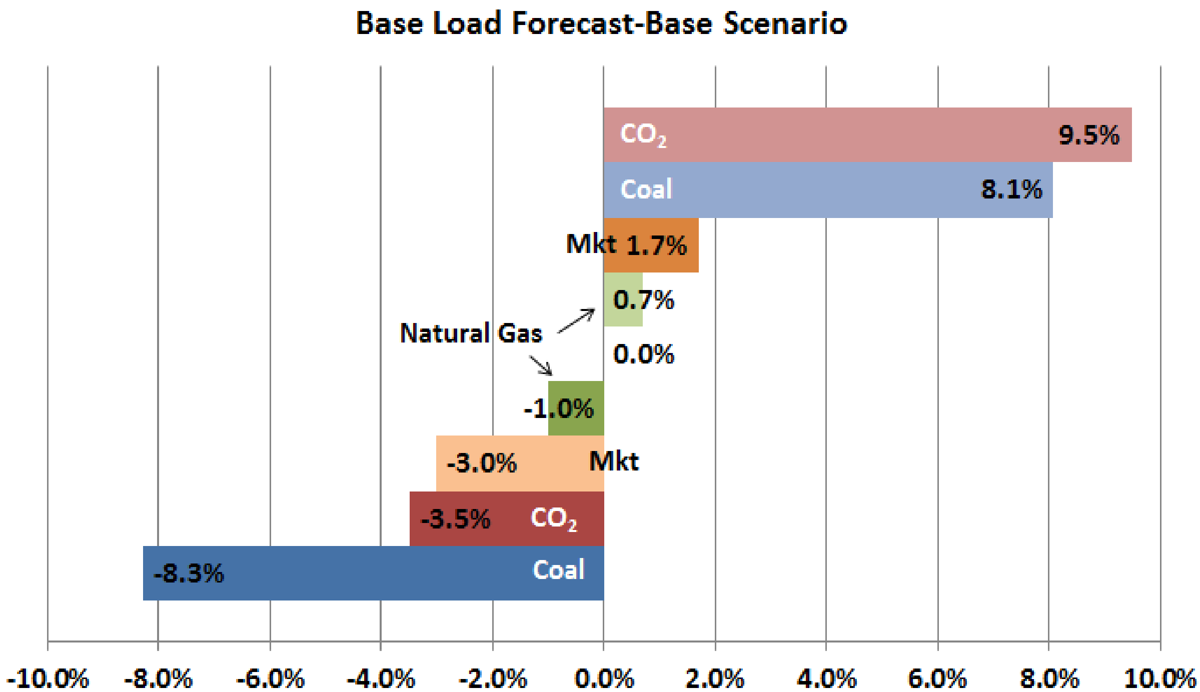
Table 10-12 Stress Tests Results for High (large load) Demand Forecast (Growth Scenario 3)

	Base (Plan A4)	FB Culley 2 Unit Retirement (Plan B4)	RPS (Plan C4)
Base	$5,156,487	$5,254,385	$5,283,860
High Gas	$5,192,745	$5,317,261	$5,318,391
Low Gas	$5,105,576	$5,163,552	$5,234,683
High Coal	$5,556,624	$5,646,923	$5,679,926
Low Coal	$4,745,742	$4,853,216	$4,877,383
High Market	$5,049,403	$5,098,566	$5,147,775
Low Market	$5,194,651	$5,328,227	$5,353,361
Low Carbon Price	$4,970,102	$5,093,626	$5,112,573
High Carbon Price	$5,665,492	$5,711,718	$5,749,275
High Capital Cost	$5,156,487	$5,322,627	$5,441,585
Low Capital Cost	$5,156,487	$5,231,638	$5,240,428
High Regulation Cost	$5,182,354	$5,273,786	$5,309,727

Relative Influence of Stress Test Factors

The relative influence of the stress tests on the net present values can be seen in table 10-13.

Table 10-13 Relative Influence of Stress Tests on Net Present Values

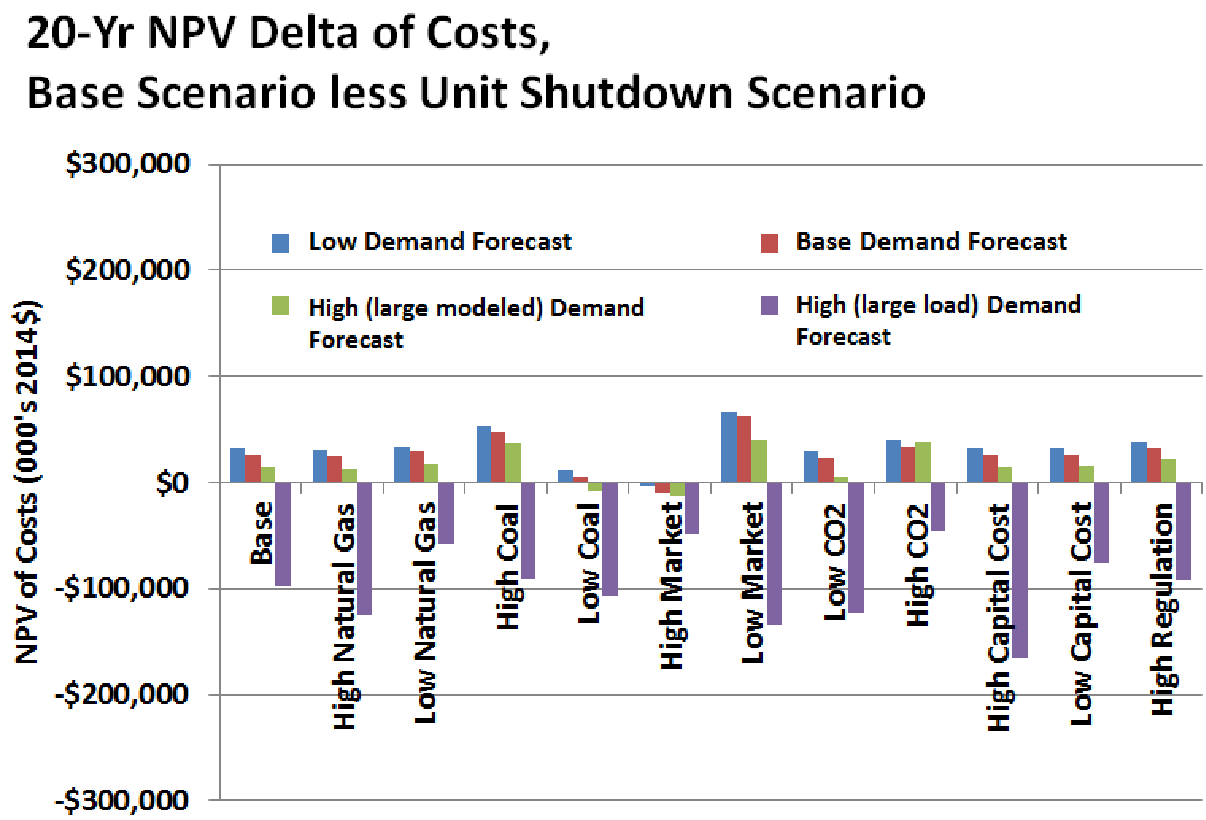


Risk Comparison

Under most risk factors, the cost of continuing operation of FB Culley or retirement in 2020 are essentially the same. As illustrated below in Table 10-14, the cost risk to customers if Vectren prematurely retires F.B. Culley 2 is potentially large under the high (large load) demand forecast.

Table 10-14 shows the risk comparison across all sensitivities and sales forecasts for the base scenario compared to the coal retirement scenario. This graph illustrates that the differences across three of the four sales forecasts are relatively small compared to the large savings in the high (large load) demand forecast case. Stated differently, the positive bars represent the extra cost of not retiring FB Culley 2 under 3 of the 4 demand scenarios. The negative bars represent the savings under 1 of the 4 sales scenarios by not retiring FB Culley 2 in 2020. The high (large load) growth scenario savings are much greater across all sensitivities by not retiring a unit. Vectren is actively working to attract new industrial customers through economic development activities in southwestern Indiana. If a large customer chooses to locate within the Vectren electric service area, it will be significantly less expensive to serve that additional load with existing resources in the near term.

Table 10-14 Comparison of Risks



Therefore, there are significant risks to retiring Culley unit 2 in the next few years. Vectren is making no decision at this time on a retirement date for several reasons. The graph above illustrates the risk of the high large load addition. Other significant risks include how the state of Indiana implements the Clean Power Plan, load uncertainties, and potential MISO shortfalls. There is little clarity on how Indiana intends to implement CO_2 guidelines. Depending on the direction that is taken, the plan may vary. Second, one of Vectren's largest customers is still finalizing plans for their co-generation unit. Vectren needs to better understand how this will affect the load forecast. Finally, with several coal plants shutting down within the MISO market, there is potential that not enough generation will be available to reliably serve the overall market. A decision about the assumed retirement of FB Culley 2 in 2020 in scenarios B1-B4 will not be made until near-term risk factors become clearer.

CONCLUSION

Based on Vectren's electric demand forecast, which includes cost effective DSM energy efficiency programs for customers, Vectren does not require additional resources. The IRP analysis indicates it is essentially the same cost to continue to operate FB Culley 2 or retire it in the near future. The decision to retire this unit is subject to a number of risks and uncertainties. Vectren is making no decision at this time on a retirement date.

As mentioned in the Risk Analysis section of this report, there are four major risks of retiring FB Culley 2 in the next few years:

1. How Indiana intends to implement CO_2 guidelines, the EPA's Clean Power Plan (111d)
2. Uncertainty about customer load due to the installation of a large co-generation unit
3. The possibility of a new large customer addition
4. Uncertainty around potential capacity shortfalls within the MISO market

Based on the risk associated with retiring FB Culley 2, Vectren will keep plan A-1 as the plan of choice in the near term, but will continue to evaluate the changing technology, environmental and regulatory developments, as well as customer costs and reliability needs. More time and analysis is needed to make a decision on the timing of retiring FB Culley 2. Note that there will be two more IRPs prepared prior to 2020.

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CHAPTER 11

ACTION PLAN

INTRODUCTION

These are the next steps the organization will take to achieve a reasonable long-term cost to retail customers with full consideration of the complex issues facing the industry in the next few years.

SUPPLY-SIDE RESOURCES

The overall objective of this study and review is to ensure that Vectren is properly positioned to meet its obligation to serve the needs of its Indiana retail customer base. Over the next several years, Vectren will continue to monitor changing market factors and risks including, but not limited to, increased environmental regulations including the EPA Clean Power Plan, large customer load, fuel price volatility, escalation of capital costs, increased emphasis on conservation measures, demand response, Smart Grid/AMI, and RTO related developments, particularly the possibility of MISO shortfalls. These items will be monitored both for their potential impact on future capacity needs and their impact on the operation of existing assets.

Vectren projects to have the generating capacity needed to meet the needs of its customers without adding any additional assets in all scenarios. All 12 plans explored are very similar or identical during the first few years. No immediate action is required. Vectren will conduct additional analysis, including another IRP in 2016. A decision about the assumed retirement of FB Culley 2 in 2020 will not be made until near term risk factors become clearer.

DEMAND-SIDE RESOURCES

Vectren plans to continue to pursue DSM, energy efficiency, and demand response opportunities by working through collaborative efforts with the IURC and OUCC. Vectren will continue to implement the 2015 DSM Plan as filed under Cause No. 44495, which was recently approved by the Commission. The programs outlined in the 2015 DSM Plan are designed to cost effectively reduce energy use and electric demand by approximately 1% of eligible retail sales. While Vectren's current resources are adequate to meet the needs of its customers, Vectren believes that conservation is in their customers' best interest. Helping customers learn to conserve energy will benefit customers through lower bills, the environment through lower emissions, and rates through the reduced need for additional system capacity in the future.

Vectren is in the process of developing a three-year Action Plan for 2016-2018 electric DSM programs. The programs outlined in this three-year Action Plan will be designed to reduce energy use by approximately 1– 1.5% of eligible retail sales. There are several variables that currently exist that may have impact on this planning process. The EPA Clean Power Plan proposal, Federal appliance and equipment minimum efficiency standards and state legislation relating to energy efficiency could all impact the savings goals for the next three years. Vectren is currently monitoring such rules and regulations and will continue to incorporate these factors into this planning process, as required.

Vectren will closely monitor trends regarding Smart Grid/AMI throughout the country. Vectren will work collaboratively with key stakeholders to determine the appropriate implementation strategy for Smart Grid/AMI in the Vectren territory.

TRANSMISSION AND DISTRIBUTION

Vectren will work closely with MISO to determine those transmission projects that will improve overall grid reliability within its service territory and those in the surrounding area. Vectren will implement system upgrades as needed to ensure reliable service to its customers. In addition, ongoing internal studies will monitor additions of industrial and commercial load in different locations within the Vectren service territory.

Detailed budgets for the short-term plan will be developed during Vectren's normal budgeting process.