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# 2011 INTEGRATED RESOURCE PLAN

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VECTREN
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## IRP Rule 7 Requirements Cross Reference Table

| Rule Reference | Rule 7 Description | Report Reference (As Page # or Attachment) |
|---|---|---|
| 170-IAC 4-7-4 | Methodology and documentation requirements - Sec. 4. An IRP covering at least a twenty (20) year future period prepared by a utility must include a discussion of the methods, models, data, assumptions, and definitions used in developing the IRP and the goals and objectives of the plan. The following information must be included: | |
| 4-7-4 (1) | (1) The data sets, including data sources, used to establish base and alternative forecasts. A third party data source may be presented in the form of a reference. 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 hard copy, or as specified by the commission. | Specific data may be available upon request |
| 4-7-4 (2) A-E | (2) A description of the utility's effort to develop and maintain, by customer class, rate class, SIC code, and end-use, a data base of electricity consumption patterns. The data base may be developed using, but not limited to, the following methods:<br>(A) Load research developed by the individual utility.<br>(B) Load research developed in conjunction with another utility.<br>(C) Load research developed by another utility and modified to meet the characteristics of that utility.<br>(D) Engineering estimates.<br>(E) Load data developed by a non-utility source. | 63, 74-77 |
| 4-7-4 (3) | (3) 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. | 77-78 |
| 4-7-4 (4) | (4) A discussion of customer self-generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting. | 94 |
| 4-7-4 (5) | (5) A description of model structure and an evaluation of model performance. | 66-74 |
| 4-7-4 (6) | (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. | 172-186 |
| 4-7-4 (7) | (7) A description of the fuel inventory and procurement planning practices, including the rationale, used in the development of the utility's integrated resource plan. | 168 |
| 4-7-4 (8) | (8) A description of the SO2 emission allowance inventory and procurement planning practices, including the rationale, used in the development of the utility's integrated resource plan. | 43-48 |

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| 4-7-4 (9) | (9) A description of the generation expansion planning criteria used in developing the integrated resource plan. The description must fully explain the basis for the criteria selected, including an analysis and rationale for the level of system wide generation reliability assumed in the IRP. | 161 |
| 4-7-4 (10) A-F | (10) A regional, or at a minimum, Indiana specific power flow study prepared by a regional or subregional organization. This requirement may be met by submitting Federal Energy Regulatory Commission (FERC) Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993. The power flow study shall include the following:<br>(A) Solved real flows.<br>(B) Solved reactive flows.<br>(C) Voltages.<br>(D) Detailed assumptions.<br>(E) Brief description of the model(s).<br>(F) Glossary of terms with cross references to the names of buses and line terminals. | 150 |
| 4-7-4 (10) (G) i-iii | (G) Sensitivity analysis, including, but not limited to, the forecast of the following:<br>(i) Summer and winter peak conditions.<br>(ii) Light load as well as heavy transfer conditions for one (1), two (2), five (5), and ten (10) years out.<br>(iii) Branch circuit ratings, including, but not limited to, normal, long term, short term, and emergency. | 150 |
| 4-7-4 (11) | (11) Any recent dynamic stability study prepared for the utility or by the utility. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993. | 150 |
| 4-7-4 (12) | (12) Applicable transmission maps. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993. | 151, Appendix |
| 4-7-4 (13) | (13) A description of reliability criteria for transmission planning as well as the assessment practice used. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993. | 151-152 |
| 4-7-4 (14) | (14) An evaluation of the reliability criteria in relation to present performance and the expected performance of the utility's transmission system. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993. | 152-153 |
| 4-7-4 (15) | (15) A description of the utility's effort to develop and improve the methodology and the data for evaluating a resource (supply-side or demand-side) option's contribution to system wide reliability. The measure of system wide reliability must cover the reliability of the entire system, including transmission, distribution, and generation. | 151 |
| 4-7-4 (16) | (16) 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:<br>(A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement.<br>(B) The avoided transmission capacity cost.<br>(C) The avoided distribution capacity cost.<br>(D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance. | 187 |

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| 4-7-4 (17) | (17) The hourly system lambda and the actual demand for all hours of the most recent historical year available. For purposes of comparison, a utility must maintain three (3) years of hourly data and the corresponding dispatch logs. | Not Applicable |
| 4-7-4 (18) | (18) A description of the utility's public participation procedure if the utility conducts a procedure prior to the submission of an IRP to the commission. | Not Applicable |
| 170-IAC 4-7-5 | Energy and demand forecasts - Sec. 5. (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: | |
| 4-7-5 (a) (1) | (1) An historical and projected analysis of a variety of load shapes, including, but not limited to, the following: | 75-77, Appendix |
| 4-7-5 (a) (1) (A) | (A) Annual load shapes. | 76, Appendix |
| 4-7-5 (a) (1) (B) | (B) Seasonal load shapes. | Appendix |
| 4-7-5 (a) (1) (C) | (C) Monthly load shapes. | Appendix |
| 4-7-5 (a) (1) (D) | (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. | 76-77, Appendix |
| 4-7-5 (a) (2) | (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. | 75-77, Appendix |
| 4-7-5 (a) (3) | (3) Disaggregation of historical data and forecasts by customer class, interruptible load, and end-use where information permits. | 75-77, Appendix |
| 4-7-5 (a) (4) | (4) The use and reporting of actual and weather normalized energy and demand levels. | 58-60, 63-74 |
| 4-7-5 (a) (5) | (5) A discussion of all methods and processes used to normalize for weather. | 63-64, 66-74 |
| 4-7-5 (a) (6) | (6) A twenty (20) year period for energy and demand forecasts. | 59 |
| 4-7-5 (a) (7) | (7)An evaluation of the performance of energy and demand forecasts for the previous ten (10) years, including, but not limited to, the following: | 78-81 |
| 4-7-5 (a) (7) (A) | (A) Total system. | 79 |
| 4-7-5 (a) (7) (B) | (B) Customer classes or rate classes, or both. | 80-81 |
| 4-7-5 (a) (7) (C) | (C) Firm wholesale power sales. | 81 |
| 4-7-5 (a) (8) | (8) If an end-use methodology has not been used in forecasting, an explanation as to why this methodology has not been used. | 57-58, 67 |
| 4-7-5 (a) (9) (A) | (9) For purposes of section 5(a)(1) and 5(a)(2) *[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(2) of this rule. | |
| 4-7-5 (b) (9) 1-7 | (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 combinations of alternative assumptions such as:<br>(1) Rate of change in population.<br>(2) Economic activity.<br>(3) Fuel prices.<br>(4) Changes in technology.<br>(5) Behavioral factors affecting customer consumption.<br>(6) State and federal energy policies.<br>(7) State and federal environmental policies. | 58-62 |

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| 170-IAC 4-7-6 | Resource assessment - Sec. 6. (a) For each year of the planning period, excluding subsection 6(a)(6) *[subdivision (6)]*, recognizing the potential effects of self-generation, an electric utility shall provide a description of the utility's electric power resources that must including: | |
| 4-7-6 (a) (1) | (1) The net dependable generating capacity of the system and each generating unit. | 166-167 |
| 4-7-6 (a) (2) A-E | (2) The expected changes to existing generating capacity, including, but not limited to, the following:<br>(A) Retirements.<br>(B) Deratings.<br>(C) Plant life extensions.<br>(D) Repowering.<br>(E) Refurbishment. | 166-167 |
| 4-7-6 (a) (3) (A) | (3) A fuel price forecast by generating unit. | 167-168 |
| 4-7-6 (a) (4) | (4) The significant environmental effects, including: | |
| 4-7-6 (a) (4) (A) | (A) air emissions; | 43-44 |
| 4-7-6 (a) (4) (B) | (B) solid waste disposal; | 52-54 |
| 4-7-6 (a) (4) (C) | (C) hazardous waste; and | 43-54 |
| 4-7-6 (a) (4) (D) | (D) subsequent disposal; at each existing fossil fueled generating unit. | 43-54 |
| 4-7-6 (a) (5) | (5) The scheduled power import and export transactions, both firm and nonfirm, as well as cogeneration and non-utility production expected to be available for purchase by the utility. | 92-93 |
| 4-7-6 (a) (6) | (6) An analysis of the existing utility transmission system that includes the following: | |
| 4-7-6 (a) (6) (A) | (A) An evaluation of the adequacy to support load growth and long term power purchases and sales. | 154-155 |
| 4-7-6 (a) (6) (B) | (B) An evaluation of the supply-side resource potential of actions to reduce transmission losses. | 155 |
| 4-7-6 (a) (6) (C) | (C) An evaluation of the potential impact of demand-side resources on the transmission network. | 154 |
| 4-7-6 (a) (6) (D) | (D) An assessment of the transmission component of avoided cost. | 155 |
| 4-7-6 (a) (7) (A) | (7) 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. | 105-147 |
| 4-7-6 (b) | (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 plan shall, at a minimum, include the following: | |
| 4-7-6 (b) (1) | (1) A description of the demand-side program considered. | 123-124 |
| 4-7-6 (b) (2) | (2) A detailed account of utility strategies designed to capture lost opportunities. | 116 |
| 4-7-6 (b) (3) | (3) 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. | 122 |
| 4-7-6 (b) (4) | (4) The customer class or end-use, or both, affected by the program. | 126-146 |
| 4-7-6 (b) (5) | (5) A participant bill reduction projection and participation incentive to be provided in the program. | 126-146 |

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| 4-7-6 (b) (6) | (6) A projection of the program cost to be borne by the participant. | 126-146 |
| 4-7-6 (b) (7) | (7) Estimated energy (kWh) and demand (kW) savings per participant for each program. | 126-146 |
| 4-7-6 (b) (8) | (8) The estimated program penetration rate and the basis of the estimate. | 126-146 |
| 4-7-6 (b) (9) | (9) The estimated impact of a program on the utility's load, generating capacity, and transmission and distribution requirements. | 126-146 |
| 4-7-6 (c) 1-4 | (c) A utility shall consider supply-side resources as an alternative in meeting future electric service requirements. The utility's plan shall include, at a minimum, the following:<br>(1) Identify and describe the resource considered, including the following:<br>(A) Size (MW).<br>(B) Utilized technology and fuel type.<br>(C) Additional transmission facilities necessitated by the resource.<br>(2) Significant environmental effects, including the following:<br>(A) Air emissions.<br>(B) Solid waste disposal.<br>(3) An analysis of how a proposed generation facility conforms with the utility-wide plan to comply with the Clean Air Act Amendments of 1990.<br>(4) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost. | Not Applicable |
| 4-7-6 (d) 1-4 | (d) A utility shall identify transmission and distribution facilities required to meet, in an economical and reliable manner, future electric service requirements. The plan shall, at a minimum, include the following:<br>(1) An analysis of transmission network capability to reliably support the loads and resources placed upon the network.<br>(2) A list of the principal criteria upon which the design of the transmission network is based. Include an explanation of the principal criteria and their significance in identifying the need for and selecting transmission facilities.<br>(3) A description of the timing and types of expansion and alternative options considered.<br>(4) The approximate cost of expected expansion and alteration of the transmission network. | 151-152, 155-157 |
| 170-IAC 4-7-7<br>4-7-7 (a) | Selection of future resources - Sec. 7. (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 (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. | 85-87 |
| 4-7-7 (b) 1-5 | (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):<br>(1) Participant.<br>(2) Ratepayer impact measure (RIM).<br>(3) Utility cost (UC).<br>4) Total resource cost (TRC).<br>(5) Other reasonable tests accepted by the commission. | 119-125 |
| 4-7-7 (c) | (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. | 119-122, 125 |
| 4-7-7 (d) | (d) A utility is required to: | |
| 4-7-7 (d) (1) | (1) Specify the components of the benefit and the cost for each of the major tests; and | 119-122 |
| 4-7-7 (d) (2) | (2) Identify the equation used to express the result. | 119-122 |

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| 4-7-7 (e) | (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. | |
| 4-7-7 (f) | (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. | 119-125 |
| 170-IAC 4-7-8 | Resource integration - Sec. 8. A utility shall select a mix of resources consistent with the objectives of the integrated resource plan. The utility must provide the commission, at a minimum, the following information: | |
| 4-7-8 (1) | (1) Describe the utility's resource plan. | 15-22 |
| 4-7-8 (2) | (2) Identify the variables, standards of reliability, and other assumptions expected to have the greatest effect on the least-cost mix of resources. | 160-161 |
| 4-7-8 (3) | (3) Determine the present value revenue requirement of the utility's resource plan, stated in total dollars and in dollars per kilowatt-hour delivered, with the discount rate specified. | 173 |
| 4-7-8 (4) | (4) Demonstrate that the utility's resource plan utilizes, to the extent practical, all economical load management, conservation, nonconventional technology relying on renewable resources, cogeneration, and energy efficiency improvements as sources of new supply. | 84-96 |
| 4-7-8 (5) | (5) Discuss how the utility's resource plan takes into account the utility's judgment of risks and uncertainties associated with potential environmental and other regulations. | 43-54 |
| 4-7-8 (6) | (6) Demonstrate that the most economical source of supply-side resources has been included in the integrated resource plan. | 84-102, 161 |
| 4-7-8 (7) | (7) Discuss the utility's evaluation of dispersed generation and 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. | 95-96 |
| 4-7-8 (8) | (8) Discuss the financial impact on the utility of acquiring future resources identified in the utility's resource plan. The discussion shall include, where appropriate, the following: | |
| 4-7-8 (8) (A) | (A) The operating and capital costs of the integrated resource plan. | 160-173 |
| 4-7-8 (8) (B) | (B) The average price per kilowatt-hour as calculated in the resource plan. The price 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. | Not Applicable |
| 4-7-8 (8) (C) | (C) An estimate of the utility's avoided cost for each year of the plan. | 188 |
| 4-7-8 (8) (D) | (D) The impact of a planned addition to supply-side or demand-side resources on the utility's rate. | Not Applicable |
| 4-7-8 (8) (E) | (E) The utility's ability to finance the acquisition of a required new resource. | Not Applicable |
| 4-7-8 (9) | (9) Identify and explain assumptions concerning existing and proposed regulations, laws, practices, and policies made concerning decisions used in formulating the IRP. | 31-40, 43-54, 105-147 |
| 4-7-8 (10) A-C | (10) Demonstrate, to the extent practicable and reasonable, that the utility's resource plan incorporates a workable strategy for reacting to unexpected changes. A workable strategy is one that allows the utility to adapt to unexpected circumstances and preserves the plan's ability to achieve its intended purpose. Unexpected changes include, but are not limited to the following:<br>(A) The demand for electric service.<br>(B) The cost of a new supply-side or demand-side technology.<br>(C) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error. | 172-186 |

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| 170-IAC 4-7-9 1-5 | Short-term action plan - Sec. 9. A short term action plan shall be prepared as part of the utility's IRP filing or separately, and shall cover each of the two (2) years beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the resource options or programs contained in the utility's current integrated resource plan where the utility must take action or incur expenses during the two (2) year period. The short-term action plan must include, but is not limited to, the following:<br>(1) A description of each resource option or program included in the short term action plan. The description must include, but is not limited to, the following:<br>(A) The objective of the resource option or program.<br>(B) The criteria for measuring progress toward the objective.<br>(C) The actual progress toward the objective to date.<br>(2) The participation of small business in the implementation of a DSM resource option or program.<br>(3) The implementation schedule for the resource option or program.<br>(4) The timetable for implementation and resource acquisition.<br>(5) A detailed budget for the cost to be incurred for each resource or program. | 191-193 |

## List of Acronyms/Abbreviations

| | |
|---|---|
| AC | Air Conditioning |
| ACESA | American Clean Energy and Security Act of 2009 |
| ADSP | Aero Derivative Steam Path |
| AMI | Advanced Metering Infrastructure |
| ARR | Auction Revenue Rights |
| ARRA | American Recovery and Reinvestment Act |
| ASHRAE | American Society of Heating, Refrigeration, and Air-Conditioning Engineers |
| ASPEN-OneLiner | Advanced Systems for Power Engineering, Incorporated |
| AUPC | Average Use Per Customer |
| BAGS | Broadway Avenue Gas Turbines |
| BCR | Benefit-cost Ratio |
| BPM | MISO's Business Practice Manual |
| CAA | Clean Air Act |
| CAC | Citizens Action Coalition |
| CAIR | Clean Air Interstate Rule |
| CAMR | Clean Air Mercury Rule |
| CAP | Community Action Partnership |
| CCGT | Combined Cycle Gas Turbine |
| CCS | Carbon Capture and Sequestration |
| CDD | Cooling Degree Days |
| CEII | Critical Electric Infrastructure Information |
| CERES | Combined Energy Efficiency and Renewable Electricity Standard |
| CFB | Circulating Fluidized Bed |
| CFC | Chlorofluorocarbons |
| CFL | Compact Fluorescent Lighting |
| $CO_2$ | Carbon Dioxide |
| CPI | Consumer Price Index |
| CPP | Critical Peak Pricing |
| 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 |
| DMS | Distribution Management System |
| DOE | United States Department of Energy |
| DR | Demand Response |
| DSM | Demand-side Management |
| DSMCC | Demand Side Management Coordination Committee |
| EA | Emission Allowances |
| EAP | Energy Assistance Program |
| ECAR | East Central Area Reliability Coordination Agreement |
| ECC | Economic Carrying Charge |
| ECM | Electronically Commutated Motor |
| EDR | Emergency Demand Response |
| EGU | Electric generating units |
| EIA | Energy Information Administration |
| EMS | Enterprise Management System |
| EMT | Energy Market Tariff |
| EM&V | Evaluated, Measured, & Verified |
| 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 |
| FTR | Financial Transmission Rights |
| GADS | Generating Availability Data System |
| GDP | Gross Domestic Product |
| GHG | Greenhouse Gas |

## List of Acronyms/Abbreviations (continued)

| | |
|---|---|
| GS | General Service |
| GWH | Gigawatt hour |
| HAN | Home Area Network |
| HAP | Hazardous Air Pollutants |
| HCFC | Hydro Chlorofluorocarbons |
| HDD | Heating Degree Days |
| HFC | Hydro Fluorocarbons |
| HRSG | Heat Recovery Steam Generator |
| HVAC | Heating, Ventilation, and Air Conditioning |
| HWAP | Home Weatherization Assistance Program |
| ICAP | Interconnection Installed Capacity |
| IDEM | Indiana Department of Environmental Management |
| IGCC | Integrated Gasification Combined Cycle |
| INCAA | Indiana Community Action Association |
| IPP | Independent Power Producers |
| IRP | Integrated Resource Plan |
| IURC | Indiana Utility Regulatory Commission |
| IVVC | Integrated Volt-VAR Control Strategy |
| LDC | Local Distribution Company |
| LMR | Load Management Receivers |
| LOLE | Loss of Load Expectation |
| LP | Low Pressure |
| LSE | Load Serving Entity |
| MACT | Maximum Achievable Control Technology Standards |
| MAPE | Mean absolute percentage error |
| MARS | Multi-Area Reliability Simulation |
| MECT | Module E Capacity Tracking |
| MISO | Midwest Independent System Operator |
| 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 |
| NEF | National Energy Foundation |
| NERC | North American Electric Reliability Council |
| NETL | National Energy Technology Laboratory |
| NOAA | National Oceanic and Atmospheric Administration |
| NOx | Nitrous Oxide |
| O&M | Operation and Maintenance |
| OH | Overhead |
| ORSANCO | Ohio River Valley Sanitation Commission |
| OUCC | Office of Utility Consumer Counselor |
| OVEC | Ohio Valley Electric Corporation |
| PC | Pulverized Coal |
| PCCI | Power Capital Cost Index |
| PJM | Pennsylvania New Jersey Maryland Interconnection LLC |
| $PM_{2.5}$ | Particulate Matter |
| PRC | Planning Reserve Credit |
| PRM | Planning Reserve Margin |
| PSD | Prevention of Significant Deterioration |
| PTI-PSS/E | Power Technologies Incorporated's Power System Simulator Program for Engineers |
| PVRR | Present Value of Revenue Requirements |
| RCRA | Resource Conservation and Recovery Act |
| REC | Renewable Energy Credit |
| RECEB | Regional Expansion Criteria and Benefits |
| RFC | Reliability First Corporation |
| RFP | Request for Proposal |
| RIM | Ratepayer Impact Measure |

## List of Acronyms/Abbreviations (continued)

| | |
|---|---|
| ROW | Right of Way |
| RPS | Renewable Portfolio Standard |
| SAE | Statistically Adjusted End-use |
| SCADA | Supervisory Control and Data Acquisition |
| SCGT | Simple Cycle Gas Turbine |
| SCR | Selective Catalytic Reduction |
| SGIG | Smart Grid Investment Grant |
| SGS | Small General Service |
| SIP | System Integration Plan |
| $SO_2$ | Sulfur Dioxide |
| TA | Transmission Automation |
| TOU | Time of Use |
| TPA | Third Party Administrator |
| TPY | Tons Per Year |
| TRC | Total Resource Cost |
| TVA | Tennessee Valley Authority |
| UCAP | Unforced Capacity Rating |
| UG | Underground |
| VCA | Voluntary Capacity Auction |
| VCEPS | Voluntary Clean Energy Portfolio Standard |
| VUHI | Vectren Utility Holdings Inc. |

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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 South), and Vectren Energy Delivery of Ohio (VEDO).

Vectren North provides energy delivery services to more than 560,000 natural gas customers located in central and southern Indiana. Vectren South provides energy delivery services to over 140,000 electric customers and approximately 110,000 gas customers located in southwestern Indiana. VEDO provides energy delivery services to approximately 315,000 natural gas customers in west central Ohio.

Vectren South's company-owned generation fleet represents 1,285 megawatts (MW)[1] of summer capacity as shown in Table 1-1.

Table 1-1 Generating Units

| Unit | Summer Capability (MW) | Primary fuel | Commercial Date |
|---|---|---|---|
| AB Brown 1 | 245 MW | Coal | 1979 |
| AB Brown 2 | 245 MW | Coal | 1986 |
| AB Brown 3 | 75 MW | Gas | 1991 |
| AB Brown 4 | 75 MW | Gas | 2002 |
| FB Culley 2 | 90 MW | Coal | 1966 |
| FB Culley 3 | 270 MW | Coal | 1973 |
| Warrick 4 | 150 MW | Coal | 1970 |
| BAGS 1 | 50 MW | Gas | 1971 |
| BAGS 2 | 65 MW | Gas | 1981 |
| Northeast 1 | 10 MW | Gas | 1963 |
| Northeast 2 | 10 MW | Gas | 1964 |
| 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 ownership interest in Ohio Valley Electric Corporation (OVEC). Vectren has also purchased 100 MW of firm peaking capacity for the three years 2010 through 2012. Vectren is also contracted to receive 80 MW of nominal capacity wind energy through two separate long-term purchased power agreements. The total firm capacity credit for the MISO 2011-2012 planning year for these wind resources is 6.2 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 Midwest 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.

Details of the highly methodical process utilized by Southern Indiana Gas and Electric Company, d/b/a Vectren Energy Delivery of Indiana, Inc. (Vectren) to develop the recommended plan in this IRP are found in Chapters 2 through 10 of this report. Chapter 11 sets forth the action plan for Vectren over the next several 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, as in the case of all prior IRPs filed by Vectren since 1983, 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 (formerly New Energy Associates) as it has in its last several IRP studies. This software is also used by some of the other Indiana utilities. The submitted plan was the result of a process that was primarily a quantitative evaluation performed using an industry standard computerized planning model.

Vectren has performed traditional modeling as part of this IRP process. However, Vectren also believes that a few industry trends that are difficult to quantify must also be considered before a final plan is recommended. Such changes have resulted principally from:

1. the increased emphasis on conservation and energy efficiency; and
2. the possibility of passage of greenhouse gas (GHG) legislation/ regulation which will increase the cost of fossil fuel-fired generation, as well as other environmental uncertainties.

These real world risks and uncertainties cannot be adequately captured in a computer model and must be addressed by Vectren management as part of the decision making process. 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 our customers and the communities we serve. Vectren understands that the Integrated Resource 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 we both attempt to carry out our respective responsibilities in the most effective manner possible.

**CHANGES SINCE LAST IRP**

In 2009 and 2010 the industry saw multiple attempts to pass climate change legislation in Congress. These various House and Senate bills failed to pass, and with the current state of the economy and a presidential election approaching, the Company does not currently foresee that Congress will take up any new attempts to regulate greenhouse gases from utility boilers for at least two more years. However, the Environmental Protection Agency (EPA) continues to expand its regulation of greenhouse gases from large stationary sources such as coal-fired utility boilers. Given the uncertainty surrounding this issue, Vectren has decided not to include the potential impacts of greenhouse gas legislation/regulation in our base case forecast. Alternatively, we have modeled the potential impact of carbon legislation/regulation in Chapter 4 Environmental and in the Sensitivity and the Risk Analysis section of Chapter 10 Electric Integration Analysis.

Utilities are facing many challenges in the environmental arena. Vectren has made significant investment in environmental compliance, from its $410 million in recent air emissions control investments to its $20 million investment in ash handling and loading, which enables Vectren to beneficially reuse 100% of its fly ash. While Vectren's previous investments in pollution control equipment position it to comply with the myriad of new federal air regulations aimed at the coal-fired power industry, Vectren will see an increase in chemical and other operating costs to achieve these reductions. Vectren is also carefully monitoring potential new requirements with respect to water discharges and ash handling which could require additional investments in the future.

On December 9, 2009 the IURC released the Phase II Generic Demand Side Management (DSM) order, which established statewide electric savings goals for

utilities starting in 2010 at 0.3% of average sales and ramping up to 2% per year in 2019. The impacts of this order have been modeled and are included in our base case forecast. On August 31, 2011 the IURC approved Vectren's DSM Plan under Cause No. 43938. The Core and Core Plus programs outlined in the plan are expected to meet the savings identified in the Phase II Order for the years 2011-2013.

As a part of Vectren's Core Plus programs, Vectren has launched a pilot that incentivizes qualifying customers to convert their inefficient electric water heaters to more efficient natural gas units. The direct use pilot is an innovative program that is designed to use natural resources more efficiently and help reduce regional electric demand. The program follows a national trend in promoting the direct use of natural gas versus using it to generate electricity. Vectren recently approached 3,000 qualifying electric customers in its southwestern Indiana service territory to consider the program and is hopeful to convert 250 customers within the next three years, which should save 1,220 megawatt hours (MWh) annually. More information on this and other conservation programs is mentioned in Chapter 8 DSM Resources.

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 (1MW) and an increase in the amount of net metering allowed (1% of most recent summer peak load). 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 August 1, 2011 Vectren had 22 active, 1 inactive and 1 pending net metering customers with a total nameplate capacity of 149.4 kW.

Finally, over the last year, Vectren has worked with Itron, Inc. to enhance our sales and demand forecasting models. As discussed later in Chapter 5 Sales and Demand

Forecast, the models' statistics were strengthened and were determined to be good predictors of Vectren sales and demand.

**PLAN RESULTS / RECOMMENDATIONS**

As of the time of this filing, Vectren does not recommend the installation of any additional generation on its system, nor does Vectren propose additional purchase power agreements during the planning period. Vectren proposes to utilize demand-side management programs to help customers use less energy, thus, lowering their total bill. Table 1-2 shows the peak and energy forecast, while Table 1-3 shows that no capacity additions are currently deemed necessary.

Vectren's base case scenario assumptions are detailed in Chapter 10. In summary, we assumed a minimum planning margin of 12.1%[1] for each year of the study. Implementation of the Phase II Generic DSM order began in 2010. Savings goals of 0.3% of average sales and ramping to 2% per year in 2019 were incorporated into our base case forecast. 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 analyses were performed around load growth rate, gas pricing, carbon pricing, no new conservation savings beyond 2019, and the addition of industrial load on the system. These results are shown in Chapter 10 Electric Integration Analysis.

**CONCLUSION**

Vectren recognizes that the electric utility industry is experiencing an extremely volatile time in terms of potential regulations, fuel availability and costs, environmental mandates, and technology advances. Given the significant impact of any decision on both our customers and our other stakeholders, Vectren will continue to actively monitor

[1] ReliabilityFirst Planning Reserve Standard discussed further Chapter 3 MISO, pages 33-34

developments in the regulatory, environmental, and technology arenas for both their impact on future generation needs and existing facilities.

Open communication with the IURC and other parties such as 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)* | Annual Energy (GWh)* |
|---|---|---|
| 2010 act. Peak, Calendar Energy | 1,275 | 6,271 |
| 2011 proj. | 1,218 | 6,146 |
| 2012 | 1,168 | 5,896 |
| 2013 | 1,168 | 5,867 |
| 2014 | 1,177 | 5,863 |
| 2015 | 1,164 | 5,772 |
| 2016 | 1,160 | 5,725 |
| 2017 | 1,151 | 5,657 |
| 2018 | 1,145 | 5,590 |
| 2019 | 1,139 | 5,520 |
| 2020 | 1,144 | 5,538 |
| 2021 | 1,149 | 5,543 |
| 2022 | 1,155 | 5,554 |
| 2023 | 1,159 | 5,563 |
| 2024 | 1,165 | 5,580 |
| 2025 | 1,171 | 5,588 |
| 2026 | 1,177 | 5,603 |
| 2027 | 1,184 | 5,618 |
| 2028 | 1,191 | 5,646 |
| 2029 | 1,199 | 5,660 |
| 2030 | 1,207 | 5,685 |
| 2031 | 1,215 | 5,711 |
| Compound Annual Growth Rate, 2012-2031 Including Wholesale | 0.21% | -0.17% |
| Compound Annual Growth Rate, 2012-2031 Without Wholesale | 0.26% | -0.12% |

*Includes wholesale contract sales for 2010-2014

## Table 1-3 Base Case Resource Plan

| Year | Retail Peak Requirements (MW) | Firm Wholesale (MW) | Firm Peak Demand (MW) | Company Owned Generation (MW) | DLC (MW) | Interruptible (MW) | Committed Purchases (MW) | Capacity Addition | | Total Resources (MW) | Reserve Margin (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Summer (MW) | Description | | |
| 2012 | 1,156 | 12 | 1,168 | 1,285 | 16 | 35 | 138 | | | 1,474 | 26.2% |
| 2013 | 1,156 | 12 | 1,168 | 1,285 | 19 | 35 | 38 | | | 1,377 | 17.9% |
| 2014 | 1,165 | 12 | 1,177 | 1,285 | 21 | 35 | 38 | | | 1,379 | 17.2% |
| 2015 | 1,164 | | 1,164 | 1,285 | 24 | 35 | 38 | | | 1,382 | 18.8% |
| 2016 | 1,160 | | 1,160 | 1,285 | 24 | 35 | 38 | | | 1,382 | 19.2% |
| 2017 | 1,151 | | 1,151 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.0% |
| 2018 | 1,145 | | 1,145 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.7% |
| 2019 | 1,139 | | 1,139 | 1,285 | 24 | 35 | 38 | | | 1,382 | 21.3% |
| 2020 | 1,144 | | 1,144 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.8% |
| 2021 | 1,149 | | 1,149 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.2% |
| 2022 | 1,155 | | 1,155 | 1,285 | 24 | 35 | 38 | | | 1,382 | 19.7% |
| 2023 | 1,159 | | 1,159 | 1,285 | 24 | 35 | 38 | | | 1,382 | 19.2% |
| 2024 | 1,165 | | 1,165 | 1,285 | 24 | 35 | 38 | | | 1,382 | 18.7% |
| 2025 | 1,171 | | 1,171 | 1,285 | 24 | 35 | 38 | | | 1,382 | 18.0% |
| 2026 | 1,177 | | 1,177 | 1,285 | 24 | 35 | 38 | | | 1,382 | 17.4% |
| 2027 | 1,184 | | 1,184 | 1,285 | 24 | 35 | 38 | | | 1,382 | 16.8% |
| 2028 | 1,191 | | 1,191 | 1,285 | 24 | 35 | 38 | | | 1,382 | 16.0% |
| 2029 | 1,199 | | 1,199 | 1,285 | 24 | 35 | 38 | | | 1,382 | 15.3% |
| 2030 | 1,207 | | 1,207 | 1,285 | 24 | 35 | 38 | | | 1,382 | 14.5% |
| 2031 | 1,215 | | 1,215 | 1,285 | 24 | 35 | 38 | | | 1,382 | 13.7% |

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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
- Improve the local environment
- Enhance shareholder value over the long-term

## PLANNING PROCESS

As shown in Figure 2-1, the IRP process has two distinct components: the long-term planning process and the short-term implementation of market-based decisions. The long-term process guides resource decisions, while the short-term decisions consider the rapid changes that occur in the market.

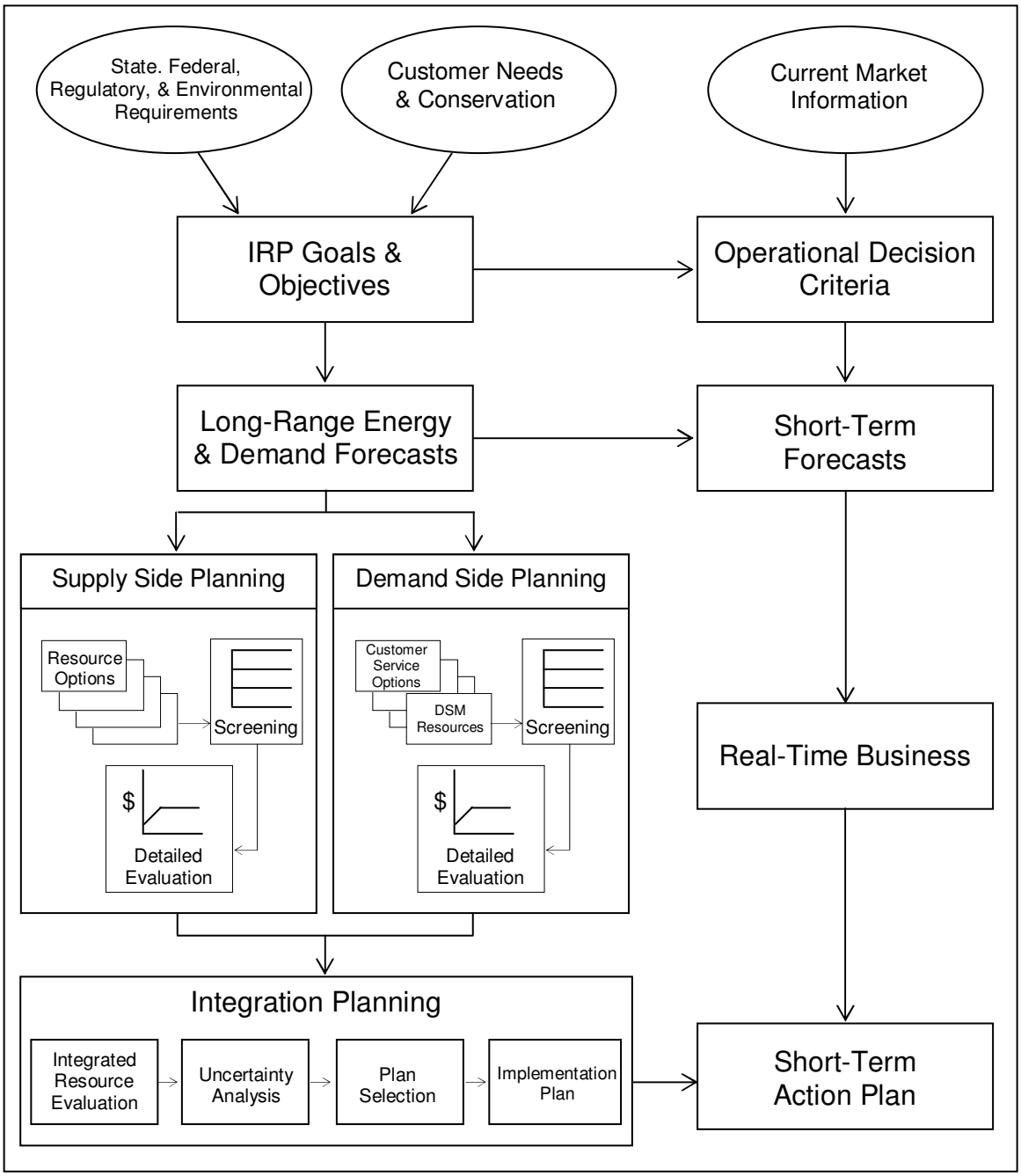
The planning process is driven by the characteristics of Vectren's markets and the needs of its customers. These elements serve to define the utility's objectives and help establish a long-term forecast of energy and demand.

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

**Figure 2-1 Overview of Vectren's IRP Process**



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
Chapter 11 - Contains action plans designed to implement the resource plan over the next two 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 (MISO), and under which authority the MISO administers its Open Access Transmission Tariff. As a traditional vertically integrated utility with responsibility for serving load within the MISO footprint, Vectren has integrated many functions with the operating procedures of the Midwest Independent System Operator (MISO). This integration involves the coordinated operation of our transmission system and generating units and the functions range from owning and operating generation and transmission, to complying with certain reliability standards. These standards are set by both the North American Electric Reliability Council (NERC) and the regional reliability entity ReliabilityFirst and include planning of resources to meet the needs of loads in the future.

## MISO OVERVIEW

MISO, headquartered in Carmel, Indiana, was approved as the nation's first regional transmission organization in 2001. MISO manages one of the world's largest energy and operating reserves markets; the market generation capacity was 134,850 MW as of June 1, 2011, and its peak load in July, 2011 was 103,975 MW. This market operates in 12 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, 2011 - Ancillary Services Markets began

**Vectren in Relation to MISO Footprint**

With a peak load of about 1,200 MW, Vectren is approximately 1.5% of the MISO market footprint and is one of 28 local balancing authorities. Figure 3-1 below is a drawing of the entire MISO market footprint.

**Figure 3-1 MISO Market**

**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 five planning principles to guide the MISO regional plan:

- Make the benefits of a competitive energy market available to customers by providing access to the lowest possible electric energy costs
- Provide a transmission infrastructure that safeguards local and regional reliability
- Support state and federal renewable energy objectives by planning for access to all such resources (e.g. wind, biomass, demand-side management)

- Create a mechanism to ensure that investment implementation occurs in a timely manner
- Develop a transmission system scenario model and make it available to state and federal energy policymakers to provide context and information regarding potential policy choices[1]

## 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 2010 MTEP recommends $1.2 billion in new projects across the MISO footprint through the year 2020. In addition, effective July 16, 2010, MISO added Multi-value projects, which are intended to provide regional public policy and/or economic benefits, and for which costs are shared.

### 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 ReliabilityFirst 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

[1] From Transmission Planning Business Practice Manual BPM-020-r4, effective date 03-09-2011

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 year the ReliabilityFirst 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%. 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-Resource Adequacy. Vectren is complying with the ReliabilityFirst Planning Resource Adequacy standard by meeting the MISO Module E individual LSE required PRM (after accounting for load diversity). This PRM is 12.06% for June 2011-July 2012.

**MISO's Module E**

As previously mentioned, Module E- Resource Adequacy is the portion of the MISO Energy and Operating Reserves Tariff which requires MISO to determine the amount of PRM(s) that load serving entities like Vectren are required to hold. Module E and its associated business practice manual, lay out the mandatory requirements to ensure access to deliverable, reliable and adequate planning resources to meet peak demand requirements on the transmission system. These procedures establish an installed reserve margin and also consider the effect of load diversity to establish an individual planning reserve requirement for load serving entities. 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 bids and offers into MISO's monthly voluntary capacity auction.

Loss of Load Expectation and Determination of Planning Reserve Margins

MISO used a Loss of Load Expectation (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 PRMs 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 installed reserve margin of 17.4% applied to the MISO system coincident peak has been established for the planning year of June 2011 through May 2012. This value was determined through the use of the GE Multi-Area Reliability Simulation (MARS) software for Loss of Load analysis. PROMOD IV® was used to perform a security constrained economic dispatch, which provided the congestion-driven zonal definitions used within MARS. The analysis also resulted with one uniform PRM, applicable to the West, Central, and East planning areas that make up the MISO market footprint. The 17.4% coincident peak reserve margin requirement is lowered to 12.06% due to the effects of load diversity, which represents one of the benefits of the MISO membership since not all entities across the footprint peak at exactly the same time.

Effect of Load Diversity

Within Module E, individual LSEs maintain reserves based on their monthly peak load forecasts. These peak forecasts do not sum to the system coincident peak because they are reported based solely on the entity's own peak, which could occur at a different time than the system peak. To account for this diversity within the system, a reserve margin was calculated for application to individual LSE peaks utilizing a diversity factor, which was developed through the Loss of Load Expectation Working Group. The diversity factor leverages the fact that utilities experience their individual peak hour of

the year at different times than the MISO footprint as a whole. It results in an individual LSE reserve level of 12.06%, reduced from what would otherwise be a 17.4% reserve without accounting for diversity. As modeled within the GE MARS software, the system will achieve this reliability level when the amount of installed capacity available is 1.174 times that of MISO system coincident peak.[1]

Forecast LSE Requirements

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

LSEs must report their non-coincident peak forecasted demand 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.

MISO calculates the forecast LSE requirements for each month of the current planning year. Forecasted demand in MISO reflects the expected "50/50" 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.

LSEs must separately register demand resources in order to have them subtracted from their forecasted demand in determining compliance with planning reserve requirements.

[1] From MISO 20011-2012 LOLE Study Report, dated December, 2010

As described in MISO's Business Practice Manual (BPM-011-r8) for Resource Adequacy, LSE's must submit a resource plan which meets certain requirements, including qualification of resources and includes the opportunity to participate in their monthly Voluntary Capacity Auction. MISO performs certain evaluations of these plans and will report results to state commissions.

Resource Plan Requirements

LSEs are obligated to provide MISO with resource plans demonstrating that planning reserve credits (PRCs) will be available to meet their resource adequacy requirements. Generally, the PRM is the forecast LSE requirement multiplied by 1 plus MISO PRM, unless the state utility commission establishes a PRM that is different from MISO's.

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.

***Qualification of Resources, Including Unforced Capacity Ratings (UCAP), Conversion of UCAP MW to Planning 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).

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.

[1] From MISO BPM-011-r8 Resource Adequacy Section 3.6 State Authority to set PRM

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 PRCs.

***Submission of Annual and Monthly Resource Plans***

By March 1st of each planning year, each LSE submits the LSE's resource plan into the Module E Capacity Tracking tool by designating PRCs toward meeting its PRM requirement for the upcoming planning year.

Prior to the first calendar day of each of the months preceding the applicable planning month in the applicable planning year (Resource Plan Deadline), each LSE documents its compliance via the MECT tool, stating for that planning month the LSE has a resource plan that includes a sufficient number of designated PRCs to meet the LSE's PRM requirement.

***Evaluation and Reporting***

MISO will maintain databases and will report to states upon request the extent to which each LSE has met or has not met the requirements in section 69.1 of the Energy Market Tariff (EMT) during relevant time periods, subject to the data confidentiality provisions in section 38.9 of the Energy and Operating Reserves Tariff.

<u>Voluntary Capacity Auction and Financial Settlements</u>

The VCA facilitates the procurement of monthly PRCs by providing an optional monthly forum for sellers and buyers to interact in order to buy and sell PRCs to meet their last-minute capacity needs.

***Deficiency Procedures***

When an LSE is determined by MISO to be capacity deficient for a given month, the LSE will be responsible for the payment of a financial settlement charge. That charge is calculated as some percentage of the Cost of New Entry, defined as the capital, operating, financial, and other costs of acquiring a new generation resource and is calculated by MISO every year.

***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 monthly VCA 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**

MISO proposed Capacity Market

The MISO tariff and associated business practice manuals, which include details of their planning processes and procedures, have undergone several changes, some of which are still pending FERC approval. In particular, they have proposed extending their one-month voluntary capacity market to a one-year forward procurement requirement beginning with the planning year that begins in June, 2013.

Footprint Changes

Also, the MISO market footprint is subject to change, evidenced by the June 1, 2011 withdrawal of First Energy and the anticipated December 31, 2011 withdrawal of Duke Ohio/KY and potential integration of Entergy Corporation, which is slated for December, 2013.

## DEMAND RESPONSE

Vectren acknowledges that demand response is an integral part of a utility's system, operations, and planning, and as such it helps efficiently meet our 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.

### 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. As the MISO market continues to evolve, we will continue to evaluate the proper reserve margin target.

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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.

## 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 Culley Units 2 and 3. As Brown Units 1 and 2 are 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**

| | Culley 2 | Culley 3 | Warrick 4 | Brown 1 | Brown 2 |
|---|---|---|---|---|---|
| Vintage | 1966 | 1972 | 1970 | 1979 | 1986 |
| MW (net) | 90 | 270 | 150 | 245 | 245 |
| $NO_X$ | Low $NO_X$ Burner | SCR | SCR | SCR | SCR |
| $SO_2$ | FGD | FGD | FGD | FGD | FGD |
| PM | ESP | FF | ESP | FF | ESP |

**Table 4-2 Current (2010) Emission Rates (lbs./mm Btu)**

| Units | $SO_2$ | Annual $NO_X$ | Ozone Season $NO_X$ |
|---|---|---|---|
| Brown 1 | 0.5550 | 0.1470 | 0.1400 |
| Brown 2 | 0.4500 | 0.3800 | 0.1600 |
| Brown 3 | 0.0006 | 0.1670 | 0.1600 |
| Brown 4 | 0.0006 | 0.0250 | 0.0200 |
| Culley 2/3 | 0.1500 | 0.1910 | 0.1430 |
| Warrick 4 | 0.1800 | 0.2520 | 0.0900 |
| BAGS 1 | 0.0006 | 0.2600 | 0.2500 |
| BAGS 2 | 0.0006 | 0.2300 | 0.2000 |

**Table 4-3 2010 $SO_2$ Acid Rain Allowances Allocated to Vectren Units**

| Plant Name | Percent Ownership | Allowances Allocated (per year) 2010 | 2011-2038 |
|---|---|---|---|
| Brown | 100% | 10,546 | 10,546 |
| Culley | 100% | 9,922 | 9,922 |
| Warrick 4 | 50% | 5,122 | 5,122 |

* Number of allowances shown are for Vectren's portion of Warrick 4

For purposes of compliance year 2011, acid rain allowances will continue to be used for compliance with the $SO_2$ emission reductions requirements of the Clean Air Interstate Rule (CAIR). However, as detailed more fully below, CAIR has been superseded by the new Cross-State Air Pollution Rule (CSAPR), which becomes effective January 1, 2012. Neither the CAIR rule nor CSAPR supersedes the Acid Rain program, and facilities will still be required to annually surrender acid rain allowances to cover emissions of $SO_2$ under the existing Acid Rain program.

**NOx SIP CALL**

Vectren's NOx 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 NOx reductions required in the NOx SIP Call. When CAIR was finalized in March of 2005, the EPA included a seasonal NOx emission reduction requirement, which incorporated, and in most cases, went beyond the seasonal NOx emission reductions required under the NOx SIP Call. For purposes of compliance year 2011, CAIR NOx seasonal allowances will continue to be used for compliance with the seasonal NOx 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 amounts of transported 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 NOx and $SO_2$ from EGUs beyond those required in the NOx 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 (NOx) 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 will be used for compliance in 2011. However, any excess CAIR allowances (vintage 2011 or older) that are not needed for compliance in 2011 cannot be used for compliance with CSAPR, which is effective January 1, 2012.

In July of 2008, a reviewing court vacated the CAIR rule. According to the court, the EPA did not present a persuasive case that the CAIR cap and trade program would bring all areas into attainment for ozone and fine particulate as required by the Clean Air Act. The court also determined that the EPA did not have authority to terminate (or reduce) the value of acid rain allowances that were created by legislation. Allowance markets were roiled by the uncertainty created by the court's remand. This uncertainty was underscored by the EPA Clean Air Market Division's announcement on its web-site that the EPA would not guarantee the value of allowances beyond the date of the CAIR revision (i.e. acid rain allowances may not be used for compliance in a revised CAIR), and a March 26, 2009, letter from the EPA to all designated representatives cautioning about uncertainty of future NOx allowance allocations.

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 allowance trading. Like CAIR, the Transport Rule proposal set individual state caps for $SO_2$ and NOx; 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 (somewhat inexplicably) renamed it the Cross State Air Pollution Rule. CSAPR sets individual allowance allocations for Vectren's units directly in the rule. See Table 4-4, a listing of individual unit allowance allocations under the recently finalized CSAPR. Given the stringent state emission caps, the limited allowance trading available under the CSAPR, and the limited amount of time utilities and states have had to review the trading restrictions established in the rule, at this time it is virtually impossible to predict with any certainty the availability of excess allowances for compliance and the costs of those allowances.

**Table 4-4 CSAPR Allowances Allocated to Vectren Units**

| | $SO_2$ Allocation | | Annual $NO_X$ | | Seasonal $NO_X$ | |
|---|---|---|---|---|---|---|
| | 2012 | 2014 | 2012 | 2014 | 2012 | 2014 |
| | | | | | | |
| Brown 1 | 3,761 | 2,080 | 1,393 | 1,376 | 595 | 586 |
| Brown 2 | 3,889 | 2,151 | 1,440 | 1,422 | 601 | 591 |
| Brown 3 | 1 | 1 | 19 | 19 | 14 | 14 |
| Brown 4 | 0 | 0 | 6 | 6 | 4 | 4 |
| | | | | | | |
| BAGS 1 | 0 | 0 | 4 | 4 | 3 | 3 |
| BAGS 2 | 0 | 0 | 26 | 26 | 18 | 8 |
| | | | | | | |
| Culley 2 | 1,488 | 925 | 619 | 612 | 268 | 264 |
| 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 enables Vectren to comply with these new more stringent $SO_2$ and NOx emission caps in CSAPR without further significant capital investment; however, while currently well controlled, Vectren will incur increased costs attributable to the 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 (Culley Unit 2). See Table 4-1. As such, Vectren will be well-positioned to comply with the new, more stringent $SO_2$ and NOx caps that are required by CSAPR starting on January 1, 2012, without reliance on a highly uncertain allowance market or further significant capital expenditures. It is important to note that the CSAPR is still subject to revision. The CSAPR is currently being litigated in federal court, and on October 6,

2011, the EPA announced it's intent to propose technical adjustments to the current regulation.

**CLEAN AIR MERCURY 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, 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 AA § 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 proposal 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 proposed stringent plant-wide mercury emission limits for two sub-categories of coal and proposed 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. EPA is currently under a consent decree deadline of November 16, 2011, to finalize its utility HAPs rule.

Vectren's original CAMR compliance plan as approved in Cause No. 42861 and part of its multi-pollutant compliance plan relied upon the co-benefits of its existing pollution control configuration to achieve the CAMR reductions. Based upon an initial review of the proposed HAPs emission limits for mercury, acid gases and non-metal HAPs, as set forth in the EPA's March 16th proposal, Vectren believes that it is well-positioned to meet these new stringent emission limits for HAPs without further significant capital investment or premature retirement of any units.

**CARBON REGULATION**

In 2009 and 2010, the industry saw multiple attempts to pass climate change legislation in Congress. These various House and Senate bills failed to pass, and with the current state of the economy and a presidential election approaching, the Company does not currently foresee that Congress will take up any new attempts to regulate greenhouse gases from utility boilers for at least two more years.

However, even though the Company does not expect Congress to finalize any major legislation in the next few years, the EPA continues to expand its regulation of greenhouse gases from large stationary sources such as coal-fired utility boilers. In 2007, the US Supreme Court determined that greenhouse gases were "pollutants" as defined by the CAA and directed the EPA to make an endangerment finding with respect to whether global warming attributed to US sources threatens public health and welfare. The EPA finalized its finding of endangerment in December of 2009. A positive endangerment finding is the first step in regulating greenhouse gas emissions from major stationary sources. In anticipation of triggering mandatory greenhouse gas permitting requirements under existing provisions under the Act, on June 3, 2010, the EPA finalized its Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule. Following finalization of its endangerment finding and its rule to control greenhouse gas emissions from light-duty vehicles, the EPA was obligated under the Act to also issue prevention of significant deterioration (PSD) and Title V regulations for

stationary sources with greenhouse gas emissions that exceed thresholds for regulated pollutants. The Act sets those thresholds at 100 tons for stationary sources in listed categories and 250 tons for any stationary source, but greenhouse gases are emitted in far greater quantities than other pollutants in the PSD program. Applying the existing PSD framework to greenhouse gases would subject literally millions of facilities to standards and permitting requirements for the first time. The PSD permitting program was never intended for these myriad of small sources, so the PSD program needed to be "tailored" to ensure that only the largest sources of greenhouses are regulated.

The new PSD tailoring rule was finalized in June of 2010 and rolled out in two phases. The first phase, from January 2, 2011 to June 30, 2011, applied only to sources such as coal-fired generating units that were already subject to PSD permitting for another PSD pollutant. The modification would also result in an increase of 75,000 tons of total greenhouse gases (CO2-equivalent or CO2e), which will trigger requirements for Best Available Control Technology (BACT) review and installation of BACT. BACT controls are selected on a case-by-case basis, taking into account commercial availability, cost effectiveness of the control, and energy and environmental impacts. During this initial phase, no sources were subject to PSD permitting due solely to an increase in greenhouse gas emissions. However, starting on July 1, 2011, PSD permitting applies to modifications of existing units solely on the basis of a 75,000 tons / year (tpy) increase in total greenhouse gas emissions.

As discussed above, greenhouse gas legislation has stalled on a federal level due to political and economic considerations. While Vectren does not currently anticipate finalization of any significant federal greenhouse gas legislation in the near term, Vectren is including a carbon sensitivity scenario in the current modeling. For the purposes of the current model, Vectren assumes that a national cap and trade plan is adopted beginning 2016. As such, Vectren has relied on a carbon price curve provided by Wood Mackenzie in its North American Gas Long Term View (September 2010)

which starts at $14 / metric ton in 2016 and grows 6% annually, reaching $32 / metric ton by 2030.

**WATER**

Vectren's units currently discharge process and cooling water to the Ohio River under water discharge permits issued by the Indiana Department of Environmental Management (IDEM). There are currently two major regulatory rulemakings that could, when finalized, require more stringent limits for these discharges.

Indiana's anti-degradation rules have been in various stages of review and proposed regulation for the last twelve years. The anti-degradation implementation procedures proposed in this rule will apply to a new or increased loading of a "pollutant of concern" to a surface water of the state. The current proposal has been issued as a second notice, and it is anticipated it will be issued as final in the fall of 2011. A facility that proposes a new or increase to an existing water discharge can be required to incorporate Best Available Demonstrated Control Technology if the discharge results in the receiving water having sufficient amounts of a pollutant of concern such that the discharge has a potentially detrimental impact on the designated or existing use of the receiving water. When finalized, plant upgrades or significant process changes at the Brown, Warrick, and Culley stations, even if federally or locally mandated, may be viewed as a new discharge and subject to increased regulation.

In addition to Indiana's anti-degradation rulemaking, the Ohio River Valley Sanitation Commission's (ORSANCO) regional water quality standards are being revised. ORSANCO is a regional state compact focused on water quality issues for the Ohio River. Once final, these water quality standards will be used as guidance by states in setting discharge limits in water discharge permit renewals for industrial facilities, including Vectren units, discharging to the Ohio River. Issues that could potentially impact the operation of Vectren's units include lower standards for selenium and

mercury, lowered thermal discharge standards, and the elimination of mixing zones for Bioaccumulative Chemicals of Concern, including but not limited to mercury.

As a result of litigation filed by environmental organizations, the EPA is drafting regulations for utility cooling water structures under Section 316(b) of the Clean Water Act (CWA). Section 316(b) requires that electric generating units use the "Best Technology Available" to prevent and / or mitigate adverse environmental impacts to shellfish, fish, and wildlife in a waterbody. On March 28, 2011, the EPA released its draft 316(b) regulations. The proposed rule maintains the agency's current standard for new units (mandatory cooling water towers), but provides flexible options for existing facilities. If finalized in its current form, the regulations will require extensive sampling and testing programs to support case by case arguments that cooling water towers are not necessary at individual facilities. Vectren's Culley and Warrick units currently use a "once through" cooling water intake system and are clearly impacted by this proposed regulation. Vectren's Brown plant currently uses a closed cooling water system. However, under the proposal Vectren would still be required to conduct extensive sampling protocols to confirm that the existing cooling water tower mitigates impingement and entrainment.

**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. However, in response to the TVA's catastrophic ash pond spill in December of 2008, the EPA was pressured to re-evaluate its regulatory options for the management of coal combustion by-products. On June 21, 2010, the EPA published three options for a proposed rule. 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 re-uses of ash will continue to be allowed. The EPA has not indicated when it intends to finalize the new regulation.

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 Brown and Culley facilities and found the facilities' surface impoundments to be satisfactory and not posing a high hazard. Historically, the Brown surface impoundments handled both fly ash and bottom ash through a wet sluicing system that sent ash to a one hundred acre on-site ash pond system. Scrubber by-products are sent to an on-site landfill permitted by IDEM. Starting in February 2010, Brown fly ash is now diverted to a new dry ash handling system and sent for beneficial reuse to a cement processing plant in St. Genevieve, Missouri, via a river barge loader and conveyor system. This major sustainability project will serve to mitigate negative impacts from the imposition of a more stringent regulatory scheme for ash disposal, as the majority of Vectren's coal combustion materials are now being diverted from the existing ash pond structures and surface coal mine backfill operations and transported offsite for recycling into a cement application.

Fly ash from the Culley facility is similarly transported off-site for beneficial reuse in cement. Until mid 2009, fly ash from the Culley facility was sent to the Cypress Creek Mine for backfill pursuant to the mine's surface coal mine permit. In May 2009, Culley began trucking fly ash to the St. Genevieve cement plant. Upon completion of the barge loading facility at the Brown facility, Culley's fly ash is now transported to the Brown loading facility and shipped to the cement plant via river barge. The 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 Culley facility is also used for beneficial reuse and shipped by river barge from 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.

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# CHAPTER 5

# SALES & DEMAND FORECAST

## INTRODUCTION

The electric sales 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 DSM/DR programs, mandated efficiency standards, and the effects of normal market forces on electricity sales.

### Overview of Vectren's Customers and Their Usage

Vectren provides delivery services to approximately 142,000 electric residential, general service (commercial), and large (industrial) customers with electricity in southern Indiana. A high proportion of Vectren's sales are made to electric-intensive general service and large customers. In 2010, about 29% of Vectren's annual retail electric energy sales were consumed by residential customers, 24% of sales were consumed by general service, and 47% of sales were consumed by approximately 100 large customers. Less than 1% served other load, including 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

Development of this IRP required 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). These forecasts, and the activities undertaken to develop them, are described in this section. A low case forecast was deemed unnecessary, as the outcome of the base case required no new generation to serve Vectren customers in the planning period.

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 our 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 lighting load is forecasted with a simple trend model. The detail of our forecasting methodology is discussed later in this chapter.

**FORECAST RESULTS**

The base case forecasts of annual energy requirements and peak loads for the 2012 - 2031 planning period are provided in Tables 5-1 and 5-2. We have included wholesale contracts to municipal customers in our territory through contract expiration in 2014. These contracts are competitively bid and are at risk for future loss. We have included growth rates on all charts both inclusive and exclusive of wholesale contracts because of the uncertainty surrounding these loads. Annual energy requirements, excluding wholesale, are projected to have a -.12% compound annual growth rate over the twenty year planning period. Peak requirements (excluding wholesale) are projected to grow at compound annual growth rates of .26% over the twenty year planning period.

## Table 5-1 Base Case Energy and Demand Forecast

| Year | Annual Energy Requirements | | Hourly Peak Demand | |
|---|---|---|---|---|
| | GWh* | Growth,% | MW* | Growth,% |
| 2010 Calendar | 6,271 | | 1,275 | |
| 2011 proj. | 6,146 | -2.0% | 1,218 | -4.5% |
| 2012[1] | 5,896 | -4.1% | 1,168 | -4.1% |
| 2013 | 5,867 | -0.5% | 1,168 | 0.0% |
| 2014 | 5,863 | -0.1% | 1,177 | 0.8% |
| 2015[2] | 5,772 | -1.5% | 1,164 | -1.1% |
| 2016 | 5,725 | -0.8% | 1,160 | -0.4% |
| 2017 | 5,657 | -1.2% | 1,151 | -0.7% |
| 2018 | 5,590 | -1.2% | 1,145 | -0.5% |
| 2019 | 5,520 | -1.3% | 1,139 | -0.5% |
| 2020 | 5,538 | 0.3% | 1,144 | 0.5% |
| 2021 | 5,543 | 0.1% | 1,149 | 0.5% |
| 2022 | 5,554 | 0.2% | 1,155 | 0.5% |
| 2023 | 5,563 | 0.2% | 1,159 | 0.4% |
| 2024 | 5,580 | 0.3% | 1,165 | 0.4% |
| 2025 | 5,588 | 0.1% | 1,171 | 0.5% |
| 2026 | 5,603 | 0.3% | 1,177 | 0.5% |
| 2027 | 5,618 | 0.3% | 1,184 | 0.6% |
| 2028 | 5,646 | 0.5% | 1,191 | 0.6% |
| 2029 | 5,660 | 0.2% | 1,199 | 0.7% |
| 2030 | 5,685 | 0.4% | 1,207 | 0.7% |
| 2031 | 5,711 | 0.5% | 1,215 | 0.7% |
| Compound Annual Growth Rate, 2012-2031 Including Wholesale | | -0.17% | | 0.21% |
| Compound Annual Growth Rate, 2012-2031 Without Wholesale | | -0.12% | | 0.26% |

*Includes wholesale contract sales for 2010-2014

[1] Drop in sales in 2012 is primarily due to new lighting standards and real price change in 2011
[2] Included wholesale contracts to municipal customers in our territory through contract expiration in 2014. This accounts for approximately a 1% drop in sales and demand in 2015.

## Table 5-2 Base Case Energy Forecast by Customer Class

Annual Sales by Class (GWh)

| Year | Residential (GWh) | General Service (GWh) | Large (GWh) | Conservation (GWh) | Other (GWh) | Wholesale (GWh) | Losses (GWh) | Total Requirements (GWh) | Total Requirements (GWh) without Wholesale |
|---|---|---|---|---|---|---|---|---|---|
| 2010 Calendar | 1,604 | 1,363 | 2,655 | | 21 | 314 | 313 | 6,271 | 5,957 |
| 2011 proj. | 1,511 | 1,358 | 2,657 | (23) | 22 | 314 | 307 | 6,146 | 5,831 |
| 2012 | 1,501 | 1,387 | 2,696 | (60) | 22 | 57 | 295 | 5,896 | 5,840 |
| 2013 | 1,483 | 1,409 | 2,714 | (110) | 22 | 57 | 293 | 5,867 | 5,810 |
| 2014 | 1,493 | 1,441 | 2,728 | (171) | 22 | 57 | 293 | 5,863 | 5,806 |
| 2015 | 1,501 | 1,463 | 2,740 | (242) | 22 | | 288 | 5,772 | 5,772 |
| 2016 | 1,511 | 1,480 | 2,750 | (324) | 22 | | 286 | 5,725 | 5,725 |
| 2017 | 1,518 | 1,489 | 2,763 | (417) | 22 | | 283 | 5,657 | 5,657 |
| 2018 | 1,530 | 1,504 | 2,776 | (520) | 22 | | 279 | 5,590 | 5,590 |
| 2019 | 1,544 | 1,520 | 2,785 | (627) | 22 | | 276 | 5,520 | 5,520 |
| 2020 | 1,559 | 1,539 | 2,795 | (653) | 22 | | 277 | 5,538 | 5,538 |
| 2021 | 1,570 | 1,551 | 2,803 | (680) | 22 | | 277 | 5,543 | 5,543 |
| 2022 | 1,585 | 1,566 | 2,809 | (706) | 22 | | 278 | 5,554 | 5,554 |
| 2023 | 1,601 | 1,580 | 2,813 | (732) | 22 | | 278 | 5,563 | 5,563 |
| 2024 | 1,622 | 1,598 | 2,819 | (758) | 22 | | 279 | 5,580 | 5,580 |
| 2025 | 1,636 | 1,609 | 2,825 | (784) | 22 | | 279 | 5,588 | 5,588 |
| 2026 | 1,655 | 1,625 | 2,832 | (811) | 22 | | 280 | 5,603 | 5,603 |
| 2027 | 1,673 | 1,642 | 2,838 | (837) | 22 | | 281 | 5,618 | 5,618 |
| 2028 | 1,695 | 1,664 | 2,846 | (863) | 22 | | 282 | 5,646 | 5,646 |
| 2029 | 1,710 | 1,680 | 2,855 | (890) | 22 | | 283 | 5,660 | 5,660 |
| 2030 | 1,729 | 1,702 | 2,865 | (916) | 22 | | 284 | 5,685 | 5,685 |
| 2031 | 1,749 | 1,724 | 2,874 | (943) | 22 | | 285 | 5,711 | 5,711 |
| Compound Annual Growth Rate for (2012-2031) | 0.81% | 1.15% | 0.34% | | 0.00% | | | -0.17% | -0.12% |

High energy and demand forecasts were developed by modifying the assumptions about the long-term growth trends of different customer classes. Base economic and demographic data were not altered for the development of the high forecasts. The annual growth rates of the load classes were adjusted to result in a 20 year compound annual growth rate of 1.0% for the high cases. The results are shown in Table 5-3 and 5-4.

## Table 5-3 Base and High Case Energy Forecasts

| Year | Base Annual Requirements | | High Growth Annual Requirements | |
|---|---|---|---|---|
| | GWh* | Growth,% | GWh* | Growth,% |
| 2010 Calendar | 6,271 | | 6,271 | |
| 2011 proj. | 6,146 | -2.0% | 6,146 | -2.0% |
| 2012 | 5,896 | -4.1% | 5,896 | -4.1% |
| 2013 | 5,867 | -0.5% | 5,955 | 1.0% |
| 2014 | 5,863 | -0.1% | 6,014 | 1.0% |
| 2015 | 5,772 | -1.5% | 6,017 | 0.0% |
| 2016 | 5,725 | -0.8% | 6,077 | 1.0% |
| 2017 | 5,657 | -1.2% | 6,138 | 1.0% |
| 2018 | 5,590 | -1.2% | 6,199 | 1.0% |
| 2019 | 5,520 | -1.3% | 6,261 | 1.0% |
| 2020 | 5,538 | 0.3% | 6,324 | 1.0% |
| 2021 | 5,543 | 0.1% | 6,387 | 1.0% |
| 2022 | 5,554 | 0.2% | 6,451 | 1.0% |
| 2023 | 5,563 | 0.2% | 6,515 | 1.0% |
| 2024 | 5,580 | 0.3% | 6,580 | 1.0% |
| 2025 | 5,588 | 0.1% | 6,646 | 1.0% |
| 2026 | 5,603 | 0.3% | 6,713 | 1.0% |
| 2027 | 5,618 | 0.3% | 6,780 | 1.0% |
| 2028 | 5,646 | 0.5% | 6,848 | 1.0% |
| 2029 | 5,660 | 0.2% | 6,916 | 1.0% |
| 2030 | 5,685 | 0.4% | 6,985 | 1.0% |
| 2031 | 5,711 | 0.5% | 7,055 | 1.0% |
| Compound Annual Growth Rate, 2012-2031 Including Wholesale | | -0.17% | | 0.95% |
| Compound Annual Growth Rate, 2012-2031 Without Wholesale | | -0.12% | | 0.95% |

*Includes wholesale contract sales for 2010-2014

## Table 5-4 Base and High Case Demand Forecasts

| Year | Base Annual Hourly Peak | | High Growth Annual Hourly Peak | |
|---|---|---|---|---|
| | MW | Growth,% | MW* | Growth,% |
| 2010 act. | 1,275 | | 1,275 | |
| 2011 proj. | 1,218 | -4.5% | 1,218 | -4.5% |
| 2012 | 1,168 | -4.1% | 1,168 | -4.1% |
| 2013 | 1,168 | 0.0% | 1,180 | 1.0% |
| 2014 | 1,177 | 0.8% | 1,191 | 1.0% |
| 2015 | 1,164 | -1.1% | 1,191 | 0.0% |
| 2016 | 1,160 | -0.4% | 1,203 | 1.0% |
| 2017 | 1,151 | -0.7% | 1,215 | 1.0% |
| 2018 | 1,145 | -0.5% | 1,227 | 1.0% |
| 2019 | 1,139 | -0.5% | 1,239 | 1.0% |
| 2020 | 1,144 | 0.5% | 1,252 | 1.0% |
| 2021 | 1,149 | 0.5% | 1,264 | 1.0% |
| 2022 | 1,155 | 0.5% | 1,277 | 1.0% |
| 2023 | 1,159 | 0.4% | 1,290 | 1.0% |
| 2024 | 1,165 | 0.4% | 1,302 | 1.0% |
| 2025 | 1,171 | 0.5% | 1,315 | 1.0% |
| 2026 | 1,177 | 0.5% | 1,329 | 1.0% |
| 2027 | 1,184 | 0.6% | 1,342 | 1.0% |
| 2028 | 1,191 | 0.6% | 1,355 | 1.0% |
| 2029 | 1,199 | 0.7% | 1,369 | 1.0% |
| 2030 | 1,207 | 0.7% | 1,383 | 1.0% |
| 2031 | 1,215 | 0.7% | 1,396 | 1.0% |
| Compound Annual Growth Rate, 2012-2031 Including Wholesale | | 0.21% | | 0.94% |
| Compound Annual Growth Rate, 2012-2031 Without Wholesale | | 0.26% | | 0.94% |

*Includes wholesale contract sales for 2010-2014

## FORECAST INPUTS & METHODOLOGY

### Forecast Inputs

Energy Data

Historical Vectren sales and revenues data were obtained through our internal database. The internal database contains detailed customer information including rate, service, 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 our 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, our 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 the thirty year period between 1971 and 2000. Historical weather data[1] is imported into our load forecasting software and is used to normalize the past usage of

[1] The large sales model also includes CDDs.

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 (East North Central Region) 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 2010 Vectren conducted an appliance survey of our residential customers to compare our actual 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 our 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:

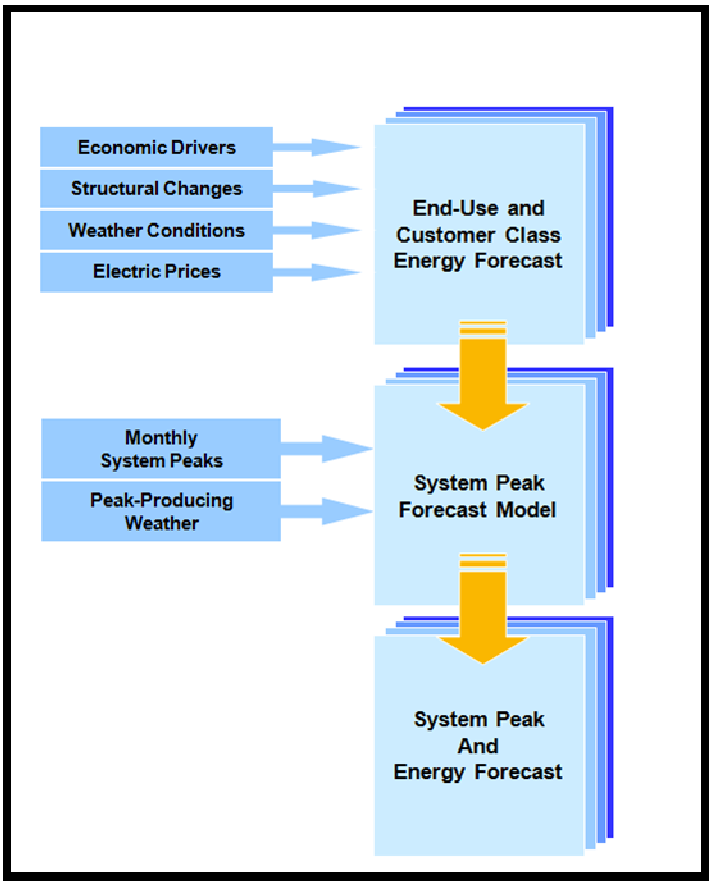
- Residential (residential average usage and customer models)
- General Service
- Large
- Street Lighting

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 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 to regional manufacturing GDP growth. Street light sales are forecasted using a simple trend and seasonal model. The results of the sales forecast modes are imported into our 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 this information to build a system peak demand model. The following factors, which affect class and end-use energy requirements, are captured in monthly class sales forecast models: economic and demographic changes, electricity prices, and changes in the appliance stock. The system energy forecast is then calculated by applying monthly loss factors to the calendarized monthly class sales forecasts. End-use energy projections derived from the sales models combined with peak-day weather conditions drive monthly system peak demand through a peak demand model. Through this construction, end-use and customer class energy growth drive changes in long-term peak demand. Note that the forecast is adjusted to reflect future conservation impacts. Figure 5-1 shows the general approach.

**Figure 5-1: Forecast Approach**




**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 reduced average energy use per customer (AUPC) will be balanced against the increasing use of household electronics and appliances. Changes in lighting standards are also likely to impact residential customer usage.

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.

$$ResAvgUsem = B0 + B1XHeatm + B2XCoolm + B3XOtherm + em$$

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:

$$XHeat = HeatUse * HeatIndex$$

Where

HeatUse = f(HDD, Household Income, Household Size, and Price)

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

The cooling variable is defined as:

XCool = CoolUse * CoolIndex

Where

CoolUse = f(CDD, Household Income, Household Size, and Price)

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

XOther captures non-weather sensitive end-uses:

XOther = OtherUse * OtherIndex

Where

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

OtherIndex = g(Other Appliance Saturation and Efficiency Trends)

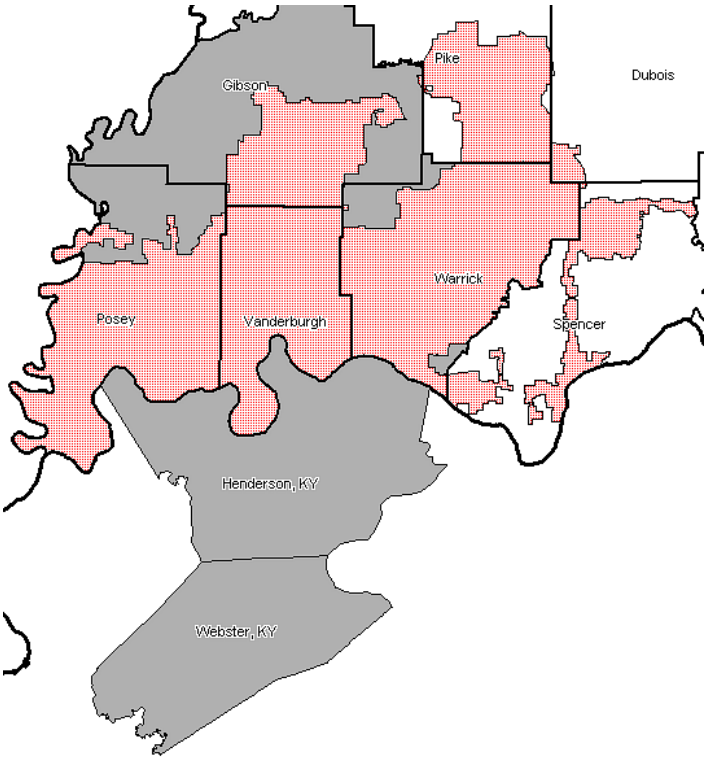
Monthly residential usage was regressed on the XHeat, XCool, and XOther variables. Prior to conservation measures, Vectren has forecasted residential average usage to grow an average of .40% per year throughout the forecast period. The model statistics were evaluated, and the model was determined to be a good predictor of residential average use, with an adjusted $R^2$ value of .981 and an in-sample mean absolute percentage error (MAPE) of 2.51%.

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.

The Evansville MSA is a good proxy for our 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 .41% throughout the planning period. The adjusted $R^2$ for this model was .987, while the MAPE was .09%.

**Figure 5-2 Vectren Service Territory Map**




General Service (GS) Sales Model

Similar to the residential average use model, the General Service SAE 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 GDP and employment (ComVarm ), real price (Pricem), and monthly HDD and CDD:

XHeatm = Elheat * Pricem -.10* ComVarm* HDDm

XCoolm = Elcool * Pricem -.10* ComVarm* CDDm

XOtherm = Elother * Pricem-.10 * ComVarm

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

ComSalesm = B0 + B1XHeatm + B2XCoolm + B3XOtherm + em

**Commercial Economic Driver**

Non-manufacturing output and employment are combined through a weighted economic variable where ComVar is defined as:

ComVarm = (NonManuf_Employm0.3) * (NonManuf_Outputm0.7)

The employment weight is 0.3 and the output weight is 0.7. The weights were selected by evaluating the in-sample and out of sample model statistics for different sets of employment and output weights.

The resulting general service sales model performs well with an adjusted $R^2$ of 0.918 and an in-sample MAPE of 2.94%.

Large Sales Model

Large customer sales are forecasted using a monthly regression model where large sales are specified as a function of manufacturing employment, manufacturing output, monthly CDD, and monthly binaries to capture seasonal load variation. Similar to the GS sales model, the economic driver is a weighted combination of real manufacturing output and manufacturing employment. The industrial economic (IndVar) variable is defined as:

IndVarm = (Manuf_Employm0.3) * (Manuf_Outputm0.7)

Again, the imposed weights are determined by evaluating in-sample and out-of-sample statistics for alternative weighting schemes. The model's adjusted $R^2$ is 0.837 with an in-sample MAPE of 4.47%.

The adjusted r-squared of the GS and Large models is considered good for the type of information being forecasted. 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. The result is that monthly street lighting sales are held constant through the forecast period. The model yielded an adjusted r-squared of .703 and a MAPE of 5.71%.

**Vectren's total energy requirements include forecasted sales for the four sectors described above, wholesale contracts, DSM savings, and delivery losses. Losses were estimated to be approximately 5.0 percent of requirements. DSM savings are highlighted separately in the sales forecast, and the DSM programs are discussed in detail in Chapter 8.**

**Peak Demand Forecast**

The energy forecast is derived directly from the sales forecast by applying a monthly energy adjustment factor to the monthly sales (calendarized) forecast. The energy adjustment factor includes line losses and any differences in timing between monthly sales estimates and delivered energy. The energy adjustment factor is calculated as the average of the monthly ratios over the last three years.

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:

$$Peakm = B0 + B1HeatVarm + B2*CoolVarm + B3* BaseVarm + em$$

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 us to estimate historical and forecasted heating and cooling load requirement.

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 us an estimate of the monthly heating and cooling load requirements. Heating requirements are calculated as:

$$HeatLoadm = B1 * ResNrmXHeatm + C1 *ComNrmXHeatm$$

B1 and C1 are the coefficients on XHeat in the residential and GS 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 large model coefficient for the CDD variable by normal monthly CDD. Cooling requirements are calculated as:

CoolLoadm = B2 * ResNrmXCoolm + C2 *ComNrmXCoolm+D2*NrmCDDm

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

In constructing the monthly peak model variables, the heating and cooling load requirements are normalized for the number of days and hours in the month by expressing heating and cooling load requirements on an average MW load basis:

HeatAvgMWm = HeatLoadm/ Daysm /24
CoolAvgMWm = CoolLoadm/ Daysm /24

The impact of peak-day weather conditions are then captured by interacting peak-day HDD and CDD with average monthly heating and cooling load requirements. The peak model heating and cooling variables are calculated as:

HeatVarm = HeatAvgMWm * PkHDDm
CoolVarm = CoolAvgMWm * PkCDDm

**Base Load Model**

The peak model base load variable (BaseVarm) is derived from the sales forecast models by first aggregating non-weather sensitive monthly sales estimates across the residential, GS, large, and street lighting revenue classes:

OtherUsem = ResOtherm + ComOtherm + IndOtherm + StLightingm

To express base load on a MW basis, the model variable is calculated as:

BaseVarm = OtherUsem / Daysm / 24

The peak-day HDD is indexed to the January normal HDD (38.5) and the peak-day CDD is indexed to the August normal CDD (21.1). This allows us to give a MW meaning to the calculated model variables.

The peak-day weather (measured using the CDD and HDD on the day of the peak), is derived from historical daily average weather data for Evansville. Peak-day HDD and CDD are calculated by first finding the peak in each month (the maximum hourly demand), identifying the day, and finding the average temperature for that day. The average peak-day temperature is then used to construct peak-day HDD and CDD variables. The appropriate breakpoints for the HDD and CDD variables are determined by evaluating the relationship between monthly peak and the peak-day average temperature. Winter peaks occur when temperatures are below 55 degrees and summer peaks occur when temperatures exceed 65.

Normal peak-day CDD and HDD are calculated from daily HDD (base 55 degrees) and CDD (base 65 degrees) for Evansville. Normal peak-day HDD and CDD are calculated using ten-years of historical weather data (2001 to 2010). The calculation process entails using a rank and average approach.

**Model Results**

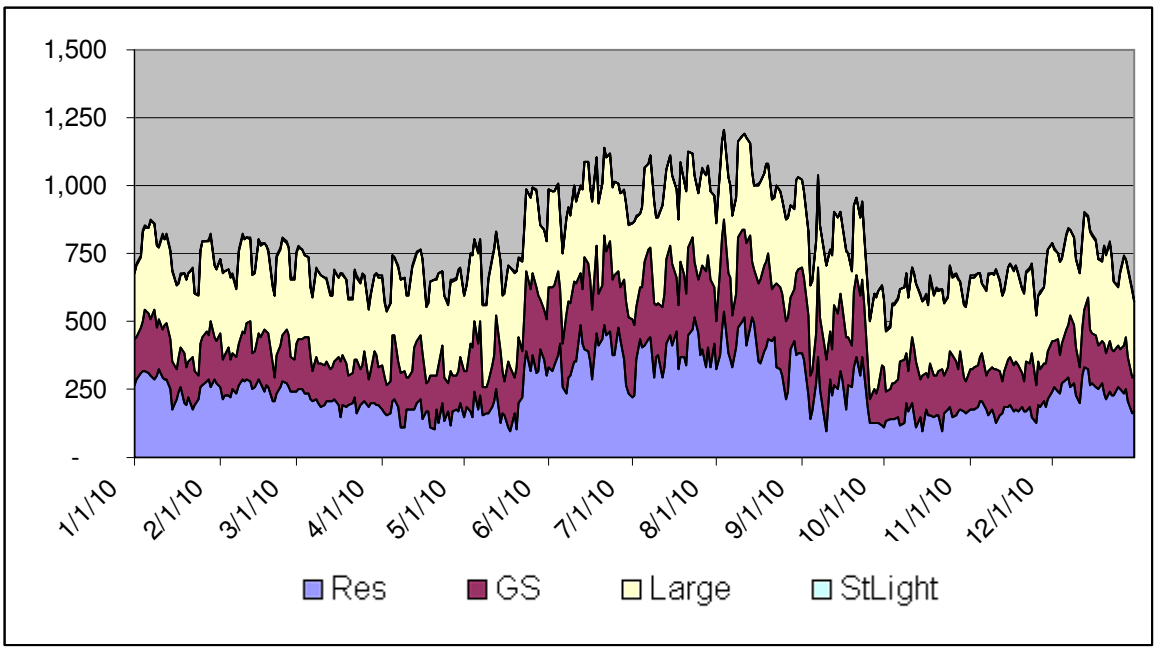
The model explains monthly peak variation well with an adjusted $R^2$ of 0.925 and an in-sample MAPE of 3.22%.

**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, Vectren borrowed class load shapes from Itron's Indiana library to break down our hourly load profile by class. We

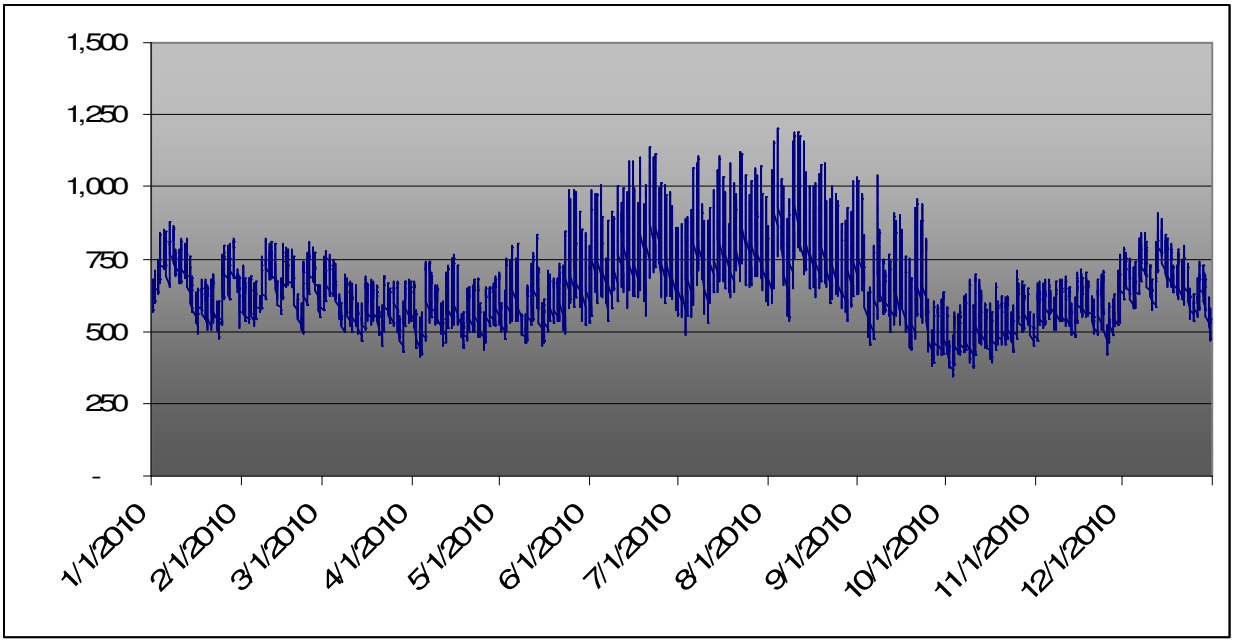
applied these load shapes to historical peak demand. Graph 5-1 shows daily class contribution to peak for 2010.

**Graph 5-1 Daily Class Contribution to Peak for 2010 (MW)**

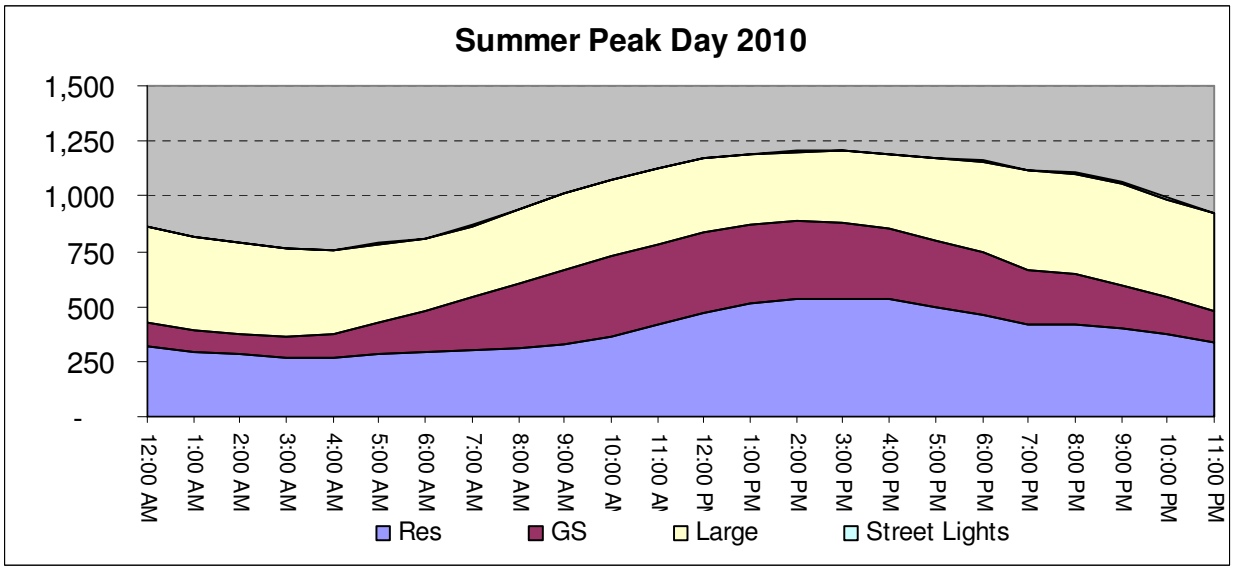



The following graphs (5-2 through 5-4) show the actual system load by day for 2010, the actual summer peak day for 2010 by hour, and the winter peak day for 2010 by hour. Note that these graphs do not include wholesale contract sales. Also included in the Technical Appendix are additional load shapes.

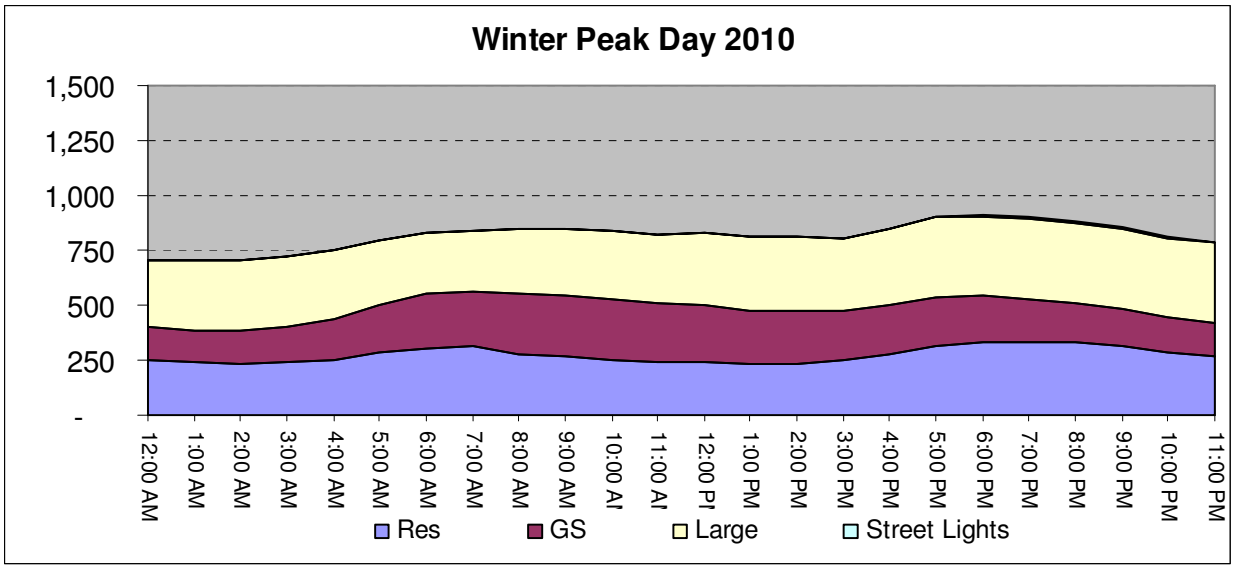
**Graph 5-2 Total System Load for 2010 (MW)**




**Graph 5-3 Summer Peak 2010 (MW)**



**Graph 5-4 Winter Peak 2010 (MW)**




## APPLIANCE SATURATION SURVEY

Vectren surveys residential customers on an as-needed basis. A residential appliance saturation survey was conducted in the spring of 2010. The survey was completed by a representative sample of customers. Results from this survey were used to reflect market shares of our actual residential customers. The residential average use model statistics were improved by including the appliance saturation of our customers in place of regional statistics. It is not necessary to run this appliance saturation survey every year. The next survey is scheduled to be sent in 2012.

At this time, Vectren does not conduct routine appliance saturation studies of our GS and large customers. These customers are surveyed when needed for special programs. However, our large and GS marketing representatives maintain close contact with our largest customers. This allows Vectren to stay abreast of pending changes in demand and consumption of this customer group. Additionally, Vectren recently purchased software that allows us to send paper surveys to businesses. In early 2011 Vectren had success in surveying commercial gas customers using a paper

survey. In an effort to better understand Vectren's electric GS customers and their energy efficiency needs, Vectren plans to conduct a mail GS appliance saturation baseline survey during the fall of 2011. The survey will ask questions about the energy-using equipment at their business, their building characteristics, and energy conservation practices employed at their business. Data provided by this survey should yield usage trends and characteristics representative of a typical electric GS customer in Vectren's service territory.

**OVERVIEW OF PAST FORECASTS**

The following tables outline the performance of Vectren's energy and demand forecasts. Forecasts from previous IRP filings from 2001 through 2010 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 Sales
- Residential Energy Sales
- GS Energy Sales
- Large Energy Sales
- Other Energy Requirements

Tables 5-5 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. Note that all of the forecasted values are weather-normalized, but the actual loads are not. This comparison would show much closer correlation if the actual loads were normalized to match the forecasts. 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.

## Table 5-5 Total Peak Requirements (MW)

| Year | Actual | Forecasts 2009 | 2007 | 2005 | 2004 | 2001 | 1999 | Deviation from most recent forecast, % |
|---|---|---|---|---|---|---|---|---|
| 2001 | 1,209 | | | | | | 1,272 | -5.2% |
| 2002 | 1,259 | | | | | 1,289 | | -2.4% |
| 2003 | 1,272 | | | | | 1,305 | | -2.6% |
| 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] | 1,275 | 1,153 | | | | | | 9.6% |
| Compound Annual Growth Rate, 2001-2010 | 0.59% | | | | | | | |

## Table 5-6 Total Energy Requirements (GWh)

| Year | Actual | Forecasts 2009 | 2007 | 2005 | 2004 | 2001 | 1999 | Deviation from most recent forecast, % |
|---|---|---|---|---|---|---|---|---|
| 2001 | 6,102 | | | | | | 6,204 | -1.7% |
| 2002 | 6,532 | | | | | 6,274 | | 3.9% |
| 2003 | 6,444 | | | | | 6,348 | | 1.5% |
| 2004 | 6,303 | | | | 6,514 | | | -3.3% |
| 2005 | 6,508 | | | | 6,624 | | | -1.8% |
| 2006 | 6,352 | | | 6,543 | | | | -3.0% |
| 2007 | 6,527 | | 6,469 | | | | | 0.9% |
| 2008 | 5,931 | | 6,160* | | | | | -3.9% |
| 2009 | 5,598 | 5,592 | | | | | | 0.1% |
| 2010[1] | 6,221 | 5,608 | | | | | | 9.9% |
| Compound Annual Growth Rate, 2001-2010 | 0.22% | | | | | | | |

*Adjusted to include wholesale sales

[1]2010 was more than 30% hotter than normal in the Vectren service territory, which contributed to a higher peak and higher energy use than was projected in the 2009 IRP

## Table 5-7 Residential Energy Sales (GWh)

| Year | Actual | Forecasts (Residential) 2009 | 2007 | 2005 | 2004 | 2001 | 1999 | Deviation from most recent forecast, % |
|---|---|---|---|---|---|---|---|---|
| 2001 | 1,424 | | | | | 1,452 | | -2.0% |
| 2002 | 1,513 | | | | | 1,479 | | 2.2% |
| 2003 | 1,460 | | | | | 1,506 | | -3.2% |
| 2004 | 1,502 | | | | 1,519 | | | -1.1% |
| 2005 | 1,571 | | | 1,536 | | | | 2.2% |
| 2006 | 1,475 | | | 1,584 | | | | -7.4% |
| 2007 | 1,631 | | 1,570 | | | | | 3.7% |
| 2008 | 1,604 | | 1,578 | | | | | 1.6% |
| 2009 | 1,449 | 1,451 | | | | | | -0.1% |
| 2010 | 1,598 | 1,467 | | | | | | 8.2% |
| Compound Annual Growth Rate, 2001-2010 | 1.29% | | | | | | | |

## Table 5-8 General Service Energy Sales (GWh)

| Year | Actual | Forecasts (GS) 2009 | 2007 | 2005 | 2004 | 2001 | 1999 | Deviation from most recent forecast, % |
|---|---|---|---|---|---|---|---|---|
| 2001 | 1,387 | | | | | 1,350 | | 2.7% |
| 2002 | 1,423 | | | | | 1,369 | | 3.8% |
| 2003 | 1,443 | | | | | 1,389 | | 3.7% |
| 2004 | 1,502 | | | | 1,468 | | | 2.3% |
| 2005 | 1,556 | | | 1,539 | | | | 1.1% |
| 2006 | 1,515 | | | 1,566 | | | | -3.4% |
| 2007 | 1,412 | | 1,371 | | | | | 2.9% |
| 2008 | 1,363 | | 1,379 | | | | | -1.2% |
| 2009 | 1,299 | 1,296 | | | | | | 0.2% |
| 2010 | 1,361 | 1,275 | | | | | | 6.3% |
| Compound Annual Growth Rate, 2001-2010 | -0.21% | | | | | | | |

## Table 5-9 Large Energy Sales (GWh)

| Year | Actual | Forecasts (Large) 2009 | 2007 | 2005 | 2004 | 2001 | 1999 | Deviation from most recent forecast, % |
|---|---|---|---|---|---|---|---|---|
| 2001 | 2,428 | | | | | 2,506 | | -3.2% |
| 2002 | 2,444 | | | | | 2,522 | | -3.2% |
| 2003 | 2,494 | | | | | 2,539 | | -1.8% |
| 2004 | 2,346 | | | | 2,568 | | | -9.5% |
| 2005 | 2,389 | | | 2,404 | | | | -0.6% |
| 2006 | 2,376 | | | 2,379 | | | | -0.1% |
| 2007 | 2,538 | | 2,573 | | | | | -1.4% |
| 2008 | 2,655 | | 2,567 | | | | | 3.3% |
| 2009 | 2,251 | 2,247 | | | | | | 0.2% |
| 2010 | 2,601 | 2,281 | | | | | | 12.3% |
| Compound Annual Growth Rate, 2001-2010 | 0.77% | | | | | | | |

## Table 5-10 Other Sales, Wholesale Contract Sales, and Losses (GWh)

| Year | Actual | Forecasts (Other, Wholesale & Losses) 2009 | 2007 | 2005 | 2004 | 2001 | 1999 | Deviation from most recent forecast, % |
|---|---|---|---|---|---|---|---|---|
| 2001 | 863 | | | | | | 949 | -10.0% |
| 2002 | 1,152 | | | | | 904 | | 21.5% |
| 2003 | 1,047 | | | | | 914 | | 12.7% |
| 2004 | 953 | | | | 959 | | | -0.6% |
| 2005 | 992 | | | 967 | | | | 2.5% |
| 2006 | 986 | | | 1,014 | | | | -2.9% |
| 2007 | 946 | | 954 | | | | | -0.9% |
| 2008 | 309 | | 636* | | | | | 5.3% |
| 2009 | 600 | 598 | | | | | | 0.3% |
| 2010 | 661 | 585 | | | | | | 11.6% |
| Compound Annual Growth Rate, 2001-2010 | -2.91% | | | | | | | |

*Adjusted to include wholesale sales

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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 and screened and from this large sampling a smaller subset of alternatives were chosen for the final planning and integration analysis. In general terms the supply-side alternatives can be grouped as follows:

- Construction of new generating facilities
- Refurbishment or modifications to existing facilities
- Capacity purchases from the wholesale market
- Distributed generation

## TECHNOLOGY ASSESSMENT

For the 2009 Electric IRP process, Vectren retained the services of Sargent & Lundy to assist in performing a technology assessment for conventional coal and gas technologies. For the 2011 IRP process Vectren elected not to fund the significant expense required to develop a detailed supply side assessment, primarily because early indications were that no supply side resource decisions would be required in the short term action plan (consistent with the 2009 IRP).

The results from the 2009 assessment were updated to current dollar terms using an appropriate cost tracking index. To develop updated capital costs, the Power Capital Cost Index (PCCI)[1] published by IHS CERA was used. Specifically, the PCCI values for the 24 month period between Q1 2009 and Q1 2011 were applied and resulted in an inflator value of 3.44% to be applied to the results of the 2009 technology assessment. It is important to note that the most recent update for the PCCI, published in July, exhibited the most significant increase in the past several years. Presumably as the result of increased construction activity and recovering commodity prices.

[1] Source: www.ihsindexes.com

**Table 6-1 Capital Cost Inflator**

| | Q1 2009 | Q1 2011 | Capital Cost Inflator (CCI) |
|---|---|---|---|
| PCCI, w/o nuclear | 174 | 180 | 1.0344 |

For O&M costs, the Consumer Price Index (CPI) as published by the Bureau of Labor Statistics of the United States Department of Labor was utilized. Specifically, the seasonally adjusted CPI values for the 24 month period of July 2009 through June 2011 were applied.

**Table 6-2 O&M Cost Inflator**

| | Jul 2009 | Jun 2011 | O&M Inflator (OMI) |
|---|---|---|---|
| CPI (US, all items) | 214.782 | 224.304 | 1.0443 |

A detailed discussion of renewable technologies can be found in Chapter 7 Renewables and Clean Energy. The full Technology Assessment report can be found in the Technical Appendix of this IRP.

## NEW CONSTRUCTION ALTERNATIVES

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 screening criteria included an extensive list of qualitative and quantitative considerations. Table 6-3 lists the criteria that were considered.

**Table 6-3 Qualitative Generation Screening Criteria**

| | |
|---|---|
| *Amount of Generating Capacity Needed* | |
| Electric energy consumption growth | Peak demand growth |
| Plant retirements | System reliability |
| *Capital Cost Considerations* | |
| Capital requirements | Cash flow during construction |
| Carrying charges on investment | Life expectancy |
| *Electricity Cost* | |
| Capital-related charges | Operating costs |
| *Plant Characteristics* | |
| Unit size | Reliability/availability |
| Compatibility | Efficiency |
| Fuel flexibility | Required fuel quality |
| *Resource Requirements* | |
| Fuel | Water |
| Land | Construction manpower |
| Staffing | |
| *Environmental Factors* | |
| Air | Water |
| Solid waste | Potential hazardous pollutant regulations |
| Environmental siting | requirements |
| *Licensing Factors* | |
| Safety issues | Regulatory climate |
| Public perception | |
| *Siting Considerations* | |
| Environmental factors | Resource requirements |
| Geological foundation requirements | Aesthetics |
| Transmission distance | Transmission routing |
| Central or dispersed location | Impact on construction cost |
| Sociological impact | Demographic impact |
| *Lead Time* | |
| Construction | Startup |
| Licensing, including preliminary requirements | |
| *Geographic Applicability* | |
| *Commercialization Aspects* | |
| Market potential | Manufacturing capability |
| Materials availability | Current utility investment |
| Current supplier investment | Commercialization cost |
| Technical uncertainty | Business uncertainty |
| Political uncertainty | Utility interest |
| Utility participation | |

The set of new construction alternatives that was selected for further assessment as a result of the screening process are presented in Table 6-4. The capital cost and O&M characteristics of these selected alternatives were assessed and developed in detail.

**Table 6-4 New Construction Alternatives**

| COAL | Nominal MW |
|---|---|
| Supercritical Pulverized Coal (PC) | 750 |
| Atmospheric Fluidized Bed (CFB) | 600 |
| Integrated (Coal) Gasification Combined Cycle (IGCC) | 625 |
| **NATURAL GAS** | |
| GE LM6000 Simple Cycle | 40 |
| GE 7EA Simple Cycle | 80 |
| GE LMS100 Simple Cycle | 100 |
| GE 7FA Simple Cycle | 190 |
| GE 2x1 7EA Combined Cycle | 600 |
| GE 2x1 7FA Combined Cycle | 260 |
| **RENEWABLE** | |
| Biomass | 50 |

**Coal-Fueled Technologies**

Three major types of coal fired generation technologies were assessed:

- A supercritical pulverized coal (PC) option was evaluated for a generating capability of 750 Megawatts (MW).
- Circulating fluidized bed (CFB) technology was assessed for a capability of 600 MW.
- Integrated coal gasification combined cycle (IGCC) technology was assessed for a capability of 625 MW.

The assessments for each of these three technologies were developed for two cases; with and without carbon capture and sequestration (CCS). For the CCS cases the assumed level of control was 90%.

Sole ownership of a viable coal alternative was deemed to be unrealistic due to maximum reserve margin and capital investment constraints associated with adding a large increment of capacity relative to the size of the Vectren electric system. However, it is recognized that partial ownership positions in such projects would allow Vectren to

capture the economies of scale and the improved efficiencies associated with larger generating units.

In general, new construction costs for PC and CFB technologies in the 200-300 MW capability range are converging as CFB technology matures and PC technology becomes more environmentally constrained. However, the application of CFB technology has been limited to unit capabilities of relatively small size, less than 300 MW, thereby limiting the available economies of scale. In contrast, PC technology possesses significant economies of scale over a very broad range of unit capability sizes. These economies of scale apply to both new construction and O&M costs.

For the purposes of the technology assessment, the conventional PC technology that was assessed included a 750 MW supercritical generation unit with full environmental controls. For the CFB technology a nominal 600 MW generating unit consisting of two CFB steam generators and one steam turbine was evaluated.

The IGCC industry is coalescing around a nominal 625 MW design using two distinct chemical trains. Per the EIA, capital costs for IGCC technology require a premium when compared to more conventional pulverized coal technologies, about 12.5% according to their published capital cost estimates updated for the 2010 Annual Energy Outlook (http://205.254.135.24/oiaf/beck_plantcosts/). The premium is somewhat less, about 5% in relative terms, when CCS is considered. In consideration of the EIA data and given the notable cost escalation concerns regarding IGCC plants currently under construction, the IGCC capital cost values from the 2009 Technology Assessment were revised accordingly. The relative percentages mentioned earlier were applied to the Pulverized Coal Supercritical option to derive the IGCC capital costs.

Vectren investigated CCS for coal fueled alternatives as part of the Technology Assessment (see Technical Appendix). The additional costs for $CO_2$ capture technology are very significant for coal fueled generation technologies.

Table 6-5 presents the results of the detailed assessment for the three selected coal alternatives with and without CCS. For the purposes of the integration analysis performed for this IRP, Vectren selected a partial ownership position (25%) of a large supercritical type coal unit (750 MW) or IGCC (625 MW) to be representative of coal fueled alternatives. The partial ownership assumption achieves two important study objectives: the capture of economies of scale coupled with obtaining an appropriate amount of incremental capacity. Both alternatives were simulated using an assumption of installed carbon controls (with CCS).

**TABLE 6-5 Assessment of Coal Technologies**

| Primary Fuel | Coal | | | | | |
|---|---|---|---|---|---|---|
| Carbon Controls | Without CCS | | | With CCS | | |
| Technology Description | Pulverized Coal Supercritical (PCSC) | Circulating Fluidized Bed (CFB) | Integrated Gasification Combined Cycle (IGCC) | Pulverized Coal Supercritical (PCSC) | Circulating Fluidized Bed (CFB) | Integrated Gasification Combined Cycle (IGCC) |
| Nominal Capability (MW) | 750 | 600 | 623 | 517 | 415 | 518 |
| Assumed Vectren Share | | | | 25% | | 25% |
| Vectren Summer Capability, MW | | | | 129 | | 130 |
| Base Load Net Heat Rate (Btu/kWh) | 9,069 | 9,568 | 9,050 | 11,790 | 12,438 | 11,313 |
| Fixed O&M (2011$/kW-yr) | 28.54 | 35.75 | 28.73 | 50.74 | 62.09 | 39.76 |
| Variable O&M (2011$/MWh) | 4.19 | 5.82 | 7.44 | 14.39 | 16.79 | 8.98 |
| Equivalent Forced Outage Rate (%) | 4.60 | 3.50 | 7.80 | 4.60 | 3.50 | 7.80 |
| Total Capital (2011 $000,000) | 2,373 | 1,889 | 2,217 | 3,071 | 2,518 | 3,231 |
| Total Capital (2011$/kW) | 3,164 | 3,148 | 3,559 | 5,940 | 6,066 | 6,237 |

### 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.

All four of the simple cycle alternatives were included in the final integration analysis. With respect to the combined cycle alternatives, Vectren assumed that it would take a partial ownership position at the levels shown in Table 6-6, which follows. As with the coal-fired options, this assumption was made on the basis of capturing economies of scale and high efficiencies while satisfying reserve margin and capital investment constraints. CCS was not evaluated for gas fuel technologies as part of the 2009 Technology Assessment. However, many of the same CCS technologies in development for coal fueled power systems can be applied to gas fueled systems as well. The inherent advantage of natural gas as compared to coal with respect to greenhouse gas concerns has thus far typically limited the discussion of CCS as applied to natural gas power generation.

**Table 6-6 Assessment of Gas Technologies**

| Primary Fuel | Gas | | | | | |
|---|---|---|---|---|---|---|
| Configuration | Simple Cycle | | | | Combined Cycle | |
| Technology Description | Aeroderivative GE LM6000 | Aeroderivative GE LMS100 | Heavy Duty GE 7EA | Heavy Duty GE 7FA | 2 X 1 GE 7EA | 2 X 1 GE 7FA |
| Nominal Capability (MW) | 85 (2x42.5) | 98 | 84 | 209 | 263 | 612 |
| Assumed Vectren Share, % | 100 | 100 | 100 | 100 | 50 | 20 |
| Vectren Summer Capability, MW | 74 | 90 | 73 | 185 | 122 | 113 |
| Base Load Net Heat Rate (Btu/kWh) | 9,845 | 9,305 | 11,730 | 9,937 | 7,430 | 6,665 |
| Fixed O&M (2011$/kW-yr) | 6.40 | 10.32 | 9.94 | 8.18 | 20.92 | 11.28 |
| Variable O&M (2011$/MWh) | 3.25 | 2.49 | 19.66 | 15.84 | 8.14 | 6.64 |
| Equivalent Forced Outage Rate (%) | 2.4 | 2.4 | 1.0 | 1.0 | 2.5 | 2.5 |
| Total Capital (2011 $000,000) | 126 | 125 | 88 | 136 | 151 | 105 |
| Total Capital (2011$/kW) | 1,705 | 1,389 | 1,206 | 736 | 1,238 | 928 |

## MODIFICATIONS TO EXISTING FACILITIES

Vectren has evaluated the feasibility of refurbishing or modifying existing facilities as part of the supply-side resource analysis of previous IRP submittals. Some of the options that have been considered in prior IRP's and remain feasible include dense pack steam turbine refurbishments and potential conversion of the Brown 3 and Brown 4 combustion turbines to a combined cycle configuration. Another potential option

would be some form of parallel repowering of the steam units, Brown 1 and Brown 2, with the co-located combustion turbines, Brown 3 and Brown 4.

A.B. Brown Dense Pack Refurbishments

Vectren will perform dense pack steam turbine refurbishments during the next planned turbine-generator overhauls for both Brown 1 (2012) and Brown 2 (2013). The refurbishment of the Brown 1 and Brown 2 steam units will primarily consist of replacing the existing high pressure and intermediate pressure steam turbine sections with a more efficient dense pack arrangement. A dense pack conversion requires significant preliminary engineering by the turbine equipment manufacturer to estimate expected performance levels. For both units, it was assumed that net unit heat rate would improve 5% due to the dense pack refurbishments.

A.B. Brown Combined Cycle Conversions

The Brown 3 and Brown 4 combustion turbines (CTs) could potentially be converted to combined cycle operation. The technology assessment examined a configuration that would consist of installing Heat Recovery Steam Generators (HRSG) on the exhaust of each CT and using the steam to power a new steam turbine power block. The overall nominal capacity rating of the resulting 2 CT by 1 steam turbine arrangement would be 250 MW. The summer capability of the combined cycle arrangement would be about 80 MW higher than the current capability of two CTs during simple cycle. In the 2007 Vectren IRP, the capital costs for the conversion project were estimated to be $171 million, yielding a cost for the incremental summer capacity of $2,080/kw. Because the cost of this project was estimated to be significantly higher than new combined cycle costs (Table 6-6), this project was not selected for further consideration in the 2007 IRP. Likewise, Vectren did not include this option as part of the integration analysis for this IRP. Vectren continues to be mindful that future considerations and developments may warrant detailed investigation of this alternative at some point in time.

A.B. Brown Parallel Repowering

A second Brown plant modification would consist of a parallel repowering project. The two steam units, Brown 1 and Brown 2, at the Brown facility are located in close proximity to the two combustion turbine units, Brown 3 and Brown 4. For the 2007 IRP, the technology assessment investigated a parallel repowering configuration that would consist of installing a heat recovery steam generator (HRSG) on the exhaust of the CT units for feedwater heating of the steam units. This concept would yield significant improvements in plant heat rate for the hours that the CT(s) are in operation. However, there would actually be an estimated loss in capability of 9 MW total for the steam units due to Low Pressure (LP) turbine flow restrictions. For this type of project to be become viable it will probably have to be mutually inclusive with refurbishment projects for the two steam units to reduce or eliminate any capability loss. Although such a project is feasible in concept, the costs, benefits, and other potential implications are not satisfactorily developed at this time. Therefore, a parallel repowering project at the Brown station was not selected for further consideration in this IRP study.

**Table 6-7 Assessment for AB Brown Plant Modifications**

| Modification | Nominal | | Summer | | Capital Cost |
|---|---|---|---|---|---|
| | Incremental Output (MW) | Plant Heat Rate (Btu/kWh) | Incremental Output (MW) | Plant Heat Rate (Btu/kWh) | (2007 $000) |
| Parallel Repowering | -9 | 9,850 | -9 | 9,924 | 54 |
| Combined Cycle Conversion | 90 | 7,830 | 82 | 7,916 | 171 |

F.B. Culley Biomass

Vectren has performed preliminary feasibility assessments of biomass co-firing for Culley Unit 2. This is discussed in more detail in the Biomass section of Chapter 7 Renewables and Clean Energy.

**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 Corporation (RFC) 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 market price for power that will be available for purchase in future years 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 less traded and therefore less transparent.

Vectren currently has a contract for 100 MW of year-round capacity that began in 2010 and expires in 2012. To determine availability and pricing of future capacity, Vectren issued a RFP in spring of 2009 for capacity beginning in 2013. Given the outcome of the 2009 IRP analysis in the Fall of 2009, Vectren elected not to pursue any of the bids received at that time.

For the early years of the current 2012-2031 IRP study period, regional reserve margins are projected to be sufficient to allow for relatively attractive capacity pricing. However, 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. At that time capacity prices will converge with replacement build prices. 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

Vectren previously spoke with its commercial and industrial customers to determine operating hours, building types, end-use saturations, and the amount of backup and/or cogeneration in use, among other things. Using this information and applying more recent information from discussions with commercial and industrial customers, utility employees, and other energy services groups, Vectren estimated that the total MW capacity of all electric self-generation in its electric service territory is about 50 MW. This generation is generally reserved for emergency operation. The condition and readiness of this equipment varies widely. Other than company owned facilities, Vectren does not have direct control of this generation. Vectren is considering incremental opportunities related to Demand Response as discussed hereafter.

In addition, larger electric customers might 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 it would be financially attractive for Vectren 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 and is not modeled in the IRP.

## RENEWABLE TECHNOLOGIES

### Wind

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

Biomass

A 50 MW nominal biomass alternative was included in the detailed Technology Assessment study. It was assumed that this alternative would consist of a circulating fluidized bed boiler firing wood waste with a conventional steam turbine generator set.

**Table 6-8 Assessment of Biomass Technology**

| | |
|---|---|
| Primary Fuel | BioMass Wood Waste |
| Technology Description | CFB and Steam Turb. |
| Nominal Capability (MW) | 48.00 |
| Assumed Vectren Share, % | 100.00 |
| Base Load Net Heat Rate (Btu/kWh) | 13,391.00 |
| Fixed O&M (2011$/kW-yr) | 111.01 |
| Variable O&M (2011$/MWh) | 3.26 |
| Equivalent Forced Outage Rate (%) | 3.50 |
| Total Capital (2011 $000,000) | 186.00 |
| Total Capital (2011$/kW) | 3,875.03 |

Other

Solar and landfill gas projects are viable renewable sources of energy. However, due to their typically small relative size compared to the larger overall system needs for capacity, 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.

**Distributed Generation**

Vectren is in the early stages of developing a formal process for the discovery and evaluation of opportunities to apply distributed generation technology. The goal of this effort will be to institutionalize the consideration of distributed generation into Vectren's business strategies and operations. This will include the consideration of distributed generation technology as an alternative for electric T&D planning and design. It will

also formalize the evaluation of distributed generation as an energy and capacity resource, although this is not expected to play a significant role in the near term.

Current activities include

- engineering and cost research on distributed generation technologies,
- assessment of current and potential customer-owned distributed generation,
- cross-functional business & operational strategy development,
- and the development & design of case studies and / or potential pilot projects to build knowledge & competencies for operating utility-owned distributed generation and / or accommodating customer-owned distributed generation.

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# CHAPTER 7

# RENEWABLES

# and

# CLEAN ENERGY

## CURRENT PROJECTS

Vectren currently receives renewable energy from three projects: two purchased 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 purchased power agreement. The nominal nameplate rating for this contract is 30 MW, and the expected annual energy to Vectren from this project is 94,500 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 purchased power agreement. The nominal nameplate rating for this contract is 50 MW, and the expected annual energy to Vectren from this project is 145,000 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 20,000 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

### 2009 Renewable RFP

Prior to the 2009 IRP submittal, Vectren issued a request for proposal (RFP) for additional renewable energy. Vectren received around 25 separate bids from renewable sources, including wind, solar, biomass, and biogas. Following evaluation of these bids, as well as Vectren's energy forecast, economic conditions, the existing renewable portfolio, and the lack of legislation to define requirements, Vectren declined to accept any of the bids. Vectren will continue to monitor the development of the renewable marketplace.

### Indiana Voluntary Clean Energy Portfolio Standard

The rules for the Voluntary Clean Energy Portfolio Standard (VCEPS), as outlined in Indiana SB251, have not been finalized at the time of the submission of this plan. Vectren has not yet determined whether or how it will participate in the program. Vectren estimates observe that the current projections for renewable generation and conservation programs as outlined in the base case of this IRP would provide enough clean energy credits to adequately comply with the proposed standards (Table 7-1). If Vectren were to enter into the program and deem it necessary to obtain additional sources of clean energy, a broad range of potential options, including utility owned projects, purchased power agreements, and / or clean energy credits would be fully considered.

Table 7-1 Clean Energy Projections

| | | Clean Energy Source | | | | |
|---|---|---|---|---|---|---|
| | Retail Sales before conservation programs | Wind Generation | Landfill Gas Generation | Conservation Programs | Vectren Clean Energy | SB251 VCEPS Standard |
| Year | GWh | GWh | GWh | GWh | % of sales | |
| 2012 | 5,606 | 240 | 20 | 60 | 6% | |
| 2013 | 5,627 | 240 | 20 | 110 | 7% | 4% |
| 2014 | 5,684 | 240 | 20 | 171 | 8% | |
| 2015 | 5,726 | 240 | 20 | 242 | 9% | |
| 2016 | 5,763 | 240 | 20 | 324 | 10% | |
| 2017 | 5,792 | 240 | 20 | 417 | 12% | |
| 2018 | 5,831 | 240 | 20 | 520 | 13% | |
| 2019 | 5,871 | 240 | 20 | 627 | 15% | 7% |
| 2020 | 5,915 | 240 | 20 | 653 | 15% | |
| 2021 | 5,946 | 240 | 20 | 680 | 16% | |
| 2022 | 5,982 | 240 | 20 | 706 | 16% | |
| 2023 | 6,017 | 240 | 20 | 732 | 16% | |
| 2024 | 6,060 | 240 | 20 | 758 | 17% | |
| 2025 | 6,093 | 240 | 20 | 784 | 17% | 10% |
| 2026 | 6,133 | 240 | 20 | 811 | 17% | |
| 2027 | 6,175 | 240 | 20 | 837 | 18% | |
| 2028 | 6,227 | 240 | 20 | 863 | 18% | |
| 2029 | 6,267 | 240 | 20 | 890 | 18% | |
| 2030 | 6,317 | 240 | 20 | 916 | 19% | |
| 2031 | 6,368 | 240 | 20 | 943 | 19% | |

Biomass

In 2010, Vectren commissioned KEMA to perform a high-level study assessing the regional availability of wood biomass resources. The assessment considered biomass volumes sufficient to co-fire 10% biomass with coal for F.B. Culley Unit #2 (90 MW nominal net capacity). At a co-fire level of 10%, it was estimated that minimal plant modifications would be required and the operational impacts would be minimal as well. Higher levels of biomass co-fire are feasible from a plant perspective but would require more detailed assessment and analysis. The KEMA study utilized secondary research methods and publicly available biomass resource databases. KEMA assumed a maximum radius from the generating unit of 100 miles. This “woodshed” area, including

portions of Illinois, Indiana, and Kentucky, was found to contain more than adequate biomass for the minimum required tonnage of 85,000 tons per year to meet 10% co-fire.

However, the scope of the study did not involve investigation of actual supply contracts or quotes. Nor did it assess the biomass demand competition of other biomass consumers or the impact that hypothetical biomass demand from F.B. Culley Unit #2 would have on the regional market for biomass, wood, or forestry products. KEMA suggested that the "primary" wood production within the woodshed was likely fully met by demand from current consumers and that Vectren would either need to induce additional production of approximately 9% from these sources or procure biomass supply from the "merchantable forest residue" market. KEMA considered both of these supply sources to be reasonable alternatives.

With the knowledge that the regional biomass supply would likely be adequate, Vectren continues to monitor biomass co-firing opportunities for F.B. Culley Unit #2.

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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.

## HISTORICAL PERFORMANCE

Since 1992, Vectren has continuously utilized DSM as a means of reducing customer load and thereby providing reliable electric service to its customers. These DSM programs were approved by the Indiana Utility Regulatory Commission (IURC or Commission) as part of Vectren's IRP process. The DSM programs provided for both peak demand and energy reductions.

Historically, DSM programs were implemented, modified, and discontinued when necessary based on program evaluations. The programs were approved by the Commission and implemented pursuant to such orders. Vectren managed the programs in an efficient and cost effective manner, and the load reductions and energy savings from the programs were significant. In all, past Vectren DSM programs reduced demand by over 70,000 kW and provided annual energy savings of over 80,000,000 kWh. Since 1992, the two programs that have continued to be offered and have historically proven to remain cost-effective over time are the Residential and Commercial Direct Load Control (DLC) Programs.

## EXISTING DSM RESOURCES and PROGRAMS

### Tariff Based Resources

Vectren has offered tariff based DSM resource options to customers for a number of years. Vectren has also recently began to offer new tariff based resources to our customers as a means to encourage efficient use of energy.

**Interruptible Rates**

In addition to the conservation DSM programs described in this chapter, Vectren has offered interruptible rate programs for commercial and industrial customers. Vectren currently has approximately 35 MW of interruptible load under contract.

Rider IP – 2 Interruptible Power Service

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.

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.

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 central cooling/heat pumps, electric water heating, and pool pumps 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. For commercial customers, other equipment may participate in the program and is evaluated on an individual basis to determine the amount of peak load reduction possible, as well as the appropriate bill credit based upon the kW load controlled by the switch. The control of central cooling units is typically a 33% cycling strategy and involves cycling the compressor off ten minutes out of every half hour during the cycling period. Based on load reduction requirements, a 50% cycling strategy may also be utilized. 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 are typically 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.

The DLC system has the capability to obtain approximately 25 MW of peak reduction capacity from the DLC system when all switches are fully functional. Because of the age of the existing DLC equipment in use by Vectren customers and based on recent field sample inspections of that equipment, in order to continue to obtain the peak demand reduction benefits from the DLC system, the Commission approved a multi-

year DLC Inspection & Maintenance Program in Cause No. 43839. This effort is timely, given 14 - 19 years has passed since the majority of DLC switches were first installed. Over time, the operability of the DLC switches has declined for a variety of reasons, including mechanical failure, contractor or customer disconnection, and lack of re-installation when customer equipment was replaced. Vectren has embarked upon an inspection and maintenance/restoration plan that will ultimately ensure maximum load reduction. By investing in the inspection and maintenance of the DLC system over the next few years, Vectren can continue its ability to rely on this demand reduction resource as part of its resource planning. Based upon recent field inspections, the percentage of switches that have been removed or are inoperable is approximately 50%.

As of July 2011, Vectren's Residential DLC Program had approximately 27,011 customers with 37,087 switches and 630 commercial customers with 2,463 switches. The following schedule provides a forecast for the amount of load reduction available from the DLC system considering the current level of operation and the DLC Inspection and maintenance program which was recently initiated:

**Table 8-1 DLC System Load Reduction Capability**

| DLC System Demand Reduction Projection | | |
|---|---|---|
| | Residential and Commercial Demand Reduction (kW) | |
| | 33% Cycling | 50% Cycling |
| 2011 DLC System Technical Potential | 26,849 | 38,702 |
| 2011 Achievable Load Reduction | 13,425 | 19,351 |
| 2012 Achievable Load Reduction | 16,110 | 23,221 |
| 2013 Achievable Load Reduction | 18,795 | 27,092 |
| 2014 Achievable Load Reduction | 21,480 | 30,962 |
| 2015 Achievable Load Reduction | 24,165 | 34,832 |
| 2016 Forward Load Potential | 24,165 | 34,832 |

**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 South 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 (now Rate EH) will be terminated 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 based upon a revenue neutral transition plan is to be filed for the Commission's consideration within two years of May 3, 2011.
- The availability of the commercial Rate OSS (Off Season Service) will also be terminated 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, based upon a revenue neutral transition plan, is to be filed for the Commission's consideration within two years of May 3, 2011.

The impacts of the rate modifications have not been explicitly quantified but should be reflected via the sales forecast based upon modeling the impacts of future rates.

**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. The impacts of rider DR have not been explicitly quantified in this IRP due to rider DR being a relatively new customer offering.

**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. This tariff originally allowed residential, K-12 schools and municipal customers who have installed, on their premises, photovoltaic, wind, or hydroelectric generator systems, which generate less than 10 kW of electrical power, to participate in Rider NM. As part of Cause No. 43839, Vectren sought and the IURC approved several variances from the current IURC rules as to the size of net metering facilities, the amount of net metering Vectren would allow and participation by commercial customers. 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 (1MW) and an increase in the amount of net metering allowed (1% of most recent summer peak load). 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 August 1, 2011, Vectren had 22 active, 1 inactive and 1 pending net metering customers with a total nameplate capacity of 149.4 kW.

**Smart Grid Resources**

Smart Grid technology has the potential to enable higher levels of energy efficiency and demand response, as well as improved evaluation, measurement, and verification of energy efficiency and demand response efforts. 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 conservation and 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
- 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 our 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. As part of this initiative Vectren completed the development of its Smart Grid strategy where it identified the need to invest in some fundamental 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 SCADA, AMI, conservation voltage reduction, and system automation. Vectren has completed the implementation of a fiber optic communication path across its transmission network, connecting at both primary generating stations. The build out of the communication system has allowed Vectren to bring on additional SCADA points into its distribution substations. These SCADA installations are fundamental to the potential implementation of future conservation and voltage management programs, such as conservation voltage reduction, 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 our 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 approved by Vectren or the Commission.

**State and Federal Energy Efficiency Developments**

**Federal - ARRA Funding**

The American Recovery and Reinvestment Act of 2009 (ARRA) was enacted in February 2009. ARRA included several provisions that expanded energy efficiency including increased tax incentives for residential energy efficiency improvements, significant increase in the amount of low-income home weatherization, as well as other significant funds channeled to state and local governments to fund energy efficiency and renewable energy efforts. The challenge over the planning horizon will be the sustainability of energy efficiency efforts in the absence or reduction of funding for these energy efficiency efforts post the ARRA funding expiration. The opportunity exists for utility funded DSM programs to play an even bigger role in moving energy efficiency efforts to new levels.

**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.

- The Energy Independence and Security Act of 2007 requires all general-purpose light bulbs that produce 310–2600 lumens of light be 30% more energy efficient (similar to current halogen lamps) than then-current incandescent bulbs by 2012 to 2014. The efficiency standards will start with 100-watt bulbs in January 2012 and end with 40-watt bulbs in January 2014. The impacts of this legislation have been contemplated and quantified in the sales forecast modeling conducted by Vectren.

- 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 November 16, 2010, the DOE announced that it is making changes to expedite its rulemaking process. The Department has already taken steps to improve its internal management of the rulemaking process and is now making further changes designed to make the rulemaking process more efficient. The likely outcome of this effort will be an acceleration of appliance and equipment efficiency standards, ENERGY STAR, and building energy codes.

**State – Codes, Standards and Legislation**

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

- Indiana has been working on the development of new building codes, which will likely be implemented in the near future.
- The IURC released the Phase II Generic DSM order on December 9, 2009. The order:
    - Established statewide electric savings goals for utilities starting in 2010 at 0.3% of average sales and ramping to 2% per year in 2019.
    - Defined a list of 5 Core DSM Programs to be offered on a statewide basis by a Third Party Administrator (TPA). Programs include residential lighting, home energy audits/kits, low income weatherization, school education programs and commercial/industrial prescriptive rebates.
    - Allows utilities the option to offer Core Plus programs in an effort to reach the 2% goal.
    - Requires programs to be evaluated, measured and verified (EM&V) by a statewide independent evaluator.
    - Established a Demand Side Management Coordination Committee (DSMCC) to oversee DSM programs.

On July 27, 2011 the IURC approved the selection of the third party administrator and evaluator contracts as submitted by the DSMCC.

- Senate Enrolled Act 251 established a Voluntary Clean Energy Portfolio Standard Program which supports an increase of renewable energy and energy efficiency.

**VECTREN DSM STRATEGY**

Vectren has adopted a cultural change that encourages conservation and efficiency. 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 our own employees. Vectren encourages each employee, especially those with direct customer contact, to promote conservation. Internal communications, 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. The following purpose and mission of “Live Smart” is the foundation of the Vectren Strategy related to DSM:

Purpose

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

Mission

We will be the industry leader in helping our customers manage their energy costs. We will achieve best-in-class safety performance and top quartile performance in customer satisfaction and productivity. We will deliver superior investor returns.

Customers are a key component of our values, and we know success comes from understanding our customers and actively helping them to use energy efficiently.

**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, Vectren, the OUCC, and CAC formed the DSM Collaborative (Collaborative) as a result of a settlement in Cause No. 42861. The Collaborative provided input in the planning of Vectren's proposed DSM programs. Initially, the Collaborative helped select Forefront Economics and H. Gil Peach and Associates to conduct the Market Assessment Study (Study or Peach Report) and provide input on the development of the Study. Upon completion of the Study (titled "Electric DSM Action Plan" and included in the Technical Appendix), the Collaborative reviewed the Peach Report, as well as other available information regarding DSM programs. The other information included Vectren's own research and the results of commercial customer surveys performed by Vectren. Numerous Collaborative meetings were conducted to consider the design of new programs, funding levels, program reporting, implementation and administration, and cost recovery issues. The Collaborative provided input on the work performed to develop the DSM portfolio. Vista Energy, a DSM consultant employed by Vectren, expanded on the work already provided to the Collaborative via the Peach Report to help finalize a portfolio of DSM programs. While aspects of Vectren's DSM planning updated the Peach Report, the Market Assessment Study served as the foundation of Vectren's efforts to identify and capture energy efficiency and DSM lost opportunities.

Through this process, in years past, Vectren's DSM portfolio of programs were developed through a sequential set of planning steps aimed at taking the most current industry and market information to screen and prioritize the relevant opportunities based on their costs and benefits. Planning steps included:

- Customer Market Research
- Leverage of Past DSM Filing & Market Assessment Information
- Development of Candidate Program Concepts
- Development of Technology and Market Data
- DSM Technology Screening

- Identification of DSM Programs for Resource Integration

On December 9, 2009, the Indiana Utility Regulatory Commission ("IURC" or "Commission") issued the Phase II Order in Cause No. 42693 which established energy saving goals for all jurisdictional utilities in Indiana. The Phase II Order required all jurisdictional utilities to implement 5 specified programs, which the Commission termed Core Programs. The Core Programs are to be administered by a third party administrator (TPA) selected through a process involving the Demand Side Coordination Committee composed of jurisdictional Utilities (IOU's) and other pertinent key stakeholders. 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.

On December 16, shortly after the Phase II Order, the Commission issued an Order in Vectren South-Electric's Petition in Cause No. 43427, in which the Commission approved all of the programs proposed by Vectren and separated them into Core and Core Plus Program categories. The DSM programs approved in Cause No. 43427 did not meet the overall savings requirements of the Phase II Order nor did the DSM plan include DSM programs for large customers. In April of 2010, Vectren began implementing electric conservation programs approved in Cause No. 43427. Table 8-2, shown below, details the programs and associated energy savings and program expenditures for programs offered under Cause No. 43427.

**Table 8-2 Vectren Core & Core Plus Programs Data – Cause No. 43427**

| Cause No. 43427 | Gross MWh Savings | | Program Expenditures | |
|---|---|---|---|---|
| **CORE PROGRAMS** | **2010 Actual** | **2011 Forecast Year End** | **2010 Actual** | **2011 Forecast Year End** |
| Residential Lighting | 0 | 19,400 | $10,050 | $600,000 |
| Home Energy Audit | 0 | 25 | $10,050 | $70,000 |
| Low Income Weatherization | 0 | 25 | $10,050 | $50,000 |
| Energy Efficient Schools | 759 | 700 | $104,958 | $105,000 |
| **Total Core Programs By Year** | 759 | 20,150 | $135,108 | $825,000 |
| **CORE PLUS PROGRAMS** | **2010 Actual** | **2011 Forecast Year End** | **2010 Actual** | **2011 Forecast Year End** |
| Residential Appliance Recycling | 1,739 | 1,600 | $210,764 | $240,000 |
| Residential New Construction | 5 | 15 | $44,274 | $120,000 |
| Commercial & Industrial Audit & Custom | 974 | 1,800 | $274,774 | $225,000 |
| Commercial & Industrial New Construction | 0 | 400 | $108,314 | $175,000 |
| **Total Core Plus Programs By Year** | 2,718 | 3,815 | $638,126 | $760,000 |

| Portfolio Summary | 2010 Actual | 2011 Forecast Year End | 2010 - 2011 Summary |
|---|---|---|---|
| Total Gross MWH Core & Core Plus | 3,477 | 23,965 | 27,442 |
| Total Program Expenditures Core & Core Plus | $773,234 | $1,585,000 | $2,358,234 |

In order to ensure compliance with the Phase II order, Vectren modified existing programs approved in Cause No. 43427 and added new programs, which were approved on August 31st, 2011 in Cause No. 43938. Outlined below is the 2011-2013 DSM Plan approved under Cause No. 43938, which provides details regarding the Core and Core Plus Programs that will be offered by or on behalf of Vectren during the period of 2011-2013 in order to meet the savings identified in the Phase II Order.

## Core Programs

- Residential Lighting
- Home Energy Audit and Direct Install
- Low Income Weatherization

- School Energy Efficiency
- Commercial & Industrial Prescriptive

**Core Plus Programs**

- Residential Second Refrigerator Pick-Up Program
- Residential Window Air Conditioner Pick-Up Program
- Residential New Construction
- Residential HVAC
- Residential Behavioral Savings
- Residential Multi-Family
- Commercial & Industrial Audit & Custom
- Commercial & Industrial New Construction
- Direct Use

**DSM SCREENING RESULTS**

Terra Vista Energy Group was utilized by Vectren to provide expertise to perform research, model the savings/benefits, and help develop the Vectren Electric DSM Program. The analysis of the energy efficiency and DSM programs was handled through the use of a spreadsheet model designed to conduct the relevant cost-effectiveness results. The model, developed by ANB Enterprises Inc., is structured to handle the accounting of costs and benefits for the various programs and the entire portfolio. The model is structured in an Excel spreadsheet with various worksheets to accommodate the range of needed data inputs.

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
- Rate Impact Measure Test

- Total Resource Cost Test

All the economic tests are based on the cost-effectiveness methodologies from the *California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects*, California Office of Planning and Research, 2002.

The model has successfully been used in analysis of energy efficiency programs in a number of states including New York, Pennsylvania, Indiana, and Ohio.

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

All results are expressed in dollars. The methodology directly copies the algorithms from the California Standard Practice Methodology. The California standard practice manual was first developed in February 1983. It was later revised and updated in 1987–88 and 2001; a correction memo was issued in 2007.

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 8-3.

**Table 8-3 Vectren Cost Effectiveness Tests Benefits & Costs Summary**

| Test | Benefits | Costs |
|---|---|---|
| Participant Cost Test | • Incentive payments<br>• Annual bill savings<br>• Applicable tax credits | • Incremental technology/equipment costs<br>• Incremental installation costs |
| Utility Cost Test (Program Administrator Cost Test) | • Avoided energy costs<br>• Avoided capacity costs | • All program costs (startup, marketing, fixed, labor, evaluation, promotion, etc.)<br>• Utility/Administrator incentive costs |
| Rate Impact Measure Test | • Avoided energy costs<br>• Avoided capacity costs | • All program costs (startup, marketing, fixed, labor, evaluation, promotion, etc.)<br>• Utility/Administrator incentive costs<br>• Lost revenue due to reduced energy bills |
| Total Resource Cost Test | • Avoided energy costs<br>• Avoided capacity costs<br>• Applicable participant tax credits | • All program costs (not including incentive costs)<br>• 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. The avoided costs used in the tests are shown below in Table 8-4.

**Table 8-4 Vectren Avoided Costs**

| | Generation Avoided Cost | Transmission/ Distribution Avoided Cost | Total Capacity Avoided Cost | Marginal Energy Cost | Marginal Energy Cost |
|---|---|---|---|---|---|
| | $/kW | $/kW | $/kW | $/MWh | $/KWh |
| 2012 | 69.02 | 6.90 | 75.92 | 44.23 | 0.0442 |
| 2013 | 70.41 | 7.04 | 77.45 | 42.01 | 0.0420 |
| 2014 | 71.81 | 7.18 | 78.99 | 44.47 | 0.0445 |
| 2015 | 73.25 | 7.33 | 80.58 | 49.11 | 0.0491 |
| 2016 | 74.72 | 7.47 | 82.19 | 52.21 | 0.0522 |
| 2017 | 76.21 | 7.62 | 83.83 | 55.92 | 0.0559 |
| 2018 | 77.74 | 7.77 | 85.51 | 60.34 | 0.0603 |
| 2019 | 79.29 | 7.93 | 87.22 | 64.85 | 0.0649 |
| 2020 | 80.88 | 8.09 | 88.97 | 69.55 | 0.0696 |
| 2021 | 82.49 | 8.25 | 90.74 | 73.44 | 0.0734 |
| 2022 | 84.14 | 8.41 | 92.55 | 77.18 | 0.0772 |
| 2023 | 85.83 | 8.58 | 94.41 | 82.37 | 0.0824 |
| 2024 | 87.54 | 8.75 | 96.29 | 87.04 | 0.0870 |
| 2025 | 89.29 | 8.93 | 98.22 | 94.74 | 0.0947 |
| 2026 | 91.08 | 9.11 | 100.19 | 99.61 | 0.0996 |
| 2027 | 92.90 | 9.29 | 102.19 | 103.99 | 0.1040 |
| 2028 | 94.76 | 9.48 | 104.24 | 108.07 | 0.1081 |
| 2029 | 96.65 | 9.67 | 106.32 | 112.80 | 0.1128 |
| 2030 | 98.59 | 9.86 | 108.45 | 118.48 | 0.1185 |
| 2031 | 100.56 | 10.06 | 110.62 | 125.81 | 0.1258 |

A review of the benefit/cost results for each of the technologies considered in the screening analysis is detailed below in Table 8-5.

## Table 8-5 Vectren DSM Technology Screening Results

### Residential Technology Analysis Results

**Results for Technology Only - One Participant in Start Year and No Program Costs**

| | | Participant Test | | RIM Test | | TRC Test | |
|---|---|---|---|---|---|---|---|
| ID | Program Name | NPV $ | BCR | NPV $ | BCR | NPV $ | BCR |
| 1 | Res 2nd Refrigerator Pickup | $1,028 | 0.00 | ($518) | 0.46 | $510 | 0.00 |
| 2 | Room AC Pickup-Ridew/Ref | $65 | 0.00 | $313 | 6.16 | $378 | 0.00 |
| 3 | Energy Star Windows | $60 | 1.40 | $1,252 | 7.38 | $1,312 | 9.75 |
| 4 | Low Income Weatherization | $1,152 | 6.26 | ($140) | 0.89 | $1,012 | 5.62 |
| 5 | Res. Lighting | $34 | 9.51 | ($15) | 0.46 | $12 | 4.87 |
| 6 | Water Heater Pipe Insulation | $197 | 7.80 | ($97) | 0.54 | $100 | 4.45 |
| 7 | Water Heater Pipe Insulation | $197 | 7.80 | ($97) | 0.54 | $100 | 4.45 |
| 8 | Residential Audit | $757 | 5.33 | ($166) | 0.81 | $591 | 4.38 |
| 9 | Low Flow Showerheads (2) | $484 | 7.36 | ($216) | 0.54 | $222 | 4.25 |
| 10 | Energy Efficient Pool Pump-Pilot | $504 | 3.80 | $33 | 1.05 | $536 | 3.98 |
| 11 | Smart Strip Plug-PA TRM | $89 | 4.42 | ($16) | 0.86 | $73 | 3.82 |
| 12 | Energy Eff. Electric Water Heater .91-.93 | $65 | 1.86 | $80 | 1.61 | $145 | 2.93 |
| 13 | Std Gas Water Heater Conversion | $785 | 5.02 | ($416) | 0.53 | $311 | 2.45 |
| 14 | House Sealing-Blower Door-All Electric | $752 | 3.51 | ($330) | 0.66 | $422 | 2.41 |
| 15 | Res. New Construction- | ($219) | 0.88 | $957 | 1.65 | $738 | 1.41 |
| 16 | Eff Split System CAC-R13-R17 | ($661) | 0.48 | $926 | 2.60 | $265 | 1.21 |
| 17 | Eff Split System CAC-R13-R16 | ($608) | 0.48 | $833 | 2.58 | $225 | 1.19 |
| 18 | Eff Split System CAC-R13-R18 | ($924) | 0.42 | $1,109 | 2.75 | $184 | 1.12 |
| 19 | Ceiling Insulation R10-R30 | ($159) | 0.53 | $162 | 1.98 | $3 | 1.01 |
| 20 | Smart Strip-7 Plug-Ohio TRM | $27 | 2.04 | ($29) | 0.42 | ($1) | 0.94 |
| 21 | Smart Strip-5 Plug-Ohio TRM | $13 | 1.83 | ($14) | 0.47 | ($1) | 0.93 |
| 22 | Ceiling Insulation R10-R38 | ($234) | 0.45 | $176 | 1.99 | ($58) | 0.86 |
| 23 | Res Ht Pump Tune Up | $129 | 1.74 | ($159) | 0.44 | ($30) | 0.83 |
| 24 | House Sealing-Blower Door-Electric/Gas | ($90) | 0.70 | $32 | 1.16 | ($58) | 0.81 |
| 25 | Energy Star Clothes Dishwasher | ($22) | 0.83 | ($14) | 0.87 | ($36) | 0.73 |
| 26 | Solar Water Heater | ($5,722) | 0.40 | $833 | 1.24 | ($4,889) | 0.49 |
| 27 | Res AC tune up | ($101) | 0.42 | ($27) | 0.61 | ($128) | 0.27 |
| 28 | Basement Wall Insulation R0-R19 batts | ($2,658) | 0.04 | $185 | 2.72 | ($2,473) | 0.11 |
| 29 | Basement Wall Insulation R0-R13 batts | ($2,417) | 0.04 | $166 | 2.93 | ($2,251) | 0.10 |
| 30 | Cool Roof | ($8,197) | 0.03 | $95 | 1.39 | ($8,102) | 0.04 |

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

Utility Cost test results are not provided since there are no program costs.

**Commercial/Industrial Technology Analysis Results**

**Results for Technology Only - One Participant in Start Year and No Program Costs**

| | | Participant Test | | RIM Test | | TRC Test | |
|---|---|---|---|---|---|---|---|
| ID | Program Name | NPV $ | BCR | NPV $ | BCR | NPV $ | BCR |
| 1 | Commercial DLC | $0 | 0.00 | $857 | 0.00 | $857 | 0.00 |
| 2 | Engineered Nozzles | $510 | 37.41 | $175 | 1.36 | $685 | 49.90 |
| 3 | Comm Premium Motors | $1,577 | 7.31 | $33 | 1.02 | $1,610 | 7.44 |
| 4 | Commercial New Construction | $29,526 | 4.11 | $14,996 | 1.41 | $44,522 | 5.69 |
| 5 | Commercial Lighting-Replacement | $12,734 | 4.46 | ($1,049) | 0.93 | $11,686 | 4.17 |
| 6 | Recast Prescriptive Rebate Program | $299 | 4.32 | ($26) | 0.93 | $273 | 4.03 |
| 7 | RetroCommissioning-Lite | $9,684 | 5.84 | ($4,264) | 0.61 | $5,420 | 3.71 |
| 8 | Energy Efficient Packaged AC-Commercial-Small Office | $5,560 | 2.86 | $2,514 | 1.31 | $8,075 | 3.71 |
| 9 | Energy Efficient Packaged AC-Commercial-Large Office | $9,261 | 2.72 | $4,387 | 1.32 | $13,648 | 3.54 |
| 10 | Energy Star Refrigerated Beverage Machine Controls | $1,256 | 5.48 | ($579) | 0.60 | $676 | 3.42 |
| 11 | Commutated Motors | $2,475 | 3.65 | ($217) | 0.93 | $2,258 | 3.41 |
| 12 | Commercial Lighting-Retrofit | $11,813 | 3.57 | ($1,049) | 0.93 | $10,765 | 3.34 |
| 13 | VendMiser | $642 | 3.99 | ($201) | 0.75 | $441 | 3.05 |
| 14 | Commercial Commissioning | $4,669 | 3.33 | ($1,291) | 0.79 | $3,377 | 2.69 |
| 15 | Older Building Roof Insulation-Large Office | $755 | 1.13 | $6,727 | 2.13 | $7,483 | 2.34 |
| 16 | Vending Machine Sensors | $695 | 4.22 | ($490) | 0.42 | $205 | 1.95 |
| 17 | Upgrade Ceiling Insulation-Old Bldg | ($484) | 0.81 | $2,761 | 2.39 | $2,278 | 1.90 |
| 18 | Older Building Roof Insulation-Small Office | ($1,603) | 0.37 | $3,074 | 4.52 | $1,471 | 1.58 |
| 19 | Comm Window Film | $118 | 1.44 | ($31) | 0.91 | $87 | 1.33 |
| 20 | Occupoancy Sensor-Plug Loads-Large Office | $19 | 1.16 | ($2) | 0.98 | $17 | 1.14 |
| 21 | Occupancy Sensor-Lighting | $134 | 2.15 | ($126) | 0.48 | $9 | 1.07 |
| 22 | Occupoancy Sensor-Plug Loads-Small Office | $19 | 1.16 | ($11) | 0.92 | $9 | 1.07 |
| 23 | Older Building Roof Insulation-Education | ($14,788) | 0.18 | $11,086 | 4.66 | ($3,702) | 0.79 |
| 24 | Solar Water Heater | ($4,740) | 0.41 | $1,776 | 1.56 | ($2,859) | 0.64 |
| 25 | Low E Windows (1500 SF) | ($16,361) | 0.45 | $3,631 | 1.28 | ($12,730) | 0.58 |
| 26 | Light Colored Roof | ($31,482) | 0.10 | ($1,071) | 0.66 | ($32,553) | 0.07 |

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

Utility Cost test results are not provided since there are no program costs.

Table 8-6, listed below, shows the Core and Core Plus Programs benefit/cost data per the portfolio of programs approved under Cause No. 43938. Core Programs savings, budgets and program designs are based on the Statewide TPA contract. It should be noted that the Statewide TPA Core Programs implementation is not expected to begin until 2012, thus the tables reflect no participation in 2011 for those programs. For the purposes of this IRP, the benefit/cost results were updated utilizing the avoided costs contained in Table 8-4.

## Table 8-6 Program Benefit/Cost Results for Three Year DSM Plan

### Core Programs

| ID | Program Name | Participant Test | | Utility Test | | RIM Test | | TRC Test | |
|---|---|---|---|---|---|---|---|---|---|
| | | NPV, 000$ | BCR | NPV, 000$ | BCR | NPV, 000$ | BCR | NPV, 000$ | BCR |
| 1 | Program Outreach-Core | $0 | 0.00 | ($128) | 0.00 | ($128) | 0.00 | ($128) | 0.00 |
| 2 | Residential On Site Audit and Kit | $6,376 | 6.13 | $1,575 | 1.63 | ($2,759) | 0.60 | $1,423 | 1.46 |
| 3 | Residential Energy Efficient Lighting | $13,605 | 11.00 | $2,609 | 2.91 | ($4,890) | 0.45 | $3,250 | 2.95 |
| 4 | Low Income Weatherization | $3,079 | 7.98 | $982 | 1.58 | ($1,600) | 0.62 | $1,183 | 1.70 |
| 5 | School Energy Efficiency | $3,407 | 6.39 | ($523) | 0.63 | ($2,522) | 0.26 | ($110) | 0.91 |
| 7 | C&I Prescriptive Rebate Program | $50,596 | 5.15 | $36,973 | 7.51 | ($2,422) | 0.95 | $35,123 | 4.09 |
| | TOTAL | $77,062 | 5.86 | $41,488 | 4.25 | ($14,321) | 0.79 | $40,742 | 3.12 |

### Core Plus Programs

| ID | Program Name | Participant Test | | Utility Test | | RIM Test | | TRC Test | |
|---|---|---|---|---|---|---|---|---|---|
| | | NPV, 000$ | BCR | NPV, 000$ | BCR | NPV, 000$ | BCR | NPV, 000$ | BCR |
| 1 | Residential Program Outreach | $0 | 0.00 | ($509) | 0.00 | ($509) | 0.00 | ($509) | 0.00 |
| 2 | Residential Refrigerator Recycling and Pickup | $6,635 | 0.00 | $1,239 | 2.54 | ($1,922) | 0.52 | $1,780 | 3.57 |
| 3 | Room AC Recycling-Ride Along | $46 | 0.00 | $13 | 1.16 | ($1) | 0.99 | $32 | 1.54 |
| 4 | Res Multi Family Program | $2,582 | 33.97 | $792 | 2.68 | ($888) | 0.59 | $977 | 3.15 |
| 5 | Res HVAC | $2,757 | 2.50 | $3,964 | 4.35 | $1,133 | 1.28 | $3,268 | 2.53 |
| 6 | Res New Construction | $181 | 1.59 | ($26) | 0.95 | ($263) | 0.64 | ($125) | 0.79 |
| 8 | Residential O Power | $5,592 | 0.00 | $695 | 1.42 | ($3,952) | 0.37 | $1,061 | 1.64 |
| 9 | Direct Use Program | $785 | 5.02 | $259 | 2.21 | ($416.08) | 0.53 | $311 | 2.45 |
| 10 | Commercial Industrial Outreach | $0 | 0.00 | ($274) | 0.00 | ($274) | 0.00 | ($274) | 0.00 |
| 11 | Comm and Industrial New Construction | $2,698 | 5.12 | $3,128 | 5.00 | $738 | 1.23 | $2,942 | 3.51 |
| 12 | Commercial and Industrial Audit-Custom | $5,668 | 3.66 | $1,102 | 1.42 | ($3,389) | 0.52 | $668 | 1.19 |
| | TOTAL | $26,944 | 6.18 | $2 | 1.86 | ($9,743) | 0.67 | $10,130 | 1.90 |

Table 8-7, listed below, shows program inputs for an individual participant in the program as well as the associated estimated bill impacts.

## Table 8-7 Vectren DSM Programs Input Data

### Core Programs

| Program Name | Annual Energy Savings, kWh | Incremental Technology Cost | Customer Incentive | Program Cost Borne By Participant | Projected Participant Annual Bill Reduction |
|---|---|---|---|---|---|
| Residential On Site Audit and Kit | 1,036 | $ 175.00 | $ 33.15 | $ 141.85 | $ 138.82 |
| Residential Energy Efficient Lighting | 61 | $ 4.00 | $ 1.59 | $ 2.41 | $ 8.17 |
| Low Income Weatherization | 1,304 | $ 219.07 | $ 219.07 | $ - | $ 174.74 |
| School Energy Efficiency | 376 | $ 48.50 | $ 48.50 | $ - | $ 50.38 |
| C&I Prescriptive Rebate Program | 363 | $ 89.97 | $ 29.99 | $ 59.98 | $ 44.07 |

Core Plus Programs

| Program Name | Annual Energy Savings, kWh | Incremental Technology Cost | Customer Incentive | Program Cost Borne By Participant | Projected Participant Bill Reduction |
|---|---|---|---|---|---|
| Residential Refrigerator Recycling | 1,647 | $ - | $ 30.00 | $ (30.00) | $ 220.70 |
| Room AC Recycling | 104 | | $ 30.00 | $ (30.00) | $ 13.94 |
| Res Multi Family Program | 704 | $ 20.00 | $ 20.00 | $ - | $ 94.34 |
| Residential HVAC ECM Program | 484 | $ 200.00 | $ 60.00 | $ 140.00 | $ 64.86 |
| Residential Cooling Program-CAC | 475 | $ 900.00 | $ 300.00 | $ 600.00 | $ 63.65 |
| Residential Cooling Program-HP | 700 | $ 1,100.00 | $ 400.00 | $ 700.00 | $ 93.80 |
| Res New Construction | 949 | $ 1,800.00 | $ 1,000.00 | $ 800.00 | $ 127.22 |
| Residential Behavioral Savings | 280 | $ - | $ - | $ - | $ 37.52 |
| Comm and Industrial New Construction | 28,000 | $ 9,486.00 | $ 3,360.00 | $ 6,126.00 | $ 3,399.20 |
| Commercial and Industrial Audit/Custom Program-Med CI | 13,246 | $ 4,166.00 | $ 1,590.00 | $ 2,576.00 | $ 1,608.06 |
| Commercial and Industrial Audit/Custom Program-Large CI | 26,492 | $ 8,332.00 | $ 3,179.00 | $ 5,153.00 | $ 3,216.13 |
| Direct Use Program | 4,879 | $ 850.00 | $ 850.00 | $ - | $ 653.79 |

## PROGRAM CONCEPTS

### Customer Outreach and Education

#### *Program*

This program will raise awareness and drive customer participation to the Core and Core Plus DSM Programs 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
- Drive participation in the Core and Core Plus 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.

The TPA will oversee and coordinate the outreach and education programs for the Core programs. Vectren will oversee the outreach and education programs for the Core Plus programs. Vectren will work closely with the TPA to provide consistent messaging across Core and Core Plus outreach and education efforts. 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."*

The budget will have $71,321 annually dedicated to Core Programs, which will be administered by the TPA, as well as $300,000 annually for Core Plus Programs to be administered by Vectren. The actual amount of the statewide Core Outreach Program is much larger but this value represents Vectren's portion of the outreach for Core Programs.

**Table 8-8 DSM Outreach & Education Program Budget**

**DSM Outreach & Education Program Budget**

| Market | Year | Program Budget $,000 |
|---|---|---|
| Residential & Commercial/Industrial | 2011 | $ 300 |
| | 2012 | $ 371 |
| | 2013 | $ 371 |
| Total Program | | $ 1,042 |

## Core Programs

### School Energy Efficiency Program

#### *Program*

The School Energy Efficiency Program is designed 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 two components:

a. A school education program for selected students attending schools served by Vectren. To help in this effort it is envisioned that each student that participates will receive a free take-home kit containing energy saving measures.
b. A school energy savings assistance program consisting of technical assistance and building energy audits. The audits help schools identify operational and capital improvements to school facilities served by Vectren.

#### *Eligible Customers*

The program will be available to selected students/schools in the Vectren electric service territory. The School Energy Efficiency Program targets two primary customer sectors:

a. Energy education targets K-12 students. The program may initially focus on a limited number of schools and students in a particular grade.

b. The school energy savings assistance program targets K-12 schools that are greater than ten (10) years old.

***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 376 kWh per participant.

**Table 8-9 School Energy Efficiency Program Data**

| Market | Program & Year | Number of Participants | Percent of Participation | Energy Savings MWh | Peak Demand kW | Program Budget $,000 |
|---|---|---|---|---|---|---|
| Residential | School Energy Efficiency | | | | | |
| | 2011 | | | | | |
| | 2012 | 6,535 | 5.4% | 2,457 | 0 | $726 |
| | 2013 | 7,987 | 6.6% | 3,003 | 0 | $843 |
| Cumulative Program Total | | 14,522 | | 5,460 | | $ 1,569 |
| Potential Participants | | | | | | 121,000 |
| Per Participant Energy Savings (kWh) | | | | | | 376 |
| Per Participant Demand Savings (kW) | | | | | | 0.000 |
| Measure Life | | | | | | 5 |
| Net To Gross Ratio | | | | | | 0.70 |

## Residential Lighting Program

***Program***

The Residential Lighting Program is proposed as 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 lights. This program is justified based on direct energy savings targets, but also has a significant market transformation opportunity.

The value of the program addresses the following: empowering customers to take advantage of new lighting technologies, accelerate the adoption of proven energy

efficient technologies, and experience the benefits of energy efficiency and decrease their energy consumption.

### *Eligible Customers*

Any Vectren residential electric customer 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 61 kWh annually with demand savings of 0.007 kW.

**Table 8-10 Residential Lighting Program Data**

| Market | Program & Year | Number of Participants (Bulbs) | Percent of Participation | Energy Savings MWh | Peak Demand kW | Program Budget $,000 |
|---|---|---|---|---|---|---|
| Residential | Residential Lighting | | | | | |
| | 2011 | | | | | |
| | 2012 | 170,557 | 141.0% | 10,404 | 1,177 | $714 |
| | 2013 | 208,443 | 172.3% | 12,715 | 1,438 | $804 |
| Cumulative Program Total | | 379,000 | | 23,119 | 2,615 | $ 1,518 |
| Potential Participants | | | | | | 121,000 |
| Per Participant Energy Savings (kWh) | | | | | | 61 |
| Per Participant Demand Savings (kW) | | | | | | 0.007 |
| Measure Life | | | | | | 5 |
| Net To Gross Ratio | | | | | | 0.62 |

## Residential Audit & Direct Install Program

### *Program*

The Residential Audit and Direct Install Program is proposed to help produce long-term, cost effective electric savings in the residential market sector by helping customers analyze and understand their energy use; recommending appropriate weatherization measures, and facilitating the direct installation of specific low-cost energy saving measures. Direct install measures will include CFLs and hot water saving products.

### *Eligible Customers*

Any Vectren single family residential electric customer is eligible.

### *Energy/Demand Savings*

For modeling purposes, the energy savings estimate is 1,036 kWh and .46 kW per participant.

**Table 8-11 Residential Audit & Direct Install Program Data**

| Market | Program & Year | Number of Participants | Percent of Participation | Energy Savings MWh | Peak Demand kW | Program Budget $,000 |
|---|---|---|---|---|---|---|
| Residential | Residential Audit & Direct Install | | | | | |
| | 2011 | | | | | |
| | 2012 | 3,565 | 2.9% | 3,693 | 1,640 | $1,261 |
| | 2013 | 4,356 | 3.6% | 4,513 | 2,004 | $1,505 |
| Cumulative Program Total | | 7,921 | | 8,206 | 3,644 | $ 2,766 |
| Potential Participants | | | | | | 121,000 |
| Per Participant Energy Savings (kWh) | | | | | | 1,036 |
| Per Participant Demand Savings (kW) | | | | | | 0.46 |
| Measure Life | | | | | | 8 |
| Net To Gross Ratio | | | | | | 0.70 |

## Low Income 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.

### *Eligible Customers*

The Residential Low Income Weatherization Program targets single-family homeowners and tenants, who have utility 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 1,304 kWh annually with demand savings of 0.55 kW.

**Table 8-12 Low Income Weatherization Program Data**

| Market | Program & Year | Number of Participants | Percent of Participation | Energy Savings MWh | Peak Demand kW | Program Budget $,000 |
|---|---|---|---|---|---|---|
| Residential | Low Income Weatherization | | | | | |
| | 2011 | | | | | |
| | 2012 | 1,010 | 4.6% | 1,317 | 556 | $853 |
| | 2013 | 1,235 | 5.7% | 1,610 | 679 | $1,023 |
| Cumulative Program Total | | 2,245 | | 2,927 | 1,235 | $ 1,876 |
| Potential Participants | | | | | | 21,780 |
| Per Participant Energy Savings (kWh) | | | | | | 1,304 |
| Per Participant Demand Savings (kW) | | | | | | 0.55 |
| Measure Life | | | | | | 10 |
| Net To Gross Ratio | | | | | | 1 |

## Commercial and Industrial Prescriptive Program

***Program***

The Commercial and Industrial (C&I) Prescriptive Program is designed to help facility managers and building owners achieve long-term, cost-effective savings in the commercial and industrial market sector by assisting them in upgrading to energy efficient products. The incentives are designed to promote lower electricity consumption, assist customers in managing their energy costs, and build a sustainable market around energy efficiency.

***Eligible Customers***

Any Vectren electric commercial or industrial customer is eligible.

***Incentive***

This program includes a prescriptive rebate structure that rewards participants with monetary rebates based on their installation of energy efficiency equipment upgrades.

***Energy/Demand Savings***

For modeling purposes, the energy savings estimate is 363 kWh per participant (measure) and demand savings of .09 kW.

**Table 8-13 Commercial and Industrial Prescriptive Program Data**

| Market | Program & Year | Number of Participants | Percent of Participation | Energy Savings MWh | Peak Demand kW | Program Budget $,000 |
|---|---|---|---|---|---|---|
| Commercial & Industrial | C&I Prescriptive | | | | | |
| | 2011 | | | | | |
| | 2012 | 67,983 | 543.9% | 24,678 | 6,200 | $2,897 |
| | 2013 | 83,091 | 664.7% | 30,162 | 7,578 | $3,428 |
| Cumulative Program Total | | 151,074 | | 54,840 | 13,778 | $ 6,325 |
| Potential Participants | | | | | | 12,500 |
| Per Participant Energy Savings (kWh) | | | | | | 363 |
| Per Participant Demand Savings (kW) | | | | | | 0.09 |
| Measure Life | | | | | | 12 |
| Net To Gross Ratio | | | | | | 0.8 |

## Core Plus Programs

### Residential Second Refrigerator Pick-Up

***Program***

The Vectren Residential Second Refrigerator Pick-Up Program is designed to provide for the removal and disposal of operable, inefficient secondary refrigerators and freezers in an environmentally safe manner. Purely from an energy perspective, the value of this program is in the disassembly of inefficient refrigerators and freezers so they do not operate on the power system. It is a tendency of some households to retain

an old refrigerator in the garage or basement when a new refrigerator takes its place in the kitchen. Generally, the old refrigerator is plugged in, but used as a convenience to cool canned beverages or casual meals or snacks. Although viewed as a convenience, the actual price, both on the household electric bill and to the electric system, is disproportionate to the benefits provided.

The removal and proper disposal of older secondary refrigerators and freezers provides many other environmental and safety benefits. Utility programs that focus on replacing and comprehensively recycling old appliances can prevent pollution in a number of valuable ways by:

- Preventing the release of chlorofluorocarbons (CFCs), hydro chlorofluorocarbons (HCFCs) and hydro fluorocarbons (HFCs), from cooling systems and insulation, which destroy the ozone layer and accelerate global climate change
- Capturing toxic materials from lubricating oil and capacitors that could contaminate surface and ground water
- Recovering and reusing metals, plastics, and other potentially valuable materials that make up the bulk of the appliance which would otherwise waste valuable landfill space

***Eligible Customers***

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

***Incentive***

The program offers customers free pick-up of working refrigerators or freezers and a $30 cash incentive.

***Energy/Demand Savings***

The program is designed to remove the old, secondary refrigerator or freezer. The savings estimate is 1,647 kWh annually, with a summer demand savings of 0.19 kW.

**Table 8-14 Residential Second Refrigerator Pick-Up Program Data**

| Market | Program & Year | Number of Participants | Percent of Participants | Energy Savings MWh | Peak Demand kW | Program Budget $,000 |
|---|---|---|---|---|---|---|
| Residential | Residential Second Refrigerator Pickup | | | | | |
| | 2011 | 1,200 | 3.5% | 1,976 | 228 | $ 270 |
| | 2012 | 1,600 | 4.7% | 2,636 | 304 | $ 330 |
| | 2013 | 1,600 | 4.7% | 2,635 | 304 | $ 330 |
| Cumulative Program Total | | 4,400 | | 7,247 | 836 | $ 930 |
| Potential Participants | | | | | | 33,880 |
| Per Participant Energy Savings (kWh) | | | | | | 1,647 |
| Per Participant Demand Savings (kW) | | | | | | 0.19 |
| Measure Life | | | | | | 8 |
| Net To Gross Ratio | | | | | | 0.6 |

## Residential Room Air-Conditioner Pick-Up

### *Program*

The Residential Room Air Conditioner program is designed to allow Vectren customers with old, inefficient room air conditioners to turn these units in and remove them from use. The program serves as a complimentary offering with the proposed Second Refrigerator Pick-Up program. Customers will be able to schedule pick-up and removal of working room air conditioners

Once picked up, the appliances will be decommissioned and dismantled so that the components can be recycled in an environmentally responsible way. Only a bare minimum of material will reach landfill sites. Particular attention will be paid to the chemicals used in units that are significant atmospheric pollutants and responsible for ozone depletion. These will be contained and destroyed.

### *Eligible Customers*

Any Vectren South residential electric customer with an operable window air conditioner is eligible.

### *Incentive*

For each residential room air conditioner collected, an incentive of $30 will be provided to the customer.

### *Energy/Demand Savings*

The program is designed to remove the old room air conditioner and assumes participants will purchase a new, energy efficient room air conditioner. The savings estimate, is 104 kWh annually, with a summer demand savings of 0.9 kW.

**Table 8-15 Residential Second Window AC Pick-Up Program Data**

| Market | Program & Year | Number of Participants | Percent of Participants | Energy Savings MWh | Peak Demand kW | Program Budget $,000 |
|---|---|---|---|---|---|---|
| Residential | Residential Window A/C Pickup | | | | | |
| | 2011 | 200 | 1.0% | 21 | 180 | $ 28 |
| | 2012 | 230 | 1.2% | 24 | 207 | $ 30 |
| | 2013 | 260 | 1.3% | 26 | 234 | $ 33 |
| Cumulative Program Total | | 690 | | 71 | 621 | $ 91 |
| Potential Participants | | | | | | 19,360 |
| Per Participant Energy Savings (kWh) | | | | | | 104 |
| Per Participant Demand Savings (kW) | | | | | | 0.9 |
| Measure Life | | | | | | 3 |
| Net To Gross Ratio | | | | | | 0.6 |

## Residential HVAC Program

### *Program*

The Residential HVAC Program provides a financial incentive in the form of a prescriptive rebate on electronically commutated motors (ECMs), central air conditioners, and heat pump systems installed in existing residences.

Electronically commutated motors were selected to be part of the program because of their low energy usage, as compared to standard motors typically utilized in HVAC equipment. When used in a variable speed blower scenario, the devices offer significant energy savings, better comfort, and increased humidity removal.

The goal of the program is to influence the residential sector to choose higher efficiency HVAC equipment when purchasing new equipment.

### *Eligible Customers*

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

### *Incentive*

The rebates will be a set amount of $60 per electronically commutated motor (ECM), $300 per central air conditioner (CAC) with a SEER rating of 16 or greater, and $400 per heat pump (HP) with a SEER rating of 16 or greater paid to residential customers who complete a rebate application and submit documentation of the equipment purchase. Note that heat pump rebates will only be paid to customers who do not have natural gas available to the premise.

### *Energy/Demand Savings*

For modeling purposes, the energy/demand savings estimates are 484 kWh/.25 kW per ECM participant, 475 kWh/.35 kW per CAC participant, and 700 kWh/.35 kW per HP participant.

**Table 8-16 Residential HVAC Program Data**

| Market | Program & Year | Number of Participants | Percent of Participation | Energy Savings MWh | Peak Demand kW | Program Budget $,000 |
|---|---|---|---|---|---|---|
| Residential | Residential HVAC | | | | | |
| | 2011 | 1,520 | 1.7% | 737 | 412 | $ 472 |
| | 2012 | 1,975 | 2.2% | 958 | 541 | $ 420 |
| | 2013 | 2,125 | 2.4% | 1,028 | 594 | $ 466 |
| Cumulative Program Total | | 5,620 | | 2,723 | 1,547 | $ 1,358 |
| Potential Participants | | | | | | 88,800 |
| Per Participant Energy Savings (kWh) - ECM | | | | | | 484 |
| Per Participant Energy Savings (kWh) - CAC | | | | | | 475 |
| Per Participant Energy Savings (kWh) - HP | | | | | | 700 |
| Per Participant Demand Savings (kW) - ECM | | | | | | 0.25 |
| Per Participant Demand Savings (kW) - CAC & HP | | | | | | 0.35 |
| Measure Life | | | | | | 18 |
| Net To Gross Ratio - ECM & HP | | | | | | 0.9 |
| Net To Gross Ratio - CAC | | | | | | 0.8 |

## Residential Behavioral Savings Program

### *Program*

Behavior-based programs motivate customers to take actions that result in measurable, large-scale energy savings. The Residential Behavioral Savings Program motivates behavior change and provides relevant, targeted information to the consumer through regularly scheduled direct contact. The direct contact, typically through letters, helps the consumer to better understand their energy use. Once a consumer has a better understanding of how they use energy, they can then start conserving energy.

The program, as modeled, will provide letters to consumers combining energy usage data along with customer demographic, housing and utility data to develop specific, targeted recommendations that educate and motivate consumers to reduce their energy consumption. The recommendations provided in the letter give the consumer a variety of ways to save energy in their home, from low to no cost to higher cost investments. The program has been implemented by a number of utilities across the country, such as Puget Sound Energy, Dominion Power, and Southern California Edison.

Program data and design were provided by OPower, who is expected to be 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*

Any residential homeowner located in the Vectren electric service territory is 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 280 kWh with demand savings of .05 kW.

**Table 8-17 Residential Behavioral Savings Program Data**

| Market | Program & Year | Number of Participants | Percent of Participation | Energy Savings MWh | Peak Demand kW | Program Budget $,000 |
|---|---|---|---|---|---|---|
| Residential | Residential Behavioral Savings | | | | | |
| | 2011 | 24,250 | 20.2% | 6,790 | 1,213 | $ 420 |
| | 2012 | 24,250 | 20.2% | 6,790 | 1,213 | $ 624 |
| | 2013 | 24,250 | 20.2% | 6,790 | 1,213 | $ 879 |
| Cumulative Program Total | | 72,750 | | 20,370 | 3,639 | $ 1,923 |
| Potential Participants | | | | | | 120,000 |
| Per Participant Energy Savings (kWh) | | | | | | 280 |
| Per Participant Demand Savings (kW) | | | | | | 0.05 |
| Measure Life | | | | | | 1 |
| Net To Gross Ratio | | | | | | 1 |

## 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. Energy savings are estimated to be approximately 15% versus a home built to current building codes. The Residential New Construction Program will work closely with builders, educating them on the benefits of building energy efficient 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.

The Residential New Construction Program will address the “lost opportunities” segment, 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 willing to construct an energy efficient home in the Vectren electric service territory is eligible.

### *Incentives*

Program incentives are designed to be paid to both all-electric and combination homes that have natural gas heating and water heating. The modeled incentive is $1,000 for an all-electric home. Vectren also plans to offer a reduced incentive for a combination home. 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.

### *Energy/ Demand Savings*

For modeling purposes, the savings estimates per home are calculated at 949 kWh and .18 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 8-18 Residential New Construction Program Data**

| Market | Program & Year | Number of Participants | Percent of Participation | Energy Savings MWh | Peak Demand kW | Program Budget $,000 |
|---|---|---|---|---|---|---|
| Residential | Residential New Construction | | | | | |
| | 2011 | 25 | 1.9% | 24 | 5 | $ 120 |
| | 2012 | 75 | 5.8% | 71 | 13 | $ 205 |
| | 2013 | 100 | 7.7% | 95 | 18 | $ 245 |
| Cumulative Program Total | | 200 | | 190 | 36 | $ 570 |
| Potential Participants | | | | | | 1,300 |
| Per Participant Energy Savings (kWh) | | | | | | 949 |
| Per Participant Demand Savings (kW) | | | | | | 0.18 |
| Measure Life | | | | | | 25 |
| Net To Gross Ratio | | | | | | 0.95 |

## Multi-Family Direct Install Program

### *Program*

The Multi-Family Direct Install Program is designed to reduce the consumption of energy by the direct installation of CFLs and low-flow water fixtures in rental units. The

rental segment of customers is a hard group to target due to the varying nature of which party pays for the utility bills. If the utility bill is included in rent, the tenant has no motivation to reduce their consumption. If the tenant is paying for the utility bill, they want to reduce but not make a substantial investment because they do not own the property. The program provides the installation and energy saving products free of charge to the landlord and/or tenant. This removes the barrier of who will make the investment to save energy.

### *Eligible Customers*

Any all electric multi-family complex with more than 8 units is eligible.

### *Energy/Demand Savings*

For modeling purposes, the energy/demand savings estimates are 704 kWh/.112 kW per participant.

**Table 8-19 Multi-Family Direct Install Program Data**

| Market | Program & Year | Number of Participants | | Energy Savings MWh | Peak Demand kW | Program Budget $,000 |
|---|---|---|---|---|---|---|
| Residential | Multi-Family Direct Install | | | | | |
| | 2011 | 1,500 | 15.0% | 1,056 | 168 | $ 213 |
| | 2012 | 1,500 | 15.0% | 1,056 | 168 | $ 163 |
| | 2013 | 1,500 | 15.0% | 1,056 | 168 | $ 163 |
| Cumulative Program Total | | 4,500 | | 3,168 | 504 | $ 539 |
| Potential Participants | | | | | | 10,000 |
| Per Participant Energy Savings (kWh) | | | | | | 704 |
| Per Participant Demand Savings (kW) | | | | | | 0.112 |
| Measure Life | | | | | | 8 |
| Net To Gross Ratio | | | | | | 0.8 |

## Commercial and Industrial Audit and Custom Efficiency Program

### *Program*

This program targets commercial and industrial customers by providing technical assistance and financial incentives for custom energy efficiency projects. The program targets a broad array of technologies and energy end-uses reflecting the diversity that

exists with Vectren's commercial and industrial customers. The various types of commercial and industrial customers present challenges due to the diversity of the buildings, as well as the services and measures that may assist them in saving energy. The measures, which may include areas such as (but not limited to) HVAC upgrades, water heating, pumps, refrigeration, and building energy system controls tend to exhibit site-specific energy savings and impacts. As a result, it becomes difficult to establish a predetermined set of measures and incentives which addresses each option.

Another component of the program available to customers is a reduced cost energy audit. This service will provide a comprehensive facility energy audit at a reduced price to qualifying customers. Vectren will pay for 1/3 of the audit price up to a cap of $2,500.

***Eligible Customers***

Any 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.

***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 13,246 kWh/2.3 kW for small and medium customers and 26,492 kWh/4.6 kW for large customers.

**Table 8-20 Commercial and Industrial Audit & Custom Efficiency Program Data**

| Market | Program & Year | Number of Participants | Percent of Participation | Energy Savings MWh | Peak Demand kW | Program Budget $,000 |
|---|---|---|---|---|---|---|
| Commercial & Industrial | C&I Audit & Custom Efficiency | | | | | |
| | 2011 | 124 | 1.1% | 2,053 | 357 | $ 824 |
| | 2012 | 148 | 1.4% | 2,451 | 425 | $ 925 |
| | 2013 | 204 | 1.9% | 3,377 | 587 | $ 1,274 |
| Cumulative Program Total | | 476 | | 7,881 | 1,369 | $ 3,023 |
| Potential Participants | | | | | | 10,861 |
| Per Participant Energy Savings (kWh) - Small/Medium Customers | | | | | | 13,246 |
| Per Participant Energy Savings (kWh) - Large Customers | | | | | | 26,492 |
| Per Participant Demand Savings (kW) - Small/Medium Customers | | | | | | 2.3 |
| Per Participant Demand Savings (kW) - Large Customers | | | | | | 4.6 |
| Measure Life | | | | | | 9 |
| Net To Gross Ratio | | | | | | 0.8 |

## Commercial and Industrial New Construction Program

### *Program*

The program offers rebates and assistance for customers that construct new facilities or significantly renovate existing facilities.

Similar programs have been successfully implemented in New Jersey (Smart Start Program, which has achieved a market share estimate of nearly 30% of all new construction) and National Grid's Design 2000 Program.

### *Eligible Customers*

Any new or existing commercial/industrial customer building in Vectren's electric service territory is eligible.

### *Incentive*

The program is designed to pay .12 cents per kWh saved.

### *Energy/Demand Savings*

For modeling purposes the estimated energy/demand savings are 28,000 kWh/5.4 kW.

**Table 8-21 Commercial and Industrial New Construction Program Data**

| Market | Program & Year | Number of Participants | Percent of Participation | Energy Savings MWh | Peak Demand kW | Program Budget $,000 |
|---|---|---|---|---|---|---|
| Commercial & Industrial | C&I New Construction | | | | | |
| | 2011 | 20 | 8.0% | 560 | 108 | $ 311 |
| | 2012 | 30 | 12.0% | 840 | 162 | $ 289 |
| | 2013 | 30 | 12.0% | 840 | 162 | $ 299 |
| Cumulative Program Total | | 80 | | 2,240 | 432 | $ 899 |
| Potential Participants | | | | | | 250 |
| Per Participant Energy Savings (kWh) | | | | | | 28,000 |
| Per Participant Demand Savings (kW) | | | | | | 5.4 |
| Measure Life | | | | | | 20 |
| Net To Gross Ratio | | | | | | 0.95 |

## Direct Use Program

### *Program*

The program offers rebates and assistance for customers who choose to convert their electric water heaters to natural gas units.

### *Eligible Customers*

Any Vectren electric residential customer on an electric water heating rate (Rate B) with an active natural gas service on their property is eligible.

### *Incentive*

The program is designed to pay up to $850 for conversion costs.

### *Energy/Demand Savings*

For modeling purposes the estimated energy/demand savings are 4,879 kWh/.3 kW.

**Table 8-22 Direct Use Program Data**

| Market | Program & Year | Number of Participants | Percent of Participation | Energy Savings MWh | Peak Demand kW | Program Budget $,000 |
|---|---|---|---|---|---|---|
| Residential | Direct Use Program | | | | | |
| | 2011 | 50 | 1.5% | 244 | 15 | $ 50 |
| | 2012 | 100 | 2.9% | 488 | 30 | $ 85 |
| | 2013 | 100 | 2.9% | 488 | 30 | $ 85 |
| Cumulative Program Total | | 250 | | 1,220 | 75 | $ 220 |
| Potential Participants | | | | | | 3,396 |
| Per Participant Energy Savings (kWh) | | | | | | 4,879 |
| Per Participant Demand Savings (kW) | | | | | | 0.3 |
| Measure Life | | | | | | 13 |
| Net To Gross Ratio | | | | | | 1 |

## DSM Portfolio Objective and Impacts

Vectren plans to reduce residential and commercial/industrial customer usage by 139,663 MWh after the third year of the program. Vectren also projects to achieve a reduction in summer peak demand of 30.3 MW after the third year. In implementing these programs, consideration will be given to utilizing small businesses when feasible. Table 8-23 outlines the portfolio and the associated programs, as well as the projected energy/demand impacts, program costs, and customer participation of Core and Core Plus programs offered under Cause No. 43938.

**Table 8-23 Projected Energy and Peak Savings – Cause No. 43938**

| | **Vectren DSM Program Portfolio Impacts, Participation & Budget - Cause No. 43938** | | | | | |
|---|---|---|---|---|---|---|
| Program Year | Participants/ Measures | Energy Savings MWh - Annual Incremental | Energy Savings MWh - Cumulative | Peak Demand Savings MW - Annual Incremental | Peak Demand Savings MW - Cumulative | Program Budget $,000 |
| 2011 | 28,889 | 13,461 | 13,461 | 2.7 | 2.7 | $3,009 |
| 2012 | 279,558 | 57,861 | 71,322 | 12.6 | 15.3 | $9,901 |
| 2013 | 335,281 | 68,341 | 139,663 | 15.0 | 30.3 | $11,754 |
| Total | 643,728 | 139,663 | | 30.3 | | $24,664 |

| | Vectren DSM Program Core Portfolio Impacts, Participation & Budget - Cause No. 43938 | | | | | |
|---|---|---|---|---|---|---|
| Program Year | Participants/ Measures | Energy Savings MWh - Annual Incremental | Energy Savings MWh - Cumulative | Peak Demand Savings MW - Annual Incremental | Peak Demand Savings MW - Cumulative | Program Budget $,000 |
| 2011 | | | | | | |
| 2012 | 249,650 | 42,549 | 42,549 | 9.6 | 9.6 | $6,525 |
| 2013 | 305,112 | 52,003 | 94,552 | 11.7 | 21.3 | $7,676 |
| | | | | | | |
| Total | 554,762 | 94,552 | | 21.3 | | $14,201 |

| | Vectren DSM Program Core Plus Portfolio Impacts, Participation & Budget - Cause No. 43938 | | | | | |
|---|---|---|---|---|---|---|
| Program Year | Participants/ Measures | Energy Savings MWh - Annual Incremental | Energy Savings MWh - Cumulative | Peak Demand Savings MW - Annual Incremental | Peak Demand Savings MW - Cumulative | Program Budget $,000 |
| 2011 | 28,889 | 13,461 | 13,461 | 2.7 | 2.7 | $3,009 |
| 2012 | 29,908 | 15,312 | 28,773 | 3.0 | 5.7 | $3,376 |
| 2013 | 30,169 | 16,338 | 45,111 | 3.3 | 9.0 | $4,078 |
| | | | | | | |
| Total | 88,966 | 45,111 | | 9.0 | | $10,463 |

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 recently approved 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.

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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 2031. 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 Midwest Independent System Operator (MISO), the Reliability First Corporation (RFC) 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 RFC 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, RFC, MISO and IURC requirements and 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.

Maps of Vectren's Electric Transmission System are defined as Critical Electric Infrastructure Information (CEII), as defined by guidelines by Homeland Security, FERC and NERC and other agencies requirements. The Maps are being provided confidentially to the IURC in the Technical Appendix. Vectren also keeps its facilities current on RFC, MISO, IEA, and MEA maps as required.

**METHODOLOGY**

The distribution system review covers native load, as described in previous chapters in this IRP. The transmission system review additionally covers loads connected to our transmission system, such as municipals and Independent Power Producers (IPP's) that Vectren is not obligated to serve or include in our generation resources. The primary reason is to determine impacts or limitations in the transmission capacity to serve the Vectren native load. Vectren is a member of the Midwest Independent System Operator (MISO) and is part of the Reliability First Corporation (RFC) region of the North America Electric Reliability Council (NERC). As such, Vectren adheres to the transmission planning criteria developed and published by MISO in its document MISO *Transmission Expansion Planning*; (MTEP) and by RFC through NERC in its *Reliability Standards* under *Transmission Planning (TPL-001 through TPL-004)*.

The basis for the selection of RFC 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 – 2010 (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.
   - Triple outages: two generators plus one line or transformer.
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 – 2012 (NEAR TERM – WITHIN 1-5 YEARS)**

Using updated load and generation forecasts and included planned upgrades, the same analysis is performed for the 2010 system. Contingency analysis is also the same as for the 2010 system.

**SYSTEM INTEGRITY ANALYSIS – 2016 (LONG TERM – 6-10 YEARS)**

Using updated load and generation forecasts and included planned upgrades, the same analysis is performed for the 2010 system. Contingency analysis is the same as for the 2010 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) | IPP's & other Gen (MW) | Vectren Firm Peak Demand (MW) | Muni's & Other Load (MW) | Proj. Inter-Change (MW) | Trans. System Import Cap (MW) |
|---|---|---|---|---|---|---|
| 2012 | 1,285 | 587 | 1,156 | 690 | 26 | 756 |
| 2013 | 1,285 | 668 | 1,156 | 690 | 107 | 847 |
| 2014 | 1,285 | 668 | 1,165 | 690 | 98 | 840 |
| 2015 | 1,285 | 668 | 1,164 | 690 | 99 | 846 |
| 2016 | 1,285 | 668 | 1,160 | 690 | 103 | 442 |
| 2017 | 1,285 | 668 | 1,151 | 690 | 112 | 454 |
| 2018 | 1,285 | 668 | 1,145 | 690 | 118 | 461 |
| 2019 | 1,285 | 668 | 1,139 | 690 | 124 | 469 |
| 2020 | 1,285 | 668 | 1,144 | 690 | 119 | 463 |
| 2021 | 1,285 | 668 | 1,149 | 690 | 114 | 362 |
| 2022 | 1,285 | 668 | 1,155 | 690 | 108 | 319 |
| 2023 | 1,285 | 668 | 1,159 | 690 | 104 | 315 |
| 2024 | 1,285 | 668 | 1,165 | 690 | 98 | 308 |
| 2025 | 1,285 | 668 | 1,171 | 690 | 92 | 301 |
| 2026 | 1,285 | 668 | 1,177 | 690 | 86 | 294 |
| 2027 | 1,285 | 668 | 1,184 | 690 | 79 | 287 |
| 2028 | 1,285 | 668 | 1,191 | 690 | 72 | 279 |
| 2029 | 1,285 | 668 | 1,199 | 690 | 64 | 269 |
| 2030 | 1,285 | 668 | 1,207 | 690 | 56 | 260 |
| 2031 | 1,285 | 668 | 1,215 | 690 | 48 | 251 |

The table reflects that the expected net interchange would be positive or exporting for all years. The lower import capability values in future years is driven by changes near a neighboring utility generation station and can be mitigated by Operational Guides (Op-Guides) and switching to maintain over 600 MW. Even without Op-Guides the import capability remains greater than the need. This reliability measure indicates that additional import transmission capacity is not needed to serve generation to load. However, the table does not reflect several other factors, such as potential purchases and sales. The table reflects total generation capability and not a reasonable economic

dispatch. 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 our system at 300 MW (Warrick 4), 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: 2010 - 2021**

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 2010, and are planned to continue into 2012 and future years, 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 Gibson to AB Brown segment is complete and energized. This project included the construction of a 345/138 kV substation at Vectren's AB Brown Station, which is also complete. Right of Way (ROW) procurement and construction of the segment from AB Brown to BREC Reid EHV Substation will continue through 2012. A new 138kV line (Z77) from FB Culley Substation to Oak Grove Substation is complete and an extension to Northeast Substation is in construction with completion expected in 2012. This facility allows for better generation dispatch diversity with lower congestion costs under contingencies. Multiple distribution substation upgrades were completed to

include Aventine and Savatran. Bergdolt Road and Libbert Rd Substations are presently in construction with completion expected in 2012. 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 Toyota South areas.

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 decrease slightly over the next five years. The primary factor is the 345kV project , expected to be complete 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 forecasted load growth is expected to stay flat or slightly decreasing. 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 | Annual Total |
|---|---|---|---|---|---|
| 2006 | $16.8M | $4.1M | $25.7M | $10.8M | $57.4M |
| 2007 | $15.5M | $3.2M | $15.5M | $24.6M | $58.8M |
| 2008 | $15.2M | $12.5M | $14.7M | $22.3M | $64.7M |
| 2009 | $27.3M | $5.2M | $27.2M | $20.2M | $79.9M |
| 2010 | $15.4M | $5.2M | $40.6M | $10.5M | $71.7M |

**Table 9-3 Planned Expenditures**

| | Dist. Lines | Dist. Substation | Trans. Lines | Trans. Substation | Annual Total |
|---|---|---|---|---|---|
| 2011 | $17.6M | $3.5M | $20.4M | $4.6M | $46.1M |
| 2012 | $19.6M | $7.4M | $24.7M | $6.7M | $58.4M |
| 2013 | $16.8M | $9.1M | $17.9M | $14.0M | $57.8M |
| 2014 | $21.5M | $9.8M | $16.6M | $10.0M | $57.9M |
| 2015 | $20.4M | $5.8M | $28.5M | $3.4M | $58.1M |

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# CHAPTER 10

# ELECTRIC INTEGRATION ANALYSIS

## INTRODUCTION

The purpose of the electric integration process is to develop the optimal strategy for adding the resources necessary to reliably meet the future demand requirements of Vectren's electric customers. The process is integrated in that both supply-side and demand-side alternatives are 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 present value of revenue requirements (PVRR).

## ELECTRIC INTEGRATION APPROACH

The process of determining the best resource plan can be approached as an optimization problem. Vectren internal resources utilized the Strategist software tool developed and supported by Ventyx (formerly New Energy Associates) of Atlanta, GA to perform the optimization analysis. 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.

It is very important to note that not all of the components of utility costs and revenue requirements were included in the analysis. Cost components that were considered include: capital costs of new construction alternatives, fuel costs of existing generation and new alternatives, economy interchange, non-fuel O&M of existing generation and new alternatives, and emissions costs.

An optimization problem 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 PVRR. For the purposes of this discussion, the planning period PVRR is defined as the present value of revenue requirements for the 20 year period, 2012 – 2031, over which the optimization analysis was performed. "End effects", estimates of revenue requirements beyond the twenty year planning period, were also considered when selecting the optimal plan. "End effects" are important due to their full consideration of the impact of resource additions that occur toward the end of the discrete 20 year planning period. The study period PVRR is defined as the planning period PVRR plus the end effects. The optimal resource plans as presented in this study were selected on a study period basis. The annual nominal revenue requirements for future years were converted to present value terms by discounting at Vectren's projected after tax weighted cost of capital of 7.29%, consistent with the most recent rate case order under IURC Cause 43839.

**Constraints**

The primary constraint was to maintain a minimum planning reserve margin of 12.1% for each year of the study period. 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. The 12.1% reserve margin constraint is lower than the 15% value that Vectren has used in prior IRP submittals. The lower value recognizes the benefits of regional load diversity that Vectren receives as a member of MISO, as discussed in Chapter 3 MISO on pages 35-36 of this IRP. This diversity is realized due to the large MISO footprint and the load diversity that exists within the MISO system during peak periods.

The 12.1% reserve margin value is the applicable value from the MISO Planning Year 2011 LOLE (Loss of Load Expectation) Study Report, found in the Technical Appendix. This value is the requirement for LSE (load serving entities) peaks on an installed capacity basis. From the report, "The goal of the study 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."

**Alternatives**

A broad array of alternatives 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.

The next several sections of this chapter discuss several of the key inputs and assumptions used for developing the integration model.

**DISCUSSION OF KEY INPUTS AND ASSUMPTIONS**

The annual revenue requirements were determined by evaluating all of the pertinent costs that could impact future resource additions. The annual revenue requirements include both 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.

Again, it is important to consider 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.

Following are discussions of key inputs and assumptions used for the integration analysis:

**New Construction Alternatives**

New construction alternatives are discussed in detail in Chapter 6 Electric Supply Analysis. The new construction alternatives that were selected to be included in the detailed integration analysis are summarized in Table 10-1. The following new construction options were included as feasible and representative alternatives in the detailed optimization and integration analysis.

**Table 10-1 Characteristics of New Construction Alternatives**

| Primary Fuel | Coal | | Gas | | | | | BioMass |
|---|---|---|---|---|---|---|---|---|
| Technology Description | With 90% CCS | | Simple Cycle | | | | Comb. Cyc. | CFB Steam Turb. Wood Waste |
| | Pulverized Coal Supercritical (PCSC) | Integrated Gasification Combined Cycle (IGCC) | Aero-derivative GE LM6000 | Aero-derivative GE LMS100 | Heavy Duty GE 7EA | Heavy Duty GE 7FA | 2 X 1 GE 7FA | |
| Nominal Capability (MW) | 517 | 518 | 85 (2x42.5) | 98 | 84 | 209 | 612 | 48 |
| Assumed Vectren Share, % | 25 | 25 | 100 | 100 | 100 | 100 | 20 | 100 |
| Vectren Summer Capability, MW | 129 | 130 | 74 | 90 | 73 | 185 | 113 | 48 |
| Base Load Net Heat Rate (Btu/kWh) | 11,790 | 11,313 | 9,845 | 9,305 | 11,730 | 9,937 | 6,665 | 13,391 |
| Fixed O&M (2011$/kW-yr) | 50.74 | 39.76 | 6.40 | 10.32 | 9.94 | 8.18 | 11.28 | 111.01 |
| Variable O&M (2011$/MWh) | 14.39 | 8.98 | 3.25 | 2.49 | 19.66 | 15.84 | 6.64 | 3.26 |
| Equivalent Forced Outage Rate (%) | 4.6 | 7.8 | 2.4 | 2.4 | 1.0 | 1.0 | 2.5 | 3.5 |
| Total Capital (2011 $000,000) | 3,071 | 2,455 | 126 | 125 | 88 | 136 | 105 | 186 |
| Total Capital (2011$/kW) | 5,940 | 4,739 | 1,705 | 1,389 | 1,206 | 736 | 928 | 3,875 |

**Conservation**

Programs

Chapter 8 DSM Resources contains a detailed discussion of demand-side management alternatives. Implementation of the Phase II Generic DSM order began in 2010. Conservation goals of 0.3% of average sales and ramping to 2% per year in 2019 were incorporated into the base case peak and energy forecast discussed in Chapter 5 Sales

and Demand Forecast. Additionally, incremental energy savings of 0.5% per year were assumed beginning in 2020 and were carried throughout the rest of the planning period. These assumptions are fully considered in the base case peak and energy forecasts.

Direct Load Control

Vectren has offered and managed a direct load control (DLC) program since 1992. This program is discussed in detail in the "Existing DSM Resources and Programs" section of Chapter 8 DSM Resources. The current and projected impacts of this program are summarized in the following table, reproduced from Chapter 8. For the purposes of the integration analysis, the 2016 level of performance was assumed to remain constant throughout the remainder of the study period.

**Table 10-2 DLC System Load Reduction Capability**

| DLC System Demand Reduction Projection | | |
|---|---|---|
| | Residential and Commercial Demand Reduction (kW) | |
| | 33% Cycling | 50% Cycling |
| 2011 DLC System Technical Potential | 26,849 | 38,702 |
| 2011 Achievable Load Reduction | 13,425 | 19,351 |
| 2012 Achievable Load Reduction | 16,110 | 23,221 |
| 2013 Achievable Load Reduction | 18,795 | 27,092 |
| 2014 Achievable Load Reduction | 21,480 | 30,962 |
| 2015 Achievable Load Reduction | 24,165 | 34,832 |
| 2016 Forward Load Potential | 24,165 | 34,832 |

**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 base case forecast results used in the optimization analysis are summarized in Table 10-3.

## Table 10-3 Electric Demand and Energy Forecast

| | Retail | | | Firm Wholesale | | Total Requirements | | |
|---|---|---|---|---|---|---|---|---|
| Year | Peak (Mw) | Annual Energy (Gwh) | Load Factor (%) | Peak (Mw) | Annual Energy (Gwh) | Peak (Mw) | Annual Energy (Gwh) | Load Factor (%) |
| 2012 | 1,156 | 5,840 | 56.9% | 12 | 57 | 1,168 | 5,897 | 56.9% |
| 2013 | 1,156 | 5,810 | 56.6% | 12 | 57 | 1,168 | 5,867 | 56.6% |
| 2014 | 1,165 | 5,806 | 56.2% | 12 | 57 | 1,177 | 5,863 | 56.1% |
| 2015 | 1,164 | 5,772 | 55.9% | | | 1,164 | 5,772 | 55.9% |
| 2016 | 1,160 | 5,725 | 55.6% | | | 1,160 | 5,725 | 55.6% |
| 2017 | 1,151 | 5,657 | 55.4% | | | 1,151 | 5,657 | 55.4% |
| 2018 | 1,145 | 5,590 | 55.0% | | | 1,145 | 5,590 | 55.0% |
| 2019 | 1,139 | 5,520 | 54.6% | | | 1,139 | 5,520 | 54.6% |
| 2020 | 1,144 | 5,538 | 54.5% | | | 1,144 | 5,538 | 54.5% |
| 2021 | 1,149 | 5,543 | 54.3% | | | 1,149 | 5,543 | 54.3% |
| 2022 | 1,155 | 5,554 | 54.2% | | | 1,155 | 5,554 | 54.2% |
| 2023 | 1,159 | 5,563 | 54.1% | | | 1,159 | 5,563 | 54.1% |
| 2024 | 1,165 | 5,580 | 54.0% | | | 1,165 | 5,580 | 54.0% |
| 2025 | 1,171 | 5,588 | 53.8% | | | 1,171 | 5,588 | 53.8% |
| 2026 | 1,177 | 5,603 | 53.6% | | | 1,177 | 5,603 | 53.6% |
| 2027 | 1,184 | 5,618 | 53.5% | | | 1,184 | 5,618 | 53.5% |
| 2028 | 1,191 | 5,646 | 53.4% | | | 1,191 | 5,646 | 53.4% |
| 2029 | 1,199 | 5,660 | 53.2% | | | 1,199 | 5,660 | 53.2% |
| 2030 | 1,207 | 5,685 | 53.1% | | | 1,207 | 5,685 | 53.1% |
| 2031 | 1,215 | 5,711 | 52.9% | | | 1,215 | 5,711 | 52.9% |
| Compound Average Growth Rate (%) 2012-2031 | 0.26% | -0.12% | | | | 0.21% | -0.17% | |

### 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 10-4. These characteristics were applied to all years of the study period as Vectren does not project any changes in the operating status or capacity of any existing company owned generating units in the foreseeable future.

**Table 10-4 Characteristics of Existing Generating Resources**

| Resource Name | Summer Capability (MW) | Primary Fuel | Resource type | EFOR (%) | Planned Maint. (Wks/yr) | Estimated Full Load Heat Rate (Btu/kwhn) | Variable O&M (2011 $/Mwh) | Fixed O&M (2011 $/Kw-yr) |
|---|---|---|---|---|---|---|---|---|
| A.B. Brown 1 | 245 | coal | steam | 7.0 | 2.5 | 10,800 | 4.4 | 24.81 |
| A.B. Brown 2 | 245 | coal | steam | 7.0 | 2.5 | 10,700 | 4.4 | 24.00 |
| F.B. Culley 1 | retired 12/31/2006 | | | | | | | |
| F.B. Culley 2 | 90 | coal | steam | 8.0 | 2.5 | 11,700 | 1.4 | 32.97 |
| F.B. Culley 3 | 270 | coal | steam | 7.0 | 2.5 | 10,400 | 1.5 | 22.16 |
| Warrick 4 | 150 | coal | steam | 7.0 | 2.5 | 10,200 | 1.5 | 20.84 |
| A.B. Brown 3 | 75 | gas | comb. turb. | 2.0 | 2.5 | 12,000 | 5.5 | 11.07 |
| A.B. Brown 4 | 75 | gas | comb. turb. | 2.0 | 2.5 | 11,700 | 5.5 | 11.07 |
| Broadway 1 | 50 | gas | comb. turb. | 2.0 | 2.5 | 14,000 | 5.5 | 11.07 |
| Broadway 2 | 65 | gas | comb. turb. | 2.0 | 2.5 | 13,000 | 5.5 | 11.07 |
| Northeast 1 | 10 | gas | comb. turb. | 10.0 | 2.5 | 15,000 | 5.5 | 11.07 |
| Northeast 2 | 10 | gas | comb. turb. | 10.0 | 2.5 | 15,000 | 5.5 | 11.07 |
| Blackfoot[1] | 3 | landfill gas | IC engine | 5.0 | 2.0 | 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 summer capability of this commitment was assumed to be 30 MW. It was also assumed that this resource would be present throughout the 20-year study period. Additionally, Vectren has a capacity purchase for 100 MW of year-round capacity for the years 2010 through 2012.

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

Finally, as discussed in Chapter 7 Renewables and Clean Energy, Vectren has entered into two long-term purchased power agreements for wind energy. These purchases were assumed to be in place for the entire IRP study period. For the purposes of this IRP, it was assumed that 10% (8 MW) of the combined nominal capacity of 80 MW was firm capacity contributing to reserve margin requirements. This is consistent with the current MISO treatment of wind generation.

**Fuel Prices**

The cost of fuel is one of the largest components of revenue requirements. 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 and expertise from Energy Ventures Analysis, Inc. (EVA) to develop the fuel price forecasts for this IRP. The natural gas price forecast is consistent with information available in EVA's 2011 FUELCAST Long-Term Outlook for Natural Gas. Basis assumptions were applied to simulate the delivered burner tip gas cost to Vectren generators. To develop the coal price forecast; known costs under contract and indicative RFP pricing was utilized in the early years of the study period and escalation rates provided by EVA for Indiana Illinois Basin coal were applied to develop the later years of the study period.

An important factor to consider when developing or analyzing long-term fuel price forecasts is that the trends fail to reflect any short term volatility that may occur beyond the near term. Historically, the conventional thinking has been that price volatility was primarily a concern for natural gas, with coal prices being considered relatively predictable. However, due to well known domestic and global factors beyond the scope of this report, recent years have seen this paradigm largely reversed with coal prices exhibiting significant volatility and natural gas prices becoming much more stable.

Market conditions and customer demand are continually evaluated when procuring fuel for use in our electric generation units. Vectren maintains an adequate supply of coal in physical inventory on the ground at each of our plant locations to ensure reliable service to our customers as a prudent contingency in the event of unforeseen supply interruptions due to weather, labor, etc.

**Table 10-5 Base Fuel Price Projection**

| | Coal Illinois Basin High Sulfur FOB plant | Natural Gas (burner tip) |
|---|---|---|
| Year | (2011 $/mmBtu) | (2011 $/mmBtu) |
| 2012 | 2.98 | 4.41 |
| 2013 | 2.40 | 4.54 |
| 2014 | 2.39 | 4.75 |
| 2015 | 2.44 | 5.28 |
| 2016 | 2.45 | 5.45 |
| 2017 | 2.46 | 5.63 |
| 2018 | 2.47 | 5.81 |
| 2019 | 2.47 | 6.08 |
| 2020 | 2.48 | 6.35 |
| 2021 | 2.51 | 6.39 |
| 2022 | 2.52 | 6.43 |
| 2023 | 2.54 | 6.53 |
| 2024 | 2.55 | 6.63 |
| 2025 | 2.56 | 6.92 |
| 2026 | 2.57 | 6.93 |
| 2027 | 2.58 | 6.94 |
| 2028 | 2.58 | 6.94 |
| 2029 | 2.59 | 6.97 |
| 2030 | 2.60 | 7.00 |
| 2031 | 2.61 | 7.15 |

**Wholesale Market Activity**

Economy Interchange

Full economic interchange was assumed and simulated for this IRP analysis. This assumption is consistent with Vectren's participation in the MISO markets. The system dispatch model was allowed to purchase and sell non-firm energy to and from a simulated external market. Purchase and sale decisions were made by comparing the Vectren system marginal costs against a projected forward price curve. The projected forward price curve was developed using a fundamentals based regional Power Markets Model developed for Vectren by Pace Global. Purchases were charged to revenue requirements and economy sales were a credit to revenue requirements, consistent with the terms of the wholesale sales sharing agreement under the most recent rate case order under IURC Cause 43839.

Firm Capacity Purchases

With respect to firm capacity purchases in the integration analysis, Vectren did not simulate the availability of future capacity alternatives beyond the existing purchase arrangements. This is discussed in more detail in the "Purchased Power Alternatives" section of Chapter 6 Electric Supply Analysis.

**Environmental Considerations**

Chapter 4 Environmental discusses environmental issues in detail. Consistent with that discussion, the integration analysis assumed full compliance with CSAPR allocation levels of emissions using existing environmental controls. Variable cost impacts associated with running FGD and SCR equipment at higher removal efficiencies 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 Table 10-6.

**Table 10-6 Financial Assumptions**

| Resource Type | Book Life (yrs) | Tax Life (yrs) | Accounting Depreciation | Tax Depreciation | AFUDC Rate (%) | Construction Term (yrs) |
|---|---|---|---|---|---|---|
| coal / biomass | 30 | 20 | Straight Line | MACRS | 5.0 | 4 |
| gas: combined cycle | 30 | 20 | Straight Line | MACRS | 5.0 | 3 |
| gas: simple cycle | 25 | 15 | Straight Line | MACRS | 5.0 | 2 |

### Inflation

The GDP chain-type price index forecast[1], as published by the Department of Energy (DOE) Energy Information Administration (EIA) in the 2011 Annual Energy Outlook (AEO), was used as a forecast for general inflation.

[1] Source: http://www.eia.gov/forecasts/aeo/topic_macroeconomic.cfm

**Table 10-7 General Inflation Forecast**

| Year | GDP Chain-type Price Index (2000=1.000) | Year to Year Increase, % |
|---|---|---|
| 2011 | 1.120 | |
| 2012 | 1.133 | 1.16 |
| 2013 | 1.152 | 1.68 |
| 2014 | 1.173 | 1.82 |
| 2015 | 1.197 | 2.05 |
| 2016 | 1.220 | 1.92 |
| 2017 | 1.246 | 2.13 |
| 2018 | 1.272 | 2.09 |
| 2019 | 1.298 | 2.04 |
| 2020 | 1.324 | 2.00 |
| 2021 | 1.350 | 1.96 |
| 2022 | 1.374 | 1.78 |
| 2023 | 1.399 | 1.82 |
| 2024 | 1.424 | 1.79 |
| 2025 | 1.450 | 1.83 |
| 2026 | 1.476 | 1.79 |
| 2027 | 1.504 | 1.90 |
| 2028 | 1.532 | 1.86 |
| 2029 | 1.561 | 1.89 |
| 2030 | 1.589 | 1.79 |
| 2031 | 1.619 | 1.89 |

Source: EIA; *Annual Energy Outlook 2011,* Reference Case, Macroeconomic Indicators, /http://www.eia.gov/forecasts/aeo/topic_macroeconomic.cfm

## INTEGRATION ANALYSIS RESULTS

The remainder of the chapter discusses the results of the resource planning integration and optimization modeling and analysis.

### Case 1: Base Case

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 PVRR. The following Table 10-8 shows the optimal resource plan for the base case that minimizes the study period PVRR.

Consistent with the 2009 Vectren IRP, the base case results in no supply-side resource additions being required for the planning period. Reserve margin remains above the 12.1% constraint for the full twenty years. In the early years of the planning period the lowest reserve margin occurs in the year 2014 with a value of 17.2%. The reserve margin begins to decline slowly in the later years of the planning period and subsequently, the lowest reserve margin occurs in the last year of the planning period, 2031, with a value of 13.7%.

## Table 10-8 Case 1: Base Case Resource Plan

| Year | Retail Peak Requirements (MW) | Firm Wholesale (MW) | Firm Peak Demand (MW) | Company Owned Generation (MW) | DLC (MW) | Interruptible (MW) | Committed Purchases (MW) | Capacity Addition | | Total Resources (MW) | Reserve Margin (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Summer (MW) | Description | | |
| 2012 | 1,156 | 12 | 1,168 | 1,285 | 16 | 35 | 138 | | | 1,474 | 26.2% |
| 2013 | 1,156 | 12 | 1,168 | 1,285 | 19 | 35 | 38 | | | 1,377 | 17.9% |
| 2014 | 1,165 | 12 | 1,177 | 1,285 | 21 | 35 | 38 | | | 1,379 | 17.2% |
| 2015 | 1,164 | | 1,164 | 1,285 | 24 | 35 | 38 | | | 1,382 | 18.8% |
| 2016 | 1,160 | | 1,160 | 1,285 | 24 | 35 | 38 | | | 1,382 | 19.2% |
| 2017 | 1,151 | | 1,151 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.0% |
| 2018 | 1,145 | | 1,145 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.7% |
| 2019 | 1,139 | | 1,139 | 1,285 | 24 | 35 | 38 | | | 1,382 | 21.3% |
| 2020 | 1,144 | | 1,144 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.8% |
| 2021 | 1,149 | | 1,149 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.2% |
| 2022 | 1,155 | | 1,155 | 1,285 | 24 | 35 | 38 | | | 1,382 | 19.7% |
| 2023 | 1,159 | | 1,159 | 1,285 | 24 | 35 | 38 | | | 1,382 | 19.2% |
| 2024 | 1,165 | | 1,165 | 1,285 | 24 | 35 | 38 | | | 1,382 | 18.7% |
| 2025 | 1,171 | | 1,171 | 1,285 | 24 | 35 | 38 | | | 1,382 | 18.0% |
| 2026 | 1,177 | | 1,177 | 1,285 | 24 | 35 | 38 | | | 1,382 | 17.4% |
| 2027 | 1,184 | | 1,184 | 1,285 | 24 | 35 | 38 | | | 1,382 | 16.8% |
| 2028 | 1,191 | | 1,191 | 1,285 | 24 | 35 | 38 | | | 1,382 | 16.0% |
| 2029 | 1,199 | | 1,199 | 1,285 | 24 | 35 | 38 | | | 1,382 | 15.3% |
| 2030 | 1,207 | | 1,207 | 1,285 | 24 | 35 | 38 | | | 1,382 | 14.5% |
| 2031 | 1,215 | | 1,215 | 1,285 | 24 | 35 | 38 | | | 1,382 | 13.7% |

| **Present Value of Revenue Requirements: PVRR** | **2011 ($000)** |
|---|---|
| Planning Period (20 years) | 2,269,501 |
| End Effects (beyond 20 years) | 1,041,144 |
| Study Period (20 years and beyond) | 3,310,645 |

**SENSITIVITY AND RISK ANALYSIS**

Virtually all of the parameters associated with the resource options considered by the IRP analysis possess a level of uncertainty. Therefore, the concept of an optimal resource strategy inherently depends on a discrete set of assumptions. While a single plan might emerge as being optimal for a given set of assumptions, uncertainties may be introduced into the assumptions that may result in a different optimal plan.

The first step in the sensitivity and risk analysis was to identify a set of possible future states and subsequently consider and assess the potential impact on key variables and assumptions for each of these future states. The second step was to use the planning model to determine the optimal plan (minimized PVRR) for each of the identified future states. The final step in the sensitivity and risk analysis was to compare the optimal plans from each future state and evaluate the short-term and long-term potential risks in terms of PVRR. Risk considerations are also discussed in qualitative terms.

Five potential future scenarios were selected for further analysis. They are as follows:

Case 2: High Demand Growth

Case 3: Industrial Load Addition

Case 4: Carbon Price

Case 5: High Natural Gas Prices

Case 6: Alternate Conservation

**Case 2: High Demand Growth**

For this sensitivity case the annual peak and energy from the high growth case as presented in Chapter 5 Sales and Demand Forecast were used for the load growth projection. This high growth case assumes that annual aggregate peak and energy increase at a rate of 1% over the prior year for each year of the study period.

This case resulted in the addition of two supply side resources during the 20 year planning period. The additions occur in the years 2019 and 2027. The selected generation technology for both additions was combined cycle. As discussed in Chapter 6 Electric Supply Analysis, Vectren assumed an ownership share of a large combined cycle unit for modeling purposes. Although purchased power options were not explicitly simulated, the combined cycle alternative, as modeled, could also be considered to be a placeholder or proxy for other market arrangements that would be investigated in due course: purchased power agreement, gas tolling arrangement, etc.

## Table 10-9 Case 2: High Demand Growth Resource Plan

| Year | Retail Peak Requirements (MW) | Firm Wholesale (MW) | Firm Peak Demand (MW) | Existing Owned Generation (MW) | DLC (MW) | Interruptible (MW) | Committed Purchases (MW) | Capacity Addition | | Total Resources (MW) | Reserve Margin (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Summer (MW) | Description | | |
| 2012 | 1,156 | 12 | 1,168 | 1,285 | 16 | 35 | 138 | | | 1,474 | 26.2% |
| 2013 | 1,167 | 12 | 1,179 | 1,285 | 19 | 35 | 38 | | | 1,377 | 16.8% |
| 2014 | 1,179 | 12 | 1,191 | 1,285 | 21 | 35 | 38 | | | 1,379 | 15.8% |
| 2015 | 1,191 | | 1,191 | 1,285 | 24 | 35 | 38 | | | 1,382 | 16.0% |
| 2016 | 1,203 | | 1,203 | 1,285 | 24 | 35 | 38 | | | 1,382 | 14.9% |
| 2017 | 1,215 | | 1,215 | 1,285 | 24 | 35 | 38 | | | 1,382 | 13.8% |
| 2018 | 1,227 | | 1,227 | 1,285 | 24 | 35 | 38 | | | 1,382 | 12.6% |
| 2019 | 1,239 | | 1,239 | 1,285 | 24 | 35 | 38 | 113 | Comb. Cyc. | 1,495 | 20.7% |
| 2020 | 1,252 | | 1,252 | 1,285 | 24 | 35 | 38 | | | 1,495 | 19.5% |
| 2021 | 1,264 | | 1,264 | 1,285 | 24 | 35 | 38 | | | 1,495 | 18.3% |
| 2022 | 1,277 | | 1,277 | 1,285 | 24 | 35 | 38 | | | 1,495 | 17.1% |
| 2023 | 1,290 | | 1,290 | 1,285 | 24 | 35 | 38 | | | 1,495 | 15.9% |
| 2024 | 1,302 | | 1,302 | 1,285 | 24 | 35 | 38 | | | 1,495 | 14.8% |
| 2025 | 1,315 | | 1,315 | 1,285 | 24 | 35 | 38 | | | 1,495 | 13.7% |
| 2026 | 1,329 | | 1,329 | 1,285 | 24 | 35 | 38 | | | 1,495 | 12.5% |
| 2027 | 1,342 | | 1,342 | 1,285 | 24 | 35 | 38 | 113 | Comb. Cyc. | 1,608 | 19.9% |
| 2028 | 1,355 | | 1,355 | 1,285 | 24 | 35 | 38 | | | 1,608 | 18.7% |
| 2029 | 1,369 | | 1,369 | 1,285 | 24 | 35 | 38 | | | 1,608 | 17.5% |
| 2030 | 1,383 | | 1,383 | 1,285 | 24 | 35 | 38 | | | 1,608 | 16.3% |
| 2031 | 1,396 | | 1,396 | 1,285 | 24 | 35 | 38 | | | 1,608 | 15.2% |

| **Present Value of Revenue Requirements: PVRR** | **2011 ($000)** |
|---|---|
| Planning Period (20 years) | 2,747,968 |
| End Effects (beyond 20 years) | 1,583,267 |
| Study Period (20 years and beyond) | 4,331,234 |

**Case 3: Industrial Load Addition**

This case represents the base case set of assumptions with the addition of a large industrial load. The load addition was simulated to represent 75 MW of peak demand at an 85% annual load factor for the year 2015 and all subsequent years of the study period. Given the size of Vectren's load, the addition of a single large industrial customer can have a significant impact on resource adequacy considerations; thus, it is prudent to consider such an impact in the planning process.

This scenario resulted in the addition of one new resource within the 20 year study period. As would be expected, the addition of a combined cycle alternative in 2015 directly corresponded to the timing of the load addition. The higher revenue requirements for this scenario are somewhat compounded by the fact that the resource addition occurs relatively early in the study period and therefore has a correspondingly higher impact in present value terms. Similar to the high growth case, the selected resource addition was the combined cycle option. As alluded to in the high growth case, the combined cycle addition should be considered to be the long-term solution to this scenario, and Vectren may pursue market based solutions for resource adequacy needs during the earlier years where additional capacity is needed.

## Table 10-10 Case 3: Industrial Load Addition Resource Plan

| Year | Retail Peak Requirements (MW) | Firm Wholesale (MW) | Firm Peak Demand (MW) | Company Owned Generation (MW) | DLC (MW) | Interruptible (MW) | Committed Purchases (MW) | Capacity Addition | | Total Resources (MW) | Reserve Margin (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Summer (MW) | Description | | |
| 2012 | 1,156 | 12 | 1,168 | 1,285 | 16 | 35 | 138 | | | 1,474 | 26.2% |
| 2013 | 1,156 | 12 | 1,168 | 1,285 | 19 | 35 | 38 | | | 1,377 | 17.9% |
| 2014 | 1,165 | 12 | 1,177 | 1,285 | 21 | 35 | 38 | | | 1,379 | 17.1% |
| 2015 | 1,242 | | 1,242 | 1,285 | 24 | 35 | 38 | 113 | Comb. Cyc. | 1,495 | 20.4% |
| 2016 | 1,238 | | 1,238 | 1,285 | 24 | 35 | 38 | | | 1,495 | 20.8% |
| 2017 | 1,230 | | 1,230 | 1,285 | 24 | 35 | 38 | | | 1,495 | 21.6% |
| 2018 | 1,224 | | 1,224 | 1,285 | 24 | 35 | 38 | | | 1,495 | 22.2% |
| 2019 | 1,217 | | 1,217 | 1,285 | 24 | 35 | 38 | | | 1,495 | 22.8% |
| 2020 | 1,223 | | 1,223 | 1,285 | 24 | 35 | 38 | | | 1,495 | 22.3% |
| 2021 | 1,228 | | 1,228 | 1,285 | 24 | 35 | 38 | | | 1,495 | 21.8% |
| 2022 | 1,233 | | 1,233 | 1,285 | 24 | 35 | 38 | | | 1,495 | 21.2% |
| 2023 | 1,238 | | 1,238 | 1,285 | 24 | 35 | 38 | | | 1,495 | 20.8% |
| 2024 | 1,243 | | 1,243 | 1,285 | 24 | 35 | 38 | | | 1,495 | 20.3% |
| 2025 | 1,249 | | 1,249 | 1,285 | 24 | 35 | 38 | | | 1,495 | 19.7% |
| 2026 | 1,255 | | 1,255 | 1,285 | 24 | 35 | 38 | | | 1,495 | 19.1% |
| 2027 | 1,262 | | 1,262 | 1,285 | 24 | 35 | 38 | | | 1,495 | 18.5% |
| 2028 | 1,269 | | 1,269 | 1,285 | 24 | 35 | 38 | | | 1,495 | 17.8% |
| 2029 | 1,277 | | 1,277 | 1,285 | 24 | 35 | 38 | | | 1,495 | 17.1% |
| 2030 | 1,285 | | 1,285 | 1,285 | 24 | 35 | 38 | | | 1,495 | 16.3% |
| 2031 | 1,294 | | 1,294 | 1,285 | 24 | 35 | 38 | | | 1,495 | 15.6% |

| **Present Value of Revenue Requirements: PVRR** | **2011 ($000)** |
|---|---|
| Planning Period (20 years) | 2,583,352 |
| End Effects (beyond 20 years) | 1,257,568 |
| Study Period (20 years and beyond) | 3,840,919 |

**Case 4: Carbon Price**

This scenario involved adding consideration of carbon pricing. CO2 price impacts were included, starting in 2016 at a level of $14/ metric ton and escalated at 6% annually for subsequent years.

The first step was to estimate the impact of CO2 price on the forecasted peak and energy. No allocation was assumed, so it was further assumed that all carbon related costs would be fully captured in retail pricing. The estimated retail price impact was approximately 15% by the end of the forecast period. Correspondingly, a certain level of demand reduction was projected to occur based on price elasticity. This was estimated to be a little more than 1% reduction of both peak and energy for the last year of the forecast period, 2031. The second step was to develop an alternate forward price curve for the wholesale market based on the CO2 price assumptions. This was developed using the Pace Global Power Markets Model discussed earlier in this chapter. The final step was to incorporate the revised peak and energy forecast, forward electric market price curve, and other pertinent CO2 related considerations into the integration model.

Similar to the base case, the carbon price scenario indicates no builds required for the entirety of the 20 year study period. However revenue requirements are significantly higher in consideration of the added cost component of carbon pricing.

## Table 10-11 Case 4: Carbon Price Resource Plan

| Year | Retail Peak Requirements (MW) | Firm Wholesale (MW) | Firm Peak Demand (MW) | Company Owned Generation (MW) | DLC (MW) | Interruptible (MW) | Committed Purchases (MW) | Capacity Addition | | Total Resources (MW) | Reserve Margin (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Summer (MW) | Description | | |
| 2012 | 1,156 | 12 | 1,168 | 1,285 | 16 | 35 | 138 | | | 1,474 | 26.2% |
| 2013 | 1,156 | 12 | 1,168 | 1,285 | 19 | 35 | 38 | | | 1,377 | 17.9% |
| 2014 | 1,165 | 12 | 1,177 | 1,285 | 21 | 35 | 38 | | | 1,379 | 17.2% |
| 2015 | 1,164 | | 1,164 | 1,285 | 24 | 35 | 38 | | | 1,382 | 18.8% |
| 2016 | 1,154 | | 1,154 | 1,285 | 24 | 35 | 38 | | | 1,382 | 19.8% |
| 2017 | 1,143 | | 1,143 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.9% |
| 2018 | 1,136 | | 1,136 | 1,285 | 24 | 35 | 38 | | | 1,382 | 21.6% |
| 2019 | 1,130 | | 1,130 | 1,285 | 24 | 35 | 38 | | | 1,382 | 22.3% |
| 2020 | 1,134 | | 1,134 | 1,285 | 24 | 35 | 38 | | | 1,382 | 21.8% |
| 2021 | 1,139 | | 1,139 | 1,285 | 24 | 35 | 38 | | | 1,382 | 21.3% |
| 2022 | 1,144 | | 1,144 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.8% |
| 2023 | 1,148 | | 1,148 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.3% |
| 2024 | 1,153 | | 1,153 | 1,285 | 24 | 35 | 38 | | | 1,382 | 19.8% |
| 2025 | 1,159 | | 1,159 | 1,285 | 24 | 35 | 38 | | | 1,382 | 19.2% |
| 2026 | 1,165 | | 1,165 | 1,285 | 24 | 35 | 38 | | | 1,382 | 18.6% |
| 2027 | 1,171 | | 1,171 | 1,285 | 24 | 35 | 38 | | | 1,382 | 18.0% |
| 2028 | 1,178 | | 1,178 | 1,285 | 24 | 35 | 38 | | | 1,382 | 17.3% |
| 2029 | 1,185 | | 1,185 | 1,285 | 24 | 35 | 38 | | | 1,382 | 16.6% |
| 2030 | 1,193 | | 1,193 | 1,285 | 24 | 35 | 38 | | | 1,382 | 15.9% |
| 2031 | 1,201 | | 1,201 | 1,285 | 24 | 35 | 38 | | | 1,382 | 15.1% |

| **Present Value of Revenue Requirements: PVRR** | **2011 ($000)** |
|---|---|
| Planning Period (20 years) | 3,778,406 |
| End Effects (beyond 20 years) | 2,979,091 |
| Study Period (20 years and beyond) | 6,757,497 |

**Case 5: High Natural Gas Prices**

For this scenario an additional 4% escalation in gas prices was applied to the first ten years of the study period. This resulted in a gas price of $9/mmBtu in 2022 and $10/mmBtu in 2031 on a 2011 constant dollar basis. Coal prices were also adjusted in this scenario as it is generally recognized that coal prices set somewhat of a floor for gas prices. Absent carbon concerns, many of the basic fundamental economic drivers will affect the price of both fuels in the same direction, albeit not necessarily equally. To recognize this linkage, coal prices were escalated at 2% for the first ten years of the study period.

The first step in developing this scenario was to model the regional electric market impacts of the higher gas price assumption using the Pace Power Markets Model. The resulting forward price curve was then incorporated into the integration model to determine the impacts to the resource plan and revenue requirements.

As in the base case, this scenario resulted in no resource additions since the projected peak and energy were unaffected by the changes in assumptions for this case. Note that the PVRR values for the high gas price case are actually slightly lower than for the base case. This is solely due to the simulated economy sales and the associated credit to revenue requirements due to these energy sales. The assumed increase in electric prices results in a larger credit to revenue requirements through increased wholesale sales opportunities and higher wholesale margins that were simulated as a credit to revenue requirements.

## Table 10-12 Case 5: High Natural Gas Price Resource Plan

| Year | Retail Peak Requirements (MW) | Firm Wholesale (MW) | Firm Peak Demand (MW) | Company Owned Generation (MW) | Existing DLC (MW) | Interruptible (MW) | Committed Purchases (MW) | Capacity Addition | | Total Resources (MW) | Reserve Margin (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Summer (MW) | Description | | |
| 2012 | 1,156 | 12 | 1,168 | 1,285 | 16 | 35 | 138 | | | 1,474 | 26.2% |
| 2013 | 1,156 | 12 | 1,168 | 1,285 | 19 | 35 | 38 | | | 1,377 | 17.9% |
| 2014 | 1,165 | 12 | 1,177 | 1,285 | 21 | 35 | 38 | | | 1,379 | 17.2% |
| 2015 | 1,164 | | 1,164 | 1,285 | 24 | 35 | 38 | | | 1,382 | 18.8% |
| 2016 | 1,160 | | 1,160 | 1,285 | 24 | 35 | 38 | | | 1,382 | 19.2% |
| 2017 | 1,151 | | 1,151 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.0% |
| 2018 | 1,145 | | 1,145 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.7% |
| 2019 | 1,139 | | 1,139 | 1,285 | 24 | 35 | 38 | | | 1,382 | 21.3% |
| 2020 | 1,144 | | 1,144 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.8% |
| 2021 | 1,149 | | 1,149 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.2% |
| 2022 | 1,155 | | 1,155 | 1,285 | 24 | 35 | 38 | | | 1,382 | 19.7% |
| 2023 | 1,159 | | 1,159 | 1,285 | 24 | 35 | 38 | | | 1,382 | 19.2% |
| 2024 | 1,165 | | 1,165 | 1,285 | 24 | 35 | 38 | | | 1,382 | 18.7% |
| 2025 | 1,171 | | 1,171 | 1,285 | 24 | 35 | 38 | | | 1,382 | 18.0% |
| 2026 | 1,177 | | 1,177 | 1,285 | 24 | 35 | 38 | | | 1,382 | 17.4% |
| 2027 | 1,184 | | 1,184 | 1,285 | 24 | 35 | 38 | | | 1,382 | 16.8% |
| 2028 | 1,191 | | 1,191 | 1,285 | 24 | 35 | 38 | | | 1,382 | 16.0% |
| 2029 | 1,199 | | 1,199 | 1,285 | 24 | 35 | 38 | | | 1,382 | 15.3% |
| 2030 | 1,207 | | 1,207 | 1,285 | 24 | 35 | 38 | | | 1,382 | 14.5% |
| 2031 | 1,215 | | 1,215 | 1,285 | 24 | 35 | 38 | | | 1,382 | 13.7% |

| **Present Value of Revenue Requirements: PVRR** | **2011 ($000)** |
|---|---|
| Planning Period (20 years) | 2,468,853 |
| End Effects (beyond 20 years) | 1,190,293 |
| Study Period (20 years and beyond) | 3,659,147 |

**Case 6: Alternate Conservation**

In this scenario it was assumed that the projected impacts due to conservation programs would remain constant after the year 2019. All other base case assumptions were unchanged. The significance of this scenario is that even with the assumption that there would be no additional energy savings above the levels mandated by the Phase II Generic DSM order; Vectren projects no resource additions until 2029. The selected alternative was a combined cycle resource in the year 2029. Years 1-20 revenue requirements are very similar to the base case because the resource addition occurs very late in the planning period.

## Table 10-13 Case 6: Alternate Conservation Resource Plan

| Year | Retail Peak Requirements (MW) | Firm Wholesale (MW) | Firm Peak Demand (MW) | Company Owned Generation (MW) | DLC (MW) | Interruptible (MW) | Committed Purchases (MW) | Capacity Addition | | Total Resources (MW) | Reserve Margin (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Summer (MW) | Description | | |
| 2012 | 1,156 | 12 | 1,168 | 1,285 | 16 | 35 | 138 | | | 1,474 | 26.2% |
| 2013 | 1,156 | 12 | 1,168 | 1,285 | 19 | 35 | 38 | | | 1,377 | 17.9% |
| 2014 | 1,165 | 12 | 1,177 | 1,285 | 21 | 35 | 38 | | | 1,379 | 17.2% |
| 2015 | 1,164 | | 1,164 | 1,285 | 24 | 35 | 38 | | | 1,382 | 18.8% |
| 2016 | 1,160 | | 1,160 | 1,285 | 24 | 35 | 38 | | | 1,382 | 19.2% |
| 2017 | 1,151 | | 1,151 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.0% |
| 2018 | 1,145 | | 1,145 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.7% |
| 2019 | 1,139 | | 1,139 | 1,285 | 24 | 35 | 38 | | | 1,382 | 21.3% |
| 2020 | 1,148 | | 1,148 | 1,285 | 24 | 35 | 38 | | | 1,382 | 20.4% |
| 2021 | 1,157 | | 1,157 | 1,285 | 24 | 35 | 38 | | | 1,382 | 19.4% |
| 2022 | 1,166 | | 1,166 | 1,285 | 24 | 35 | 38 | | | 1,382 | 18.5% |
| 2023 | 1,175 | | 1,175 | 1,285 | 24 | 35 | 38 | | | 1,382 | 17.6% |
| 2024 | 1,184 | | 1,184 | 1,285 | 24 | 35 | 38 | | | 1,382 | 16.7% |
| 2025 | 1,194 | | 1,194 | 1,285 | 24 | 35 | 38 | | | 1,382 | 15.7% |
| 2026 | 1,204 | | 1,204 | 1,285 | 24 | 35 | 38 | | | 1,382 | 14.8% |
| 2027 | 1,215 | | 1,215 | 1,285 | 24 | 35 | 38 | | | 1,382 | 13.8% |
| 2028 | 1,226 | | 1,226 | 1,285 | 24 | 35 | 38 | | | 1,382 | 12.7% |
| 2029 | 1,238 | | 1,238 | 1,285 | 24 | 35 | 38 | 113 | Comb. Cyc. | 1,495 | 20.8% |
| 2030 | 1,250 | | 1,250 | 1,285 | 24 | 35 | 38 | | | 1,495 | 19.6% |
| 2031 | 1,262 | | 1,262 | 1,285 | 24 | 35 | 38 | | | 1,495 | 18.5% |

| **Present Value of Revenue Requirements: PVRR** | **2011 ($000)** |
|---|---|
| Planning Period (20 years) | 2,323,752 |
| End Effects (beyond 20 years) | 1,167,968 |
| Study Period (20 years and beyond) | 3,491,719 |

**RESULTS OF SENSITIVITY AND RISK ANALYSIS**

The results of the sensitivity cases, as presented in Table 10-14 and discussed previously for each alternative case, show that while there are significant differences in the PVRR values, very few resource additions are required for this set of scenarios. Furthermore, a combined cycle option was selected in all cases where a resource addition was required.

As mentioned previously, the IRP analysis takes into account only a subset of total electric revenue requirements, primarily O&M and new capital related to power generation. Therefore, the percentage comparisons as presented below are material only for the costs that were included and cannot be interpreted as a comparison of the total electric revenue requirements.

## Table 10-14 Comparison of Planning Cases

| Year | Case 1 Base | | Case 2 High Growth | | Case 3 Large Load Addition | | Case 4 Carbon Price | | Case 5 High Gas Price | | Case 6 Alternate Conservation | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | MW | Description | MW | Description | MW | Description | MW | Description | MW | Description | MW | Description |
| 2012 | | | | | | | | | | | | |
| 2013 | | | | | | | | | | | | |
| 2014 | | | | | | | | | | | | |
| 2015 | | | | | 113 | Comb. Cyc. | | | | | | |
| 2016 | | | | | | | | | | | | |
| 2017 | | | | | | | | | | | | |
| 2018 | | | | | | | | | | | | |
| 2019 | | | 113 | Comb. Cyc. | | | | | | | | |
| 2020 | | | | | | | | | | | | |
| 2021 | | | | | | | | | | | | |
| 2022 | | | | | | | | | | | | |
| 2023 | | | | | | | | | | | | |
| 2024 | | | | | | | | | | | | |
| 2025 | | | | | | | | | | | | |
| 2026 | | | | | | | | | | | | |
| 2027 | | | 113 | Comb. Cyc. | | | | | | | | |
| 2028 | | | | | | | | | | | | |
| 2029 | | | | | | | | | | | 113 | Comb. Cyc. |
| 2030 | | | | | | | | | | | | |
| 2031 | | | | | | | | | | | | |
| **PVRR** | | | | | | | | | | | | |
| **Difference from Base** | | | | | | | | | | | | |
| Years 1 -20 | | | | 21% | | 14% | | 66% | | 9% | | 2% |
| Beyond Year 20 | | | | 52% | | 21% | | 186% | | 14% | | 12% |
| Total | | | | 31% | | 16% | | 104% | | 11% | | 5% |

**AVOIDED COST DISCUSSION**

As discussed previously, Vectren utilizes the Strategist software tool to perform the resource planning integration analysis and optimization. Strategist utilizes the concept of "economic carrying charge" (ECC) when evaluating new resource additions. In this context, ECC is defined as the capital charges avoided by delaying a resource one year. This approach assumes a replacement cost perspective where the value of an asset increases as a result of inflation and cost escalation. Table 10-15 Avoided Costs presents the ECC values for the Vectren IRP base case. Note that the values provided are for reference purposes only, as the base case resulted in no required resource.

Avoided operating costs can be stated in terms of marginal costs. Table 10-15 also shows the annual average marginal costs values from the Vectren base case resource plan analysis. Avoided transmission and distribution costs were considered. However, since no transmission or distribution project was required or planned due to a result of this study, transmission and distribution facilities were not explicitly listed in the resource planning analysis.

**Table 10-15 Avoided Costs**

| | Economic Carrying Charge | | Marginal Cost |
|---|---|---|---|
| | Combustion Turbine | Combined Cycle | |
| | $/kW | $/kW | $/MWh |
| 2012 | 69.02 | 92.75 | 44.23 |
| 2013 | 70.41 | 94.61 | 42.01 |
| 2014 | 71.81 | 96.50 | 44.47 |
| 2015 | 73.25 | 98.43 | 49.11 |
| 2016 | 74.72 | 100.40 | 52.21 |
| 2017 | 76.21 | 102.41 | 55.92 |
| 2018 | 77.74 | 104.46 | 60.34 |
| 2019 | 79.29 | 106.54 | 64.85 |
| 2020 | 80.88 | 108.68 | 69.55 |
| 2021 | 82.49 | 110.85 | 73.44 |
| 2022 | 84.14 | 113.07 | 77.18 |
| 2023 | 85.83 | 115.33 | 82.37 |
| 2024 | 87.54 | 117.64 | 87.04 |
| 2025 | 89.29 | 119.99 | 94.74 |
| 2026 | 91.08 | 122.39 | 99.61 |
| 2027 | 92.90 | 124.84 | 103.99 |
| 2028 | 94.76 | 127.34 | 108.07 |
| 2029 | 96.65 | 129.88 | 112.80 |
| 2030 | 98.59 | 132.48 | 118.48 |
| 2031 | 100.56 | 135.13 | 125.81 |

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# CHAPTER 11

# ACTION PLAN

## INTRODUCTION

This section presents a summary of the activities Vectren will undertake during the next 24 months to ensure that the customers' long-term energy supply needs are met. The action plan will define the immediate 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 general.

## 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. During the planning period Vectren will continue to monitor changing market factors including, but not limited to, increased environmental regulations, renewable portfolio standards, fuel price volatility, escalation of capital costs, increased emphasis on conservation measures, demand response, Smart Grid/AMI, and RTO related developments. These items will be monitored both for their potential impact on future capacity needs and their impact on the operation of existing assets.

As presented in this plan, Vectren projects to have the capacity needed to meet the needs of our customers without adding any additional generation assets. Additionally, Vectren does not currently anticipate or project the retirement of any existing generating capacity. Vectren has utilized the Pace Power Markets Model to analyze the viability of company owned generation within the regional power market under various environmental and economic scenarios. To date, the findings have indicated that the Vectren generation fleet is fully viable for the foreseeable future. However, Vectren will continue to monitor the energy needs of our customers and will consider retirement of less viable units if justified in the future.

Vectren has formed internal teams that monitor developments in the environmental legislative arena, the renewable marketplace, and power plant efficiency efforts. Although current projections do not indicate a need for additional generation in the near term, Vectren remains committed to monitoring technology progress in all related areas, including the following supply-side options:

- Regional coal based development projects
- Integrated Gasification Combine Cycle (IGCC) Technology
- Carbon capture & sequestration (CCS)
- Other clean coal development projects
- Renewable energy sources
- Simple cycle peaking turbines
- Combined cycle applications
- Distributed generation
- Merchant plant capacity purchases
- Block energy purchases
- Contractual capacity purchases
- Interruptible contract status

**DEMAND-SIDE RESOURCES**

We plan 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 DSM Plan under Cause No. 43938. The Core and Core Plus programs outlined in the plan are expected to meet the savings identified in the Phase II Order for the years 2011-2013. While our current resources are adequate to meet the needs of our customers, we believe that conservation is in our customers' best interest. Helping customers learn to conserve energy will benefit our customers through lower bills, our environment through lower emissions, and our rates through the reduced need for additional system capacity in the future.

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

**TRANSMISSION AND DISTRIBUTION**

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

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