Submitted to the Western Area Power Administration
Public Document

April 2013

BASIN ELECTRIC POWER COOPERATIVE
A Touchstone Energy® Cooperative
# Table of Contents

**Executive Summary** ................................................................. 9  
  General ................................................................. 9  
  Resource Needs Assessment .................................................. 9  

**Analytical Approach** ............................................................ 12  
  Regional Transmission Organization (RTO) .................................. 14  
  Conclusions ................................................................. 14  

**1. Introduction** ................................................................. 17  
  Study Scope ............................................................... 17  
  Report Format ............................................................. 17  

**2. Basin Electric Overview** .................................................... 18  
  History ................................................................. 18  
  About Us ............................................................... 19  
  Basin Electric Membership Classification .................................. 20  
  Service Territory And Membership ........................................ 22  

**3. Environmental Considerations** ........................................... 26  
  Overview ............................................................... 26  
  Federal Regulations ....................................................... 27  

**4. Load Forecast** ................................................................ 32  
  Load Forecast Preparation .................................................... 32  
  Basin Electric: Load Forecast Sectors ....................................... 38  
  Basin Electric: Load Forecast Results ....................................... 48  

**5. Basin Electric Supply Side Resources** ..................................... 53  
  Basin Electric Existing Resources ........................................... 55  
  Power Supply Contracts ....................................................... 61  

**6. Transmission System** .......................................................... 65  
  U.S. Transmission System ..................................................... 65  
  Regional Transmission Organization (RTO) ................................ 66  
  Existing Transmission System ................................................ 67  
  Basin Electric New Transmission Projects .................................. 69  

**7. Demand-Side Management** ................................................... 70  
  Member Load Management Program ......................................... 76  
  Basin Electric Load Management Program ................................. 85  

**8. Renewable Energy Sources** ................................................ 87  
  Existing Renewable Portfolio .................................................. 87
# Table of Contents

Renewable Energy Objectives (REO) ................................................................. 90
Basin Electric Portfolio Compared to REOs ...................................................... 103

9. Resource Needs Assessment ................................................................. 105
   Load And Capability ................................................................. 105
   Characteristics Of Energy Needs ......................................................... 109
   Summary Of Need ................................................................. 110

10. Regional Power Supply Analysis ......................................................... 111
    Midwest Reliability Organization ......................................................... 111
    Western Electricity Coordinating Council (WECC) ................................. 116

11. Analytical Approach ............................................................................ 121
    Introduction ............................................................................ 121
    Modeling Process .................................................................... 121
    Summary ............................................................................ 123

12. Resource Alternatives ........................................................................ 124
    Demand-Side Management .......................................................... 125
    Renewable Energy Sources .......................................................... 126
    Wind .................................................................................. 127
    Solar .................................................................................. 136
    Hydroelectric .................................................................... 138
    Geothermal ....................................................................... 142
    Biomass Power .................................................................. 145
    Biogas ............................................................................. 145
    Municipal Solid Waste ............................................................ 146
    Fossil Fueled Generation ........................................................... 147
    Nuclear Power .................................................................. 154
    Repowering/Uprating Of Existing Generating Units ......................... 157
    Purchased Power / Request For Proposals ....................................... 157
    Summary Of Alternatives ............................................................. 158

13. Risks And Uncertainties ..................................................................... 159
    Introduction ............................................................................ 159
    Risk Assessment ...................................................................... 159
    Key Uncertainties .................................................................... 160
    Summary ............................................................................ 162

14. Resource Portfolios ............................................................................. 163
    Introduction ............................................................................ 163
    Portfolio Development ............................................................... 163
## Table of Contents

Candidate Portfolios .......................... 164

Summary ........................................ 168

15. Conclusion .................................. 169

Introduction .................................... 169
Initial Analysis ................................. 169
Summary ......................................... 181
Conclusions And Recommendations .......... 181

Appendix A - Acronyms and Abbreviations .......... 185

Appendix B – Model Descriptions .................. 188

Appendix C – References .......................... 191
Table E-1. Basin Electric Resource Expansion ........................................... 15
Table 4-1. Historical Member Sales (Billing Load Levels) ................. 51
Table 5-1. Basin Electric Generation Resource Diversification EOY 2012 .......... 54
Table 5-2. Basin Electric Generation Carbon Dioxide (CO2) Emission Rates EOY 2012 .......... 54
Table 6-1. DC Tie Capacity, Ownership and Rights ........................... 68
Table 6-2. Basin Electric Transmission .............................................. 68
Table 7-1. Annual Dollars Spent on DSM Programs ........................ 71
Table 7-2. Annual kW Savings on DSM Programs ........................ 71
Table 7-3. Annual kWh Savings on DSM Programs ......................... 72
Table 7-4. Central Power Load Management Levels (Summer) ............ 81
Table 7-5. Central Power Load Management Levels (Winter) ............. 81
Table 7-6. East River Load Management Make-up/Magnitude ............. 82
Table 7-7. L&O Load Management .................................................. 83
Table 8-1. Colorado REO ............................................................. 91
Table 8-2. Iowa REO ................................................................ 93
Table 8-3. Minnesota REO ......................................................... 94
Table 8-4. Montana REO ............................................................ 96
Table 8-5. Nebraska REO .......................................................... 97
Table 8-6. New Mexico REO ...................................................... 98
Table 8-7. North Dakota REO ..................................................... 99
Table 8-8. South Dakota REO ...................................................... 101
Table 8-9. Wyoming REO .......................................................... 103
Table 10-1. MRO-MAPP: Planning Reserve Margins ....................... 112
Table 10-2. MRO-MAPP: Demand Outlook ................................ 113
Table 10-3. MRO-MAPP: Existing and Projected Transmission .......... 115
Table 10-4. Peak Load (MW) ....................................................... 116
Table 10-5. WECC total Installed Generation Capacity (MW) as of EOY 2011 .... 116
Table 10-6. Demand Outlook - WECC Total ................................. 118
Table 10-7. WECC-Total: Existing and Projected Transmission .......... 120
Table 12-1. Total hydropower in Basin Electric’s Service Territory States ........ 140
Table 12-2. Costs of New Resource Power Generation Plants .......... 158
Table 13-1. Matrix Form of Initial Risk Scenarios ............................ 160
Table 14-1. Portfolio A ................................................................. 165
Table 14-2. Portfolio B ................................................................. 166
Table 14-3. Portfolio C ................................................................. 167
Table 14-4. Portfolio D ................................................................. 168
Table 15-1. New Unit Capacity Factor (15yr) - Market ..................... 174
Table 15-2. New Unit Capacity Factor (15yr) – No-Market ............... 180
Table 15-3. Basin Electric Resource Expansion ............................... 182
Index of Figures

Figure E-1. West System Surplus Capacity ......................................................... 11
Figure E-2. East System Summer Surplus .......................................................... 12
Figure E-3. IS (WAUE) System Surplus Capacity .............................................. 12
Figure E-4. Consolidation of Model Results ....................................................... 14
Figure E-5. IS (WAUE) System Surplus Capacity with preferred resource expansion plan .......................................................... 17
Figure 2-1. Basin Electric Membership Service Area ........................................ 23
Figure 4-1. Unemployment Rates by County ..................................................... 36
Figure 4-2. 2010 Total Member Requirements by Sector ................................ 39
Figure 4-3. 2025 Member Requirements by Sector .......................................... 40
Figure 4-4. Williston Basin Total Load Growth ................................................. 42
Figure 4-5. Williston Basin Total Oil Area Load Growth .................................. 43
Figure 4-6. Williston Basin ............................................................................. 44
Figure 4-7. Study Area Load Forecast .............................................................. 46
Figure 4-8. Total Member Requirements by Sector .......................................... 50
Figure 4-9. Annual Demand by Power Supplier .............................................. 51
Figure 4-10. Basin Electric Annual Demand ....................................................... 52
Figure 4-11. Basin Electric Actual v. Forecast ............................................... 53
Figure 6-1. Electric System Separation ............................................................. 66
Figure 6-2. Direct Current Ties ....................................................................... 67
Figure 6-3. Control Area Map of Basin Electric’s Service Territory .................. 68
Figure 6-4. Proposed Transmission Locations ............................................... 70
Figure 6-5. IS (WAUE) System Surplus Capacity with preferred resource expansion plan .......................................................... 78
Figure 7-2. Maximum Load Management for Basin Electric Members (Total) .... 78
Figure 7-3. 2012 Total Load Management (kWh) ........................................... 78
Figure 7-4. Load Management System Percent of Utilization ....................... 79
Figure 7-5. Load Factor With and Without Load Management ......................... 79
Figure 7-6. Load Factor With and Without Load Management (Total Eastern System) .......................................................... 80
Figure 7-7. Total Days of Load Management ................................................... 80
Figure 7-8. Average Daily Hours of Load Management .................................. 81
Figure 7-9. 2012 Load Management Strategy in Place by Month ..................... 86
Figure 7-10. 2012 Total Load Management (kWh) by Month ......................... 86
Figure 7-11. Number of Days per Month Load Management Was Used ........ 87
Figure 7-12. 2012 Total Hours of Operation for Load Management by Month . 87
Figure 8-1. Wind and Recovered Energy Generation Facilities ......................... 90
Figure 8-2. REO Requirements by State (GWh) ............................................ 104
Figure 8-3. REO Requirements and Current Renewable Generation Portfolio (GWh) .......................................................... 105
Figure 9-1. Total System Surplus Capacity ....................................................... 106
Figure 9-2. Western System Surplus Capacity ............................................... 108
Figure 9-3. Eastern System Seasonal Surplus Capacity ................................ 108
<table>
<thead>
<tr>
<th>Figure Number</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>9-4</td>
<td>IS (WAUE) System Seasonal Surplus Capacity</td>
<td>109</td>
</tr>
<tr>
<td>9-5</td>
<td>Western System Surplus Capacity</td>
<td>109</td>
</tr>
<tr>
<td>9-6</td>
<td>IS (WAUE) System 2020 Energy Graph</td>
<td>110</td>
</tr>
<tr>
<td>9-7</td>
<td>West System 2020 Energy Graph</td>
<td>111</td>
</tr>
<tr>
<td>10-1</td>
<td>MRO Footprint</td>
<td>113</td>
</tr>
<tr>
<td>10-2</td>
<td>MRO-MAPP: Summer (Left) and Winter (Right) Planning Reserve Margins</td>
<td>114</td>
</tr>
<tr>
<td>10-3</td>
<td>MRO-MAPP: Total Installed Generation Capacity (MW) as of 2012</td>
<td>115</td>
</tr>
<tr>
<td>10-4</td>
<td>MRO-MAPP: Summer Net Capacity Change</td>
<td>116</td>
</tr>
<tr>
<td>10-5</td>
<td>Total Installed Generation Capacity (MW) as of 12/31/2011</td>
<td>118</td>
</tr>
<tr>
<td>10-6</td>
<td>Capacity Outlook - WECC-US</td>
<td>120</td>
</tr>
<tr>
<td>10-7</td>
<td>Capacity Outlook - WECC-CAN,</td>
<td>120</td>
</tr>
<tr>
<td>11-1</td>
<td>Consolidated Model</td>
<td>123</td>
</tr>
<tr>
<td>12-1</td>
<td>U.S. Electricity Generation by Energy Source, 2011</td>
<td>127</td>
</tr>
<tr>
<td>12-2</td>
<td>United States Wind Power Capacity (MW) (Oct 25, 2012)</td>
<td>128</td>
</tr>
<tr>
<td>12-3</td>
<td>Classes of Wind Power in the United States</td>
<td>129</td>
</tr>
<tr>
<td>12-4</td>
<td>Montana Wind Resource Map</td>
<td>130</td>
</tr>
<tr>
<td>12-5</td>
<td>North Dakota Wind Resource Map</td>
<td>131</td>
</tr>
<tr>
<td>12-6</td>
<td>South Dakota Wind Resource Map</td>
<td>132</td>
</tr>
<tr>
<td>12-7</td>
<td>Minnesota Wind Resource Map</td>
<td>133</td>
</tr>
<tr>
<td>12-8</td>
<td>Iowa Wind Resource Map</td>
<td>134</td>
</tr>
<tr>
<td>12-9</td>
<td>Nebraska Wind Resource Map</td>
<td>135</td>
</tr>
<tr>
<td>12-10</td>
<td>Solar Resources for a Photovoltaic Collector in the United States</td>
<td>137</td>
</tr>
<tr>
<td>12-11</td>
<td>Solar Resources for a Concentrating Collector in the United States</td>
<td>138</td>
</tr>
<tr>
<td>12-12</td>
<td>Hydropower and Other Renewable Electricity Generation, 1990-2011</td>
<td>140</td>
</tr>
<tr>
<td>12-13</td>
<td>Total Estimated Potential for Hydropower</td>
<td>141</td>
</tr>
<tr>
<td>12-14</td>
<td>Megawatts of Undeveloped Hydropower Potential by State</td>
<td>142</td>
</tr>
<tr>
<td>12-15</td>
<td>Primary Purpose or Benefit of U.S. Dams</td>
<td>142</td>
</tr>
<tr>
<td>12-16</td>
<td>Geothermal Temperatures for Resources in the United States</td>
<td>144</td>
</tr>
<tr>
<td>12-17</td>
<td>Simple Cycle Unit Process Flow Diagram</td>
<td>149</td>
</tr>
<tr>
<td>12-18</td>
<td>Combined Cycle Unit Process Flow Diagram</td>
<td>150</td>
</tr>
<tr>
<td>12-19</td>
<td>Pulverized Coal Unit Process Flow Diagram</td>
<td>152</td>
</tr>
<tr>
<td>12-20</td>
<td>Circulating Fluidized Bed Unit Process Flow Diagram</td>
<td>153</td>
</tr>
<tr>
<td>12-21</td>
<td>Integrated Gasification Combined Cycle Process Flow Diagram</td>
<td>154</td>
</tr>
<tr>
<td>12-22</td>
<td>Nuclear Power Plant Process Flow Diagram</td>
<td>155</td>
</tr>
<tr>
<td>12-23</td>
<td>U.S. Nuclear Power Spent Fuel Storage Installations</td>
<td>156</td>
</tr>
<tr>
<td>13-1</td>
<td>IRP Load Forecast Sensitivities</td>
<td>162</td>
</tr>
<tr>
<td>13-2</td>
<td>Natural Gas Price Sensitivity</td>
<td>162</td>
</tr>
<tr>
<td>15-1</td>
<td>Annual Revenue Requirement Difference – Base Load Forecast &amp; Market</td>
<td>171</td>
</tr>
</tbody>
</table>
Figure 15-2. Annual Revenue Requirement Difference – High Load Forecast & Market .......... 171
Figure 15-3. 15 & 20 Year PVRR Base Load Forecast & Market .................................................. 172
Figure 15-4. 15 & 20 Year PVRR High Load Forecast & Market ................................................... 172
Figure 15-5. 15 & 20 Year PVRR Difference Base Load Forecast & Market .......................... 173
Figure 15-6. 15 & 20 Year PVRR Difference High Load Forecast & Market ........................... 173
Figure 15-7. Annual Capacity Factors of Existing Coal Generation – Market ......................... 175
Figure 15-8. Annual Capacity Factors of Existing Gas Generation – Market ......................... 176
Figure 15-9. Annual Revenue Requirement Difference Base Load Forecast – No Market .............. 176
Figure 15-10. Annual Revenue Requirement Difference High Load Forecast – No Market .......... 177
Figure 15-11. 15 & 20 Year PVRR Base Load Forecast & No-Market ........................................ 177
Figure 15-12. 15 & 20 Year PVRR High Load Forecast & No-Market ........................................ 178
Figure 15-13. 15 & 20 Year PVRR Difference Base Load Forecast & No-Market ....................... 178
Figure 15-14. 15 & 20 Year PVRR Difference High Load Forecast & No-Market ....................... 179
Figure 15-15. Annual Capacity Factors of Existing Coal Generation – No Market .................... 181
Figure 15-16. Annual Capacity Factors of Existing Gas Generation – No Market .................... 182
Figure 15-17. IS (WAUE) System Surplus Capacity with preferred resource expansion plan .......... 184
Executive Summary

The 2012 Integrated Resource Plan (2012 IRP) provides an in-depth look at Basin Electric Power Cooperative’s (Basin Electric) current operating system, future load growth and the framework for future expansion, including both supply-side and demand-side resource expansion. This Plan covers the period 2013-2028, presents a long-term view of Basin Electric’s system needs, documents the analytical approach that Basin Electric uses for new resource justification and defines a five year action plan to most effectively meet growing member needs.

General

Basin Electric is a regional wholesale electric generation and transmission cooperative owned and controlled by the member cooperatives it serves. These cooperatives began operation in the 1940s and early 1950s as a result of Franklin D. Roosevelt’s 1935 executive order establishing the Rural Electrification Administration (REA). At that time only 3.5 percent of the rural people of the Great Plains received central station electricity. The establishment of the REA made it possible for cooperatives to receive assistance in electrifying rural America where there were only one or two farms per mile of line. Prior to REA, electricity was not generally available in the rural areas, as investor-owned utilities had limited incentive to serve the low-density areas.

Today Basin Electric is the largest G&T cooperative in the nation in terms of land area served. As of January 2013, Basin Electric provides wholesale, supplemental electric service for 133 member cooperatives in the states of Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota, and Wyoming. Approximately 2.8 million consumers are served by Basin Electric’s member cooperative systems.

Resource Needs Assessment

Between 2013 and 2018, Basin Electric’s system peak demand is expected to increase 665 megawatts (MW) from 3,192 MW to 3,857 MW or approximately 133 MW per year. Basin Electric’s system energy sales is expected to increased 4.3 million megawatt-hour (MWh) or from 20.8 million MWh to 25.1 million MWh, approximately 860,000 MWh per year. Basin Electric forecasts peak demand on its system to grow by 1,295 MW from 2013 through 2025 or approximately 107 MW per year. Basin Electric forecasts energy consumption on its system to grow by approximately 8 million MWh from 2013 through 2025 or approximately 670,000 MWh per year. The average expected increase in energy sales compared to the average expected increase in peak demand results in a 74 percent annual load factor for the forecasted load growth and with this magnitude of growth, Basin Electric is forecasted to grow by 38% the next 12 years. The load growth is driven mainly by commercial sector growth which includes energy-related development in the form of coal, oil and gas development and also increased loads in the residential sector mainly located on the outskirts of larger cities within the service territory.
The difference in the load forecast plus other obligations (such as non-member sales, losses, and reserves, less Basin Electric’s system-wide load management) and existing and committed generating resources along with purchases, define the load and capability of the Basin Electric system which shows the amount of surplus capacity on Basin Electric’s system. The approved load forecast only goes through 2025. To move the forecast out to 2028 (to obtain a 15 year study time period), Basin Electric calculated an Average Annual Compound Growth Rate between 2023-2025 and applied that average growth rate to each additional year after 2025.

Since Basin Electric’s member systems reside on both the eastern and western interconnection and there is limited capability in moving power between the systems, Basin Electric narrows its view on load and capability to the eastern and western systems.

Figure E-1 shows Basin Electric’s western system summer season surplus capacity. The western system doesn’t show to be deficit throughout the study period.

Basin Electric has access to direct current (DC) ties to move power between the eastern and western systems. Transfers utilizing these DC ties are not incorporated into the graph and would allow Basin Electric to move surplus west-side generation to the east, up to the capability and rights to the ties, which is currently 240 megawatts in a west-to-east direction.
Figure E-2 shows Basin Electric’s eastern system summer season surplus capacity. Basin Electric’s eastern system is shown to be deficit 28 MW in 2014. This deficit is forecasted to grow larger year over year, to 488 MW by 2017 and 1,425 MW the end of the forecast period. This graph does not include the potential transfers across available DC ties – the Rapid City DC tie or the Stegall DC tie – to transfer power in either direction.

Basin Electric’s eastern system can be broken into three areas, the Integrated System (IS), Southwest Power Pool (SPP) and Midwest Independent Transmission System Operator (MISO). Figure E-3 shows Basin Electric’s IS (WAUE) system. The IS is a transmission partnership between Western Area Power Administration (WAPA), Basin Electric and Heartland Consumer’s Power District (HCPD). This is the portion of the eastern system showing the greatest load growth over the forecasted period. This area encompasses the oil developing region known as the Williston Basin. This graph does include transfers across DC ties – the Rapid City DC tie or the Stegall DC tie – to transfer power from the west to the east. The graph shows the IS (WAUE) to be deficit.
48 MW in 2016. This deficit is forecasted to grow year over year, to 172 MW by 2017 and 905 MW by the end of the forecast period.

If the DC ties are unavailable, or there is no surplus on the west to move east, the IS (WAUE) would show a deficit of 166 MW in 2014 and this deficit would continue to grow year over year to 1,146 MW by the end of the forecast period.

The high voltage transmission system into the Williston Basin area is very close to its maximum load serving capacity, in that the load serving ability of the area may be impacted until additional transmission facilities are built to bring power into the region or Basin Electric has the ability to start generation located within the area. Currently Basin Electric is in the process of building a 345kV High Voltage Transmission line from Antelope Valley Station to Williston to Tioga, scheduled to be complete in 2016. Until that line is completed, the growing load in this area will be constrained by transmission limitations and will limit the amount of load that can be served in the area without the support of local generation.

Analytical Approach

Introduction

The main analytical objective of the Integrated Resource Plan is to determine the optimum portfolio, which is the resource portfolio with the best balance of costs and risk. The process compares the cost (as measured by the Present Value of Revenue Requirements or PVRR) and performance of the various portfolios. This section highlights the framework for accomplishing this objective.

Modeling Process

The modeling process consists of five distinct steps. A detailed explanation of these steps follows.

Step 1: Portfolio Development

Basin Electric used Ventyx’s System Optimizer modeling software to help develop resource plans and evaluate RFP responses. This software can produce 20 to 30-year horizon resource investment plans to meet long-term reliability requirements, incorporating data such as technology type, fuel, size, location, and timing of capital projects.

The first step in the portfolio development process is to input the existing Basin Electric system, power supply, transmission, load forecasts, and current and future market conditions into the System Optimizer Modeling Software. This current system configuration is considered the “Base Case.”

After the existing system data has been input into the system, new projected or purchases can be added. These can range from responses to RFPs or self-build options. The software will include these potential new resources or purchases in developing the optimal resource portfolio for Basin Electrics load obligations.

These optional new resources/purchases are all run through System Optimizer to produce a “Resource Expansion Plan”. This expansion profile details which new resource/purchase should be added and when they should come online.

Step 2: Risk Analysis

Several risk scenarios are performed to see what, if any, changes there are to what System Optimizer outputs as the best possible resource expansion plan portfolios. The risk analysis modifies outside variables and how these external changes affect the proposed resources. The “Risks and Uncertainties” chapter describes the risk scenarios in more detail.
The results of the scenario risk analyses identify and create portfolios that optimize performance according to the various risk measures. The end result of this risk analysis is a set of portfolios that are considered superior.

**Step 3: Operational Simulation**

These superior portfolios are then modeled within the Ventyx Planning and Risk Module. (The appendix contains a discussion on the Ventyx Planning and Risk model.) The model is used to simulate a 25-year study period. This results in a detailed simulation of the dispatch of the existing and new resources to meet forecasted obligations according to the constraints defined by the system topology.

Each simulation provides a breakdown of the cost to operate the Basin Electric system, including all existing and new resources, unit capacity factors, market purchases and market sales. This information provides valuable information as to the financial performance of the portfolio.

![Diagram](image)

**Step 4: Cost Analysis**

The Consolidated Model is a tool that combines the operating cost results from the Planning and Risk model with capacity purchases and the revenue required for new capital additions to provide a PVRR projection for each portfolio. This consolidation process is illustrated in Figure E-4. The net variable cost from Planning and Risk includes system costs for fuel, variable plant operations and maintenance, unit start-up, market contracts and spot market purchases and sales. The variable costs included are for new resources and include existing system operations as well. Additional costs calculated in the Consolidated Model (if applicable to the portfolio), capacity purchases and all the revenue requirement costs associated with adding incremental investment in new resources.

The Consolidated Model calculates the PVRR of the annual combined revenue requirement for the 25-year analysis period for comparison among portfolios. Using the Consolidated Model for each portfolio, the PVRR along with several other cost metrics and operational parameters are used to facilitate side-by-side comparisons.
Step 5: Selection of Preferred Portfolio

Upon evaluating all the cost metrics and considering non-modeling consideration, a Preferred Portfolio is selected.

Basin Electric’s analytical approach to portfolio analysis is comprehensive and results in the Preferred Portfolio of resource additions to meet future needs. This analytical approach is the general approach Basin Electric uses for resource expansion justification.

Regional Transmission Organization (RTO)

Basin Electric and the other partners of the Integrated System (IS) have been evaluating participation in an organized electricity market. The outcome of the study will be a recommendation to either join a regional transmission organization (RTO) or maintain transmission independence with the IS and continue operating in a “hybrid mode.”

If the outcome of the study indicates that joining is the best option, Basin Electric and the IS partners will begin the process of joining either the Midwest Independent Transmission System Operator (MISO) or the Southwest Power Pool (SPP). Currently, Basin Electric has load within both the MISO and SPP footprints and has been operating in this hybrid mode by putting some of its generation in their markets. RTO participation would require a trade-off between transmission independence and greater generation flexibility.

The study will make a quantitative comparison of how we are operating today with what could be expected by joining each RTO such as trade benefits, administrative costs, transmission expansion costs, capacity benefits, driveouts, and transmission revenue. There will also be a number of issues to study, such as potential impacts to service reliability, use of member load management systems, new interconnections, and governance and control.

The IS parties are on track to complete the study during the first half of 2013 with a recommendation to join an RTO or remain independent during the 3rd quarter of 2013.

Conclusions

The 2012 IRP is intended to provide guidance and rationale for Basin Electric’s resource development options over the next several years. This section includes the major conclusions and recommendations from the 2012 IRP.

There were commonalities within a majority of the portfolios. This included 200 MW growing to 350 MW of short-term power purchases. These purchases are for the 2013-2018 time frame. All portfolios also include two LM6000s in 2014 and two LM6000s in 2015. (See Table E-1)

The retrofit option of Wisdom Unit 1 from a coal to natural gas unit has shown to have value. This would result in 38 MW capacity for a $3 million-$4 million investment, or approximately $79-$105/kW in capital costs to maintain this resource. This retrofit option will continue to be evaluated to determine if it is beneficial to be included in the Basin Electric portfolio.

The System Optimizer software also indicated that a large natural gas combined cycle (NGCC) unit is the next chronologically and most economical option to serve the forecasted load. All proposed portfolios included the installations of new Natural Gas Combined Cycle units but they differ in the year based on how rapidly the load growth appears. The first NGCC is modeled to be installed in the 2019-2020 time frame, depending on future load forecasts and actual load growth. This would be a $700 million-$800 million (2020 dollars) capital investment. Additional future power purchases could be explored to possibly push back the timing before the resource needs to be committed to.
After the 2012 update to the Load Forecast was completed, there were other third party load forecasts completed (see Load Forecast chapter). Basin Electric did its own internal review and expects the load will be higher than shown in the 2012 Load Forecast. This increase will be one of the determining factors if and/or when a second NGCC unit would be needed.

Additional wind generation could provide a hedge against long term greenhouse gas taxes and a hedge against gas price volatility. Basin Electric will need to study the effects of joining an RTO on our current wind resources with respect the wind resource capacity credit and whether additional wind is warranted.

This proposed portfolio allows for surplus generation that Basin Electric could grow into over the next five years, should the load grow faster than expected, so development of new generation could be delayed a couple of years until 2020 and beyond along with technological breakthroughs for new generation relating to CO2. Basin Electric’s preferred resource expansion plan includes:

<table>
<thead>
<tr>
<th>Acquisition Schedule</th>
<th>Description (total MW)</th>
<th>Resource Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013 – 2017</td>
<td>50 MW Energy &amp; Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>50 MW Energy &amp; Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>25 MW MISO Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>25 MW MISO Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2014 – 2018</td>
<td>50-200 MW Energy &amp; Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2014</td>
<td>(2) 45 MW GE LM 6000 Units</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>2015</td>
<td>(2) 45 MW GE LM 6000 Units</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>Possible 2015</td>
<td>37 MW Retrofit of Wisdom Unit</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>Possible 2019-2021</td>
<td>520 MW NGCC (2x2x1)</td>
<td>Intermediate Power</td>
</tr>
<tr>
<td>Possible (forecast dependent)</td>
<td>520 MW NGCC (2x2x1)</td>
<td>Intermediate Power</td>
</tr>
</tbody>
</table>

Table E-1. Basin Electric Resource Expansion
Figure E-5 shows Basin Electric’s IS (WAUE) system summer season surplus capacity with the preferred resource expansion plan from 2013-2018.

With the development of new resources to meet Basin Electric’s preferred resource expansion plan, Basin Electric’s IS will have enough generation to meet its forecasted need until 2018. With the resource additions Basin Electric is approximately 183 MW deficit in 2019.

However, if load growth develops more quickly than anticipated, Basin Electric would be in a good position to meet that additional need. This resource development plan would also allow for a small surplus generation if the load growth materializes as is anticipated or possibly allow for reconsideration of the size/timing of the next facility if load growth does not develop as anticipated.

**Five-Year Action Plan**

On the basis of these conclusions, and in order to ensure Basin Electric has adequate resources available to meet our member’s needs the following 5-year action plan will be implemented:

1. Move ahead with the following power purchases:
   a. Short Term Purchase: 50 MW of Unit Contingent Power, 2013-2018
   b. Short Term Purchase: 50 MW On Peak 40 MW Off Peak Firm, 2014-2018
   c. Short Term Purchase: 50 MW for 2014 and 2015, 200 MW Summer of 2016-2018
   d. MISO Capacity Purchase: 25 MW of Capacity in the MISO BA
   e. MISO Capacity Purchase: 25 MW of Capacity in the MISO BA
2. Move ahead with the development of 180 MW of peaking generation, such as GE LM6000 combustion turbines within Basin Electric’s IS (WAUE) system.
3. Continue to work on developing and expanding upon energy conservation and efficiency within the Basin Electric service territory.
4. Work with the members to develop more load management within the Basin Electric system where viable.
1. Introduction

Study Scope

1. The 2012 Integrated Resource Plan (2012 IRP) provides an in depth look at Basin Electric's current operating system, future load growth and the framework for future expansion, including both supply-side and demand-side resource expansion. This Plan covers the period 2013-2028 and presents a long-term view of Basin Electric’s system needs.

2. The 2012 IRP provides the analytical approach that Basin Electric uses for new supply-side resource justification.

3. The 2012 IRP addresses the current legislation for renewable energy.

4. The 2012 IRP defines a five-year action plan to most effectively meet growing customer needs and adheres to Basin Electric’s Vision Statement and Guiding Principles.

5. The 2012 IRP is intended to meet the IRP requirements for those members who have a firm power contract with Western. Exceptions include Tri-State Generation & Transmission Association, which prepares its own IRP, and three Minnesota members whose Western allocations are assigned to Great River Energy: Minnesota Valley Electric Cooperative, Wright-Hennepin Electric Association, and Crow Wing Cooperative Power and Light Company.

Report Format

To fulfill the study’s scope, the report includes these main sections:

   Executive Summary
   1. Introduction
   2. Basin Electric Overview
   3. Environmental Considerations
   4. Load Forecast
   5. Supply Side Resources
   6. Transmission System
   7. Demand-side Management
   8. Renewable Energy Sources
   9. Resource Needs Assessment
   10. Regional Power Supply Analysis
   11. Analytical Approach
   12. Resource Alternatives
   13. Risks and Uncertainties
   14. Resource Portfolios
   15. Conclusions
   Appendices
2. Basin Electric Overview

Highlights

- Basin Electric Power Cooperative is a not-for-profit generation and transmission cooperative incorporated in 1961 to provide supplemental power to a consortium of rural electric cooperatives.
- Its diverse energy portfolio includes coal, gas, oil, nuclear, distributed, and renewable energy, including wind power.
- It is consumer owned by 133 member cooperative systems in nine states that ultimately serve 2.8 million end-use consumers (as of January 2013).
- Nineteen member systems are considered Class A members, as they have long-term wholesale power supply contracts with Basin Electric.

History

Basin Electric is a regional wholesale electric generation and transmission cooperative owned and controlled by the member cooperatives it serves. These cooperatives began operation in the 1940s and early 1950s as a result of Franklin D. Roosevelt’s 1935 executive order establishing the Rural Electrification Administration (REA). At that time only 3.5 percent of the rural people of the Great Plains received central station electricity. The establishment of the REA made it possible for cooperatives to receive assistance in electrifying rural America. Prior to REA, electricity was not generally available in the rural areas, as investor-owned utilities had limited incentive to serve the low-density areas.

Initially, the Basin Electric member cooperatives obtained nearly all of their wholesale power requirements from the dams on the Missouri River, which were constructed by the Army Corps of Engineers in accordance with Congressional authorization provided in the Flood Control Act of 1944. The primary purpose of the dams was for flood control, with other benefits consisting of hydroelectric generation, irrigation, municipal water supply, recreation and navigation. The Bureau of Reclamation was charged with marketing the electricity generated at the dams. Their marketing was done in accordance with the 1944 Flood Control Act, which stated; “Preference in the sale of power and energy shall be given to public bodies and cooperatives.” The preference customers, who consisted primarily of rural electric cooperatives, municipal electric systems, and public power districts, were assigned allocations of hydroelectric power by the Bureau of Reclamation to meet their power requirements. Since 1977, marketing of power has been performed by the Western Area Power Administration (Western), an agency of the U.S. Department of Energy (DOE).

With the assistance of the REA and the availability of the hydropower from the Missouri River dams, the electrification of the rural areas rapidly proceeded during the 1940s and 1950s. The increase in power usage by rural consumers quickly surpassed earlier projections as refrigerators, ovens, water pumps, grain dryers, feed grinders, lathes, welders, drills, heaters, radios, and lights in every room were obtained by the rural cooperative consumers.

In 1958, the Interior Department announced that the Bureau of Reclamation could not guarantee there would be sufficient generating capacity from the Missouri River dams to meet the increasing cooperative power requirements and that additional sources of power would be needed.
As a result, on May 5, 1961, 67 electric cooperatives joined together to form Basin Electric Power Cooperative, directing it to plan, design, construct, and operate the power generating and transmission facilities required to meet their increasing power needs. Basin Electric was organized on the basis of an open membership, so that all cooperatives that wished to join could share in the benefits.

**About Us**

Basin Electric is a generation and transmission (G&T) cooperative organized under the laws of the State of North Dakota. Basin Electric is composed of member cooperatives (in four classifications, described below) which, with the exception of the Class B Member, are G&T cooperatives or distribution cooperatives.

A G&T cooperative is a cooperative engaged primarily in providing wholesale electric service to its members, which generally consist of distribution cooperatives. Service by a G&T cooperative is provided from its own generating facilities or through power purchase agreements with other wholesale power suppliers. A distribution cooperative is a local membership cooperative whose members are the individual retail consumers of an electric distribution system.

Basin Electric is the largest G&T cooperative in the nation in terms of land area served. As of December 31, 2012, Basin Electric provides wholesale, supplemental electric service for 134 member cooperatives in the states of Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota, and Wyoming. Approximately 2.8 million consumers are served by Basin Electric’s member cooperative systems.

Basin Electric’s generation and transmission facilities are located in North Dakota, South Dakota, Montana, Wyoming, Nebraska, Iowa and Minnesota. The cooperative is parent company to eight subsidiaries, the largest of which is Dakota Gasification Company, which operates the Great Plains Synfuels Plant. Together, all Basin Electric and subsidiary facilities employ more than 2,050 people.
As of year-end 2012, Basin Electric held approximately 5,152 megawatts in its resource portfolio, including generation fueled by coal, gas, oil, nuclear, wind and recovered energy, and owned 2,165 miles of high-voltage transmission line.

Basin Electric's financial statements are consolidated with those of its subsidiaries. As of year-end 2012, Basin Electric’s consolidated net margin and earnings were $120.6 million.

**Basin Electric Membership Classification**

Class A members are G&T cooperatives and distribution cooperatives that have entered into long-term wholesale power contracts with Basin Electric. Ten wholesale G&T cooperatives and nine distribution cooperatives are Class A members of Basin Electric. Class A membership in Basin Electric gives such a member the right to vote at annual membership meetings.

Class B membership is available to any municipality or association of municipalities operating within an area served by a Class A Member and that is a member of and contracts for its electric power and/or energy from that Class A Member. Class B Members within any Basin Electric voting district are entitled to one vote collectively at annual membership meetings of Basin Electric. Basin Electric has one Class B member. The Class B member does not purchase power directly from Basin Electric.

Class C members consists of 112 distribution cooperatives and public power districts that are members of the Class A G&T cooperatives defined above. Class C membership in Basin Electric gives that member the right to vote at annual membership meetings of Basin Electric. Class C members do not purchase power directly from Basin Electric.

Class D membership is available to an electric cooperative that purchases power from Basin Electric on other than the full Class A member base rate. Class D Members may vote at the annual meeting, but have limited rights to vote in the election of directors. Basin Electric has one Class D member.

Basin Electric has entered into wholesale power contracts with each of its Class A members. Pursuant to the contracts with our nine Class A distribution cooperative members and six of Basin Electric’s ten Class A G&T cooperative members, Basin Electric sells and delivers to each member its capacity and energy requirements over and above specifically enumerated amounts of power and energy available to such member from other specified sources, primarily Western.

Tri-State Generation & Transmission Association, Inc. (Tri-State) has entered into a wholesale power contract that requires Tri-State to buy and receive from Basin Electric: (i) with respect to Tri-State’s Colorado and Wyoming members, 150 MW plus an additional 75 MW that began with the commercial operation of the Dry Fork Station in 2011, and (ii) all of Tri-State’s supplemental power and energy requirements (in excess of the amount supplied by Western) for Tri-State’s Nebraska members. Basin Electric has no obligations to deliver to Tri-State for the members that reside in New Mexico.

Basin Electric’s wholesale power contracts with its Class A members stipulate that capacity and energy must be furnished in accordance with the member systems’ normal annual load patterns, and that Basin Electric’s obligations are limited to the extent of which Basin Electric has capacity, energy and facilities available.
The wholesale power contracts provide that each member shall pay Basin Electric on a monthly basis for capacity and energy furnished. Member payments under the contracts constitute operating expenses of the member systems. The contracts provide that if a member fails to pay any bill within 15 days, Basin Electric may, upon 15 days’ written notice, discontinue delivery of capacity and energy. The contracts also provide that the member may not, when any notes are outstanding from Basin Electric to the Rural Utilities Service (RUS), reorganize, consolidate, merge, or sell, lease or transfer all or a substantial portion of its assets unless it has (i) either obtained the written consent of Basin Electric and the RUS, or (ii) paid a portion of the outstanding indebtedness on the notes and other commitments and obligations of Basin Electric then outstanding as determined by Basin Electric with the RUS approval. The wholesale power contracts may be amended with the approval of the RUS.

Each Class A Member is required to pay Basin Electric for capacity and energy furnished under its wholesale power contract in accordance with rates established by Basin Electric. Electric rates by Basin Electric are subject to the approval of the RUS, but are not subject to the approval of any other federal or state agency or authority.

The wholesale power contracts between Basin Electric and its members currently extend through 2050. After such date, all wholesale power contracts remain in effect until terminated by either party giving six months’ notice of its intent to terminate.

Each of Basin Electric’s Class A G&T cooperative members has entered into a wholesale power supply contract with each of its distribution members. These contracts are all supplemental requirements contracts under which each Class A Member supplies all power and energy required by its respective members, except for an arrangement with respect to Capital Electric Cooperative, Inc. (Capital Electric). Some of the Class A G&T members have extended their wholesale power contracts with distribution members to coincide with Basin Electric’s contract extension.
Service Territory And Membership

Figure 2-1. Basin Electric Membership Service Area

Basin Electric’s members as shown in the figure above by district number are listed on the next page.
Class A Members
- District 1 – East River Electric Power Cooperative (East River)
- District 2 – L&O Power Cooperative (L&O)
- District 3 – Central Power Electric Cooperative (Central Power)
- District 4 – Northwest Iowa Power Cooperative (NIPCO)
- District 5 – Tri-State G&T Association (Tri-State)
- District 6 – Central Montana Electric Power Cooperative (Central Montana)
- District 7 – Rushmore Electric Power Cooperative (Rushmore)
- District 8 – Upper Missouri G&T Electric Cooperative (Upper Missouri)
- District 9
  - Capital Electric Cooperative (Capital Electric)
  - Crow Wing Cooperative Power & Light Company (Crow Wing)
  - Grand Electric Cooperative (Grand)
  - KEM Electric Cooperative (KEM)
  - Minnesota Valley Cooperative Light & Power Association (Minnesota Valley CL&PA)
  - Minnesota Valley Electric Cooperative (Minnesota Valley EC)
  - Mor-Gran-Sou Electric Cooperative (Mor-Gran-Sou)
  - Rosebud Electric Cooperative (Rosebud)
  - Wright-Hennepin Cooperative Electric Association (Wright-Hennepin)
Class D Members
- Flathead Electric Cooperative (Flathead)
- District 10 – Powder River Energy Corporation (PRECorp)
- District 11 – Corn Belt Power Cooperative (Corn Belt)
OUR VISION

Basin Electric Power Cooperative will provide cost-effective wholesale energy along with products and services that support and unite rural America.
Guiding Principles

Basin Electric’s strategies will...

- Support Basin’s Vision
- Be related to Basin’s core business
- Define revenue potential
- Demonstrate return on investment and/or provide strategic benefit for Basin and its members
- Manage risk
- Leverage Basin’s core competencies and capabilities
- Reflect detailed analysis (Key Questions, SWOT, Issues)
- Clearly outline an action plan
- Communicate fully with all constituents
3. Environmental Considerations

**Highlights**

- Regulatory uncertainty is an ever-growing challenge to Basin Electric’s power supply planning process.
- Without a clear energy policy from Washington, D.C., the Environmental Protection Agency uses the Clean Air Act to drive more stringent regulations.
- Basin Electric and subsidiaries have been proactive in its environmental commitment and has invested $1.08 billion million in environmental control technologies through year-end 2012.
- Basin Electric monitors and provides comments on EPA rules in an attempt to influence their development in ways that minimize adverse impacts to the cooperative’s power supply system and members.

**Overview**

In Basin Electric’s opinion, regulatory policy has also become ad hoc energy policy for the United States. Clean air and clean water are important to our environment and future generations. Our region has some of the cleanest electric generation plants in the nation. Our commitment to the environment is strong. However, without a clear energy policy from Washington, DC, environmental groups have encouraged the Environmental Protection Agency (EPA) to use the Clean Air Act to drive their environmental agenda through proposed new and more stringent regulations.

The EPA is also attempting to drive energy policy by issuing new regulations that fail to take into account regional differences in power plant age, fuel type, cost, or mining and reclamation practices. This ad hoc “policy through regulation” will continue until Congress and the Administration work together to craft a workable solution.

Regulatory uncertainty is an ever-growing challenge to Basin Electric’s power supply planning process. This challenge is one the cooperative attempts to influence through lobbying and responding during the rule-making process; however, the resulting finalized rules are largely out of Basin Electric’s control.

Despite the uncertain regulatory process regarding federal environmental standards, Basin Electric presses forward with planning the appropriate power supply portfolio to meet member cooperative needs.

To that end, Basin Electric and subsidiaries have been proactive in meeting new federal emissions standards ahead of schedule. Through year-end 2012, Basin Electric has invested $1.08 billion in environmental control technology. Approximately $124.8 million was invested in the operation and maintenance of those controls in 2012.
The following projects have been undertaken at our majority-owned coal-based facilities to ensure compliance with federal standards. It is important to note that all of Basin Electric facilities are in full compliance with all federal and state environmental permits.

• Leland Olds Station: The EPA’s Regional Haze Rule requires greater emission control through the installation of Best Available Retrofit Technology, or BART. Basin Electric is installing wet limestone scrubbers in both units to control sulfur dioxide (SO2) emissions. Unit 2’s scrubber was commissioned in 2012; Unit 1’s is scheduled for commissioning in 2013. Over-fire air injection has also been incorporated into both units at the Leland Olds Station. This technology introduces air high in the boiler, which reduces combustion temperatures. Since formation of nitrogen oxides (NOx) is a function of temperature, over-fire air technology reduces these emissions.

• Laramie River Station: Over-fire air injection and low NOx burners were incorporated into all three units at the Laramie River Station between 2007 and 2009 to aid in the reduction of NOx emissions.

• Antelope Valley Station: The startup fuel is being switched from fuel oil to natural gas. Also, the capacity of the slaking system for the Antelope Valley Station’s dry scrubbers has been doubled. The slaking system uses a water-and-lime slurry to remove SO2 emissions from flue gas as it passes through the dry scrubbers. The additional capacity allows for more lime to be used in the scrubbers when higher sulfur lignite coal is burned.

• Dry Fork Station: Air-quality control system technology employed at Basin Electric’s newest coal-based power plant includes low-NOx burners, over-fire air and selective catalytic reduction (SCR) to control NOx emissions; reflux circulating fluid bed scrubber to control SO2 emissions; and post-combustion activated carbon injection to control mercury emissions.

Basin Electric is also adding activated carbon injection at the Antelope Valley Station, Laramie River Station and Leland Olds Station to control mercury emissions. Additionally, the cooperative is exploring refined coal processes at the same three facilities.

Federal Regulations

Basin Electric is monitoring the following regulations promulgated by the EPA, and where appropriate, provides comments to influence their development in ways that minimize adverse impacts to the cooperative’s power supply system and members. The following regulations are on Basin Electric’s radar and are in various stages of development.1

---


2012 Integrated Resource Plan
Air Toxics Rule for Reciprocating Internal Combustion Engines (RICE)

The EPA signed the final diesel generator air toxics rule, also known as the RICE (reciprocating internal combustion engines) rule, on January 14, 2013. This rule finalizes amendments to the national emission standards for hazardous air pollutants (NESHAP) for stationary reciprocating internal combustion engines. The final rule tightens emission controls but allows for greater demand response than the proposed version. Emergency engines may now be used to prevent electrical outages and for testing and maintenance for a total of up to 100 hours per year. In 2015, emergency engines will be required to burn ultra-low sulfur diesel (ULSD) if they operate or commit to operate for more than 15 hours each year as part of demand response. Also starting in 2015, operators of engines greater than 100 hp operating or committing to operate for more than 15 hours annually for demand response will be required to collect data for and submit an annual report. Emergency engines that commit to running less than 15 hours annually for emergency demand response are not required to meet federal control requirements or emission limits.

The 100 hours per year limit for emergency engines includes the following activities/purposes:

- Monitoring and testing;
- Emergency demand response for Energy Emergency Alert Level 2 situations;
- Responding to situations where there is at least a 5 percent or more change in voltage; and
- Operating for up to 50 hours to head off potential voltage collapse, or line overloads, that could result in local or regional power disruption.

In the event of an emergency, there is no limit for operating hours or emission limits. EPA is also allowing engines to be used for “peak shaving” for 50 hours per year at area sources until May 2014. After May 3, 2014, large diesel generators that have previously been utilized for peak shaving will no longer be available for that purpose.

Electric generating unit Boiler Maximum Achievable Control Technology (MACT) for Mercury and Air Toxics Standards (MATS)

The EPA promulgated Maximum Achievable Control Technology (MACT) standards for mercury for existing units on February 16, 2012. According to the EPA, the standards can be met by 56 percent of coal- and oil-fueled electric generating units using pollution control equipment already installed; the other 44 percent would be required to install technology that will reduce uncontrolled mercury and acid gas emissions by about 90 percent, at an annual cost of $9.6 billion.

Following promulgation of these standards, existing power plants will have three years, with a possible one-year extension, to meet the standards. Standards for new facilities are more stringent, and many, including the industry that manufactures pollution control and monitoring equipment, doubt whether compliance with the mercury portion of these standards can be measured. In response to industry petitions, EPA agreed to reconsider the mercury limit for new facilities on July 20, 2012. The agency expects the reconsideration process to take until March 2013.
Industrial Boiler Maximum Achievable Control Technology (MACT) for Mercury and Air Toxics Standards (MATS)

The EPA proposed Maximum Achievable Control Technology (MACT) standards to control emissions of toxic air pollutants from commercial and industrial boilers in June 2010. A final rule was issued February 21, 2011 under a court order by the Federal District Court for the District of Columbia.

Because of voluminous comments and new information received from industry during a public comment period, the EPA had asked the court to extend the deadline for promulgating final standards to April 2012. Having been denied that extension, the agency issued a statement saying, “The standards will be significantly different than what the EPA proposed…. The agency believes these changes still deserve further public review and comment and expects to solicit further comment through a reconsideration of the rules.” The agency initiated a reconsideration after it released the final rule, and it proposed changes to the rule December 2, 2011, stating that it expected promulgation of changes by April 30, 2012. The final rule was published in the Federal Register on January 31, 2013.

Regional Haze

The EPA’s Regional Haze Rule requires state and federal agencies to work in cooperation to improve visibility in 156 national parks and wilderness areas. States are required to develop State Implementation Plans (SIPs) to reduce pollution that negatively impacts visibility. Once a SIP has been developed, EPA reviews the plan and either approves parts or all of the plan. The EPA will then issue a Federal Implementation Plan (FIP) if necessary.

In North Dakota, the EPA has partially approved the SIP and has issued a FIP for the remaining portions. The state of North Dakota has filed an appeal on the FIP. This appeal is on-going. In Wyoming, the EPA has approved most of the SIP. However, prior to issuing a final FIP/SIP, the EPA announced additional information needed to be considered. A final FIP/SIP is due September 2013.

Cross-State Air Pollution Rule (CSAPR)

EPA promulgated the Cross-State Air Pollution Rule (CSAPR) on August 8, 2011. It was to as a replacement for the Clean Air Interstate Rule (CAIR). The original rule, designed to control emissions of air pollution that causes air quality problems in downwind states, established cap-and-trade programs for SO$_2$ and NOx emissions from coal-fueled electric power plants in 28 eastern states, at an estimated annual cost of $3.6 billion in 2015. The replacement rule also applied to 28 states; it allowed unlimited intrastate allowance trading, but limited interstate trading. Iowa was the only state in Basin Electric’s service territory to be included in the rules.

Numerous parties petitioned the D.C. Circuit for review of the Cross-State rule, and the court stayed its implementation pending the completion of the court’s proceedings. On August 21, 2012, the court vacated the standards and remanded them to the EPA. Because of the earlier CAIR requirements, which remain in effect pending their replacement and, more recently, because power companies have replaced substantial amounts of coal-fueled generation with natural gas-fueled units, electric generators have already achieved more than two-thirds of the pollution reductions necessary to comply with the 2014 standards.
Coal Combustion Residue (CCR)

To establish national standards intended to address risks associated with potential coal combustion residue mismanagement, on June 21, 2010, EPA proposed two regulatory options to manage the waste.

The first option would draw on EPA's existing authority to identify a waste as hazardous and regulate it under the waste management standards established under Subtitle C of the Resource Conservation and Recovery Act (RCRA). The second option would establish regulations applicable to CCR disposal units under RCRA's Subtitle D solid waste management requirements. Under Subtitle D, EPA does not have the authority to implement or enforce its proposed requirements. Instead, EPA would rely on states or citizen suits to enforce new standards. EPA has not projected a date to promulgate a final rule. However, on April 5, 2012, a coalition of environmental groups filed suit to compel EPA to finalize its proposed rulemaking. If CCR becomes regulated under Subtitle C, disposal costs will greatly increase for the industry and beneficial use of CCR will likely be negatively impacted.

Greenhouse Gas New Source Performance Standards (GHG – NSPS)

EPA has stated for some time that it would undertake a review of the New Source Performance Standards (NSPS) to consider greenhouse gas emission standards for electric generating units at the same time as it developed the electric utility MACT standards. In a settlement agreement with 11 states and other parties, EPA agreed to propose the NSPS for power plants by July 26, 2011, and take final action on the proposal by May 26, 2012. This schedule has encountered delays, such as proposed standards were not released until March 27, 2012, and the final standards have been delayed as well.

EPA set the proposed GHG emission standards at a level achievable by uncontrolled natural-gas fired units or by coal-fired units using carbon capture and storage (CCS) technology. Although the components of CCS technology have been demonstrated, no existing power plant combines them all in an operating unit, and the electric power industry has generally concluded that a CCS requirement would effectively prohibit the construction of new coal-fired plants, other than those already permitted. EPA maintains otherwise, but it also says that, because of low natural gas prices and abundant existing generation capacity, it believes no new coal-fired units subject to the proposed standards will be constructed between now and 2020.
Criteria Pollutants under the National Ambient Air Quality Standards (NAAQS)

NAAQS are the cornerstone of the Clean Air Act, in effect defining what EPA considers to be clean air. They do not directly limit emissions, but they set in motion a process under which “nonattainment areas” are identified and states and EPA develop plans and regulations to reduce pollution in those areas. Nonattainment designations may also trigger statutory requirements, including that new major sources offset certain emissions by reducing emissions from existing sources.

Currently, there are NAAQS for six pollutants: ozone, particulate matter, sulfur dioxide, carbon monoxide, nitrogen dioxide, and lead. The Clean Air Act requires that these standards be reviewed every five years, and all of the standards have been under court-ordered deadlines for review.

Sulfur Dioxide (SO2)
Three other NAAQS reviews (for sulfur dioxide, nitrogen dioxide, and carbon monoxide) were completed in 2010 and 2011. Of these, only the sulfur dioxide (SO2) NAAQS is considered an economically significant rule.

Ozone
On January 19, 2010, EPA proposed a revision of the National Ambient Air Quality Standard (NAAQS) for ozone. At the President’s request, on September 2, 2011, this proposal was withdrawn. The President’s statement noted that work is already under way to update a 2006 review of the science that will result in the reconsideration of the ozone standard in 2013, and stated that he did not support asking state and local governments to begin implementing a new standard that will soon be reconsidered.

Particulate Matter
The current NAAQS sets standards for both “fine” particulates (PM2.5) and larger, “coarse” particles (PM10). The PM2.5 standards affect far more people and far more counties than the standard for PM10, and both sets of standards have affected mostly industrial, urban areas. Nevertheless, agricultural interests have made substantial efforts over the last year to assail a supposed EPA plan to regulate emissions of farm dust through the PM10 NAAQS review, and have urged Congress to prevent the agency from doing so. The House passed legislation, H.R. 1633, to prevent EPA from regulating most sources of rural dust, in December 2011. On June 29, 2012, the agency proposed to strengthen the existing annual standard for PM2.5, but not to change the PM10 standard.

Under a consent agreement, EPA has agreed to sign final standards by December 14, 2012. As of January 2013, the final standards had not been issued.
4. Load Forecast

**Highlights**

- The Load Forecast is jointly prepared by Basin Electric and its G&T and distribution cooperative members. It forecasts each system’s power supply obligations to their consumer-owners.

- A need for additional generating capacity is driven by the increasing use of electricity and the resulting load growth including industrial growth, energy sector development and new rural development. Between actual 2012 and forecasted 2025, Basin Electric’s portion of this load growth is expected to grow approximately 1,493 megawatts.

- Strong growth in the Williston Basin oil sector is underpinned by historically strong residential and non-energy related commercial sectors. An independent third-party load forecast reinforced Basin Electric’s oil load projections.

**Load Forecast Preparation**

Basin Electric’s primary mission is to provide electrical power to its member-owners. In order to accomplish this objective, the cooperatives must understand how the consumers are presently using their electricity and must forecast the consumers’ future electrical requirements. The projection of future requirements serves as one of the main planning tools in determining the cooperative’s future operating strategy. Adequate resources and transmission facilities must be maintained and, where necessary, developed to deliver the required power to the members.

Two major studies are jointly prepared by the members and Basin Electric to address where the members are presently using their power (end use survey) and how much they will require in the future (load forecast). These studies are prepared in accordance with the Rural Utilities Service (RUS) general guidelines. Both the end use survey and the load forecast represent a joint effort by the distribution cooperatives, the G&T cooperatives, and Basin Electric. In order to assure all segments of the cooperative’s structure are involved, a Load Forecast Technical Committee was established. This committee consists of representatives from the three tier cooperative structure.

The Load Forecast Technical Committee approved the timetable and procedures used in preparing the 2012 Load Forecast. RUS attendance and participation at the committee meeting provided a forum for the cooperatives and RUS to exchange ideas and discuss problems.

This committee establishes the project timetable and develops the general procedures used in the two projects. RUS attendance and participation at the committee meetings provides a forum for the cooperatives and RUS to exchange ideas and improve the process. RUS requires the submittal of a board approved load forecast work plan, was the 2012 Update of the 2011 Load Forecast Work Plan as approved by the Basin Electric Board of Directors and by RUS.

End use surveys and load forecasts are prepared for all Basin Electric members, except Tri-State, which conducts their own studies. The other participating members represent cooperatives located in North Dakota, South Dakota, Minnesota, Montana, Iowa and Wyoming. Individual studies are prepared for each of the participating distribution cooperatives. The distribution cooperative studies are combined to obtain G&T studies and the G&T studies are combined to obtain a Basin Electric report.
The purpose of the load forecast is to provide the distribution cooperatives, the G&T’s, and Basin Electric with a forecast of their power supply obligations to their consumer-owners. The load forecast, which is prepared on a distribution cooperative basis, is conducted in accordance with RUS criteria. The criteria defines a load forecast as a thorough study of a cooperative’s electric loads and the factors that affect those loads in order to determine as accurately and as practical the cooperative’s future requirements for energy and capacity. The individual member’s load forecast analyzed the cooperative’s service area for historical and projected developments that have and will influence future load growth.

The 2012 Load Forecast is a weather normalized forecast. As a result, temperature extremes and extended periods of hot, cold, wet, and/or dry weather conditions can cause deviations from weather normalized demand and energy forecasts. Basin Electric has done analysis suggesting these weather deviations could amount to a 10 percent deviation in the demand forecasts and potentially lower variations in energy forecasts. Prudent planning for extreme weather events should be considered when using this forecast.

Econometric Models

The basis for econometric modeling is to identify factors in the economy that have historically affected electrical consumption. This is accomplished by using regression analysis software that establishes a mathematical relationship between the economic factors and power usage. The mathematical relationship, which is in the form of algebraic equations, represents the econometric model.

The econometric models are based on regression analysis. Regression analysis is a statistical technique used to identify a relationship between an observed event and other measured events that can be shown to be related. These are known as the dependent and the independent variables, respectively.

Independent variables must be applicable to the members’ service territory and be of importance to the local economy. This is the first step to ensure the model will accurately explain the historical trends. This gives the confidence that the same factors that have influenced previous trends will accurately reflect future expectations.

The next step to determine if the model is acceptable is the combination of the statistical results of the model. The model statistics include the R-squared, adjusted R-squared, and basic statistical information. The R-squared indicates the amount of variation of the dependent variable explained by the independent variables. To show the impact of changes in the number of independent variables used in a model, an adjusted R-squared is used; therefore, the explained variation can be compared with the same dependent variable and different numbers of independent variables.

The statistical significance of the explanatory variables used in the model is measured by a t-statistic. A t-statistic (ignoring negative signs) of at least 2.0 would be required for a 95 percent level of confidence and 1.5 for a 90 percent level of confidence, depending upon the number of observations and variables used in the model.

The Durbin-Watson test examines the equation residuals that are the differences between the fitted and the actual historical values. In a good model the residuals are randomly distributed and are of approximately constant magnitude. This indicates the model has explained all of the patterns in the data. In general, a Durbin-Watson near 2.00 indicates the absence of autocorrelation.

When residuals are not randomly distributed, a Cochrane-Orcutt transformation (AR term) can be computed to develop an equation that does have randomly distributed residuals. After the variables are transformed by adjusting the equation according to the value of the AR term, a new equation is developed.

The combination of the variables selected, model statistics, and the forecasted results all are considered together to determine the validity of the forecast.
To develop the 2012 Load Forecast, as well as the 2011 Load Forecast, a more efficient and powerful econometric software package was used. It is called MetrixND. Itron has developed, tested, and refined MetrixND for more than 10 years, providing a proven track record in the real world of energy forecasting.

MetrixND allows rapid development of accurate forecasts, releasing valuable time for making decisions and communicating results. Designed to take advantage of advanced Microsoft Windows capabilities, the intuitive user interface and drag-and-drop architecture streamline the development of forecasting variables and models. Powerful forecasting techniques, such as neural networks, multivariate regression, Autoregressive Integrated Moving Average (ARIMA) and exponential smoothing make MetrixND the only tool needed to forecast annual and monthly sales and long-term demand patterns. It also allows rapid computations of G&T totals and power supply shares after the total forecast loads have been developed for the Class C cooperative membership. The implementation of the MetrixND product allows the forecasts to be updated quickly with the most up-to-date information possible. This rapid forecast development tool allows Basin Electric and its members too quickly and accurately model changes in macroeconomic and microeconomic conditions to be reflected in the final results.

Econometric models are used for the majority of the member systems to forecast residential sales. In most instances, two residential econometric models are developed for each cooperative. The first model relates the number of historical residential consumers to factors that have been shown to influence their numbers in the past. The second model is developed for the average annual usage per residential consumer. Multiplying the forecasts of these two models developed the total residential energy forecast.

The small commercial modeling and other smaller consumer sectors are developed using econometric or trending models. In some cases they may also be judgmental forecasts or a combination of the three.

The distribution member forecasts are forecasts of annual energy requirements by category. To translate the annual energy requirements into monthly energy and demand needs, two econometric models were developed to distribute this correctly. The first model uses historical monthly energy purchases along with actual weather patterns to determine the monthly per unit purchase pattern. This purchase pattern is applied to the annual energy forecast to develop a monthly energy forecast. The second model was used to develop a monthly demand forecast where an econometric model is fitted through the historical load factors. The resultant load factor pattern is applied to the monthly energy forecast to determine the monthly demand forecast.
Explanatory Variables

The economy of the upper Midwest has fared the recent nationwide economic downturn quite well, due to the relative strength of the agricultural economy and energy exploration. Employment in the Basin Electric territory, for the most part, has not seen the major swings that other areas of the country have. Due to a diverse economy that is not centered in a singular industry these strong historical employment trends are expected to continue into the future. The following graph indicates the average unemployment rates for the last 12 months with the Basin Electric cooperative service territory overlaid, and shows the relative strength of the economy in the upper Midwest.

Figure 4-1. Unemployment Rates by County

The major sources of the explanatory variables are as follows:

Historical data for county and metropolitan statistical area (MSA) level employment, population, earnings and income is provided by the U.S. Department of Commerce Bureau of Economic Analysis (BEA) and the Census Bureau. The state and federal governments monitor the data closely as it serves as a measure of the state of the local economies.

Since the BEA implemented the North American Industrial Classification System (NAICS) to replace its previous Standard Industrial Classification System (SICS), and have only 2001-2008 data available on the new database, the entire set of historical and forecast employment data was used from Woods & Poole Economics, Inc. (W&P). W&P is an econometric forecasting firm that provides projections for employment, earnings, income, and population on a county and MSA basis. W&P used BEA data through year 2009. The exception to this is the population data, where W&P data was updated to include the 2010 data available from the US Census Bureau.
W&P is used as sources for the economic and demographic historical and forecasted county data. IHS Global is used for county, metro, state and national economic data.

Historical agricultural production and price data was obtained from the United States Department of Agriculture (USDA) and forecasted data was obtained from the Food and Agricultural Policy Research Institute (FAPRI) 2010 U.S. Baseline, as well as the USDA baseline agricultural projections. FAPRI specializes in agricultural research and forecasting.

FAPRI’s primary responsibility is to analyze for Congress the effects of proposed agricultural legislation. In addition to that primary responsibility, it provides forecasts to many other external organizations which are heavily influenced by agricultural activities. FAPRI is recognized for its expertise in agriculture analysis and forecasting.

The FAPRI baseline projection used is a result of a three-step process. It begins with macroeconomic assumptions for the U.S. developed by Global Insight (formally DRI-WEFA). The assumptions are used to develop a FAPRI preliminary baseline, which is then distributed to a group of reviewers. The reviewers critique and comment on the validity of the assumptions and the baseline projection. After receiving comments, the baseline projection is revised and finalized.

The FAPRI baseline developed includes the assumptions that government laws or policies remain unchanged, that normal weather occurs, and that random events such as droughts, diseases, and floods do not occur.

The FAPRI and the USDA historical and projected data are used for forecasting some of the residential service areas where farming and ranching have a big influence.

The majority of the members’ consumers are engaged in farming/ranching and agriculture. In most of the states the members serve, farming/ranching and agriculture is first in new wealth creation.

Since agriculture is the dominant industry in most of the areas our members serve, agricultural explanatory variables have been heavily incorporated into the econometric models. In the 2012 Load Forecast, agricultural explanatory variables included: national beef production and average prices, national corn production and average prices, national wheat production and average prices, national hog production and average prices, along with county level production of selected agricultural variables.
Other demographic and economic variables used in the 2012 Update included:

- Population
- Households
- Total Employment
- Farm Earnings
- Transfer Payments
- Total Personal Income
- Farm Employment

The forecasts for these variables, which are available on a county basis, were obtained from W&P.

Another major consideration in the load forecast econometric modeling is the competition between electricity and alternate fuels. This competition occurs in space heating, water heating, cooking, clothes drying, and grain drying. The future price of alternate fuels and how they compare with the distribution cooperative’s electricity prices affects electric consumption.

Historical alternative fuel prices are obtained on a state level from the DOE’s, State Energy Data 2009 Price, Consumption and Expenditures Data (SEDS). Basin Electric uses DOE projections of regional price forecasts to develop projections of alternative fuel prices. A further explanation can be found in the ratio variable narrative in the residential energy use per consumer section.

IHS CERA is used for natural gas and oil prices for the energy related loads. Wood Mackenzie, IHS, and DOE data are also used in the energy related sectors.

Projected electricity prices were obtained from the distribution cooperative’s financial forecast. The econometric models address the competition between electricity and alternate fuels by including a ratio computed by dividing electricity costs by the predominant alternate fuel cost in each member’s service territory. The ratio is a weighted average of alternate fuels used by the residential consumers for their primary heating system, as indicated by the cooperative’s end use survey. In order to compare the energy alternatives on a uniform basis, the alternate fuel and electricity prices are converted to real dollars on a per million British thermal unit (Btu) basis.

Weather has a significant effect on the cooperative’s energy requirements due to energy uses such as heating, grain drying, and air conditioning. In order to address these effects, the econometric models normally include either heating degree days, cooling degree days, or a combination of both. Historical heating and cooling degree day’s weather data was obtained from the National Oceanic and Atmospheric Administration (NOAA). This information is received for first-order stations, as well as all cooperative stations within the geographic region. Forecasts for weather data are assumed to be the simple average of 1996-2010 values.

### Inflation Indexes

For the 2012 Update there are three inflation indexes used to deflate historical data and the same to project future inflation. These indexes or deflators use the base 2010 equals 100. Those three indexes include:
Producer Price Index (PPI) (all commodities): This index is used to deflate crude oil prices. Real 2010 dollar crude oil prices are used as a variable in the oil related models and forecasts and also in residential models in oil producing areas. The forecast for the PPI is obtained from the Energy Information Administration’s 2011 Annual Energy Outlook (AEO).

Gross Domestic Product - Implicit Price Deflator (GDP-IPD): This index is used to deflate all agricultural monetary data from FAPRI to real 2010 dollars. The forecast is obtained from the Congressional Budget Office.

Personal Consumptions Expenditures - Implicit Price Deflator (PCE-IPD): This index is also obtained from the Congressional Budget Office. This implicit price deflator is used to deflate all non-FAPRI monetary data other than that covered by GDP-IPD and PPI to real 2010 dollars. This index is used to deflate such data as electricity prices, alternative fuels, personal income and earnings. Also, it is used to convert current prime interest rates to real prime interest rates.

In addition to the previously mentioned forecast variables, there is a tremendous array of commercial projects being monitored for their impacts on Basin Electric’s wholesale energy sales. These industries are oil, coal, coal bed methane (CBM), ethanol, and bio-diesel related. Each of these categories is discussed in detail below.

**Basin Electric: Load Forecast Sectors**

In 2010 Basin Electric’s membership sold 37% of their energy to the residential sector. The large and small commercial represented 15% and 13% of sales respectively. The other 35% of sales were spread among the remaining sectors.

![2012 Load Forecast Total Member Requirements by Sector](Image)

**Figure 4-2. 2010 Total Member Requirements by Sector**
At the end of the forecast period the growth in the oil related sector is evident. Sales to this sector are forecasted to grow from 9% of sales in 2010 to 22% of member sales in 2025. Other growth is overshadowed by the growth in this sector. In this section, we will discuss each sector in detail.

![2012 Load Forecast Total Member Requirements by Sector](image)

**Figure 4-3. 2025 Member Requirements by Sector**

**Residential Forecasts**

The load forecast continues to concentrate on the residential classification since it represents a large portion of the energy sales for Basin Electric. The residential energy forecasts are prepared by (i) forecasting the number of residential consumers; (ii) forecasting the average annual energy consumption per residential consumer; and (iii) multiplying the two forecasts together to obtain a total residential sector energy forecast. All load forecasts are net of demand side management.

The starting point in the forecasting process is to develop historical databases for each distribution cooperative. These databases contain information on the member’s monthly energy sales by consumer classification. They also provide data on the cooperative’s own use and losses, and data on their monthly demand and energy wholesale power purchases. The databases are developed annually from the information the members report to RUS on Form 7 or its equivalent. The data is updated and modified to reflect reclassifications that occasionally occur between consumer categories at the distribution cooperative. These reclassifications may result from changes in the cooperative’s rate structure or the size criteria of different rate categories.
Subsequent to the completion of the historical database development, regression analysis software is used to identify economic, demographic, and meteorological factors that have affected the member’s power requirements. These factors are called explanatory variables as they explain why the electric requirements change. While the explanatory variables are first used to develop the econometric models based on historic relationships, the variables are also used to develop the forecasts that require historical and forecasted values.

**Small Commercial**

The small commercial classification consists of commercial accounts that are generally 1,000 kVA or less. This section addresses the econometric models that forecast the small commercial consumers and energy use. The models developed took into consideration the historical factors that statistically, demographically, and economically influenced each member's number of small commercial consumers and small commercial energy use.

The make-up of the small commercial accounts is generally larger farms, small retail and wholesale establishments and other types of accounts that do not qualify for residential status. It has been observed that the small commercial sector closely mirrors the cooperatives local and regional economy. Therefore, the small commercial sector is generally modeled using the same type of variables that are used in the residential modeling.

**Large Commercial**

The large commercial classification consists of commercial accounts that are generally 1,000 kVA or larger. The types of businesses that are included in this classification are generally manufacturing, large retail, and processing facilities. These types of businesses do not necessarily mirror the local economy. The factors that drive these accounts usually have national impacts. Therefore, we use national macroeconomic variables to determine annual energy usage.

**Oil-Related Commercial Forecast**

The service territory of Basin Electric's members in Western North Dakota, Eastern Montana, and Northwest South Dakota lies within a geological formation known as the Williston Basin. In addition to the Williston Basin, Basin Electric also provides wholesale electricity to the Powder River Basin (PRB) in Northeastern Wyoming, which also produces a considerable amount of oil. Significant oil related commercial load growth is not anticipated in the PRB, therefore, the rest of this section deals with the Williston Basin.
The following graph depicts the growth of the oil related load. A tremendous amount of growth is expected in the next 15 years.

![Williston Basin Total Load Growth](image)

Figure 4-4. Williston Basin Total Load Growth

The small and large commercial loads of those members that serve in the heavy oil production areas of the basin are heavily influenced by oil and gas exploration, production and distribution activities. Direct loads, such as oil pumps, pipelines, compressors and processing plants contribute directly to the amount of commercial load. Other commercial loads, such as support services, are indirectly related to oil activity as they would not exist without the oil exploration, development and extraction activities.

For those members whose commercial loads are heavily influenced by oil activities, three tier econometric models were developed to project their commercial loads.

The econometric models generally consist of three models for each distribution cooperative. They generally address new oil production, oil prices, and number of commercial consumers, total commercial energy, and other factors. New upcoming oil projects and services are also included.

The most important variable in the determination of oil production and related loads is crude oil prices. The crude oil price used in the models is the domestic refiner’s acquisition cost of crude oil, which represents an average cost the domestic refineries pay for their crude oil.

The following graph depicts the monthly performance of the 2012 Load Forecast for the members located within the Williston Basin. Winter 2011-2012 load levels were experienced by November 2012, before the heavy onset of the heating season.
Oil loads have been somewhat cyclical in the past. This was mainly due to oil price volatility. Domestic oil prices are largely influenced by international oil markets, which are influenced by sometimes radical conditions and unstable situations. Oil prices are also significantly influenced by radical weather conditions such as the hurricanes occurring in the Gulf of Mexico. Oil prices are also influenced by national and international demand, the value of natural gas, and the value of the U.S. dollar. In recent years, developing India and China economies have been identified as very significant users of oil and hence putting upward pressure on oil prices.

Due to the magnitude of the forecasted oil loads, a decision was made to get an independent forecast of the regional loads for the Williston Basin.
Williston Basin Oil And Gas Related Independent Load Forecast

Due to the unprecedented electric growth expected in the forecast period, a decision was made to get another opinion of the growth potential for the Williston Basin. This forecast not only looked at the oil industry, but includes the electrical load with the ancillary services that go along with this type of economic activity such as housing, consumer service businesses, retail, oil and gas service companies, etc. Growth in Williston Basin communities is impacting Montana Dakota Utilities Co. (MDU) and the electric cooperatives in North Dakota, Montana, and South Dakota. The scope of this study focused on the electric utilities’ service areas, encompassing all of the Williston Basin within the United States. The following graphic details the area covered by the study.

Figure 4-6. Williston Basin

The North Dakota Transmission Authority (NDTA) was the lead agency for procuring a consultant to perform the study. Due to the impact and breadth of this growth, four parties were involved in this contract, the North Dakota Transmission Authority, Basin Electric Power Cooperative, MDU, and the oil industry through the North Dakota Petroleum Council.

Kadrmas, Lee & Jackson (KLJ) were the consultants selected to perform the forecast. The 2012 Power Forecast – Williston Basin Oil and Gas Related Electrical Load Growth Forecast (PF12) was completed in October 2012. Public results were presented to the North Dakota Industrial Commission in October. Basin Electric results were presented to the Basin Electric Power Cooperative Board of Directors in November 2012.

Independent Oil Load Forecast Model and Inputs
The consultant performed an assessment of Williston Basin oil and gas activity and developed an econometric model for the development of the oil plays within the service area. The independent input assumptions to this model included, but not be limited to, the following:

Required Infrastructure. The consultant evaluated the demand and energy needs of current and expected temporary and permanent housing, small industrial and commercial businesses required to service the oil and gas activity, and retail and lodging impacts. Consultant developed a correlation between well count and required infrastructure.

Drilling Activity. The consultant evaluated, assessed and forecasted the number of new oil wells to be drilled and completed in all of the formations in the Williston Basin for the twenty year period. The consultant determined the energy requirements of new wells in the Bakken/Three Forks, Tyler, and Spearfish formations. The consultant also determined well spacing and energy requirements per drill site to fully develop the oil play.

Power Requirements. The consultant developed qualitative oil and gas production curves and identified the pumping loads for a generic well in each of the identified formations. In addition, they will determined the total oil and gas production for the entire service area, including the number of salt water disposal injection wells needed to fully develop the oil and gas play and the associated power needs over the life cycle.

Well Life-Cycle. The consultant identified the characteristic life-cycle operating well profile for each formation and recovery technique (primary, secondary, tertiary), as well as the amount of energy and demand required for each stage of the life-cycle, the number of wells (as a percentage) that are currently using secondary and tertiary recovery methods, and the length of time such methods can be used.

Oil Price Forecasts. The consultant provided an independent high, medium and low regional oil price forecast for the 20-year forecast period, along with a break even oil price range by formation for continued development.

Pipeline and Refinery Capacity. The consultant determined the ability for the existing infrastructure to adequately move oil and gas to regional refineries and processing centers and other export market hubs, including obtaining information on new projects and identifying their potential power load requirements.

Opinions. The consultant included opinions regarding: The future of hydraulic fracturing, water availability, air quality impacts, flaring restrictions, and salt water disposal well needs as it could impact oil development; and limiting factors, including availability of drilling rigs, equipment, materials, labor, housing and service companies.
Independent Oil Load Forecast Model Results

The results of the independent assessment of the energy needs for the Williston Basin were similar to the Basin Electric forecast. Due to timing issues, some of the projects included in the PF12 were canceled or delayed. To reflect these changes, the PF12 was modified to reflect these changes. The following graph compares the forecasts. Due to the similar expectations of future load growth in the intermediate term, a decision was made to continue using 2012 Load Forecast for planning for future power supply needs.

![Study Area Load Forecast](image)

**Figure 4-7. Study Area Load Forecast**

Coal-Related Commercial Forecast

The service territory for the coal production of Basin Electric members is located in Wyoming, Montana, and Western North Dakota. Generally, this region is considered by the Energy Information Administration as Western coal production in the United States, which has grown steadily since 1970 and continues to increase. Most of the increase in output originates from mines located in Wyoming, Montana, and North Dakota. The majority of this Western coal production occurs in Wyoming and Montana in the coal fields referred to as the Powder River Basin (PRB), which includes the Northern PRB (in Montana) and the Southern PRB (in Wyoming).

According to the Energy Information Agency (EIA), Wyoming has been the largest coal producing state for many years. In 2010, Wyoming produced 442 million short tons of coal.

Econometric forecasts are developed for the coal related portion of the small and large commercial sector for the PRB in Wyoming. These forecasts are derived by the use of econometric models, as well as upcoming coal projects and services.

The coal production and energy forecasts for Western North Dakota’s coal fields are judgmental forecasts based on the estimated production of the mines located in Mercer County that supply Basin Electric's Antelope Valley Station, the Leland Olds Station, and the Dakota Gasification Company.
Coal Bed Methane Load

A major load development is also occurring in Northeastern Wyoming. This load is related to the extraction of methane gas that is contained in the sub-bituminous coal reserves located within one of Basin Electric’s member service territory.

Coal bed methane (CBM) loads were first considered in the 1998 Power Requirements Study (PRS). At that time only limited activity was taking place and the forecast was not particularly significant. By 2000, the CBM play was more active and therefore a more comprehensive forecast was conducted in-house by Basin Electric staff and was included in the January 1, 2001, Powder River Energy Corporation (PRECorp) Load Forecast.

After the 2001 PRECorp Load Forecast was completed, the Bureau of Land Management (BLM) was required to prepare an environmental impact statement (EIS), which essentially put a freeze on further drilling on federal leases until the record of decision (ROD) was finalized. It was also felt a more thorough, comprehensive, and independent forecast should be conducted. Therefore, PACE Global Energy Services (PACE) was retained after a careful review of many consultants, to develop the next PRECorp CBM forecast. PACE completed four consecutive CBM load forecasts for Basin Electric. Basin Electric also participated with other companies in a Pace Global Energy Services Wyoming Pipeline Study in 2003.

Since the CBM load had been thoroughly researched and developed by external consultants for four consecutive load forecasts, when there was not as much CBM development and little historical data, it was decided the 2009 CBM load forecast could be developed internally. Basin Electric continues to develop the CBM load forecast internally. The use of the IHS Global Database and forecasting software was necessary to create econometric models based on historical data to forecast with. This is the same software and databases that were used in the oil load forecasting process.

One of the main drivers of such a forecasting process was to develop a CBM well drilling forecast, as well as the company plans for the larger CBM loads such as water pumping and large gas compressors. Therefore, Basin Electric and PRECorp held joint conference calls with the major CBM producers to get their opinions and outlook for their companies and the industry as a whole.

After the development of 12 regional econometric equations based on PRECorp historical CBM energy data, IHS Global data, projected company drilling plans and other factors, such as water and gas production (from IHS Global), were applied to the equations to develop forecasts of existing and new CBM loads. All existing loads were included in the historical load data for model development; therefore, any projected loads will include the same ratio of smaller water gathering or treatment, as well as any field gas gathering type of loads. New large loads, such as water pipelines (>1000 HP) and large gas compressors obtained from the company plans were added judgmentally to these modeled and projected forecasts to produce a total CBM load forecast for PRECorp.

Also a great assistance for data and information was obtained from the Wyoming Oil and Gas Commission website. They track and post a variety of monthly CBM data.

Due to the increase of extensive shale drilling in the United States, higher cost coal bed methane natural gas has been relegated to a niche play, and growth is not expected in this sector.

Ethanol and Bio-Diesel Related Commercial Load

The ethanol sector loads were judgmentally projected by the distribution members that have had contact with the companies planning new plants or expansion of existing facilities. No new facilities are expected during the forecast period.

Other retail sectors that are considered when compiling the distribution forecasts follow.
Other Commercial Load Forecasts

Those commercial loads that are not oil or coal related are generally prepared using trending and sometimes judgmental forecasts. These forecasts that consider past trends and expected future developments reflect the knowledge and expertise the local cooperatives have of their service territories.

Irrigation

Irrigation sales fluctuate during the historical periods due to the weather, the state of the farm economy, and government programs. Trending models were used to forecast consumers and energy.

Other Sales

These represent sales to categories such as Public Street and highway, public authorities, and other RUS borrowers. These sales, which are usually quite small, are forecasted using trending models.

Losses

The forecasted sales for each of the previous consumer categories are on an at-load basis, meaning the sales represent the amount of power delivered to the retail consumers. One of the objectives of the load forecast process is to obtain a forecast of the distribution cooperative’s wholesale power requirements at its substations. These requirements, which correspond to their purchases, are obtained by increasing the distribution cooperative sales to reflect their own use, as well as system losses occurring on its transmission and substation facilities. Own use and losses are represented together as a percent of purchases. An estimate is derived by considering historical percentages and planned improvements to the cooperative’s distribution system that would affect the amount of future losses.
Basin Electric: Load Forecast Results

The Basin Electric load forecasts are prepared for the three levels of membership. At each level of membership, the total energy and demand needed is totaled and is required to be approved by the board of directors of that particular cooperative. Each of the three levels of load forecasts is discussed as follows:

Distribution Cooperative Load Forecasts

The previous forecasting process is employed, with the exception of Tri-State, for each Basin Electric distribution cooperative. The resultant load forecast provides the member with a detailed document outlining the derivations and assumptions utilized in the preparation of its forecast. Member involvement is an integral part of this process as the members provide retail rate projections, judgmental forecasts, and review the econometric models for forecast reasonability and explanatory variable appropriateness. The final product provides each distribution cooperative with a forecast of its annual energy sales by consumer category and monthly forecasts of its wholesale power demand and energy requirements.

G&T Cooperative Load Forecasts

The G&T’s Load Forecasts are prepared by adding together the projected purchases of their distribution members. Transmission losses and member diversity within G&T’s are also considered where applicable. The G&T Load Forecasts provide a forecast of the total sales of the G&T distribution member categorized according to consumer classifications. It also contains a forecast of the total wholesale power requirements of the G&T. These power requirements are separated into Western and Basin Electric, along with any other power suppliers’ components in accordance with the member’s contracts with the power supply organizations.

Basin Electric’s Load Forecast

Basin Electric’s Load Forecast is prepared by adding together the projected power requirements of its 19 Class A Members and the three Class D Members. The resultant forecast reflects the combined power requirements of Basin Electric member cooperatives.

These results are then translated into a model that represents the Basin Electric system on a delivery point basis. This allows the planning of infrastructure improvements to be made where needed.

The Load Forecast is then monitored on a monthly basis to ensure that the forecast is performing as expected. Also, due to the detailed information available from the large commercial sector, individual projects can be monitored to ensure that they are proceeding as planned. If the load deviates significantly from the forecast, modifications can be made for future load forecasts.

Summary of the Latest Load Forecast

Basin Electric finalized the 2012 Load Forecast which went to the Basin Electric Board of Directors in April 2012 and was sent on to the RUS for approval in April 2012. Basin Electric received approval of the 2012 Load Forecast from RUS in June 2012. The load forecast is net of any member’s load management activity, which is discussed in more detail later.
**Member Forecast**

The following graph shows actual total member sales by class such as residential, commercial, etc, from 1971 to 2010 and projected member sales by class from 2011 to 2025. The need for additional generating capacity is driven by the increasing use of electricity and the resulting load growth including industrial growth, energy sector (coal, oil, gas and ethanol bio-diesel) development and new rural development. Between actual 2010 and forecasted 2025, Basin Electric’s portion of this load growth is expected to grow 12.3 million MWh in total energy sales which is approximately 820,387 MWh per year. Strong growth in the Williston Basin Oil sector is underpinned by historically strong residential and non-energy related commercial sectors. A discussion of each sectors growth is below.

![Figure 4-8. Total Member Requirements by Sector](image-url)
Basin Electric finalized the 2012 Load Forecast which went to the Basin Electric Board of Directors in April 2012 and was sent on to the RUS for approval in April 2012. Basin Electric received approval of the 2012 Load Forecast from RUS in June 2012.

Basin Electric’s supplemental power supply responsibility to its member systems is, in most cases, computed by subtracting the members’ direct Western allocation from their total power requirements. In instances where other power supply sources are applicable, contractual arrangements are considered.

After other power suppliers obligations are considered, the remainders of the loads are Basin Electric’s responsibility. The following graph depicts the expected Annual Demands for Basin Electric.

![2012 Load Forecast Annual Demand by Power Supplier](image)

Figure 4-9. Annual Demand by Power Supplier
The following table shows Basin Electric’s member energy sales and member peak demand from 2004 through 2010. System peak demand increased on average by 186 MW annually from 2004 to 2010. System energy sales have been increasing on average by 1,158,173 MWh annually from 2004 to 2010. The total system experienced annual average percent load factors in the high 60’s during this same time period.

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak MW</th>
<th>Annual MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>2004</td>
<td>1,542</td>
<td>9,559,319</td>
</tr>
<tr>
<td>2005</td>
<td>1,709</td>
<td>10,291,152</td>
</tr>
<tr>
<td>2006</td>
<td>1,933</td>
<td>11,759,408</td>
</tr>
<tr>
<td>2007</td>
<td>2,053</td>
<td>12,912,847</td>
</tr>
<tr>
<td>2008</td>
<td>2,421</td>
<td>14,073,369</td>
</tr>
<tr>
<td>2009</td>
<td>2,672</td>
<td>14,947,627</td>
</tr>
<tr>
<td>2010</td>
<td>2,658</td>
<td>16,508,356</td>
</tr>
</tbody>
</table>

| Average Annual Increase | 186 | 1,158,173 |

Table 4-1. Historical Member Sales (Billing Load Levels)

![2012 Load Forecast BEPC Annual Demand](image)

Figure 4-10. Basin Electric Annual Demand
The following graph depicts the performance of the 2012 Load Forecast. Significant growth is expected to continue in the future. Summer 2012 actual peak load was 167 MW or 5.9% above the weather normalized forecast.

![BEPC Actual v. Forecast](image)

Figure 4-11. Basin Electric Actual v. Forecast
5. Basin Electric Supply Side Resources

Highlights

- Basin Electric has three types of generating capacity available: base load, intermediate and peaking.
- Basin Electric’s generation portfolio includes 5,149 megawatts as of year-end 2012.
- Resources include coal, wind, nuclear, hydro and natural gas fueled generation, as well as capacity in two direct-current ties in the transmission grid.
- Basin Electric also contracts sales and purchases on short- and long-term bases to meet member load obligations.

The most economical means of supplying power to a load that varies every hour on an electric power system is to have three basic types of generating capacity available to use:

a) Base load capacity,
b) Intermediate capacity, and
c) Peaking capacity.

Base load capacity runs at its full capacity continuously throughout the day and night, all year round. The output of base load type plants cannot be rapidly decreased or increased to “follow load.” Base load units are designed to optimize the balance between high capital/installation cost and low fuel cost that will give the lowest overall production cost under the assumption that the unit will be heavily loaded for most of its life. Typically, base load capacity units are operated around 80 percent capacity factor or more. Coal-fired steam–cycle power plants, nuclear plants, and hydroelectric plants are examples of base load generation capacity; however, hydro plants that follow load are not base load units.

Intermediate capacity units are designed to be “cycled” at low load periods, such as evening and weekends. The units are loaded up and down rapidly to handle the load swings of the system while the unit is online. Typically, intermediate capacity units are operated between 20 and 80 percent capacity factor range, or between base load and peaking. Technologies for intermediate load plants include oil or gas-fired steam cycle plants, combined cycle plants, some hydroelectric plants, and internal combustion engine generators.

Peaking capacity is only operated during peak load periods and during emergencies. Very low capital/installation costs are very important due to the fact these units are typically not operated very much. The production costs are relatively high due to the high cost and volatility in the price of fuel; this is why these resources are not operated too much. Types of peaking capacity power plants include combustion turbines, internal combustion engine plants, and pumped storage hydroelectric facilities. Typically, peaking capacity is operated under 20 percent capacity factor.

Employing electrical generating resources off all three types, Basin Electric has a diversified mix to meet the membership’s needs in the most economical means. Figure 5-1 details the mix of generation and explains the difference in summer and winter capacity available.
By utilizing resources of all different types, Basin Electric has managed its carbon dioxide emissions. Table 5-2 details Basin Electric’s carbon dioxide emission rates as of EOY 2012.

<table>
<thead>
<tr>
<th></th>
<th>Summer</th>
<th>Winter</th>
<th>Summer %</th>
<th>Winter %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal–based Generation</td>
<td>3,020.1</td>
<td>3,097.6</td>
<td>64.2%</td>
<td>60.2%</td>
</tr>
<tr>
<td>Hydro Generation</td>
<td>37.9</td>
<td>315.7</td>
<td>0.8%</td>
<td>6.1%</td>
</tr>
<tr>
<td>Natural Gas Generation</td>
<td>654.1</td>
<td>719.8</td>
<td>13.9%</td>
<td>14.0%</td>
</tr>
<tr>
<td>Nuclear Generation</td>
<td>75.2</td>
<td>77.2</td>
<td>1.5%</td>
<td>1.5%</td>
</tr>
<tr>
<td>Oil, Diesel and Jet Fuel Generation</td>
<td>156.9</td>
<td>181.4</td>
<td>3.3%</td>
<td>3.5%</td>
</tr>
<tr>
<td>Biogas/Flare gas Generation</td>
<td>0.690</td>
<td>0.690</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Recovered Energy Generation</td>
<td>44.0</td>
<td>44.0</td>
<td>0.9%</td>
<td>0.9%</td>
</tr>
<tr>
<td>Wind Generation</td>
<td>712.7</td>
<td>712.7</td>
<td>15.2%</td>
<td>13.8%</td>
</tr>
<tr>
<td>Total generation</td>
<td>4,701.5</td>
<td>5,149.2</td>
<td>100.0%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

By utilizing resources of all different types, Basin Electric has managed its carbon dioxide emissions. Table 5-2 details Basin Electric’s carbon dioxide emission rates as of EOY 2012.

<table>
<thead>
<tr>
<th></th>
<th>MWh</th>
<th>Ton CO2</th>
<th>T/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal Generation</td>
<td>19,047,950</td>
<td>22,647,643</td>
<td>1.19</td>
</tr>
<tr>
<td>Hydro Generation</td>
<td>2,403,826</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Nuclear Generation</td>
<td>435,533</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Wind Generation</td>
<td>2,692,177</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Peaking Generation</td>
<td>272,725</td>
<td>148,267</td>
<td>0.54</td>
</tr>
<tr>
<td>Recovered Energy Generation</td>
<td>339,716</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

Table 5-2. Basin Electric Generation Carbon Dioxide (CO2) Emission Rates EOY 2012
Basin Electric Existing Resources

1. **Leland Olds Station**: Leland Olds Unit 1 was placed in-service on January 9, 1966 and is a base-load coal fueled unit located near Stanton, ND, with a net capacity of 222 MW. Leland Olds Unit 2 is a coal fueled unit that was placed in-service on December 15, 1975 and its net capacity is rated at 445 MW. Basin Electric installed emission control equipment at the Leland Olds Station which requires an increase to the station service. This equipment was put in service after the 2012 fall outage on Unit 2 reducing the net capacity from 448 MW to 445 MW due to additional station service required. The Unit 1 emissions control equipment is scheduled to be placed into service after the spring 2013 maintenance outage. Leland Olds Station Unit 1 is the oldest base-load generating unit in Basin Electric’s fleet and its current depreciable life is listed as 2030 while Unit 2 is 2040. While this seems relatively close, Basin Electric has verified the usable life of the equipment and successfully been granted depreciable life extensions from the Rural Utility Service in the past.

2. **Laramie River Station**: Basin Electric, together with five other consumer-owned power supply entities, began construction of the three coal-fired base-load units at Laramie River Station near Wheatland in southeast Wyoming in July, 1976. LRS has three steam turbine generators supplied by General Electric Company and three steam boilers supplied by Babcock and Wilcox Company. The station’s three units became fully operational on November 1, 1982, with Unit 1 at a net capacity of 570 MW; Unit 2 at a net capacity of 570 MW; and Unit 3 at a net capacity of 570 MW. The current rating of the units is due to turbine upgrades that occurred in 2007, 2008 and 2009. Basin Electric owns 42.27 percent of the entire project, which results in 723 MW today. Basin Electric, as Project Manager and Operating Agent for the Missouri Basin Power Project, was assigned overall responsibility for the design, construction and operation of the power plant and related transmission. Units 2 and 3 of the Laramie River Station are electrically connected to the western system; Unit 1 is electrically connected to the eastern system. The amount of power Basin Electric receives from the eastern unit is 48 MW and the amount of power Basin Electric receives from the western units is 675 MW.

LRS was financed through the RUS for all but 19.8 percent. The 19.8 percent financed elsewhere pertains to pollution control bonds and Tax Benefit Transfers. Tax Benefit Transfers were a financing mechanism allowed by the IRS several years ago where an entity that was unable to use tax credits was able to sell those to an entity who could use the credits against the income taxes to be paid. Currently Laramie River Station Units 1, 2, and 3 have a depreciable life to 2032, 2033, and 2034 respectively for financial purposes.
3. **Antelope Valley Station:** Antelope Valley Station (AVS) is a two-unit lignite-fired steam electric generating station located in Mercer County, North Dakota. AVS Unit 1 went into commercial operation on July 1, 1984 and AVS Unit 2 went into commercial operation June 1, 1986. AVS is equipped with two steam turbine generators supplied by Westinghouse Electric Corporation and two steam boilers supplied by Combustion Engineering. The most recent Uniforms Rating of Generating Equipment (URGE) is 450 MW for AVS Unit 1 and 450 MW for AVS Unit 2. Antelope Valley provides approximately 135 MW of electric power for the neighboring Dakota Gasification Company’s Great Plains Synfuels Plant.

Designed to be environmentally sound, over $319 million has been invested in capital pollution control asset investments for AVS, to date. Dry scrubbers use lime to capture and remove up to 90 percent of sulfur dioxide emissions from stack gases. Fabric filter bag houses capture and remove up to 99 percent of particulate matter. Each bag house contains more than 8,000, 35-foot tall bags. AVS is a “zero-discharge” facility. Even water is used efficiently only leaving the plant site through evaporation. Basin Electric is 100 percent owner of AVS. A portion (45.3%) of AVS Unit 1 was financed through RUS while the other portion (54.7%) was financed through pollution control financing and a loan from CoBank that subsequently replaced a leveraged lease financing. AVS Unit 2 was not financed by the Rural Utilities Service (RUS) but rather by pollution control financing and a leveraged lease. For financial purposes, Antelope Valley Units 1 and 2 have a depreciable life to the years 2036 and 2038 respectively.
4. **Spirit Mound Station**: Basin Electric placed in service a two-unit, 60 MW nameplate No. 2 fuel oil combustion turbines on June 30, 1978 to provide power as a peaking resource. The combined winter rating of the two units is 120 MW and the summer rating is 100 MW. The capacity is intended to be used primarily as reserves or replacement during initial outages of base-load units or during peak load periods when existing base-load units cannot meet the demand. The site can store in containers up to 8 million gallons of fuel. When the station is in use it consumes 100 gallons of fuel per minute. The Spirit Mound Station is located near Vermillion, SD. Spirit Mound Station has a depreciable life lasting through 2025 for financial purposes.

5. **Earl F. Wisdom Unit 1**: Earl F. Wisdom Generating Station Unit 1 is a 38 MW coal based unit located near Spencer, IA. Basin Electric and Corn Belt Power Cooperative (Corn Belt), one of Basin Electric’s member cooperatives, negotiated a power supply contract which provides that Corn Belt will sell to Basin Electric Corn Belt’s 38 MW of uncommitted capacity and associated energy from the Earl F. Wisdom Unit 1. In return, Corn Belt entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to Corn Belt all of Corn Belt’s capacity and energy requirements in excess of the power and energy available to Corn Belt from the Western Area Power Administration. On February 1, 2015, Wisdom Unit 1 will be forced to stop burning coal in accordance with the Utility Mercury and Air Toxics Standards. Corn Belt retained Burns and McDonnell to perform a technology assessment for Wisdom covering five options. See index Future Power Supply Options for Wisdom Station. These options were included in Basin Electrics analysis of future resource options and will be explained in greater detail in following sections.

6. **Earl F. Wisdom Unit 2**: Basin Electric partnered with Corn Belt Power Cooperative to build the 80 MW General Electric model 7EA natural gas peaking unit near Spencer, Iowa. Although the combustion turbine uses natural gas as a primary fuel, it can also burn fuel oil as a contingency. Basin Electric owns one half of the unit, which was placed in service in April 2004. Basin Electric purchases 87.5% of Corn Belt’s owned half in response to Corn Belt entering into a Wholesale Power Contract. Therefore Basin Electric has 93.75% or 75 MW from the 80 MW combustion turbine. Wisdom Unit 2 has a depreciable life lasting to 2037.

7. **Wyoming Distributed Generation**: The Wyoming Distributed Generation consists of 9 peaking resource units located at 3 sites; Arvada, Hartzog, and Barber Creek released for commercial operation in 2002. These units are natural gas fired simple cycle turbines manufactured by Solar and consisting of a total net output of 45 MW summer and 54 MW winter. The turbines are used to hold a portion of the necessary reserves for Basin Electric’s west side electrical requirements. Financially, the Wyoming Distributed Generation turbines have a depreciable life ending in 2035.

8. **Groton Generation Station**: The Groton Generation Station near Groton, SD consists of 2 General Electric LMS100 simple cycle gas turbines which provide about 98 MW for Unit 1 and 97 MW for Unit 2, each as a peaking resource. Basin Electric commissioned Groton Unit 1 in 2006 which was the first commercial application of General Electric’s LMS100. Unit 2 began providing power as a peaking resource in 2008. The two gas turbines get their natural gas from the Northern Border Pipeline. Through Dakota Gasification Company’s Great Plains Synfuels Plant, the units have firm gas transport which gives them fuel security without requiring a backup or alternative fuel supply. A unique aspect of the station is the ability that Unit 1 has to disconnect the generator from the gas turbine through a synchronous clutch allowing the generator rotor to spin independent from the gas turbine to provide voltage stability to the electrical grid.
9. Culbertson Generation Station: The Culbertson Generation Station, near Culbertson, MT is a single LMS 100 simple cycle gas turbine providing 91 MW (winter rating) of peaking power. Operating since 2010, Culbertson Unit 1 is Basin Electric’s first resource located in Montana. Similar to the Groton Generation Station, Culbertson Unit 1 has no need for an alternative fuel source as it receives its fuel from the Northern Border Pipeline and has firm gas transport via the Great Plains Synfuels Plant.

10. Deer Creek Station: The Deer Creek Station combined-cycle natural gas facility is a 300 MW intermediate resource located near Elkton, SD. This is the newest unit in Basin Electric’s fleet achieving commercial operation in August of 2012. The combined-cycle plant electrical generators are powered by a General Electric model 7FA gas turbine and an Alstom steam turbine. The natural gas fuel used by the station comes from the Northern Border Pipeline where firm gas transport is possible through Dakota Gasification Company’s Great Plains Synfuels Plant. The exhaust gases from the gas turbine pass through a heat recovery steam generator where they boil water into steam and provide steam to the Alstom steam turbine. When the combustion turbine has reached full load, duct burners can burn additional fuel within the heat recovery steam generator to produce more steam and reach the full station output ability of 300 MW.

11. Dry Fork Station: The Dry Fork Station is a 405 MW coal fired power plant located 10 miles north of Gillette, Wyoming which was released for commercial operation in 2011. Basin Electric owns 92.9% of the station or 376 MW of the base-load resource. The station utilizes Powder River Basin coal from the next door Dry Fork Mine to ensure an uninterrupted, stable priced fuel supply. The latest generation of pollution control technology was implemented resulting in very low emission rates.
12. **Pioneer Generation Station:** Basin Electric is finishing construction of Pioneer Generation Station unit 1 which consists of a 45MW General Electric LM6000 natural gas fired simple cycle combustion turbine located near Williston, North Dakota. This peaking resource fueled by natural gas from the Northern Border Pipeline is projected to be in-service the spring of 2013. Unit 1 has a synchronous clutch located between the combustion turbine and generator allowing the generator rotor to rotate independent of the turbine to provide voltage stability to the electrical grid.

13. **Lonesome Creek Station:** The Lonesome Creek Station Unit 1 is under construction of unit 1 which is a 45 MW GE LM6000 natural gas fired combustion turbine located near Watford City, North Dakota. This peaking resource fueled by natural gas from the Northern Border Pipeline is projected to be placed in service during the spring of 2013. Unit 1 will also have a synchronous clutch located between the combustion turbine and the generator allowing the generator rotor to spin independent of the turbine providing voltage stability to the electrical grid.

14. **Chamberlain Wind Project:** Basin Electric, in partnership with East River Power Cooperative, has constructed a wind energy project near Chamberlain, South Dakota. The 2.6 megawatt capacity project was placed into commercial service in January 2002. Chamberlain Wind Project is owned by Basin Electric Power Cooperative and the energy is delivered to members as part of Basin Electric’s overall power supply. The Chamberlain wind turbines have a depreciable life lasting to 2022 for financial purposes.

15. **Minot Wind Project:** Basin Electric, in partnership with Central Power Electric Cooperative, has constructed a wind energy project 14 miles south of Minot, North Dakota. The 2.6 megawatt capacity wind project was placed into commercial service in February 2002. Three additional turbines were added in December 2009 for a total output of 7.1 megawatts. The facility is owned by Basin Electric’s subsidiary PrairieWinds ND 1 Inc. and energy is purchased by Basin Electric and delivered to members through a long term power purchase agreement with PrairieWinds ND1 Inc. The Minot Wind turbines have a 20 year depreciable life showing their financial end of life in 2023 and 2029 per their installation dates.

16. **PrairieWinds 1:** Basin Electric, in partnership with PrairieWinds ND 1 Inc., has constructed a wind energy project of 77 turbines near Minot, North Dakota which is owned by Basin Electric’s subsidiary PrairieWinds ND 1 Inc. Basin Electric purchases the output of the 115.5 MW capacity wind project via a long term power purchase agreement Prairie Winds 1 was placed into commercial service in December, 2009. With a 20 year depreciable life allowed, the wind turbines are shown with an end of service to 2029 from a financial perspective.
17. **Crow Lake Wind Project**: Basin Electric, in partnership with Prairie Winds SD1 Inc., South Dakota Wind Partners and Mitchell Technical Institute, has constructed a wind energy project of 108 turbines near White Lake, South Dakota. The 162 MW capacity wind project was placed into commercial service in 2011. Basin Electric’s subsidiary, Prairie Winds SD1, owns 100 turbines or 150 MW. Basin Electric has a purchase power contract for the output from all 108 turbines or 162 MW from the Crow Lake Wind Project. The 20 year depreciable life is shown from 2011 to 2031.
Power Supply Contracts

1. **George Neal Station Unit 4:** Unit 4 is a 644 MW coal-fired electric generation facility located south of Sioux City, Iowa that has been providing base-load power since 1979. Basin Electric and Northwest Iowa Power Cooperative (NIPCO), one of Basin Electric’s member cooperatives, negotiated a power supply contract which provides that NIPCO will sell to Basin Electric NIPCO’s 31 MW of uncommitted capacity and associated energy from Unit 4 of the George Neal Generating Station. In return NIPCO entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to NIPCO all of NIPCO’s capacity and energy requirements in excess of the power and energy available to NIPCO from the Western Area Power Administration.

Basin Electric and Corn Belt Power Cooperative (Corn Belt), one of Basin Electric’s member cooperatives, negotiated a power supply contract which provides that Corn Belt will sell to Basin Electric Corn Belt’s 73 MW of uncommitted capacity and associated energy from Unit 4 of the George Neal Station. In return, Corn Belt entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to Corn Belt all of Corn Belt’s capacity and energy requirements in excess of the power and energy available to Corn Belt from the Western Area Power Administration. Unit 4 is connected to MidAmerican Energy Company (MEC) where NIPCO and Corn Belt have rights to bring this energy to the IS or Midwest Independent System Operator via MEC.

2. **Walter Scott 3 and 4:** The Walter Scott Energy Center located near Council Bluffs, IA provides base-load power through the 690 MW Unit 3 and the 790 MW Unit 4. While both of the units are coal-based, Unit 3 has been operating since 1979 and Unit 4 began operation in 2007.

Basin Electric and Corn Belt Power Cooperative (Corn Belt), one of Basin Electric’s member cooperatives, negotiated a power supply contract which provides that Corn Belt will sell to Basin Electric Corn Belt’s 26 MW of uncommitted capacity and associated energy from Unit 3 and 45 MW of uncommitted capacity and associated energy from Unit 4 of the Walter Scott Energy Center. In return, Corn Belt entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to Corn Belt all of Corn Belt’s capacity and energy requirements in excess of the power and energy available to Corn Belt from the Western Area Power Administration. Walter Scott 3 and 4 are connected to MidAmerican Energy Company (MEC) where Corn Belt has rights to bring this energy into the IS or MISO via MEC.

3. **Duane Arnold Energy Center:** The Duane Arnold Energy Center consists of a 615 MW nuclear powered unit located near Cedar Rapids, IA, that has been providing base-load power since 1975. Basin Electric and Corn Belt Power Cooperative (Corn Belt), one of Basin Electric’s member cooperatives, negotiated with a power supply contract. The contract provides that Basin Electric will purchase Corn Belt’s 10% share, which is about 62 MW of uncommitted capacity and associated energy from the Duane Arnold Energy Center. In return, Corn Belt entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to Corn Belt all of Corn Belt’s capacity and energy requirements in excess of the power and energy available to Corn Belt from the Western Area Power Administration. Interconnected to the Alliant West (ALTW) system, Corn Belt has the rights to bring the power to Corn Belt’s transmission system which is within the WAUE balancing area.

4. **Western Area Power Administration Peaking Capacity:** In 1968 Basin Electric executed a long-term contract with the federal government for USBR (now WAPA) hydro peaking from the dams in the Missouri River Basin. This contract currently provides Basin Electric with 268.2 MW of winter peaking capacity at load and for Basin Electric to return a like amount of energy to Western during off-peak periods. This contract has been extended through the year 2039.
5. **Western Native American Purchase:** Basin Electric receives a Native American Allocation of 37 MW in the winter and 38 MW in the summer season. This allocation is a result of congressional action that made federal power available to the Native Americans.

6. **Madison Diesel:** Basin Electric purchases capacity and energy output (when scheduled) from diesel generators owned by the City of Madison, South Dakota. The purchase is for five, 2 MW Caterpillar diesel generators that went commercial in April 2005. The agreement goes through December 2025.

7. **Northern Border Waste Heat:** Basin Electric purchases the energy from eight Recovered Energy Generation (REG) power plants fueled by hot exhaust off the Northern Border Pipeline compression stations with three units in North Dakota, three units in South Dakota, and one in both Montana and Minnesota for a total generating capacity of 44 MW; 22 MW went commercial in 2006, 22 MW went commercial by the end of 2009. The generation is environmentally benign, using virtually no additional fuel and producing virtually zero emissions. Basin Electric has signed a 25-year contract with the developer for the output of the REGs.

8. **NextEra Wind:** Basin Electric purchases all of the energy from six wind projects owned and operated by NextEra. The wind projects include:
   a. **Edgeley Wind Project:** 40 MW wind facility near Edgeley, North Dakota. Wind Facility went commercial in 2003. Basin Electric has entered into a 25 year PPA for the power from this facility.
   b. **Hyde County Wind Project:** 40 MW wind facility near Highmore, South Dakota. Wind Facility went commercial in 2003. Basin Electric has entered into a 25 year PPA for the power from this facility.
   c. **Wilton 1 Wind Projects:** 49.5 MW wind facility near Wilton, North Dakota. The Wilton 1 Wind Project went commercial in early 2006. Basin Electric has entered into a 25-year PPA for power from this facility.
   d. **Wilton 2 Wind Projects:** 49.5 MW wind facility near Wilton, North Dakota. Wilton 2 Wind Project went commercial November 2009. Basin Electric has entered into a 25-year PPA for the power from this facility.
   e. **Day County Wind Project:** 99 MW wind facility near Aberdeen, South Dakota. Wind Facility went commercial in 2010. Basin Electric has entered into a 30 year PPA for the power from this facility.
   f. **Baldwin Wind Project:** 100 MW wind facility near Baldwin, North Dakota. Wind Facility went commercial in 2011. Basin Electric has entered into a 30 year PPA for the power from this facility.

9. **Tri-State Sheridan-Johnson:** Basin Electric has a power purchase arrangement with Tri-State to serve a portion of its member obligations in northeast Wyoming’s Sheridan and Johnson counties. Under this agreement Basin Electric receives 11 MW to 13 MW varying on a monthly basis. The agreement extends through December 31, 2025, and may be extended for up to two successive terms of five consecutive years.
10. **Tri-State Nebraska Allocation:** The Tri-State Nebraska Allocation is a power allocation from the Western Area Power Administration – Rocky Mountain Region. This allocation provides for fixed monthly capacity and energy deliveries that correspond to the monthly resource capability of the Federal hydro systems. The load for Tri-State Nebraska members is split between the east and the west electrical interconnections. For planning purposes Basin Electric and Western have agreed to split the amount of Contracted Rates of Delivery (CROD) between the east and west electrical interconnections. As a result, the planned power program shows the minimum Tri-State Nebraska CROD delivered west of the electrical separation, and the balance between the maximum CROD as delivered east of the electrical separation. The CROD under the federal power deliveries for Tri-State Nebraska reaches the maximum CROD of 83 MW for the summer season in July. However, as a system, Basin Electric’s maximum west side member load obligations may occur in either July or August.

For prudent planning, Basin Electric assumes the maximum member load as indicated by the Load Forecast as occurring in July, but uses the August CROD of 73 MW. The winter CROD at the point of delivery is 49 MW. The Basin Electric west side planning numbers are a summer value of 27 MW and a winter value of 10 MW. Basin Electric uses these allocations to the extent possible, as peaking resources due to the limited amount of energy that can be scheduled to maximize the value of these allocations. Effective October 1, 2014 the seasonal energy and CROD for future winter and summer seasons may be reduced by up to 1 percent from the then current seasonal energy and CROD.

11. **PRECorp Allocation:** The PRECorp Allocation is a power allocation from the Western Area Power Administration – Rocky Mountain Region (RMR). The RMR allocation provides for fixed monthly capacity and energy deliveries that correspond to the monthly resource capability of the Federal hydro systems. The PRECorp Allocation uses 24 MW in the winter season and 21 MW in the summer season for planning purposes. Basin Electric uses these allocations to the extent possible, as peaking resources due to the limited amount of energy that can be scheduled to maximize the value of these allocations. Effective October 1, 2014 the seasonal energy and CROD for future winter and summer seasons may be reduced by up to 1 percent from the then current seasonal energy and CROD.

12. **Municipal Energy Agency of Nebraska:** Basin Electric has signed a contract with Municipal Energy Agency of Nebraska (MEAN) to purchase 30 MW of Mid-Continent Energy Marketers Association Schedule Q, Mid-Continent Area Power Pool Product K: System Participation Power Interchange Service. The purchase began May 1, 2007 and the contract goes through April 30, 2014. All capacity and energy from MEAN is deemed delivered at the Cooper Nuclear Station bus.

13. **Webster City CT:** Basin Electric has signed a contract with Corn Belt Power Cooperative, a member of Basin Electric, to purchase the output of the Webster City CT peaking plant (20.8 MW) that is fueled by fuel oil. The purchase begins September 1, 2009 and continues through the term of the Wholesale Power Contract between Basin Electric and Corn Belt.
14. **Estherville Diesel Generators**: Basin Electric has signed a contract with Corn Belt Power Cooperative, a member of Basin Electric, to purchase the output from the City of Estherville’s six diesel generators (13.0 MW). The purchase begins September 1, 2009 and will remain in effect so long as Corn Belt continues to purchase the output of the diesel generators pursuant to the Wholesale Agreement between Iowa Lakes Electric Cooperative and the City of Estherville, provided that this will not extend through the term of the Wholesale Power Contract between Basin Electric and Corn Belt.

15. **Pocahontas Diesel Generators**: Basin Electric has signed a contract with Corn Belt Power Cooperative, a member of Basin Electric, to purchase the output from the City of Pocahontas’s two diesel generators (3.8 MW). The purchase begins September 1, 2009 and will remain in effect so long as Corn Belt continues to purchase the output of the diesel generators pursuant to the Wholesale Agreement between Iowa Lakes Electric Cooperative and the City of Pocahontas, Iowa, provided that this will not extend through the term of the Wholesale Power Contract between Basin Electric and Corn Belt.

16. **Spencer Combustion Turbine (CT) Generator**: Basin Electric has signed a contract with Corn Belt Power Cooperative, a member of Basin Electric, to purchase 10 MW from the City of Spencer’s 20 MW combustion turbine. The purchase begins September 1, 2009 and will remain in effect so long as Corn Belt continues to purchase the output of the combustion turbine pursuant to Corn Belt being a party to the Spencer Power Purchase Agreement with Spencer Municipal Utilities of the City of Spencer, Iowa, provided that this will not extend through the term of the Wholesale Power Contract between Basin Electric and Corn Belt.

17. **Corn Belt Wind**: Basin Electric has signed a contract with Corn Belt Power Cooperative, a member of Basin Electric, to purchase the output of Corn Belt’s wind projects. The purchase begins September 1, 2009 and continues through the term of the Wholesale Power Contract between Basin Electric and Corn Belt. The wind projects include: 7.3 MW from the Hancock County Wind Project; 16.8 MW from the Crosswind Generators; 10.5 MW from the Lakota Wind Project; and 10.5 MW from the Superior Wind Project.

18. **Minnesota Power Purchase**: Basin Electric has signed a contract with Minnesota Power to purchase 100 MW from the Clay Boswell Energy Center. This facility is a four unit coal-fired power station with a nameplate capacity of 1,025 MW. It is owned and operated by ALLETE and is located near Cohasset, MN. The PPA ends on April 30, 2020.
6. Transmission System

Highlights

- Basin Electric is one of the few utilities that supply electricity on both sides of the national electric system. Transmission constraints are associated with serving territory on both sides.
- Basin Electric owns 2,143 miles of high-voltage transmission line.
- Basin Electric is planning a 190-mile 345-kilovolt transmission line and a 15-mile 115-kilovolt line, both in western North Dakota. The projects will increase the cooperative’s load-serving capability in the area.
- Basin Electric and the other partners of the Integrated System have been meeting to evaluate participation in an organized electricity market.

U.S. Transmission System

Figure 6-1. Electric System Separation
Figure 6-1 shows Basin Electric’s service territory. Basin Electric’s service territory includes areas located on both the eastern system and western system. Basin Electric is one of the few utilities that supply electricity on both sides of the national electric system. As a result, there are constraints associated with transfers between Basin Electric’s east and west service territories.

Direct current (DC) ties, also called interties, bridge the national electric system separation by taking alternating current (AC) electricity on one side, converting it to direct current, and then converting it back to alternating current so that it is in sync with the alternating current of the other side of the national electric system separation (see Figure 6-2).

Figure 6-2. Direct Current Ties

Every generator east of the electrical transmission separation drives and affects that system and every generator west of the separation drives and affects that system. Electricity is generally transmitted at alternating current of 60 Hertz (cycles) per second. The lower load density in the central part of the country as compared to the east and west coast areas of the United States has resulted in the development of lower amounts of generation and high voltage transmission facilities. The slightest upset such as an electric generating unit abruptly separating from the system changes the standard 60 Hertz per second so the two systems are not synchronized and therefore cannot be connected directly. Connecting the systems would cause several system disconnects because protective devices for the facilities would activate.

Regional Transmission Organization (RTO)

Basin Electric and the other partners of the Integrated System (IS) have been meeting to evaluate participation in an organized electricity market. The outcome of the study will be to either join a regional transmission organization (RTO) or maintain transmission independence with the IS and continue operating in a “hybrid mode.”

If the outcome of the study indicates that joining is the best option, Basin Electric and the IS partners will begin the process of joining either the Midwest Independent Transmission System Operator (MISO) or the Southwest Power Pool (SPP). Currently, Basin Electric has load within both the MISO and SPP footprints and has been operating in this hybrid mode by putting some of its generation in these markets. RTO participation would require a trade-off between transmission independence and greater generation flexibility.
The study will make a quantitative comparison of how we are operating today with what could be expected by joining each RTO such as trade benefits, administrative costs, transmission expansion costs, capacity benefits, and transmission revenue. There will also be a number of qualitative issues to study, such as potential impacts to service reliability, use of member load management systems, new interconnections, and governance and control.

The IS parties are on track to complete the study during the first half of 2013 with a recommendation to join an RT or remain independent during the 3rd quarter of 2013.

**Existing Transmission System**

Figure 6-3 shows the states in Basin Electric’s service territory. Basin Electric has member loads in the following Balancing Authorities, Midwest ISO (MISO), Western Area Power Administration Upper Great Plains Region East (WAUE), Nebraska Public Power District (NPPD), NorthWestern Energy (NWMT), PacifiCorp East (PACE), Western Area Power Administration Upper Great Plains Region West (WAUW) and Western Area Colorado Missouri (WACM).

![Planning Areas](image)

**Figure 6-3. Control Area Map of Basin Electric’s Service Territory**

Figure 6-3 is shown broken up into five distinct planning regions. These regions are used in Basin Electric’s internal modeling. Load is served by Generation either directly within each area or by moving power between areas in an attempt to optimize the complete system. The capabilities to move power from one region to the next is based on transmission constrains that are modeled between each planning region. For movement from the east to west, or vice versa, it is determined by the DC tie amounts to which Basin Electric has rights. (See Table 6-1.)
Basin Electric has several DC ties that bridge the national electric system. In total, Basin Electric has ownership or capacity rights to transfer 240 MW in the west-to-east direction and 423 MW in the east-to-west direction, as shown in Table 6-1.

<table>
<thead>
<tr>
<th>DC Tie</th>
<th>Capacity (MW)</th>
<th>BEPC % Ownership</th>
<th>BEPC Rights (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Miles City DC Tie</td>
<td>200</td>
<td>40</td>
<td>183 (east–west only)</td>
</tr>
<tr>
<td>Stegall DC Tie</td>
<td>110</td>
<td>0 (Tri-State Owned)</td>
<td>110 (bi-directional)</td>
</tr>
<tr>
<td>Rapid City DC Tie</td>
<td>200</td>
<td>65</td>
<td>130 (bi-directional)</td>
</tr>
</tbody>
</table>

Table 6-1. DC Tie Capacity, Ownership and Rights

Table 6-2 shows the transmission lines that Basin Electric owns on Basin Electric’s eastern and western systems as of December 31, 2012.

<table>
<thead>
<tr>
<th>System</th>
<th>Joint Ownership</th>
<th>Total Circuit Miles</th>
<th>Owned</th>
<th>Basin Electric Planned</th>
</tr>
</thead>
<tbody>
<tr>
<td>Integrated System</td>
<td>Basin Electric, Western, Heartland Consumers Power District</td>
<td>9,447</td>
<td>1,544</td>
<td>206</td>
</tr>
<tr>
<td>Common Use System</td>
<td>Basin Electric, Black Hills Power, PRECorp</td>
<td>910</td>
<td>278</td>
<td>0</td>
</tr>
<tr>
<td>MBPP System</td>
<td>Basin Electric, Tri-State, WMPA, MRES, Heartland Consumers Power District, Lincoln Electric</td>
<td>681</td>
<td>288</td>
<td>0</td>
</tr>
<tr>
<td>Other</td>
<td></td>
<td>0</td>
<td>25</td>
<td>0</td>
</tr>
<tr>
<td><strong>Basin Electric Total</strong></td>
<td></td>
<td><strong>2,143</strong></td>
<td><strong>190</strong></td>
<td></td>
</tr>
</tbody>
</table>

Table 6-2. Basin Electric Transmission
Basin Electric New Transmission Projects

**AVS-Williston-Tioga 345kV Transmission Line**: This project, indicated by the dotted red line in Figure 6-4, is a 190-mile long 345kV transmission line that will provide a new high voltage delivery into the northwestern North Dakota area. It is scheduled to be complete in 2016. The line will provide a significant increase to the transmission system load serving capacity in northwestern North Dakota.

**Blaisdell-Berthold 115kV Transmission Line**: This project, indicated by the dotted black line in Figure 6-4, is a 16-mile long 115kV line that will connect the Blaisdell 230/115kV substation with the Berthold 115kV load delivery substation. It is scheduled to be complete in December 2013. The project will increase load serving capacity in the area west of Minot, ND.

![Figure 6-4. Proposed Transmission Locations](image)
7. Demand-Side Management

**Highlights**

- DSM programs aim to achieve three broad objectives: energy conservation, energy efficiency and load management.
- In 2011, Basin Electric and member cooperatives collectively invested about $7.1 million in demand-side management programs, resulting in an annual savings of 171,811 kilowatts.
- Basin Electric and several of its members utilize load management systems to control peak demand.

Demand-side Management (DSM) is the process of managing the consumption of energy, generally to optimize available and planned generation resources. According to the DOE, DSM refers to “actions taken on the customer’s side of the meter to change the amount or timing of energy consumption. Utility DSM programs offer a variety of measures that can reduce energy consumption and consumer energy expenses. Electricity DSM strategies have the goal of maximizing end-use efficiency to avoid or postpone the construction of new generating plants.”

DSM programs aim to achieve three broad objectives; energy conservation, energy efficiency and load management. Energy conservation can reduce the overall consumption of electricity by reducing the need for heating, lighting, cooling, cooking and other functions. Energy efficiency encourages consumers to use energy more efficiently, thus more effectively. Load management allows generation companies to better manage the timing of their consumers’ energy use and will help reduce the large discrepancy between on-peak and off-peak demand.

Basin Electric and its members are engaged in a variety of conservation and energy efficiency programs. The programs and activities were developed to promote, support and market dual heat, water heaters, heat pumps, air conditioning, storage heating, grain drying, irrigation, photovoltaic, energy audits, and numerous other programs. A number of Basin Electric’s members have developed programs. These vary depending on the cooperative; some elect to utilize rebates, others energy resource conservation (ERC) loans, others rates, some all three and some may elect not to adopt any of the programs.

Prior to 2011, Basin Electric had surveyed its membership directly on all DSM activities and reported the information accordingly. Starting in 2011 Basin Electric adopted the new Rural Utilities Service (RUS) and Cooperative Finance Corporation (CFC) energy efficiency information reported by Basin Electric’s members on their RUS’s Form 7 part P or CFC’s Form part S documents.

The Energy Efficiency and Conservation Basin Electric Power Cooperative (BEPC) Grant Program was implemented to assist our member cooperatives in furthering their current energy efficiency efforts. We accomplished this by providing matching funding on a wide variety of rebates that were offered to member owners. The program ran from 2008 through 2010.
The dollars spent on DSM program activities by Basin Electric/Members for the last three years are summarized in Table 7-1 below.

<table>
<thead>
<tr>
<th>DSM Programs</th>
<th>2011</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy Efficiency &amp; Conservation</td>
<td>5,102,919</td>
<td>7,093,956</td>
<td>7,615,581</td>
</tr>
<tr>
<td>Load Management</td>
<td>2,021,134</td>
<td>1,166,555</td>
<td>960,148</td>
</tr>
<tr>
<td>BEPC Grant Program</td>
<td>0</td>
<td>722,674</td>
<td>1,000,000</td>
</tr>
<tr>
<td><strong>Total DSM Programs</strong></td>
<td><strong>$7,124,053</strong></td>
<td><strong>$8,983,185</strong></td>
<td><strong>$9,575,729</strong></td>
</tr>
</tbody>
</table>

Table 7-1. Annual Dollars Spent on DSM Programs

Energy conservation and efficiency programs are capable of lessening the impact of electrical demand and reducing the capacity needs of additional future generation facilities. Energy conservation is behavior based while energy efficiency is technology based. Therefore, energy conservation and efficiency programs could be considered in parallel of adding additional generating capability to meet the Basin Electric projected demand.

The Demand (kW) Savings associated with DSM program activities by Basin Electric/Members for the last three years are summarized in Table 7-2 below.

<table>
<thead>
<tr>
<th>Demand (kW) Savings</th>
<th>2011</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy Efficiency &amp; Conservation</td>
<td>9,767</td>
<td>12,169</td>
<td>11,723</td>
</tr>
<tr>
<td>Load Management</td>
<td>162,044</td>
<td>177,860</td>
<td>179,257</td>
</tr>
<tr>
<td><strong>Total DSM Programs</strong></td>
<td><strong>171,811</strong></td>
<td><strong>190,029</strong></td>
<td><strong>190,980</strong></td>
</tr>
</tbody>
</table>

Table 7-2. Annual kW Savings on DSM Programs
Energy conservation and efficiency programs are capable of lessening the impact of electrical energy needs therefore reducing additional future generation facilities. Energy conservation is behavior based while energy efficiency is technology based. Energy conservation and efficiency programs could be considered in parallel of adding additional generating capability to meet the Basin Electric projected energy obligations.

The Energy (kWh) Savings associated with DSM program activities by Basin Electric/Members for the last three years are summarized in Table 7-3 below.

<table>
<thead>
<tr>
<th>Energy (kWh) Savings</th>
<th>2011</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy Efficiency &amp; Conservation</td>
<td>59,892,755</td>
<td>38,198,584</td>
<td>28,977,182</td>
</tr>
<tr>
<td>Load Management</td>
<td>39,925,128</td>
<td>46,258,213</td>
<td>38,740,665</td>
</tr>
<tr>
<td>Total DSM Programs</td>
<td>99,817,883</td>
<td>84,456,797</td>
<td>67,717,847</td>
</tr>
</tbody>
</table>

Table 7-3. Annual kWh Savings on DSM Programs

The Energy Efficiency & Conservation information can include a combination of but not limited to the following DSM activities:

**Agriculture/Irrigation**
- Appliance rebate programs
- Audit and building envelope measures
- Cooling/ventilation measures
- Heating/drying measures
- Load management programs
- Pump/motor/ASD measures
- Refrigerator/freezer measures

**Commercial/Industrial**
- Air conditioning measures
- Appliance rebate programs
- Audit and building envelope measures
- Cooking measures
- Heating measures
- Hot water measures
- Motor/ASD programs
- Refrigerator/freezer measures
- Ventilation measures
Demand-Side Management

Commercial/Industrial/Agriculture/Irrigation
  Lighting measures
  Load management programs
  Industrial process measures

Residential
  Air conditioning measures
  Appliance rebate programs
  Audit and building envelope
  Cooking measures
  Domestic hot water measures
  Heating measures
  Lighting measures
  Load management programs
  Refrigerator/freezer measures
  Ventilation measures
  Other
It is the objective of our members to work for and support programs to promote the conservation of electrical energy that includes the widespread understanding, participation and involvement of the member-consumers of the cooperative. Some of their objectives are to:

- Constantly examine their use of energy. This includes, but is not limited to, plant engineering design and construction, lighting and climate control.
- Direct effort toward conservation of energy by discouraging wasteful and unnecessary uses of energy.
- Encourage improved efficiency in energy-consuming devices.
- Encourage the effective and efficient use of energy in the home, on the farm, and in business uses that includes energy conservation, adequate home insulation and weatherization.
- Develop and carry out information programs that will encourage energy conservation through proper thermostat settings for heating and cooling devices.
- Develop training as appropriate for all employees and others interested in such training.

Basin Electric and its members are engaged in a variety of conservation and energy efficiency programs. The programs and activities were developed to promote, support and market dual heat, water heaters, heat pumps, air conditioning, storage heating, grain drying, irrigation, photovoltaic, energy audits, and numerous other programs.
Electric Heat Programs
The membership promotes the utilization of electric heat in consideration of its efficiency, convenience, safety, cleanliness, quietness, reliability and versatility. The programs for electric heat include four categories consisting of heat pumps, storage heating, dual heating and conventional electric heat.

Electric Heat Pump Programs
The heat pump programs consist of both ground source and air-to-air systems. Ground source heat pumps do not utilize a heating element. They operate by extracting heat from the ground, which has a temperature of 40 to 50 degrees, and delivering it to the home at 90 to 125 degrees. The heat exchange with the ground occurs via a series of plastic pipes that are placed in either vertical or horizontal positions. This process results in efficiencies between 300 and 400 percent. A reversible valve enables the heat pump to remove heat from inside the home in the summertime and return it to the ground. Ground source heat pumps are normally connected to the consumer’s hot water heater, which also provides for very economical water heating costs.

Air-to-air heat pumps operate on the same principal as ground source heat pumps. The only difference is the heat exchange occurs with the air and results in efficiencies of 200 to 300 percent.

Electric Storage Heat Systems
The electric storage heat systems are normally constructed of high-density bricks. This enables the bricks to be electrically charged with heat during the off-peak low load periods and the heat is then discharged from the bricks into the home during the high load on-peak periods rather than using electricity to generate the heat. This operation, which transfers on-peak electrical usage to off-peak periods, is incorporated as part of the members’ demand-side management (DSM) systems.

Conventional Electric Heat
As heat pumps and storage heaters continue to gain acceptance, the percent of electrically heated homes utilizing conventional electric resistance heat has decreased.

Dual Heating Systems
Dual heating systems are also installed as part of the members’ DSM programs. These systems allow the consumer to heat their residence with electric heat or a fossil fuel such as propane or fuel oil. DSM systems may be used to remotely turn off the electric heat and start the backup fossil fuel furnaces to reduce on-peak electric usage. This reduces the on-peak amount of electric power while still meeting the consumer needs for heat.

The members utilize the dual fuel concept as a marketing tool that enables them to market additional power without increasing their purchase power costs during peak periods. Dual heat systems have typically resulted in electric heat being added to homes with fossil fuel furnaces. There are, however, many cases where fossil fuel furnaces have been added to all electric homes, which demonstrate the members’ commitment to this program.
Member Load Management Program

Approximately half of the members are utilizing load management to manage their power purchases from Basin Electric. Other members have investigated load management, but the high load factor of their commercial loads and the system cost results in marginal economics. Some of Basin Electric’s members have provided hourly estimated data regarding their Load Management Systems. Those members include:

- Central Power Electric Cooperative
- East River Electric Power Cooperative
- L and O Power Cooperative
- Northwest Iowa Power Cooperative
- Rushmore Electric Power Cooperative

Figure 7-2 shows the amount of load management by month for the Basin Electric members that have provided data, based on year 2012 strategy. The graph shows the maximum load management that occurred within those member systems with load management in any one hour for each month in 2012, as well as, a comparison to the strategy that was in place going into the year for Central Power East River, L&O, NIPCO, and Rushmore the other members are not monitored within Basin Electric to determine actual amounts of load management that occurred. This magnitude of load management is factored into the load forecast for each member with load management.
Figure 7-2. Maximum Load Management for Basin Electric Members (Total)

Figure 7-3 shows the total amount of load management that the member systems with load management had on their systems each month for 2012.

Figure 7-3. 2012 Total Load Management (kWh)
Figure 7-4 shows that actual percent of utilization that occurred by month for load management for 2012.

![Figure 7-4. Load Management System Percent of Utilization](image)

Figure 7-5 shows a comparison of the load factors with and without the load management factored in. As can be seen in Figure 7-5, implementing load management increases the load factor on the system.

![Figure 7-5. Load Factor With and Without Load Management](image)
Figure 7-6 shows a comparison of the load factors with and without the load management factored in when evaluating Basin Electric’s Eastern System. As can be seen in Figure 7-6, implementing a load management increases the load factor on the system.

![Figure 7-6. Load Factor With and Without Load Management (Total Eastern System)](image)

Figure 7-7 shows the number of days the member systems with load management systems had load management. There were a total of 281 days with load management.

![Figure 7-7. Total Days of Load Management](image)
Figure 7-8 shows the average number of hours per day load management operated when there was load management operating. There were a total of 3,864 hours of load management during 2012.

![Graph showing average daily hours of load management](image)

**Figure 7-8. Average Daily Hours of Load Management**

Details about individual members’ load management systems were provided by each member.
Central Power Load Management

Central Power Electric Cooperative (Central Power) operates a 17-level, ladder control system; i.e., control levels, numbered from zero to sixteen, with zero exercising no control and 16 exercising maximum control.

Control is activated at predetermined demand thresholds and deactivated at much lower predetermined thresholds to accommodate demand rebound. In order for a device that is being controlled to be released from control, all of the devices assigned to higher numbered control levels must first be released from control. Level 16 must be released before 15 can be released, etc.

<table>
<thead>
<tr>
<th>Device</th>
<th>Irrigation and Coal Creek</th>
<th>Grain Heat</th>
<th>Large Water Heaters 25% off 75% on</th>
<th>Small Water Heaters 25% off 75% on</th>
<th>Irrigation</th>
<th>Large Water Heaters 50% off 50% on</th>
<th>Non-Heat</th>
<th>Grain Heat</th>
</tr>
</thead>
<tbody>
<tr>
<td>Control Level</td>
<td>1</td>
<td>2</td>
<td>3</td>
<td>4</td>
<td>5</td>
<td>6</td>
<td>7</td>
<td>8</td>
</tr>
<tr>
<td>Device</td>
<td>A/C</td>
<td>Large Water Heaters 75% off 25% on</td>
<td>Large Water Heaters 75% off 25% on</td>
<td>Small Water Heaters 50% off 50% on</td>
<td>Generate</td>
<td>Small Water Heaters 75% off 25% on</td>
<td>Grain Fans</td>
<td>Generate, Small Water Heaters 75% off 25% on</td>
</tr>
<tr>
<td>Control Level</td>
<td>9</td>
<td>10</td>
<td>11</td>
<td>12</td>
<td>13</td>
<td>14</td>
<td>15</td>
<td>16</td>
</tr>
</tbody>
</table>

Table 7.4. Central Power Load Management Levels (Summer)

Level 1 control initiated based on total load including commercial pumping. Level 11 no time limit. Level 16 has a two-hour time limit with two hours of recovery time before re-entry.

<table>
<thead>
<tr>
<th>Device</th>
<th>Irrigation and Coal Creek</th>
<th>Grain Heat</th>
<th>Large Water Heaters 25% off 75% on</th>
<th>Small Water Heaters 25% off 75% on</th>
<th>Irrigation</th>
<th>Large Water Heaters 50% off 50% on</th>
<th>Non-Heat</th>
<th>Grain Heat</th>
</tr>
</thead>
<tbody>
<tr>
<td>Control Level</td>
<td>1</td>
<td>2</td>
<td>3</td>
<td>4</td>
<td>5</td>
<td>6</td>
<td>7</td>
<td>8</td>
</tr>
<tr>
<td>Device</td>
<td>A/C</td>
<td>Large Water Heaters 75% off 25% on</td>
<td>Large Water Heaters 75% off 25% on</td>
<td>Small Water Heaters 50% off 50% on</td>
<td>Generate</td>
<td>Small Water Heaters 75% off 25% on</td>
<td>Grain Fans</td>
<td>Generate, Small Water Heaters 100% off</td>
</tr>
<tr>
<td>Control Level</td>
<td>9</td>
<td>10</td>
<td>11</td>
<td>12</td>
<td>13</td>
<td>14</td>
<td>15</td>
<td>16</td>
</tr>
</tbody>
</table>

Table 7.5. Central Power Load Management Levels (Winter)

Level 1 control initiated based on total load including commercial pumping. Level 11 has a six-hour time limit with two hours of recovery before reentry. Level 16 has a two-hour time limit with two hours of recovery before re-entry.
East River Load Management

Load management refers to the control of various customer electric loads during times of peak usage on the electric system. By managing loads so that they are not all on at the same time, the cooperative is able to reduce wholesale power purchases, thus saving money and resources.

East River member cooperatives’ load management system has been operating for over 28 years and has saved almost $150 million in avoided wholesale power costs. Almost 72,000 different electric loads in homes, farms and businesses of member consumers throughout Eastern South Dakota and Western Minnesota with a total 453 MW are connected to the system. These loads include electric water heaters, air conditioners, irrigation systems and large industrial processes.

Control is initiated monthly through a highly sophisticated system that communicates with control receivers connected to the various loads. East River operates the system on a federated basis on behalf of its member systems to moderate wholesale power costs, improve system efficiencies and provide member consumers with energy options.

Make-up/Magnitude

Table 7-6 shows the make-up and magnitude of load management on East River’s system.

<table>
<thead>
<tr>
<th>Loads</th>
<th>A/C</th>
<th>Central Heat Storage Furnaces</th>
<th>Residential Demand Limiters</th>
<th>Water Heaters</th>
<th>Irrigation</th>
<th>Industrial and Grain Dryers</th>
<th>Diesel Generators</th>
</tr>
</thead>
<tbody>
<tr>
<td>MW</td>
<td>71</td>
<td>5</td>
<td>1</td>
<td>200</td>
<td>96</td>
<td>43</td>
<td>37</td>
</tr>
</tbody>
</table>

Table 7-6. East River Load Management Make-up/Magnitude

Operation

Operated on a monthly basis, each control is initiated by East River dispatch. Using Supervisory Control and Data Acquisition (SCADA) to monitor the East River system load, East River dispatchers initiate low frequency power line carrier signals to over 57,000 load control receivers installed at consumer loads. Participation by consumers is voluntary.

Jointly defined and reviewed annually by East River and our members systems, the operating strategy limits the amount of the time water heaters, air conditioners, and central storage units are controlled during each control period. The goal is to have 100 percent of all applicable controllable load groups for each month controlled during the East River monthly peak.

The East River load curve, our controllable/non-controllable load ratio, and the voluntary participation of our consumers require a portion of the controllable water heating load and air conditioning load to be on during the monthly peak.
Summary of Studies Concerning Potential Expansion

Under current programs, we are connecting approximately 1 MW of additional controllable water heater load and approximately 2 MW of additional controllable air conditioning load to our system each year. Currently we do not directly limit additional controllable load.

Much attention has been given to the existing load management system, the amount of load connected to it, how we operate it, and the impact on our consumers. In addition to new controllable loads, we have non-controllable load growth as well. This has resulted in a relatively stable controllable/non-controllable load ratio.

L & O Power Cooperative Load Management

The current L&O Power Cooperative (L&O) load management system consists of a power line carrier Cannon Yukon system.

L&O currently operates the system to attempt to have all controlled load “off” over their monthly peak, each month. The loads controlled change from month to month (season, interruptible 5/7, etc.) but the operational goal each month is to have all controllable load off over their monthly peak.

L&O feels that its current ratio of controlled load to total load is probably as high as it wants to go at this time. Its Load Management is fairly high and the control times each month is as high as or higher than its customers would like to see, resulting in some cold water complaints. Note that this is based upon historical data and L&O’s current load management system operations. The current switches operated by the L&O load management system are as follows:

<table>
<thead>
<tr>
<th>A/C</th>
<th>Heat Pump (Summer)</th>
<th>Dual Fuel</th>
<th>Water Heaters</th>
<th>Irrigation</th>
<th>Grain Dryers</th>
<th>Interruptible (5/7)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>79</td>
<td>118</td>
<td>538</td>
<td>3,364</td>
<td>21</td>
<td>23</td>
</tr>
</tbody>
</table>

Table 7-7. L&O Load Management

Northwest Iowa Power Cooperative (NIPCO)

One of NIPCO’s most successful programs is the “Switch Makes Cents” program. It was launched in 1983 to encourage the wise use of electricity. The objective of the program is to increase the cost-effective use of energy efficient equipment applications while maximizing the power supply resources and transmission system. The NIPCO Members make available to the member-consumers incentives, equipment rebates and rate savings offered for the installation of new energy efficient equipment. Special electric rates are made available in exchange for allowing this equipment to be interrupted during system peak use through the demand-side component of the Switch Makes Cents program.

To date, more than 16,000 demand-side management switches have been installed in members’ homes and businesses. This 30 year old energy and demand efficiency program has resulted in member savings of more than $30 million. The demand side management component of the program saved the member consumers over $3 million in 2012 alone.
Rushmore Electric Power Cooperative

Rushmore Electric Power Cooperative uses load management to shift load during system peak periods to lower peak demands and minimize the electrical stress on the system. This is done by turning off high usage electrical equipment during peak hours through an automated system. Currently we control water heaters, central AC units, irrigation, water systems, and storage heat.

Rushmore’s load management program is still in its infancy stage, only being in operation for a year and a half. Typical monthly control ranges from 1-8 days with most control windows lasting 1-4 hours. Currently there are 3,800 different electrical loads under control. This resulted in a reduction of 4.5 MW in January 2013. To date, REPC members have saved a total of $650,000 through load management.

The load management system is made up of several components which are seamlessly integrated. It starts with the ACS SCADA system monitoring each of Rushmore Electric’s delivery points. The kW load is summed, giving the total load on Rushmore’s system. This load data is sent to the load control program to be used as a trigger for load control.

The load control program was designed in house and is the brains behind when load control is started and stopped. There are predefined control windows set within the program, one for morning control and one for afternoon/evening control. The program monitors the system load that it receives from the SCADA system. When the system load is above a preset limit and within one of the two control windows, a signal is sent out to the member cooperatives TWACS servers to turn load off. The same is done for turning load back on. When the system load is below a preset level, a signal is sent to the TWACS servers to turn load back on. The TWACS serves process the signal and tell the corresponding DRU (Demand Response Unit) located on the consumer end to turn load on/off.

The control program has many other features that help with the automation process. This has allowed Rushmore Electric to minimize the overhead costs of having an employee monitor the system 24/7.

Future Expansion

The program is voluntary with each member cooperative providing different incentives to entice consumers to sign up. Within four years, it is Rushmore’s goal to have a total of 15,000 water heaters and 2,000 central AC units under control. Storage heat, irrigation and other larger motor loads will be perused as well.

The load control program will also change as time goes on. As the amount of load under control grows, the philosophy on how it is controlled will have to change and adapt.
Basin Electric Load Management Program

Basin Electric has implemented an east side system-wide load management program that enables Basin Electric to target large loads and/or generation that are not included in the members’ load management programs to be used during Basin Electric’s seasonal peak periods. Basin Electric has approximately 20-35 MW of load management available at this time.

Figure 7.9 below is the total amount of load management in place in 2012 that Basin Electric used to control their seasonal peak.

![Figure 7.9. 2012 Load Management Strategy in Place by Month](image)

Figure 7-10 shows the total amount of load management used by month.

![Figure 7-10. 2012 Total Load Management (kWh) by Month](image)
Figure 7-11 shows the total number of days load management was called upon by month.

Figure 7-11. Number of Days per Month Load Management Was Used

Figure 7-12 shows the total number of hours load management operated by month. There were a total of 55 hours of load management in 2012.

Figure 7-12. 2012 Total Hours of Operation for Load Management by Month

Basin Electric will continue to work on developing and expanding on energy conservation and efficiency within the Basin Electric service territory. Basin Electric has always empowered the membership to have the majority of the load management programs at the membership level to allow members to manage their peak and avoid BEPC’s demand rate. Basin Electric will also work with the members to develop more load management within the Basin Electric system where it is viable.
8. Renewable Energy Sources

Highlight

- Basin Electric’s membership adopted a resolution in 2005 calling for a development of renewable generating resources goal equivalent to 10 percent of the cooperative’s demand deliveries to members by 2010.
- In 2010, Basin Electric exceeded that goal by securing renewable resources totalling more than 22 percent of member demand deliveries.
- Several states within Basin Electric’s service territory have adopted Renewable Energy Objectives (REO). Basin Electric and its members have always met all the REO requirements for those states that currently have such requirements and will continue to work with the members on small renewable generation purchases within Basin Electric’s system.

Existing Renewable Portfolio

Basin Electric’s commitment to the development of renewable energy was underscored in 2005 when the cooperative’s membership adopted a resolution calling for a development of renewable generating resources goal equivalent to 10 percent of the cooperative’s demand deliveries to members by 2010.

In 2010 Basin Electric’s renewable generation portfolio totaled 596 megawatts (MW) (excluding hydro) and Basin Electric’s member peak was 2,658 MW in 2010, resulting in renewable resources of more than 22% of member demand deliveries, far exceeding the 10% goal by 2010.

At the end of 2012 Basin Electric’s renewable generation portfolio exceeded 757 MW (excluding hydro) and Basin Electric’s member peak came in at 2,994 MW resulting in renewable resources of 25% of member demand deliveries in 2012. Also, from an energy prospective in 2012, Basin Electric’s renewable portfolio equaled just over 16% of total sales to its members.

The renewable energy credits (RECs) that are generated from Basin Electric’s renewable generation portfolio have been allocated to Basin Electric’s members beginning in 2012. This allows the members full control to retire these RECs to meet Renewable Portfolio Standards (RPSs), sell directly to consumers or into the REC markets.

Through direct investments and annual payments under renewable power purchase agreements, Basin Electric has made a capital investment of more than $1 billion in renewable resources.
As of year-end 2012, Basin Electric will hold about 757 megawatts of green and renewable\(^1\) generating capacity in its portfolio, including:

- 713 megawatts of wind generation
- 44 megawatts of recovered energy generation
- 690 kilowatts of flare gas generation

Basin Electric also has another large renewable resource in the form of 279 megawatts of hydropower (winter peaking power purchased from the Western Area Power Administration).

**Wind Energy**

In February 2011, Basin Electric subsidiary PrairieWinds SD 1 commissioned the largest wind project in the nation operated by a cooperative, the 162-megawatt Crow Lake Wind Project, in central South Dakota.

The project consists of 108 GE 1.5-megawatt turbines: 100 are owned by PrairieWinds SD 1 Inc.; one turbine is owned by Mitchell Technical Institute (MTI), Mitchell, SD, for training wind technology students; and seven are owned by a group of local community investors called the South Dakota Wind Partners. Basin Electric operates the project and purchases the output of the MTI and Wind Partners turbines.

Basin Electric subsidiary PrairieWinds ND 1 owns two projects in North Dakota: the 77 turbines of PrairieWinds 1, commissioned in 2009, and Minot Wind, which consists of two 1.3-megawatt turbines and three 1.5-megawatt turbines. Both projects are operated by Basin Electric and located south of Minot, ND.

\(^1\) The actual renewable energy attributes (aka green tags or RECs) of much of that generation was sold to others and no claims of environmental attributes may be claimed for any part of Basin Electric’s power supply, unless those attributes are assigned to the power claimed as green or renewable.
Basin Electric owns and operates a small wind project at Chamberlain, SD. The site has two 1.3-megawatt turbines. Basin Electric purchases power from several wind energy projects, such as the following in North Dakota, South Dakota and Iowa, as well as others in Minnesota and South Dakota:

**NextEra Energy Wind Energy Centers**

- Edgeley Wind Project (ND): 40 megawatts
- Wilton Wind Project (ND): 49.5 megawatts
- Wilton Wind 2 (ND): 49.5 megawatts
- Baldwin Wind Project (ND): 100 megawatts
- Hyde County Wind Project (SD): 40 megawatts
- Day County Wind Project (SD): 99 megawatts

**Corn Belt Power Cooperative wind resources in Iowa**

- Iowa Lakes Electric Cooperative
  - Superior Wind Project: 10.5 megawatts
  - Lakota Wind Project: 10.5 megawatts
- Hancock County: 7.3 megawatts
- Crosswinds: 16.8 megawatts

Basin Electric’s total wind renewable portfolio had a stout year in 2012 with a production capacity factor rating of 42%.

![Wind & Recovered Energy Generation](image)

*Figure 8.1. Wind and Recovered Energy Generation Facilities*
Basin Electric purchases the output from more than 145 small wind, solar and biomass generators owned by members throughout the cooperative’s service territory, totaling about 1,919 kilowatts. Two major issues face wind energy development: transmission constraints and wildlife protection. Establishing predictable and reasonable regulations regarding wildlife can help move wind energy projects forward more quickly and efficiently. Overly restrictive regulations or uncertainty in the interpretation of rules can delay or end wind energy development in this region altogether.

**Recovered Energy Generation**

Basin Electric purchases the output from eight recovered energy generation sites along the Northern Border Pipeline: Culbertson, MT; Manning, St. Anthony, and Zeeland, ND; Wetonka, Clark and Estelline, SD; and Garvin, MN.

Each generates 5.5 megawatts of renewable energy from exhaust heat produced by the pipeline’s compressor stations. The sites produce power with virtually no incremental emissions and are considered carbon-free generation. These sites are recognized as a renewable energy source in North Dakota, South Dakota and Colorado. The sites are owned and operated by subsidiaries of Ormat Technologies of Reno, NV.

Basin Electric has joined with other electric cooperatives across the nation to form the National Renewables Cooperative Organization (NRCO). NRCO is an effort among cooperatives to help each other to diversify generating portfolios and to look at renewable generation as part of an overall strategy.

**Renewable Energy Objectives (REO)**

Several states within Basin Electric’s service territory have adopted Renewable Energy Objectives (REO’s) that requires renewable generation to meet a certain percentage of retail sales in that state. Many states in the Basin Electric membership service territory adopted REO’s such as Colorado, Minnesota, Montana, North Dakota and South Dakota and several states have not which include Iowa, Nebraska, New Mexico, and Wyoming. The following information provides details of the adopted REO’s.
Colorado

I. State Summary

<table>
<thead>
<tr>
<th>Renewable Energy Requirements</th>
<th>Conservation/ Energy Efficiency Requirements</th>
<th>Treatment of Hydro</th>
</tr>
</thead>
<tbody>
<tr>
<td>MANDATORY</td>
<td>None</td>
<td>(IV) “RENEWABLE ENERGY RESOURCES” MEANS SOLAR, WIND, GEOTHERMAL, BIOMASS, NEW HYDROELECTRICITY WITH A NAMEPLATE 10 RATING OF TEN MEGAWATTS OR LESS, AND HYDROELECTRICITY IN EXISTENCE ON JANUARY 1, 2005, WITH A NAMEPLATE RATING OF THIRTY 12 MEGAWATTS OR LESS.</td>
</tr>
<tr>
<td>Colorado</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1%-2008-2010</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3%-2011-2014</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6%-2015-2019</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10%2020-and thereafter</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 8-1. Colorado REO

II. Colorado Conservation & Energy Efficiency Requirements

a. The State of Colorado has no requirements with respect to conservation or energy efficiency.

III. Renewable Energy Requirements

a. Standard: 40-2-124 Renewable Energy Standard provides, “Each provider of retail electric service in the state of Colorado, other than municipally owned utilities that serve forty thousand customers or less, shall be considered a qualifying retail utility. Each qualifying retail utility, with the exception of cooperative electric associations that have voted to exempt themselves from commission jurisdiction pursuant to section 40-9.5-104 and municipally owned utilities, shall be subject to the rules established under this article by the commission.

(IV) To the extent that the ability of a qualifying retail utility to acquire eligible energy resources is limited by a requirements contract with a wholesale electric supplier, the qualifying retail utility shall acquire the maximum amount allowed by the contract. For any shortfalls to the amounts established by the commission pursuant to subparagraph (I) of this paragraph (c), the qualifying retail utility shall acquire an equivalent amount of either renewable energy credits; documented and verified energy savings through energy efficiency and conservation programs; or a combination of both. Any contract entered into by a qualifying retail utility after December 1, 2004, shall not conflict with this article:
b. Colorado Community Based Projects: 40-2-124 (VI) Renewable Energy Standard provides, “Each kilowatt-hour of electricity generated from eligible energy resources at a community-based project shall be counted as one and one-half kilowatt-hour. For purposes of this subparagraph (VI), “community-based project” means a project located in Colorado.

c. Hydro/Waste Heat Energy: 40-2-124 (VI) Renewable Energy Standard provides, defines Recycled Energy as, “solar, wind, geothermal, biomass, and new hydroelectricity with a nameplate rating of ten megawatts or less, and hydroelectricity in existence of January 1, 2005 with a nameplate rating of thirty megawatts or less.” Additionally, Colorado law provides that Recycled Energy means, “a means energy produced by a generation unit with a nameplate capacity of not more than fifteen megawatts that converts the otherwise lost energy from the heat from exhaust stacks or pipes to electricity and that does not combust additional fossil fuel. “Recycled Energy” does not include energy produced by any system that uses energy, lost or otherwise, from a process whose primary purpose is the generation of electricity, including, without limitation, any process involving engine-driven generation or pumped hydroelectricity generation.”

d. Reporting Requirements & Time Periods: 40-2-124 (5.5) Procedure for exemption and inclusion-election provides that, “Each cooperative electric association that is a qualifying retail utility shall submit an annual compliance report to the commission no later than June 1 of each year in which the cooperative electric association is subject to the renewable energy standard requirements established in this section. The annual compliance report shall describe the steps taken by the cooperative electric association to comply with the renewable energy standards and shall include the same information set forth in the rules of the commission for jurisdictional utilities. Cooperative electric associations shall not be subject to any part of the compliance report review process as provided in the rules for jurisdictional utilities. Cooperative electric associations shall not be required to obtain commission approval of annual compliance reports, and no additional regulatory authority of the commission other than that specifically contained in this subsection (5.5) is created or implied by this subsection (5.5).”
Iowa

I. State Summary

<table>
<thead>
<tr>
<th></th>
<th>Renewable Energy Requirements</th>
<th>Conservation/ Energy Efficiency requirements</th>
<th>Treatment of Hydro</th>
</tr>
</thead>
<tbody>
<tr>
<td>Iowa</td>
<td>None</td>
<td>Co-ops must file with IUB by 7/1 even numbered years. Iowa Statewide files for members.</td>
<td>N/A</td>
</tr>
</tbody>
</table>

Table 8-2. Iowa REO

II. Conservation & Energy Efficiency Requirements

a. Cooperatives in Iowa must file energy efficiency plans with the Iowa Utilities Board (IUB) by July 1 of even-numbered years. The IUB does not review or approve these plans, nor does it verify the information filed. The IUB simply compiles the results of the plans. The goals and implementation of plans by cooperatives are not the responsibility of the IUB. However, IUB rules [199 IAC Chapter 36] specify the data cooperatives should provide in their plans.

b. The IUB typically sends each consumer-owned utility a reminder in the spring of the year plans are due, including a form which utilities may use to compile and report the data for their plans. Cooperatives in Iowa are allowed to file their plans jointly with other utilities. For the past 14 years and continuing in 2006, the Iowa Association of Electric Cooperatives (IAEC) has filed joint plans for many of their member utilities. There are no specific requirements for the amount of energy that needs to be conserved each year.

III. Renewable Energy Requirements

a. At this time, Iowa does not have any renewable energy requirements.
Minnesota

I. State Summary

<table>
<thead>
<tr>
<th></th>
<th>Renewable Energy Requirements</th>
<th>Conservation/ Energy Efficiency requirements</th>
<th>Treatment of Hydro</th>
</tr>
</thead>
</table>
| Minnesota          | GOOD FAITH OBJECTIVE until 2012 then MANDATORY 7%- 2010-2011 12%- 2012-2015 17%- 2016-2019 24%- 2020-2024 25%-2025 | CIP- 1.5 percent of the utility’s annual retail energy sales in MN (ER, MN Valley L&P and SVE file) | Eligible Renewable- hydro with a capacity of less than 100 megawatts is considered an “eligible energy technology”.
|                    |                                |                                              | Calculation of total Retail Sales: WAPA allocations are included in definition of retail sales so ER & L&O cannot deduct those from the baseline amount. |

Table 8-3. Minnesota REO

II. Conservation & Energy Efficiency Requirements

a. The Next Generation Energy Act of 2007 revised the CIP statute (Minnesota Statute 216B.241) to set an annual energy savings goal for each electric and gas utility beginning in 2010. The energy savings goal is equivalent to 1.5 percent of the utility’s annual retail energy sales in Minnesota, averaged over the most recent 3-year period and weather-normalized. In certain circumstances, the Department of Commerce may reduce a utility’s energy savings goal at its request. However, 1 percent is the minimum energy savings goal percentage. Electric utilities are required to invest 1.5 percent of their annual revenues in CIP Beginning in 2002, rural electric cooperatives and municipal utilities were required to spend the same amount as regulated utilities (1.5 percent for electric, and 0.5 percent for natural gas) on energy conservation programs. Utilities must file their CIP plans with the Department of Commerce at least every three years on a schedule determined by the commission. In 2010, the statutory energy savings goals established by the Next Generation Energy Act of 2007 take effect. Utilities were required to develop plans to meet at least the 1.0 percent minimum savings goal specified, measured as a percent of average retail electricity.

b. Energy savings resulting from electric utility infrastructure upgrade projects approved by the public utilities commission or certain waste heat recovery projects may be counted towards a utility’s energy savings goal in addition to the 1 percent savings floor for energy conservation programs.

c. Minnesota members file their CIP reports with the Minnesota Office of Energy Security (OES).
III. Renewable Energy Requirements

a. 216B.1691 RENEWABLE ENERGY OBJECTIVES: Each electric utility shall make a good faith effort to generate or procure sufficient electricity generated by an eligible energy technology to provide its retail consumers, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that commencing in 2005, at least one percent of the electric utility’s total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies and seven percent of the electric utility’s total retail electric sales to retail customers in Minnesota by 2010 is generated by eligible energy technologies. An “Electric utility” means a public utility providing electric service, a generation and transmission (G&T) cooperative electric association, a municipal power agency, or a power district. On November 12, 2008, the MN PUC issued an order establishing the requirement of renewable energy in the years 2008 and 2009 at 1%.

b. Eligible energy technology standard - (a) Except as provided in paragraph (b), each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that at least the following standard percentages of the electric utility’s total retail electric sales to retail customers in Minnesota are generated by eligible energy technologies by the end of the year indicated. See table below.

c. Hydro: hydroelectricity with a capacity of less than 100 megawatts is considered an “eligible energy technology.”
Montana

1. State Summary

<table>
<thead>
<tr>
<th>Renewable Energy Requirements</th>
<th>Conservation/ Energy Efficiency requirements</th>
<th>Treatment of Hydro</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO REQUIREMENT FOR COOPERATIVES WITH LESS THAN 5,000 MEMBERS</td>
<td></td>
<td>None</td>
</tr>
<tr>
<td>2010-2014- 10% 2015-15%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Co-op Exemption: 1) A cooperative is exempt from the graduated renewable energy standard (2) Each governing body of a cooperative utility that has 5,000 or more customers is responsible for implementing and enforcing a RES for that cooperative that recognizes the intent of the legislature to encourage new renewable energy production and rural economic development, while taking into consideration the effect of the standard on rates, reliability, and financial resources *Park &amp; Sun River are only cooperatives over 5,000 customers</td>
<td></td>
<td>Eligible Renewable- “Eligible renewable resource” means a facility either located within MT or delivering electricity from another state into MT that commences commercial operation after January 1, 2005, and that produces electricity from one or more of the following sources: (d) water power, in the case of a hydroelectric project that: (i) does not require a new appropriation, diversion, or impoundment of water and that has a nameplate rating of 10 megawatts or less; or (ii) is installed at an existing reservoir or on an existing irrigation system that does not have hydroelectric generation as of April 16, 2009, and has a nameplate capacity of 15 megawatts or less.</td>
</tr>
</tbody>
</table>

Table 8-4. Montana REO
II. Conservation & Energy Efficiency Requirements
   a. The State of Montana has no requirements with respect to energy conservation or energy efficiency

III. Renewable Energy Requirements
   a. Basin Electric will not transfer any green tags to any Montana members per the Green Tag Policy.

**Nebraska**

I. State Summary

<table>
<thead>
<tr>
<th></th>
<th>Renewable Energy Requirements</th>
<th>Conservation/ Energy Efficiency requirements</th>
<th>Treatment of Hydro</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nebraska</td>
<td>None</td>
<td>None</td>
<td>N/A</td>
</tr>
</tbody>
</table>

Table 8-5. Nebraska REO

I. Conservation & Energy Efficiency Requirements
   a. The State of Nebraska has no requirements with respect to energy conservation or energy efficiency.

II. Renewable Energy Requirements:
   a. At this time, Nebraska does not have any renewable energy reporting requirements.
New Mexico

I. State Summary

<table>
<thead>
<tr>
<th></th>
<th>Renewable Energy Requirements</th>
<th>Conservation/ Energy Efficiency requirements</th>
<th>Treatment of Hydro</th>
</tr>
</thead>
<tbody>
<tr>
<td>New Mexico</td>
<td>None</td>
<td>None</td>
<td>N/A</td>
</tr>
</tbody>
</table>

Table 8-6. New Mexico REO

I. Conservation and Energy Efficiency Requirements

a. Basin Electric does not have direct sales in New Mexico and there are no conservation or energy efficiency requirements in the state.

II. Renewable Energy Requirements:

a. Basin Electric does not have direct sales in New Mexico.
## North Dakota

### I. State Summary

<table>
<thead>
<tr>
<th>Renewable Energy Requirements</th>
<th>Conservation/ Energy Efficiency requirements</th>
<th>Treatment of Hydro</th>
</tr>
</thead>
<tbody>
<tr>
<td>North Dakota VOLUNTARY OBJECTIVE 10 % by 2015</td>
<td>None</td>
<td>Eligible Renewable: For purposes of qualifying for the renewable electricity and REO contained in section 49-02-28, electricity, except for electricity generated from a hydroelectric facility with an in-service date before January 1, 2007, and electricity that is not obtained from repowering or efficiency improvements to a hydropower facility existing on August 1, 2007, regardless of the source’s in-service date, qualifies for meeting the statewide objective provided that the source meets the requirements of ND PSC’s rules for tracking, recording, and verifying renewable energy certificates. Calculation of total Retail Sales: For purposes of calculating the amount of electricity from renewable energy and recycled energy sources needed to meet the REO, a retail provider may deduct from its baseline of total retail sales the proportion of electricity obtained from hydroelectric facilities with an in-service date before January 1, 2007.</td>
</tr>
</tbody>
</table>

Table 8-7. North Dakota REO

### II. Conservation & Energy Efficiency Requirements

a. The State of North Dakota has no requirements with respect to conservation or energy efficiency.

### III. Renewable Energy Requirements

a. North Dakota law: Chapter 49-02-28 establishes a state renewable and recycled energy objective. The statute provides that “ten percent of all electricity sold at retail within the state by the year 2015 be obtained from renewable energy and recycled energy sources. The objective must be measured by qualifying megawatt-hours delivered at retail or by certificates representing credits purchased and retired to offset non-qualifying retail sales. This objective is voluntary and there is no penalty or sanction for a retail provider of electricity that fails to meet this objective.”
b. Hydro: Chapter 49-02-30 provides that, “a retail provider may deduct from its baseline of total retail sales the proportion of electricity obtained from hydroelectric facilities with an in-service date before January 1, 2007.”

c. Waste Heat: Chapter 49-02-25 provides that, “recycled energy systems producing electricity from currently unused waste heat resulting from combustion or other processes into electricity and which do not use an additional combustion process,” may be counted as renewable.

d. Independent Verification: Chapter 49-02-33 provides that, “Electricity generation applied to the renewable energy and recycled energy objective, as well as certificate purchases and certificate retirements, must be independently verified through a third-party tracking system selected by the public service.”

e. Reporting Requirements & Time Periods: Chapter 49-02-34 provides that, “Commencing on June 30, 2009, retail providers shall report annually on the provider’s previous calendar year’s energy sales. This report must include information regarding qualifying electricity delivered and renewable energy and recycled energy certificates purchased and retired as a percentage of annual retail sales and a brief narrative report that describes steps taken to meet the objective over time and identifies any challenges or barriers encountered meeting the objective. The last annual report must be made on June 30, 2016. Retail providers shall report to the public service commission, which shall make data and narrative reports publicly available and accessible electronically on the Internet. Distribution cooperatives may aggregate their reporting through generation and transmission (G&T) cooperatives.” At this time, the ND PSC does not require green tags to be retired through M-RETS.
South Dakota

I. State Summary

<table>
<thead>
<tr>
<th>Renewable Energy Requirements</th>
<th>Conservation/ Energy Efficiency requirements</th>
<th>Treatment of Hydro</th>
</tr>
</thead>
<tbody>
<tr>
<td>South Dakota</td>
<td>VOLUNTARY OBJECTIVE 10 % by 2015</td>
<td>None but conserved energy qualifies as a renewable energy</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Eligible Renewable- new hydro with a nameplate rating of 10 megawatts or less, and hydro in existence on January 1, 2005, with a nameplate rating of 30 megawatts or less.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Calculation of total Retail Sales: For purposes of calculating the amount of electricity from renewable energy and recycled energy sources needed to meet the REO, a retail provider may deduct from its baseline of total retail sales the proportion of electricity obtained from hydroelectric facilities with an in-service date before January 1, 2007.</td>
</tr>
</tbody>
</table>

Table 8-8. South Dakota REO

II. Conservation & Energy Efficiency Requirements

a. In February 2008, South Dakota enacted legislation (HB 1123) establishing an objective that 10% of all retail electricity sales in the state be obtained from renewable and recycled energy by 2015. In March 2009, this policy was modified by also allowing “conserved energy” to meet the objective. The objective applies to all retail providers of electricity in the state. However, as a voluntary objective (as opposed to a mandatory standard), there are no penalties or sanctions for retail providers that fail to meet the goal. In the case of conserved energy, the objective will be measured by methods established by the South Dakota Public Utilities Commission (PUC). At this time, the PUC has not established such methods.
Ill. Renewable Energy Requirements

a. South Dakota Law 49-34A-101, “establishes a state renewable and recycled energy objective that ten percent of all electricity sold at retail within the state by the year 2015 be obtained from renewable energy and recycled energy sources. The objective shall be measured by qualifying megawatt-hours delivered at retail or by certificates representing credits purchased and retired to offset non-qualifying retail sales. This objective is voluntary and there is no penalty or sanction for a retail provider of electricity that fails to meet this objective.”

b. Hydro: 49-34A-103 South Dakota law provides that, “a retail provider may deduct from its baseline of total retail sales the proportion of electricity obtained from hydroelectric facilities with an in-service date before July 1, 2008.”

c. Waste Heat: South Dakota does consider waste heat recycled energy and thus qualifies as renewable electricity.

d. Independent Verification: Electricity generation applied to the renewable energy and recycled energy objective, as well as certificate purchases and certificate retirements, must be independently verified through a third-party tracking system selected by the public service.

e. Reporting Time Period: 49-34A-105 South Dakota law provides that, “Commencing on July 1, 2009, retail providers shall report annually on the provider’s previous energy sales during the twelve month period ending on the preceding December 30. This report shall include information regarding qualifying electricity delivered and renewable energy and recycled energy certificates purchased and retired as a percentage of annual retail sales and a brief narrative report that describes steps taken to meet the objective over time and identifies any challenges or barriers encountered meeting the objective. The last annual report must be made on December 1, 2017. The commission shall make the data and narrative reports available and accessible to the public on the Internet. The commission shall compile the data obtained from the reports and submit the data to the Legislature by the following January 1. A distribution cooperative may aggregate its reporting through generation and transmission (G&T) cooperatives.”
Wyoming

I. State Summary

<table>
<thead>
<tr>
<th></th>
<th>Renewable Energy Requirements</th>
<th>Conservation/ Energy Efficiency requirements</th>
<th>Treatment of Hydro</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wyoming</td>
<td>None</td>
<td>None</td>
<td>N/A</td>
</tr>
</tbody>
</table>

Table 8-9. Wyoming REO

II. Conservation & Energy Efficiency Requirements

a. The State of Wyoming has no requirements with respect to conservation or energy efficiency.

III. Renewable Energy Requirements

a. At this time, Wyoming does not have any renewable energy reporting requirements.

**Basin Electric Portfolio Compared to REOs**

Figure 8-2 shows the magnitude of renewable generation needed to meet voluntary and mandated state REO requirements.

Figure 8-3 compares the voluntary and mandated state REO requirements to Basin Electric’s current renewable generation portfolio.
Basin Electric and its members have always met all the REO requirements for those states that currently have such requirements and will continue to work with the members on small renewable generation purchases within Basin Electric's system.
9. Resource Needs Assessment

Highlights

- Basin Electric’s Eastern System is forecasted to be short of generation capacity starting summer of 2014 and is forecasted to continue to grow more deficit over time.
- By 2018, Basin Electric needs 575 megawatts (MW) of additional generation capacity to meet its obligations, by the end of the forecast period in 2028 that addition grows to 1,424 MW.
- Further evaluation will be done to determine exactly what magnitude and type (base load, intermediate or peaking) would best fit Basin Electric’s need by use of a production cost model.

Load And Capability

The difference in the load forecast plus other obligations (such as non-member sales, losses, and reserves, less Basin Electric system-wide load management) and existing and committed generating resources along with purchases define the load and capability of the Basin Electric system. The approved forecast only goes out to 2025, to move the forecast out to 2028 (to obtain a 15 year study time period) Basin Electric calculated an Average Annual Compound Growth Rate between 2023-2025 and applied that average growth rate to each additional year after 2025. This section provides the load and capability for the Basin Electric total system, as well as the eastern and western system separately. Figure 9-1 shows Basin Electric’s total system load and capability surpluses for 2013 through 2028.
Basin Electric’s total system is deficit 98 MW in 2017. This deficit is forecasted to grow to 1,016 MW by 2028. Since Basin Electric’s member systems reside on both the eastern and western interconnection and there is limited capability in moving power between the systems, Basin Electric further narrows its view on load and capability to the western and eastern systems.

Figure 9-2 shows Basin Electric’s western system load and capability surpluses through the year 2028. The western system does not show to be deficit through the study period.

Basin Electric has access to direct current (DC) ties to move power between the eastern and western systems. Transfers utilizing these DC ties are not incorporated into the graph and would allow Basin Electric to move surplus west-side generation to the east, up to the capability and rights to the ties, which is currently 240 megawatts in a west-to-east direction.
Basin Electric’s eastern system is 28 MW deficit in 2014 and is forecasted to grow to a 1,425 MW deficiency by 2028. The eastern system contains the Williston Basin area where there is considerable oil load development forecasted in the coming years.

Figure 9-3. Eastern System Seasonal Surplus Capacity

Basin Electric’s eastern system can be broken into three areas: the Integrated System (IS), Southwest Power Pool (SPP) and Midwest Independent Transmission System Operator (MISO). Figure 9-4 shows Basin Electric’s IS (WAUE) system. The IS is a transmission partnership between Western Area Power Administration (WAPA), Basin Electric and Heartland Consumers Power District (HCPD). This is the portion of the eastern system showing the greatest growth over the forecasted period. This area encompasses the oil developing region known as the Williston Basin. This graph does include transfers across direct current (DC) ties; the Rapid City DC Tie and the Stegall DC Tie; to transfer power from the west to the east. The graph shows the IS (WAUE) to be deficit 48 MW in 2016. This deficit is forecasted to grow year over year, to 172 MW by 2017 and 905 MW the end of the forecast period.
If the DC tie transfers are unavailable, or there is no surplus on the west to move east, the IS (WAUE) would show a deficit of 166 MW in 2014 and this deficit would continue to grow year over year to 1,146 MW by the end of the forecast period. This graph does not include potential transfers across the Rapid City DC Tie or Stegall DC Tie in either direction.

Figure 9-5 is Basin Electrics West Side system with the tie transfers moving power from the west to east. Even with the tie transfers the west side is still shown as having surplus capacity.
Basin Electric continually monitors how the load forecast is developing. This is completed prior to each season. The summer and winter forecast is monitored for peak load activity. The spring and fall forecasts are monitored to ensure power supply is available during maintenance periods. This is done because the forecast is developed every two years and some sectors may be growing faster or slower than anticipated in the official forecast. Once the load is determined for that season, Basin Electric determines if any surpluses are available to market or if power purchases are necessary. Purchases are typically for periods longer than a month.

**Characteristics Of Energy Needs**

Initially, load and capability is considered, which evaluates the peak hour of the season to determine if enough generation will be available to meet the peak load obligation plus reserves. Secondly, an evaluation is done on an hourly basis to determine what type of generation is needed to meet the hourly load obligations. This hourly energy evaluation is performed by starting with a historical per-unitized load pattern and scaling it to the forecasted load in a given year. Contracted sales are added on to develop the obligations portion.

The resource section is divided into energy resources and peaking resources, where peaking resources are peaking generation facilities that are only operated on an as-needed basis to cover the peaks and the energy resources are operated all the time as base load generation. Planned maintenance schedules are factored into the resource sections. Wind is modeled as negative load by taking the 2012 hourly wind generation profile and scaling it to the anticipated output of wind generation in a particular year and subtracting it from the obligations portions since it fluctuates constantly and would cause the graph to be difficult to read.

Evaluating Basin Electric’s system assumes available DC ties to transfer power between the eastern and western systems and this is not always how the two systems would operate in real time. But if pure optimization could occur, by 2020 Basin Electric’s IS (WAUE) System would be into its peaking resources all year round at varying degrees. In the peak months of December to January and July to August shows Basin Electric to be short energy. Figure 9-6 indicates Basin Electric would benefit with some form of intermediate resource in the 2020 time frame.

![Figure 9-6. IS (WAUE) System 2020 Energy Graph](image)
Figure 9-7 shows Basin Electric’s Western System in 2020. The western system is energy situation shows that Basin Electric has sufficient generation throughout the year.

The high voltage transmission system into the Williston Basin area is very close to its maximum load serving capacity, in that the load serving ability of the area may be impacted until additional transmission facilities are built to bring power into the region or Basin Electric has the ability to start generation located within the area. Currently Basin Electric is in the process of building a 345kV High Voltage Transmission line from Antelope Valley Station to Williston to Tioga, scheduled to be complete in 2016. Until that line is completed, the growing load in this area will be constrained by transmission limitations and will limit the amount of load that can be served in the area without the support of local generation.

Summary Of Need

The load and capability is used to determine the resource deficits over the planning horizon. The major inputs and assumptions affect the determination of future resource needs.

Basin Electric will need some portion of local generation in 2014 and 2015 to help with transmission reliability issues in the Williston Basin area until the 345kV High Voltage Transmission line from Antelope Valley Station to Williston will be completed. The local generation will also provide support during transmission outages with the line in place as well as support if the load within the area grows faster than is currently forecasted.

By 2018 Basin Electric’s IS System will need 250 MW of additional generating capacity and another 655 MW by 2028 for a total of approximately 905 MW. This is considering all DC Tie Transfers are available at all times.

Further evaluation will be done to determine exactly what magnitude and type (base load, intermediate or peaking) would best fit Basin Electric’s need by use of a production cost model. Also, it would be prudent to build slight surplus generation so Basin Electric is not out purchasing power the year after new generation is built.
10. Regional Power Supply Analysis

**Highlights**

- As it evaluates the need for future generation, Basin Electric must consider an analysis of the regional power supply system.
- The east side of Basin Electric’s service territory lies within the Midwest Reliability Organization’s MRO-U.S. subregion.
- The west side of Basin Electric’s service territory lies within the Western Electricity Coordinating Council’s (WECC) Rocky Mountain Power Area subregion.
- Both the MRO and the WECC are projecting adequate planning reserve margins until 2022.

In order to fully understand the need for new generation and how it will be met, a Regional Power Supply Analysis needs to be performed to determine what the region as a whole looks like. The two regions evaluated are the Midwest Reliability Organization (MRO), with a focus on the United States subregions and the Western Electricity Coordinating Council (WECC), with a focus on the Rocky Mountain Power Area subregion.

**Midwest Reliability Organization**

In January 2005, the MRO replaced MAPP as the North American Electric Reliability Corporation (NERC) regional reliability council. The MRO is a voluntary association committed to safeguarding reliability of the electric power system in the North Central Region of North America. The MRO membership is comprised of municipal utilities, cooperatives, investor-owned utilities, federal power marketing agency, Canadian Crown Corporations, and independent power producers. The MRO region spans eight states and two Canadian provinces covering roughly one million square miles. In January 2006, the MRO acquired additional members from the former Mid-America Interconnected Network, Inc. (MAIN) regional reliability council. Figure 10-1 shows the footprint of the MRO. There are two subregions within the MRO, the MRO-U.S. and MRO-Canada.
The following information is from pages 122-127 of the NERC Long-Term Reliability Assessment November 2012 report.

Planning Reserve Margins

MAPP is projecting adequate Planning Reserve Margins during the 2013–2022 assessment period. All Planning Reserve Margin categories (Anticipated, Prospective, and Adjusted Potential) exceed the NERC Reference Margin Level of 15 percent due to the area’s strong generation portfolio and Demand-Side Management programs through 2019 (MRO-MAPP Table 10-1 and MRO-MAPP Figure 10-2).

<table>
<thead>
<tr>
<th>MRO-MAPP-Table 1: Planning Reserve Margins</th>
</tr>
</thead>
<tbody>
<tr>
<td>ANTICIPATED</td>
</tr>
<tr>
<td>PROSPECTIVE</td>
</tr>
<tr>
<td>ADJUSTED POTENTIAL</td>
</tr>
<tr>
<td>NERC REFERENCE</td>
</tr>
</tbody>
</table>

| ANTICIPATED | 37.37% | 34.28% | 34.82% | 29.00% | 27.20% | 24.70% | 22.11% | 20.07% | 18.10% | 16.29% |
| PROSPECTIVE | 37.37% | 34.28% | 34.82% | 29.00% | 27.20% | 24.70% | 22.11% | 20.07% | 18.10% | 16.29% |
| ADJUSTED POTENTIAL | - | - | - | - | - | - | - | - | - |
| NERC REFERENCE | - | - | - | - | - | - | - | - | - |

Table 10-1. MRO-MAPP: Planning Reserve Margins

1 Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.
The Anticipated Reserve Margin falls below the NERC Reference Margin Level in 2020 and reaches 10.36 percent in 2022. This is a common situation in MAPP, which has traditionally planned to meet the NERC Reference Margin Level at least five to six years in advance, without considerations for additional Firm contracts or new peaking capacity units that have less certainty in the final years of the 10-year assessment. MAPP will provide more accurate plans for 2020–2022 in future long-term assessments, as load projections become more accurate, long-term contracts are executed, and new generation resources are planned. MAPP does not anticipate any scenarios that would lead to a significant detraction from these projections for this assessment period.

**Demand**

The forecasted 10-year compound annual growth rate for Total Internal Demand remains flat at 2.09 percent for the summer and 2.19 percent for the winter, increasing from 4,995 MW in 2013 to 6,015 MW in 2022 for the peak season (MRO-MAPP Table 10-2). This amounts to a 2.09 percent CAGR for the summer demand.

<table>
<thead>
<tr>
<th>MRO-MAPP-Summer</th>
<th>2013</th>
<th>2022</th>
<th>10-Year Change</th>
<th>CAGR</th>
</tr>
</thead>
<tbody>
<tr>
<td>NET INTERNAL DEMAND</td>
<td>4,904</td>
<td>5,906</td>
<td>1,002</td>
<td>20.4%</td>
</tr>
<tr>
<td>Load-Modifying Demand Response</td>
<td>91</td>
<td>109</td>
<td>18</td>
<td>19.3%</td>
</tr>
<tr>
<td>TOTAL INTERNAL DEMAND</td>
<td>4,995</td>
<td>6,015</td>
<td>1,020</td>
<td>20.4%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>MRO-MAPP-Winter-1/2</th>
<th>2013/14</th>
<th>2022/23</th>
<th>10-Year Change</th>
<th>CAGR</th>
</tr>
</thead>
<tbody>
<tr>
<td>NET INTERNAL DEMAND</td>
<td>4,858</td>
<td>5,904</td>
<td>1,047</td>
<td>21.5%</td>
</tr>
<tr>
<td>Load-Modifying Demand Response</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>TOTAL INTERNAL DEMAND</td>
<td>4,858</td>
<td>5,904</td>
<td>1,047</td>
<td>21.5%</td>
</tr>
</tbody>
</table>

Table 10-2. MRO-MAPP: Demand Outlook
**Generation**

Current capacity amounts to 7,319 MW. There is currently no capacity categorized as Existing-Other or Existing-Inoperable. The primary fuel sources in MAPP are coal, hydro, natural gas, followed by oil and wind. Added capacity since the 2011LTRC amounts to only about 50 MW.

There are 584 MW of Future-Planned and Conceptual resources projected to come on-line throughout the assessment time frame (MRO-MAPP Table 10-3 and MRO-MAPP Figure 10-3).

<table>
<thead>
<tr>
<th>MRO-MAPP-Summer</th>
<th>Current</th>
<th>2022 Planned</th>
<th>2022 Planned &amp; Conceptual</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Capacity</td>
<td>Share</td>
<td>Capacity</td>
</tr>
<tr>
<td>Coal</td>
<td>3,174</td>
<td>43.4%</td>
<td>3,322</td>
</tr>
<tr>
<td>Petroleum</td>
<td>597</td>
<td>8.2%</td>
<td>597</td>
</tr>
<tr>
<td>Gas</td>
<td>999</td>
<td>13.7%</td>
<td>1,435</td>
</tr>
<tr>
<td>Nuclear</td>
<td>60</td>
<td>0.8%</td>
<td>60</td>
</tr>
<tr>
<td>Other/Unknown</td>
<td>41</td>
<td>0.6%</td>
<td>41</td>
</tr>
<tr>
<td>Renewables</td>
<td>2,448</td>
<td>33.4%</td>
<td>2,448</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>7,319</td>
<td>100.0%</td>
<td>7,903</td>
</tr>
</tbody>
</table>

Table 10-3. MRO-MAPP: Capacity Outlook

**MRO-MAPP Total Installed Generation Capacity (MW) as of 2012**

![Diagram showing generation capacity by fuel type]

**Total: 7319**

---

2 "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peak assessment areas) or 2012/2013 winter (for winter-peak assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
There have been no significant unit retirements, deferments, derates, or other negative impact to Existing. Certain capacity in the prior year.

MAPP is not projecting any significant new generation, generator uprates, units taken out of service, units brought back in service, or long-term outages over the assessment period. There has been no change in behind-the-meter generation, or changes in other “non-traditional” resources in the previous year.

Transmission

MAPP has 230 miles of greater-than-100 kV transmission line under construction and 716 miles of planned transmission projects above 100 kV that are expected to be in service within five years (MRO-MAPP Table 10-7). These projects are anticipated to come into service during the 2013–2022 study period to enable reliable and efficient transmission service for the MAPP Assessment Area. There is no potential reliability impact in not meeting target in-service dates of transmission identified. MAPP does not anticipate any existing, significant transmission lines or transformers being out of service through the assessment period. MAPP does not have any transmission constraints that could significantly impact reliability. One transmission project was noted to have permitting delays, but the delays are not expected to impact reliability. Sufficient transmission is being built to support its Future-Planned generation. During the assessment period, several significant transformers are also planned to be upgraded.

<table>
<thead>
<tr>
<th>MRO-MAPP</th>
<th>AC (Circuit Miles)</th>
<th>DC (Circuit Miles)</th>
<th>Total (Circuit Miles)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EXISTING</td>
<td>10,266</td>
<td>0</td>
<td>10,266</td>
</tr>
<tr>
<td>Currently Under Construction</td>
<td>230</td>
<td>0</td>
<td>230</td>
</tr>
<tr>
<td>Planned - Completed within First Five Years</td>
<td>716</td>
<td>0</td>
<td>716</td>
</tr>
<tr>
<td>Planned - Completed within Second Five Years</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2022 TOTAL (UNDER CONSTRUCTION &amp; PLANNED)</td>
<td>11,211</td>
<td>0</td>
<td>11,211</td>
</tr>
<tr>
<td>Conceptual - Completed within First Five Years</td>
<td>107</td>
<td>0</td>
<td>107</td>
</tr>
<tr>
<td>Conceptual - Completed within Second Five Years</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2022 TOTAL (UNDER CONSTRUCTION, PLANNED &amp; CONCEPTUAL)</td>
<td>11,318</td>
<td>0</td>
<td>11,318</td>
</tr>
</tbody>
</table>

Table 10-4. MRO-MAPP: Existing and Projected Transmission
Western Electricity Coordinating Council (WECC)

Western Electricity Coordinating Council (WECC) is one of 10 electric reliability councils in North America, encompassing a geographic area equivalent to over half the United States and the only reliability council operating in three countries. WECC is responsible for promoting electric system reliability, supporting competitive electricity markets, assuring access to the transmission grid, and providing a forum for coordinating the operating and planning activities of the western interconnected power grid. WECC’s 169 member companies and organizations, encompass an area of nearly 1.8 million square miles with about 71 million people. It is the largest and most diverse of the ten regional councils of the North American Electric Reliability Council (NERC).

WECC’s service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia; the northern portion of Baja, California; Mexico; and all or portions of the 14 western states in between. WECC is split into nine subregions: Alberta, Basin, British Columbia, Desert Southwest, Mexico, Northern California, Northwest United States, Rocky Mountain Power Area (RMPA), and Southern California. Basin Electric Power Cooperative focuses on the WECC-RMPA portion of WECC that consists of Colorado, Eastern Wyoming, and portions of Western Nebraska and South Dakota.

<table>
<thead>
<tr>
<th></th>
<th>Rocky Mountain</th>
</tr>
</thead>
<tbody>
<tr>
<td>Summer</td>
<td>12178</td>
</tr>
<tr>
<td>Winter</td>
<td>10331</td>
</tr>
</tbody>
</table>

Table 10-5. Peak Load (MW)

<table>
<thead>
<tr>
<th>Energy Source</th>
<th>Rocky Mountain</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>6309</td>
</tr>
<tr>
<td>Hydro</td>
<td>1313</td>
</tr>
<tr>
<td>Coal</td>
<td>7467</td>
</tr>
<tr>
<td>Wind</td>
<td>1629</td>
</tr>
<tr>
<td>Nuclear</td>
<td>0</td>
</tr>
<tr>
<td>Geothermal</td>
<td>0</td>
</tr>
<tr>
<td>Other Conv.</td>
<td>367</td>
</tr>
<tr>
<td>Biomass</td>
<td>0</td>
</tr>
<tr>
<td>Solar</td>
<td>30</td>
</tr>
<tr>
<td>Total</td>
<td>17114</td>
</tr>
</tbody>
</table>

Table 10-6. WECC total Installed Generation Capacity (MW) as of EOY 2011
Planning Reserve Margins

The Planning Reserve Margins, or target margins, were derived using the 2013 load forecast and the same method as the 2011 Power Supply Assessment (PSA). The PSA uses a building block method for developing the Planning Reserve Margins and has four elements:

- Contingency reserves
- Operating reserves
- Reserves for forced outages
- Reserves for one-year-in-ten weather events

By the summer of 2022, the difference between WECC’s Anticipated Resources (194,401 MW) and WECC’s Net Internal Demand (168,973 MW) is anticipated to be 25,429 MW (15.0 percent margin). This would be 759 MW above the target margin. Since the expected capacity resources result in margins that exceed target margins, it is reasonable to assume that only a portion of the reported resource additions will ultimately enter commercial service within the planning horizon.

WECC does not have an interconnection-wide formal Planning Reserve Margin standard. As previously mentioned, the WECC annual PSA summer and winter reserve target margins are developed using a building block method.

---

The Anticipated, Prospective, and Adjusted Potential Reserve Margins for the WECC Assessment Area remain above NERC Reference Margin Level throughout the 2013–2022 planning horizon. However, individual subregions do drop below the target in future years.

In the resource adequacy process, each BA is responsible for complying with the resource adequacy requirements of the state or provincial areas in which they operate. Some BAs perform resource adequacy studies as part of their Integrated Resource Plans, which usually provide a 20-year outlook. Other BAs perform resource adequacy studies that focus on the very short-term (1-2 years), but most projections provide at least a 10-year outlook. WECC’s PSA uses a study period of 10 years and uses the same zonal reserve target margins throughout the entire period. These target margins are applied as the NERC Reference Margin Level for each WECC subregion.

Similar to WECC’s PSA, resources that are energy-only or energy-limited resources (e.g., the portion of wind resources that is not projected to provide generation at the time of peak) are not counted toward meeting resource adequacy in this assessment. Also, resources such as distributed or behind-the-meter generation that are not monitored by the BA’s energy management systems are excluded from the resource adequacy calculation.

**Demand**

Total Internal Demand for the summer, the peak season for the entire WECC Assessment Area, decreased by 0.8 percent from 2010 to 2011. Summer temperatures in both 2010 and 2011 were normal to slightly warmer than normal which indicates actual demand reduction is associated with the continued slow economic recovery. The projected 2013 and 2022 Total Internal Demand forecasts and compound annual growth rates are presented in the following tables.

<table>
<thead>
<tr>
<th>WECC-Total-Summer</th>
<th>2013</th>
<th>2022</th>
<th>10-Year Change</th>
<th>CAGR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load-Modifying Demand Response</td>
<td>5,041</td>
<td>5,583</td>
<td>542</td>
<td>10.8%</td>
</tr>
<tr>
<td>TOTAL INTERNAL DEMAND</td>
<td>149,977</td>
<td>174,556</td>
<td>24,578</td>
<td>16.4%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>WECC-Total-Winter</th>
<th>2013/14</th>
<th>2022/23</th>
<th>10-Year Change</th>
<th>CAGR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load-Modifying Demand Response</td>
<td>2,018</td>
<td>2,385</td>
<td>367</td>
<td>18.2%</td>
</tr>
<tr>
<td>TOTAL INTERNAL DEMAND</td>
<td>134,024</td>
<td>152,814</td>
<td>18,790</td>
<td>14.0%</td>
</tr>
</tbody>
</table>

**Table 10-7. Demand Outlook - WECC Total**

The Total Internal Demand for the summer season is projected to increase by 1.7 percent per year for the 2013–2022 time frame, which is unchanged from the 1.7 percent projected last year for the 2012–2021 period. The annual energy load is projected to increase by 1.6 percent per year for the 2013–2022 time frame, which is unchanged from the 1.6 percent projected last year for the 2012–2021 period.

**Generation**

The generation data for this assessment was provided by all of the BAs within the Western Interconnection and was processed by WECC staff under the direction of the WECC Loads and Resources Subcommittee (LRS). The reported generation additions generally reflect extractions from generation queues.

Distributed generation, including rooftop solar and behind-the-meter generation, represents an insignificant portion of both the existing and planned resources. As noted previously, these resources are excluded from the resource adequacy calculation (i.e., they are not included as resources). The current resource mix by fuel type includes natural gas, hydro-powered, and coal-fired generation at 87,769 MW, 61,439 MW, and 35,069 MW, respectively.
Since last year’s assessment, expected available capacity increased by 363 MW. Thermal plant additions were largely gas-fired combined-cycle plants, while renewable additions were largely wind farms.

Gross Future-Planned additions are 12,033 MW for the United States, and 7,329 MW for Canada. Conceptual additions amount to 20,669 MW and 9,206 MW for the United States and Canada, respectively.

4 “Current” represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peak assessment areas) or 2012/2013 winter (for winter-peak assessment areas). “Share” represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

5 Ibid

6 Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.
Transmission

WECC is spread over a wide geographic area with significant distances between generation and load centers. In addition, the northern portion of the Assessment Area is winter peaking, while the southern portion of the assessment area is summer-peaking. Consequently, entities within the Western Interconnection may seasonally exchange significant amounts of surplus electric energy. These conditions result in periodic full loading on numerous transmission lines, but that full loading is deemed not to adversely impact reliability. Due to the inter-subregional transmission constraints, reliability in the Western Interconnection is best examined at a subregional level.

AC transmission line additions through 2022 have been reported at 15,841 circuit miles and 535 circuit miles of DC transmission. The reported existing and projected transmission additions are compiled in the following table (WECC-Total Table 10-12).

<table>
<thead>
<tr>
<th>WECC-Total</th>
<th>AC (Circuit Miles)</th>
<th>DC (Circuit Miles)</th>
<th>Total (Circuit Miles)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EXISTING</td>
<td>127,019</td>
<td>1,744</td>
<td>128,763</td>
</tr>
<tr>
<td>Currently Under Construction</td>
<td>199</td>
<td>0</td>
<td>199</td>
</tr>
<tr>
<td>Planned - Completed within First Five Years</td>
<td>5,784</td>
<td>535</td>
<td>6,319</td>
</tr>
<tr>
<td>Planned - Completed within Second Five Years</td>
<td>4,501</td>
<td>0</td>
<td>4,501</td>
</tr>
<tr>
<td>2022 TOTAL (UNDER CONSTRUCTION &amp; PLANNED)</td>
<td>137,503</td>
<td>2,279</td>
<td>139,782</td>
</tr>
<tr>
<td>Conceptual - Completed within First Five Years</td>
<td>2,759</td>
<td>0</td>
<td>2,759</td>
</tr>
<tr>
<td>Conceptual - Completed within Second Five Years</td>
<td>2,598</td>
<td>0</td>
<td>2,598</td>
</tr>
<tr>
<td>2022 TOTAL (UNDER CONSTRUCTION, PLANNED &amp; CONCEPTUAL)</td>
<td>142,860</td>
<td>2,279</td>
<td>145,139</td>
</tr>
</tbody>
</table>

Table 10-8. WECC-Total: Existing and Projected Transmission

There are a large number of transmission projects that have been reported to WECC. Some of these projects are duplicative in nature and may have a proposed path similar to another project. Since WECC does not yet the reported new projects and does not identify minimum transmission addition needs, the above tabulation may not closely reflect transmission additions that could occur during the assessment period. A delay of these projects could impact the timing and location of resource additions but should not adversely impact system reliability. The subregion sections of this assessment may identify some projects that could impact local area reliability. The WECC Transmission Project Information Portal provides a single location where interested parties can find basic information about major transmission projects in the Western Interconnection.

Transmission owners in the subregion have started construction on significant grid reinforcements and enhancements to support intra-regional power transfers and exports of wind generation.

---

7 WECC Transmission Project Information Portal: http://www.wecc.biz/PLANNING/TRANSMISSIONEXPANSION/MAP/Pages/
11. Analytical Approach

Highlights

• Basin Electric’s analytical approach for determining its options for resource expansion includes five steps: 1) portfolio development; 2) risk analysis; 3) operational simulation; 4) cost analysis; 5) selection of preferred portfolio.

• The process compares the cost and performance of various portfolios.

• Upon evaluating all the portfolio cost analysis and considering non-modeling factors, a preferred portfolio is selected.

Introduction

The main analytical objective of the Integrated Resource Plan is to determine the optimum portfolio, which is the resource portfolio with the best balance of costs and risk. The process compares the cost as measured by the Present Value of Revenue Requirements, or PVRR, and performance (risk or variability of PVRR) of the various portfolios. This chapter highlights the framework for accomplishing this objective.

Modeling Process

The modeling process consists of five distinct steps. A detailed explanation of these steps follows.

Step 1: Portfolio Development

Basin Electric uses Ventyx’s System Optimizer modeling software to help develop resource plans and evaluate RFP responses. This software can produce 20- to 30-year horizon resource investment plans to meet long-term reliability requirements, incorporating data such as technology type, fuel, size, location, and timing of capital projects.

The first step in the portfolio development process is to input the existing Basin Electric system, power supply, transmission, load forecasts, and current and future market conditions into the System Optimizer Modeling Software. This current system configuration is considered the “Base Case.”

After the base case has been input into the system, new projects or purchases can be added. These can range from responses to RFPs or self-build options. The software will include these potential new resources or purchases in developing the optimal resource portfolio for Basin Electrics load obligations.

These optional new resources/purchases are all run through System Optimizer to produce a “Resource Expansion Plan.” This expansion profile details which new resource/purchase should be added and when they should come online.
Step 2: Risk Analysis

Several risk base scenarios are performed to see what, if any changes, there are to what System Optimizer outputs as the best possible resource expansion plan portfolios. The risk analysis modifies outside variables and how these external changes affect the proposed resources. The Risks and Uncertainties chapter describes the risk scenarios in more detail.

The results of the scenario risk analyses identify and create portfolios which will perform the best according to the various risk measures. The end result of this risk analysis is a set of portfolios that are considered superior.

Step 3: Operational Simulation

These superior portfolios are then modeled within the Ventyx Planning and Risk Module. (The appendix contains a discussion on the Ventyx Planning and Risk model.) The model is used to simulate 15- and 20-year study periods. This results in a detailed simulation of the dispatch of the existing and new resources to meet forecasted obligations according to the constraints defined by the system topology.

Each simulation provides in a breakdown of the cost to operate the Basin Electric system, including all existing and new resources, unit capacity factors, market purchases and market sales. This information provides valuable information as to the financial performance of the portfolio.

Step 4: Cost Analysis

The Consolidated Model is a tool that combines the operating cost results from the Planning and Risk model with capacity purchases and the revenue required for new capital additions to provide a PVRR projection for each portfolio. This consolidation process is illustrated in Figure 11-1. The net variable cost from Planning and Risk includes system costs for fuel, variable plant operations and maintenance, unit start-up, market contracts and spot market purchases and sales. The variable costs included are for new resources and include existing system operations as well. Additional costs calculated in the Consolidated Model (if applicable to the portfolio) are capacity purchases and all the revenue requirement costs associated with adding incremental investment in new resources.
Analytical Approach

The Cost Analysis Model calculates the PVRR of the annual combined revenue requirement for the 15- and 20-year analysis periods for comparison among portfolios. Using the Cost Analysis Model for each portfolio, the PVRR along with several other cost metrics and operational parameters are used to facilitate side-by-side comparisons.

Step 5: Selection of Preferred Portfolio

Upon evaluating all the portfolio cost analyses and considering non-modeling factors, a Preferred Portfolio is selected.

Summary

Basin Electric’s analytical approach to portfolio analysis is comprehensive and results in the Preferred Portfolio of resource additions to meet future needs. This analytical approach is the general approach Basin Electric uses for resource expansion justification.
12. Resource Alternatives

Highlights

- Resource alternatives evaluated by Basin Electric as options for generation within its eastern system include: demand-side management, renewable energy sources, fossil fuel generation, nuclear power, repowering or uprating existing units, and purchased power or requests for proposals.

- The power-generation technologies presented with their respective competitive costs are wind, solar, hydroelectric, geothermal, biomass, biogas, municipal solid waste, simple cycle combustion turbine combined cycle combustion turbine, microturbines, and coal facilities.

The specific alternatives addressed in this analysis include the following:

- Demand-Side Management
- Renewable Energy Sources
  - Wind
  - Solar
  - Hydroelectric
  - Geothermal
  - Biomass Power
  - Biogas
  - Municipal Solid Waste
- Fossil Fuel Generation
  - Simple Cycle Combustion Turbine
  - Combined Cycle Combustion Turbine
  - Microturbine
  - Coal Facility
- Nuclear Power
- Repowering/Uprating of Existing Generating Units
- Purchased Power / Request for Proposal
Demand-Side Management

Demand Side Management (DSM) is the process of managing the consumption of energy, generally to optimize available and planned generation resources. According to the Department of Energy, DSM refers to “actions taken on the customer’s side of the meter to change the amount or timing of energy consumption. Utility DSM programs offer a variety of measures that can reduce energy consumption and consumer energy expenses. Electricity DSM strategies have the goal of maximizing end-use efficiency to avoid or postpone the construction of new generating plants.”

DSM programs aim to achieve three broad objectives: energy conservation, energy efficiency and load management. Energy conservation can reduce the overall consumption of electricity by reducing the need for heating, lighting, cooling, cooking energy and other functions. Energy efficiency can encourage consumers to use energy more efficiently, and thus get more out of each unit of electricity produced. Load management allows generation companies to better manage the timing of their consumers’ energy use, and thus help reduce the large discrepancy between on-peak and off-peak demand.

Basin Electric and its members are engaged in a variety of conservation and energy efficiency programs. The programs and activities were developed to promote, support and market dual heat, water heaters, heat pumps, air conditioning, storage heating, grain drying, irrigation, photovoltaic, energy audits, and numerous other programs. A number of Basin Electric’s members have developed programs and these programs vary depending on the cooperative; some elect to utilize rebates, others energy resource conservation (ERC) loans, others rates, some all three and some may elect not to adopt any of the programs.

Energy conservation and efficiency programs are capable of lessening the impact of electrical demand and reducing the capacity of future additional generation facilities. Energy conservation is behavior based while energy efficiency is technology based. Therefore, energy conservation and efficiency programs could be considered in parallel to adding additional generating capability to meet the Basin Electric projected demand.

Approximately half of the Basin Electric members are utilizing load management to manage their power purchases from Basin Electric. This was further discussed in Chapter 9: Resource Needs Assessment. Basin Electric has implemented a system-wide load management program on its eastern system which enables Basin Electric to target large loads and/or generation that are not included in the members’ load management programs to be used during Basin Electric’s seasonal peak periods. Basin Electric has approximately 20-33 MW of load management available at this time and is continuing to look to improve this.
Renewable Energy Sources

Renewable energy comes from sources that are essentially inexhaustible in duration, but limited in the amount of energy that is available per unit of time. These energy supplies can be endless resources such as the sun, the wind, and the heat of the Earth, or they can be replaceable fuels such as biomass, i.e. combustible plants or plant extracts, such as ethanol. The renewable energy sources evaluated in this section include wind, solar, hydroelectric, geothermal, biomass, biogas and municipal solid waste. In 1850, about 90 percent of energy consumed in the United States was from renewable energy resources. Now the United States is heavily reliant on the non-renewable fossil fuels: coal, natural gas, and oil. In 2011, the United States generated about 4,106 billion kilowatt-hours of electricity. About 68% of the electricity generated was from fossil fuel (coal, natural gas, and petroleum), with 42% attributed from coal.

Energy sources and percent share of total for electricity generation in 2011:

- Coal 42%
- Natural Gas 25%
- Nuclear 19%
- Hydropower 8%
- Other Renewable 5%
  - Biomass 1.38%
  - Geothermal 0.41%
  - Solar 0.04%
  - Wind 2.92%
- Petroleum 1%
- Other Gases < 1%

These statistics show that 13 percent of total electricity production was contributed from renewable energy in 2011. Non-hydro renewables make up 5 percent of the total generation in the United States in 2011.

Figure 12-1. U.S. Electricity Generation by Energy Source, 2011

Wind

1 http://www.eia.gov/energy_in_brief/article/renewable_electricity.cfm
Wind turbines convert the power in the wind into electricity by extracting the kinetic energy in the wind, and utilizing the wind turbine to generate mechanical power. The greatest advantage of wind power is its electricity generation without local emissions of any kind. Another advantage of wind power is once a wind farm is built, the cost of the electricity it generates remains stable because there are no fuel price increases or volatility. Acquiring wind power allows utilities to lock in stable priced electricity for as long as 30 years.

The development of wind power is increasing in many regions of the United States including the states that Basin Electric serves. Installed wind electric generating capacity expanded by 17 percent, which amounted to 39,135 MW during 2010 in the United States to 45,982 MW by 2011\(^2\). Figure 12-2 shows the amount of generating capacity in each state as of the end of 2012.

Figure 12-2. United States Wind Power Capacity (MW) (Oct 25, 2012)\(^3\)

---

\(^2\) EIA Electric Power Annual 2011, Release Data: January 30, 2013; Table 3-13 http://www.eia.gov/electricity/annual/

\(^3\) http://www.nrel.gov/gis/images/windcap1-1-23currcap.jpg
As a renewable resource, wind is classified according to wind power classes, which are based on typical wind speeds. These classes range from class 1 (the lowest) to class 7 (the highest). In general, wind power class 4 or higher can be useful for generating wind power with large (utility-scale) turbines, and small turbines can be used at any wind speed. Class 4 and above are considered good resources. Figure 12-3 is a map of the United States showing the general wind speeds at 80 meter heights.

Figures 12-4 through 12-9 show, in greater detail, some of the states wind resources within Basin Electric’s eastern system. The states include Montana (Figure 12-4), North Dakota (Figure 12-5), South Dakota (Figure 12-6), Minnesota (Figure 12-7), Iowa (Figure 12-8), and Nebraska (Figure 12-9).

* http://www.nrel.gov/gis/images/80m_wind/USwind300dpe4-11.jpg
The map shows good to excellent wind resource areas are distributed throughout the eastern two-thirds of Montana. The region just east of the Rocky Mountains in Northern Montana has excellent to superb wind resource. Other outstanding resource areas are on the hills and ridges between Great Falls and Havre. The region between Billings and Bozeman also has excellent wind resource areas. Ridge crest locations have the highest resource in the western third of Montana. The American Wind Energy Association (AWEA) estimated the state wind resource to be 944,044 MW at 80 meter hub heights and ranks Montana as 3rd in the US for wind potential.\(^5\)

\(^5\) http://www.nrel.gov/gis/mapsearch/
\(^6\) http://www.awea.org/learnabout/publications/factsheets/factsheets_state.cfm
The map shows good to excellent wind resource areas are located throughout North Dakota. The American Wind Energy Association estimated the state wind resource to be 770,196 MW at 80 meter hub heights and ranks North Dakota as 6th in the U.S. for wind potential. 

---

7 http://www.nrel.gov/gis/mapsearch/
8 http://www.awea.org/learnabout/publications/factsheets/factsheets_state.cfm
The map shows good to excellent wind resource areas are located in areas throughout the state especially north of the Black Hills region and east of the Missouri River. The American Wind Energy Association estimated the state wind resource to be 882,412 MW at 80 meter hub heights and ranks South Dakota as 5\textsuperscript{th} in the US for wind potential.\textsuperscript{10}
The map shows that Minnesota has significant wind resources in the extreme Southwest region of the state. The areas of the east and northeast show a very poor area of wind resources. The American Wind Energy Association estimated the state wind resource to be 489,271 MW at 80 meter hub heights and ranks Minnesota as 11th in the US for wind potential.\(^\text{12}\)

---

11 http://www.nrel.gov/gis/mapsearch/

12 http://www.awea.org/learnabout/publications/factsheets/factsheets_state.cfm
The map shows good to excellent wind resource areas are located throughout Iowa especially in the west and northwest areas of the state. The American Wind Energy Association estimated the state wind resource to be 570,714 MW at 80 meter hub heights and ranks Iowa as 7th in the US for wind potential.¹⁴

Figure 12-8. Iowa Wind Resource Map¹³

http://www.nrel.gov/gis/mapsearch/

http://www.awea.org/learnabout/publications/factsheets/factsheets_state.cfm
The map shows good to excellent wind resource areas are located throughout Nebraska. The American Wind Energy Association estimated the state wind resource to be 917,999 MW at 80 meter hub heights and ranks Nebraska as 4th in the US for wind potential.\(^{16}\)

Fixed, investment-related costs are the largest component of wind-based electricity costs. Improved designs with greater capacity per turbine have reduced investment costs. Wind power plants incur no fuel costs and their maintenance costs have also declined with improved designs.

Due to the intermittent nature of wind, a wind power plant’s economic feasibility strongly depends on the amount of energy it produces. Capacity factor serves as the most common measure of a wind turbine’s productivity. Estimates of capacity factors range from 30 to 40 percent. Wind is considered a fuel displacer and it can be integrated with natural gas fueled facilities to provide the energy shape required in most areas.

A major issue regarding wind is it is intermittent and that the wind power can offer energy, but not on-demand capacity. With wind’s unpredictable nature, forecasting how the wind is going to blow and accurately scheduling the generation is rather difficult. Work is being done to improve the forecasting capability of wind generation to make wind or wind integrated with natural gas peaking generation a more economical alternative.

Currently Basin Electric’s wind resource capacity is calculated using the MAPP guidelines. Basin Electric calculates an URGE value for our wind resources based on the median value of the daily net generation occurring during the four continuous hours when the usual peak demand hour of every month occurs. This results in the appropriate, but significant derate from the nameplate of these resources.

\(^{15}\) http://www.nrel.gov/gis/mapsearch/

\(^{16}\) http://www.awea.org/learnabout/publications/factsheets/factsheets_state.cfm
Basin Electric is currently in the process of studying whether or not to join an RTO. The two RTOs being studied are MISO and SPP. Below is a summary of how each RTO handles wind resource capacity credits.

The MISO system-wide wind resource capacity credit for Planning Year 2013 is 13.3 percent\textsuperscript{17}. This system-wide MISO wind capacity credit is based on determining the Effective Load Carrying Capability (ELCC) of the intermittent wind resources. A first LOLE simulation is done with the historical-hourly load and same corresponding historical-hour wind resource outputs. This sets an LOLE benchmark. In a second LOLE simulation the wind resources are removed and replaced with a trial amount of load reduction that is varied until the same benchmark LOLE result is achieved. The amount of load reduction that achieves the same LOLE result is then the ELCC. As a percentage the ELCC is the resulting load reduction MW divided-by registered wind capacity MW.

The SPP system-wide wind resource capacity credit is a calculated value and varies from wind facility to wind facility. The calculation involves the all available hourly net power measured at the system interconnection and the hourly net power output values occurring during the top 10% of load hours for the SPP Member. Then select the hourly net power expected from the facility 85% of the time or greater. Those facilities less than 3 years of commercial operation must include all available data up to 3 years for calculation or can forgo the calculation and submit a 3% resource capacity credit for wind. Facilities with 4 or more years of commercial operation must include all available data up to 10 years for calculation in no calculation is completed the net capability of the resource will be 0 MW\textsuperscript{18}.

Wind cannot fulfill the long-term capacity need for generation for Basin Electric due to its intermittent nature, typically having an annual capacity factor of 30 to 40 percent. Wind could, however, help meet the intermediate generation need of Basin Electric if it could be forecasted accurately or integrated with natural gas generation to provide a schedulable product. Basin Electric will need to study the effects on our current wind with respect the wind resource capacity credit and whether additional wind is warranted.

\textsuperscript{17} MISO Planning Year 2013-2014 Wind Capacity Credit, December 2012

\textsuperscript{18} Southwest Power Pool Criteria, January 30, 2012
Solar

The sun is an infinite source of energy for our planet. Current technologies allow for the harness of solar energy for heating, lighting, cooling, and electricity. The sun’s energy can be converted to electricity directly through photovoltaic cells (solar cells). However, solar energy varies by location and by the time of year. Solar resources are expressed in watt-hours per square meter per day (Wh/m²/day). This is roughly a measure of how much energy falls on a square meter over the course of an average day.

There are two types of solar collectors, first is a flat-plate collector and the second is a concentrator collector. The flat-plate collectors are generally fixed in a single position, but can be mounted on structures that tilt toward the sun on a seasonal basis, or on structures that roll east to west over the course of the day. The concentrator collectors focus direct sunlight onto solar cells for conversion to electricity. These collectors are on a tracker, so they always face the sun directly and because these collectors focus the sun’s rays, they only use the direct rays coming straight from the sun.

Figure 12-10 shows a map of the United States and the amount of solar resource capability with a flat-plate collector in an area.

---

19 http://www.nrel.gov/gis/mapsearch/
Figure 12-11 shows a map of the United States and the amount of solar resource capability with a concentrator collector in the area.

North Dakota, South Dakota, Minnesota, Montana, Iowa and Nebraska could pursue some type of solar technologies, but likely not for large-scale thermal electricity systems as large-scale systems are not effective with this resource.

Photovoltaic systems are expected to be used in the United States for residential and commercial buildings, distributed utility systems for grid support, peak power shaving, and intermediate daytime load following with electric storage and improved transmission, for dispatchable electricity, and Hydrogen gas (H2) production for portable fuel.

Due to the intermittent nature of solar power, economic feasibility strongly depends on the amount of energy it produces. Capacity factor serves as the most common measure of solar power productivity. Estimates of capacity factors range from 20 to 35 percent.

The main advantages of photovoltaic (PV) systems are their modularity, portability, high reliability, and low environmental impact. These systems have no (or few) moving parts, which means operating and maintenance costs are low. Another obvious benefit of PV systems is that the sun provides abundant and free fuel. But it can be very unpredictable due to weather. However, solar power is not dispatchable in a traditional sense, meaning its output cannot be controlled and scheduled to respond to the variable consumer demand for electricity. It does, however, have the advantage of providing output that has considerable coincidence with natural demand for electricity, driven largely by daytime activities particularly in the summer when a large amount of electricity is used for air conditioning.

20 http://www.nrel.gov/gis/mapsearch/
Fixed, investment-related charges are the largest component of solar-based electricity costs. Capital costs for PV systems range from $4,200 to $5,000 per kilowatt and are offset by low operating costs, i.e. no fuel. The 20-year life cycle cost range from $200/MWh to $500/MWh21.

Solar power could not fulfill a long-term capacity need for generation for Basin Electric because the intermittent power is not schedulable and it has a high cost of generation. Solar power could help fulfill the need for intermediate generation as it generally has an annual capacity factor of 20-35 percent. It could be integrated with natural gas generation to provide a more stable product for the time when the sun does not shine. Basin Electric would probably look at wind generation as being a better alternative than solar especially when factoring in the wind potential within the Dakotas and the limited availability of solar power within Basin Electric’s eastern system.

Basin Electric has a policy within its rate structure to purchase small renewable power from a member that has either wind, solar or biomass generation facilities located on their respective members systems. Due to this policy, Basin Electric would work with its member systems for this type of renewable power and would not move toward developing the resource itself.

**Hydroelectric**

Hydroelectric power (hydropower) is the kinetic energy of flowing watery. Hydropower is captured and used to power machinery or converted to electricity. Hydropower plants will typically dam a river or stream to store water in a reservoir. The water is released from the reservoir and it flows through a turbine causing it to spin and activates a generator to produce electricity.

Completed in 1962, Oahe Dam is one of six main stem projects in the upper Missouri River Basin.

---

Another type of hydroelectric power plant, referred to as a pumped storage plant, has the capacity to store energy. The water flows through (forward) a generator to a lower reservoir to produce electricity. Later the generators turn the turbines backward, and cause the turbines to pump water from the lower reservoir to an upper reservoir, where the energy (water) is stored. To use the energy, the water is released from the upper reservoir back down to the lower reservoir which turns the turbines forward and activates the generators to produce electricity. The main efficiency in using this process is to pump water up to the upper reservoir during off-peak time and then release the water to flow down through the generators during on-peak times.

To have a viable hydropower resource, a state must have both a large volume of water and a significant change in elevation. In 2011 there was 78,652 MW of hydropower capacity producing 260,000 to 320,000 million kWh of generation annually. Figure 12-13 shows the potential for hydropower in the United States. The amount of hydropower resource varies widely among states. The northwest and western states have the highest potential for hydropower.

---

22 EIA Electric Power Annual, Release Data: January 30, 2013; Table 1-1 http://www.eia.gov/electricity/annual/
Figure 12-13. Total Estimated Potential for Hydropower

Table 12-1. Total hydropower in Basin Electric’s Service Territory States

<table>
<thead>
<tr>
<th>State</th>
<th>2010</th>
<th>2009</th>
<th>% Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minnesota</td>
<td>752</td>
<td>809</td>
<td>-7</td>
</tr>
<tr>
<td>North Dakota</td>
<td>2,042</td>
<td>1,475</td>
<td>38.4</td>
</tr>
<tr>
<td>South Dakota</td>
<td>5,765</td>
<td>4,432</td>
<td>30.1</td>
</tr>
<tr>
<td>Montana</td>
<td>9,230</td>
<td>9,506</td>
<td>-2.9</td>
</tr>
<tr>
<td>Iowa</td>
<td>831</td>
<td>971</td>
<td>-14.4</td>
</tr>
<tr>
<td>Nebraska</td>
<td>449</td>
<td>434</td>
<td>3.6</td>
</tr>
</tbody>
</table>

Table 12-1 shows the total hydropower in Basin Electric’s service territory states.

Figure 12-14 shows the undeveloped hydropower capacity potential by state. North Dakota has 50 MW of undeveloped potential, Minnesota has 136 MW of undeveloped potential, South Dakota has 695 MW of undeveloped potential, and Montana has 1,014 MW of undeveloped potential. The graph does not included pumped storage potential.

There are different categories of hydropower facilities: impoundment hydropower, diversion hydropower, run-of-river hydropower, microhydropower and pumped-storage hydropower. Most hydropower facilities are built through federal, state, or local agencies and are part of a multipurpose project. In addition to producing electricity, the multipurpose project may include for flood control, water supply, irrigation, transportation, recreation, or wildlife habitat and refuges, this is shown in Figure 12-15.

Impoundment hydropower facilities use a dam to store water in a reservoir. Water is released from the reservoir to meet changing electricity need, maintain a constant water level, or for environmental purposes such as preserving wildlife habitat.

Diversion hydropower is the diversion of a portion of the river or stream through a canal or penstock (but may require a dam) to the turbines. The weather and seasonal variation in the river’s water level can result in significant fluctuations in power production.

Run-of-River hydropower utilizes the flow of water within the natural range of the river, requiring little or no impoundment. Run-of-river plants can be designed using large flow rates with low head or small flow rates with high head.

26 http://hydropower.inel.gov/hydrofacts/benefit_us_dams.shtml
Micro hydropower projects produce 100 kilowatts (kW) or less. Micro hydro plants can utilize low heads or high heads.

Pumped-storage hydropower facilities have reversing turbines that can pump water from a lower reservoir to an upper reservoir at times when demand for electricity is low and excess electricity is available from other sources on the power grid.

Some major environmental impacts would be the ecology of the natural river system, water quality, alteration of river flows, land use alternations, and construction of reservoirs and structures.

Hydropower is the least expensive source of electricity in the United States, with typical efficiencies of 85 to 92 percent during production. The EIA reports hydropower capital costs to be $2,000 to $3,000/kW. The EIA states the operating and maintenance costs are relatively low at about $4 to $6/MWh and the total levelized cost of hydropower is projected to be about $40-80/MWh. A hydropower facility will most likely operate longer than 50 years and on average they are around 50 MW in size. Due to the seasonal nature of hydropower, the average annual capacity factor for most facilities is approximately 40 to 50 percent. Another major issue regarding hydropower is its year-to-year unpredictable nature due to annual rainfall variability.

Over the last 30 years, Basin Electric, as well as other entities, has evaluated the option of the Gregory County Pumped Storage Project. This project is for a pumped storage facility located within Gregory County South Dakota near Lake Francis Case. Some of the advantages of this project include 1,200 MWs of new generation (battery), the facility has a quick response time and the facility would be considered renewable energy. However, there are a number of disadvantages to this project which include roughly 1.4 MWs in to the facility off peak to produce 1.0 MW out of the facility when needed, the facility includes a very high capital cost of approximately $2,900/kW and could only operate at most 40 percent capacity factor and probably, more realistically, 15 to 20 percent. It would most likely take 10 years or more to get the unit permitted, constructed and ready for commercial operation. One way Basin Electric evaluated this option was by using System Optimizer. The economics did not justify the investment. Also due to the tremendous difference in time to commercial operation, resource availability, such as in the reservoir being full when needed, and the need for partners with the pumped storage facility, Basin Electric determined this would not be an alternative to move forward with at this time.

Due to the fact that hydroelectric power production is seasonal with an average annual capacity factor of 40 to 50 percent and depends greatly on year-to-year rainfall levels, this type of resource could not meet a base-load generation need for Basin Electric. It could meet potential intermediate need, but the costs are too high and permitting would be very difficult. Therefore Basin Electric would not pursue hydroelectric power any further.

Geothermal

Geothermal energy is thermal energy from the Earth’s interior where temperatures reach greater than 7,000°F. The heat is brought to the surface as steam or hot water and used to produce electricity or applied directly for space heating and industrial processes. Currently, there is about 9,700 MWs of geothermal electricity around the world, with approximately 3,500 MWs in the United States.

---

30 EIA Electric Power Annual 2011, Release Data: January 30, 2013, Table 4-3 http://www.eia.gov/electricity/annual/
There are three types of geothermal energy. The first is power generation (or electric), which utilizes steam turbines using natural steam or hot water flashed to steam, and binary turbines produce mechanical power that is converted to electricity. The second is a direct use application where a well brings heated water to the surface. A mechanical system delivers the heat to the space or process and a disposal system either injects the cooled geothermal fluid under ground or disposes of it on the surface. The third and most rapidly growing use for geothermal energy is geothermal heat pumps, which use the earth or groundwater as a heat source in winter and a heat sink in summer. This is otherwise known as a device which transfers heat from the soil to the house in winter and from the house to the soil in summer. Figure 12-16 shows geothermal resources throughout the United States.

It is generally said that electric use would be 200°C or greater, direct use would be 150°C to 200°C and heat pumps would be 100°C to 150°C. Therefore, North Dakota has low to moderate temperature resources that can be tapped for direct heat or for geothermal heat pumps. However, electricity generation is not possible with these resources. South Dakota has high-temperature resources that are suitable for electricity generation, as well as direct use and heat pump applications. Montana has high-temperature resources that are suitable for electricity generation as well as direct use and heat pump applications. Minnesota has vast low-temperature resources suitable for geothermal heat pumps. However, Minnesota does not have sufficient resources to use the other geothermal technologies.

Geothermal power plants are very reliable when compared to conventional power plants. Geothermal power plants will typically have an availability factor of 95 percent or more and their capacity factor is highest among all types of power plants. Steam plants use very hot (more than 300°F or roughly 150°C) steam and hot water resources. Binary plants use lower-temperature, but much more common, hot water resources (100°F to 300°F or approximately 40°C to 150°C).

---

31 http://www.nrel.gov/gis/mapsearch/
Geothermal electric power capital costs typically range from $2,400-$3,000/kW with a variable cost of 9.6 cents/kWh. Technology improvements are lowering that range steadily.

Due to the limited locations that electric generation from geothermal is available within Basin Electric's service territory, this alternative will not be pursued any further. However, if an entity came to Basin Electric with a proposed project, Basin Electric would fully evaluate that option and determine if it was a viable option at that time.

**Biomass Power**

Biomass power (biopower) is the generation of electric power from biomass resources. These resources include urban waste wood, crop and forest residues and, in the future, crops grown specifically for energy production. Biomass reduces most emissions compared with fossil fuel-based electricity. Biomass results in very low Carbon Dioxide (CO2) emissions due to the absorption of CO2 during the biomass cycle of growing, converting to electricity, and re-growing biomass.

There are four primary types of biomass power systems: direct-fired, co-fired, gasification, and modular systems. Nearly all current biomass generation is based on direct-fired combustion in small, biomass-only plants with relatively low electric efficiency. Most biomass direct-fired combustion generation facilities utilize the basic Rankine cycle for electric power generation, which burns biomass fuel in a boiler to produce steam that is expanded in a Rankine Cycle prime mover to produce power. Currently, co-firing is the most cost-effective technology for biomass. Co-firing substitutes biomass for coal or other fossil fuels in existing coal-fired boilers. Biomass is the second most widely utilized renewable energy behind hydroelectricity.

Biomass power growth can also create new markets and employment for farmers and foresters. It can establish new processing, distribution, and service industries in rural communities.

The price of electricity depends on the type of technology used, the size of the power plant and the cost of the biomass fuel supply. Currently, the most economically attractive technology for biomass is co-firing. These projects require small capital investments per unit of power generation capacity. Co-firing systems range in size from 1 MW to 30 MW of biopower capacity. When low-cost biomass fuels are used, co-firing systems can result in payback periods as low as 2 years.

Co-firing power plant produces power utilizing inexpensive biomass fuels for about $40-$130/MWh depending on the cost of biomass fuels. In direct-fired biomass power plants, generation costs are about $70-$200/MWh.

For biomass to be economical as a fuel for electricity, the source of biomass must be located near where it is used for power generation. This reduces transportation costs. The most economical conditions exist when the energy used is located at the site where the biomass fuel is generated.

Basin Electric has a policy within its rate structure to purchase small renewable power from a member that has either wind, solar or biomass generation facilities located on their respective members systems. Due to this policy, Basin Electric would work with its member systems for this type of renewable power and would not move toward developing the resource itself.

---


Biogas

A biogas power plant is a system where biogas is used to generate electricity. Biogas power plants are a combination of anaerobic digestion systems with associated electricity generators such as gas turbines or gas engines. Feedstock into the biogas power plants must be biodegradable in order to produce methane. Suitable feedstocks include (but are not limited to):

- Biodegradable waste
- Sewage treatment sludge (primary or raw sludge and/or secondary sludge)
- Slaughterhouse waste
- Food waste
- Farm waste
- Organic component of mixed municipal waste (in mechanical biological treatment)
- Biomass like maize

Anaerobic digestion is the harnessed and contained, naturally occurring process of anaerobic decomposition. An anaerobic digester is an industrial system that harnesses these natural processes to treat waste, produce biogas that can be used to power electricity generators, provide heat and produce soil improving material. There are three stages of anaerobic digestion: hydrolysis, acidogenesis, and methanogenesis. These stages can occur in the same digestion tank or can be controlled independently and optimized according to the requirements of the different bacterial processes.

Biogas is one of the principal by-products of anaerobic digestion and is a gaseous mixture comprised mostly of methane and carbon dioxide, but also contains a small amount of hydrogen and occasionally trace levels of hydrogen sulfide. Biogas can be burned to produce electricity, usually with a reciprocating engine or microturbine. The gas is often used in a cogeneration arrangement, to generate electricity and use waste heat to warm the digesters or to heat buildings. Electricity produced by anaerobic digesters is considered to be green energy. Since the gas is not released directly into the atmosphere and the carbon dioxide comes from an organic source with a short carbon cycle, biogas does not contribute to increasing atmospheric carbon dioxide concentrations; because of this, it is considered to be an environmentally friendly energy source.

Processing biodegradable waste using anaerobic digestion helps to reduce global warming. The carbon in biodegradable waste is part of a complete carbon-cycle: the carbon released from the combustion of biogas was removed by plants in the recent past, and does not contribute to the global accumulation of carbon in the same manner that fossil fuels do. Furthermore, if this waste was landfilled it would break down naturally and the biogas would escape directly into the atmosphere. Using the biogas for energy is an intermediate use that does not affect the overall cycle. In this way anaerobic digestion is considered to be a sustainable technology and biogas is considered to be a renewable fuel.

The projected capital cost component of biogas power is approximately $2,500-$6,200/KW. The total levelized cost of biogas power is projected to be approximately $60-$150/MWh.

Basin Electric has a policy within its rate structure to purchase small renewable power from a member that has either wind, solar or biomass generation facilities located on their respective members systems. Due to this policy, Basin Electric would work with its member systems for this type of renewable power and would not move toward developing the resource itself.
Municipal Solid Waste

The municipal solid waste (MSW) industry includes four components: recycling, composting, landfilling and waste-to-energy via incineration. MSW is total waste excluding industrial waste, agricultural waste, and sewage sludge. As defined by the U.S. Environmental Protection Agency (U.S. EPA), MSW includes durable goods, non-durable goods, containers and packaging, food wastes, yard wastes, and miscellaneous inorganic wastes from residential, commercial, institutional, and industrial sources.

MSW can be directly combusted in waste-to-energy facilities to generate electricity after the separation of recyclables. Because no new fuel sources are used other than the waste that would otherwise be sent to landfills, MSW is often considered a renewable power source. Although MSW consists mainly of renewable resources such as food, paper, and wood products, it also includes nonrenewable materials derived from fossil fuels, such as tires and plastics. The U.S. EPA, the federal government and some state governments classify MSW as renewable energy source because MSW is abundant and contains significant amounts of biomass.

There are currently two main waste-to-energy facility designs. The first and most common is mass burn, in which MSW is combusted directly in much the same way as fossil fuels are used in other direct combustion technologies. Burning MSW converts water to steam to drive a turbine connected to an electricity generator.

The second is refuse-derived fuel (RDF) facilities which process the MSW prior to direct combustion. The level of pre-combustion processing varies among facilities, but generally involves shredding of the MSW and removal of metals and other bulky items. The shredded MSW is then used as fuel in the same manner as at mass burn plants.

Burning MSW can generate energy while reducing the volume of waste by up to 90 percent and 75 percent in weight. Ash disposal and the air polluting emissions from the plant combustion operations are the primary environmental impact control issues.

Waste-to-energy plants work very much like coal-fired power plants, the difference being the fuel. Waste-to-energy plants use garbage – not coal – to fire an industrial boiler. The same steps are used to make electricity in a waste-to-energy plant as in a coal-fired power plant.

1. The fuel is burned, releasing heat.
2. The heat turns water into steam.
3. The high-pressure steam turns the blades of a turbine generator to produce electricity.

Like coal plants, waste-to-energy plants produce air pollution when the fuel is burned to produce steam or electricity. Burning garbage releases the chemicals and substances found in the waste. Some chemicals can be dangerous to people, the environment, or both, if they are not properly controlled. The EPA requires waste-to-energy plants to use anti-pollution devices, including scrubbers, fabric filters, and electrostatic precipitators.

One ton of garbage has about the same heat energy as ¼ ton of coal. A ton of garbage generates about 525 kWh of electricity, enough energy to heat a typical office building for one day.

Today, there are 90 waste-to-energy plants in the United States, producing approximately 2,500 MW or about 0.3 percent of total national power generation. The capital cost of an MSW power project is approximately $7,000 to $8,000/KW. Typically, MSW power plants become non-economical when landfills for MSW disposal are not available near the collection area and hauling costs become excessive.

Municipal Solid Waste power could not fulfill a need for a long-term, cost-effective generation capacity due to the rural nature of Basin Electric’s service territory. A solid waste-to-energy project would be very costly.

Fossil Fueled Generation

Chemically, fossil fuels consist largely of hydrocarbons, which are compounds composed of hydrogen and carbon. Some fossil fuels also contain smaller amounts of other compounds. Hydrocarbons form from ancient living organisms that were buried under layers of sediment millions of years ago. As accumulating sediment layers exerted increasing heat and pressure, the remains of the organisms gradually transformed into hydrocarbons. The most commonly used fossil fuels are coal, oil and natural gas.

Fossil fueled energy resources evaluated in this section are simple cycle combustion turbine (SCCT), combined cycle combustion turbine (CCCT), microturbines, and various base-load coal resources, such as pulverized coal (PC), circulating fluidized bed coal (CFB) and integrated gasification combined cycle (IGCC).

Simple Cycle Combustion Turbine (SCCT)

Simple cycle is a type of combustion turbine generator (CTG) application. In simple cycle operation, gas turbines are operated alone, without any recovery of the energy in the hot exhaust gases. Simple cycle gas turbines in the power industry require smaller capital investment than coal, nuclear or even combined cycle natural gas plants and can be designed to generate small or large amounts of power. Also, the actual construction process can take as little as several weeks to a few months, compared to years for base-load power plants. Their other main advantage is the ability to be turned on and off within minutes, supplying power during peak demand. Since they are less efficient than combined cycle plants, they are usually used as peaking power plants, which primarily are operated during the peak summer months and less than a total of 2,000 hours per year. A typical large simple cycle gas turbine may produce 45 to 150 megawatts of power and have 35 to 40 percent thermal efficiency, with some reaching up to 46 percent efficiency. Simple cycle applications are rarely used in base-load applications because of the lower heat rate efficiencies. Figure 12-17 show a typical simple cycle unit process flow diagram.

Simple Cycle Process

There are two types of combustion gas turbines: heavy industrial “frame” machines and aero-derivative machines. Gas turbine power plants are pre-assembled at the factory, skid or baseplate mounted, and shipped to the site along with other major components including the generator, cooling, lube oil, and electrical modules. Because of the pre-assembled modular approach, field erection hours are significantly reduced, particularly as compared to a coal-fired plant.
The capital cost component of the levelized cost of SCCT power is approximately $47/MWh for a plant that runs about 20 percent annual capacity factor. The total levelized cost of SCCT power is projected to be relatively high at approximately $103/MWh for about 1,750 hours of operation in a year or about 20 percent annual capacity factor. If a SCCT were operated at 80 percent annual capacity factor, the levelized cost of power would be about $67/MWh. Most of the power-generation cost for SCCT is from the variable/fuel cost at approximately $48/MWh, assuming the cost of fuel is about $4.00/MMBTu. Natural gas cost is highly variable and strongly affected by the economy, production and supply, demand, weather, and storage levels. Weather and demand are large factors that affect gas prices and are very unpredictable. Traditionally, demand for natural gas peaks in the coldest months, but with the nation's power increasingly being generated by natural gas, demand also spikes in summer when companies fire-up peaking plants to provide more power for cooling needs.

Permitting of Simple Cycle units has an average time frame of 2-3 years. This permitting time frame is dependent on the type of machine selected and the area that you intend to construct it. If it is on or near environmentally protected area this time frame would increase. The construction of the Simple Cycle unit is relatively small 1-1.5 years. This is of course dependent on availability of units, transmission and construction resources.

SCCT could easily fulfill Basin Electric’s peaking power need. Natural gas prices are currently low and are projected to remain low for the foreseeable future. With the increased oil and as a result NG production in North Dakota and Montana, natural gas fired generation has to be considered in Basin’s Electrics future resource portfolios.
**Combined Cycle Combustion Turbine (CCCT)**

Combined cycle is a term used when a power producing engine or plant employs more than one thermodynamic cycle. In a combined cycle power plant (CCPP) or combined cycle combustion turbine (CCCT) plant, a gas turbine generator generates electricity and the waste heat from the gas turbine is used to make steam to generate additional electricity via a steam turbine; this last step enhances the efficiency of electricity generation. In a thermal power plant, high-temperature heat is input to the power plant, usually from burning of fuel, is converted to electricity as one of the outputs and low-temperature heat as another output. As a rule, in order to achieve high efficiency, the temperature of the input heat should be as high as possible and the temperature of the output heat as low as possible. This is achieved by combining the Rankine (steam power system) and the Brayton (gas turbine) thermodynamic cycles. Figure 12-18 show a typical combined cycle unit process flow diagram.

The thermal efficiency of a combined cycle power plant is normally rated in terms of the net power output of the plant as a percentage of the lower heating value of the fuel. In the case of generating only electricity, power plant efficiencies of up to 59 percent can be achieved. In the case of combined heat and power generation, the efficiency can increase to about 85 percent. Typical combined cycle plants are powered by natural gas, although other sources of fuel can be used such as fuel oil or synthetic gas.

Combined cycle equipment is pre-engineered and factory packaged to minimize installation time and cost. All major equipment (gas turbine generator, heat recovery steam generator [HRSG], and steam turbine generator) is shipped to the field as assembled and tested components. CCCT plants have demonstrated high reliability and low operations and maintenance costs.

![Combined Cycle Unit Process Flow Diagram](image-url)
The capital cost component of the levelized cost of CCCT power is approximately $21/MWh for a plant that runs about 60 percent annual capacity factor. The total levelized cost of CCCT power is projected to be approximately $62/MWh for about 5,250 hours of operation in a year or about 60 percent annual capacity factor. If a CCCT were operated at 80 percent annual capacity factor, the levelized cost of power would be about $55/MWh. Most of the power-generation cost for CCCT is from the variable/fuel cost at approximately $40/MWh, assuming the cost of fuel is about $4.00/MMBTu. Natural gas cost is highly variable and strongly affected by the economy, production and supply, demand, weather, and storage levels. Weather and demand are large factors that affect gas prices and are very unpredictable. Traditionally, demand for natural gas peaks in the coldest months, but with the nation’s power increasingly being generated by natural gas, demand also spikes in summer, when companies fire-up peaking plants to provide more power for cooling needs.

Permitting of Combined Cycle units has an average time frame of 3-4 years. This permitting time frame is dependent on the type of machine selected and the area that you intend to construct it in. If it is on or near an environmentally protected area this time frame would increase. The construction of the combined cycle unit is 2-2.5 years. This is of course dependent on availability of units, transmission and construction resources.

CCCT could potentially fulfill Basin Electric’s intermediate power need. Natural gas prices are currently low and are projected to remain low for the foreseeable future. With the increased oil (and as a result NG) production in North Dakota and Montana, natural gas fired generation has to be considered in Basin’s Electrics future resource portfolios.

**Microturbines**

Microturbines are small combustion turbines, approximately the size of a refrigerator, with outputs of 25-500 kW. They evolved from automotive and truck turbochargers, auxiliary power units for airplanes, and small jet engines and are composed of a compressor, a combustor, a turbine, an alternator, a recuperator, and a generator. Microturbines entered field-testing around 1997 and began initial commercial service in 2000. They are able to operate on a variety of fuels, including natural gas, sour gas (high sulfur, low Btu content), and liquid fuels such as gasoline, kerosene and diesel fuel/heating oil. Microturbines are classified by the physical arrangement of their component parts: single shaft or two-shaft, simple cycle or recuperated, inter-cooled and reheat. The design life of microturbines is estimated to be in the 40,000 to 80,000 hour range. While units have demonstrated reliability, they have not been in commercial service long enough to provide definitive life data.

Microturbines are ideally suited for distributed generation applications due to their small power output and space requirement, flexibility in connection methods, ability to be stacked in parallel to serve large loads, ability to provide stable and reliable power and low emissions. Types of applications include stand-alone primary power, backup/standby power, peak shaving and primary power (grid parallel), primary power with grid as backup, resource recovery and cogeneration.

The total capital cost of microturbines is approximately $750-$1,400/kW, with a total installed cost of $1,125-$2,200/kW. Microturbines are still on a learning curve in terms of maintenance, as initial commercial units have seen only a few years of service so far. Most manufacturers offer service contracts for specialized maintenance priced at about $0.01/kWh. This cost information was based on information gathered by Energy Nexus Group for the Environmental Protection Agency (EPA)\(^35\).

With the small number of units in commercial service, information is not yet sufficient to draw conclusions about reliability and availability of microturbines. The basic design and low number of moving parts hold the potential for systems of high availability; manufacturers have targeted availabilities of 98 to 99 percent.

Microturbines cannot fulfill the need for long-term, cost-effective and competitive generation for Basin Electric due to high installed cost. A large number of microturbines would be needed to fulfill the capacity requirement.

### Coal Facility

Three types of coal facilities are discussed below, they include pulverized coal (PC), circulating fluidized bed (CFB) and integrated gasification combined cycle (IGCC).

#### Pulverized Coal

Modern pulverized coal (PC) plants generally range in size from 80 MW to 1,300 MW and can use coal from various sources. Coal is most often delivered by unit train to the site, although barges or trucks are also used. Many plants are situated adjacent to the coal source where coal delivery can be by conveyor. The source of coal and coal characteristics can have a significant effect on the plant design in terms of coal-handling facilities and types of pollution control equipment required. Coal can have various characteristics with varying heating values, sulfur content, and ash constituents.

Regardless of the source, the plant coal-handling system unloads the coal, stacks out the coal, reclaims the coal required, and crushes the coal for storage in silos. Then the coal is fed from the silos to the pulverizers and blown into the steam generator. The steam generator mixes the pulverized coal with air, which is combusted, and in the process produces heat to generate steam. Steam is conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to produce electricity. This process is shown in Figure 12-19 below.

![Figure 12-19. Pulverized Coal Unit Process Flow Diagram](image)

Typically, a PC unit would be utilized in base-load operation to optimize the cost of the facility. Coal burning generating stations tend to be higher in capital cost and lower in operating cost and have a longer life span than a typical combustion turbine facility, thereby reducing the overall cost of generation.
Environmental impacts associated with PC resources include air emissions, water/wastewater discharge issues, and solid waste disposal. Impacts are minimized by utilizing air pollution control equipment, wastewater pretreatment controls, and the potential reuse of ash.

The permitting and environmental study requirements to install a new PC coal fired unit would take approximately 5 years and construction time after permitting would require 4 years. The permitting and environmental portions of this process would require the latest technologies in carbon capture. Without the carbon capture processes these potential new facilities will not be granted required air quality permitting or environmental state and federal regulations.

Basin Electric currently owns and operates several PC resources within its system. These facilities have been upgrading their emission control equipment over the years. See Chapter 3: Environmental Considerations for details of the emission control retrofits of the Basin Electric coal fleet.

Circulating Fluidized Bed

Circulating fluidized bed (CFB) technology utilizes the fluidized bed principle in which crushed fuel and limestone are injected into the furnace or combustor. The particles are suspended in a stream of upwardly flowing air (60 to 70 percent of total air) which enters the bottom of the furnace through air distribution nozzles. The balance of combustion air is admitted above the bottom of the furnace as secondary air. While combustion takes place at 840 to 900°C (1,550 to 1,650°F), the fine particles exit the furnace with flue gas velocity of 406 m/s. The particles are then collected by the solids separators and circulated back into the furnace. This combustion process is called circulating fluidized bed (CFB). The particles’ circulation provides efficient heat transfer to the furnace walls and longer residence time for carbon and limestone utilization.

The CFB fuel delivery system is similar to the PC unit, but somewhat simplified to produce a coarser material. Figure 12-20 shows a typical circulating fluidized bed unit process flow diagram. CFBs are designed for the particular coal to be used. The method is principally of value for low grade, high-ash coals that are difficult to pulverize and that may have variable combustion characteristics. It is also suitable for co-firing with low-grade fuels, including some waste materials.

![Circulating Fluidized Bed Unit Process Flow Diagram](image)
Typically, a CFB unit would be utilized in base-load operation to optimize the cost of the facility. Coal burning generating stations tend to be higher in capital cost and lower in operating cost and have a longer life span than a typical combustion turbine facility, thereby reducing the overall cost of generation.

Environmental impacts associated with CFB resources include air emissions, water/wastewater discharge issues, and solid waste disposal. Impacts are minimized by utilizing air pollution control equipment, wastewater pretreatment controls, and the potential reuse of ash.

The permitting and environmental study requirements to install a new CFB coal fired unit would take approximately 5 years and construction time after permitting would require 4 years. The permitting and environmental portions of this process would require the latest technologies in carbon capture. Without the carbon capture processes these potential new facilities will not be granted required air quality permitting or environmental state and federal regulations.

**Integrated Gasification Combined Cycle**

Integrated gasification combined cycle (IGCC) merges gasification with gas cleaning, synthesis gas conversion, and turbine power technologies. IGCC uses a gasifier to convert a carbon-based feedstock (i.e. coal) into synthesis gas, a mixture of carbon monoxide (CO) and hydrogen (H2). The synthesis gas is cleaned of particulates, sulfur, and other contaminants and is then combusted in a high-efficiency Brayton cycle gas turbine/generator. Heat from the turbine exhaust gas is extracted to produce steam to drive a Rankine cycle steam turbine/generator. The specifics of a plant design are influenced by the gasification process, degree of heat recovery, and methods to clean up the gas. This combination of power-generating cycles is known as a combined cycle. Figure 12-21 show the typical process flow diagram for an IGCC unit.

![Figure 12-21. Integrated Gasification Combined Cycle Process Flow Diagram](image)

The gasifier has the flexibility to handle a variety of feedstocks. In addition to coal, possible feedstocks include petroleum coke, refinery liquids, biomass, municipal solid waste, tires, plastics, hazardous wastes and chemicals, and sludge. The main incentive for IGCC development has been that units may be able to achieve higher thermal efficiencies (40 percent or greater) than conventional power plants (35 percent) and may be able to match the environmental performance of gas-fired plants. IGCC is capital intensive, it needs economies of scale and fuel cost advantages to be an attractive investment option.
The permitting and environmental study requirements to install a new IGCC coal fired unit would take approximately 4.5 years and construction time after permitting would require 4 years. The permitting and environmental portions of this process would require the latest technologies in carbon capture. Without the carbon capture processes these potential new facilities will not be granted required air quality permitting or environmental state and federal regulations.

Summary of Coal Facilities

Before delving into the cost of the three coal facilities, a thorough technology assessment would need to be performed. However, for this IRP a generic coal facility was assumed which was estimated to have a capital cost of $3,763/kW, fixed O&M of $30/kW-yr, variable O&M of $5.00/MWh and assumed $1.00/MMBTu. This results in a first-year bus bar of approximately $58/MWh or a levelized bus bar of $56/MWh at 85 percent capacity factor.

A coal facility is capable of meeting a portion of Basin Electric’s capacity and energy needs on its eastern system because it has a relatively low and stable cost of fuel. More analysis would need to be performed to more thoroughly evaluate the alternatives of PC, CFB and IGCC.

Nuclear Power

Nuclear power is a type of nuclear technology involving the controlled use of nuclear reactions to release energy for work including propulsion, heat, and the generation of electricity. Nuclear energy is produced by a controlled nuclear chain reaction and creates heat, which is used to boil water, produce steam and drive a steam turbine to generate electricity.

As of 2012, the International Atomic Energy Agency (IAEA) reported there are 437 nuclear power reactors in operation in the world, with 372556 MW of capacity\(^36\). Currently there are 67 reactors under construction, mostly in Asia and Europe\(^37\). The EIA reported that there are 104 nuclear power reactors operating in the United States with a capacity of 107,001MW\(^38\) and 790,204 GWh\(^39\) of energy were produced.

\(^{38}\) EIA Electric Power Annual 2011, Release Data: January 30, 2013; Table 4-3 http://www.eia.gov/electricity/annual/
\(^{39}\) EIA Electric Power Annual 2011, Release Data: January 30, 2013; Table 3-12 http://www.eia.gov/electricity/annual/
Conventional thermal power plants all have a fuel source to provide heat (i.e. coal, oil and gas). For a nuclear power plant, this heat is provided by nuclear fission inside the nuclear reactor. When a relatively large fissile atomic nucleus is struck by a neutron it forms two or more smaller nuclei as fission products, releasing energy and neutrons in a process called nuclear fission. When this nuclear chain reaction is controlled, the energy released can be used to heat water, produce steam and drive a turbine to generate electricity. Figure 12-22 shows the process flow diagram of a nuclear power plant.

A nuclear reactor is only part of the life-cycle for nuclear power. The process starts with mining in which the uranium ore is extracted, usually converted in a stable and compact form such as yellowcake, and then transported to a processing facility. Here, the yellowcake is converted to uranium hexafluoride, which is then enriched using various techniques. At this point, the enriched uranium, containing more than the natural 0.7 percent U-235 (Uranium -235), is used to make rods of the proper composition and geometry for the particular reactor that the fuel is destined for. The fuel rods will spend 1.5 to 3 years inside the reactor, generally until about 3 percent of their uranium has been fissioned, then the rods will be moved to a spent fuel pool where the short lived isotopes generated by fission can decay away. After about 1 year in a cooling pond, the spent fuel is radioactively cool enough to handle. The US NRC has two acceptable storage methods. It can be kept in the spent fuel cooling pond at the reactor site or moved to dry storage casks. Dry storage casks are steel cylinders that are either welded or bolted closed. The steel cylinder provides a leak-tight confinement of the spent fuel. Each cylinder is surrounded by additional steel, concrete, or other material to provide radiation shielding to workers and members of the public. Some of the cask designs can be used for both storage and transportation.
Nuclear power plants are generally (although not always) considered “hard” targets. The reactor is typically protected by about four feet of steel-reinforced concrete with a thick steel liner, and the reactor vessel is made of steel about 6 inches thick. Steel-reinforced concrete containment structures are designed to withstand the impact of many natural disasters, including hurricanes, tornadoes, earthquakes and floods, as well as airborne objects with a substantial force. In the U.S., plants are surrounded by a double row of tall fences which are electronically monitored and the plant grounds are patrolled by a sizable force of armed guards. The NRC holds nuclear power plants to the highest security standards of any American industry. Since 2001, the agency has elevated nuclear plant security requirements numerous times by issuing orders and other formal requirements.

Nuclear generation does not directly produce sulfur dioxide, nitrogen oxides, carbon dioxide, mercury or other pollutants associated with the combustion of fossil fuels. With increased interest in air pollution and global warming, nuclear power generation would be an excellent source of electric power generation since nuclear generation does not contribute to the causes of air pollution and global warming via green house gas emissions.

Nuclear generation is considered base-load generation, with the existing U.S. fleet of nuclear power plants operating at approximately 90 percent capacity factor for the last number of years. Nuclear fuel costs are not volatile and account for only a small portion of overall production costs, thus providing excellent overall price stability.

---

Figure 12-23. U.S. Nuclear Power Spent Fuel Storage Installations

---

http://pbadupws.nrc.gov/docs/ML1305/ML13057A527.pdf
There are many issues to overcome in order to develop new nuclear generation. Some of the issues pertain to cost, standardization, financing, plant licensing and construction. The cost of new nuclear generation needs to be competitive with other generation in order to facilitate new nuclear generation. Financing provides an issue due to the hefty price tag associated with new generation and scrutiny due to that price. Construction of new nuclear power plants is likely to face bottlenecks due to the availability of key components and the workforce of craft workers and construction managers. Increased demand of the key components will eventually lead to greater manufacturing capacity, but there will be a delay in that greater manufacturing capacity. One of the largest issues facing new nuclear plants is the public perception of nuclear power. The March 2011 earthquake and tsunami that devastated northeast Japan led to a severe accident at the Fukushima Daiichi nuclear energy facility. This incident significantly hurt the nuclear power industry and led to a complete inspection of all US domestic nuclear power plants.

The new plant licensing process that has three components: approval of standard reactor designs, early site permits and combined construction and operating licenses. The U.S. Nuclear Regulatory Commission has certified several reactor designs as meeting all safety requirements, and the agency expects to certify two more designs in the near term. These designs can be found on the Nuclear Energy Institute website, under “New Nuclear Energy Facilities.”

The U.S. Nuclear Regulatory Commission voted in February 2012 to grant a combined construction and operating license for two reactors at Southern Co. subsidiary Georgia Power’s Plant Vogtle, near Waynesboro, VA. It is the first combined license ever approved for a U.S. nuclear energy facility, which will become the nation’s first new nuclear units built in 30 years. On March 30, 2012, the NRC issued combined construction and operating licenses to South Carolina Electric & Gas Company for two reactors near Jenkinsville, South Carolina.

Due to the many issues that the utility industry will face with new nuclear generation, Basin Electric believes it would be sometime after 2030 that a new nuclear power plant could be built to help meet the growing need of Basin Electric. However, due to the advantage nuclear generation would bring to the growing air quality restrictions, Basin Electric will continue to evaluate the options but for the time frame of this IRP will look to other technologies to meet its growing needs.

**Repowering/Uprating Of Existing Generating Units**

The Utility MATS (Mercury and Air Toxics Standards) will force Wisdom Generation Station, Unit #1 to stop burning coal as a fuel source by December 2014. Corn Belt Cooperative retained Burns & McDonnell to perform a technology assessment for Wisdom on five options:

1. Convert Unit 1 boiler to burn 100% natural gas
2. Replace Unit 1 steam turbine with combustion turbine engine
3. Add new combustion turbine
4. Convert Unit 2 to Combined Cycle with reusing Unit 1 steam turbine/generator
5. Convert Unit 2 to Combined Cycle with adding new steam turbine/generator

Basin Electric has added the technology assessment details to the System Optimizer modeling software to be included in the future resource portfolio runs. If the model indicates one of these option(s) is justified to move forward Basin Electric will further evaluate that (those) option(s).
Purchased Power / Request For Proposals
Basin Electric developed and issued a Request for Proposals (RFP) in early 2012 for short- and long-term power supply on its eastern system. The long-term proposals were used to evaluate against Basin Electric’s self-build options. The short-term proposals could be utilized to meet some of Basin Electric’s need in the next couple of years. Basin Electric received 5,706 MW of power supply bids. Basin Electric evaluated the short- and long-term proposals and shortlisted the total number of qualifying bids to 15 totaling 1,276 MW.

These shortlisted projects details were added to the System Optimizer modeling software to be included in the future resource portfolio runs. If the model indicates one or more of these options is justified to move forward, Basin Electric will further evaluate that (those) option(s).

Summary Of Alternatives
A summary of the projected costs for alternative generation within Basin Electric eastern system, where cost information is known, is shown in Table 12-2. The power-generation technologies presented with their respective competitive costs are wind, solar, hydroelectric, geothermal, biomass, biogas, municipal solid waste, simple cycle combustion turbine combined cycle combustion turbine, microturbines, and coal facilities.

<table>
<thead>
<tr>
<th>Type of Power Plant</th>
<th>Capital Cost ($/kW)</th>
<th>Fixed O&amp;M ($/kW-yr)</th>
<th>Variable / Fuel Costs ($/MWh)</th>
<th>Total Bus Bar Cost ($/MWh)</th>
<th>Average Capacity Factor (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>2,300</td>
<td>14.00</td>
<td>2.00</td>
<td>40-60</td>
<td>30-40</td>
</tr>
<tr>
<td>Solar – Photovoltaic</td>
<td>4,200-5,000</td>
<td>64.00</td>
<td>0</td>
<td>NA</td>
<td>20-35</td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>2,000-3,000</td>
<td>14.00</td>
<td>4.00-6.00</td>
<td>40-80</td>
<td>40-50</td>
</tr>
<tr>
<td>Geothermal (Electric)</td>
<td>2,400-3,000</td>
<td>NA</td>
<td>9.60</td>
<td>30-50</td>
<td>90+</td>
</tr>
<tr>
<td>Biomass Power</td>
<td>1,880-4,260</td>
<td>NA</td>
<td>NA</td>
<td>90</td>
<td>90</td>
</tr>
<tr>
<td>Biogas</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>90</td>
<td>90</td>
</tr>
<tr>
<td>Municipal Solid Waste</td>
<td>7,000-8,500</td>
<td>378</td>
<td>8.33</td>
<td>85</td>
<td>90</td>
</tr>
<tr>
<td>Simple Cycle CT</td>
<td>950</td>
<td>12.00</td>
<td>47.00</td>
<td>103</td>
<td>20</td>
</tr>
<tr>
<td>Combined Cycle CT</td>
<td>1,209</td>
<td>11.80</td>
<td>40.00</td>
<td>62</td>
<td>60</td>
</tr>
<tr>
<td>Microturbines</td>
<td>750-1,450</td>
<td>NA</td>
<td>10</td>
<td>100-150</td>
<td>90</td>
</tr>
<tr>
<td>Coal Facility</td>
<td>3,763</td>
<td>30.00</td>
<td>19.00</td>
<td>56</td>
<td>85</td>
</tr>
</tbody>
</table>

Table 12-2. Costs of New Resource Power Generation Plants
The generation types capable of meeting a base-load need of Basin Electric’s would be the alternatives that exceed 80 percent capacity factor which include geothermal, biomass, biogas, municipal solid waste, microturbines and coal facilities. Geothermal electric generation is very limited and almost not available within Basin Electric eastern system. Biomass power is fairly costly for base-load power and a large number of facilities would be needed to fulfill Basin Electric’s base-load need. A large amount of biogas would be needed in order to offset Basin Electric’s base-load need. Municipal solid waste is fairly costly for a base-load facility and Basin Electric’s service territory is generally rural therefore it would be even more costly. Microturbines are generally very small in size and therefore a large quantity would be needed to meet Basin Electric’s base-load need as well as being fairly costly for base-load generation. However, if entities came to Basin Electric with proposed projects for geothermal, biomass, biogas, municipal solid waste and microturbines, Basin Electric would consider the projects and determine if the projects were viable and economical. Coal facilities would be an excellent source to meet Basin Electric’s need; coal facilities generally have a high capital cost but make up for that high capital cost with low variable and fuel costs. The coal facility was carried forward to the modeling software. Basin Electric modeled both Super Critical Pulverized Coal and Integrated Gasification Combined Cycle coal units (with emission controls) against all other power supply resources.

The generation types capable of meeting an intermediate need of Basin Electric’s would be the alternatives that have a capacity factor between 20 percent and 80 percent, which include wind, solar, hydroelectric and combined cycle combustion turbines. Wind is an intermittent resource that cannot be scheduled when to operate but has a low cost due to the fact it is a fuel displacer. Wind would integrate very well with gas fired generation to produce a more usable product. Solar is also an intermittent resource that cannot be scheduled when to operate however it is very costly. Hydroelectric power generally operates between 40 to 50 percent capacity factors; however it is very dependent on the annual rainfall and therefore can go through some long periods of low generation. Combined cycle combustions turbines are an excellent source to meet Basin Electric’s intermediate need; combined cycles have a low stable fuel cost and if siting is done with regard to existing Natural Gas lines, fuel supply can be firmed up. The wind and a variety of combined cycle plant sizes were carried forward the modeling software. Basin Electric modeled Wind and Natural Gas Combined Cycle (130, 250, 520 MW) units against all other power supply resources.

The generation types capable of meeting a peaking need of Basin Electric would be the alternatives that have a capacity factor less than 20 percent, which include simple cycle combustion turbines. The simple cycle combustion turbine was carried forward to determine if and how much peaking generation is needed for Basin Electric. A generic Natural Gas Simple Cycle unit and specific peaking units (were carried forward the modeling software. Basin Electric modeled Generic Simple Cycle, GE LMS100 and LM6000 units against all other power supply resources.
13. Risks And Uncertainties

Highlights

- Basin Electric, like all electric utilities, operates in an uncertain and volatile environment.
- Variations in natural gas prices and load forecast growth have potential to affect Basin Electric’s revenue requirements and operational practices.
- Another key uncertainty of particular interest to Basin Electric was the uncertainty of production tax credits available for the development of wind, before they were extended in late 2012.

Introduction

Electric utilities operate in a sometimes uncertain and volatile environment. There are increasing potential risks with fuel, including supply, transportation and emissions which in turn affect the market prices. Due to these increasing risks, it is prudent to perform a risk assessment to help determine how these potential risks affect Basin Electric’s revenue requirements and how operations change with these risks.

Risk Assessment

The bulk of the scenarios include variations of natural gas prices and load forecast growth. The scenarios were input into the Ventyx System Optimizer software and database to create the optimal portfolios for each scenario set. The Production Tax Credit (PTC) scenario was for the possible extension of the PTC. The Most Likely Natural Gas prices are based on the July 2012 IHS Gas Prices (Henry Hub) and the Most Likely Load Forecast is Basin Electrics 2012 Load Forecast Update. The scenario labeled as High Natural Gas is the July 2012 IHS prices plus $2.00, the scenario labeled as Low Natural Gas is the July 2012 IHS prices minus $2.00. The scenario labeled as “High Load Forecast” is the 2012 Load Forecast Update increased 10%, the scenario labeled as “Low Load Forecast” is the 2012 Load Forecast Update decreased by 10%.

The main scenarios include:

- PTC extended - High Natural Gas – High Load Forecast
- PTC not extended - High Natural Gas – High Load Forecast
- PTC extended - High Natural Gas – Most Likely Load Forecast
- PTC not extended - High Natural Gas – Most Likely Load Forecast
- PTC extended - High Natural Gas – Low Load Forecast
- PTC not extended - High Natural Gas – Low Load Forecast
- PTC extended - Most Likely Natural Gas – High Load Forecast
- PTC not extended - Most Likely Natural Gas – High Load Forecast
• PTC extended - Most Likely Natural Gas – Most Likely Load Forecast
• PTC not extended - Most Likely Natural Gas – Most Likely Load Forecast
• PTC extended - Most Likely Natural Gas – Low Load Forecast
• PTC not extended - Most Likely Natural Gas – Low Load Forecast
• PTC extended - Low Natural Gas – High Load Forecast
• PTC not extended - Low Natural Gas – High Load Forecast
• PTC extended - Low Natural Gas – Most Likely Load Forecast
• PTC not extended - Low Natural Gas – Most Likely Load Forecast
• PTC extended - Low Natural Gas – Low Load Forecast
• PTC not extended - Low Natural Gas – Low Load Forecast

Another way to look at the main list of scenarios is to look at it in a matrix form. Table 13-1 shows the matrix form of the scenarios discussed above. The table below would be developed for each of the PTC being extended and PTC not being extended.

<table>
<thead>
<tr>
<th></th>
<th>High Load Growth (H)</th>
<th>Most Likely Load Growth (M)</th>
<th>Low Load Growth (L)</th>
</tr>
</thead>
<tbody>
<tr>
<td>High Natural Gas (H)</td>
<td>HH</td>
<td>HM</td>
<td>LH</td>
</tr>
<tr>
<td>Most Likely Gas (M)</td>
<td>HM</td>
<td>MM</td>
<td>LM</td>
</tr>
<tr>
<td>Low Natural Gas (L)</td>
<td>HL</td>
<td>ML</td>
<td>LL</td>
</tr>
</tbody>
</table>

Table 13-1. Matrix Form of Initial Risk Scenarios

The risk assessment scenarios were all done under the assumption that there would be no opportunity to sell any surplus energy to the market, only the ability to serve member and contracted obligations, known as a “No Market” case. An additional sensitivity with the inclusion of market opportunity to sell any available surplus energy to the market, known as “Market” case was also performed.

**Key Uncertainties**

Performing analyses of the optimal resource under an assumption of expected conditions in the future provides important information for decision makers. However, decision makers are also interested in performance of these portfolios under influences that vary from the expected. The following uncertainties were of particular note to Basin Electric.

**Load**

As the load forecast was developed, it became evident that a bandwidth forecast was more appropriate to the large sensitivities in commercial development, including the large oil play that is currently underway in the Williston Basin area. Figure 13-1 shows the bandwidth forecast developed within the IRP. The IRP utilized the Baseline (2012 Load Forecast), High Case and Low Case.
Natural Gas Price

Figure 13-2 below shows the natural gas price forecast for Henry Hub that was used in the IRP in nominal dollars. This was used as the Most Likely price. High price was an additional $2.00/MMBTu and Low price was a reduction of $2.00/MMBTu. Upon using this natural gas forecast and seeing events in early to mid-2012 unfold, Basin Electric felt as though with the extremely low cost of Natural Gas that the Low Natural Gas price was not a feasible option and therefore removed it from the scenarios.
PTC Sensitivity

Another uncertainty is what the future may hold for Production Tax Credits for the development of wind. At the start of this analysis the future extension of the Production Tax Credit was still uncertain. Currently Congress has extended the PTC for another additional year, till the end of 2013, but Congress still hasn’t developed a long term philosophy for these credits. Also this sensitivity or excluding wind was used to determine the magnitude of benefits provided by wind. If PTCs were shown as being extended in the model, the two wind purchases solved for all cases.

Summary

By using System Optimizer to perform sensitivities under PTC extension, load growth and natural gas (excluding the Low Natural Gas Case), there are 12 distinct Portfolios created that are considered optimal for each set of sensitivities. Portfolios are listed in the Appendices.
14. Resource Portfolios

**Highlights**

- Four resource portfolios were evaluated for meeting future resource requirements.
- All portfolios required significant resource development, 1,200 to 1,675 MW, to meet forecasted peak demand.
- Portfolio 0 is Basin Electric’s system as it stands today with committed projects fully developed.
- Portfolios A-D are each composed of various combinations of purchased power, peaking power, intermediate power, and/or wind.

**Introduction**

This chapter describes the portfolios that were developed and evaluated in this (IRP) based on the methodology described in Chapter 11: Analytical Approach and Chapter 13: Risks and Uncertainties. Each portfolio contains realistic feasible supply-side alternatives for balancing resource supply with electricity demand.

**Portfolio Development**

As shown in Chapter 13, 12 distinct portfolios were developed for each set of risk scenarios that could meet future resource requirements. All portfolios required significant resource development to meet forecasted demand shown to take place over the course of the study period.

The 12 separate portfolios were evaluated to find commonalities and differences between each of them. All portfolios detailed taking a list of short term purchases from Basin Electrics RFP process, a majority of the portfolios included the retrofit of the Wisdom Unit #1 from coal to natural gas, and if the PTC was extended then the two wind PPA from Basin Electrics RFP process were included in all portfolios. This set of resources was detailed in all portfolios.

As described in Chapter 13, upon using this natural gas forecast and seeing events in early to mid-2012 unfold, Basin Electric felt as though with the extremely low cost of Natural Gas that the Low Natural Gas price was not a feasible option and therefore removed it from the scenarios.

In reviewing the High Natural Gas portfolios it was determined that since there are not any significant differences between the High Natural Gas and July 2012 Natural Gas portfolios until after the actual study period of this IRP, around 2030, that we would not carry the High Natural Gas portfolios into the cost analysis.
Basin Electric’s IS(WAUE) area includes the area known as the Williston Basin. This area is experiencing extraordinary load growth at an accelerated rate. Basin Electric is currently installing and building out transmission in support of this area. The load-serving capability of the transmission in this area has become an issue for the area but these improvements will not be completed until 2016. This has drove two decisions for the portfolio development, one is that Basin Electric should install (2) LM6000 units at the existing Pioneer Generation Station in 2014 and (2) LM6000 units at the existing Lonesome Creek Generation Station in 2015, the other is that the low forecast portfolios are not a feasible conclusion going forward and therefore were removed from consideration.

Candidate Portfolios

Based on the above section the Candidate Portfolios that will be used in the cost modeling are:

- Portfolio A – PTC extension, July 2012 Natural Gas forecast – 2012 Load Forecast
- Portfolio B – PTC not extended, July 2012 Natural Gas forecast – 2012 Load Forecast
- Portfolio C – PTC not extended, July 2012 Natural Gas forecast – High Load Forecast
- Portfolio D – PTC extension, July 2012 Natural Gas forecast – High Load Forecast

This section describes the different portfolios created to meet future resource requirements.

Portfolio 0

Portfolio 0 reflects Basin Electric’s system today with no new addition of facilities other than those that are already committed projects. There are no new generating resources added to this portfolio, as needed energy is purchased from the market under the assumption that there is energy available to be purchased.
Portfolio A (PTC extension; 2012 Load Forecast)

Portfolio A emphasizes short term power purchases and Natural Gas Combined Cycle Intermediate and Simple Cycle peaking units along with Wind PPAs to meet Basin Electric's requirements. Table 11 includes the new resource expansion for Portfolio A. By 2028 (after purchases expire) there will be 1,191 MW of added generation with this portfolio.

<table>
<thead>
<tr>
<th>Acquisition Schedule</th>
<th>Description (total MW)</th>
<th>Resource Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013 – 2017</td>
<td>50 MW Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>50 MW Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>25 MW Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>25 MW Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2014 – 2018</td>
<td>50-200 MW Power Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2014 – 30 years</td>
<td>99 MW Wind Project PPA</td>
<td>Intermediate Wind</td>
</tr>
<tr>
<td>2014 – 30 years</td>
<td>100 MW Wind Project PPA</td>
<td>Intermediate Wind</td>
</tr>
<tr>
<td>2014 – 30 years</td>
<td>(2) 45 MW GE LM 6000 Units</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>2015 – 30 years</td>
<td>(2) 45 MW GE LM 6000 Units</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>2015 – 30 years</td>
<td>37 MW Retrofit of Wisdom Unit</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>2017 – 2028</td>
<td>50 MW Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2021 – 30 years</td>
<td>520 MW NGCC (2x2x1)</td>
<td>Intermediate Power</td>
</tr>
<tr>
<td>2022 – 2024 – 30 years</td>
<td>(3) 85 MW SCCC Units</td>
<td>Peaking Power</td>
</tr>
</tbody>
</table>

Table 14-1. Portfolio A
Portfolio B (PTC not extended; 2012 Load Forecast)

Portfolio B emphasizes short term power purchases and Natural Gas Combined Cycle Intermediate units to meet Basin Electric’s requirements. Table 12 includes the new resource expansion for Portfolio B. By 2028 (after purchases expire) there will be 1,220 MW of added generation with this portfolio.

<table>
<thead>
<tr>
<th>Acquisition Schedule</th>
<th>Description (total MW)</th>
<th>Resource Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013 – 2017</td>
<td>50 MW Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>50 MW Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>25 MW Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>25 MW Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2014 – 2018</td>
<td>50-200 MW Power Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2014 – 30 years</td>
<td>(2) 45 MW GE LM 6000 Units</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>2015 – 30 years</td>
<td>(2) 45 MW GE LM 6000 Units</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>2020 – 30 years</td>
<td>520 MW NGCC (2x2x1)</td>
<td>Intermediate Power</td>
</tr>
<tr>
<td>2024 – 30 years</td>
<td>520 MW NGCC (2x2x1)</td>
<td>Intermediate Power</td>
</tr>
</tbody>
</table>

Table 14-2. Portfolio B
**Portfolio C (PTC not extended; High Load Forecast)**

Portfolio C is a base-load and peaking portfolio with moderate amounts of base-load and moderate amounts of peaking to meet Basin Electric’s requirements. Table 13 includes the new resource expansion for Portfolio C. By 2028 (after purchases expire) there will be 1,560 MW of added generation with this portfolio.

<table>
<thead>
<tr>
<th>Acquisition Schedule</th>
<th>Description (total MW)</th>
<th>Resource Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013 – 2017</td>
<td>50 MW Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>50 MW Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>25 MW Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>25 MW Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2014 – 2018</td>
<td>50-200 MW Power Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2014 – 30 years</td>
<td>(2) 45 MW GE LM 6000 Units</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>2015 – 30 years</td>
<td>(2) 45 MW GE LM 6000 Units</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>2015 – 10 years</td>
<td>37 MW Retrofit of Wisdom Unit</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>2017 – 2028</td>
<td>50 MW Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2019 – 30 years</td>
<td>520 MW NGCC (2x2x1)</td>
<td>Intermediate Power</td>
</tr>
<tr>
<td>2022 – 30 years</td>
<td>520 MW NGCC (2x2x1)</td>
<td>Intermediate Power</td>
</tr>
<tr>
<td>2023-2025 – 30 years</td>
<td>(3) 85 MW SCCC Units</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>2028 – 30 years</td>
<td>85 MW SCCC Unit</td>
<td>Peaking Power</td>
</tr>
</tbody>
</table>

Table 14-3. Portfolio C
Portfolio D (PTC extension; High Load Forecast)

Portfolio D emphasizes short term power purchases and Natural Gas Combined Cycle Intermediate and Simple Cycle peaking units along with Wind PPAs to meet Basin Electric’s requirements. Table 14 includes the new resource expansion for Portfolio D. By 2028 (after purchases expire) there will be 1,674 MW of added generation with this portfolio.

<table>
<thead>
<tr>
<th>Acquisition Schedule</th>
<th>Description (total MW)</th>
<th>Resource Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013 – 2017</td>
<td>50 MW Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>50 MW Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>25 MW Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>25 MW Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2014 – 2018</td>
<td>50-200 MW Power Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2014 – 30 years</td>
<td>99 MW Wind Project PPA</td>
<td>Intermediate Wind</td>
</tr>
<tr>
<td>2014 – 30 years</td>
<td>100 MW Wind Project PPA</td>
<td>Intermediate Wind</td>
</tr>
<tr>
<td>2014 – 30 years</td>
<td>(2) 45 MW GE LM 6000 Units</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>2015 – 30 years</td>
<td>(2) 45 MW GE LM 6000 Units</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>2015 – 30 years</td>
<td>37 MW Retrofit of Wisdom Unit</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>2017 – 2028</td>
<td>50 MW Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2019 – 30 years</td>
<td>520 MW NGCC (2x2x1)</td>
<td>Intermediate Power</td>
</tr>
<tr>
<td>2020 – 30 years</td>
<td>85 MW SCCC Unit</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>2023 – 30 years</td>
<td>520 MW NGCC (2x2x1)</td>
<td>Intermediate Power</td>
</tr>
<tr>
<td>2024-2025 – 30 years</td>
<td>(2) 85 MW SCCC Units</td>
<td>Peaking Power</td>
</tr>
</tbody>
</table>

Table 14-4. Portfolio D

Summary

This chapter provided an overview of the portfolios Basin Electric developed to determine the Preferred Portfolio.
15. Conclusion

Highlights

- Each portfolio evaluated was compared to a Portfolio 0, which included no new resource development, to determine how more or less cost effective the portfolio was to not developing any new resources.
- Portfolios were evaluated under both a market and a no-market case. The market case available surplus generation was marketed. In the no-market case, there were no available markets to use for sales or purchases.
- Basin Electric will also continue to work on developing and expanding upon energy conservation and efficiency within the Basin Electric service territory and work with the members to develop more load management within the Basin Electric system where it is viable.

Introduction

Previous chapters derived the methodology for simulating the marketplace, deriving a set of portfolios and modeling a set of portfolios. This chapter discusses these results and analyzes them to identify context and meaning. From here the final chapter is established by the conclusion of the report and the recommendations to move forward with.

Initial Analysis

The portfolios developed in Chapter 14: Resource Portfolios were evaluated on the basis of present value revenue requirements (PVRR) to operate the Basin Electric system, with the explicit goal of minimizing PVRR. Portfolios A and B are designed to cover a base load forecast while Portfolios C and D are designed to cover a base load forecast plus 10%. Comparisons of the Portfolios have to be made on the basis of A vs. B and C vs. D and not cross between different load forecasts. For this chapter “Base Load Forecast” will refer to the Basin Electric 2012 Load Forecast Update.

Market Cases

Each portfolio evaluated was compared to Portfolio 0 (for example Portfolio A – Portfolio 0), which included no new resource development, to determine how more or less cost effective the portfolio was to not developing any new resources. A positive value indicates the portfolio is more expensive than Portfolio 0, while a negative value indicates the portfolio is less expensive than Portfolio 0 and would require less revenue to be collected from Basin Electric’s membership. Figure 15-1 shows the annual revenue requirement difference as compared to Portfolio 0 under a base load forecast and a market case, which meant any available surplus generation was marketed and the revenue received was included in the run results.

Annual revenue requirement differences are difficult to determine how much advantage one portfolio has over another. It can be used to show a definite split between some portfolios and in general a year-by-year difference from one portfolio to the other.
Figure 15-2 shows the annual revenue requirement difference as compared to Portfolio 0 under a high load forecast and a market case, which meant any available surplus generation was marketed and the revenue received was included in the run results.

The next step from the annual revenue requirement was to look at the PVRR of each portfolio. Figure 15-3 shows the 15 and 20 year PVRR for Portfolio A and B, as split out by run results, capacity purchases, and capital costs under a market case. Run results include all expenses and revenue created during the model run which includes operating costs, fuel costs, energy purchase costs and revenue from sales. Capacity purchases included the cost of buying capacity from the market to hold reserve obligations. Capital costs include the capital costs from the new resources.
Figure 15-3. 15 & 20 Year PVRR Base Load Forecast & Market

Figure 15-4 shows the 15 and 20 year PVRR for Portfolio C and D, as split out by run results, capacity purchases, and capital costs under a market case.

Figure 15-4. 15 & 20 Year PVRR High Load Forecast & Market
Figure 15-5 shows the 15 & 20 year PVRR difference as compared to Portfolio 0 (Portfolio ‘X’ – Portfolio 0) where a negative value indicates the portfolio is less expensive than Portfolio 0. The results show that over 15 years Portfolio A was approximately $144 million or 1.51 percent PVRR more cost effective over Portfolio 0, while Portfolio B was approximately $54 million or 0.57 percent PVRR more cost effective over Portfolio 0. Over 20 years Portfolio A was approximately $656 million or 5.28 percent PVRR more cost effective over Portfolio 0, while Portfolio B was approximately $551 million or 4.44 percent PVRR more cost effective over Portfolio 0.

Figure 15-5. 15 & 20 Year PVRR Difference Base Load Forecast & Market

Figure 15-6 shows that over 15 years Portfolio C was approximately $1,193 Million or 9.98 percent PVRR more cost effective over Portfolio 0, while Portfolio D was approximately $1,249 Million or 10.45 percent PVRR more cost effective over Portfolio 0. Over 20 years Portfolio C was approximately $2,821 Million or 17.18 percent PVRR more cost effective over Portfolio 0, while Portfolio D was approximately $2,901 Million or 17.67 percent PVRR more cost effective over Portfolio 0.

Figure 15-6. 15 & 20 Year PVRR Difference High Load Forecast & Market
Table 15-1 shows the minimum, maximum and average capacity factors achieved by the new resources in each portfolio over the course of this study under the Market case.

<table>
<thead>
<tr>
<th>Portfolio A (2012 Load Forecast)</th>
<th>Minimum (%)</th>
<th>Maximum (%)</th>
<th>Average (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LM6000 (2014) 1</td>
<td>1%</td>
<td>11%</td>
<td>5%</td>
</tr>
<tr>
<td>LM6000 (2014) 2</td>
<td>1%</td>
<td>11%</td>
<td>5%</td>
</tr>
<tr>
<td>LM6000 (2015) 1</td>
<td>2%</td>
<td>10%</td>
<td>5%</td>
</tr>
<tr>
<td>LM6000 (2015) 2</td>
<td>2%</td>
<td>9%</td>
<td>4%</td>
</tr>
<tr>
<td>NGCC 2x1 (2021)</td>
<td>15%</td>
<td>28%</td>
<td>23%</td>
</tr>
<tr>
<td>NGSC (2022)</td>
<td>0.00%</td>
<td>0.43%</td>
<td>0.17%</td>
</tr>
<tr>
<td>NGSC (2023)</td>
<td>0.00%</td>
<td>0.43%</td>
<td>0.16%</td>
</tr>
<tr>
<td>NGSC (2024)</td>
<td>0.00%</td>
<td>0.34%</td>
<td>0.10%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Portfolio B (2012 Load Forecast)</th>
<th>Minimum (%)</th>
<th>Maximum (%)</th>
<th>Average (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LM6000 (2014) 1</td>
<td>1%</td>
<td>7%</td>
<td>3%</td>
</tr>
<tr>
<td>LM6000 (2014) 2</td>
<td>1%</td>
<td>7%</td>
<td>3%</td>
</tr>
<tr>
<td>LM6000 (2015) 1</td>
<td>1%</td>
<td>6%</td>
<td>3%</td>
</tr>
<tr>
<td>LM6000 (2015) 2</td>
<td>1%</td>
<td>5%</td>
<td>3%</td>
</tr>
<tr>
<td>NGCC 2x1 (2019)</td>
<td>16%</td>
<td>33%</td>
<td>33%</td>
</tr>
<tr>
<td>NGCC 2x1 (2022)</td>
<td>7%</td>
<td>11%</td>
<td>10%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Portfolio C (10% High Load Forecast)</th>
<th>Minimum (%)</th>
<th>Maximum (%)</th>
<th>Average (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LM6000 (2014) 1</td>
<td>3%</td>
<td>16%</td>
<td>6%</td>
</tr>
<tr>
<td>LM6000 (2014) 2</td>
<td>3%</td>
<td>15%</td>
<td>6%</td>
</tr>
<tr>
<td>LM6000 (2015) 1</td>
<td>2%</td>
<td>14%</td>
<td>5%</td>
</tr>
<tr>
<td>LM6000 (2015) 2</td>
<td>2%</td>
<td>13%</td>
<td>5%</td>
</tr>
<tr>
<td>NGCC 2x1</td>
<td>26%</td>
<td>49%</td>
<td>40%</td>
</tr>
<tr>
<td>NGCC 2x1</td>
<td>17%</td>
<td>28%</td>
<td>23%</td>
</tr>
<tr>
<td>NGSC (2023)</td>
<td>0.00%</td>
<td>0.26%</td>
<td>0.05%</td>
</tr>
<tr>
<td>NGSC (2024)</td>
<td>0.00%</td>
<td>0.17%</td>
<td>0.03%</td>
</tr>
<tr>
<td>NGSC (2025)</td>
<td>0.00%</td>
<td>0.23%</td>
<td>0.03%</td>
</tr>
<tr>
<td>NGSC(2026)</td>
<td>0.00%</td>
<td>0.05%</td>
<td>0.00%</td>
</tr>
</tbody>
</table>
**Portfolio D (10% High Load Forecast)**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>LM6000 (2014)</td>
<td>2%</td>
<td>12%</td>
<td>6%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LM6000 (2014)</td>
<td>2%</td>
<td>12%</td>
<td>5%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LM6000 (2015)</td>
<td>2%</td>
<td>12%</td>
<td>5%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LM6000 (2015)</td>
<td>2%</td>
<td>10%</td>
<td>5%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NGCC 2x1 (2019)</td>
<td>23%</td>
<td>44%</td>
<td>35%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NGCC 2x1 (2023)</td>
<td>17%</td>
<td>24%</td>
<td>21%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NGSC (2020)</td>
<td>0.00%</td>
<td>1.30%</td>
<td>0.28%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NGSC (2024)</td>
<td>0.00%</td>
<td>0.15%</td>
<td>0.06%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NGSC (2025)</td>
<td>0.00%</td>
<td>0.04%</td>
<td>0.03%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 15-1. New Unit Capacity Factor (15yr) - Market

Now evaluating the capacity factor operation of the new resources for the portfolios under a Market opportunity case, it is shown that the first intermediate resource in each portfolio operate between 15 and 49 percent and on average between 23 and 35 percent. Those portfolios with a second intermediate resource operate between 7 and 28 percent and on average between 10 and 23 percent. The LM6000 peaking resources in each portfolio operate between 1 and 13 percent and on average between 3 and 6 percent. The NGSC peaking resources in each portfolio operate between 0 and 1.3 percent and on average between 0.03 and 0.28 percent.

Figure 15-7 shows the average annual capacity factor operation of the existing coal based generation within Basin Electric’s current resource mix for each portfolio evaluated under the market opportunity case. The graph shows that additional generation added to the current resource mix does not have much of an impact on the existing coal generation primarily because any surplus generation available is sold to the market if it is economical.
Figure 15-8 shows the average annual capacity factor operation of the existing natural gas generation within Basin Electric’s current resource mix for each portfolio evaluated under the market opportunity case. The graph shows that the magnitude of additional generation added to the current resource mix does impact the existing natural gas generation. The current gas generation was chosen to serve the increased load growth because the low gas prices made it the most economical. By adding additional gas generation in the portfolios proposed the load growth was served by more/larger gas resources thus moving the capacity factor lower.

No Market Cases

Each portfolio evaluated was compared to Portfolio 0 (for example, Portfolio A – Portfolio 0), which included no new resource development, to determine how more or less cost effective the portfolio was to not developing any new resources. A positive value indicates the portfolio is more expensive than Portfolio 0, while a negative value indicates the portfolio is less expensive than Portfolio 0. Figure 15-9 shows the annual revenue requirement difference for each portfolio as compared to Portfolio 0 under a base-load forecast and a no-market case, which meant there is no availability to outside markets. Annual revenue requirement differences are difficult to determine how much advantage one portfolio has over another. It can be used to show a definite split between some portfolios and in general a year-by-year difference from one portfolio to the other.
Figure 15-10 shows the annual revenue requirement difference as compared to Portfolio 0 under a high load forecast and a no market case, which meant there is no availability to outside markets.

The next step from the annual revenue requirement was to look at the present value revenue requirements (PVRR) of each portfolio. Figure 15-11 shows the 15 and 20 year PVRR for Portfolio A and B, as split out by run results, capacity purchases, and capital costs under a no-market case. Run results include all expenses and revenue created during the model run which includes operating costs, fuel costs, energy purchase costs and revenue from sales. Capacity purchases included the cost of buying capacity from the market to hold reserve obligations. Capital costs include the capital costs from the new resources.
Figure 15-12 shows the 15 and 20 year PVRR for Portfolio C and D, as split out by run results, capacity purchases, and capital costs under a no-market case.

Figure 15-12. 15 & 20 Year PVRR High Load Forecast & No-Market

Figure 15-13 shows the 15 & 20 year PVRR difference as compared to Portfolio 0 (Portfolio ‘X’ – Portfolio 0) where a negative value indicates the portfolio is less expensive than Portfolio 0. The results show that over 15 years Portfolio A was approximately $9,392 Million or 47.51 percent PVRR more cost effective over Portfolio 0, while Portfolio B was approximately $9,316 Million or 47.12 percent PVRR more cost effective over Portfolio 0.

Over 20 years Portfolio A was approximately $15,807 Million or 54.57 percent PVRR more cost effective over Portfolio 0, while Portfolio B was approximately $15,725 Million or 54.28 percent PVRR more cost effective over Portfolio 0.

Figure 15-13. 15 & 20 Year PVRR Difference Base Load Forecast & No-Market
Figure 15-14 shows the 15 & 20 year PVRR difference as compared to Portfolio 0 (Portfolio ‘X’ – Portfolio 0) where a negative value indicates the portfolio is less expensive than Portfolio 0. The results show that over 15 years Portfolio C was approximately $17,835 million or 56.59 percent PVRR more cost effective over Portfolio 0, while Portfolio D was approximately $18,218 million or 56.59 percent PVRR more cost effective over Portfolio 0. Over 20 years Portfolio C was approximately $28,632 million or 61.74 percent PVRR more cost effective over Portfolio 0, while Portfolio D was approximately $29,076 million or 62.70 percent PVRR more cost effective over Portfolio 0.
Table 15-2 shows the minimum, maximum and average capacity factors achieved by the new resources in each portfolio under the No Market case.

<table>
<thead>
<tr>
<th>Portfolio A (2012 Load Forecast)</th>
<th>Minimum (%)</th>
<th>Maximum (%)</th>
<th>Average (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LM6000 (2014) 1</td>
<td>25%</td>
<td>66%</td>
<td>40%</td>
</tr>
<tr>
<td>LM6000 (2014) 2</td>
<td>26%</td>
<td>63%</td>
<td>39%</td>
</tr>
<tr>
<td>LM6000 (2015) 1</td>
<td>24%</td>
<td>63%</td>
<td>37%</td>
</tr>
<tr>
<td>LM6000 (2015) 2</td>
<td>23%</td>
<td>60%</td>
<td>34%</td>
</tr>
<tr>
<td>NGCC 2X1 (2021)</td>
<td>70%</td>
<td>84%</td>
<td>79%</td>
</tr>
<tr>
<td>NGSC (2022)</td>
<td>6%</td>
<td>20%</td>
<td>14%</td>
</tr>
<tr>
<td>NGSC (2023)</td>
<td>6%</td>
<td>17%</td>
<td>11%</td>
</tr>
<tr>
<td>NGSC (2024)</td>
<td>5%</td>
<td>15%</td>
<td>10%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Portfolio B (2012 Load Forecast)</th>
<th>Minimum (%)</th>
<th>Maximum (%)</th>
<th>Average (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LM6000 (2014) 1</td>
<td>15%</td>
<td>63%</td>
<td>36%</td>
</tr>
<tr>
<td>LM6000 (2014) 2</td>
<td>15%</td>
<td>63%</td>
<td>36%</td>
</tr>
<tr>
<td>LM6000 (2015) 1</td>
<td>15%</td>
<td>62%</td>
<td>35%</td>
</tr>
<tr>
<td>LM6000 (2015) 2</td>
<td>12%</td>
<td>60%</td>
<td>32%</td>
</tr>
<tr>
<td>NGCC 2x1 (2019)</td>
<td>75%</td>
<td>83%</td>
<td>80%</td>
</tr>
<tr>
<td>NGCC 2x1 (2022)</td>
<td>54%</td>
<td>82%</td>
<td>57%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Portfolio C (10% High Load Forecast)</th>
<th>Minimum (%)</th>
<th>Maximum (%)</th>
<th>Average (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LM6000 (2014) 1</td>
<td>12%</td>
<td>60%</td>
<td>30%</td>
</tr>
<tr>
<td>LM6000 (2014) 2</td>
<td>11%</td>
<td>60%</td>
<td>30%</td>
</tr>
<tr>
<td>LM6000 (2015) 1</td>
<td>11%</td>
<td>59%</td>
<td>27%</td>
</tr>
<tr>
<td>LM6000 (2015) 2</td>
<td>9%</td>
<td>56%</td>
<td>25%</td>
</tr>
<tr>
<td>NGCC 2x1</td>
<td>67%</td>
<td>78%</td>
<td>76%</td>
</tr>
<tr>
<td>NGCC 2x1</td>
<td>51%</td>
<td>67%</td>
<td>60%</td>
</tr>
<tr>
<td>NGSC (2023)</td>
<td>2%</td>
<td>5%</td>
<td>4%</td>
</tr>
<tr>
<td>NGSC (2024)</td>
<td>2%</td>
<td>4%</td>
<td>3%</td>
</tr>
<tr>
<td>NGSC (2025)</td>
<td>2%</td>
<td>5%</td>
<td>2%</td>
</tr>
<tr>
<td>NGSC (2026)</td>
<td>0%</td>
<td>2%</td>
<td>1%</td>
</tr>
</tbody>
</table>
**Portfolio D (10% High Load Forecast)**

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capacity Factor</th>
<th>Capacity Factor 15yr</th>
<th>Capacity Factor 15yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>LM6000 (2014) 1</td>
<td>11%</td>
<td>52%</td>
<td>43%</td>
</tr>
<tr>
<td>LM6000 (2014) 2</td>
<td>12%</td>
<td>51%</td>
<td>27%</td>
</tr>
<tr>
<td>LM6000 (2015) 1</td>
<td>11%</td>
<td>51%</td>
<td>25%</td>
</tr>
<tr>
<td>LM6000 (2015) 2</td>
<td>9%</td>
<td>48%</td>
<td>25%</td>
</tr>
<tr>
<td>NGCC 2x1 (2019)</td>
<td>59%</td>
<td>73%</td>
<td>69%</td>
</tr>
<tr>
<td>NGCC 2x1 (2023)</td>
<td>49%</td>
<td>59%</td>
<td>71%</td>
</tr>
<tr>
<td>NGSC (2020)</td>
<td>1%</td>
<td>13%</td>
<td>36%</td>
</tr>
<tr>
<td>NGSC (2024)</td>
<td>1%</td>
<td>3%</td>
<td>3%</td>
</tr>
<tr>
<td>NGSC (2025)</td>
<td>1%</td>
<td>2%</td>
<td>2%</td>
</tr>
</tbody>
</table>

Table 15-2. New Unit Capacity Factor (15yr) – No-Market

Now evaluating the capacity factor operation of the new resources for the top portfolios under a No Market opportunity case it is shown that the intermediate resources in each portfolio operate between 59 and 84 percent and on average between 69 and 80 percent. Those portfolios with a second intermediate resource operate between 49 and 82 percent and on average between 60 and 80 percent. The LM6000 peaking resources in each portfolio operate between 11 and 66 percent and on average between 25 and 43 percent. The NGSC peaking resources in each portfolio operate between 2 and 20 percent and on average between 1 and 14 percent.

Figure 15-15 shows the average annual capacity factor operation of the existing coal based generation within Basin Electric’s current resource mix for each portfolio evaluated under the no market opportunity case. The graph show that additional generation brought into Basin Electric’s current resource mix has a direct impact on the operation of the existing coal generation operation.
Figure 15-16 shows the average annual capacity factor operation of the existing natural gas generation within Basin Electric’s current resource mix for each portfolio evaluated under the no market opportunity case. The graph shows that the additional generation brought into Basin Electric’s current resource mix has a direct impact on the operation of the existing gas generation operation.

Summary

Portfolios A (2012 Load Forecast) and D (10% Higher Load Forecast) were the lowest cost resource expansion portfolios under both the Market and No Market scenarios. The entire sets of portfolios are very similar with the exception of both A and D includes a wind power purchase of approximately 200 MW while B and C do not have wind included. Basin Electric is currently studying whether or not to join a RTO and, if so, which RTO to join, MISO or SPP. This initial study work has shown that the amount of resource capacity credit valued for wind changes between MISO and SPP, and it changes from year to year. Wind also cannot fulfill the long-term capacity need for generation for Basin Electric due to its intermittent nature. Wind could however help meet the intermediate generation need of Basin Electric if it could be integrated with natural gas generation to provide a schedulable product. It would also be a hedge against the volatility of the gas market and future greenhouse gas taxes. Basin Electric will need to study the effects on our current wind, of which we have more than 700 MW, with respect the wind resource capacity credit and whether additional wind is warranted.

There are several drivers affecting the decisions. The Portfolios were evaluated under both a No Market and Market opportunity scenarios, however, it is appropriate to say that Basin Electric will have the opportunity to sell surplus generation in the market and therefore believes the Market opportunity scenarios is a more appropriate scenario to evaluate and make a decision on. And finally there are uncertainties in the load forecast that having additional intermediate and peaking generation would be appropriate and if the load forecast does not develop as anticipated the generation portfolios can be reevaluated to determine if it is still an appropriate course of action.

Conclusions And Recommendations

The 2012 IRP is intended to provide guidance and rationale for Basin Electric’s resource development options over the next several years. This section includes the major conclusions and recommendations from the 2012 IRP.
Conclusions

There were commonalities within a majority of the portfolios. This included 200 MW growing to 350 MW of short-term power purchases. These purchases are for the 2013-2018 time frame. All portfolios also include two LM6000s in 2014 and two LM6000s in 2015. (See Table 15-3)

The retrofit option of Wisdom Unit 1 from a coal to natural gas unit has shown to have value. This would result in 38 MW capacity for a $3 million-$4 million investment, or approximately $79-$105/kW in capital costs to maintain this resource. This retrofit option will continue to be evaluated to determine if it is beneficial to be included in the Basin Electric portfolio.

The System Optimizer software also indicated that a large natural gas combined cycle (NGCC) unit is the next chronologically and most economical option to serve the forecasted load. All proposed portfolios included the installations of new Natural Gas Combined Cycle units but they differ in the year based on how rapidly the load growth appears. The first NGCC is modeled to be installed in the 2019-2020 time frame, depending on future load forecasts and actual load growth. This would be a $700 million-$800 million (2020 dollars) capital investment. Additional future power purchases could be explored to possibly push back the timing before the resource needs to be committed to.

After the 2012 update to the Load Forecast was completed, there were other third party load forecasts completed (see Load Forecast chapter). Basin Electric did its own internal review and expects the load will be higher than shown in the 2012 Load Forecast. This increase will be one of the determining factors if and/or when a second NGCC unit would be needed.

Additional wind generation could provide a hedge against long term greenhouse gas taxes and a hedge against gas price volatility. Basin Electric will need to study the effects of joining an RTO on our current wind resources with respect the wind resource capacity credit and whether additional wind is warranted.

This proposed portfolio allows for surplus generation that Basin Electric could grow into over the next five years, should the load grow faster than expected, so development of new generation could be delayed a couple of years until 2020 and beyond along with technological breakthroughs for new generation relating to CO2. Basin Electric’s preferred resource expansion plan includes:

<table>
<thead>
<tr>
<th>Acquisition Schedule</th>
<th>Description (total MW)</th>
<th>Resource Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013 – 2017</td>
<td>50 MW Energy &amp; Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>50 MW Energy &amp; Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>25 MW MISO Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2013 – 2017</td>
<td>25 MW MISO Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2014 – 2018</td>
<td>50-200 MW Energy &amp; Capacity Purchase</td>
<td>Purchased Power</td>
</tr>
<tr>
<td>2014</td>
<td>(2) 45 MW GE LM 6000 Units</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>2015</td>
<td>(2) 45 MW GE LM 6000 Units</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>Possible 2015</td>
<td>37 MW Retrofit of Wisdom Unit</td>
<td>Peaking Power</td>
</tr>
<tr>
<td>Possible 2019-2021</td>
<td>520 MW NGCC (2x2x1)</td>
<td>Intermediate Power</td>
</tr>
<tr>
<td>Possible (forecast dependent)</td>
<td>520 MW NGCC (2x2x1)</td>
<td>Intermediate Power</td>
</tr>
</tbody>
</table>

Table 15-3. Basin Electric Resource Expansion
Figure 15-17 shows Basin Electric’s IS (WAUE) system summer season surplus capacity with the preferred resource expansion plan from 2013-2018.

With the development of new resources to meet Basin Electric’s preferred resource expansion plan, Basin Electric’s IS will have enough generation to meet its forecasted need until 2018. With the resource additions Basin Electric is approximately 183 MW deficit in 2019.

However, if load growth develops more quickly than anticipated, Basin Electric would be in a good position to meet that additional need. This resource development plan would also allow for a small surplus generation if the load growth materializes as is anticipated or possibly allow for reconsideration of the size/timing of the next facility if load growth does not develop as anticipated.
Five-Year Action Plan

On the basis of these conclusions, and in order to ensure Basin Electric has adequate resources available to meet our member’s needs the following five-year action plan will be implemented:

1. Move ahead with the following power purchases:
   a. Short Term Purchase: 50 MW of Unit Contingent Power, 2013-2018
   b. Short Term Purchase: 50 MW On Peak 40 MW Off Peak Firm, 2014-2018
   c. Short Term Purchase: 50 MW for 2014 and 2015, 200 MW Summer of 2016-2018
   d. MISO Capacity Purchase: 25 MW of Capacity in the MISO BA
   e. MISO Capacity Purchase: 25 MW of Capacity in the MISO BA

2. Move ahead with the development of 180 MW of peaking generation, such as GE LM6000 combustion turbines within Basin Electric’s IS (WAUE) system.

3. Continue to work on developing and expanding upon energy conservation and efficiency within the Basin Electric service territory.

4. Work with the members to develop more load management within the Basin Electric system where viable.
<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AC</td>
<td>Alternating Current</td>
</tr>
<tr>
<td>AES</td>
<td>Alternative Evaluation Study</td>
</tr>
<tr>
<td>AVS</td>
<td>Antelope Valley Station</td>
</tr>
<tr>
<td>Basin Electric</td>
<td>Basin Electric Power Cooperative</td>
</tr>
<tr>
<td>Biopower</td>
<td>Biomass Power</td>
</tr>
<tr>
<td>Black Hills</td>
<td>Black Hills Power &amp; Light Association</td>
</tr>
<tr>
<td>BPA</td>
<td>Bonneville Power Administration</td>
</tr>
<tr>
<td>Btu</td>
<td>British Thermal Units</td>
</tr>
<tr>
<td>Capital Electric</td>
<td>Capital Electric Cooperative</td>
</tr>
<tr>
<td>CBM</td>
<td>Coal Bed Methane</td>
</tr>
<tr>
<td>Central Montana</td>
<td>Central Montana Electric Power Cooperative</td>
</tr>
<tr>
<td>Central Power</td>
<td>Central Power Electric Cooperative</td>
</tr>
<tr>
<td>CGS</td>
<td>Culbertson Generation Station</td>
</tr>
<tr>
<td>CO</td>
<td>Carbon Monoxide</td>
</tr>
<tr>
<td>CO2</td>
<td>Carbon Dioxide</td>
</tr>
<tr>
<td>Corn Belt</td>
<td>Corn Belt Power Cooperative</td>
</tr>
<tr>
<td>CRN</td>
<td>Cooperative Research Network</td>
</tr>
<tr>
<td>Crow Wing</td>
<td>Crow Wing Cooperative Power &amp; Light Company</td>
</tr>
<tr>
<td>CTG</td>
<td>Combustion Turbine Generators</td>
</tr>
<tr>
<td>CUS</td>
<td>Black Hills/Basin Electric/PRECorp Common Use System</td>
</tr>
<tr>
<td>DC</td>
<td>Direct Current</td>
</tr>
<tr>
<td>DCS</td>
<td>Deer Creek Station</td>
</tr>
<tr>
<td>DOE</td>
<td>U.S. Department of Energy</td>
</tr>
<tr>
<td>DFS</td>
<td>Dry Fork Station</td>
</tr>
<tr>
<td>DSM</td>
<td>Demand-side Management</td>
</tr>
<tr>
<td>East River</td>
<td>East River Electric Power Cooperative</td>
</tr>
<tr>
<td>EEERE</td>
<td>U.S. DOE Energy Efficiency and Renewable Energy</td>
</tr>
<tr>
<td>EPRI</td>
<td>Electric Power Research Institute</td>
</tr>
<tr>
<td>ERC</td>
<td>Energy Resource Conservation</td>
</tr>
<tr>
<td>FAPRI</td>
<td>Food and Agricultural Policy Research Institute</td>
</tr>
<tr>
<td>Flathed</td>
<td>Flathed Electric Cooperative</td>
</tr>
<tr>
<td>FPL</td>
<td>Florida Power &amp; Light Energy</td>
</tr>
<tr>
<td>GGS</td>
<td>Groton Generation Station</td>
</tr>
<tr>
<td>Grand</td>
<td>Grand Electric Cooperative</td>
</tr>
<tr>
<td>GWh</td>
<td>Gigawatt-Hours (1,000,000,000 watt-hours)</td>
</tr>
<tr>
<td>G&amp;T</td>
<td>Generation and Transmission</td>
</tr>
<tr>
<td>HP/IP</td>
<td>High Pressure and Intermediate Pressure</td>
</tr>
<tr>
<td>Hydropower</td>
<td>Hydroelectric Power</td>
</tr>
<tr>
<td>IS</td>
<td>Integrated System</td>
</tr>
<tr>
<td>KEM</td>
<td>KEM Electric Cooperative</td>
</tr>
<tr>
<td>kW</td>
<td>Kilowatts (1,000 watts)</td>
</tr>
<tr>
<td>kWh</td>
<td>Kilowatt-Hours (1,000 watts-hours)</td>
</tr>
<tr>
<td>L&amp;O</td>
<td>L&amp;O Power Cooperative</td>
</tr>
<tr>
<td>LOS</td>
<td>Leland Olds Station</td>
</tr>
<tr>
<td>LRS</td>
<td>Laramie River Station</td>
</tr>
<tr>
<td>MAIN</td>
<td>Mid-America Interconnected Network, Inc.</td>
</tr>
<tr>
<td>Acronym</td>
<td>Full Form</td>
</tr>
<tr>
<td>---------</td>
<td>-----------</td>
</tr>
<tr>
<td>MAPP</td>
<td>Mid-Continent Area Power Pool</td>
</tr>
<tr>
<td>MBPP</td>
<td>Missouri Basin Power Project</td>
</tr>
<tr>
<td>MCP</td>
<td>Market Clearing Price</td>
</tr>
<tr>
<td>Miles City Tie</td>
<td>Miles City Direct Current Tie</td>
</tr>
<tr>
<td>MEC</td>
<td>Mid-American Energy Company</td>
</tr>
<tr>
<td>Minnesota Valley CL&amp;P</td>
<td>Minnesota Valley Cooperative Light &amp; Power Association</td>
</tr>
<tr>
<td>Minnesota Valley EC</td>
<td>Minnesota Valley Electric Cooperative</td>
</tr>
<tr>
<td>MISO</td>
<td>Midwest Independent Transmission System Operator</td>
</tr>
<tr>
<td>MMBtu</td>
<td>Million British Thermal Units</td>
</tr>
<tr>
<td>Mor-Gran-Sou</td>
<td>Mor-Gran-Sou Electric Cooperative</td>
</tr>
<tr>
<td>MRO</td>
<td>Midwest Reliability Organization</td>
</tr>
<tr>
<td>MSA</td>
<td>Metropolitan Statistical Area</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatts (1,000,000 watts)</td>
</tr>
<tr>
<td>MWh</td>
<td>Megawatt-Hours (1,000,000 watts-hours)</td>
</tr>
<tr>
<td>NEI</td>
<td>Nuclear Energy Institute</td>
</tr>
<tr>
<td>NERC</td>
<td>North American Electric Reliability Corporation</td>
</tr>
<tr>
<td>NDEX</td>
<td>North Dakota Export Constraint</td>
</tr>
<tr>
<td>NIPCO</td>
<td>Northwest Iowa Power Cooperative</td>
</tr>
<tr>
<td>NOAA</td>
<td>National Oceanic and Atmospheric Administration</td>
</tr>
<tr>
<td>NPPD</td>
<td>Nebraska Public Power District</td>
</tr>
<tr>
<td>NPV</td>
<td>Net Present Value</td>
</tr>
<tr>
<td>NRECA</td>
<td>National Rural Electric Cooperative Association</td>
</tr>
<tr>
<td>NSP</td>
<td>Northern States Power (now, Xcel Energy)</td>
</tr>
<tr>
<td>NWPP</td>
<td>Northwest Power Pool</td>
</tr>
<tr>
<td>NYMEX</td>
<td>New York Mercantile Exchange</td>
</tr>
<tr>
<td>Roughrider</td>
<td>Roughrider Electric Cooperative</td>
</tr>
<tr>
<td>OTP</td>
<td>Otter Tail Power Company</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>Operating and Maintenance</td>
</tr>
<tr>
<td>PAC</td>
<td>PacifiCorp</td>
</tr>
<tr>
<td>Pace Global</td>
<td>Pace Global Energy Services</td>
</tr>
<tr>
<td>PRB</td>
<td>Powder River Basin</td>
</tr>
<tr>
<td>PRECorp</td>
<td>Powder River Energy Corporation</td>
</tr>
<tr>
<td>PSA</td>
<td>Power Supply Analysis</td>
</tr>
<tr>
<td>PSCO</td>
<td>Public Service Company of Colorado</td>
</tr>
<tr>
<td>PVR</td>
<td>Present Value Revenue Requirements</td>
</tr>
<tr>
<td>PWND1</td>
<td>Prairie Winds ND 1, Inc. (PWND1)</td>
</tr>
<tr>
<td>PWSD1</td>
<td>Prairie Winds SD 1, Inc. (PWSD1)</td>
</tr>
<tr>
<td>Rapid City Tie</td>
<td>Rapid City DC Tie</td>
</tr>
<tr>
<td>REA</td>
<td>Rural Electrification Administration</td>
</tr>
<tr>
<td>REC</td>
<td>Rural Electric Cooperative</td>
</tr>
<tr>
<td>REG</td>
<td>Recovered Energy Generation</td>
</tr>
<tr>
<td>RFP</td>
<td>Request for Proposal</td>
</tr>
<tr>
<td>RMPA</td>
<td>Rocky Mountain Power Area</td>
</tr>
<tr>
<td>Rosebud</td>
<td>Rosebud Electric Cooperative</td>
</tr>
<tr>
<td>REO</td>
<td>Renewable Energy Objective</td>
</tr>
<tr>
<td>RUS</td>
<td>Rural Utilities Service</td>
</tr>
<tr>
<td>Rushmore</td>
<td>Rushmore Electric Power Cooperative</td>
</tr>
<tr>
<td>SCADA</td>
<td>Supervisory Control and Data Acquisition</td>
</tr>
<tr>
<td>Acronym</td>
<td>Description</td>
</tr>
<tr>
<td>-----------</td>
<td>------------------------------------------------------------------</td>
</tr>
<tr>
<td>SMS</td>
<td>Spirit Mound Station</td>
</tr>
<tr>
<td>SO2</td>
<td>Sulfur Dioxide</td>
</tr>
<tr>
<td>SPP</td>
<td>Southwest Power Pool</td>
</tr>
<tr>
<td>Stegall Tie</td>
<td>Stegall DC Tie</td>
</tr>
<tr>
<td>TLR</td>
<td>Transmission Line Loading Relief</td>
</tr>
<tr>
<td>TOT</td>
<td>Total Flow on a specific grouping of transmission lines</td>
</tr>
<tr>
<td>Tri-State</td>
<td>Tri-State Generation and Transmission Association</td>
</tr>
<tr>
<td>Upper Missouri</td>
<td>Upper Missouri Generation and Transmission Electric Cooperative</td>
</tr>
<tr>
<td>URGE</td>
<td>Uniform Rating of Generating Equipment</td>
</tr>
<tr>
<td>USDA</td>
<td>United States Department of Agriculture</td>
</tr>
<tr>
<td>U.S. DOE EIA</td>
<td>United States Depart of Energy: Energy Information Administration</td>
</tr>
<tr>
<td>U.S. DOE NREL Laboratory</td>
<td>United States. Department of Energy National Renewable Energy Laboratory</td>
</tr>
<tr>
<td>U.S. EPA</td>
<td>United States Environmental Protection Agency</td>
</tr>
<tr>
<td>W&amp;P</td>
<td>Woods and Poole Economics, Inc.</td>
</tr>
<tr>
<td>WB</td>
<td>Williston Basin</td>
</tr>
<tr>
<td>WECC</td>
<td>Western Electricity Coordinating Council</td>
</tr>
<tr>
<td>WECC-RMPA</td>
<td>Western Electricity Coordinating Council – Rocky Mountain Power Area</td>
</tr>
<tr>
<td>Western</td>
<td>Western Area Power Administration</td>
</tr>
<tr>
<td>WMPA</td>
<td>Wyoming Municipal Power Agency</td>
</tr>
<tr>
<td>Wright-Hennepin</td>
<td>Wright-Hennepin Cooperative Electric Association</td>
</tr>
<tr>
<td>WTI</td>
<td>West Texas Intermediate</td>
</tr>
</tbody>
</table>
Appendix B – Model Descriptions

Ventyx EPM System

The EPM Framework System provides a Windows®-based application platform providing a common interface for the electric market simulation modules, including the Planning and Risk, Zonal Market Analysis and System Optimizer. The system enables multi-user access and scenario control of simulation study parameters and results via integrated SQL databases for input and output data. As well as providing common controls and operational standards across Ventyx software modules.

Planning and Risk Module

The Planning and Risk Management solution is a portfolio management tool used to analyze, report, and actively manage your energy market assets, including power plants, customer loads, fuels, and contractual positions. Planning and Risk allows for comprehensive description of energy assets and markets, and can be used to estimate the optimal dispatch of a generation portfolio against either a market price or a load requirement.

Planning and Risk provides the technology for portfolio management, asset and contract review. The solution is an analytic tool that can assist with the planning and risk evaluation decisions related to electricity-based asset portfolios. Planning and Risk’s modeling framework supports a wide variety of planning and risk management decisions, and addresses the following needs:

- Portfolio and market representation, including multiple market modeling
- Multiple customer load modeling
- Portfolio reporting and risk assessment
- Budget setting and sensitivity analysis
- Physical and Financial Contract evaluation
- Assessment of key risk drivers
- Allow scenario analysis, stress testing and Monte Carlo evaluation
- Facilitates fuel procurement plans and budgets for rate setting
- Long-term resource planning recognizing uncertainty in future economic and physical factors; valuation of physical transactions and physical assets
- Analysis of different portfolio combinations, with comparison of their expected values and Cash flow at Risk (CfAR) levels
- Audit and Control infrastructure that reflects the latest market requirements and technology
- Interface to Corporate Finance

Planning and Risk’s uncertainty modeling technology allows for the flexibility to perform either scenario or Monte Carlo simulation analysis of electricity based portfolios, thereby fitting in with either traditional analytical methods, or those based on modern financial theory.
Planning and Risk is driven by Ventyx’s PROSYM chronological calculation engine for modeling power systems, developed for over 20 years to meet the needs of utilities facing portfolio planning decisions. PROSYM’s engine is used to simulate a portfolio’s operation by reflecting detailed unit operating constraints like start-up costs, ramp rate restrictions, minimum up and down times, and other plant dynamics, providing a credible analysis of asset valuation and risk exposure.

**System Optimizer Module**

The System Optimizer module is a mid to long-term company portfolio or regional system optimization model. The core logic handles both Capacity Expansion and Emissions Compliance decisions.

System Optimizer has been integrated into the EPM Core platform and is operated as a module within EPM. This situation provides sharing of data across application modules and corporate systems, and the latest in graphical user environments. The System Optimizer module has a consistent GUI and data sharing capabilities with other modules within EPM. The optimized capacity plan can be fed into the Planning and Risk or Zonal Market Analysis modules for a detailed analysis without changing base data or scenario data.

System Optimizer performs a deterministic evaluation of the optimal resource plan for a single company portfolio or for an interconnected region. The resource planning variables include both investment and operational parameters. The objective function is to minimize the net present value of system costs (or revenue requirements) subject to energy balance constraints, reserve margin and/or reliability constraints, generation and transmission constraints, emission allowance constraints, fuel purchase constraints, and other operational constraints. The study period may be one to 30 years.

System Optimizer may be used as part of a larger supply planning, integrated resource planning (IRP), or power contracts procurement study. The goal of System Optimizer is to minimize the net present value of generation, contract and spot market transactions, amortized capital costs of generation, DSM program, and transmission expansion projects, as well as generating station decommissioning costs subject to load balance, reliability, and investment constraints. Thus, the criterion for evaluation is minimization of the net present value of revenue requirements (PVRR) or system cost.

An important part of a capacity expansion exercise is to evaluate the future resources needed to meet growing demand in order to present a balanced and responsible resource strategy to the stakeholders and the state regulatory bodies. This strategy must meet system reliability requirements, accounts for current and future environmental regulations, and balances risks and costs.

- System Optimizer answers the key investment decisions of:
  - What to build (retire)?
  - When to build (retire)?
  - Where to build?
  - How much to build?

Decisions to build generating units or expand transmission capacity, purchase or sell contracts, or retire generating units are made based on the expected market value (revenue) less costs including both variable and fixed cost components. System Optimizer is intended for use only as one decision tool, along with other tools and final judgment before formulating an IRP. Long-term expansion decisions must consider alternate growth, environmental regulations, and supply scenarios.
Appendix C – References

Chapter 3
1 http://www.fas.org/sgp/crs/misc/R41561.pdf ......................................................... 27

Chapter 10
3 WECC’s Power Supply Assessment: http://www.wecc.biz/Planning/ResourceAdequacy/PSA/Documents/Forms/AllItems.aspx ......................................................... 117
7 WECC Transmission Project Information Portal: http://www.wecc.biz/PLANNING/TRANSMISSIONEXPANSION/MAP/Pages/ ......................................................... 120

Chapter 12
1 http://www.eia.gov/energy_in_brief/article/renewable_electricity.cfm ......................................................... 126
2 http://www.eia.gov/electricity/annual/ ......................................................... 127
3 http://www.nrel.gov/gis/images/windcap1-1-23currcap.jpg ......................................................... 127
4 http://www.nrel.gov/gis/images/80m_wind/USwind300dpe4-11.jpg ......................................................... 128
5 http://www.nrel.gov/gis/mapsearch/ ......................................................... 129
6 http://www.awea.org/learnabout/publications/factsheets/factsheets_state.cfm ......................................................... 129
7 http://www.nrel.gov/gis/mapsearch/ ......................................................... 130
8 http://www.awea.org/learnabout/publications/factsheets/factsheets_state.cfm ......................................................... 130
9 http://www.nrel.gov/gis/mapsearch/ ......................................................... 131
10 http://www.awea.org/learnabout/publications/factsheets/factsheets_state.cfm ......................................................... 131
11 http://www.nrel.gov/gis/mapsearch/ ......................................................... 132
12 http://www.awea.org/learnabout/publications/factsheets/factsheets_state.cfm ......................................................... 132
13 http://www.nrel.gov/gis/mapsearch/ ......................................................... 133
14 http://www.awea.org/learnabout/publications/factsheets/factsheets_state.cfm ......................................................... 133
15 http://www.nrel.gov/gis/mapsearch/ ......................................................... 134
16 http://www.awea.org/learnabout/publications/factsheets/factsheets_state.cfm ......................................................... 134
19 http://www.nrel.gov/gis/mapsearch/ ......................................................... 136
20 http://www.nrel.gov/gis/mapsearch/ ......................................................... 137
22 EIA Electric Power Annual, Release Data: January 30, 2013; Table 1-1 http://www.eia.gov/electricity/annual/ ........................................................................ 139
23 http://www.nrel.gov/docs/fy12osti/51946.pdf ......................................................... 140
24 http://www.eia.gov/creaf/solar.renewables/page/hydroelec/hydroelec.html ......................................................... 140
25 http://hydropower.inel.gov/hydrofacts/pdfs/01-ga50627-01-brochure.pdf ......................................................... 141
Appendix C - References

26 http://hydropower.inel.gov/hydrofacts/benefit_us_dams.shtml .................................................. 141
27 http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf .............................................. 142
28 http://www.riverviewconsultinginc.com/uncategorized/industry-update-microgrid-backbone-generation-assets-part-3-microturbines .............................................................. 142
30 EIA Electric Power Annual 2011, Release Data: January 30, 2013; Table 4-3 http://www.eia.gov/electricity/annual/ .............................. 142
31 http://www.nrel.gov/gis/mapsearch/ ......................................................................................... 143
32 http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf .............................................. 144
33 http://www.riverviewconsultinginc.com/uncategorized/industry-update-microgrid-backbone-generation-assets-part-3-microturbines .............................................................. 144
34 http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf .............................................. 146
35 http://www.riverviewconsultinginc.com/uncategorized/industry-update-microgrid-backbone-generation-assets-part-3-microturbines .............................................................. 150
38 EIA Electric Power Annual 2011, Release Data: January 30, 2013; Table 4-3 http://www.eia.gov/electricity/annual/ .............................................................. 154
39 EIA Electric Power Annual 2011, Release Data: January 30, 2013; Table 3-12 http://www.eia.gov/electricity/annual/ .............................................................. 154
40 http://pbadupws.nrc.gov/docs/ML1305/ML13057A527.pdf ...................................................... 156