APPENDIX J

minnesota power

AN ALLETE COMPANY

2013 Resource Plan

March 1, 2013
Docket No. E015/RP-13-53

minnesota power / 30 west superior street / duluth, minnesota 55802-2093 / 218-722-5642 / www.mnpower.com

Lori Hoyum
Policy Manager
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March 1, 2013

VIA E-FILING
Dr. Burl W. Haar Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of Minnesota Power's Application for Approval of its 2013-2027 Resource Plan
Docket No. E015/RP-13-53

Dear Dr. Haar:

Minnesota Power presents for approval its 2013 Integrated Resource Plan ("2013 Plan" or "Plan") pursuant to the requirements set forth in the Minnesota Public Utilities Commission's ("Commission") Orders dated May 6, 2011 and September 13, 2012 in Docket No. E015/RP-09-1088. This Plan is being filed under Minn. Stat. § 216B.2422 and Minn. Rules Chapter 7843.

Minnesota Power's 2013 Plan is focused on a balanced approach to delivering safe, reliable service at the lowest possible cost to customers while protecting and improving the region and state's quality of life through continued environmental stewardship. It continues the transition of Minnesota Power's fleet to become more diverse, more flexible and less emitting with additional major steps that address a changing energy landscape and respond to the Commission's Orders in Minnesota Power's previous integrated resource plan docket. Minnesota Power's short-term action plan during the five-year period of 2013 through 2017 is comprised of steps that will: a) preserve competitive base load generating resources while reducing emissions, b) continue implementation of least cost demand side resources including conservation, c) reduce reliance on coal fired generation, d) reduce carbon intensity on Minnesota Power's system and e) add renewable energy and transmission infrastructure to the benefit of customers. The Company's long-term action plan strategy will focus on further reducing carbon emissions in its portfolio and reshaping its generation mix towards a balance of approximately one-third renewable resources, one-third efficient coal-fired generation and one-third natural gas/other sources.

The 2013 Plan is organized into six sections with supporting appendices as presented in the Table of Contents. The supporting appendices contain in-depth or extensive information and, as appropriate, specific responses to the Orders dated May

6, 2011 and September 13, 2012, respectively, including all agreed-to actions by Minnesota Power.

Certain portions of the Plan contain trade secret information and are marked as such, pursuant to the Commission's Revised Procedures for Handling Trade Secret and Privileged Data, which procedures further the intent of Minn. Stat. § 13.37 and Minn. Rule 7829.0500. As required by the Commission's Revised Procedures, a statement providing the justification for excising the Trade Secret Data is attached to this letter.

As reflected in the attached Affidavit of Service, the Executive Summary has been filed on the official general service list utilized by Minnesota Power as well as the 2010 Integrated Resource Plan service list.

Please contact me at the number or the email address provided if you have any questions.

Yours truly,

Lori Hoyum

Lori Hoyum

cc: Service List

STATE OF MINNESOTA)
) ss
COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA
ELECTRONIC FILING

Susan Romans of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 1st day of March, 2013, she served Minnesota Power's 2013 Integrated Resource Plan in Docket No. E015/RP-13-53 to the Minnesota Public Utilities Commission via electronic filing. The remaining parties were served as so indicated on the attached Official Service List.

*/s/ Susan Romans*___________

Subscribed and sworn to before
me this 1st day of March, 2013.

*/s/ Jodi Nash*_______________
Notary Public - Minnesota
My Commission Expires Jan. 31, 2015

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STATEMENT REGARDING JUSTIFICATION FOR EXCISING TRADE SECRET INFORMATION

Pursuant to the Commission's revised Procedures for Handling Trade Secret and Privileged Data in furtherance of the intent of Minn. Stat. § 13.37 and Minn. Rule 7829.0500, Minnesota Power has designated portions of its attached 2013 Integrated Resource Plan ("Plan") as Trade Secret.

Minnesota Power is requesting approval of its Plan under Minn. Stat. § 216B.2422 and Minn. Rules Chapter 7843. Minnesota Power has removed certain information from the Plan to prevent disclosure of Minnesota Power's information regarding its methods, techniques, and process for identifying, obtaining, managing, and comparing various resources. This is highly confidential information; Minnesota Power's competitors, as well as its potential suppliers, would gain a commercial advantage over Minnesota Power if this information were publicly available. Minnesota Power follows strict internal procedures to maintain the secrecy of this information in order to capitalize on economic value of the information to Minnesota Power. As a result of public availability, Minnesota Power and its customers would suffer in providing resources to its retail load. Minnesota Power respectfully requests the opportunity to provide additional justification in the event of a challenge to the trade secret designation provided herein.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

MINNESOTA POWER 2013 RESOURCE PLAN

PETITION FOR APPROVAL

March 1, 2013

Docket No. E015/RP-13-53

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I. About Minnesota Power

Minnesota Power, in its second century of energizing communities and businesses, is transforming its energy supply by bringing more renewable power to customers while reducing its reliance on coal.

A division of ALLETE, Inc., Minnesota Power serves about 144,000 retail electric customers and 16 municipal systems across a 26,000-square-mile service area in central and northeastern Minnesota. ALLETE subsidiary Superior Water, Light and Power ("SWLP") sells electricity to 15,000 customers, natural gas to 12,000 customers and water services to 10,000 customers in northwestern Wisconsin.

More than half of Minnesota Power's total energy supply is sold to industrial customers who operate around the clock. This ratio of industrial demand gives Minnesota Power a uniquely high load factor and a load profile with less variation than most utilities. The Company's industrial customers produce taconite, iron nuggets, paper and pulp, and serve the pipeline and refining industry.

Minnesota Power has nine Large Power contracts serving 10 customer locations which include: five taconite producing facilities, one iron nugget plant and four paper and pulp mills. The processing of taconite, an iron-bearing rock used to make pellets which are a primary ingredient in blast furnace steel, requires large quantities of electric power. A new mining customer, Mesabi Nugget, produces iron-bearing nuggets. PolyMet, a nonferrous mining operation awaiting final permitting, is also under contract to purchase electricity from Minnesota Power. Another new mining customer, Essar Steel Minnesota, obtains its electricity from the municipality of Nashwauk, which is served as a municipal customer by Minnesota Power. The Essar facility under construction is expected to begin processing taconite this year. In addition to directly serving three major paper and pulp mills, Minnesota Power indirectly serves another mill with wholesale service. Minnesota Power also powers four wood products manufacturers and provides electric service to two oil pipelines and a refinery.[1] Minnesota Power is expected to remain a winter-peaking utility for the foreseeable future, as residential customers account for less than 10 percent of total and do not have the influence on overall demand seen with summer peaking utilities.

Factors that support the steadiness and predictability of Minnesota Power's electric load contribute to the Company's comparatively low-cost power. According to 2012 statistics[2] compiled by the Edison Electric Institute, Minnesota Power's total average retail electric rate of 5.97 cents per kilowatt-hour was the fourth lowest in the U.S. among 169 providers surveyed. Minnesota Power's retail electric rate was the second-lowest in the West North Central region (average rate: 7.87 cents per kWh) and the lowest in Minnesota (average: 8.09 cents per kWh).

Minnesota Power generates the majority of its electricity from coal-fired units at the Boswell, Laskin and Taconite Harbor Energy Centers in Minnesota, supplemented

[1] The refinery is one of the 15,000 customers SWLP sells electricity to in northwestern Wisconsin.
[2] Typical Bills and Average Rates Report Summer 2012, dated July 1, 2012.

by a long-term purchase from Square Butte's Milton R. Young 2 ("Young 2") lignite coal generating station in North Dakota. But the percentage of coal-based generation on the Minnesota Power system is declining, from about 95 percent in 2006 to approximately 80 percent today. The Company anticipates reaching a coal, non-coal balance of 50/50 by 2025 and a long-term state of approximately one-third renewable resources, one-third natural gas/other, and one-third coal. Minnesota Power is working toward a more diverse mix of energy producing technologies and fuels to provide its customers with a reliable supply of electric energy at reasonable cost.

Building off the company-founding hydroelectric assets, over the past six to seven years, the Company has undertaken a systematic effort to increase its deployment of renewable energy. In 2006 and 2007, Minnesota Power began purchasing the entire output of the Oliver 1 and Oliver 2 wind farms built in North Dakota by NextEra Energy. In 2008, Minnesota Power built Taconite Ridge, the first commercial wind generating facility in northern Minnesota. Most recently, the Company completed three phases of the Bison Wind Energy Center in North Dakota between 2010 and 2012. All told, these wind projects added more than 400 MW of renewable electricity to Minnesota Power's system.

As the state's largest producer of hydroelectric power with 10 federally licensed facilities, Minnesota Power is well acquainted with the power of water. The Company in 2011 signed a 15-year agreement to buy 250 MW of carbon-free hydroelectricity from Manitoba Hydro beginning in 2020. Minnesota Power is planning the construction of the Great Northern Transmission Line to carry this Canadian hydropower to the Mesabi Iron Range and Duluth which will also improve regional reliability.

Minnesota Power has utilized innovation and synergy in balancing its generation fleet. It purchased a 465-mile direct current transmission line linking energy resources in North Dakota to Duluth and began phasing out a long-term purchase of coal-based electricity replacing it with wind power from the new Bison project. A creative provision of Minnesota Power's energy purchase from Manitoba Hydro will allow the Company to "store" North Dakota wind energy within the Manitoba system.

Minnesota Power has partnered with large industrial customers to create cogeneration using wood resources from the region. These cogeneration facilities take advantage of the synergies in process steam and electric production and include the Rapids Energy Center at the Blandin Paper Company in Grand Rapids, Minnesota, and the Cloquet Sappi No. 5 Turbine at the Sappi facility in Cloquet, Minnesota. Minnesota Power's Hibbard Energy Center in Duluth, Minnesota uses a mix of wood, natural gas and coal to supply steam to the NewPage paper-making facility and to Minnesota Power's Units 3 and 4 turbine generators.

Another facet of the Company's generation fleet transition involves further reducing the emissions from the two largest baseload coal generators on the system. A major environmental retrofit completed at Boswell Energy Center Unit 3 ("BEC3") in 2009 will be followed by a similar emission reduction project at Boswell Energy Center Unit 4 ("BEC4"). Decisions regarding Minnesota Power's Laskin and Taconite Harbor generating facilities are thoroughly detailed elsewhere in this plan. These facilities have served the Company and its customers well. Just as the Company developed from a 100 percent hydroelectric provider after its incorporation in 1906, Minnesota Power will continue to evolve its power supply, seeking a sustainable balance of energy generation that is dependable, affordable and environmentally sound to best serve its customers.

II. 2013 Resource Plan Summary

This Petition presents Minnesota Power's Integrated Resource Plan ("Plan" or "2013 Plan") for the period 2013 through 2027. The Plan is filed pursuant to Minn. Stat. § 216B.2422, the Minnesota Public Utilities Commission's ("Commission") May 6, 2011 Order on Minnesota Power's 2010 Integrated Resource Plan ("2010 Plan") and its September 13, 2012 Order on Minnesota Power's baseload diversification compliance filing (Docket No. E015/M-09-1088).

Minnesota Power is pleased to submit its 2013 Integrated Resource Plan ("IRP"), the next chapter in the company's *Energy**Forward*** resource strategy, designed to supply its customers with a safe, reliable, and affordable power supply while reducing coal fleet emissions, sustaining its high quality energy conservation program, adding renewables in the near term and adding natural gas in the long-term. Minnesota Power's *Energy**Forward*** strategy is reshaping the company's power supply from a predominantly coal-based energy mix to one that is diverse while minimizing customer costs and retaining reliability.

Minnesota Power finds itself in a very different planning position than most of the electric industry as it is forecasting system growth in a time of recession recovery. Taconite production levels have generally recovered, economic diversification in the way of alternative mining and forest industry product facilities have begun operating and more new operations are on the horizon in Northeast Minnesota. The continued reduction in power demand seen in the rest of the industry plus abundant supplies of coal and natural gas are resulting in historic lows in electric power market prices. This is producing an outlook for competitively priced surplus power that creates a valuable opportunity to help Minnesota Power keep power supply costs low through select and well-timed bilateral purchases as it implements its resource plans, especially nearer term.

Proactive environmental control investments to date, along with more recent engineering design work on plant retrofits, will enable Minnesota Power to timely address environmental regulations, including the finalized Environmental Protection Agency ("EPA") Mercury and Air Toxics ("MATS") Rule.[3] The Company has been and will continue to concentrate additional environmental control investment on its largest, most efficient resources to help ensure cost effective investments on behalf of customers.

[3] Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for air pollutants for certain source categories. The EPA published the final MATS Rule in the Federal Register on February 16, 2012, addressing mercury and other emissions from coal-fired utility units greater than 25 MW.

Minnesota Power's 2013 Plan is focused on a balanced approach to delivering safe, reliable service at the lowest possible cost to customers while protecting and improving the region and state's quality of life through continued environmental stewardship. Additionally, the themes of the 2013 Plan reflect the Company's long-held resource planning principles and strategic goals, while meeting regulatory and legislative objectives. This Plan:

- Preserves reliable and environmentally compliant service to meet customer needs. Through implementation of a diverse and flexible resource mix of renewable, coal and natural gas supplies, Minnesota Power will balance its fuel sources and be well positioned to meet the needs of its customers.
- Further improves environmental performance through ongoing and significant mercury and other air emission reductions.
- Cost effectively serves increasing customer load requirements while reducing carbon intensity per unit of energy delivered through an optimum mix of effective customer conservation programs, reduced reliance on coal, generating facility efficiency improvements, added development and acquisition of innovative renewable energy sources from wind, water and wood and the addition of natural gas in the long term. Minnesota Power will reduce carbon emissions by about 30 percent on its system in 2015 while serving about 20 percent more load, exceeding the 2015 state goal for carbon reduction by 15 percent.[4]
- Protects affordability through power supply actions that maintain competitive electric service rates for Minnesota Power's customers. The 2013 Plan demonstrates through a first of its kind rate outlook that the Plan is cost effective in meeting customer needs even as Minnesota Power meets its forecasted growth and complies with environmental and energy policies.
- Specifically addresses resource planning Order requirements as detailed in Minnesota Power's 2010 Plan Order and its 2012 baseload diversification study ("BDS") Order. Relative to the baseload diversification study in particular, the 2013 Plan addresses:

    i. *A proposal to address the viability of Laskin Energy Center, Units 1 and 2 ("LEC"), and Taconite Harbor Energy Center, Unit 3 ("THEC3").* With Commission Approval, Minnesota Power plans to convert LEC to a gas peaking facility and it plans to retire THEC3 as described in this Plan.

    ii. *An evaluation of the consequences – including all relevant costs and the consequences for transmission adequacy – of retiring Boswell Energy*

[4] Minn. Stat. § 216H.06, Subd. 1, states, "It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050. The levels shall be reviewed based on the climate change action plan study."

Center, Units 1 and 2 ("BEC1&2") by 2020. Minnesota Power's analysis in this Plan shows that BEC1&2 are an integral highly economic part of the Boswell Energy Center ("BEC") providing station electric and water service, and benefit from site economies of scale. BEC1&2 remain valuable customer assets for customers.

iii. *Scenarios that add 100 to 200 MW of wind capacity in the 2014-2016 time frame.* A very recent federal production tax credit ("PTC") extension[5] and projected customer load growth have created the dynamic for further wind supplies to be considered for Minnesota Power's portfolio. In the short-term action plan contained in this Petition, Minnesota Power is investigating taking this opportunity to create additional cost effective renewable supply for its customers by issuing a request for proposal for up to 200 MW of wind energy in service in the 2014-15 timeframe.

iv. *Scenarios that add 400 to 600 MW of natural gas capacity in the 2014-2016 time frame.* As this Plan illustrates, a natural gas combined cycle unit is not economic for Minnesota Power's customers prior to 2020 largely due to an industry surplus of economic power. However, natural gas combined cycle technology is in the long-term planning horizon and will likely be Minnesota Power's next large power supply addition beyond 2020.

v. *A comprehensive socioeconomic impact analysis by customer class in conformance with the Commission's resource planning rules.* Minnesota Power is sensitive to the economic health of its service territory. Indeed, given its natural resource economic base, Minnesota Power's service territory employment is particularly sensitive to economic swings and global competition. Jobs in heavy industry, including those at Minnesota Power, are a key economic driver of the region's economy. As the region's power provider, Minnesota Power plays an important role in its communities through being an employer, tax revenue source, and purchaser of vendor services. The economic impact to the region and communities of generating unit closure alternatives at LEC and THEC3 were evaluated and helped quantify the vital role that Minnesota Power's generation facilities play in the region.

vi. *Rate impact projection order point.* Minnesota Power has included a projected rate impact by major customer class for its short-term action plan as a first of kind forward look at future rate projections due to the changes in power supplies outlined in Minnesota Power's 2013 Plan.

[5] The wind energy production tax credit ("PTC") was extended by President Obama on January 2, 2013 as part of the American Taxpayer Relief Act of 2012 legislation. The PTC is available to wind energy production facilities that begin construction prior to January 1, 2014.

Minnesota Power's 2013 Plan continues the transition of Minnesota Power's fleet toward more diversity, more flexibility and less emissions with additional major steps that address a changing energy landscape and respond to the Commission's Orders in Minnesota Power's previous IRP Docket. The need for Minnesota Power's industrial customers to be globally competitive combined with the inherent cyclicality of these natural resource based industries, along with the knowledge that environmental regulation will continue to be a major factor in energy supply decisions, requires Minnesota Power to thoughtfully consider and plan for its existing and future resource mix in a transformational way. The 2013 Plan helps to ensure that Minnesota Power remains well positioned under most economic and regulatory scenarios to best serve the needs of its customers large and small.

Key Items Shaping the 2013 Plan

The Commission's September 13, 2012, Order[6] concluded Minnesota Power's 2010 IRP, accepted Minnesota Power's Baseload Diversification Report[7] filed on February 6, 2012, and folded further consideration of the study into Minnesota Power's next resource planning docket. Additionally, the Order closed the 2010 Plan.[8] Minnesota Power's study provided high level, benchmark understanding of projected environmental challenges and uncertainties facing LEC and THEC3 over the next decade. The study also provided initial insight into estimated customer power supply cost trends using gross assumptions about retrofit infrastructure and high level estimation of plant retrofits and replacement energy supplies. The study underscored the pivotal impact and fluid nature of assumptions made about key drivers such as carbon penalties and natural gas pricing on the viability of LEC and THEC3 and on the risks and costs of their potential replacements. The study identified the value to customers of Minnesota Power's well-maintained, environmentally well-controlled units. The study also provided direction on how to refine the analysis of future resource alternatives such as natural gas and additional wind in order to identify the power supply resources that are projected to best meet Minnesota Power customer needs in the future. Further, the study provided additional forums for stakeholder input. While the study did the assessments that the Commission's 2010 Plan Order requested, the study itself was necessarily only exploratory and largely provisional, especially given the absence of any final pertinent EPA environmental rule information when it was developed.

Figure 10 on page 35 illustrates the role and context of the study within the overall resource planning process for LEC and THEC3 and what key decision making information for action around LEC and THEC3 and potential replacement resources will stem from the Plan filed in this Petition. Unlike the Report, Minnesota Power's 2013 Plan provides the level of information necessary to allow the Commission to meet its

[6] Docket No. E015/M-09-1088
[7] Minnesota Power's Baseload Diversification Report provides a summary of its baseload diversification study findings.
[8] Docket No. E015/M-09-1088

responsibilities under the statutes and rules relative to resource decision making on LEC and THEC3 in the public interest.

Integrated Resource Plan Process Streamlining

As the pace of change in the nation's energy landscape quickens, so has that of Minnesota Power in developing its 2013 resource plan so that it will support timely decisions on key aspects of the Company's energy supply. To that end, Minnesota Power's 2013 Plan offers several first of kind features to enable effective and comprehensive stakeholder input and efficient consideration and decision making. These actions include:

- Filing the Company's load forecast and load and capability calculation in advance of the overall 2013 Plan.
- Parallel filing of large datasets utilized in the evaluation and analysis, including Strategist software input and output files, along with detailed scripts on Minnesota Power's analysis process.
- Commitment to a two-month initial comment and one-month reply comment period in order to facilitate action on the 2013 Plan in a timely manner.
- Provision of projected customer rate impacts due to changes in power supplies reflected in the short-term action plan.

Creating a More Flexible and Diverse Fleet

As noted, Minnesota Power's resource strategy includes a major evolution from a primarily coal-based fleet to a more balanced and flexible set of resources. A more balanced and flexible fleet will provide Minnesota Power the capability to meet customers' needs reliably and cost-effectively while still managing the inherent variability of large industrial customer business cycles. Minnesota Power is aiming for an energy mix of approximately one-third renewable resources such as wind, wood and hydropower, one-third natural gas/other and one-third coal for its long-term position. Diversification of the Company's fleet is already well underway with much of the progress attributed to the successful implementation of its renewable plans, including wind and wood additions plus Minnesota Power's 250 MW power purchase agreement ("PPA") with Manitoba Hydro.

Wisely Planning for Growth <u>and</u> Inherent Business Cycles

Historically, Minnesota Power has been required to flexibly respond to business cycles, including large increases and decreases in load due to business cycles. This need for flexibility will continue and will be combined with a forecast for growth in the current planning period. In order to account for system growth while retaining its historical business cycle flexibility, Minnesota Power evaluated four forecast scenarios. Three of the scenarios centered around variations of load growth, while the remaining scenario examined load contraction. The evaluation showed Minnesota Power will have the power it needs to serve large load additions under various timing requirements while providing those customers with the cost effective electricity they depend upon. Minnesota Power will also have a more flexible fleet to provide contingency capability during business cycles.

Sound Coal Unit Direction

Minnesota Power's small coal unit plan aligns well with the Company's vision of achieving an energy mix of one-third renewable resources, one-third natural gas/other, and one-third coal in the long term. Minnesota Power has determined that 185 MW of coal generation from its small coal-fired facilities is not cost effective to retrofit with environmental controls. Instead, Minnesota Power plans to cease coal energy conversion at the 75 MW THEC3 and refuel the 110 MW LEC with natural gas in 2015. Minnesota Power's newer and larger BEC3 and BEC4 remain core assets that supply large volumes of cost effective energy to Minnesota Power customers 24 hours a day. The BEC4 Environmental Retrofit Project ("BEC4 Project") currently before the Commission[9] will help to sustain the essential BEC4 resource for customers in an environmentally compliant manner. BEC1 & 2, part of the Boswell Energy Center ("BEC") system and Taconite Harbor Energy Center Units 1 and 2 ("THEC1 & 2"), are environmentally compliant and more efficient as a result of prior investments in environmental control technology.

Competitive Renewable Supply Ahead of RES Target

With strong regulatory support, and through wise planning and capitalizing on the very economical opportunities, Minnesota Power is ahead of schedule in meeting its requirement to have 25 percent of projected 2025 retail and wholesale electric sales from Minnesota-eligible renewable resources. Minnesota Power constructed and placed into operation three large and cost effective wind farms located in North Dakota - the Bison 1, 2 and 3 Wind Projects. Given the recent Congressional extension of the PTC, one additional wind project is anticipated in North Dakota to complete this element of the Company's renewable expansion plans. The Company continues to evaluate other renewable options including solar, biomass, battery storage, and cost-effective wind projects located in and around Minnesota.

Natural Gas Additions and Market Purchases: Well-timed to Optimize Opportunities

Minnesota Power plans to incorporate a natural gas combined cycle resource into its power supply portfolio when the timing is right. Presently, the Company plans to add 200 – 250 MW of natural gas combined cycle generation after 2020. Existing resources, recent and proposed additional renewables and cost-effective, bilateral

[9] Docket No. E015/M-12-920

market purchases will provide a stable, cost effective resource mix for a defined period between now and 2020 as a bridge to implementation of a natural gas resource.

Bi-lateral market purchases have a distinct role in meeting customers' energy needs between now and 2020 and are not a standing supply approach for the long term. Rather, they provide a particular opportunity for very economical, shorter term (2 to 5 year) energy supply given the low demand for power in the current wholesale energy market. Using stably priced, bilateral purchases with strong counterparties from existing assets for some shorter term supply helps mitigate rate impacts on Minnesota Power customers by deferring the addition of capital costs for a gas resource between now and 2020. They also allow for flexibility as large new customer loads ultimately materialize, given the wide range of load growth projections illustrated in Minnesota Power's 2012 Annual Forecast Report ("AFR2012"). As well, a more paced timing of adding a natural gas combined cycle resource will aid the development of the best natural gas project for Minnesota Power's customers.

Technological Evolution

Technology evolution in the energy industry is occurring rapidly. Advancements in detecting and extracting shale gas, for example, are impacting gas supply and moderating price volatility outlook. Additionally, advances in solar technology have resulted in a reduction in the cost of solar photovoltaic panels, making solar energy a more viable consideration for distributed generation portfolio expansion in the future. Minnesota Power's customers are best served by a resource strategy that is flexible and nimble to be able to help develop and capitalize on these technology developments at the right time. Advancing too soon creates unnecessary risk for customers and not being flexible to move soon enough can stymie creative and cost effective solutions as well. The most recent example of "right timing" with technology has been the way Minnesota Power advanced its wind development. This effort began first with smaller power purchase agreements and small self-build projects, stepping up to larger commitments as technology matured eventually leading to Minnesota Power's delivery of a very efficient and cost effective large wind generating portfolio in the North Dakota Bison projects.

Minnesota Power is steadily following and studying technology developments to determine if and to what extent the significant incorporation of new technologies in its plans to serve customers is appropriate.

Updates Since the Last Approved Minnesota Power Resource Plan

Specific actions taken since the May 2011 approval of Minnesota Power's 2010 Plan include:

1. Minnesota Power has acted to implement and procure the most appropriate sources to add to its renewable energy supply (see Appendix G). The Company has:

i. Commissioned the 81.9 MW Bison 1 Wind Project near Center, North Dakota[10] in December 2011.

ii. Received Commission approval and commissioned the 105 MW Bison 2 and Bison 3 Wind Projects[11] also located near Center, North Dakota before year end 2012.

2. In addition to the wind energy noted above, Minnesota Power has made, or is making, the following modifications to its supply side resources:

i. Secured a 250 MW PPA with Manitoba Hydro to begin in 2020 which has been subsequently approved by the Commission.[12] This PPA requires a new, international transmission interconnection. Minnesota Power, in partnership with Manitoba Hydro, has initiated the Certificate of Need process for the Great Northern Transmission Line[13] that will facilitate delivery of the PPA energy and additional resources for the Upper Midwest. The agreements also provide for a unique wind storage provision that will allow Minnesota Power to effectively store excess wind energy from the Bison projects in North Dakota in Manitoba Hydro's hydro facilities. As well, the Midwest Independent System Operator, Inc. ("MISO") has recognized the Manitoba PPA will meet capacity eligibility standards.

ii. Advanced an efficiency improvement rerunnering project at the Company's Fond du Lac hydroelectric facility, in partnership with the U.S. Department of Energy. The project is in final construction phase and is expected on-line in 2013. Additionally, the Company has restored the smaller, Prairie River hydroelectric facility near Coleraine, Minnesota which was destroyed by fire. It, too, is expected to be operational in 2013. Further, the Thomson Hydroelectric facility, flood damaged in 2012, is being engineered for restoration to service.

iii. Requested Commission approval for the transfer of Rapids Energy Center ("REC") into Minnesota Power's regulated operations.[14] Additionally, Minnesota Power has requested Commission approval for an optimization project at REC that will increase biomass generation by approximately 56,000 MWh annually at a cost of approximately $10 million. At the same time, the Company has tabled plans for a biomass expansion at its Hibbard Renewable Energy Center ("HREC"), as more cost effective biomass and wind projects changed the priority of this project to beyond 2020.

[10] Docket No. E015/M-09-285
[11] Docket No. E015/M-11-234 and Docket No. E015/M-11-626, respectively
[12] Docket No. E015/M-11-938
[13] Docket No. E015/CN-12-1163
[14] Docket No. E015/M-12-1349

iv. Further reductions of Young 2 capacity from the current 227.5 MW level will occur upon Minnkota Power Cooperative, Inc. ("Minnkota") placing in-service its new Center to Grand Forks 345 kV transmission line in late 2013. As set forth in Docket E015/PA-09-526, the new line will trigger phase out of Young 2 from Minnesota Power supply resources entirely by 2026.

v. Finalizing key power purchase extensions in 2013 that leverage Minnesota Power's transmission assets and securing economic bilateral contracts to bridge Minnesota Power's customer supply requirements to the 2020 time period.

vi. Preparing to complete major environmental retrofits on BEC4 to address MATS, the Minnesota Mercury Emissions Reduction Act of 2006 ("MERA") and other new and existing state and federal emission control regulations.[15] Minnesota Power plans to begin BEC4 project construction in spring 2013, assuming receipt of permits, with in-service expected by 2016.

3. Minnesota Power continues its participation in the CapX2020[16] multi-state transmission reliability improvement initiative. Specifically, Minnesota Power is a participant in the Bemidji to Grand Rapids, Minnesota project; the Fargo, North Dakota to St. Cloud, Minnesota project; and the St. Cloud to Monticello, Minnesota project. The 230 kV Bemidji to Grand Rapids, Minnesota transmission line was energized on September 12, 2012.

4. Minnesota Power has remained a state leader in energy conservation and demand side management ("DSM"). (See Appendix B). Under its Conservation Improvement Program ("CIP"), Minnesota Power has met or exceeded the state's 1.5 percent energy savings goal by refining its conservation program strategy and expanding upon a proven program platform. In fact, Minnesota Power exceeded the energy savings goal, achieving a total savings of 1.8 percent of eligible retail energy sales for 2010, and 2.1 percent of eligible retail energy sales for 2011.[17]

Minnesota Power has a solid load research foundation and has initiated an updated load research study. This study is leveraging Minnesota Power's experience with its large customers' years of more sophisticated metering as well as the broader and more recent deployment of advanced metering infrastructure among residential and other customers along with insight gained through ongoing customer surveys.

[15] Docket No. E015/M-12-920
[16] CapX2020 is a joint initiative of 11 transmission-owning utilities in Minnesota and the surrounding region to expand the electric transmission grid to ensure continued reliable and affordable service.
[17] Minnesota Power will file its 2012 CIP Consolidated filing giving its 2012 results on April 1, 2013 and will be providing the Triennial Plan in June 1, 2013.

Minnesota Power continues development and implementation of its residential Time-of-Day Rate with critical peak pricing pilot project. The Commission approved Minnesota Power's proposed Pilot Rider for Residential Time-of-Service in November 2012.[18] The associated web portal that enables customers to view their usage information in monthly, daily, or hourly increments was introduced to two groups of customers in 2012, one in March and the next in August. This pilot builds upon Minnesota Power's existing conservation improvement effort and will offer further insight into customers' appetites for more frequent and in depth information about their energy usage as well as a rate offering with price signals.

Resource Plan Overview: Short and Long Term Action Plans

Minnesota Power considered potential environmental regulation and economic futures along with its sales outlook to develop a resource plan that creates a more flexible and diverse power supply, while balancing cost, reliability and environmental impact for customers. The 2013 Plan continues the transformation of the Company's resource base by investing in renewable generation, adding natural gas to its fuels portfolio, installing more emissions-control technology at its core, baseload generating facilities, and maintaining its strong energy conservation and demand side management programs. Supported by the information and analysis in the Appendices of this Plan, the action plan outlined in the following sections identifies both short and long term measures that will help Minnesota Power continue to meet customer needs near term and be poised to deliver safe and reliable service at the lowest possible cost to customers for many years.

Short-term Action Plan (2013 through 2017)

Minnesota Power's short-term action plan during the five-year period of 2013 through 2017 is comprised of steps that will: a) preserve competitive base load generating resources while reducing emissions, b) continue implementation of least cost demand side resources including conservation, c) reduce reliance on coal-fired generation, d) reduce the carbon intensity of Minnesota Power's system and e) add renewable energy and transmission infrastructure to the benefit of customers. The specific strategic and necessary actions to achieve these steps include:

1. Reducing emissions associated with converting coal energy to electricity through a series of actions that assures environmental compliance and a sound energy supply for customers. Minnesota Power has identified that LEC (110 MW) and THEC3 (75 MW) are not cost effective to retrofit with additional environmental controls. LEC will become a gas peaking station; THEC3 will be retired. The remaining balances of LEC and THEC3 will be recovered through normal retirement accounting (see Appendix L). The Company also has confirmed a robust plan to retrofit BEC4, its largest generating unit (585 MW).

[18] Docket No. E015/M-12-233

2. Minimize short-term rate impacts for customers while meeting increased demand for electricity, by taking advantage of a lower cost power market. Minnesota Power plans to use economic, asset backed bilateral market purchases to flexibly help bridge energy and capacity requirements in the period between 2014 and 2020. As well, Minnesota Power will continue to examine its load projections and adapt to the ultimate timing of new large industrial loads on its system as well as any significant downward business cycles that may affect demand from existing large industrial customers.

3. Continue optimization of Minnesota Power’s renewable energy supply. With 400 MW of competitive wind projects already present in its portfolio, Minnesota Power is ahead of its renewable energy standard (“RES”) requirements and is closely monitoring the need for additional intermittent renewable energy. With the extension of the PTC, Minnesota Power will solicit a request for proposal for a minimum of 100 MW and up to 200 MW of competitive wind to be installed in the next two to three years. These plans are subject to maximizing the benefit of the PTC for customers.

4. Consider enhancements to selected CIP and DSM programs, while continuing to apply best practices from the conservation industry and develop leading-edge programs. Minnesota Power has maintained a strong record of conservation performance and been a state leader in meeting and exceeding the Minnesota 1.5 percent energy savings conservation standard. Along with this strong dedication to conservation, Minnesota Power will continue to work to identify reasonable additions to its DSM programs where they are most beneficial for customers.

5. Prepare Minnesota Power’s transmission system for the longer term addition of new power supply resources. The Company will, subject to Commission approval, begin implementation of the Great Northern Transmission Line to deliver its approved 250 MW energy purchase from Manitoba Hydro for the period 2020-2034, a key element of Minnesota Power’s long-term action plan. The Certificate of Need application for the Line will be filed in 2013 as part of project development.

6. Complete its 2013 Load Research Study Advanced Metering Infrastructure Project to better understand customer energy use, providing a refreshed and robust basis for future customer conservation projects and sound rate design.

7. Execute an industrial distributed generation/renewable project at REC and continue to explore energy efficient distributed generation projects with large customers. Additionally, Minnesota Power will develop a fair, equitable and customer focused distributed generation approach that best leverages unique customer and regional attributes to deliver valued and cost effective energy solutions for customers.

8. Continue fleet maintenance programs to sustain the economic viability, availability and reliability of Minnesota Power’s generating units. A continuing Company priority throughout this planning period will be to carefully maintain

its generation fleet to ensure productivity and efficiency in operation. A rigorous process is in place to sustain existing production across Minnesota Power's wind-water-wood-coal energy conversion facilities while maintaining an excellent environmental record, working through an orderly workforce transition and meeting more stringent environmental standards.

9. Continue participation in the Midwest Renewable Energy Tracking System ("M-RETS") as provide for by the Commission's October 9, 2007 Order,[19] as well as establishing a program and protocols for tradable, renewable energy credits.[20] Minnesota Power will leverage the value of renewable energy credits that the M-RETS program certifies to deliver RES compliance in Minnesota at the lowest possible cost to customers. Minnesota Power will utilize renewable energy credits generated across the years in order to optimally meet the 25 percent RES by 2025.

Long-Term Plan (2017 through 2027)

Minnesota Power will focus its long-term plan on a strategy to further reduce carbon emissions in its portfolio and reshape its generation mix towards a balance of approximately one-third renewable resources, one-third efficient coal-fired generation and one-third natural gas/other sources. This long-term strategy will continue resource diversification and position Minnesota Power to be able to successfully adapt to a range of economic and environmental futures while maintaining service to its customers at a competitive cost. Each component of this long-term plan has been proven through the planning process analysis to be flexible and robust to keep progress toward the Company's strategic resource goals on track in a variety of future scenarios. Planned components include:

1. Continue implementation of the 250 MW Manitoba Hydro PPA and associated transmission in the 2020 timeframe.

2. Optimize the timing of implementing the remaining renewable projects to cost effectively meet the state RES by 2025.

3. Investigate opportunities to further diversify Minnesota Power's power supply including, further reducing reliance on coal-based generation. Minnesota Power will continue to closely assess THEC1&2 economics during this period to determine these units' competitive position.

4. Begin investigation, for inclusion in its next resource plan, of an intermediate natural gas generation resource for Minnesota Power's generation fleet to meet expected capacity and energy needs in the 2020 timeframe and beyond.

[19] Docket No. E999/CI-04-1616
[20] Docket Nos. E999/CI-04-1616 and E999/CI-03-869

Plan Implementation Potential Impact on Costs

In accordance with Minn. Rule 7843.0400, subp, 4, Minnesota Power's 2013 resource planning analysis includes consideration of potential cost impacts resulting from actions taken to be in compliance with Minnesota's RES, and potential expansion plans. The 2013 Plan's preferred plan ("Preferred Plan") would be expected to increase the average residential rate by about 4.4 percent on a compounded annual basis through 2017. That is equivalent to a total increase of $19.65 per month above the 2013 estimated Base Rate. The impact to the average Large Power rate would be an increase of about 3.7 percent on a compounded annual basis through 2017. That is equivalent to an increase of 1.09 cents per kWh above the 2013 estimated base rate. Refer to Appendix J for more detail.

Summary: 2013 Plan Designed to Meet Customer Needs

As Minnesota Power addresses uncertainty in the economic and environmental landscape around energy matters on behalf of its customers, the Company maintains its strong leadership of the transformation required to successfully meet future needs. In order to achieve the goals outlined on page 5 of this Section, Minnesota Power respectfully requests Commission approval of its 2013 Plan, as presented in this filing, for the planning period of 2013 through 2027. Minnesota Power is requesting Commission approval of its action plan that includes the following:

- Cease coal energy conversion at the 75 MW THEC3 and refuel the 110 MW LEC with natural gas, with both actions completed in 2015.
- Optimize Minnesota Power's renewable energy supply by evaluating the addition of a minimum of 100 MW and up to 200 MW of competitive wind that would be installed in the next two to three years, with plans subject to maximizing the benefit of the PTC for customers.
- Begin investigation, for inclusion in its next resource plan, of an intermediate natural gas generation resource for Minnesota Power's customers to meet expected capacity and energy needs in the post 2020 timeframe. Bridging to implementation of an intermediate gas unit, Minnesota Power will use bilateral market purchases to flexibly and economically help meet needs in the period between 2014 and 2020, as the Company continues to review load projections and adapts to the ultimate timing of new large industrial loads on its system.

Minnesota Power believes its 2013 Plan will serve its customers in a wise and forward-looking way during the 2013–2027 planning period. Minnesota Power respectfully submits this Plan for the Commission's review and approval.

III. Current Outlook

The electric industry landscape has continued to evolve since Minnesota Power's 2010 Plan. As well, the Company took action to further improve its fleet environmental performance, monitor and assess emerging regulations and increase renewable energy output. As this 2013 Plan is submitted, Minnesota Power is a very unique utility in the present dampened national economic outlook as significant growth is being projected for its large industrial customer segment in the current planning horizon.

This section identifies the major items contributing to Minnesota Power's outlook for customer demand for electricity and the supply resources that will be utilized as the foundation ("Base Case") for this resource plan. Minnesota Power starts this 2013 Plan planning period with minimal near-term power supply needs; however, due to projected customer growth, Minnesota Power will need additional power supply in the long term; post 2020.

Changes since May 2011 Commission Approval of the 2010 Plan

Continued Progress on Renewable Energy Standard

The 2007 Minnesota Legislature enacted legislation requiring Minnesota Power generate or procure increasing renewable energy supplies based on total retail sales to Minnesota customers beginning with 7 percent by 2010 and incrementally increasing to 25 percent by 2025 (Minn. Statute § 216B.1691).

Since May 2011, Minnesota Power has brought extraordinary benefit to its customers with its renewable energy development. Through effective project planning and competitive equipment supply, Minnesota Power has executed its North Dakota wind initiative plan introduced in 2009, including the recent commissioning of over 200 MW of additional wind through the Bison 2 and Bison 3 Wind Projects in 2012, and the continued operation of its Bison 1 Wind facility.

Further, the Bison wind initiative provides a unique opportunity to expand renewable resources in North Dakota by securing additional wind development land options and designing associated facilities in preparation for future wind energy projects. The development, planning and timing of these projects will be based on customer growth, availability of economical wind energy and the impact of this intermittent generation on Minnesota Power's system. Minnesota Power is ahead of the state's 25 percent by 2025 requirement and will only propose adding new wind projects if they are economical and bring benefit to customers. Appendix G provides a more detailed presentation of the current renewable portfolio that Minnesota Power plans to utilize to meet its renewable requirement.

Rapids Energy Center

Minnesota Power submitted its petition for approval of a biomass energy optimization project for its industrial distributed operation facility in Grand Rapids, Minnesota on December 19, 2012.[21] The REC optimization project will increase biomass generation by approximately 56,000 MWh annually.

Corporate Commitment to Greenhouse Gas Reductions

Minnesota Power continues its commitment to taking action to reduce carbon emissions. Fundamental to this initiative is a significant expansion of Minnesota Power's already substantial renewable energy supply, its commitment to improve efficiency and to consider only carbon-minimizing resources for addition to its generation portfolio. These actions are leading to a transformation of Minnesota Power's generating fleet. Increasing amounts of energy will be supplied by renewable resources or natural gas resulting in less reliance on coal-fired energy.

Demand Response and Conservation—Energy Reduction Requirements

The 2007 Minnesota Legislature enacted legislation requiring utilities to adopt an annual energy savings goal equivalent to 1.5 percent of gross annual retail energy sales beginning in 2010. Minnesota Power has a successful track record in meeting the 1.5 percent benchmark and plans to maintain conservation efforts at this level.[22] Minnesota Power is evaluating an air conditioning cycling program and how this type of program may fit into its future power supply planning. Appendix B addresses Minnesota Power's DSM and current conservation efforts.

Move to MISO Module E Planning Year 4

As a result of tariff revisions in 2008 by MISO, Minnesota Power now falls under the requirements of the MISO Module E Resource Adequacy Program for near-term planning. Each year MISO produces a new planning reserve requirement for its footprint. For 2012, Minnesota Power was required to meet a non-coincident peak reserve margin of 11.32 percent. This 2012 reserve requirement was a reduction from the 2011 reserve requirement of 12.04 percent. This savings has resulted in more capacity being available to serve customer requirements.[23]

Softening of Energy Market

Since 2009, the nationwide recession and the onset of natural gas supply surpluses have created a significant shift in the regional energy markets. Prices have shifted lower to create a new normal for markets unparalleled in recent history.

[21] Docket No. E015/M-12-1349
[22] Minnesota Power incorporates the effects of its successful conservation program into its energy forecast. Appendix A outlines this methodology in more detail.
[23] Minnesota Power has requested that MISO provide a non-coincident reserve margin for its 2013 Loss of Load Expectation update to allow for continued incorporation of MISO's system reliability studies into Minnesota Power's long-term planning process.

Minnesota Power has worked to secure extensions of existing key bilateral purchase contracts for energy and capacity totaling 150 MW[24] during the 2015-2020 timeframe.

Evaluating the options for an economical power supply to meet the projected growth in northeastern Minnesota, 100 MW[25] of additional short-term bilateral purchase transactions were initiated to capture the benefit of the lower market trends for customers and bridge to the approved 250 MW power purchase from Manitoba Hydro that starts in the 2020 time period. In addition to providing a cost effective bridge to Minnesota Power's long-term resource strategy, these transactions also help customers avoid costly generation expense as new large industrial loads transition onto the system.

Certified Interruptible Demand ("CID") Anticipated to be 96 MW

Minnesota Power has continued offering its interruptible product that permits the curtailment of large industrial load to support Minnesota Power's management of system reliability. Interruptible capability continues to be a robust demand response resource for customers. Based on current indications from the industrial customers who have used these products, Minnesota Power is planning on the new CID product creating the availability of 96 MW of interruptible demand as of June 2013.

Specific Load Additions

Since 2009, several potential industrial load additions have been closely monitored in Minnesota Power's and its wholesale customers' service territories. Essar Steel Minnesota, a significant new customer for the City of Nashwauk, Minnesota, has been incorporated into Minnesota Power's 15 year forecast outlook as Minnesota Power serves the City of Nashwauk, a valued municipal customer. This is reflected in the Base Case of this resource plan. Minnesota Power is utilizing the Wholesale Industrial Customer Addition scenario of its AFR2012 for the Base Case of its planning evaluation.

Minnesota Power will continue to monitor the status of the load potential in northeast Minnesota and has incorporated a high and low forecast as sensitivities in its evaluation. Appendix A goes into more detail on the other customer load scenarios that Minnesota Power is monitoring.

Current Outlook for Large Power and Resale Customers

Recognizing that the majority of Minnesota Power's capacity and energy is used by 10 Large Power customers, it is important to monitor the current outlook of these customers to provide insight into their future electric needs.

[24] These transactions include the current 50 MW **[TRADE SECRET DATA EXCISED]** contracts. Minnesota Power will be seeking in 2013 regulatory approval of transactions that span five years or greater once terms are finalized.
[25] These market surplus transactions include the current 50 MW **[TRADE SECRET DATA EXCISED]** **[TRADE SECRET DATA EXCISED]** agreements.

Minnesota Power recognizes that not all projected growth in its industrial customer class will be forthcoming exactly on its proposed schedule. Through its econometric forecasting processes and by working closely with customers, Minnesota Power identified and included with its AFR2012 forecast submittal four scenarios for this growth potential and their impact to electric requirements in its service. For the 2013 Plan, the Wholesale Industrial Customer Addition scenario is utilized, recognizing 166 MW of overall industrial growth for this 15-year time period.

Following are current industry summaries and load potential that Minnesota Power is tracking for its largest industrial customers:

Mining Customers

Minnesota Power provides electric service to six taconite customers with current production capability up to 41 million tons of taconite pellets annually (see Table 1). Taconite pellets produced in Minnesota are primarily shipped to North American steel making facilities that are part of the integrated steel industry. Steel produced from these North American facilities is used primarily in the manufacture of automobiles, appliances, pipe and tube products for the gas and oil industry, and in the construction industry. Historically, less than five percent of Minnesota taconite production is exported outside of North America.

Minnesota Power Taconite Customer Production	
Year	**Tons (Millions)**
2012	39 (est.)
2011	39
2010	35
2009	17
2008	39
2007	38
2006	39
2005	40
2004	39
2003	34

Table 1--Minnesota Power Taconite Customer Production

The 2008-2009 recession notwithstanding, Minnesota taconite production has been very near capacity for the past ten years. Domestic demand and production for the traditional taconite product has been very steady.

- As well, newer types of iron-bearing products have emerged and are being produced on the Iron Range. Further, the potential for steelmaking on the Iron Range also exists. All together the combination of new iron ore based projects or expansions indicates growth forecast for mining and mining processing activity. Mesabi Nugget Delaware, LLC, a partnership of Steel Dynamics Incorporated and Kobe Steel, began production of iron nuggets in 2009. This 500,000 metric ton per year prototype iron nugget facility has added over 20 MW of demand to the Minnesota Power system. Mesabi

Nugget is continuing with permitting activities relating to an expansion of the facilities to allow for its own taconite mining to produce concentrate to feed the nugget facility. This could more than double the facility load within the next five years.

- Magnetation, Inc. is a high-growth iron ore producer and inventor of hematite beneficiation technology. Magnetation has developed a patented mineral reclamation process (Magnetation Process™) to extract weakly magnetic particles from stockpiles left from the natural ore mining that occurred primarily in the first half of the Twentieth Century. Magnetation currently operates two facilities in Minnesota: Plant 1 located south of Keewatin; and Plant 2 near Taconite. Minnesota Power recently filed a petition with the Commission to amend its contract with Magnetation to reflect increased service extension costs resulting from an anticipated load increase of 3 to 5 MW as a result of an expansion to Plant 2 that will begin in spring 2013. Magnetation is also an equity partner in the Mining Resources Plant 3 facility near Chisholm. Mining Resources Plant 3 is producing at nearly their budgeted full load level. They activated their ball mill circuit in January 2013 and peak demands are now in the 5 to 7 MW range. Additionally, Magnetation LLC has announced that it will build two more facilities similar to Plant 2 in the coming years. Magnetation's contemplated Plant 4 facility will be sited north of Coleraine near the Canisteo Mine and is slated to come on line in late 2014. The other facility site is just south of the town of Calumet. It is tentatively planned to come online in 2015. Minnesota Power currently provides electric service to the Plant 2 facility as well as to the Jesse Mine train loading facility and Minnesota Power will also provide service to the Plant 4 and 5 facilities.
- Mining Resources, LLC is an 80-20 joint venture between Steel Dynamics, Inc. and Magnetation, Inc. Mining Resources will utilize the Magnetation beneficiation technology in Plant 3 located to the south of Chisholm. The concentrate for this facility supplies the Mesabi Nugget plant in Hoyt Lakes until such a time as Mesabi Nugget is able to obtain permits to mine and produce its own concentrate from the former LTV mining company holdings.
- Essar Steel is developing a fully integrated, onsite, mining through steelmaking project on the Mesabi Range in northern Minnesota. It is designed to produce up to 2.5 million tons of steel products each year and to employ up to 700 people. Groundbreaking occurred in fall 2008 for the taconite production facility. Construction activities are well underway for the initial 4.1 million ton per year taconite plant, and the permits have been finalized for the expansion to a 6.5 million ton per year taconite production rate. Essar continues to work on the financing for the 6.5 million ton per year operation. Mining operations are slated to start in 2013. Minnesota Power provides wholesale electric service to the City of Nashwauk who in turn provides retail electric service to the Essar mine, crusher, concentrator, and pellet plant. Minnesota Power also provides retail service to Essar at two points for pit dewatering.

- Keewatin Taconite is wholly owned by United States Steel ("USS") Corporation. In February 2008, USS Corporation announced its intent to restart a pellet line at its Keewatin Taconite processing facility ("Keetac"). If restarted, this pellet line, which has been idle since 1980, could bring 3.6 million tons of additional pellet making capability to northeastern Minnesota and could result in over 60 MW of additional load. USS Corporation announced in late January 2013 that the project is on hold while the Company looks at business conditions, and some proposed regulatory standards that would be relevant to the project.

In addition to robust growth projections in ferrous mining, exploration and permitting work continue on several other fronts for future development of non-ferrous resources located in the Duluth Complex geologic formation. PolyMet mining is in its permitting processes, and Minnesota Power has entered into a long-term power supply agreement with PolyMet. Additionally, business cases are being developed for Twin Metals Minnesota and Teck America, as well as for other prospective customers.

Wood Product Customers

Minnesota Power serves four paper and pulp customers who produce market pulp and various grades of printing and writing paper used in office papers, magazines, catalogs, and print advertising/direct mail. The North American paper manufacturing industry has experienced a significant decline in the last decade resulting in mill consolidation and closures throughout North America. Minnesota has directly experienced forest product-related mill closures. Six Minnesota mills have closed since 2006 including three Ainsworth board mills, the Weyerhaeuser truss plant in Deerwood, the Verso paper mill in Sartell, and the Georgia Pacific board plant in Duluth. Minnesota Power provided electric service to the Deerwood and Duluth mills.

As shown in Figure 1 below, U.S. printing and writing paper demand is projected to continue to decline, although at a less precipitous rate than during the 2007-2009 period. This decline in demand for printing and writing paper is driven by electronic media substitution and the associated migration of advertising budgets away from catalogs, newspaper inserts, brochures and direct mail.

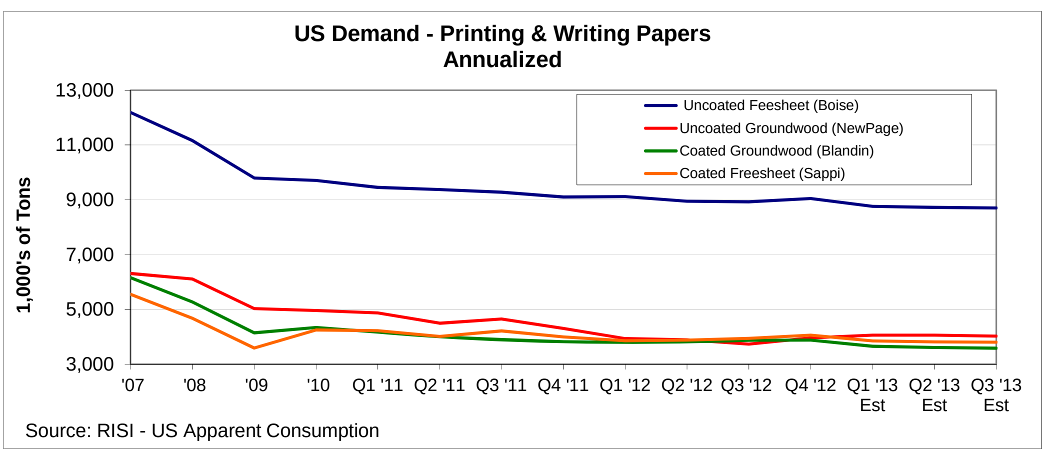


Figure 1--US Paper Demand 2007-2013 (est.)

In spite of the demand trends for US printing and writing paper, the remaining US paper industry continues to profitably operate at over 20 million tons of productive and competitive capacity and pursue development of new wood-related products. The most cost competitive mills with the strongest parent corporations continue to effectively serve their customers.

The four paper mills served by Minnesota Power, representing approximately 1.5 million tons of paper production, are owned by well-established and major paper industry leaders (Sappi, UPM, NewPage, and Boise). As reflected in this resource plan, Minnesota Power believes these corporations view their Minnesota assets as strategic to their respective business strategies. Each of the Minnesota mills is well positioned and cost-competitive in their respective paper markets with excellent customer relationships. Minnesota Power projects steady and profitable capacity utilization rates for these four mills over the forecast period as these mills successfully control costs, reshape their products and compete for market share.

Pipeline Customers

Minnesota Power has two pipeline customers, Enbridge Energy and Minnesota Pipeline. Both companies rely heavily on Western Canadian crude oil production. Enbridge Energy transports crude oil across North America. Minnesota Pipeline receives oil from Enbridge Energy at Clearbrook, Minnesota, and delivers it to refining centers in the Twin Cities metro area. A significant oil discovery in northern Alberta ("Oil Sands") in the early 1990s has led to increased throughputs on both the Enbridge Energy and Minnesota Pipeline systems. At the same time, shale oil production in North Dakota has also been increasing rapidly. Oil Sands and North Dakota shale crude production is forecast to increase significantly over today's levels over the next few years, which will prompt the need for increased transport capacity on the Enbridge Energy and Minnesota Pipeline systems.

Both Enbridge Energy and Minnesota Pipeline take service under Minnesota Power's Large Light and Power Service Schedule ("LLP Schedule"). Neither Enbridge Energy nor Minnesota Pipeline is now required to provide Minnesota Power with demand nominations under the LLP Schedule; however, these loads have historically been very consistent. Enbridge Energy is adding pumping equipment at its Superior, Wisconsin pumping station (served by Minnesota Power's affiliate and wholesale customer, Superior Water, Light & Power) and Enbridge has increased pumping capacity at its Deer River, Minnesota substation, with significant projected increases in load through 2017. Other expansion-related projects are in the planning phase at these companies and could potentially further increase load across the Minnesota Power service territory within a five to ten-year horizon.

Expected Minnesota Power Load and Capability

Northeastern Minnesota's economy underwent a severe downturn in the recent national recession. Both peak demand and energy use dropped considerably in late 2008, but quickly rebounded in 2010 led by the region's taconite and wood products industries. Core sectors – residential, commercial and industrial – have recovered most of the ground lost during the recession, and growth is expected throughout the long-term planning horizon.

For the 2013 Plan, the load outlook includes a projection for considerable growth over the fifteen-year period. In particular, Minnesota Power is expecting significant industrial customer expansion. With several growth scenarios incorporated into its latest forecast outlook, Minnesota Power has identified the Wholesale Industrial Customer Addition scenario as its consensus outlook for its 2013 Plan. Appendix A contains details on Minnesota Power's AFR2012.

Minnesota Power is historically a winter peaking utility and, based on monthly trends in load behavior, is expected to remain winter peaking for the AFR forecast period of 2012 to 2026. Throughout the forecast time-frame, the seasonal peaks run in parallel. Underlying seasonal peak demand growth is projected to increase at a rate consistent with observed history, about 0.7 percent per year. However, load growth in the 2013 to 2014 timeframe will be accelerated as the Company realizes expansions in its industrial customer base. Annual load growth is projected to average 4 percent per year in 2013 and 2014.

Figure 2 presents both Minnesota Power's historic and forecast peak demand from the Wholesale Industrial Customer Addition scenario in its AFR2012 submittal and the foundation for the 2013 Plan evaluation. The graph depicts the significant growth being projected in the forecast period.

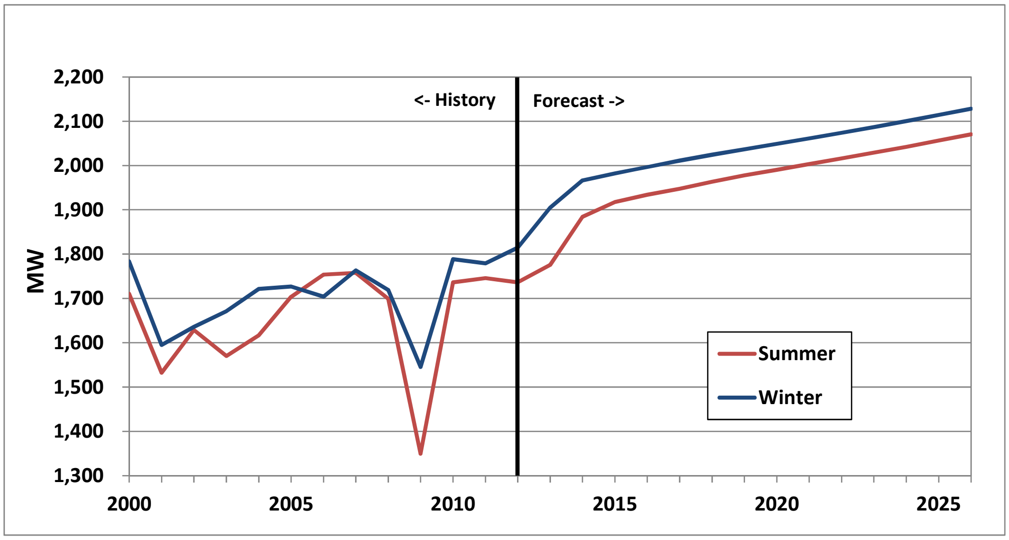


Figure 2--Peak Demand by Season

Figure 3 shows historic and forecast energy requirements by customer class and depicts the large influence the industrial class continues to have on Minnesota Power's energy requirements. The large growth in the Resale customer class includes the addition of the City of Nashwauk load as described above.

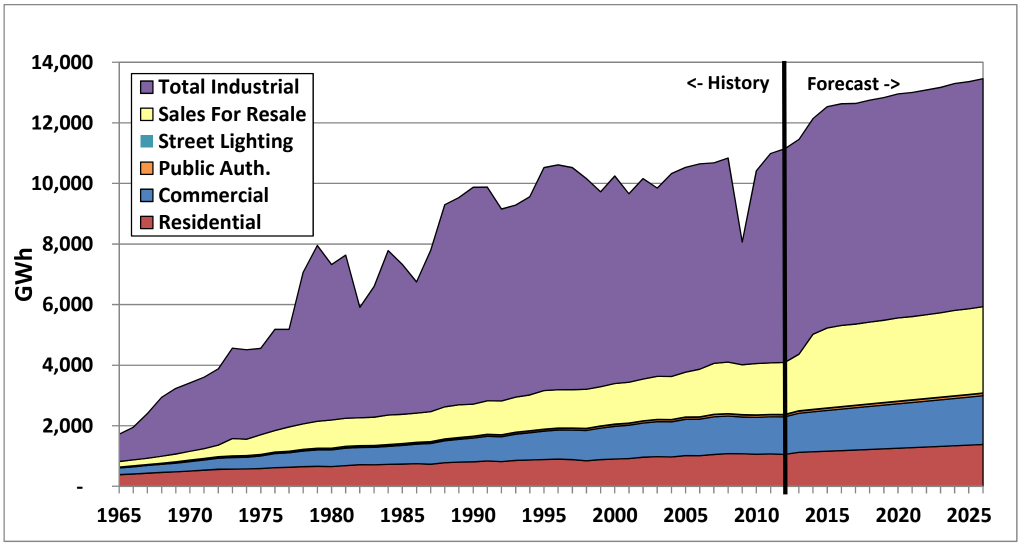


Figure 3--Energy by Customer Class

Taken together, Figure 2 and Figure 3 clearly show the expected future growth and the impact of the 2009 recession. As outlined in the AFR2012, Minnesota Power's peak demand and energy use are each expected to grow quickly in the near-term with several industrial additions and are then projected to return to more normal growth levels for the long term.

Minnesota Power's system load forecast reflects a projected (summer) peak demand of 1,918 MW by 2015 and 2,070 MW by 2026. While Minnesota Power's load growth can be unpredictable due to industrial changes, about a 0.7 percent underlying demand growth is projected through the forecast period. Energy requirements continue to dominate Minnesota Power's supply picture, as the industrial load contributes to an average Minnesota Power system load factor of approximately 80 percent—still one of the highest in the nation.

Minnesota Power uses the 2012 MISO Module E Load and Capability ("L&C") calculation as one measure to assess resource need. The MISO L&C calculation takes into consideration Minnesota Power's load forecast, expected demand-side resources, Firm and Participation Purchases and Sales, Accredited Installed Generating Capability and MISO's required 11.3 percent planning reserves. The result of the L&C calculation is a capacity surplus (or deficit) number for each planning season.[26] Minnesota Power is a winter peaking utility, but, as previously noted, bases its resource need on the summer season L&C balance. Most other regional utilities are summer peaking and, accordingly, have large winter capacity surpluses. Therefore, winter capacity is typically available for purchase, and prices are expected to be lower than summer capacity.

Minnesota Power utilizes the Wholesale Industrial Customer Addition scenario from its AFR2012 in its 2013 planning analysis. To create an understanding of what the

[26] Minnesota Power does not utilize MISO's UCAP (unforced capacity) planning reserve method for its long-term planning; rather, it relies on the ICAP (installed capability) that is more appropriate for long-term evaluations. Please see Appendix H for more detail.

potential capacity needs are under this outlook, the load levels of the scenario are combined with an expected set of capacity resources utilizing the L&C guidelines noted above to estimate a remaining surplus or deficit for the planning period. Figure 4 depicts the Base Case summer season capacity needs that are projected as Minnesota Power considers its 2013 Plan resource planning analysis. For the near term (pre 2020), Minnesota Power expects some minimal capacity surpluses in its Base Case outlook, with capacity need starting to grow in the post-2020 time period.

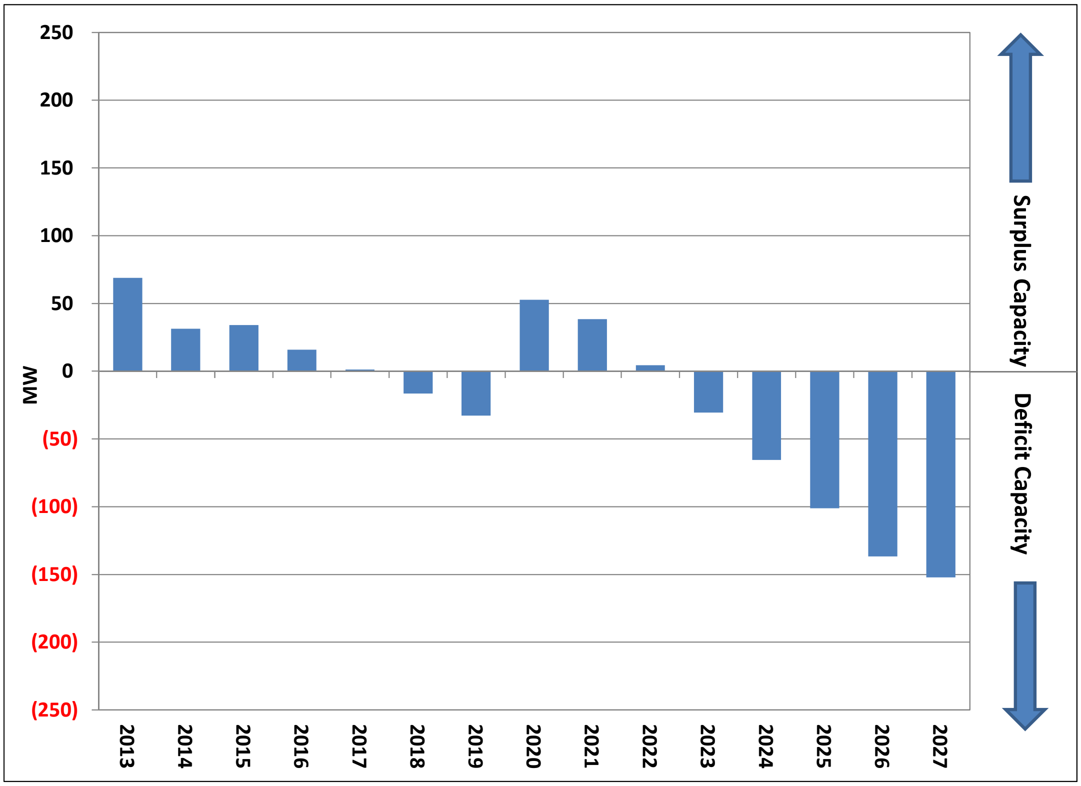


Figure 4--Projected Summer Season Capacity Position

<u>Base Case:</u>

<u>Minnesota Power's Summer and Winter Season Load and Capability (2013–2027)</u>

Figures 5 and 6 present Minnesota Power's Base Case load and capability for summer and winter seasons, respectively, during the forecast period. Key assumptions and events reflected in the Base Case load and capability projections include:

1. No permanent large industrial customer plant closures are projected during the forecast period (see Appendix A). Growth in the industrial customer class brings 166 MW of additional requirements by the end of the planning period.
2. Continuing commitment to conservation initiatives throughout the forecast period resulting in achieving at or near the currently filed level of 1.6 percent annual retail energy savings. Load reductions from Minnesota Power's conservation efforts are included as reductions in Minnesota Power's projected load (see Appendix A).

3. Through the North Dakota initiative, a phased reduction of the Minnesota Power 227 MW portion of the Young 2 coal resource will occur starting in 2014 and conclude in 2026.
4. Operating renewable resource additions required to meet Minnesota's RES including: Taconite Ridge, Wing River and Bison 1, 2 and 3 wind projects are added to the fleet (see Appendix G).
5. Implementation of the 250 MW Manitoba Hydro power purchase starting in 2020.
6. Estimated accredited capacity associated with remaining planned renewable additions per Minnesota Power's renewable mandate strategy are not included in the capability as committed resources because final timing is yet to be determined such as additional wind at the Bison location in North Dakota and additional biomass energy at the REC and HREC (see Appendix G).
7. Minnesota Power continues its large industrial customer generation partnerships for distributed generation and behind the meter generation purchases.
8. Existing wholesale power sales and purchase changes (see Appendix C).
   - Base load power sale of 100 MW (2010-2020)
   - Extension of 150 MW of key bilateral purchase contracts (2015-2020)
   - Inclusion of 100 MW of economic market surplus bilateral purchase contracts (2015-2020)
9. CID is estimated to be 96 MW for the planning period. This reflects changes in contractual requirements of the existing interruptible service commitments for the large industrial class and a changed future market environment.
10. No retirements of Minnesota Power's thermal or hydro generation resources are included in the Base Case outlook depicted in this section. Within this 2013 Plan is an evaluation of Minnesota Power's small thermal coal-fired generation to determine an environmental compliance strategy for MATS regulation. This Base Case is the starting point for that evaluation.

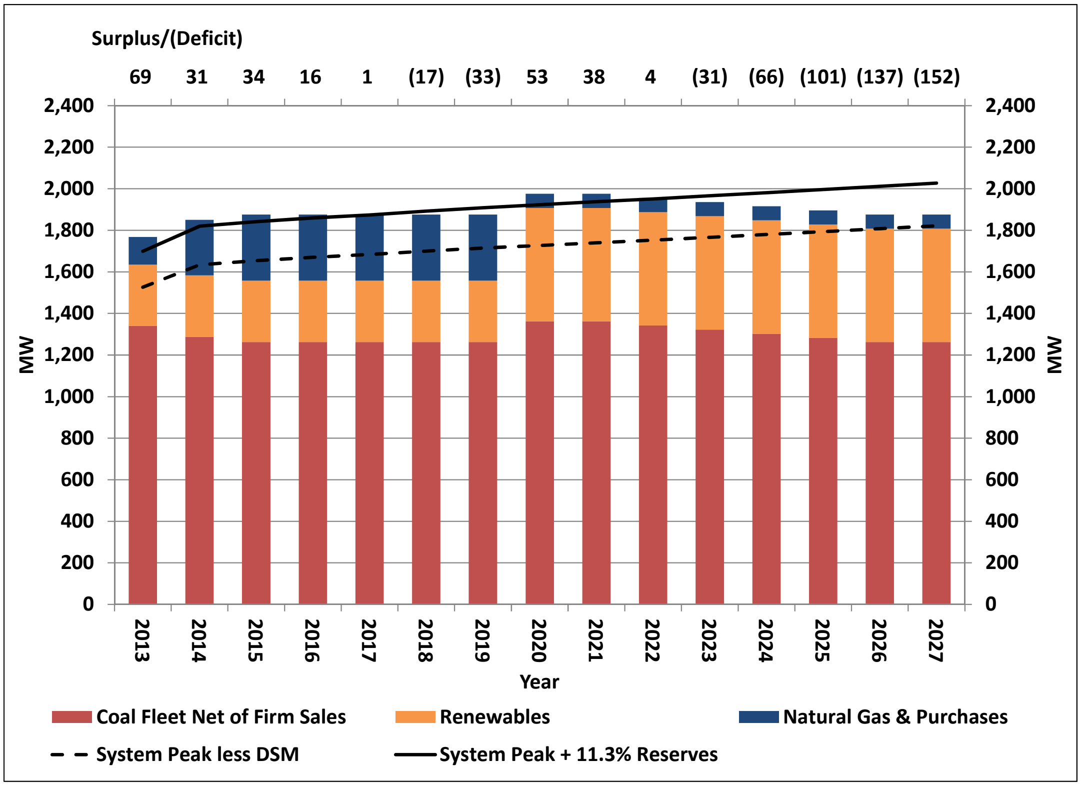


Figure 5--Base Case Summer Season Load and Capability

Minnesota Power's winter peak is typically close to 60 MW higher than its summer season peak; therefore, the surplus and deficit outlook is slightly different when shown for the winter season peaks. The general trends remain the same with very little deficit in the near term and growing long-term needs for capacity.

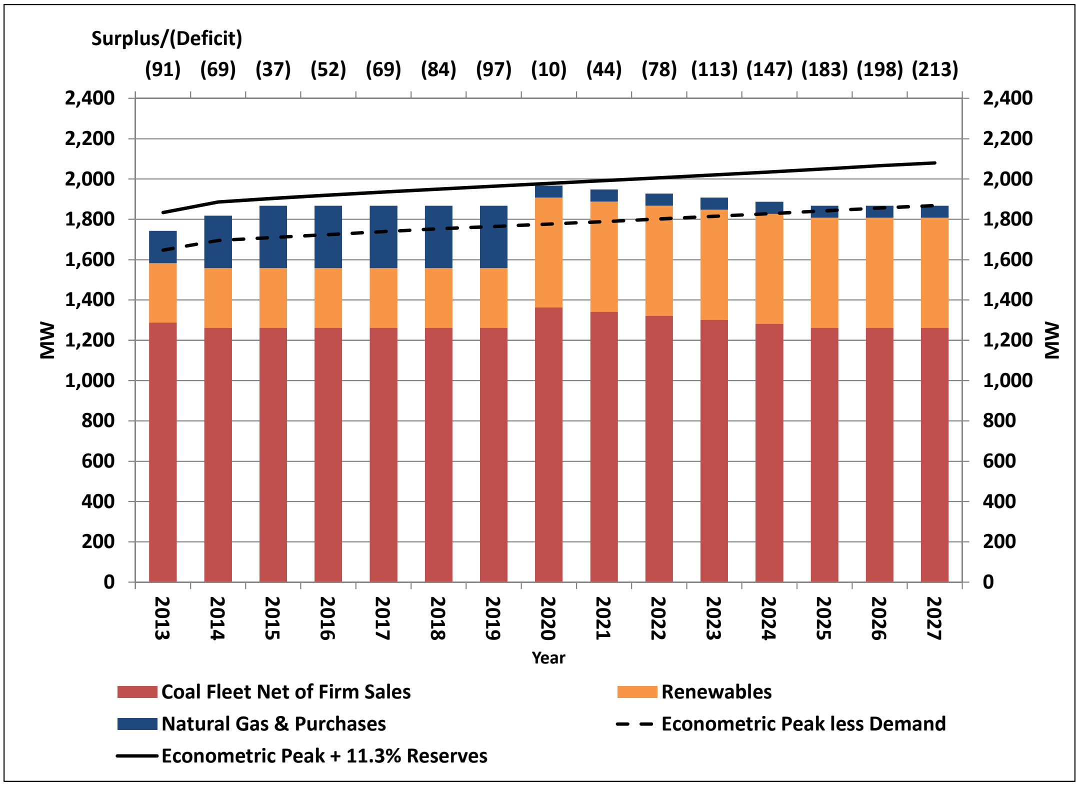


Figure 6--Base Case Winter Load and Capability

Minnesota Power has positioned its resources, including its existing generation (thermal and renewable) along with economic purchases, to meet the projected needs of its customers in the near term and create a bridge to longer-term additions like the Great Northern Transmission Line and accompanying Manitoba Hydro power purchase. The 2013 Plan evaluation identifies how Minnesota Power will implement a power supply strategy to meet any remaining needs after consideration of small thermal coal-fired generation decision making and projected customer growth.

The Base Case energy position is shown in Figure 7, identifying that, in the near term, Minnesota Power has minimal energy needs and will use the regional wholesale market to optimize its energy supply for customers in keeping with its least cost strategy.

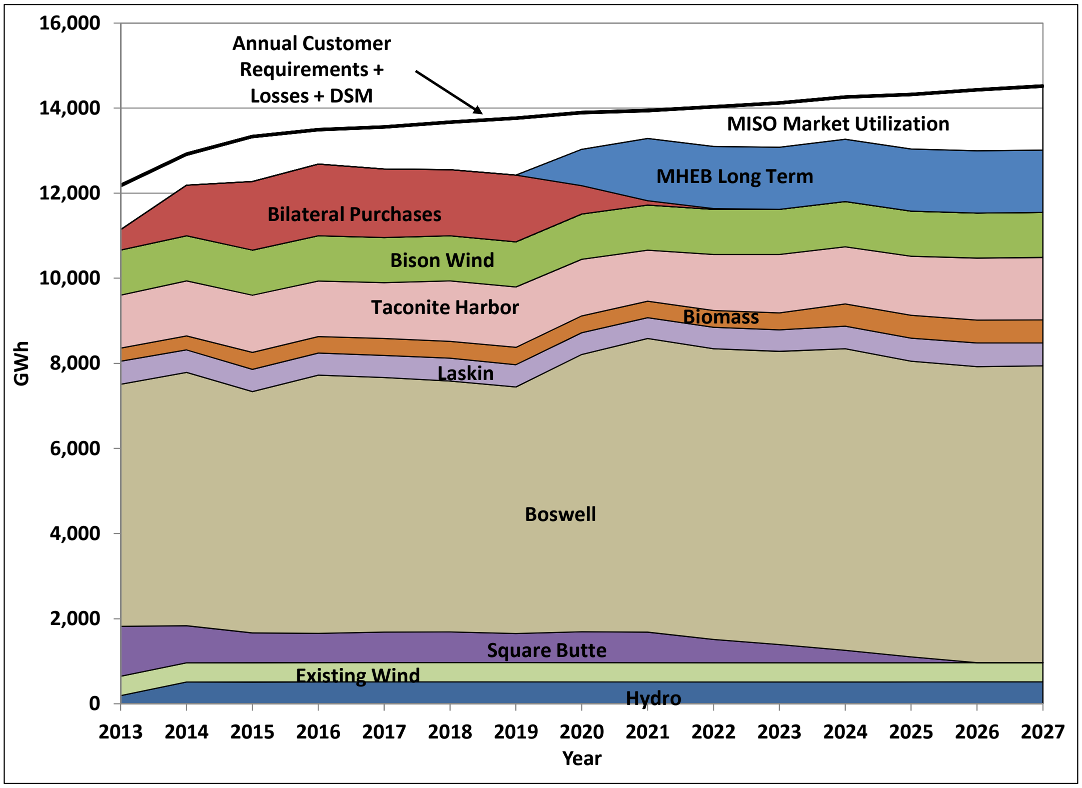


Figure 7--Base Case Energy Position

The regional market allows Minnesota Power to maximize its generation and transactions. In particular, the market provides timely and cost effective flexibility to help support the integration of additional renewable energy into Minnesota Power's system. The maturity of and flexibility within the regional energy market allows Minnesota Power to buy and sell electricity to manage supply and demand for the topmost portion of its load at the lowest possible cost.

High and Low Sensitivities for Demand and Energy

To capture the plausible ranges of uncertainty in Minnesota Power's customer outlooks, three additional sensitivities were chosen for further examination from the AFR2012: the Moderate Industrial Expansion, High Industrial Expansion and Low Economic and Industrial forecasts. These outlooks, shown in Figures 8 and 9, were used to determine contingencies for Minnesota Power's short- and long-term action plans and recognize the range of uncertainty that exists with Minnesota Power's unique customer base.

The Moderate and High Industrial Expansion outlooks contemplate significant growth in the mining industry, capturing up to 600 MW of growth potential in a high economic boom in the industrial sector. The Low Economic and Industrial forecast evaluates a slowdown in the key industries Minnesota Power serves along with a continued sluggish U.S. economy that could deliver up to 200 MW of demand destruction in Northeast Minnesota. Appendix A contains additional detail on each scenario.

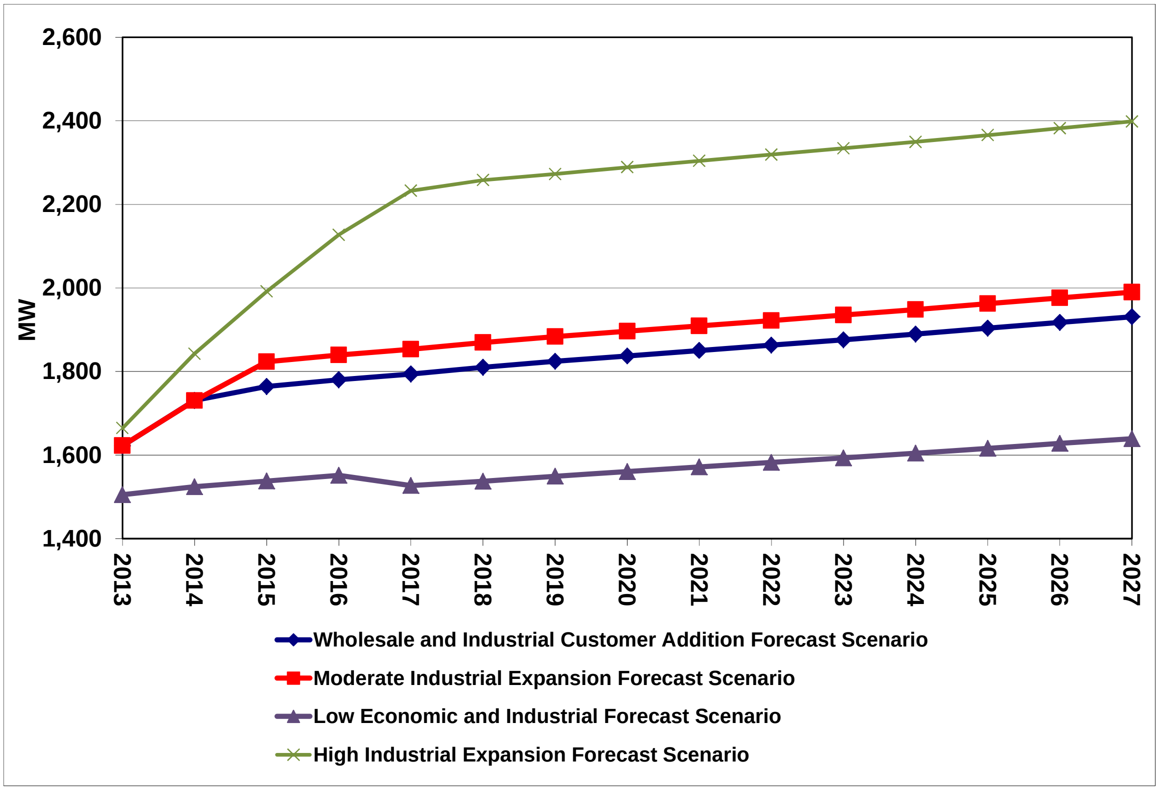


Figure 8--High and Low Demand Outlook Sensitivities

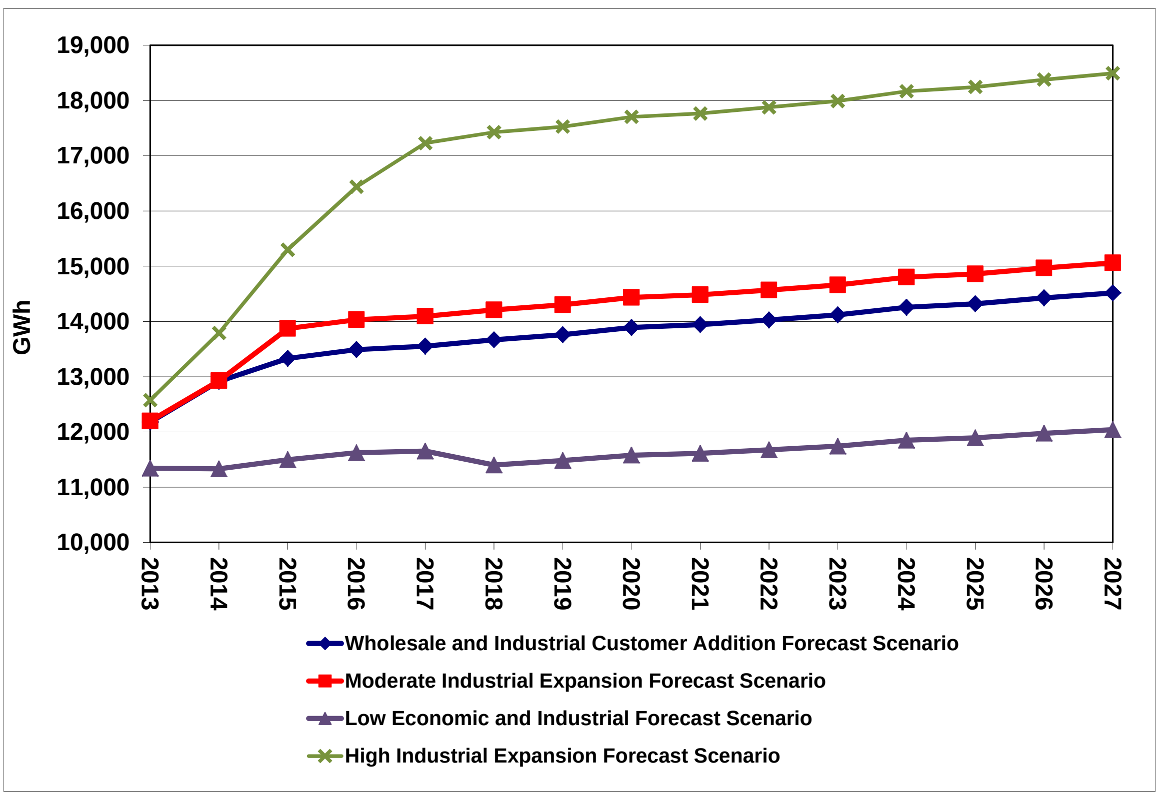


Figure 9--High and Low Energy Outlook Sensitivities

Minnesota Power continually monitors the potential for industrial growth in Northeastern Minnesota and recognizes the key role the mining and paper industries play in its customer make-up, system needs and system costs. The viability of these customers is the engine that helps drive the northeastern Minnesota economy. Making prudent and reasonable power supply plans for meeting future electric needs for industry and all other customers is critical in helping to keep economic balance in place to best serve all customers.

IV. 2013 Plan Development

Minnesota Power's 2013 Plan is focused on a balanced approach to delivering safe, reliable service at the lowest possible cost to customers while protecting and improving the region and state's quality of life through continued environmental stewardship. Since its baseload diversification study, Minnesota Power has refined and updated its outlook on major factors driving its power supply decisions and identified specific environmental compliance options that are viable at its coal-fired facilities. Building upon insights gained during the analysis completed over the past several months, the 2013 Plan documents how Minnesota Power utilized its planning process to develop a path toward reducing emissions, protecting reliability, and ensuring cost-effective rates for its customers.

Evaluation Framework

Minnesota Power faces two key long-term planning questions in this fifteen-year planning period. First, what environmental compliance strategies will be utilized to keep its coal-fired generation in compliance with the recently finalized MATS regulations, and second, how will it position and augment its power supply to meet the load growth potential that is emerging in its service territory. Minnesota Power recognizes the continued uncertainty of other federal environmental regulations as described in Appendix E and must plan accordingly to take appropriate actions. The 2013 Plan takes into consideration Minnesota Power's expected levels of additional regulations and projected customer power supply needs, and identifies the Preferred Plan as the least cost and most reasonable for this planning period.

Minnesota Power has worked through a transparent and iterative process with its stakeholders to identify the alternatives and considerations for environmental compliance at its coal-fired generation fleet. Starting with its 2010 Plan, Minnesota Power identified key themes of power supply diversification and environmental pressure on its coal-fired generating facilities. The February 2012 Baseload Diversification Report framed the high level cost ranges for Minnesota Power's coal-fired generating facilities to meet a wide range of potential outcomes for air, water and waste regulations being contemplated at the federal level. As more information and certainty with the final MATS Rule became known in December 2011, Minnesota Power was able to continue the process of designing and evaluating detailed alternatives for its coal-fired generation facilities. Using engineering and site specific detail, Minnesota Power determined specific quantifiable and actionable options for each alternative available during Plan development.

As shown in Figure10 below, the Baseload Diversification Report identified key trends of pending environmental regulations and their potential impact on Minnesota Power's generation fleet. Additionally, the knowledge gained from the baseload diversification study prepared Minnesota Power to proceed toward more detailed consideration of the three main alternatives available for meeting environmental compliance requirements of the final MATS Rule: "Retrofit," "Remission," and "Closure." Each of these alternatives has facility specific characteristics that must be taken into consideration. The 2013 Plan addresses each of Minnesota Power's facilities impacted by the MATS regulation and identifies how Minnesota Power determined the best compliance path for serving its customer power supply.

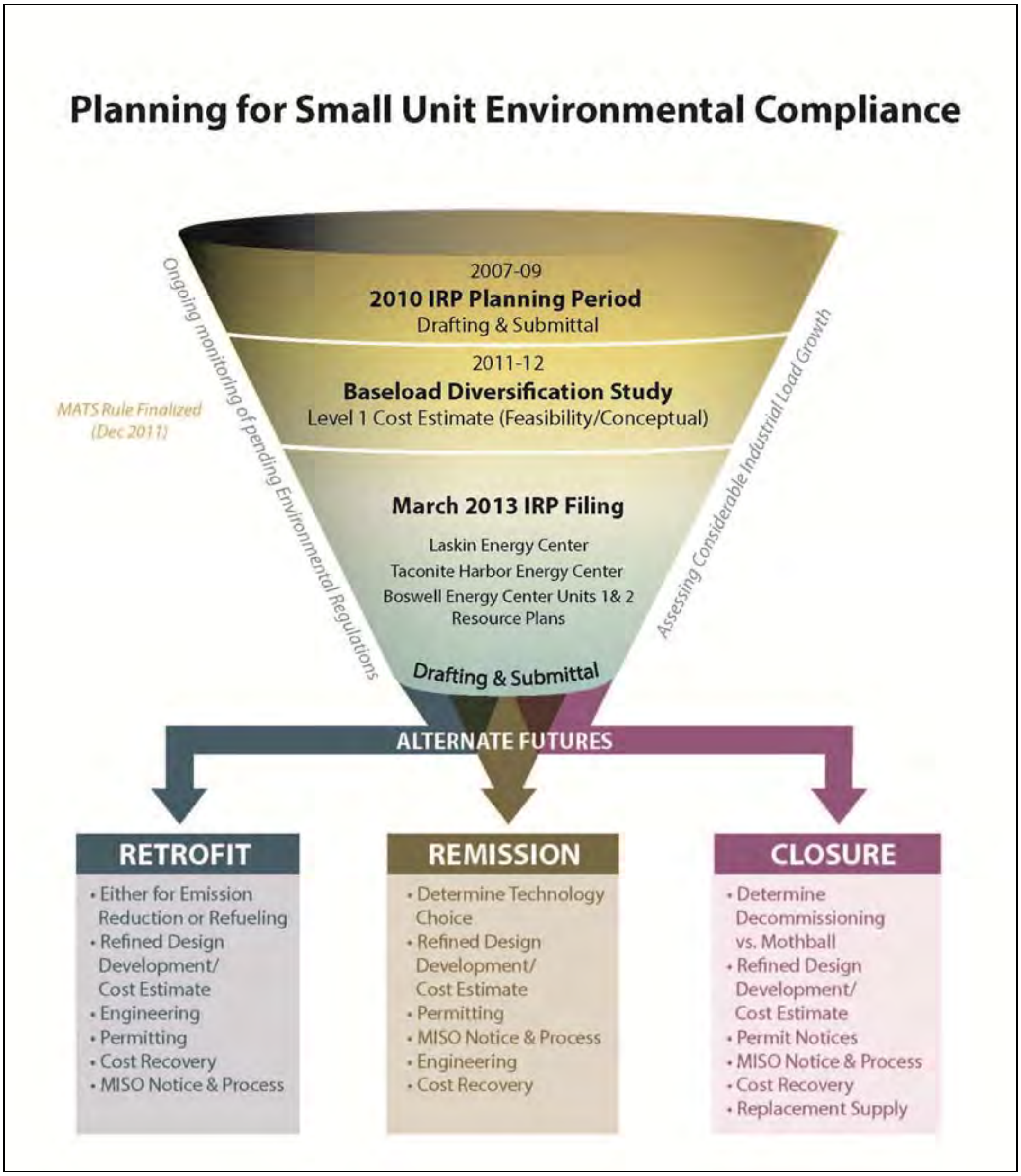


Figure 10--Planning for Small Unit Environmental Compliance

To advance the evaluation of Minnesota Power's coal-fired fleet to the next level and prepare for the 2013 Plan, several items were updated and refined from the Baseload Diversification Report. These items include:

a) Environmental Regulation Outlooks (see Appendix E) - Minnesota Power evaluated the status and certainty around the ten environmental regulations it monitors on an ongoing basis and determined which rules would be part of its Base Case evaluation and those that would be considered in an EPA sensitivity for the purposes of the 2013 Plan. In general, the Coal Ash Residuals and Steam Effluent Guidelines still contain sufficient uncertainty where inclusion in the Base Case is not appropriate until more detail is determined. Therefore, these uncertainties were considered in an EPA sensitivity.

b) Environmental Retrofit and Remission alternatives were refined to be specific to each Minnesota Power facility to gain necessary insight to cost estimates for decision-making.

c) Generation revenue requirements were updated with the latest information on ongoing capital and operating expenses at each facility.

d) Minnesota Power's capacity resources were updated to include the latest in near-term bilateral contracts and accredited capacity values.

e) Industry Outlooks (see Appendix H) - Minnesota Power assembled the latest industry data for generation technology, natural gas, coal, and other key power supply drivers and trends to ensure an up-to-date set of assumption data was available.

f) Minnesota Power's energy demand outlook was updated with AFR2012, its latest submittal to the Department of Commerce – Division of Energy Resources ("Department").

Together, the items above were considered in the 2013 Plan evaluation to a level appropriate for establishing a power supply strategy and determining Minnesota Power's short and long term action plans.

Utilities plan in an uncertain business environment recognizing not all assumptions will become reality. The resource planning process in Minnesota is dynamic and allows additional information to be gathered, applied, and resource strategy adjustments to be incorporated in the best interests of the customers on an ongoing basis.

For the 2013 Plan, a four step planning evaluation was used to arrive at the environmental compliance strategy for each facility and to find the best resource alternatives to augment Minnesota Power's supply for long-term customer requirements. Minnesota Power created its Preferred Plan by first determining its actions needed to comply with the MATS Rule on its coal-fired generation facilities (Preferred Coal Plan) and then augmenting this with the expansion plan that best serves customer needs over the planning period. The four sequential steps include:

1. "MATS Compliance" – Determine if a retrofit or remission alternative is most cost-effective for each coal-fired facility to meet the MATS Rule.

2. "Shutdown Consideration"– Determine if the generation facility should be closed/shutdown rather than move forward with the cost effective retrofit or remission option from Step 1.

   These first two steps will define Minnesota Power's Preferred Coal Plan.

3. "Identifying the Preferred Plan"– Identify a resource expansion plan that will augment the environmental compliance strategy identified in Steps 1 and 2 (Preferred Coal Plan) to best meet customer requirements over the study period.

4. "Comparative Analysis" – Compare and stress Minnesota Power's Preferred Plan against three other viable alternatives in a swim lane[27] analysis.

   a. The three other swim lane alternatives include these action plans:

      i. Retrofit all Minnesota Power's coal-fired facilities with needed emission reducing technology to meet the MATS Rule.

      ii. Close Minnesota Power's LEC and THEC generating facilities.

      iii. Evaluate adding the closure of THEC1 and THEC2 to Minnesota Power's Preferred Plan.

   b. Comparison of the three swim lane alternatives include a series of 21 sensitivities that stress the key power supply cost drivers such as fuel, capital and additional customer load outlooks (see Appendix I).

To begin to understand Step 1 and Step 2 in this evaluation (see Figure 11), Minnesota Power has, through the 'Coal-Fired Generation Considerations' section on page 38, identified for each of its coal-fired generation facilities impacted by the MATS Rule, the site specific alternatives available and gives insight to how it made the decision to retrofit, remission or close the generation facility.

[27] A swim lane is a mechanism to evaluate alternatives by considering them in a side-by-side "lane." For the 2013 Plan, each lane contains an alternative path for Minnesota Power's supply options.

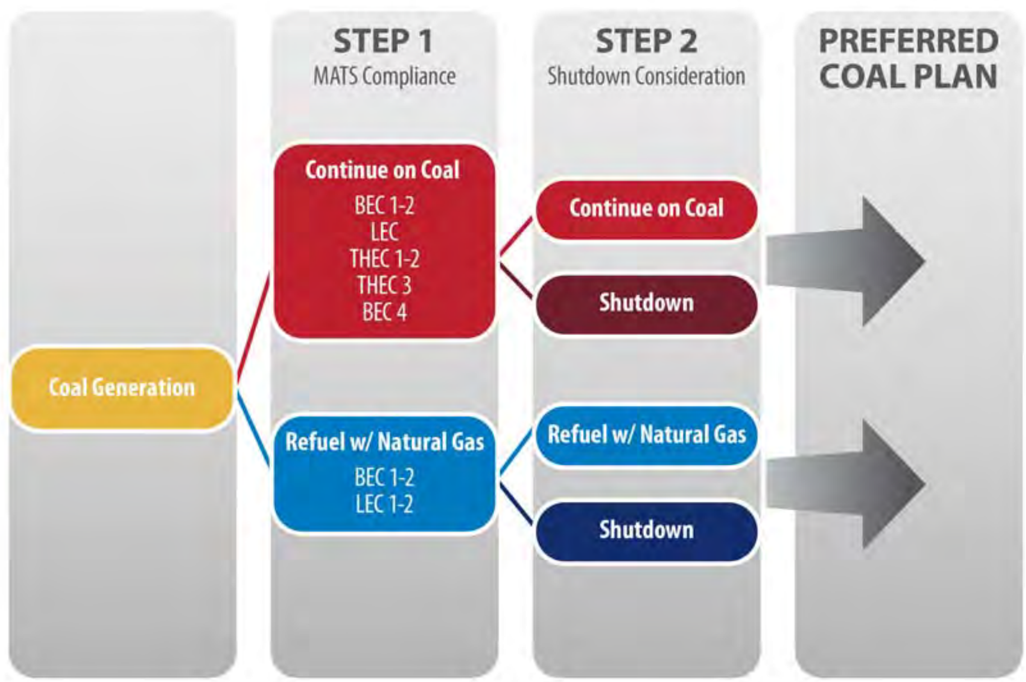


Figure 11--Plan Development Process - Steps 1 and 2

The 'Expansion Planning for New Generation Resources' section beginning on page 55 will share the results from Step 3 that determines which resources should augment Minnesota Power's supply portfolio. Finally, Step 4, the comparison of the three swim lane alternatives, will be discussed in the 'Analysis and Insights' section and will demonstrate how the Preferred Plan will bring cost and environmental benefits to customers' electric supply. Steps 3 and 4 are shown in Figure 12.

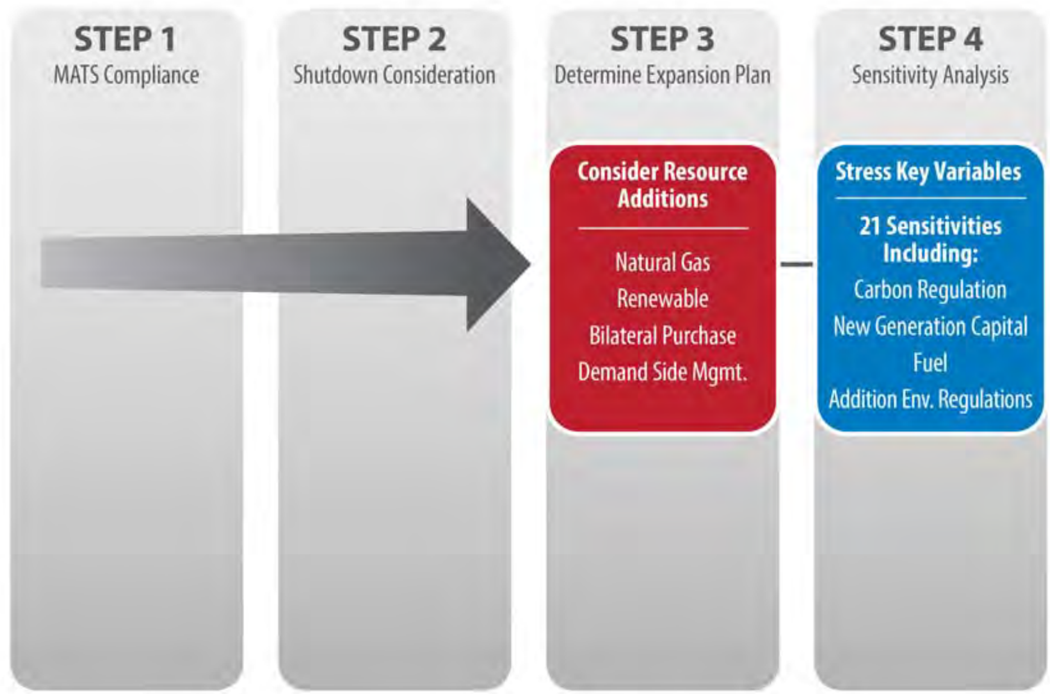


Figure 12--Plan Development Process - Steps 3 and 4

Coal-Fired Generation Considerations

Minnesota Power's LEC in Hoyt Lakes, Minn., THEC near Schroeder, Minnesota and BEC in Cohasset, Minnesota are each impacted by the finalization of the MATS Rule. Additional state requirements exist for BEC3 and BEC4 under MERA. For each of its coal-fired facilities Minnesota Power identified and considered detailed alternatives for retrofit, remission and closure to meet finalized MATS requirements. This section, with support from Appendix C and Appendix E, will describe the drivers of the environmental compliance strategies that Minnesota Power is moving forward with in its 2013 short and long-term action plan (see Sections V and VI).

Boswell Energy Center

Minnesota Power's largest coal-fired facility has just over 1,000 MW and a shared infrastructure that supports the operation of four generating units. BEC3 (365 MW) and BEC4 (585 MW of which Minnesota Power has an 80 percent ownership share), are the largest units of BEC, producing over 5.8 million MWh annually for customers (over one-third of the Company's power supply). The two smaller units, BEC1&2, combine for a total of approximately 140 MW and provide vital restoration capability during startup operations and facility-wide support. Operating at baseload levels, BEC provided nearly half of the energy that Minnesota Power generated to meet customer requirements in 2012. BEC employs about 200 full-time Minnesota Power employees.

Substantial investments have been made at the BEC facility for environmental and efficiency related improvements over the past several years, with the largest investment in BEC3. As explained in more detail in Appendix E, BEC3 underwent a significant multi-pollutant environmental retrofit completed in 2009 for controlling sulfur dioxide ("SO_2), oxides of nitrogen ("NO_x), particulate matter ("PM") and mercury. The controls put in place on BEC3 reduced air emissions by 90 percent or more for the four effluents, below prescribed MATS levels, and BEC3 will not require any additional technology investment to remain environmentally compliant with the MATS Rule and MERA.

BEC4, Minnesota Power's largest baseload generating resource, is slated for an extensive environmental retrofit from 2013 to 2015 to address mercury, trace metals and PM to meet requirements of MERA and the MATS Rule. Minnesota Power completed a careful evaluation and engineering for mercury reduction alternatives over the past several years[28] to begin preparing for the MERA requirements. With the finalization of the MATS Rule in late 2011 and confirmation that the multi-pollutant retrofit alternative Minnesota Power was evaluating for MERA would also meet the finalized MATS Rule, Minnesota Power moved forward on the BEC4 retrofit. In August 2012, Minnesota Power requested approval from the Commission of its BEC4 Project,[29] proposing an environmental retrofit was the most reasonable and least-cost, environmentally compliant strategy for Minnesota Power customers. Minnesota Power's Baseload Diversification Report and the Department's comments in that Docket further supported the decision to move forward with an environmental retrofit on BEC4. Initial Department analysis determined that, at the expected level of environmental compliance costs, retiring BEC4 is not a cost-effective option. BEC4 joint owner, WPPI Energy,[30] requested and gained approval for the BEC4 Project from the Public Service Commission of Wisconsin.[31] The BEC4 Project is included as part of Minnesota Power's 2013 Plan for all four swim lane alternatives.

BEC1&2 are also well positioned for upcoming MATS requirements and for continuation as valuable resources in Minnesota Power's customer supply. BEC1&2 operate with emission control equipment including low NO_x burners and fabric filters to control particulates and substantial mercury capture co-benefits. In 2008 and 2009, Units 2 and 1, respectively, were retrofitted with Mobotec Rotating Opposed Fired Air and ROTAMix emission control systems to further reduce the NO_x emissions from these

[28] Minnesota Power filed Mercury Emission Reduction Reports with the Commission in 2011 and 2012 (see Docket No. E015/M-11-712 and Docket No. E015/M-12-734).
[29] Docket No. E015/M-12-920
[30] See Docket No. E015/PA-90-153.
[31] The Public Service Commission of Wisconsin ("PSCW") docket number for the WPPI Energy. Certificate of Authority filing is: PSCW Docket No. 6685-CE-110. The PSCW issued its written Certificate of Authority order for WPPI Energy's participation in the BEC4 environmental retrofit project on February 11, 2013.

units. Fabric filter operation co-benefits at BEC1&2, plus the mercury reductions being realized at BEC3 and BEC4 (post retrofit), will allow the entire BEC facility to achieve compliance with the MATS Rule with no additional technology installations, as well as position the facility long term.

As part of the outcome of the baseload diversification study the commission requested further evaluation of BEC1&2 and that Minnesota Power include in its 2013 IRP:

> *"An evaluation of the consequences – including all relevant costs and the consequences for transmission adequacy – of retiring Boswell Energy Center, Units 1 and 2 by 2020."*

It is important to recognize the integration of BEC1&2 with the overall BEC facility when considering its potential closure. As mentioned above, the BEC units are not stand alone in such a way they can easily be separated; they share infrastructure, ancillary services and fuel handling with the rest of BEC. Specifically, BEC1&2 provide support to BEC3 and BEC4 during start up procedures, ongoing operations,[32] and during critical system restoration activities for Minnesota Power. When considering a closure of these two units it is necessary and appropriate to include the replacement cost of a 37 MW generating resource at the site to facilitate the continued operations of BEC. In its retirement evaluation, Minnesota Power included a 37 MW reciprocating engine project into the closure scenario to account for energy replacement and the ability to participate in the system restoration plans for the BEC facility. Site-wide operational costs would need to continue if BEC1&2 were shut down, including an average $1.7 million in capital cost annually and $3 million in operation and maintenance ("O&M") cost annually. These costs include common equipment and services that will need to continue for power production to occur at BEC if BEC1&2 were shutdown. This would effectively increase the operations cost for the remaining units. Minnesota Power included the necessary costs for the BEC1&2 shutdown scenario that was analyzed to ensure BEC3 and BEC4 would have the operational support needed.

No concerns were identified in screening the transmission considerations of shutting down BEC1&2. Due to its location in Cohasset, Minnesota with robust transmission system interconnections with the rest of the regional network, no transmission concerns were identified. However, if a shutdown were to be needed, Minnesota Power would enter into the appropriate Attachment Y process with MISO to secure official confirmation about impact from its regional transmission operator.

A refuel of the BEC1&2 boilers to natural gas was also an alternative considered for meeting the Commission Order point above. Before conducting the shutdown evaluation, Minnesota Power compared the existing BEC1&2 resources with a natural gas refuel option. The refuel conversion would entail inserting natural gas burners into

[32] BEC1&2 provide compressed air, service water and intake cooling water to the large BEC facility. The electrical and communication infrastructure of BEC1&2 is also closely intertied with BEC3.

the current boilers and allowing them to fire completely on natural gas as a fuel source. This would maintain full capacity benefit for customers and serve as a peaking energy resource to protect customers from high regional market prices. To help meet the start-up time requirements for BEC1&2 on natural gas, steam needs to be routed from BEC3 to the BEC1&2 turbines to keep the turbines warm and ready for start-up.[33] The refuel option also allows BEC1&2 to continue to operate as part of the larger BEC facility infrastructure and meet system restoration requirements. BEC has natural gas supply infrastructure in place, including appropriately sized pipe that could accommodate the operation of BEC1&2 on natural gas; minimal common infrastructure would need to be added to implement the refuel. The estimated capital cost of a natural gas refuel for BEC1&2 is $14 million (see Appendix M).

Figure 13 below identifies BEC1&2 as resources that run a large part of the year, or at high capacity factors of 70 to 80 percent.[34] If BEC1&2 are converted to natural gas and continue to run at the same high capacity factor level (shaded area in graph below), the cost is higher than if BEC1&2 were kept as coal-fired generators.[35] The graphic also identifies that if BEC1&2 were running less than 40 percent of the time, then the natural gas refuel option could have benefit. It is evident that the existing BEC1&2 resources are the lowest cost options for customer power supply when comparing costs of the existing unit to the costs with a natural gas refuel option.

[33] The steam needed for a BEC1&2 start-up on natural gas is taken into account by reducing the output at BEC3 by 14 MW when considering the refuel alternative.
[34] Based on operations data over the past six-year period.
[35] A capacity factor represents how much of the year a generator resource runs in comparison to its nameplate capacity. Minnesota Power's coal-fired fleet runs at higher capacity factors to serve the high energy needs of its customers and provide low cost energy all hours. Peaking natural gas resources typically run at low capacity factors (less than 20 percent on average).

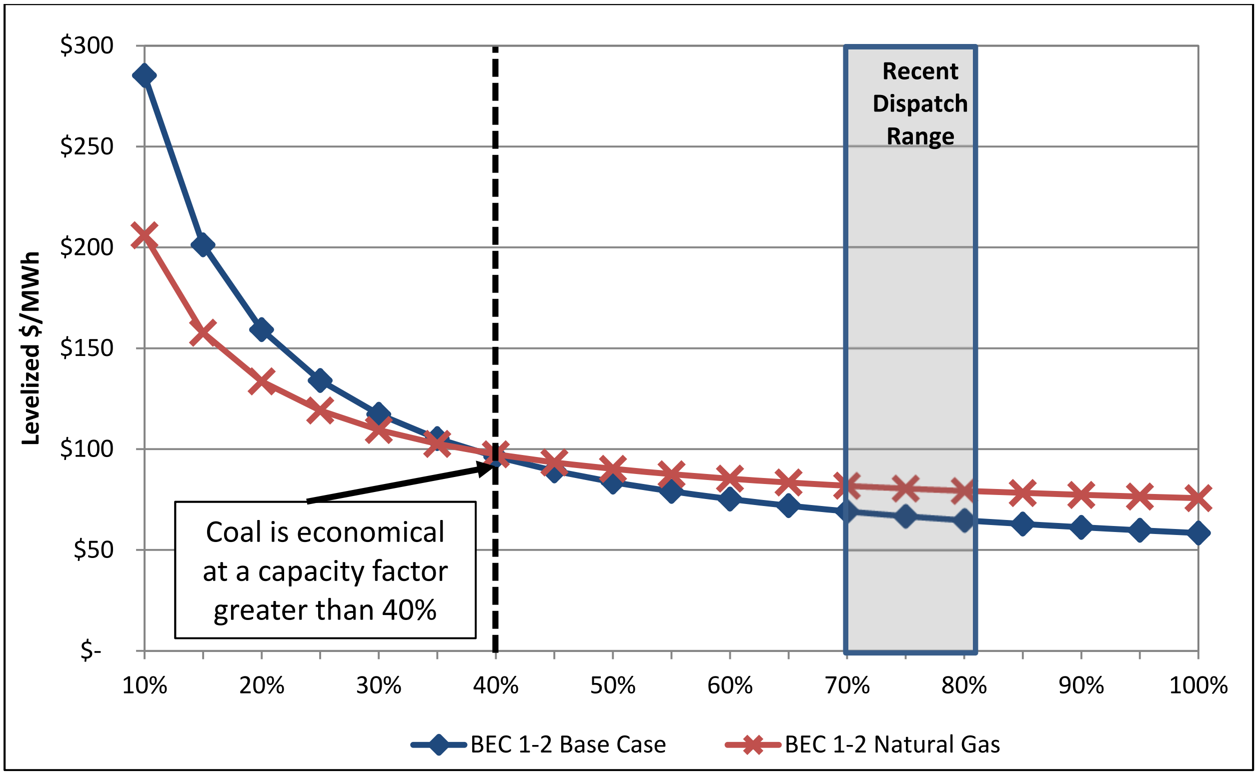


Figure 13--BEC1&2 Levelized Product Cost at Varying Capacity Factors

Figure 13 should be considered in context. It is a limited comparison of the two options and does not consider the remaining power supply resources. When the natural gas refuel and existing operation options are evaluated through a full production cost analysis of Minnesota Power's system in the Strategist software, BEC1&2 as a coal-fired facility continues to be the lowest cost option for customers under 1) Minnesota Power's base assumptions (as defined in Appendix H) with about $90 million of benefit, and 2) a greenhouse carbon regulation penalty scenario with about $70 million of benefit. The carbon regulation penalty scenario placed additional costs on existing generating sources that emit carbon dioxide ("CO_2") starting in 2017 with $21.50/ton.[36] In both outlooks, keeping BEC1&2 as environmentally compliant coal-fired generators serving baseload operations continues to have cost benefits for customers when compared to converting to natural gas for meeting the MATS requirements (see Table 2).

[36] Minnesota Power ran the greenhouse gas scenario as required by the Commission's Orders implementing Minn. Stat. § 216H.06 to consider carbon regulation penalties that hypothetically occur beginning in 2017. Minnesota Power has concerns that utilizing carbon regulation penalties other than predetermined externality values until a valid penalty structure is implemented or designed may be detrimental to customers. Appendix E gives more insight to this perspective.

Table 2--BEC1&2 Power Supply Cost Comparison for MATS Solution

Strategist Power Supply Cost 2013-2034 NPV ($ Millions)	BEC1&2 Coal	BEC1&2 Natural Gas Refuel	Customer Impact (Gas Refuel – Coal)
Base Assumptions	$8,147	$8,237	$91
With CO_2 Regulation Penalty $21.50/Ton in 2017)	$9,750	$9,819	$70

Step 2 or the “Shutdown Evaluation” indicated that customers would not benefit from a retirement of BEC1&2; in fact, it would be unnecessarily costly to retire these two units. The evaluation included the optimization of a BEC1&2 retirement option with the rest of the system alongside new generating resource alternatives. When the option to retire BEC1&2 was given to the system wide optimization evaluation in the Strategist Proview software, it identified that BEC1&2 remain viable power supply resources as environmentally compliant coal-fired generation; the retirement option was not economically beneficial for customers (see Appendix I).

Minnesota Power identified through the BEC1&2 closure evaluation that at this time, with current environmental regulations and no greenhouse gas regulation in place, there are no driving factors to close these two resources. BEC1&2 will best serve customers through their continued operation providing economic capacity and energy. Minnesota Power will continue to monitor industry, environmental and system conditions that impact BEC1&2 and all of its resources. Through its ongoing resource planning process, Minnesota Power will communicate with stakeholders as power supply action plans evolve for BEC1&2.

Laskin Energy Center

LEC has been evaluated over the past year to determine the specific environmental compliance options available to allow the facility to meet the finalized MATS Rule. The Commission requested as part of the outcome of the baseload diversification study further evaluation of LEC and that Minnesota Power include in its 2013 IRP:

> *“A proposal to address the viability of Laskin Energy Center, Units 1 and 2, and Taconite Harbor Energy Center, Unit 3.”*

This section will describe Minnesota Power’s consideration of environmental compliance alternatives and the viability for LEC, supporting the decision that refueling the two generating units to natural gas in 2015 is in the best interest of customers.

Each LEC unit operates with a generation capability of 60 MW gross (55 MW net) with about 5 MW of existing station service steam per unit to operate auxiliary equipment. Originally known as the Aurora Steam Station, the facility was commissioned in 1953 with a total station capability of 88 MW and was designed to serve the needs of an expanding taconite industry. Both units were uprated to the present capability (110 MW) in 1967 through boiler, control system, turbine, and generator upgrades. In 1971, the units were retrofitted with full particulate wet scrubbers, among the first full-scale scrubbers in the U.S., and converted to utilize low-sulfur western fuels. A second stage of scrubber enhancements was later added to improve efficient particulate removal. The infrastructure has been well maintained and the two units share electric and heating infrastructure with a single control room for operations. The units have maintained a 50 to 60 percent capacity factor over the past six years as market and operating conditions have changed, providing an average of 518,000 MWh for customers each year. The facility is in close proximity to one of the major natural gas pipelines in the region, Northern Natural, and utilizes natural gas as a starting fuel for its current coal-fired operations.

From an environmental control perspective these units are well controlled. The units have two-stage wet particulate scrubbers for PM, SO_2 and co-benefit mercury removal. As a part of Minnesota Power's Arrowhead Regional Emissions Abatement ("AREA") Plan, LEC received significant investment beginning in 2006 through 2008, with the installation of low NO_x burners and over-fire air systems to reduce the NO_x emissions by 66 percent. The MATS Rule would require that LEC install additional boiler injection technology to further reduce mercury emissions to meet required thresholds. Other alternatives for environmental compliance with the MATS Rule include a natural gas refuel or closure of the facility.

The injection technology option would introduce sorbents into the LEC boilers and, through active management with the other environmental control systems in the plant, keep mercury and other hazardous air pollutants below required MATS thresholds. The active sorbent that would be utilized in the process is considered a variable cost and would fluctuate with the production of electricity. Minnesota Power identified through an engineering evaluation that the cost to install an injection system into the two boilers at LEC would be approximately $6 million in capital expense and would increase variable costs by approximately $1.50 per MWh for the needed sorbents to control mercury.

The refuel conversion option would place natural gas burners into the current boilers and allow them to fire completely on natural gas as a fuel source rather than coal. The conversion would maintain the full capacity benefit of approximately 110 MW for customers at a reasonable cost and serve as a peaking energy resource to protect customers from high regional market prices. A peaking resource would run considerably less than the current LEC operation as coal-fired generation; typically a gas peaking resource will run less than a 20 percent capacity factor each year. However, even though the unit does not run continuously, the value is in the protection it provides to customers against high regional power prices and provided capacity. Energy supply would be optimized between LEC and the regional power market on a real-time basis, taking the least cost power supply for customers.

Natural gas is an environmentally cleaner combustion process, so emissions would be reduced overall through an LEC conversion to natural gas. Greenhouse gas would be reduced, as coal is no longer the fuel source utilized. A LEC conversion to natural gas would reduce CO_2 by 1,075 pounds per MWh. In addition, SO_2, mercury, lead and PM would be reduced by over 90 percent and NO_x would be reduced by approximately 50 percent from current emission levels, bringing significant environmental benefit to the region. Minnesota Power identified that to refuel LEC to natural gas would require an estimated $14 million in capital expense[37] and would significantly decrease O&M costs. The facility would require about one-third of the current staff and maintenance requirements would decrease with natural gas-fired operations in comparison to coal. The natural gas fuel supply would be available from an adjacent high pressure regional pipeline. A fuel procurement strategy would be put into place before 2015 to ensure fuel supply is available. LEC is already serviced by a gas supply making this option beneficial to customers as Minnesota Power is able to optimize the fuel procurement for LEC.[38]

The first step in the LEC evaluation was to compare the environmental compliance options of injection technology and the refuel to natural gas before considering a shutdown alternative for the facility. LEC has been maintaining 50 to 60 percent capacity factors for the past 6 years. When the generation costs are compared one-to-one, the natural gas refuel and injection technology implementation costs are extremely close. Figure 14 below identifies that at a 55 percent capacity factor, the two compliance options are essentially equal. As the capacity factor of LEC is decreased, the natural gas refuel option is the lower-cost option for customers. Since LEC would face additional economic pressure with injection technology from where it is operating today due to increased costs, it is likely that capacity factors would decrease from today's level. If LEC were to reduce its capacity factor, it would essentially be operating more like an intermediate or peaking resource than a baseload unit; the natural gas refuel would be more economical for customers.

[37] This capital expense includes necessary natural gas fuel infrastructure to meet the requirements of the 110 MW generating capability. The natural gas procurement and strategies would be developed closer to the implementation date.
[38] The high pressure line is located less than one mile from LEC and an existing line into the facility will be upgraded to accommodate its new mission.

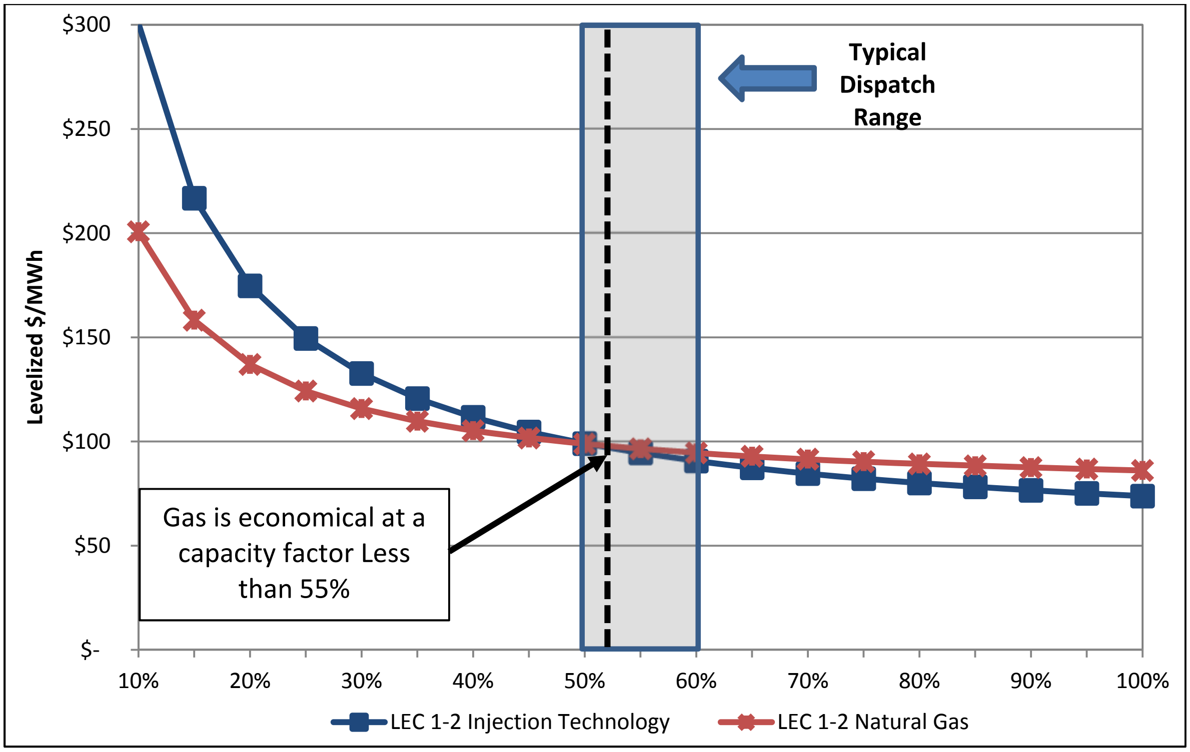


Figure 14--LEC Levelized Product Cost at Varying Capacity Factors ($-2016)

Figure 14 should be considered in context. It is a limited comparison of the two options and does not consider the remaining power supply resources. To clarify the MATS compliance options available, the natural gas refuel and injection technology alternatives were evaluated and compared through a full production cost analysis in the Strategist software. LEC as a natural gas facility is identified to be the lowest cost option under 1) Minnesota Power's base assumptions (as defined in Appendix H) and 2) a greenhouse carbon regulation penalty scenario where additional costs are placed on existing generating sources that emit CO_2 starting in 2017 of $21.50 per ton. In both outlooks refueling LEC to natural gas as an environmental compliance option has cost benefits of between $50 million and $90 million for customers when compared to installing injection technology. In the natural gas refuel option and with very minimal capital additions, Minnesota Power is able to optimize the natural gas operation of LEC with the regional market, bringing the lowest cost power supply option that ultimately brings savings to customers as illustrated in Table 3.

Table 3--LEC Power Supply Cost Comparison for MATS Solution

Strategist Power Supply Cost 2013-2034 NPV ($ Millions)	LEC Coal-Fired	LEC Natural Gas Refuel	Customer Impact (Gas Refuel – Coal-Fired)
Base Assumptions	$8,160	$8,110	($50)
With CO_2 Regulation Penalty ($21.50/Ton in 2017)	$9,763	$9,677	($86)

A natural gas refuel for LEC would bring many changes for its operations. There would be coal-fired generating equipment and systems that would require additional action, including the existing coal ash ponds and associated equipment. The cost for these transitions was factored into the refuel analysis.

To further determine if LEC should be shut down or continue operation after the MATS Rule deadline, the lowest cost environmental compliance option from Step 1 above (the natural gas refuel) was compared with an alternative to shut down the facility (Step 2). A generating unit closure analysis is complex and must take into account many pieces including the remaining plant asset balance at the time of the closure, costs related to decommissioning the facility, the impacts on the transmission system and socioeconomic impact on local communities. Remaining plant asset balance and decommissioning requirements were included in the shutdown alternative and assumptions for a ten-year recovery of these costs were assumed.[39] Through the shutdown alternative comparison, Minnesota Power conducted a local transmission evaluation to determine the impacts of having LEC removed from the power system and found that no reliability concerns would be created under current customer load outlooks (see Appendix F).[40]

While not included as a direct cost to the LEC shutdown alternative, Minnesota Power evaluated the socioeconomic impact on the local communities in conformance with state resource planning statutes. A partnership with the University of Minnesota

[39] The retirement mechanism for the remaining plant balance and decommissioning costs is based on the same methodology utilized in Minnesota Power's baseload diversification study and is included in Appendix H.
[40] Minnesota Power did not request MISO to conduct a region reliability study for LEC as its evaluation identified that moving forward with a natural gas refuel for the unit was the best outcome for customers and it would not be closing this unit. It is expected that LEC would not have significant impact on the regional reliability of the bulk transmission system due to its geographic location on the transmission system in northern Minnesota.

Duluth was established to leverage their expertise in evaluating the socioeconomic impact of a facility closure (see Appendix K). Their findings emphasized that Minnesota Power's generating facilities provide significant benefit to the communities and surrounding region through tax payments, employment and vendor utilization. If Minnesota Power were to close the LEC facility, the loss of 41 jobs and the associated support roles throughout the region would create a 2 percent increase in unemployment almost immediately for the area. Home prices could be expected to decline 5 percent as migration from the area increased as families leave to find new employment. An average of $10 million would be lost in revenue each year for the area economy after the closure. As demonstrated during the baseload diversification study process and associated stakeholder outreach, Minnesota Power has been a trusted community partner for decades and continues to consider these impacts of its electric service in a thoughtful way.

In Step 2 of the evaluation, a shutdown of LEC as a natural gas-fired facility was considered through the Strategist Proview software. The evaluation identified that LEC, as a natural gas resource, would continue to be a viable power supply resource for customers after the MATS compliance date with and without a carbon regulation penalty (see Appendix I). LEC operating as a natural gas unit provides a least-cost power supply alternative that significantly reduces emissions from a coal-fired operation.

Minnesota Power's short-term action plan includes converting LEC to natural gas in 2015. This will create Minnesota Power's first natural gas generating unit and aligns with the transformation and reshaping strategy that Minnesota Power is implementing to preserve reliability, protect affordability and reduce emissions for its customers.

Taconite Harbor Energy Center

THEC has been evaluated over the past year to determine the specific environmental compliance options that are available to allow the facility to meet the MATS Rule. The commission requested as part of the outcome of the baseload diversification study further evaluation of THEC, specifically Unit 3 and that Minnesota Power include in its 2013 IRP:

> *"A proposal to address the viability of Laskin Energy Center, Units 1 and 2, and Taconite Harbor Energy Center, Unit 3."*

This section will describe the continuation of Minnesota Power's development of environmental compliance alternatives and viability for THEC3 and support the decision in its short-term action plan that continuing the operation of THEC1&2, while ceasing coal-fired operation at Unit 3 in 2015, is in the best interest of customers.

THEC is located near Schroeder, Minnesota, on the North Shore of Lake Superior, and has a generation capability of 225 MW. The generators all operate at high capacity factors on an annual basis of 60 to 75 percent, providing baseload energy for Minnesota Power's customers. The three 75 MW units were purchased from bankrupt LTV Steel Mining Co. in 2001. Significant investment was made as the units were restarted in 2002. THEC employs 45 full-time Minnesota Power employees. The three generating units are housed in a single building with shared electrical and heating infrastructure and a single control room for unit operations. The facility does not have direct access to natural gas as a fuel source, no pipeline is present and the closest access is 30 miles to the south in Silver Bay, Minnesota. The facility is located at an active shipping port on Lake Superior and receives coal shipments via boat for its operations.

The THEC units received significant investment in the period 2006 to 2008 as part of Minnesota Power's AREA Plan. THEC1&2 were fitted with Mobotec multi-emission control technology designed to deliver a 62 percent reduction in NO_x emissions, a 65 percent reduction in SO_2 emissions and up to a 90 percent reduction in mercury emissions. Conversion of the hot-side electrostatic precipitator ("ESP") to a cold-side ESP for improved particulate removal also took place in this time period. The final mercury removal system is being installed on these two units. THEC1&2 are well positioned to meet the requirements of the MATS Rule in 2015. Sorbents will be utilized with the existing Mobotec injection system to reduce mercury and other air emissions below required thresholds.

The additions of sorbents to THEC1&2 will have positive environmental benefits; however, they will add costs to the unit operations. These operational costs add on average \$3.20/MWh to the current THEC operating costs. Mercury emissions will be reduced to MATS requirement levels by adding activated carbon sorbents into the boilers. The combined sorbents being added to remove mercury will also have a positive impact on SO_2 removal and Minnesota Power should see an additional 30 percent reduction in these emissions.

The additional costs for the sorbents were evaluated through a full production cost analysis in the Strategist software and compared to existing operations. As Table 4 below identifies, a 0.3 percent increase (or approximately \$20 million) in overall power supply system costs was estimated for the study period when the sorbents were added to THEC1&2 under scenarios with and without a carbon regulation penalty. The previous AREA investment creates a viable mechanism to meet the MATS Rule requirements without additional capital investment. As demonstrated below, these additional operating costs for THEC1&2 do not impact the viability of the generating resources.

Table 4--Change in Power Supply Cost with THEC1&2 MATS Solution

Strategist Power Supply Cost 2013-2034 NPV ($ Millions)	THEC1&2 Base Case	THEC1&2 Additional Sorbents	Customer Impact (Sorbents – Base)
Base Assumptions	$8,147	$8,172	$25
With CO_2 Regulation Penalty ($21.50/Ton in 2017)	$9,750	$9,773	$23

THEC3 does not currently have the necessary emission controls in place to meet the upcoming MATS requirements. THEC3 is fitted with a hot-side ESP for particulate control and also utilizes low sulfur, low mercury coal. THEC3 is categorized as a Regional Haze unit for Minnesota and, until the MATS Rule was finalized, was on track to add injection technology controls similar to those installed on THEC1&2 to meet the NO_x and SO_2 requirements in 2017. The MATS Rule now requires THEC3 to meet additional air emission requirements in 2015. A multi-pollutant environmental retrofit alternative to meet both Regional Haze and MATS requirements was developed for THEC3; however, refuel is not viable at this time as natural gas is not in close proximity to the site.[41]

The multi-pollutant retrofit alternative developed for THEC3 includes a scrubbing technology, similar to the proposed BEC4 Project, able to handle a multi-pollutant reduction for both MATS and Regional Haze regulations. This project alternative consists of installing a Hitachi Power Systems America Enhanced All-Dry scrubber and Pulse Jet Fabric Filter for treating THEC3 flue gas for control of SO_2 and PM, respectively. Additionally, a powdered activated carbon injection would be employed for control of mercury emissions. To address NO_x emissions an additional project to install low NO_x burner and over fired air technology was also included. Estimated capital cost for this alternative is $60 million with increased variable costs of approximately $2.50 per MWh. Emission reduction would be approximately 90 percent for SO_2 and mercury and 60 percent for PM after the installation is complete.

The multi-pollutant environmental retrofit alternative was evaluated and compared to existing operations through a full production cost analysis in the Strategist software. Table 5 below identifies a 0.7 percent increase in overall power supply system costs (or approximately $60 million) is estimated for the study period when the retrofit is added to THEC3 under scenarios with and without a carbon regulation penalty. The power supply impacts of the THEC3 retrofit alternative are twice the impact of

[41] Biomass as a fuel source can be considered in the future, however at this time is not an economical option due to fuel handling and boiler modifications that would be required.

THEC1&2, indicating that THEC3 requires significant investment for ongoing operations.

Table 5--Change in Power Supply Cost with THEC3 MATS Solution

Strategist Power Supply Cost 2013-2034 NPV ($ Millions)	THEC3 Base Case	THEC3 Multi-pollutant Retrofit	Customer Impact (Retrofit – Base Case)
Base Assumptions	$8,147	$8,209	$63
With CO_2 Regulation Penalty ($21.50/Ton in 2017)	$9,750	$9,811	$62

To determine if THEC3 remains a viable option for customer power supply or if a shutdown is needed due to the MATS Rule deadline, the environmental compliance alternative above was compared with an alternative to shut down the unit. A generating unit closure analysis is complex and includes many considerations including the remaining plant asset balance at the time of the closure, costs related to decommissioning the facility, and the impacts on the transmission system and socioeconomic impact on local communities. In this case, if one unit at a facility is shut down there are increased costs for the remaining two units, as not all facility-wide operating cost reductions can be taken as with a full facility shutdown. Staff is still required to conduct the remaining operations. THEC has been operating very efficiently with only 45 staff, so reductions would be minimal and the remaining operating costs would be spread over a smaller power production from just THEC1&2. Minnesota Power increased the costs associated with THEC1&2 in the THEC3 shutdown alternative to accurately reflect this dynamic. An increase in costs for a generating facility leads to a question of whether the viability of the remaining generating units are in jeopardy; therefore, Minnesota Power continued to evaluate THEC1&2 as it conducted its shutdown evaluation in its 2013 Plan.

Through the shutdown alternative comparison, Minnesota Power conducted a local transmission evaluation to determine the impacts of having THEC3 removed from the power system, and found that no reliability concerns would be created under current customer load outlooks (see Appendix F). However, when the entire THEC facility is removed (all three units) there are transmission reliability concerns, for which upgrades are required to ensure the electric service to Minnesota Power customers can be maintained.[42] Remaining plant asset balance and decommissioning requirements were

[42] Minnesota Power is not recommending the closure of the entire THEC facility; therefore, did not include additional transmission costs into the shutdown alternatives identified in the transmission evaluation.

included in the shutdown evaluation and assumptions for a ten-year recovery of these costs were included.[43]

While not included as a direct cost to the THEC shutdown alternative, Minnesota Power evaluated the socioeconomic impact on the local communities in conformance with the Commission's resource planning rules. A partnership with the University of Minnesota Duluth was established to leverage their expertise in evaluating the socioeconomic impact of a facility closure (see Appendix K). Their findings emphasized that Minnesota Power's generating facilities provide significant benefit to the communities and surrounding region through tax payments, employment and vendor utilization. If Minnesota Power were to close the THEC facility, the loss of 45 jobs and the associated support roles throughout the region would create a 2 percent increase in unemployment almost immediately for the area. Home prices could be expected to decline 6 percent as migration from the area increased as families leave to find new employment. Overall, the loss of revenue and wages would contribute to $14 million in loss each year for the area after the closure. As demonstrated during the baseload diversification study process and associated stakeholder outreach, Minnesota Power has been a trusted community partner for more than a decade and continues to consider these impacts of its electric service in a thoughtful way.

To ensure a robust analysis of the shutdown alternatives for this facility, the option to retire THEC3 and/or THEC1&2 was included in a system wide optimization evaluation in the Strategist Proview software. The shutdown alternative was considered with the rest of the power supply system and new resource alternatives. The evaluation identified that all three units should continue as coal-fired generation after the MATS compliance date and that shutdown was not an economic option for customers under Minnesota Power's base assumptions. However, when a carbon regulation penalty was applied to the evaluation, the scenario identified that THEC3 should be shutdown in 2015 before the MATS compliance date and prior to the need to invest in the retrofit alternative.

The carbon regulation penalty scenario further indicated that THEC1&2 should be considered for shutdown once a carbon regulation penalty is active, as the additional cost from the carbon penalty ($21.50/ton) under current industry outlooks makes these generating resources less economical for customers. Currently, there are no greenhouse gas regulation penalty provisions in place or pending. As Appendix E describes, there are other policy mechanisms that are helping to drive down carbon production and a penalty provision may not occur. At the same time, significant uncertainty remains on the outcome of greenhouse gas regulation. Minnesota Power is committed to continuing to reduce its carbon intensity and reduce emissions in-line with state goals.

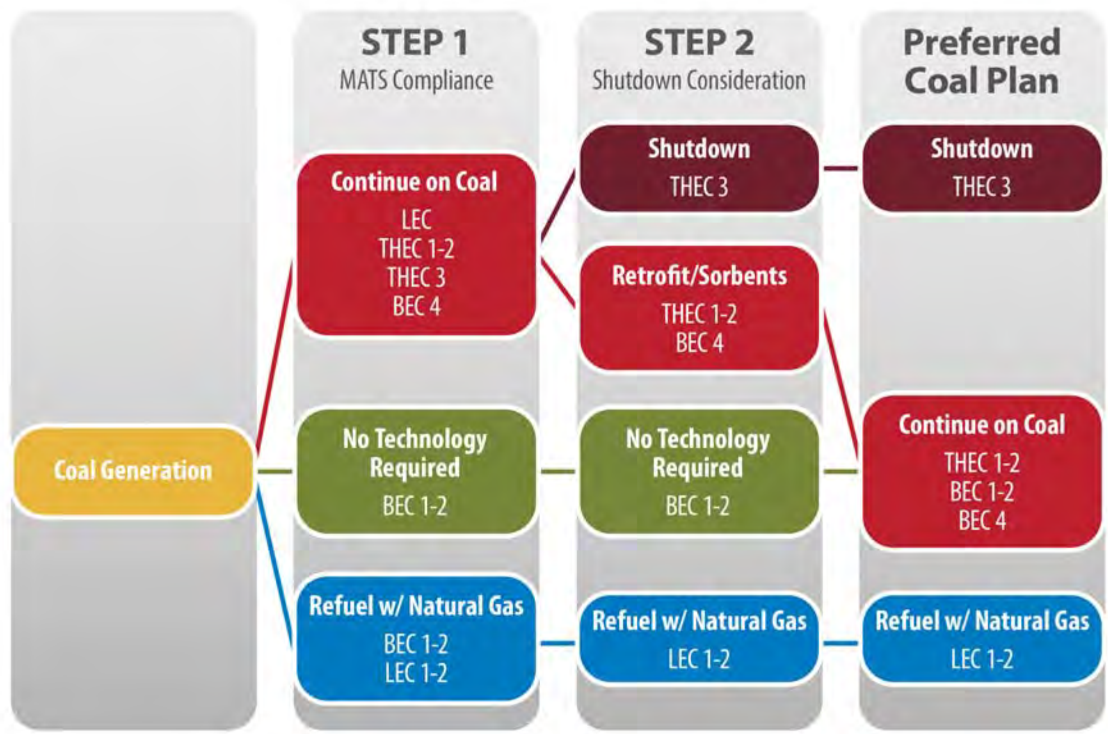
[43] The retirement mechanism for the remaining plant balance and decommissioning costs is based on the same methodology utilized in Minnesota Power's baseload diversification study and is included in Appendix H.

For its short-term action plan, Minnesota Power has identified that the investment in retrofit technology for THEC3 (approximately $60 million) would not be in the best interest of its customers. To protect affordability for customers in the near term and reduce emissions further in the region, Minnesota Power will proactively cease coal operation for the THEC3 75 MW generating resource by April 2015. This action will occur prior to the MATS compliance deadline and will avoid the $60 million cost in retrofit technology and associated annual O&M. The THEC3 equipment will physically remain in place at the THEC facility as it is tightly integrated into the current operations. Future utilization of the asset and its components can be considered in future planning and optimization of the THEC facility (see Appendix L). Minnesota Power will begin the MISO Attachment Y notification process in 2013 to confirm no additional regional transmission considerations will be needed before 2015. The THEC3 shutdown will reduce overall emissions, and specifically carbon emissions, by approximately 500,000 tons per year starting in 2015. Replacement for the capacity and energy that will be lost in 2015 is considered in Minnesota Power's expansion planning in Step 3 of this evaluation.

Minnesota Power recognizes that carbon policy is a key driver for the cost effectiveness of its thermal generating facilities and will continue to monitor through the resource planning process the evolving industry outlooks and key changes in environmental regulations. The shutdown evaluation for THEC1&2 identified that customer costs would be impacted by a large carbon penalty. Minnesota Power will include in its long-term action plan that it will continue operation of these two facilities and monitor THEC1&2 economics during the 2018-2027 time period to determine these units' competitive position. Taking action now to shut down these environmentally well controlled units that also have a minimal impact compliance plan for the MATS Rule would be a premature and reactive action to a speculative carbon regulation signal that is not yet in place or may not develop. By increasing customer costs unnecessarily without a carbon regulation, customers would lose the benefit of the recent investment in significant emission controls put into place at the facility as part of the AREA Plan and cause unnecessary negative socioeconomic impact to the host communities.

Conclusions for Small Coal

Minnesota Power has taken the necessary time since its baseload diversification study and the finalization of the MATS Rule to evaluate specific environmental compliance strategies for its coal-fired fleet. Under its most up-to-date outlooks and with engineering estimates taken into consideration, Minnesota Power is confident that its small coal strategy and action steps included in its Preferred Plan are the best path forward for customers. Utilizing least cost alternatives and protecting affordability, Minnesota Power will refuel LEC to natural gas, cease operations at THEC3 to proactively reduce emissions, and continue operation of its remaining coal-fired fleet (see Figure 15). This includes adding a key environmental retrofit to its largest resource, BEC4, and operating its coal-fired fleet as baseload resources for its customer power supply requirements as well as continuing to closely monitor resource viability of THEC1&2 in its long-term action plan.



Note: BEC3 has already been retrofitted with a multi-pollutant technology and does not require additional investment. Minnesota Power will continue to operate this unit as a coal-fired facility (see Appendix C).

Figure 15--Minnesota Power Preferred Plan for Coal-Fired Fleet

Recognizing that a wide range of plausible futures should be considered, Minnesota Power incorporated into its evaluation a comparison of the other key options available for compliance with the MATS Rule. The comparison will allow stakeholders to consider the impact of not only Minnesota Power's Preferred Coal Plan, but also three alternative paths for Minnesota Powers coal-fired facilities that include:

1. Retrofit all Minnesota Power's coal-fired facilities with needed emission reducing technology to meet the MATS Rule
2. Close Minnesota Power's LEC and THEC entirely
3. Implement Minnesota Power's Preferred Coal Plan and close THEC1&2

These alternative paths are illustrated in Figure 16.

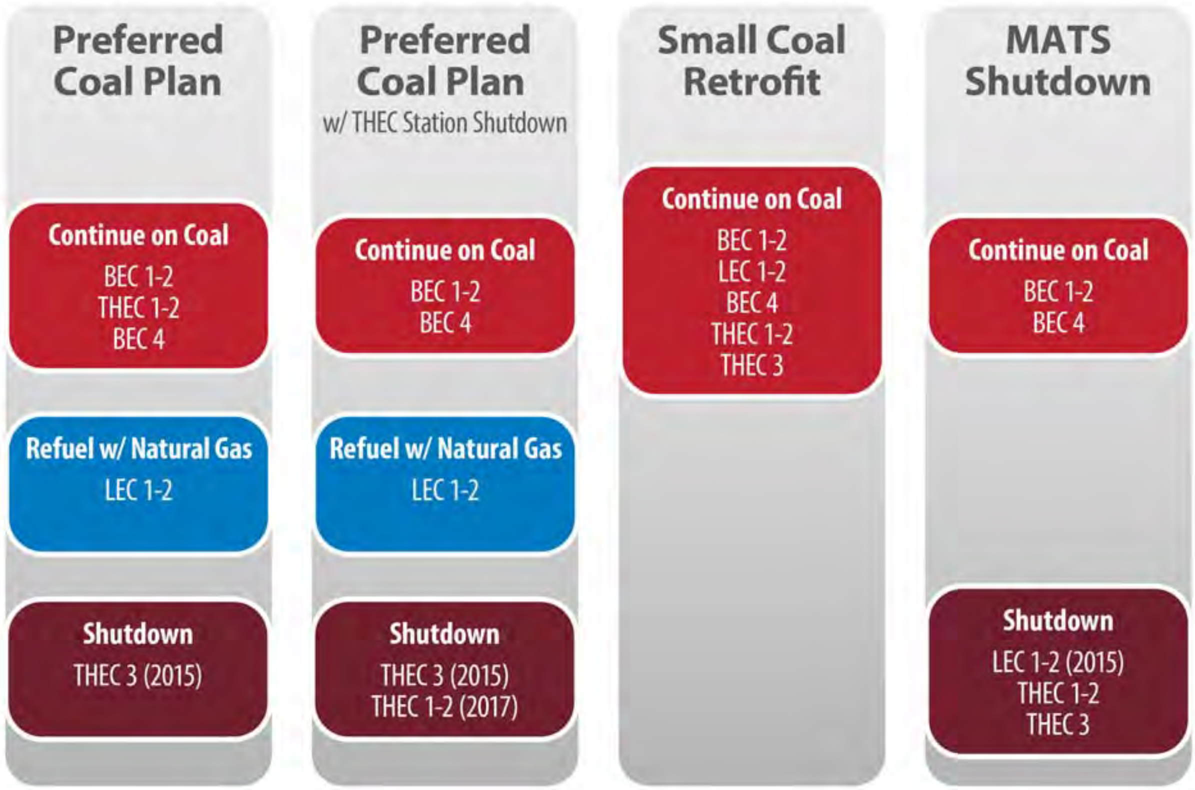


Figure 16--Coal Strategy for Preferred Plan and Three Alternative Swim Lanes

The Analysis and Insight section (see page 63) will compare and contrast these alternative outcomes for Minnesota Power's coal-fired fleet. First, expansion plans for additional resources that will augment the small coal plan must be considered in order to create Minnesota Power's complete Preferred Plan. These new resources are discussed in the next two sections.

Expansion Planning for New Generation Resources

Minnesota Power is considering many technologies to help serve its growing customer power requirements. Solar, wind, storage, biomass, traditional natural gas, and clean coal thermal generation are the major categories Minnesota Power is monitoring that are emerging and improving. Appendix I identifies how Minnesota Power screens available alternatives for its resource planning evaluation. For its 2013 Plan, Minnesota Power identified primarily wind and natural gas technologies (both small and large options) along with expanded DSM to best position the Company to meet its growing power supply needs.

This resource selection does not indicate that Minnesota Power has a position on any particular emerging technology. In many cases, the Company supports further advancement of developing technologies through regional studies and academic research as described in Appendix D, or through partnership on distributed generation projects as described in Appendix C. Resource options continually evolve, and for its 2013 Plan Minnesota Power utilized the lowest cost resources from each of the baseload, intermediate and peaking resource categories to help determine the best fit for its power supply needs. Further, the Commission requested as part of the outcome of the baseload diversification study specific consideration of wind and natural gas technologies and that Minnesota Power include in its 2013 IRP:

> *Scenarios that add 100 to 200 MW of wind capacity in the 2014-2016 time frame.*
>
> *Scenarios that add 400 to 600 MW of natural gas capacity in the 2014-2016 time frame.*

Minnesota Power utilized the Strategist Proview software for expansion planning. The software allows a utility to offer many resources into an evaluation and optimizes which technologies best fit to meet projected customer needs over a defined study period. Through its resource screening and the requested scenarios from the Department, Minnesota Power allowed the Strategist Proview software to select from the following resource options:[44]

i. 200 MW share of a natural gas fired 1x1 combined cycle
ii. 198 MW natural gas fired combustion turbine
iii. 55 MW natural gas fired reciprocating internal combustion engine
iv. 105 MW wind farm located in North Dakota.
v. 50 MW bilateral bridge transaction

Using this approach and the selected resource options ensured that Minnesota Power would meet the request of the Department and allow the optimization process to choose from the lowest cost resources. A DSM peak shaving program was also considered as a supply side resource (see Appendix B) and as a specific sensitivity evaluation which will be discussed later in the section.

Minnesota Power's Preferred Plan for its coal-fired generation results in approximately 70 MW less capacity resource available due to the closure of THEC3.[45] Minnesota Power's updated capacity resource position from Section III is included below and was the starting point for the expansion planning (Step 3) of the evaluation. Minnesota Power has less than 200 MW of capacity need for the majority of the 15-year planning period, most of which is required after 2020 as shown in Figure 17.

[44] Note that more than one of each resource option can be chosen during the optimization process.
[45] The full nameplate capability of THEC3 is 75 MW, however, due to transmission system constraints only 66 MW of capacity is possible from the unit.

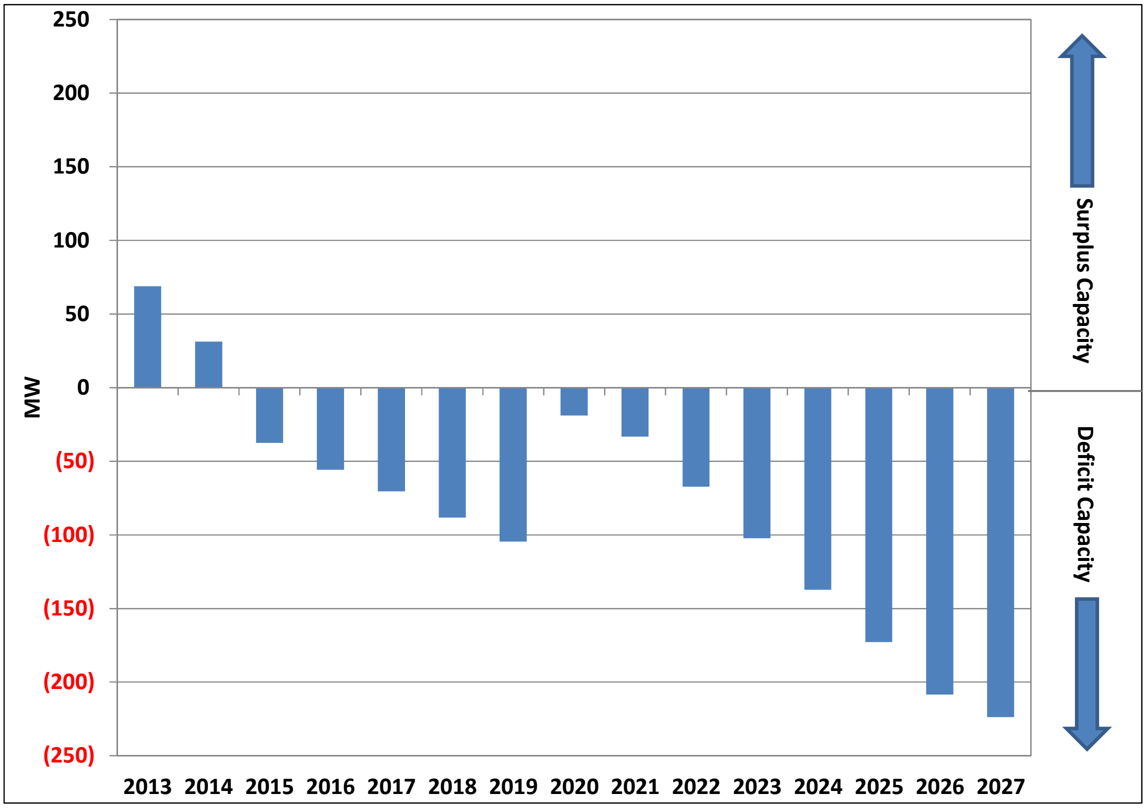


Figure 17--Updated Summer Season Capacity Position with preferred Coal Plan

The expansion plan optimization was conducted for two scenarios: 1) Minnesota Power's base assumptions (as defined in Appendix H) and 2) a carbon regulation penalty scenario where additional costs are placed on existing generating sources that emit CO_2 starting in 2017 of $21.50 per ton. The lowest cost power supply expansion plans are shown in Table 6 below.

Both expansion plans are very similar, identifying that in the short term wind and bilateral transactions are the most economic resource additions due to regional power market surpluses and the extension of the PTC for wind generation. The long-term expansion plan identifies that natural gas and additional wind would be beneficial if a carbon regulation penalty is enacted. The fact that these two expansion plans are similar, especially in the short term, provides confidence that these actions will be prudent in both a future with and without a carbon penalty regulation.

Table 6--Minnesota Power's Preferred Plan Resource Actions

	Preferred Plan	Preferred Plan *if CO_2 regulation implemented*
Short-Term (2013-2017) Actions		
Small Coal Shutdown/Refuel:		
Taconite Harbor 1-2		
Taconite Harbor 3	X	X
Laskin (Refuel to Gas)	X	X
Boswell 1-2		
Resource Additions:		
Combustion Turbine		
Combine Cycle (partial share)		
Reciprocating Engine		
Wind	X	X
Bilateral Bridge Transaction	X	X
Long-Term (2018-2027) Actions		
Small Coal Shutdowns:		
Taconite Harbor 1-2		
Taconite Harbor 3		
Laskin		
Boswell 1-2		
Resource Additions:		
Combustion Turbine		
Combine Cycle (partial share – 200 MW)	X	X
Reciprocating Engine		
Wind		X (2)
Strategist Power Supply Cost 2013-2034 NPV:	**$8.29 B**	**$9.73 B**

The expansion plan for the Preferred Plan also highlights the extreme difference in power supply costs that a carbon regulation penalty future could bring to customers. Over $1 billion dollars in cost is added to customers' power supply costs with essentially the same recommended power supply generation additions. As further described in Appendix E, the addition of a carbon regulation penalty does not always drive significantly different power supply outcomes and in many cases, unnecessarily increases costs of electric supply for customers.

Natural Gas

Minnesota Power has identified through both its baseload diversification study and now its 2013 Plan evaluation that natural gas technology is showing benefits for its long-term power supply diversification. The LEC refuel will provide Minnesota Power its first fully natural gas-fired unit in 2015 (110 MW) and provide valuable peaking generation and a MATS compliance solution for the facility. The 2020 and beyond time period in both expansion plans noted in Table 6, identified 200 MW natural gas additions to augment a growing customer base and renewable power supply. Natural gas fits well with intermittent generation like wind, as the technology is typically a flexible, fast acting resource that can be present to deliver energy when wind is not available. The expansion planning identified that an efficient and low cost natural gas product, such as a portion of a combined cycle ("CC") generating unit, should be considered over a combustion turbine ("CT"). Minnesota Power's high load factor and energy intensive customers gain value from generating resources that can produce efficient, low cost energy. It is important to note in this finding that a full sized 1x1 CC resource was not identified. This resource would have added over 400 MW of additional generation, much more than Minnesota Power's identified need in its base case outlook. The expansion plan demonstrates that a partial ownership share in a larger facility could provide benefit to customers over the smaller natural gas technologies; however, this will have to be carefully considered in the final stages of planning, as the CT technology is very close in size (200 MW) and could also be added to help meet Minnesota Power's long-term requirements.

Minnesota Power will conduct additional evaluation and planning for the specific size, type, location and timing of a new natural gas resource. As Minnesota Power's load growth materializes later this decade and as additional environmental regulations gain more certainty, Minnesota Power will be able to address the specifics of its next phase of natural gas strategy. Considerations will include procurement versus build options, transmission requirements, regional integration, and fuel procurement. The Company's long-term action plan identifies that Minnesota Power will advance its planning for a natural gas resource for the 2020 time period.

Wind Generation

Both expansion plans, with and without a carbon regulation penalty, identified the addition of wind generation in the pre-2020 timeframe. The extension of the PTC for wind in late 2012 was a late breaking development for consideration in Minnesota Power's 2013 Plan evaluation. With several unknowns of this PTC extension including the application and limitations, Minnesota Power, along with the rest of the industry, is still evaluating the full impact this will have on near term resource plans.

Minnesota Power's expansion plan under its base assumptions identified that 100 MW of additional wind could provide significant value for customers if the cost of the wind was below $50 per MWh with the PTC. This is a preliminary threshold and indicator utilized from the baseload diversification study.[46] Minnesota Power is already ahead of its implementation plan for meeting its renewable energy requirements for the state RES (see Appendix G) and it has done so economically to the benefit of its customers. However, the Company has identified that based on its projection for current load growth, additional renewable resources will be needed to meet the longer-term 2025 requirement of 25 percent. Consequently, Minnesota Power has identified a renewable strategy that includes the addition of 200 MW of high capacity factor wind energy similar to Minnesota Power's current Bison projects near Center, North Dakota to meet this requirement.

The expansion planning process identified that pursuing a minimum of 100 MW and up to 200 MW of low cost wind energy could have multiple benefits for Minnesota Power's customers. It could provide a least cost plan for meeting the 2025 RES requirement if it is possible to take advantage of the recent PTC extension.

A competitive request for proposal process will be initiated for up to 200 MW of wind as part of Minnesota Power's short-term action plan to determine what cost range is available for implementing additional wind on its system. If cost-effective and in the customers' interests, the Company will pursue Commission approval in the 2013-2014 timeframe to expand its supply portfolio with additional wind energy.

Bilateral Bridge Transactions

Another important component of a utility's power supply are contracted purchases and sales conducted within the industry to optimize the power surpluses and deficits that occur due to industry load and supply changes. These agreements are called bilateral transactions and they allow Minnesota Power to work with other entities to procure energy and capacity from existing resources (see Appendix C for a list of Minnesota Power's current bilateral transactions included in the Base Case).

A bilateral transaction is functionally different than the day-ahead regional energy and capacity markets represented by the MISO tariff construct. Bilateral transactions are typically forward, medium to longer-term contracts with defined pricing terms, while day-ahead markets operate in the 24-hour to 48-hour time frame with spot market prices (see Appendix H). Minnesota Power monitors the bilateral power markets to identify opportunities to contract with other entities when it is in the best interest of its customers. In the Preferred Plan, a short-term bilateral bridge purchase allows Minnesota Power to delay further investment in new generation resources until 2023. Around 2023, a 200 MW share of a CC resource is added in the Plan, providing significant savings to customers when compared to a wholly-owned resource while bilateral bridging agreements provide near term stability in power supply costs.

[46] Minnesota Power is still evaluating the full impact of the PTC extension and will engage in a request for proposal process to determine the wind costs for customers as part of its short-term action plan.

These bilateral purchases have a distinct role in meeting customers' energy needs and are not a standing approach to supplying customers in the long term. Rather, they are a distinct opportunity for very economical shorter-term (several year) energy supply given the current low demand for power in the wholesale energy market. This approach of using stably priced, bilateral purchases with strong counterparties for shorter-term power supply helps mitigate electricity requirements. It also allows for flexibility as large new customer loads materialize on Minnesota Power's system, given the wide range of load growth projections illustrated in the AFR2012.[47]

Demand Side Management

Minnesota Power currently has in place a significant amount of DSM capability (over 100 MW) on its system. Through its partnership with its Large Industrial Customers and its Dual Fuel Rate programs with its Residential and Commercial customers, these existing programs provide a valuable component of Minnesota Power's least cost supply strategy and help to ensure the reliability of the regional power system.

Minnesota Power is investigating additional demand response opportunities through the evaluation of a peak shaving program for air conditioning ("AC") customers. Minnesota Power's load forecast process (see Appendix A) identified an increasing trend in air conditioning saturation for its customers. Typically a winter peaking utility, Minnesota Power previously focused its residential and commercial demand response programs on electric heating characteristics of its load. However, with the emerging air conditioning use trend, an AC interruption program might benefit the power supply. Through a preliminary design process identified in Appendix B, Minnesota Power created an AC cycling program for consideration in its expansion planning.

Based on the AC peak shaving program design and the current projection of AC saturation on Minnesota Power's system, there is an estimated 7 MW available for this type of program by 2017. The net present value of the sample AC cycling program's costs is estimated to be $1,550/kW, as described in Appendix B. This is a higher cost resource option compared to other supply side alternatives Minnesota Power is utilizing in its expansion planning. Therefore, this demand side resource option was analyzed as a sensitivity and added to the Preferred Plan in the Strategist software in order to evaluate the cost and benefits of the AC cycling program.[48] Table 7 identifies the power supply costs with and without the AC cycling program and indicates that implementing this type of program under current outlooks would increase the cost to customers, rather

[47] As Minnesota Power has experienced in its past, surplus generating assets due to large industry cyclicality has wide-sweeping implications as was seen with the BEC4 commissioning (Docket No. E002, 015/PA-86-722). Minnesota Power believes a more paced resource addition strategy best serves its customers.

[48] If the demand side resource was added to the expansion planning optimization with other lower cost alternatives, it would be less likely for the option to be selected. Minnesota Power wanted to understand how a DSM peak shaving program would impact its power supply; therefore, it was analyzed as a sensitivity.

than reduce it. Due to the expected availability of lower cost capacity resources, the AC cycling program is not showing economic benefits at this time.

Table 7--AC cycling Program Sensitivity on Preferred Plan

	A Preferred Plan	B Preferred Plan w/ AC DSM Program	Customer Impact (B-A)
Strategist Power Supply Cost 2013-2034 NPV ($ Millions)	$8,288	$8,302	$13

The initial design and investigation of an AC cycling program is a good starting point for identifying beneficial DSM options for Minnesota Power's system. Along with a strong dedication to conservation, as demonstrated by its exceptional CIP performance, Minnesota Power has a significant amount of DSM capabilities developed through the longstanding commitment and relationships with its customers. Minnesota Power will continue to work to identify reasonable additions to its DSM programs that will most benefit customers.

Analysis and Insights - Comparison of Preferred Plan to Alternatives and Sensitivity Analysis

Minnesota Power considered its Preferred Plan plus three primary alternative paths for its coal-fired generation fleet to meet compliance with the MATS Rule as shown in Figure 16 on page 56. These paths also reflect the main alternatives expressed by external stakeholders:

1. Retrofit all Minnesota Power's coal-fired facilities with needed emission reducing technology to meet the MATS Rule
2. Close Minnesota Power's LEC and THEC entirely
3. Implement Minnesota Power's Preferred Coal Plan and close THEC1&2

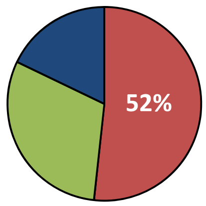
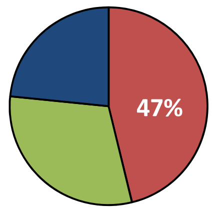
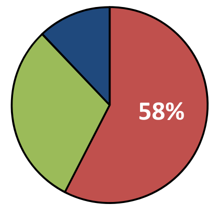
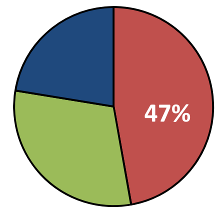
Minnesota Power wanted to verify whether or not these alternative paths, or swim lanes, were in the best interests of customers compared to the Preferred Plan and to further assess the benefits of its Preferred Plan for stakeholders. The three swim lane alternatives were first put through Minnesota Power's expansion planning process for direct comparison to the Preferred Plan. In this process, the least cost power supply additions were identified for each option (see Appendix I). The expansion plan for each alternative contains similar resource additions to Minnesota Power's Preferred Plan, demonstrating the resilient nature of Minnesota Power's short and long term action plans. These additions include:

- A 100 MW wind addition is made across all swim lanes, reflecting the benefit of the potential for reduced wind costs due to the PTC extension.

- With the exception of the Retrofit Small Coal Plan, all swim lanes utilize some amount of short-term bilateral bridge purchase, reflecting the benefit that economical short-term purchases provide to improving the timing of new generation additions.
- With the exception of the Retrofit Small Coal Plan, the next thermal generation resource alternative added is a 200 MW share of a CC facility, reflecting the benefit of additional efficient natural gas generation.

Table 8 provides an overview of each of the alternatives and gives the highlights of the initial Strategist evaluation for the options. The plans vary slightly in terms of generation mix and estimated emission reductions; however, the Preferred Plan is the lowest cost under the base assumptions utilized.

Table 8--Overview of Preferred Plan and Swim Lane Alternatives

Portfolio Name	Preferred Plan	Preferred Plan w/ THEC Station Shutdown	Small Coal Retrofit	MATS Shutdown
Energy Portfolio by 2027				
	Coal	Renewables	Natural Gas + Purchases	
2013 NPV of Plan Costs	$8.29 B	$8.35 B	$8.32 B	$8.41 B
Renewable: Installed Capacity & Contracts 2027 (MW)	989	989	989	989
Coal: Installed Capacity 2027 (MW)	1,095	962	1,262	962
Natural Gas: Installed Capacity 2027 (MW)	296	494	198	453
CO_2: Cumulative Reduction from 2013–2027 (Tons)	15.8 M	21.3 M	4.9 M	24.4 M
Mercury: Cumulative Reduction from 2013–2027 (lbs.)	4,259	4,356	4,093	4,396
Other Emissions: Cumulative Reduction from 2013–2027 (Tons)	107,400	128,100	88,400	134,400

Each swim lane alternative and the Preferred Plan were then put through a series of 21sensitivities that stressed the main drivers for resource decisions including fuel, capital, additional EPA regulation and carbon sensitivities. The sensitivities help determine whether the Preferred Plan and its resource actions would be the best option for customers if these drivers were to vary from the current base case outlooks.

The Preferred Plan provided the low cost power supply in over 50 percent of the sensitivities considered. The Preferred Plan represents a diverse generation portfolio fuel mix that allows flexibility for Minnesota Power to take advantage of changing fuel cost and/or carbon regulation trends in the future. Only an extreme drop in natural gas prices from the expected forecast or a carbon regulation penalty would favor a THEC facility shutdown along with the Preferred Plan. Minnesota Power considers an extreme drop in natural gas that is sustained for the long term unlikely given the current outlooks. Minnesota Power identified that THEC1&2 have no additional environmental capital requirements to meet the MATS Rule. This will keep future closure costs lower and provide the Company more flexibility when determining options for this facility if new regulations arise.

ensitivity Analysis: 2013 NPV of Alternative Cost with Sensitivities ($millions)

ties	Preferred Plan	Preferred Plan w/ THEC Station Shutdown	Retrofit Small Coal	MATS Shutdown
sumption	$8,288	$8,349	$8,318	$8,409
pital Cost (-30%)	$8,214	$8,213	$8,268	$8,242
pital Cost (+30%)	$8,455	$8,577	$8,460	$8,668
nalty $9/ton	$8,796	$8,835	$8,852	$8,890
nalty $21.50/ton	$9,733	$9,715	$9,861	$9,764
nalty $34/ton	$10,648	$10,574	$10,849	$10,620
l Forecast (-30%)	$7,650	$7,775	$7,596	$7,848
al Forecast (+30%)	$8,901	$8,910	$9,011	$8,959
mass (-10%)	$8,275	$8,336	$8,305	$8,396
mass (+10%)	$8,301	$8,361	$8,331	$8,422
atural Gas (-50%)	$8,032	$7,977	$8,187	$8,023
ural Gas (-25%)	$8,165	$8,184	$8,256	$8,234
tural Gas (+25%)	$8,396	$8,489	$8,388	$8,567
latural Gas (+50%)	$8,496	$8,601	$8,454	$8,701
ernality Values	$8,054	$8,124	$8,064	$8,190
ernality Values	$8,523	$8,574	$8,572	$8,629
olesale Market (-50%)	$7,868	$7,906	$7,951	$7,988
olesale Market (+50%)	$8,566	$8,629	$8,562	$8,680
lesale Market	$8,487	$8,456	$8,462	$8,536
lesale Mkt w/CO2 Penalty $21.50/ton	$9,962	$9,853	$10,059	$9,921
l Program	$8,302	$8,364	$8,333	$8,423
al Environmental Regulations	$8,456	$8,503	$8,509	$8,563
nt	**12 plans**	**6 plans**	**4 plans**	**Zero plans**

ding in Table 9 indicates the lowest cost alternative.

The MATS shutdown swim lane, which assumes a shutdown at both the LEC and THEC facilities, is not identified as the lowest cost option under any of the 21 sensitivities. In addition, the socioeconomic impacts that unit closures would have on communities is negative. According to initial evaluation, the two communities would see a total of approximately $28 million in loss of revenue and wages each year after shutdown, as well as a loss of up to 200 jobs. See Appendix K for additional details on the socioeconomic impact of unit closures Minnesota Power considered in this analysis.

The potential for additional EPA regulations was considered as a sensitivity to include costs for the coal ash residual and steam effluent guidelines currently being contemplated (see Appendix E). This sensitivity added costs to each generation facility under the current expectation for the rules. As Table 9 identifies, the Preferred Plan continues to be the lowest cost alternative for customers when compared to the other swim lane options.

Minnesota Power's customers would see unnecessarily increased costs if the Company were to take action in its Preferred Plan to protect against only a chance of extremely low natural gas prices or a mid to high carbon regulation penalty. Minnesota Power will have the flexibility through its ongoing resource planning process with the Commission and its stakeholders to consider alternate actions if these outcomes were to unfold in future resource plan cycles.

The sensitivities and consideration of the swim lane alternatives help solidify that the Preferred Plan will meet its goal to balance improving environmental performance, preserving reliability and protecting affordability for customers.

Characteristics of Minnesota Power's Preferred Plan

The Preferred Plan continues the transition of Minnesota Power's fleet to become more diverse, more flexible and less emitting. To accomplish this, the Company is taking major steps that address a changing energy business environment and responding to the Commission's Orders in the 2010 Plan Docket. The Preferred Plan implements both capacity and energy resource changes that will provide a more balanced supply portfolio with the least cost for customers reaching 50 percent coal-fired generation by 2027. The 2013 Plan will move Minnesota Power toward its *Energy**Forward*** resource strategy and a supply that is made up of a third renewable, a third coal-fired, and a third natural gas and purchases over the long term. It protects affordability, preserves reliability and sustains environmental stewardship.

Figures 18 and 19 demonstrate the resulting capacity and energy position of the Preferred Plan. The 2013 Plan reduces coal-fired generation by 20 percent and doubles renewables and introduces natural gas to meet the projected load growth in the planning period.

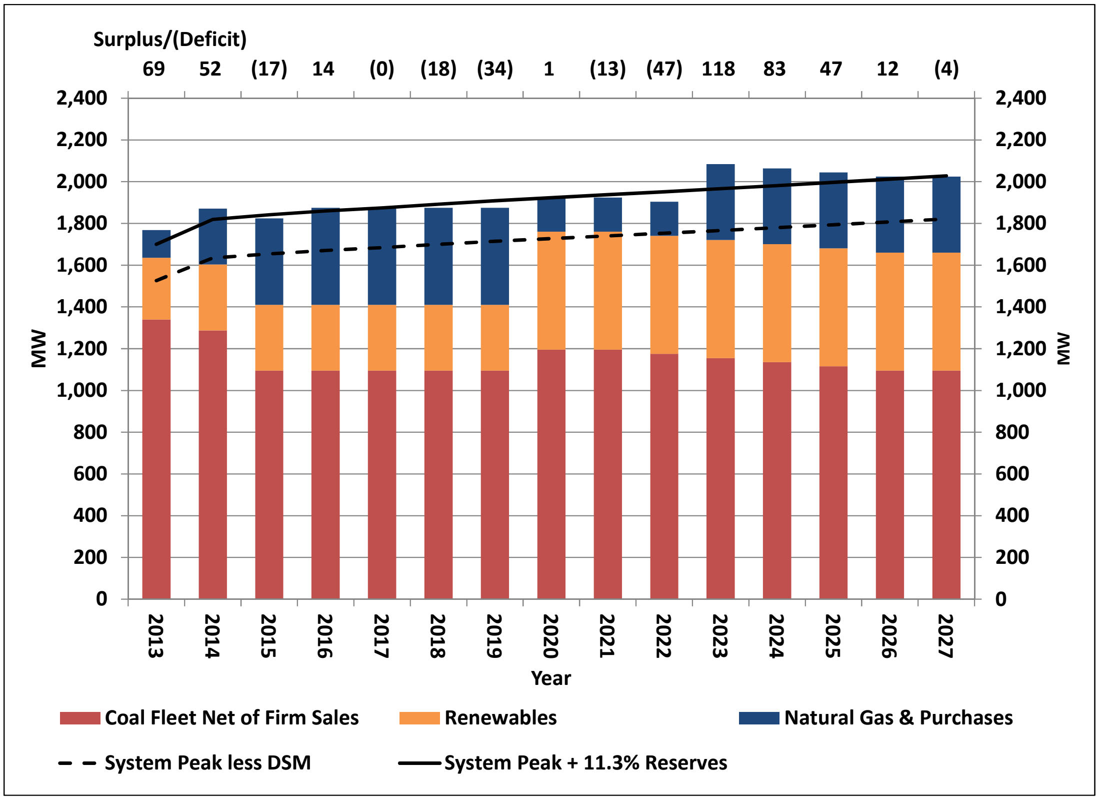


Figure 18--Preferred Plan Summer Season Capacity Outlook

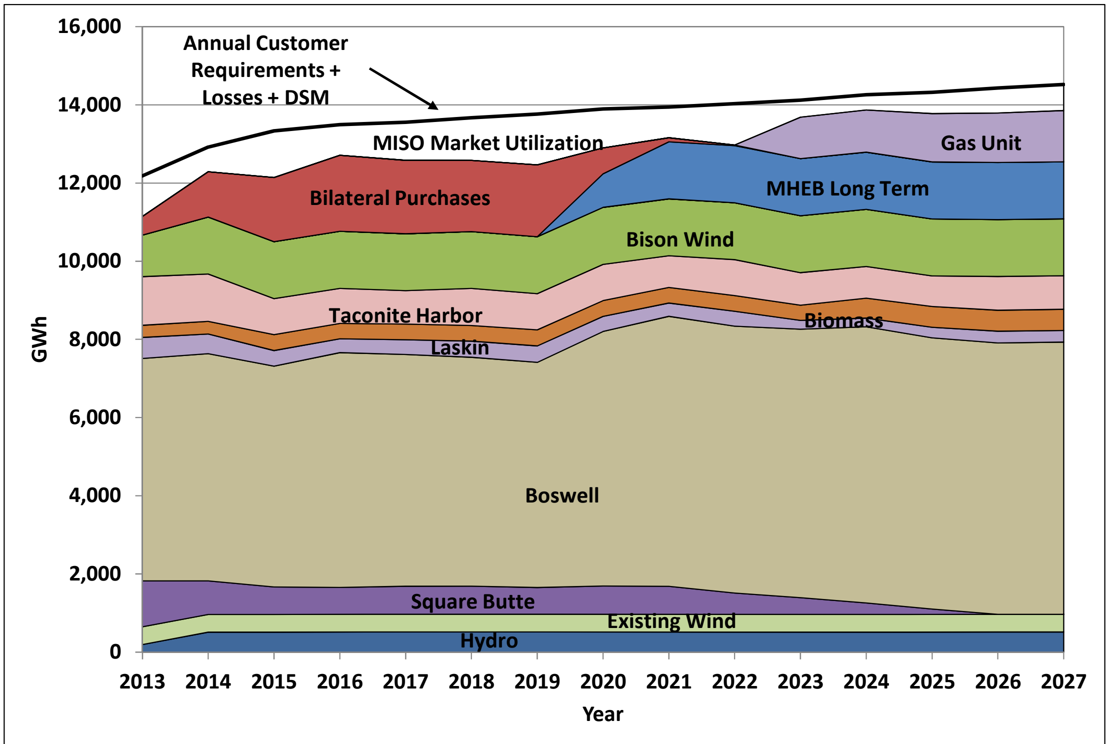


Figure 19--Preferred Plan Energy Position Outlook[49]

The Preferred Plan will add environmental benefits and help ensure rate stability for customers. The environmental compliance strategy included in the Preferred Plan to meet the upcoming MATS Rule will ensure Minnesota Power's fleet is prepared to meet the 2015 requirements in a reasonable manner for customers. Minnesota Power will achieve immense environmental reductions with the implementation of its Preferred Plan - over 75 percent reductions in overall emissions and over 80 percent for key air effluents like SO_2 and mercury (see Figure 20).

[49] This energy position represents the full capability of energy sources in Minnesota Power's Preferred Plan. Actual dispatch will vary in real time operations.

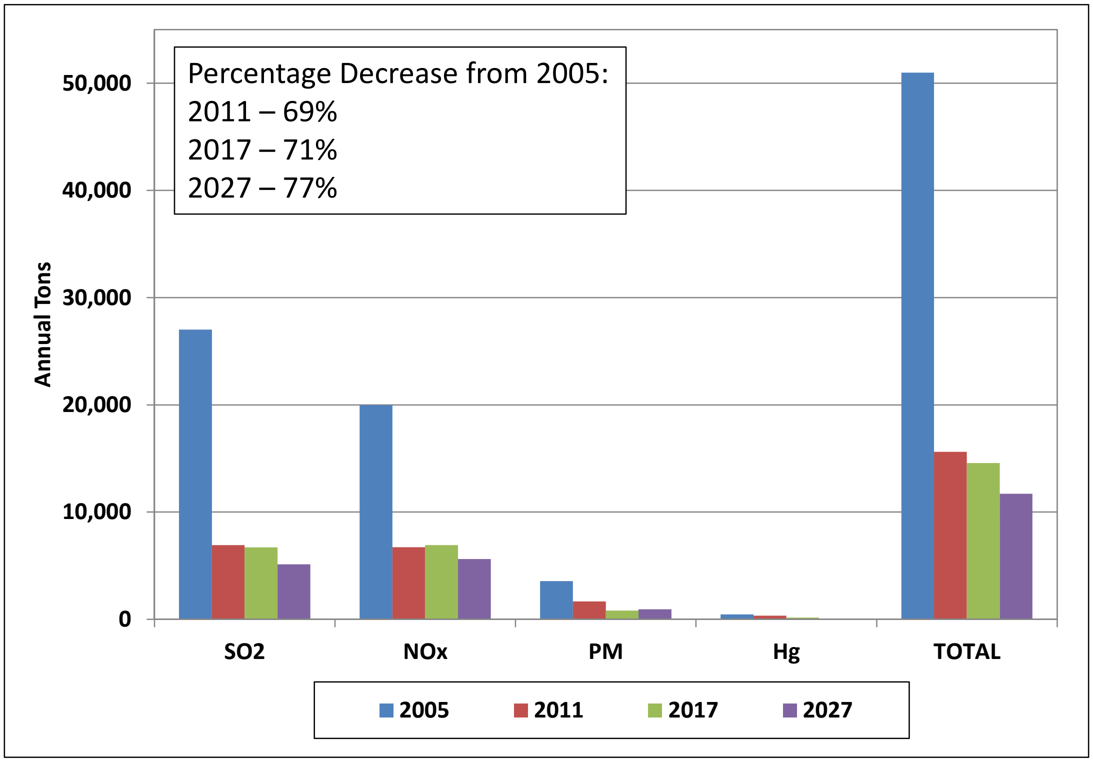


Figure 20--Emission Reductions Achieved and Projected with Preferred Plan

The most dramatic results of emission reduction will be with mercury. Minnesota Power's investment in mercury reductions since 2005 on its coal-fired facilities will contribute to Minnesota's power utilities being cited as the lowest source contributor to mercury in Minnesota by 2016.[50] Figure 21 includes the projected mercury reductions on Minnesota Power's system due to actions of its Preferred Plan.

[50] Letter dated February 11, 2013, from the Minnesota Pollution Control Agency addressing mercury emissions.

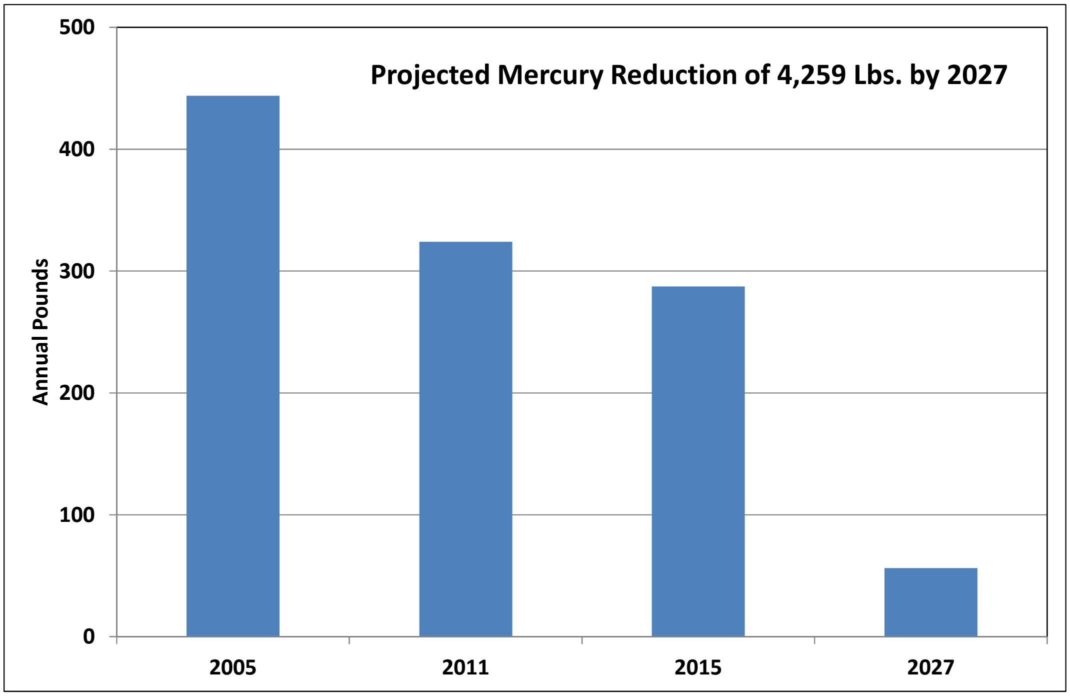


Figure 21--Mercury Emission Reductions Achieved and Projected with Preferred Plan

Minnesota Power has committed since 2005 to add only carbon-minimizing resources to its generation fleet. As load continues to grow, Minnesota Power has kept to this strategy and is continually reducing the carbon intensity of its power supply. Over 1,100 MW of generation reshaping will take place for Minnesota Power's supply portfolio by 2027: adding renewable energy such as wind (over 500 MW) and Manitoba Hydro hydroelectric power (250 MW), reducing coal-fired generation where prudent as through the phase out of its power purchase from Young 2 (227 MW), refueling LEC (110 MW) with natural gas and closing THEC3 (75 MW). This represents a significant transformation for a utility with a current peak demand of about 1,800 MW.

Figure 22 identities how the Company's Preferred Plan will help ensure its power supply is not only on track to meet the Minnesota state goals for greenhouse gas reduction, but will exceed the 2015 goal of a 15 percent reduction from 2005 levels. At the same time, Minnesota Power is planning for its largest growth in industrial customers since the late1970s. Minnesota Power remains committed to taking appropriate greenhouse gas actions as it makes its power supply decisions. To meet the long-term emission reduction goals of the state,[51] the Company will evaluate additional resource actions in the post-2020 time period as environmental regulations continue to evolve and gain clarity. Minnesota Power's cumulative resource actions, including those in the Preferred Plan, will reduce greenhouse gases by 30 percent in the 2005 to 2015 time period. This will be accomplished while concurrently serving a 20

[51] Minnesota's Next Generation Energy Act of 2007 measures set a goal for greenhouse gas emission reductions staging a 15 percent reduction in carbon dioxide equivalent emissions from all sources by 2015, 30 percent by 2025 and 80 percent by 2050 (see Minn. Stat. § 216H.02, Subd. 1).

percent increase in customer load requirements and maintaining competitive rates over the same period.

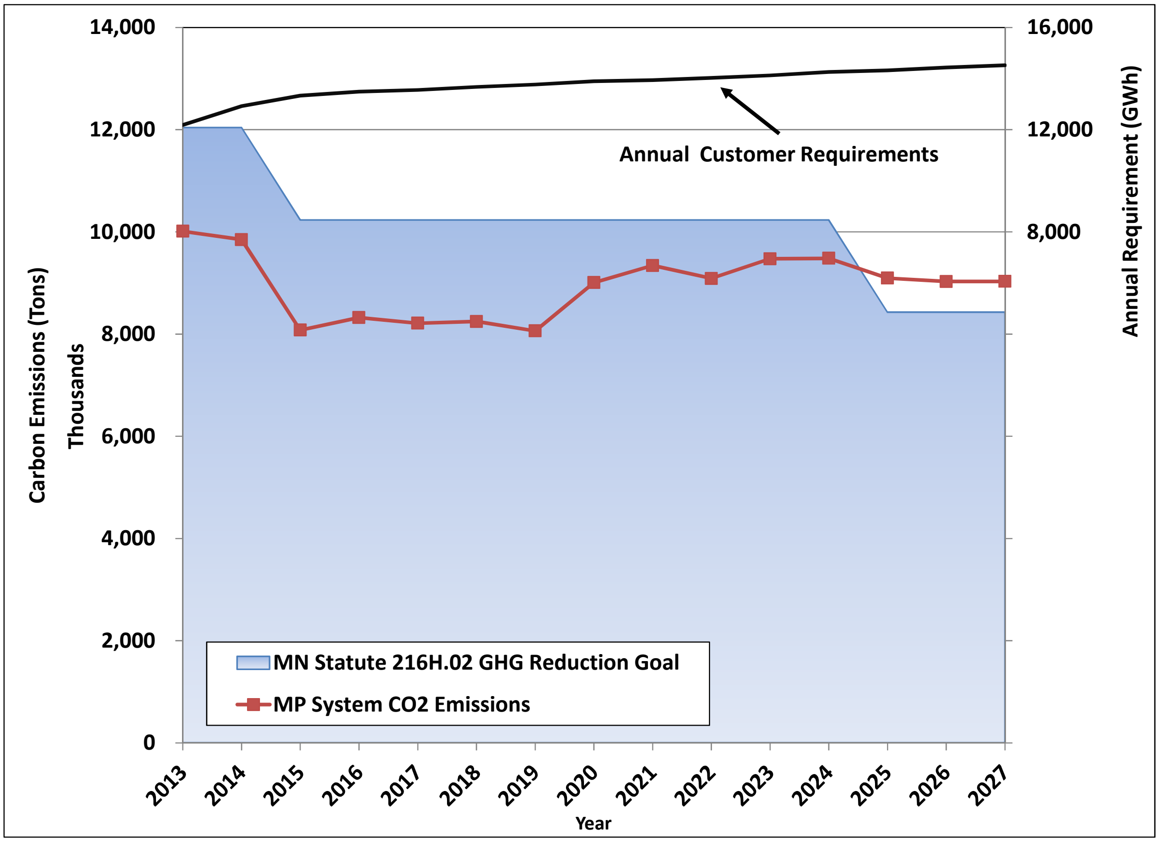


Figure 22--Greenhouse Emission Reductions Achieved with Preferred Plan

Minnesota Power was asked in Order Point 5.f. of the Commission's May 6, 2011, 2010 Plan Order[52] to include a "cost impact analysis by customer class" in its next resource plan. This analysis would help stakeholders identify how the proposed power supply actions could potentially impact their electricity costs into the future.[53] Minnesota Power worked diligently to identify the most efficient way of translating the forward-looking cost projections into an estimate for each customer class. Appendix J describes the methodology used to develop the calculations and includes projected customer cost detail for the Preferred Plan and swim lane alternatives.

For purposes of this analysis, the terms "cost impact" and "rate impact" are assumed to have the same meaning. However, the estimated rate impacts may not correspond with actual rates that the Commission sets for various rate classes in the future. In addition, numerous simplifying assumptions have been made in both the calculation methodology and the input variables, and these assumptions naturally cause imprecision in the estimates. Long-term resource planning is inherently uncertain, rather

[52] Docket E-015/RP-09-1088
[53] Minnesota Power utilized a five-year forward look for the rate impact estimation, as further projection would carry a significant level of uncertainty and be less meaningful for customers.

directional, and therefore causes additional uncertainty in these resulting rate impacts projections.

Power supply costs have inherently been increasing across the industry as new requirements and infrastructure are being incorporated. Minnesota Power has been diligent in its effort to protect affordability for its customers and has maintained some of the lowest electricity rates in the nation.[54] The Preferred Plan was evaluated to determine the potential future impact on average retail rates. The results indicate that future cost increases through 2017 would trend similar to the cost increases in its recent history. Implementation of the Preferred Plan is not indicating a dramatic shift in rates as can be the case during significant transformations. Figure 23 plots the recent average retail rates and identifies that an average 4.6 percent annual increase would be plausible if perfect ratemaking were to take place in the next five-year timeframe.

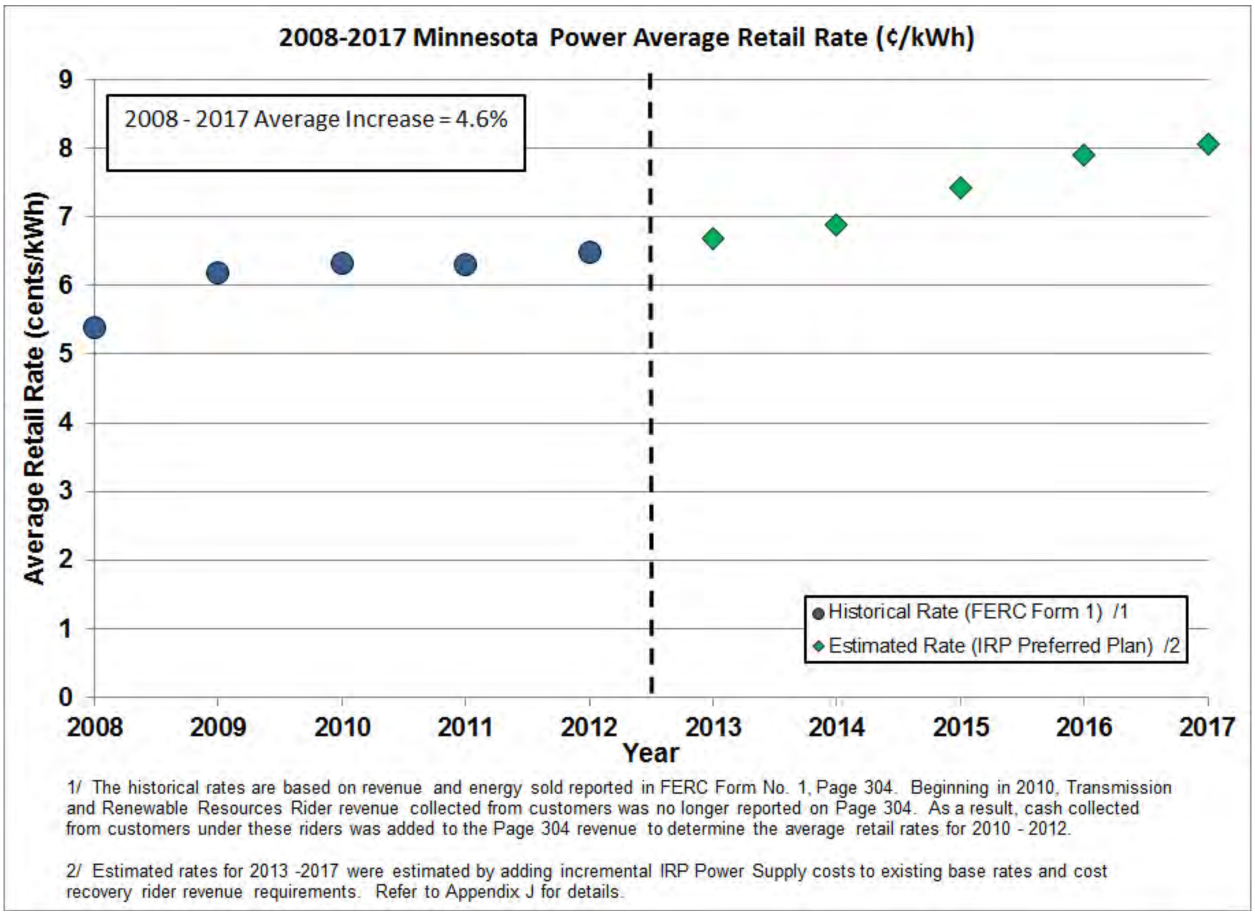


Figure 23--Average Retail Rate Recent History and Outlook with Preferred Plan

To gain more granularity and meet the intent of the Commission request, the rate impacts were estimated by customer class for the 2013-2017 time period (see

[54] Minnesota Power has most recently been noted as having the fourth lowest electricity rates out of 169 utilities by the Edison Electric Institute and second lowest in the region consisting of Iowa, Kansas, Minnesota, Missouri, North Dakota, South Dakota and Wisconsin.

Appendix J). As new resources are added as part of the Preferred Plan there are year-to-year fluctuations in costs. The resulting 2017 increases (compounded from 2013 levels) are identified in Figure 24 along with an estimate of the average customer impact per month in each class.

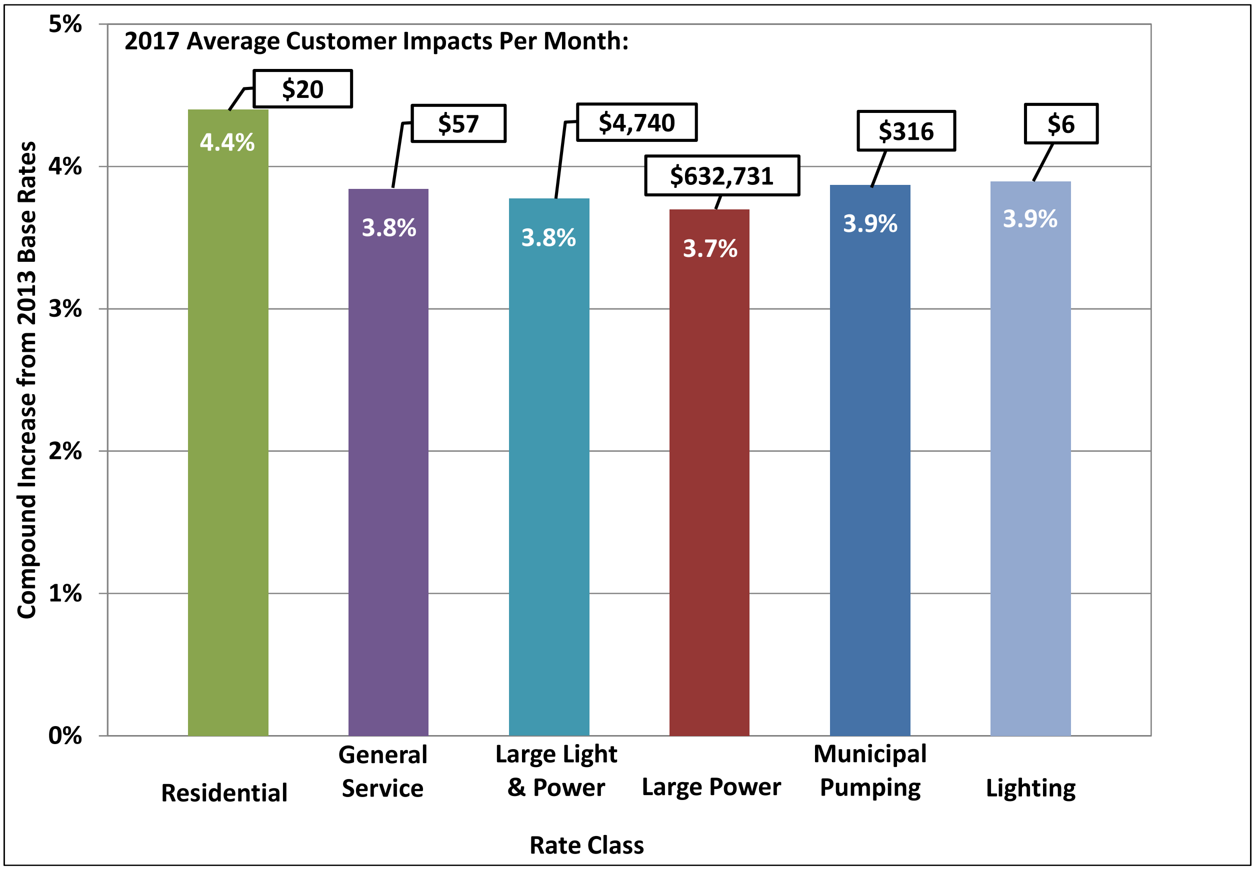


Figure 24--Estimated Rate Impact Outlook by Customer Class

Minnesota Power gained interesting insights when it incorporated the Preferred Plan under the scenario with the $21.50/ton carbon regulation penalty starting in 2017 into the rate impact evaluation. The rate impact outlook for this scenario is dramatic and immediate in 2017 for customers when the carbon regulation penalty is added. Figure 25 identifies that the average customer increase in 2017 would more than double if a carbon penalty was assumed. As identified above in Minnesota Power's expansion planning, there are almost no differences in the resource additions that Minnesota Power would make for its 2013 Plan under the carbon regulation scenario; however, there was over $1 billion in additional power supply costs under the scenario. Therefore, these cost increases, as shown by customer class in Figure 25, would be due to the burden of the additional carbon penalty on power supply costs.

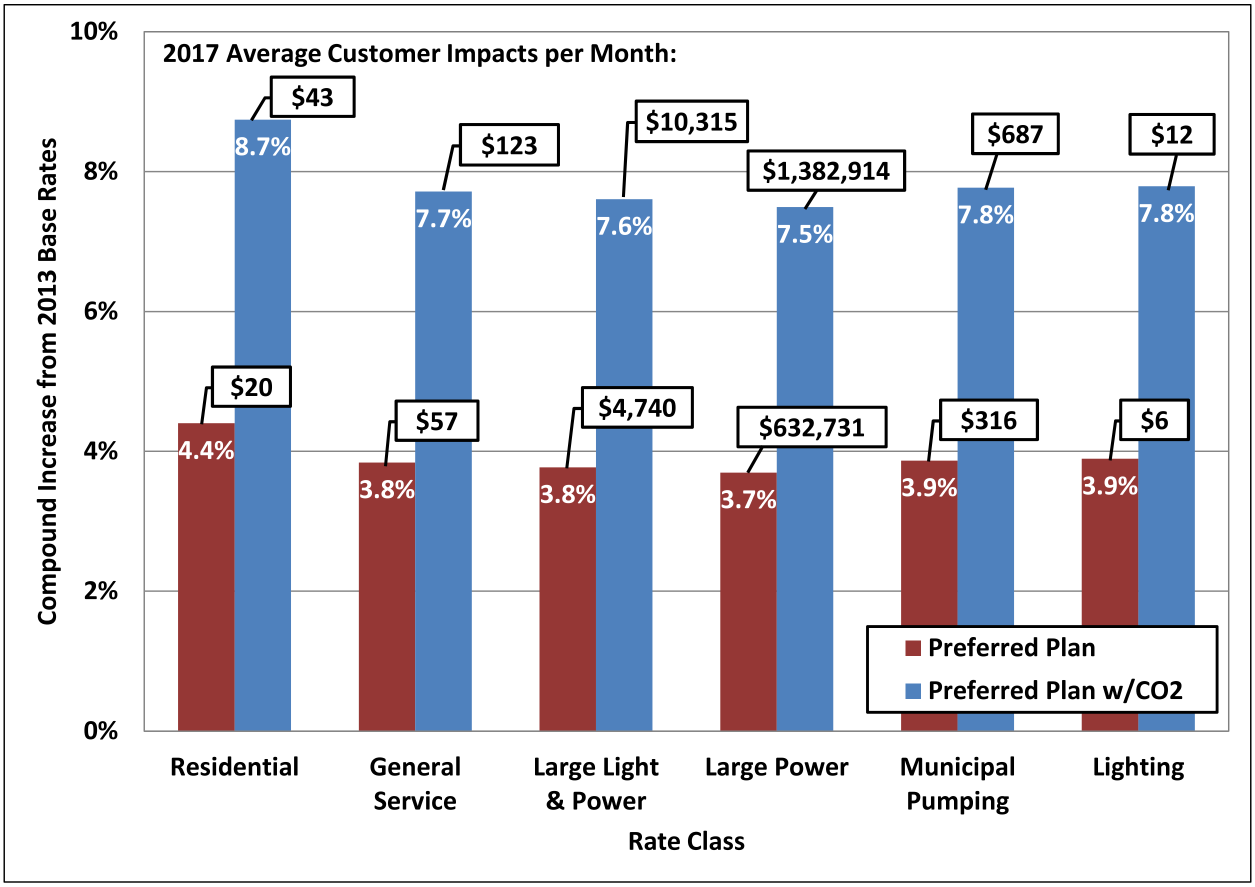


Figure 25--Estimated Rate Impact Outlook by Customer Class with Carbon Penalty

Minnesota Power continues to incorporate the power supply actions needed to reshape and transform its electric supply at reasonable customer costs. These actions are driven in part by Minnesota's RES, Conservation Improvement Plans and the Next Generation Energy Act of 2007. The actions taken to meet these standards are creating meaningful change on the power system and creating emission reductions that are outperforming even national goals (see Appendix E). At the same time, under this environment, Minnesota Power continues to carefully and prudently evaluate its system and protect affordability for customers.

The current Commission requirement to consider a carbon regulation penalty in 2017 in its resource planning evaluation is a speculative cost increase projection for Minnesota customers. Until a carbon regulation penalty is determined at the national or state level, impeding resource plans with an assumed carbon price penalty and taking premature actions that could increase costs to Minnesota electric consumers for speculative reasons without delivering commensurate environmental benefits.

V. Short-term Action Plan

Minnesota Power considered potential environmental and economic futures along with its sales forecast outlook to develop a resource plan that creates a more flexible and diverse power supply, while balancing cost, reliability and environmental impact for customers. The 2013 Plan continues the transformation of the Company's resource base by investing in renewable generation, adding natural gas to its fuels portfolio, installing more emissions-control technology at its core, coal-fired baseload generating facilities, and maintaining its strong energy conservation and DSM programs. Supported by the information and analysis in the appendices of this Plan, the resulting action plan outlined in the following sections identifies both short and long term measures that will help Minnesota Power continue to meet stakeholder needs in the near term and be poised to deliver safe and reliable service at the lowest possible cost to customers for many years.

Plans to Meet Short-term Need (2013-2017)

Minnesota Power's short-term action plan during the five-year period of 2013 through 2017 is comprised of steps that will: a) preserve competitive base load generating resources while reducing emissions, b) continue implementation of least cost demand side resources including conservation, c) reduce reliance on coal-fired generation, and d) add renewable energy and transmission infrastructure to the benefit of customers. The specific strategic and necessary actions to achieve these steps include:

1. Reducing emissions associated with converting coal energy to electricity through a series of actions that assures environmental compliance and a sound energy supply for customers. Minnesota Power has identified that LEC and THEC3 (185 MW) are not cost effective to retrofit with additional environmental controls. LEC will become a gas peaking station; THEC3 will be retired. The Company also has confirmed a robust plan to retrofit BEC4, its largest generating unit (585 MW).

2. Minimize short-term rate impacts for customers while meeting increased demand for electricity, as the northeast Minnesota economy is forecasted to grow in the next several years, by taking advantage of a lower cost power market. Minnesota Power plans to use economical, bilateral market purchases to flexibly help bridge needs in the period between 2014 and 2020, as it continues to examine its load projections and adapts to the ultimate timing of new large industrial loads on its system as well as any significant downward business cycles that may affect demand from existing large industrial customers.

3. Continue optimization of Minnesota Power's renewable energy supply. With over 400 MW of competitive wind projects already present in its portfolio, Minnesota Power is ahead of its RES requirements and is closely monitoring the need for additional intermittent renewable energy. With the extension of

the PTC, Minnesota Power will solicit a request for proposal for a minimum of 100 MW and up to 200 MW of competitive wind to be installed in the next two to three years, plans subject to maximizing the benefit of the PTC for customers.

4. Consider enhancements to selected CIP and DSM programs, while continuing to apply best practices from the conservation industry and developing leading-edge programs. Minnesota Power has maintained a strong record of conservation performance and been a state leader in meeting the Minnesota 1.5 percent energy savings conservation standard. Along with this strong dedication to conservation, Minnesota Power will continue to work to identify reasonable additions to its DSM programs where it is most beneficial for customers.

5. Prepare Minnesota Power's transmission system for the longer term addition of new power supply resources. The Company will, subject to Commission approval, begin implementation of the Great Northern Transmission Line to deliver its approved 250 MW energy purchase from Manitoba Hydro for the term 2020-2034 (a critical element of Minnesota Power's long-term action plan). The Certificate of Need will be initiated in 2013 as part of project development.

6. Complete its 2013 Load Research study Advanced Metering Infrastructure Project to better understand customer energy use, providing a robust basis for future customer conservation projects and sound rate design.

7. Execute an industrial distributed generation/renewable project at REC and continue to explore energy efficiency distributed generation projects with large customers. Additionally, Minnesota Power will develop a fair, equitable and customer-facing distributed generation program that best leverages unique customer and regional attributes to deliver valued and cost effective energy solutions for customers.

8. Continue fleet maintenance programs to sustain the economic viability, availability and reliability of Minnesota Power's generating units. A continuing Company priority throughout this planning period will be to carefully maintain its generation fleet to ensure productivity and efficiency in operation. A rigorous process is in place to sustain existing production across Minnesota Power's wind-water-wood-coal sources of energy conversion while maintaining an excellent environmental record and meeting more stringent environmental standards.

9. Continue participation in M-RETS as provide for by the Commission's October 9, 2007 Order,[55] as well as establishing a program and protocols for

[55] Docket No. E999/CI-04-1616

tradable, renewable energy credits.[56] Minnesota Power will leverage the value of renewable energy credits that the M-RETS program certifies to deliver RES compliance in Minnesota at the lowest possible cost to customers. Minnesota Power will utilize renewable energy credits generated across the years in order to optimally meet the 25 percent RES by 2025.

Three Key Contingencies

The planning process and analysis discussed in this Plan allowed Minnesota Power to consider several sensitivities that address the uncertainty that is present with the state of the economy and environmental compliance policy. Each sensitivity evaluated gave Minnesota Power the insight needed to be prepared for the potential paths each of these can take in the near term. Three key contingencies that Minnesota Power will continue to monitor and anticipated implications of these contingencies are:

1. *Extensive customer load additions or expansions do not materialize in the short term.* Minnesota Power would have excess capacity after its supply side action plan and will consider making commitments for long-term power sales to mitigate the effect of the unrealized customer load. This is made easier with Minnesota Power's plan to utilize the bilateral power market rather than a large new resource investment to optimize the power supply costs while integrating the new customer load.
2. *Carbon regulation policy implementation is expedited on a national level for existing generating resources.* Minnesota Power would accelerate its long-term actions to reduce carbon and consider the addition of new carbon minimizing generation resources and/or secure additional bilateral purchases until a resource could be placed into service.
3. *Economic recession or industry contraction.* If the recession re-emerges or key industries are forced under additional economic pressure impacting our largest customers, Minnesota Power will have significant amounts of excess capacity and will consider making commitments for power sales to mitigate the effect of the reduced customer load.

Minnesota Power will continue to closely monitor the economic and environmental control outlooks and evaluate its short-term action plan as the landscape unfolds to ensure that customers and stakeholders are served in a reliable and forward-looking way during the planning period.

[56] Docket Nos. E999/CI-04-1616 and E999/CI-03-869

VI. Long-term Action Plan

Plans to Meet Long-term Need (2018-2027)

Minnesota Power will focus its long-term plan on a strategy to further reduce carbon emissions in its portfolio and diversify its generation mix towards a balance of approximately one-third renewable resources, one-third natural gas/other, and one-third efficient coal-fired generation. This long-term strategy will position Minnesota Power to be able to successfully adapt to a range of economic and environmental futures while maintaining service to its customers at a competitive cost. Each component of this long-term plan has been proven through the planning process analysis to be flexible and robust to proceed towards the Company's strategic resource goals in a variety of future scenarios. Planned components include:

1. Continue implementation of the 250 MW Manitoba Hydro PPA and Great Northern Transmission Line in the 2020 timeframe (250 MW).
2. Optimize the timing of implementing the remaining renewable projects to meet the state renewable energy standard by 2025.
3. Investigate opportunities to further diversify Minnesota Power's power supply including, further reducing reliance on coal-based generation. Minnesota Power will continue to closely assess THEC1&2 economics during this period to determine these units' competitive position within the fleet.
4. Begin investigation of an intermediate natural gas generation resource for Minnesota Power's generation fleet to meet expected capacity and energy needs in the 2020 timeframe.