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Susan Ludwig
Policy Manager
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PUBLIC DOCUMENT
TRADE SECRET DATA
HAS BEEN EXCISED

July 3, 2014

VIA ELECTRONIC 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 the Petition of Minnesota Power for Approval of Investments and Expenditures in the Thomson Project for Recovery through Minnesota Power's Renewable Resources Rider under Minn. Stat. § 216B.1645
Docket No. E015/M-14___

Minnesota Power ("the Company") is pleased to present this Petition to the Minnesota Public Utilities Commission ("Commission") for approval for investments, expenditures and costs for a hydroelectric restoration project ("Thomson Project") at Minnesota Power's Thomson Hydroelectric Development ("Thomson"), pursuant to Minn. Stat. § 216B.1645 and Minn. Rules 7829.1300.

On June 19 and 20, 2012, record rainfall and flooding occurred in Duluth, Minnesota and surrounding areas. The flooding severely damaged Minnesota Power's St. Louis River hydroelectric system and particularly the Thomson facility, which was forced offline due to damage to the forebay canal and flooding at the facility. Thomson has been out of service since the flood.

The Company has been working with the Federal Energy Regulatory Commission and other regulatory agencies since the flood occurred to rebuild the forebay and return Thomson to service. The Thomson Project is a $90 million construction project that includes the forebay canal reconstruction, electrical restoration, mechanical and general civil rehabilitation, upgrades to the water conveyance system and construction of additional spillway facilities at the Thomson main dam. The Thomson Project will allow Thomson to resume operations and provide approximately 280,000 MWh of annual low-cost renewable energy for Minnesota Power customers. The Thomson Project is a key part of Minnesota Power's strategy to meet its Renewable Energy Standard requirements under Minn. Stat. § 216B.1691.

The Company understands the use of trade secret designations in filings to the Commission must be limited. Certain portions of the Petition contain trade secret information and are marked as such, pursuant to the Commission's Revised Procedures for Handling Trade Secret and Privileged Data which further the intent of Minn. Stat. § 13.37 and Minn. Rule 7829.0500. As required by the Commission's Revised Procedures, a statement providing justification for excising the Trade Secret Data is included in the Petition.

In accordance with Minn. Rule 7829.1300, Minnesota Power has included a Summary with this filing. As reflected in the attached Affidavit of Service, the Summary has been filed on the official general service list utilized by Minnesota Power.

The Company looks forward to the opportunity to work with the Department of Commerce – Division of Energy Resources and the Commission to advance the Thomson Project. Please contact me at (218) 355-3586 with any questions related to this Petition.

Yours truly,

Susan Ludwig

SL:sr
Enc.

STATE OF MINNESOTA	)	AFFIDAVIT OF SERVICE VIA
	) ss	E-FILING AND
COUNTY OF ST. LOUIS	)	FIRST CLASS MAIL

Susan Romans, of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 3rd day of July, 2014, she e-filed Minnesota Power's Petition for Approval of Investments and Expenditures in the Thomson Project on Burl Haar and Sharon Ferguson. The remaining parties on the attached Service List were served as indicated.

/s/ Susan Romans
Susan Romans

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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STATEMENT REGARDING JUSTIFICATION FOR EXCISING
TRADE SECRET INFORMATION

Minnesota Power has excised material from this Petition because of the power supply and resource planning data information. This is highly confidential information relating to Company financial and planning information; Minnesota Power's competitors and vendors would acquire highly confidential commercial information about Minnesota Power if this information were publicly available.

Minnesota Power believes that this statement justifies why the information excised from the attached report should remain a trade secret under Minn. Stat. §13.37. 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
HAS BEEN EXCISED

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

****

In the Matter of the Petition of Minnesota Power for Approval of Investments and Expenditures in the Thomson Project for Recovery through Minnesota Power's Renewable Resources Rider under Minn. Stat. § 216B.1645	Docket No. E015/M-14-___

****

SUMMARY

Minnesota Power ("the Company") submits this Petition to the Minnesota Public Utilities Commission ("Commission") pursuant to Minn. Stat. § 216B.1645 and Minn. Rules 7829.1300. Minnesota Power is seeking Commission approval pursuant to Minn. Stat. § 216B.1645 for investments, expenditures and costs for a hydroelectric restoration project ("Thomson Project") at Minnesota Power's Thomson Hydroelectric Development ("Thomson") on the St. Louis River hydroelectric system ("St. Louis River Hydro System") through Minnesota Power's Commission-approved Renewable Resources Rider.

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STATE OF MINNESOTA
BEFORE THE
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In the Matter of the Petition of Minnesota Power for Approval of Investments and Expenditures in the Thomson Project for Recovery through Minnesota Power's Renewable Resources Rider under Minn. Stat. § 216B.1645	Docket No. E015/M-14-___

****

I. INTRODUCTION

Minnesota Power ("the Company") submits this Petition to the Minnesota Public Utilities Commission ("Commission") pursuant to Minn. Stat. § 216B.1645, and Minn. Rules 7829.1300. Minnesota Power is seeking Commission approval pursuant to Minn. Stat. § 216B.1645 for investments, expenditures and costs for a hydroelectric restoration project ("Thomson Project") at Minnesota Power's Thomson Hydroelectric Development ("Thomson") on the St. Louis River hydroelectric system ("St. Louis River Hydro System") through Minnesota Power's Commission-approved Renewable Resources Rider.

A. <u>Overview of the Thomson Project</u>

Just over two years ago in June 2012, record rainfall and flooding occurred near Duluth, Minnesota and surrounding areas. The flooding severely damaged Minnesota Power's St. Louis River Hydro System, particularly the Thomson facility, which was forced off-line due to damage to the forebay canal and flooding at the facility. Minnesota Power has been working closely with the appropriate regulatory bodies which oversee the hydro system operations to assess options for restoring the Thomson facility and rebuilding the forebay canal. This coordination began immediately after the flood and continues to the present. Forebay construction is substantially complete and Minnesota Power is working toward final authorization from the Federal Energy Regulatory Commission ("FERC") to refill it with water and return it to service. In addition to the forebay work, Minnesota Power is performing restoration and upgrade work on electrical, mechanical and water conveyance systems at the Thomson facility. Thomson is more than 100 years old and must be reconstructed to meet today's safety and engineering standards, and to meet high flow events like that experienced in June 2012. The Company is working towards returning to partial generation from Thomson in August 2014 and to full generation in early 2015. Construction of additional spillway facilities at the Thomson main dam to increase spillway capacity as required by the FERC is expected to be in-service by the end of 2016.

The following Figures 1, 2, and 3 are aerial photographs taken during and shortly after the June 2012 flood. Figure 1 shows the city of Thomson, Figure 2 the Thomson forebay breach, and Figure 3 the Thomson powerhouse. Figure 4 on page 6 is a photograph of the flooding in the basement of the Thomson powerhouse taken during the June 2012 flood.

Figure 1. City of Thomson During the June 2012 Flood

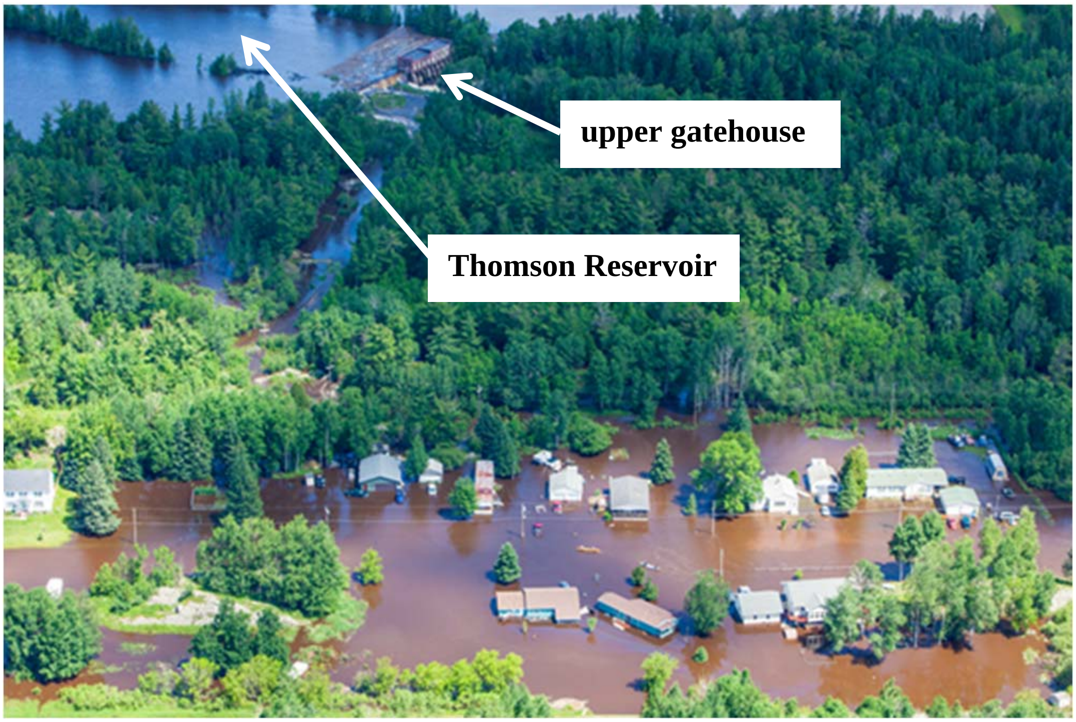

Figure 2. Forebay Breach After the June 2012 Flood

Figure 3. Thomson Powerhouse During the June 2012 Flood

Figure 4. Thomson Basement After the June 2012 Flood

The Thomson Project will restore Thomson from the damages incurred in the June 2012 flood and upgrade Thomson to meet current safety and engineering standards. The Thomson Project includes the forebay canal reconstruction, electrical restoration, mechanical and general civil rehabilitation, upgrades to the water conveyance system and construction of additional spillway facilities at the Thomson main dam. Some of the construction projects will be made to take advantage of the extended unplanned outage to perform necessary upgrades to the hydro system, as described in Section IV.

B. Background of Minnesota Power's Renewable Resources Rider

On May 11, 2007, the Commission established Minnesota Power's Rider for Renewable Resources (Renewable Resources Rider) through an Order approving the Renewable Resources Rider for recovery of contracts, investments and expenditures allowed under Minn. Stat. § 216B.1645.[1] The Commission issued orders approving subsequent rate adjustments for the Renewable Resources Rider on July 21, 2010[2] and November 15, 2011.[3] Minnesota Power is

[1] Docket No. E015/M-07-216.
[2] Docket No. E015/M-10-273.

currently applying to customer bills the 2013 Renewable Resources Factor approved on December 3, 2013.[4]

On April 29, 2014, Minnesota Power submitted its 2014 Renewable Resources Factor Filing, seeking approval to adjust the 2013 Renewable Resources Factor for updated costs of renewable investments.[5] An Order has not yet been issued in that Docket. The Thomson Project was not included in the recent Petition, but would be included in a future factor filing, pending Commission approval of the Project.

C. Eligibility of Thomson Project for Current Cost Recovery

The Company realizes that current cost recovery of the Thomson Project under the Renewable Energy Cost Recovery Statute ("Renewable Statute") is a unique application under Minn. Stat. § 216B.1645. Prior to June 2012, Thomson provided renewable energy for customers that has counted toward Minnesota Power's requirements under Minn. Stat. § 216B.1691. The flood damage in June 2012 completely wiped out 280,000 MWh of annual energy production from Thomson, eliminating 71 MW of accredited renewable energy capacity[6] from the Minnesota Power system. The "old" Thomson generating facility ceased to exist. The Thomson Project is the means to create a "new" Thomson generating facility and restore 71 MW of renewable energy to the Company's energy mix.

On February 7, 2014, the Commission approved a similar application of the Renewable Statute in Xcel Energy's Petition for Approval of 2012 Transmission Cost Recovery.[7] In this Docket, Xcel requested that restoration costs related to storm damage at Xcel's Buffalo Ridge transmission facilities be recoverable under the Renewable Statute. The Buffalo Ridge transmission facilities were needed to deliver renewable generation to Xcel's customers. The Commission concurred with the Department of Commerce that, since the repairs were necessary to provide an outlet for the energy generated by the wind farms on the Buffalo Ridge, the Buffalo Ridge Restoration Project was eligible under Minn. Stat. § 216B.1645 for current cost recovery.

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[3] Docket No. E015/M-11-274.
[4] Docket No. E015/M-13-410.
[5] Docket No. E015/M-14-349.
[6] Refers to Midcontinent Independent System Operator (MISO) ICAP accredited capacity.
[7] Docket No. E-002/M-12-50.

The Thomson Project, similar to Xcel Energy's Buffalo Ridge project, came about as a result of a catastrophic weather event and is necessary in order to deliver renewable generation to customers. And, as is demonstrated in this Petition, the Thomson Project is in the public and economic interests of Minnesota Power's customers.

II. PROCEDURAL MATTERS

A. General Filing Information

Pursuant to Minn. Rule 7829.1300, Minnesota Power provides the following required general filing information.

1. Summary of Filing (Minn. Rule 7829.1300, subp.1)

A one-paragraph summary accompanies this Petition.

2. Service on Other Parties (Minn. Rule 7829.1300, subp. 2)

Pursuant to Minn. Stat. § 216.17, subd. 3 and Minn. Rules 7829.1300, subp. 2, Minnesota Power eFiles the Petition on the Department of Commerce – Division of Energy Resources and the Office of Attorney General – Antitrust and Utilities Division. A summary of the filing prepared in accordance with Minn. Rules 7829.1300, subp. 1 is being served on Minnesota Power's general service list.

3. Name, Address and Telephone Number of Utility (Minn. Rule 7829.1300, subp. 4(A))

Minnesota Power
30 West Superior Street
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(218) 722–2641

4. Name, Address and Telephone Number of Utility Attorney (Minn. Rule 7829.1300, subp. 4(B))

David R. Moeller
Senior Attorney
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dmoeller@allete.com

5. Date of Filing and Date Proposed Rate Takes Effect (Minn. Rule 7829.1300, subp. 4(C))

This Petition is being filed on July 3, 2014, and will have no effect on Minnesota Power's base rates.

6. **Statute Controlling Schedule for Processing the Filing (Minn. Rule 7829.1300, subp. 4(D))**

This Petition is made pursuant to Minn. Stat. § 216B.1645. Furthermore, Minnesota Power's Petition falls within the definition of a "Miscellaneous Tariff Filing" under Minn. Rules 7829.0100, subp. 11 and 7829.1400, subp. 1 and 4, permitting comments in response to a miscellaneous filing to be filed within 30 days, and reply comments to be filed no later than 10 days thereafter.

7. **Utility Employee Responsible for Filing (Minn. Rule 7829.1300, subp. 4(E))**

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8. **Impact on Rates and Services (Minn. Rule 7829.1300, subp. 4(F))**

The Petition will have no effect on Minnesota Power's base rates. The additional information required under Minn. Rule 7829.1300, subp. 4(F) is included throughout this Petition.

9. **Service List (Minn. Rule 7829.0700)**

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B. <u>Trade Secret Designation (Minn. Rule 7825.0500)</u>

Pursuant to Minn. Stat. §§ 13.01 et seq. and Minn. Rule 7829.0500, Minnesota Power has designated portions of the Petition as containing Trade Secret information and these have been redacted as appropriate to reflect the Trade Secret nature of the documents. Trade Secret and Public copies of the Petition are being eFiled in accordance with the Commission's Rules and Minn. Stat. § 216.17, subd. 3. A statement regarding justification for excising Trade Secret information accompanies this Petition.

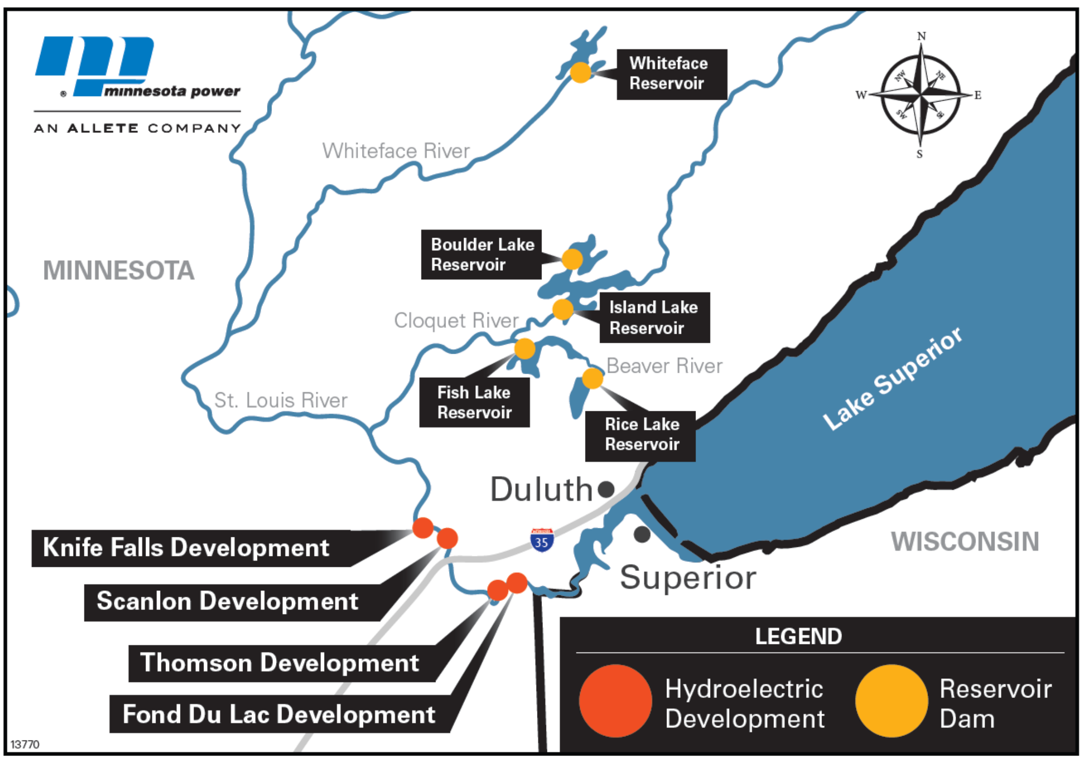
III. FACILITY DESIGN

The Thomson Project is located at the Thomson Development in Minnesota Power's St. Louis River Hydro System. The entire St. Louis River Hydro System relies on operations headquartered at Thomson.

A. Overview of the St. Louis River Hydro System

Minnesota Power owns and operates the largest hydroelectric system in Minnesota, licensed to produce 120.8 MW of electricity. The St. Louis River Hydro System is the Company's largest hydroelectric system, licensed to produce 87.6 MW of electricity. It is located along the St. Louis River with its headwaters north of Duluth, Minnesota. The Company is licensed to operate the St. Louis River Hydro System by the FERC.[8] The St. Louis River Hydro System consists of nine separate developments, including four generating stations and five headwater reservoirs as shown in Figure 5 below.

Figure 5. St. Louis River Hydro System Map



[8] FERC Project 2360.

The individual developments within the St. Louis River Hydro System were developed in various years between 1905 and 1924. The St. Louis River Hydro System developments and six other hydroelectric developments are remotely operated from the Thomson control room, where Minnesota Power's Hydro Operations Department controls the generating units at each station plus a limited number of spillway gates at certain dams that are remotely operated.

B. Description of Individual Hydroelectric Facilities

The following is a description of the five reservoirs and each individual hydro development within the St. Louis River Hydro System. The descriptions are sequenced in a generally upstream to downstream order. Appendix D – Glossary of Dam-Related Terms includes definitions of some of the technical terms related to dams included in the Petition. Additional information on the St. Louis River Hydro System can be found at Minnesota Power's "Hometown Hydropower" website at www.mphydro.com.

1. Headwater Reservoirs

The primary purpose of the headwater reservoirs is to provide water for wintertime generation at Minnesota Power's four downstream hydroelectric generating stations. In addition, the reservoirs provide water for recreational opportunities and aquatic habitat. Although they are not designed for or capable of significant flood control, the reservoirs also provide some water regulation to help mitigate high downstream flows. There are no generating facilities at these developments. The following reservoirs are part of the St. Louis River Hydro System:

- The 5,440-acre Whiteface Reservoir[9] is located on the Whiteface River, a tributary to the St. Louis River, and is the northernmost development in the system.
- The 4,480-acre Boulder Lake Reservoir[10] is located on the Otter River and discharges directly into Island Lake Reservoir, which subsequently discharges into the Cloquet River.

[9] FERC Project 2360-09.
[10] FERC Project 2360-08.

- The 10,800-acre Island Lake Reservoir[11] is located on the Cloquet River, a tributary of the St. Louis River, and immediately downstream from the Boulder Lake Reservoir.

- The 2,590-acre Rice Lake Reservoir[12] is located on the Beaver River. Discharges from the reservoir flow through a reach of the Beaver River and then into Fish Lake Reservoir.

- The 5,120-acre Fish Lake Reservoir[13] is located on the Beaver River downstream from the Rice Lake Reservoir. Discharges from the reservoir flow through a short reach of the Beaver River and into the Cloquet River.

2. Knife Falls Development

The Knife Falls Development[14] dam and hydroelectric station are located within the City of Cloquet, Carlton County, Minnesota on the lower St. Louis River. The development was constructed in 1922 to generate electricity. The powerhouse contains three turbine-generator units with a normal head[15] of about 18 feet and a licensed capacity of 2.4 MW.

3. Scanlon Development

The Scanlon Development[16] dam and hydroelectric station are located near the City of Scanlon, Carlton County, Minnesota on the lower St. Louis River downstream from the Knife Falls Development. It was constructed in 1922 to 1923 to generate electricity. The powerhouse has four turbine-generator units, with a normal head of about 15 feet and a licensed capacity of 1.6 MW.

4. Thomson Development

The Thomson Development[17] is located about ten miles west of the City of Duluth, Minnesota, near the small cities of Carlton and Thomson in Carlton County on the lower St. Louis River downstream from the Scanlon Development. The Thomson Development was

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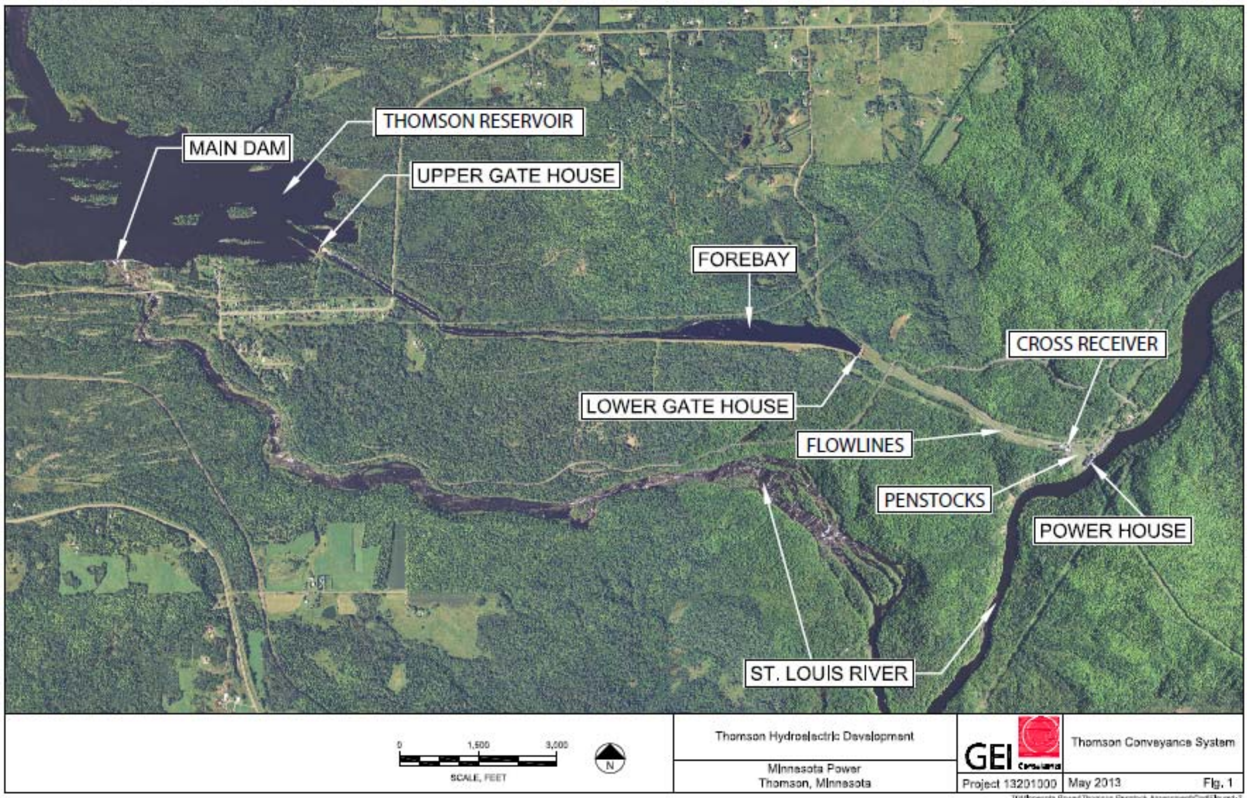
[11] FERC Project 2360-07.
[12] FERC Project 2360-06.
[13] FERC Project 2360-05.
[14] FERC Project 2360-04.
[15] Normal head is the height of water that feeds the generator.
[16] FERC Project 2360-03.
[17] FERC Project 2360-02.

constructed in 1905 through 1907 to generate electricity. Principal features include the Thomson Reservoir, an upper gatehouse, a power canal and forebay, a lower gatehouse, steel flowlines, two steel surge tanks, a cross receiver,[18] steel penstocks,[19] and a powerhouse. The powerhouse has six turbine-generator units with a normal head of about 370 feet and a licensed capacity of 72.0 MW. Figure 6 shows an aerial photograph of the Thomson Development.

Figure 6. Aerial Photograph of Thomson Development



The Thomson Reservoir is formed by a series of 25 earth, rock-fill, and concrete dam structures totaling more than a mile in length, and ranging in height from 4 to 50 feet. The Thomson Reservoir is designed to control water releases into the St. Louis River system as well as the power canal, which is downstream of the upper gatehouse. Discharge to the river is controlled at the main dam with 14 tainter gates and 3 deep sluice gates. Discharge to the power canal is controlled by the upper gatehouse with 4 sluice gates.

[18] The cross receiver splits water flow from three flowlines into six penstocks downstream.
[19] A penstock is a pipeline constructed to direct the flow of water to an individual hydraulic turbine.

The power canal extends 3,500 feet, and then widens into the forebay, which is formed by a 20- to 50-foot tall earth embankment on the south side. The total length of the canal and forebay is approximately 11,000 feet. Discharge from the forebay into three steel flowlines is controlled by four sluice gates in the lower gatehouse. The 7-, 11-, and 12-foot diameter, 4,400-foot long flowlines conduct water from the lower gatehouse to the cross receiver, which splits the flow from the three flowlines into six penstocks, one for each powerhouse turbine. Two 230-foot tall surge tanks are connected to the pipelines at the cross receiver. The steel penstocks are 7 to 8 feet in diameter, and approximately 500 feet long.

The Thomson powerhouse is the home base for Minnesota Power's Hydro management personnel and the majority of the Company's Hydro operations and maintenance personnel. All of Minnesota Power's hydroelectric and reservoir developments (except the Grand Rapids hydroelectric facility) are operated from the control room at the Thomson powerhouse.

The Thomson Reservoir has a surface area of approximately 375 acres and contains 4,352 acre-feet of water at full pool elevation of 1,069 feet. Thomson is typically operated as a peaking energy resource, providing energy when Minnesota Power customers most need it or during periods of higher market energy prices, and the pond level can fluctuate several feet on a daily basis.

The June 2012 flood was an extremely unusual event and the largest flood on record at Thomson. The pre-2012 historical peak discharge at Thomson was 39,695 cfs[20] and occurred on April 23, 1979. During the June 2012 flood an estimated peak discharge of about 52,000 cfs occurred on June 21. The reservoir peaked about 1.2 feet above the crest elevation of most of the non-overflow sections.

5. Fond du Lac Development

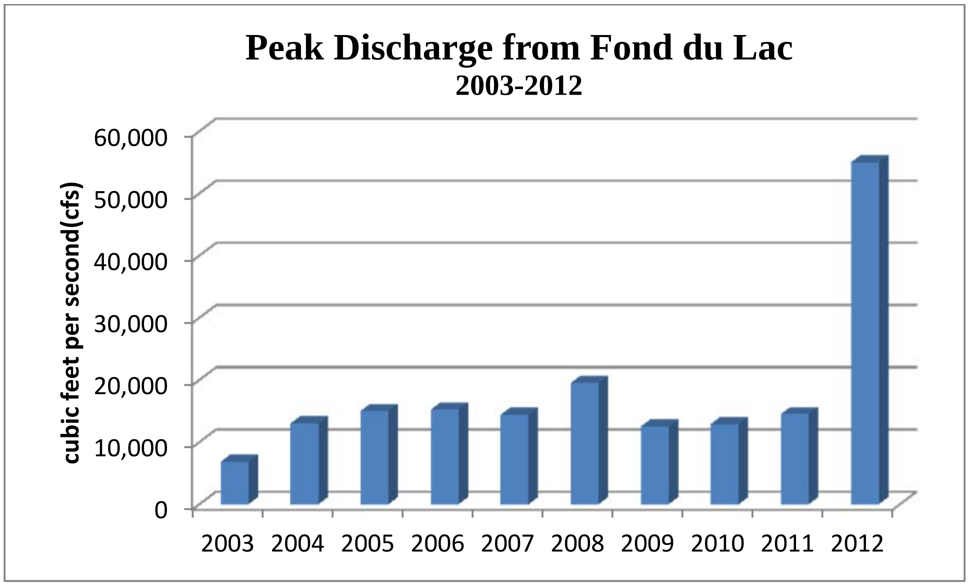
The Fond du Lac Development[21] is the most downstream development of the St. Louis River Hydro System. The development is roughly two miles downstream from where the Thomson powerhouse discharges into the St. Louis River. The Fond du Lac dam and hydroelectric station borders the southwest city limit of Duluth, Minnesota, and is approximately

[20] Cubic feet per second.
[21] FERC Project 2360-01.

one-and-a-half miles upstream of the Fond du Lac neighborhood and twelve miles from the city center. The river at this location forms the boundary between St. Louis and Carlton Counties.

The Fond du Lac Development was constructed in 1923 to 1924 to generate electricity. The powerhouse has one turbine-generator unit, with a normal head of about 78 feet and a licensed capacity of 11.6 MW. The peak flow at Fond du Lac of 55,000 cfs occurred during the June 2012 flood. Figure 7 demonstrates how the 2012 peak discharge compares with the past ten-year period. The peak flow at Fond du Lac is significant because the discharge from the entire St. Louis River Hydro System flows through this facility, as it is the most downstream development on the system.

Figure 7. Peak Discharge from Fond du Lac



IV. THOMSON PROJECT – RENEWABLE RESOURCES RIDER AUTHORIZATION

Minn. Stat. § 216B.1645 allows the Commission to approve a schedule that provides for the automatic adjustment of charges to recover prudently incurred investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the requirements of Minn. Stat. § 216B.1691.

The hydroelectric energy generated by the Thomson Project qualifies as eligible energy technology under Minn. Stat. § 216B.1691, subd. 1. Minnesota Power requests Commission approval pursuant to Minn. Stat. § 216B.1645, subd. 2a of this Petition for eligibility to include cost recovery of incurred investments, expenditures and costs for the Thomson Project through Minnesota Power's Commission-approved Renewable Resources Rider.

A. Overview of Damage to Hydro System

Heavy rainfall of up to 10 inches occurred in northeastern Minnesota on June 19 and 20, 2012, resulting in record flows on the St. Louis River. The severe flood flows, combined with coincident heavy precipitation, made project operations extremely difficult, with operating personnel often unable to get to project sites due to road washouts and debris. The peak flows of approximately 52,000 cfs at Thomson and 55,000 cfs at the downstream Fond du Lac Hydro Development represent the flood of record at those facilities and other hydro developments that comprise the St. Louis River Hydro System. The flood event caused significant damage to the Thomson powerhouse and other facilities. Most significantly, on the afternoon of June 20, the Thomson powerhouse basement was severely flooded and later that evening a section of the forebay embankment at Thomson failed. The forebay and other elements damaged in the flood are essential components in the production of energy at Thomson. The entire Thomson Development has been out of service since the June 2012 flood. Figure 8 on page 18 shows an aerial photograph of the Thomson Reservoir at the Minnesota State Highway 210 bridge during the flood.

Figure 8. Thomson Reservoir at Highway 210 on June 20, 2012

B. Coordination with Other Agencies

Minnesota Power notified the FERC immediately following the flooding and damage to the St. Louis River Hydro System in June 2012. Under the FERC-mandated framework, an independent Board of Consultants ("BOC") was established and approved by the FERC to oversee the forebay failure analysis and reconstruction. The Company hired an engineering consultant, URS Energy and Construction Inc. ("URS"), and held several meetings with the BOC, URS, and representatives from the FERC Division of Dam Safety and Inspections regarding reconstruction of the forebay. The Company also coordinated repair plans and acquired approvals as necessary from the FERC Division of Hydropower Administration and Compliance, the Minnesota Pollution Control Agency, the Minnesota Department of Natural Resources, the United States Army Corp of Engineers, and the State Historic Preservation Office.

Minnesota Power submitted three significant reports to the FERC relative to the forebay embankment failure and reconstruction.

1. Root Cause Failure Report

This report, submitted June 20, 2013, investigated the causes of the forebay failure. The report concluded that extreme flood conditions caused the loss of control of water into and out of the forebay canal resulting in overtopping, erosion, and failure of the forebay embankment.

2. Environmental Analysis Report

This report, submitted July 17, 2013, included an environmental analysis of the proposed reconstruction to the forebay. Analysis considered the reconstruction impact on water quality, air quality, fisheries and aquatic resources, botanical and terrestrial resources, threatened and endangered species, wetlands, recreation, visual resources, noise, traffic, and cultural resources. The report concluded that the proposed forebay reconstruction plan was environmentally sound.

3. Embankment Reconstruction Plan

This report, setting out a reconstruction plan for the Thomson forebay, was submitted July 19, 2013, with input from the BOC, URS, and the FERC. The report included the final forebay design, the geotechnical investigation report, hydraulic capacity review and summary report, potential failure modes and analysis report, supporting design report with design drawings, technical specifications, and a quality control inspection plan.

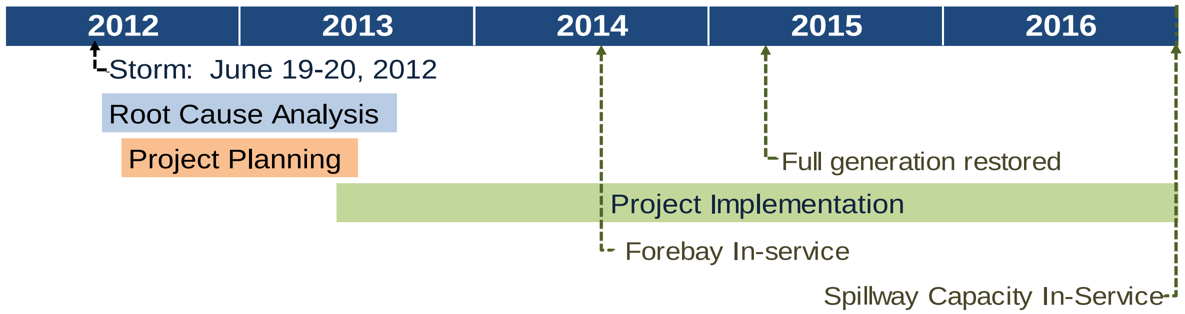
The reconstruction plan was authorized by the FERC in a letter dated September 19, 2013, allowing reconstruction of the Thomson forebay to proceed. The reconstruction plan is based on conclusions from the forensics investigation of the forebay failure in the Root Cause Failure Report and the Environmental Analysis Report.

The FERC and the BOC continue to be involved in the completion and refill of the forebay and the spill capacity improvements portion of the Thomson Project. In addition, the FERC will continue to be involved with ongoing operations at Thomson.

C. Timeline of Events

Figure 9 on page 20 shows a timeline of Minnesota Power’s actions following the June 2012 flood and the projected schedule of the Thomson Project.

Figure 9. Timeline of Events



D. **<u>Construction Project Descriptions (Minn. Stat. § 216B.1645, subd. 2a(b)(1))</u>**

The Thomson Project can be generally categorized into the following major construction areas:

1) Forebay Reconstruction
2) Electrical
3) Mechanical and General Civil
4) Water Conveyance System
5) Spill Capacity

Table 1 on page 21 shows the construction costs of the Thomson Project for each construction area.

Table 1. Thomson Project Costs

Thomson Project Costs Net of Insurance ($ in millions)		
Forebay Reconstruction		$28.4
Electrical		16.9
Hydroelectric station electrical infrastructure	11.5	
Substation - breakers	2.0	
Back-up control room	0.3	
Substation electrical infrastructure	3.1	
Total Electrical	16.9	
Mechanical and General Civil		4.1
Units 1-6 flood inspection and refurbishment	3.7	
Basement lead abatement	0.1	
Basement flood proofing	0.2	
Penstock valve operators	0.1	
Total Mechanical and General Civil	4.1	
Water Conveyance System		30.0
Flowline/penstock lead abatement and lining	21.8	
Lower gatehouse structural steel and trash racks	1.6	
Upper gatehouse head gates	1.8	
Lower gatehouse gates	1.9	
Valve refurbishment or replacement	2.1	
Cathodic protection system	0.8	
Total Water Conveyance System	30.0	
Thomson Dam Spill Capacity		11.0
Total Thomson Project Costs Net of Insurance		**$90.4**

Following is a description of each of these construction areas.

1. Forebay Reconstruction

A significant component of the Thomson Project is to reconstruct the forebay embankment that was damaged in the 2012 flood. This project is estimated to cost approximately $28 million.

A root-cause failure analysis of the forebay embankment failure concluded that extreme flood conditions caused the loss of control of water into and out of the forebay canal resulting in overtopping, erosion, and failure of the forebay embankment. A geotechnical site investigation and forensic analysis determined that the original embankment, which was constructed in 1905, does not meet current design standards. Therefore, repair of the existing embankment to its original configuration was not considered to be a viable solution to meet dam safety criteria, and reconstruction or replacement of the existing embankment was necessary. Alternatives analyses determined that reconstruction of the embankment and adding a passive spillway in the existing embankment footprint was the most viable and cost-effective option.

Following are the principal components of the forebay reconstruction:

- Replacing the existing earthfill embankment with a new dam section consisting of a 2,900-foot long sheet pile cutoff wall and partially reconstructing the existing embankment with new earthfill and rockfill materials.
- Adding a passive reinforced concrete emergency spillway.
- Raising the non-overflow crest of the lower gatehouse to El. 1056.5 and adjacent natural ground areas which are currently lower than El. 1056.0.
- Reconstructing the existing fuse plug spillway by raising the existing channel with an earthfill embankment to a crest El. 1056.0.
- Conducting a canal embankment crest survey and raising any areas found to be lower than El. 1056.0 feet.
- Adding new access and maintenance roads for the dam toe[22] and crest.
- Grading the site to establish appropriate drainage.
- Restoring contractor work areas including revegetation, modifying the drainage channel downstream of the emergency spillway, and reconstructing park trails that were damaged in the forebay breach.

2. Electrical

Another significant component of the Thomson Project is to reconstruct the Thomson electrical equipment and facilities damaged in the 2012 flood, and to complete electrical infrastructure improvements necessary to improve safety and reliability. Minnesota Power has been implementing a generation electrical reliability and arc flash improvement program to improve electrical reliability and bring its facilities to current safety standards. This work was

[22] Dam toe is the juncture of the downstream face of the dam with the ground surface.

scheduled to be done at Thomson in future years. Due to the impact of the flood, this work was moved forward and expanded to address damage created by the flood as well as to take advantage of the extended outage and insurance contribution for damaged equipment.

The electrical reconstruction includes relocating facilities as necessary to lessen impacts of future significant events. The Thomson electrical projects are expected to cost approximately $22 million, which will be offset by about $5 million of insurance proceeds for a net Company cost of about $17 million.

The electrical reconstruction includes the following four projects:

- Hydroelectric station electrical infrastructure
- Substation – breakers
- Back-up control room
- Substation electrical infrastructure

a. Hydroelectric station electrical infrastructure

The hydroelectric station electrical infrastructure project is to repair flood damaged equipment and reconfigure the new installations to withstand significant future flood and adverse weather events. The project includes the addition of new switchgear, including generator circuit breakers, along with new step-up and auxiliary transformers and 480V switchgear. The result will be an electrical infrastructure that is not only safer to operate and maintain, but also much more reliable for Thomson. The total costs for this construction category are expected to be approximately $15.5 million, which will be offset by about $4 million of insurance proceeds for a net Company cost of about $11.5 million.

b. Substation – breakers

The substation – breakers project is to repair flood damaged equipment and substation oil containment facilities and to elevate facilities to withstand future flooding events. The project will increase system reliability of Thomson and repair critical assets damaged by the June 2012 Flood. The project includes replacing the oil containment system for the substation, and the result will be an infrastructure that is more reliable, and much safer for the environment. This project is expected to cost approximately $2.3 million, which will be offset by about $0.3 million of insurance proceeds for a net Company cost of about $2.0 million.

c. Back-up control room

The back-up control room project is necessary to ensure the safe operation of Minnesota Power's overall hydro system in the event of an evacuation or catastrophic event at Thomson. The 2012 flood nearly forced the Thomson control room out of service, and a backup facility is necessary to ensure continuous safe operation throughout any potential future significant event. The Thomson control room remotely monitors and operates ten hydroelectric generating stations (32 generating units) and five head-waters reservoirs – the entire Minnesota Power Hydro system except for the small hydro facility at Rapids Energy Center. This project will adapt all remote hydro facilities by engineering and programming redundant control architectures to allow for operation of all hydro facilities from either the Thomson control room or the Rowe Energy Control Center. The total project cost for the back-up control room is about $0.3 million.

d. Substation electrical infrastructure

As part of the Minnesota Power Generation electrical reliability and arc flash improvement programs to bring facilities to current standards, the Thomson 6.6kV and 13.8kV electrical infrastructure will be replaced. This project will incorporate the substation portion of the hydroelectric station electrical infrastructure project and also be in conjunction with the substation breaker project. It will include purchasing two new step up transformers with oil containment foundations and also constructing an oil containment foundation under the existing step up transformer. The total project cost net of insurance is about $3.1 million.

3. Mechanical and General Civil

The mechanical and general civil projects include repairs and replacements at Thomson's generating units and basement flood abatement. The costs for this construction category are expected to be approximately $13 million, which will be offset by approximately $9 million of insurance proceeds, for a net Company cost of about $4 million. Key components of these projects include the following:

- Units 1-6 flood inspection and refurbishment

- Basement lead abatement
- Basement flood proofing
- Penstock valve operators

a. Units 1-6 flood inspection and refurbishment

All six generating units suffered significant damage in the flood. Each turbine and generator will be disassembled, cleaned, inspected and refurbished as required. Insurance will cover flood-damaged equipment. Other necessary repairs include an electrical rewind of the generator on Unit 6, which had experienced electrical deterioration prior to the flood.

A significant portion of this project will be covered by insurance. The total project cost of refurbishing the six generating units is estimated to be about $10 million, with insurance proceeds covering about $6 million of that amount.

b. Basement lead abatement

The June 2012 flood filled the Thomson basement with river water causing complete paint coating failure throughout the basement. This project includes complete removal and reapplication of all existing paint coatings (including the proper removal and disposal of lead-based coatings) throughout the basement area. The majority of this $1.9 million project is insurance-recoverable. The total project cost net of insurance is expected to be about $0.1 million.

c. Basement flood proofing

In the 2012 flood, the river water elevation rose higher than the sills of the Thomson powerhouse basement windows, causing them to fail and allowing water to flow into the basement, which significantly contributed to the basement flooding. This project is to flood-proof these windows or to permanently seal them and to provide effective ventilation lost by sealing the windows. Repairing the damaged windows is insurance reimbursable, and the project is anticipated to cost about $0.2 million net of insurance.

d. Penstock valve operators

Penstock valve operators on Units 2-6 were damaged in the June 2012 flood and are inoperable. The project to replace the damaged operators is estimated to cost about $0.6 million, with most of the cost covered by insurance proceeds.

4. Water Conveyance System

The water conveyance system rehabilitation projects consist of repairs and upgrades to flowlines, penstocks, surge tanks and gatehouses. The facilities were originally installed in various years between 1905 and 1974, with most installed prior to 1924. These projects are necessary to ensure the continued safe, reliable operation of the Thomson facility. Reconstruction will upgrade facilities to current engineering standards, preventing unplanned outages in the future due to unexpected issues. These projects are estimated to cost approximately $30 million.

The unplanned outage at Thomson brought the opportunity to inspect the entire water conveyance system while the system was dry and initiate projects that would otherwise be significantly more difficult and expensive to complete under normal operations. Inspection and rehabilitation of these facilities was originally planned to be phased over the next four to eight years. Completing these projects now will avoid future long-term outages by taking advantage of the current extended unplanned outage.

There are significant benefits to conducting the inspection and evaluation of water conveyance facilities, as well as the effective remediation, while the hydro facility is not in operation. Under normal operations, it would be considerably more difficult to gain access to all parts of the system. Some rehabilitation at the gatehouses would have to be done by divers working under water. In the pipeline system, at a minimum, partial outages would be required and much more work would be necessary to isolate portions of the system to allow for rehabilitation. Conducting the work under normal operating conditions is very inefficient and much more expensive than taking advantage of doing this work while Thomson is out of service for flood repairs.

Key components of these projects include the following:

- Flowline/penstock lead abatement and lining
- Lower gatehouse structural steel and trash racks
- Upper gatehouse head gates
- Lower gatehouse gates
- Valve refurbishment or replacement
- Cathodic protection system

a. Flowline/penstock lead abatement and lining

A significant part of the water conveyance project is lead abatement and lining of the flowlines and penstocks (pipelines that convey water from the upper gatehouse to the Thomson powerhouse). This project was initially planned to abate the old internal lead paint coating, conduct a thorough internal inspection of the pipelines, and install a new liner system to protect the steel from future internal corrosion. As the inspection and evaluation identified deficiencies, the project was expanded to include minor repairs and some major rehabilitation.

Initial post-flood inspections of the pipelines identified numerous holes and areas of significant internal corrosion, which led to a more extensive inspection and evaluation program. Consultants with expertise in corrosion, structural analysis of flowlines and penstocks, and coating/lining were hired to complete the inspections and analysis and recommend rehabilitation options. It was decided that holes and deep corrosion pitting will be patched, sections of structural deficiency rehabilitated, and the entire interior lined with the application of a spray-applied polyurethane.

The flowlines and penstocks are integral elements in the production of energy at Thomson, and maintaining the integrity of these pipelines is essential to their safe, reliable operation. Lining is an effective means of mitigating internal corrosion. External corrosion will be mitigated by upgrading the cathodic protection system under a separate project as described later in this section. The project in total is estimated to cost about $22 million, with the lead abatement and lining portion estimated to cost about $12 million and the pipeline rehabilitation portion to cost about $10 million.

b. Lower gatehouse structural steel and trash racks

The lower gatehouse trash racks and the steel framework that supports the racks have significant corrosion, no longer provide the proper structural support, and need to be replaced. The trash racks prevent large woody debris from entering the Thomson flowlines. Such debris could severely damage the hydroelectric generating units, causing significant economic loss and a potential safety hazard. This project is expected to cost about $1.6 million.

c. Upper gatehouse head gates

The existing head gates at the upper gatehouse are original. An inspection in March 2013 found all four gates in poor condition and revealed that one gate in particular must be replaced before Thomson is back in service. Since portions of the roof must come off and a large crane mobilized to the site to replace the head gate, it was determined that all four head gates should be replaced at the same time. The head gates are critical to the operation of the Thomson facility, as they are used to maintain pond elevation. This project is expected to cost approximately $1.8 million.

d. Lower gatehouse gates

The gates at the lower gatehouse no longer provide a water-tight seal when closed due to wear and tear over a century of normal use. This project will rehabilitate the gates to provide an appropriate seal and continued reliable operation. The gates control water flow into the flowlines. Sound gates with good seals are needed for worker safety during inspections and maintenance of the flowlines, penstocks and turbines. This project is expected to cost approximately $1.9 million.

e. Valve refurbishment or replacement

Several valves have exceeded their engineered design life and need to be refurbished or replaced for safety reasons. The scope of the various valve projects is to inspect, evaluate, and rehabilitate or replace valves as necessary to provide safe operation and isolation for plant maintenance. Mainline valves in the flowline and penstock pipelines range from 5.5 to 8.0 feet in diameter, and bypass valves range from 8 to 12 inches in diameter. The projects are estimated to cost approximately $2.1 million.

f. Cathodic protection system

Cathodic protection ("CP")[23] is necessary to mitigate external corrosion on the underground steel flowlines and penstocks and maintain their integrity. The flowlines at Thomson are currently protected with eleven independent impressed current CP systems and the penstocks are protected with four independent impressed current systems. An impressed current CP system consists of a cathodic protection rectifier, an anode groundbed (consisting of numerous anodes drilled or buried adjacent to and along the length of the pipe) and associated underground cabling to connect the anode groundbed to the rectifier and the rectifier to the pipe. This project is necessary to upgrade systems that are no longer providing effective CP to mitigate corrosion and to add additional systems as necessary to provide CP mitigation to the entire pipeline system. Project costs for these replacements and additions are estimated to be approximately $0.8 million.

5. Thomson Dam Spill Capacity

The spillway at the Thomson Reservoir is adequate to pass normal flows and moderate floods. In an extreme flood, the reservoir rises and overtops additional sections of the dam passing water through areas beside the natural river channel, including through the City of Thomson. The spillway and other dam sections will be modified to better contain extreme flood flows in the river channel in accordance with FERC requirements. This is anticipated to be done through a combination of adding spillway structures to increase the spillway discharge capacity and increasing the height of dam structures.

The engineering work began on this project in 2013 and is still underway. The final design is expected to be completed in 2014 and construction will occur over 2015 and 2016, with an expected in-service date at year-end 2016.

Additionally, routine survey monitoring of Thomson Dam 6 has shown movement requiring rehabilitation. Since the overall spill capacity improvement project will likely include implications to Thomson Dam 6, the recommended modifications to the spill capacity project will incorporate rehabilitation to Dam 6.

[23] Cathodic protection is a technique used to control the corrosion of a metal surface by making it the cathode of an electrochemical cell.

Although the planning for these projects is still at a high level, the preliminary projections show that the projects will cost approximately $11 million.

E. Summary of Investments, Expenditures and Customer Rate Impacts

The customer rate impact for the Thomson Project was calculated by using capital expenditures net of insurance proceeds. In addition, the estimated revenue requirements currently being recovered in base rates associated with plant equipment that will be retired as a result of the Thomson Project were deducted from the project revenue requirements in order to prevent double-recovery on these assets. The customer rate impact analysis also excluded internal capitalized labor as well as the associated AFUDC (allowance for funds used during construction) on internal capitalized labor.

1. Estimated Project Costs (Minn. Stat. § 216B.1645, subd. 2a(b)(3))

The Thomson Project is expected to be completed over the 2014 to 2016 timeframe. Portions of the project will be placed in-service in late 2014 and the overall project is expected to be placed in-service by the end of 2016 with projected capital expenditures of $90 million,[24] net of insurance proceeds. Minnesota Power anticipates no incremental O&M expense for the Thomson Project.

Minnesota Power's proactive engagement and collaboration with many federal and state agencies[25] enabled the development of the Thomson Project to be completed in a much shorter timeframe than initially expected. The collaboration more clearly defined the work that needed to be done and resulted in a lower total construction cost. For example, the environmental permitting process, which can often be a long, critical path process, was completed as fast as could have been anticipated. In another example, as a result of collaboration with the Minnesota Department of Natural Resources – Jay Cooke State Park, soil excavated from the forebay project was used for fill to repair damage in the park, saving the costs and time to transport and dispose of the soil for the Company and solving a problem for the Park.

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[24] Capital expenditures net of internal costs and AFUDC on internal costs are expected to be $84 million.

[25] See Section B. Communications with Other Agencies on page 18 for a list of agencies involved in the Thomson Project.

Pursuant to Minn. Stat. § 216B.1645, subd. 2a(b)(4), Minnesota Power has employed multiple steps to help ensure the lowest overall cost for the Thomson Project. Minnesota Power utilized its purchasing procedures to obtain competitive quotations for most major purchases and awarded contracts to the lowest bidder(s) based on the best overall economic value for its customers. In some cases, contracts were awarded on a single source basis to qualified contractors based on utilizing existing partnering agreements or based upon original equipment manufacturer considerations. Minnesota Power will also provide any additional information deemed necessary, as part of notice and comment, for the Commission to conclude that "the utility's efforts to ensure that costs of the facilities are reasonable and were prudently incurred."

2. Estimated Customer Rate Impacts

The Thomson Project will have a minor impact on Minnesota Power's overall system costs. For the years 2015 to 2017, total revenue requirements for the Thomson Project would represent an increase of approximately 1.3 percent, 1.1 percent and 1.1 percent relative to the 2015 to 2017 projected total company electric revenue requirements, respectively. These cost increases are expected to be partially offset by a benefit the Thomson Project would bring to the Fuel and Purchased Energy Rider, since Thomson produces a fuel-free energy. This benefit is not reflected in the customer rate impact analysis described in this section below.

Table 2 on page 33 summarizes the estimated revenue requirements and rate impacts by customer class, assuming current cost recovery begins in January 2015. For the average residential customer, the rate impact for the first year of current cost recovery of the Thomson Project would be approximately $0.94 per month or a 1.16 percent rate increase. For the year 2016 this impact will increase slightly to $0.99 per month or a 1.22 percent rate increase. For the year 2017 this impact will decrease slightly to $0.98 per month or a 1.21 percent rate increase. For Large Power customers, the estimated rate impact for the first year of current cost recovery of the Thomson Project would be approximately 0.106 cents per kWh of energy or an increase of 1.85 percent. The estimated rate impact per kWh for the year 2016 would be approximately 0.112 cents per kWh or an increase of 1.96 percent. For the year 2017 this impact will decrease slightly to 0.111 cents per kWh or a 1.94 percent rate increase.

The Minnesota Jurisdictional Revenue Requirements shown in Table 2 include a credit for plant equipment that will be retired as a result of the Thomson Project. Equipment with original installed cost of approximately $3.5 million will be retired as part of the Thomson Project. The estimated jurisdictional revenue requirements associated with this equipment that are currently in base rates are deducted from the Thomson Project jurisdictional revenue requirements shown in Table 2. This credit includes a return on average rate base, depreciation expense, and associated property tax. It is anticipated that this credit will begin upon Commission approval of the Thomson Project and continue until the Thomson Project revenue requirements are rolled into base rates in Minnesota Power's next rate case.

Table 2 – Estimated Customer Rate Impact

Year	**2015**	**2016**	**2017**
MN Jurisdictional Revenue Requirements	$ 10,200,826	$ 10,754,123	$ 10,661,838
Rate Class Impacts (Note 1)			
Residential			
Average Current Rate (¢/kWh)	10.032	10.032	10.032
Increase (¢/kWh)	0.116	0.122	0.121
Increase (%)	1.16	1.22	1.21
Average Impact ($/month)	0.94	0.99	0.98
General Service			
Average Current Rate (¢/kWh)	10.032	10.032	10.032
Increase (¢/kWh)	0.116	0.122	0.121
Increase (%)	1.16	1.22	1.21
Average Impact ($/month)	3.22	3.39	3.36
Large Light & Power			
Average Current Rate (¢/kWh)	8.109	8.109	8.109
Increase (¢/kWh)	0.116	0.122	0.121
Increase (%)	1.43	1.50	1.49
Average Impact ($/month)	264.39	278.06	275.78
Large Power			
Average Current Rate (¢/kWh)	5.716	5.716	5.716
Increase (Demand & Energy combined) (¢/kWh)	0.106	0.112	0.111
Increase (%)	1.85	1.96	1.94
Average Impact ($/month)	58,876	62,209	61,653
Municipal Pumping			
Average Current Rate (¢/kWh)	9.174	9.174	9.174
Increase (¢/kWh)	0.116	0.122	0.121
Increase (%)	1.26	1.33	1.32
Average Impact ($/month)	14.06	14.79	14.67
Lighting			
Average Current Rate (¢/kWh)	15.653	15.653	15.653
Increase (¢/kWh)	0.116	0.122	0.121
Increase (%)	0.74	0.78	0.77
Average Impact ($/month)	0.17	0.18	0.18

Note: 1/ Average current rates are 2014 estimated rates based on Final 2010 TY General Rates in Minnesota Power's 2009 Rate Case without riders (E015/GR-09-1151) adjusted to include rider rates. The current rider rates include the Renewable Resources Rider rates, Transmission Cost Recovery Rider rates, Conservation Program Adjustment, and estimated 2014 budgeted Fuel and Purchased Energy adjustment. Average $/month impact based on 2014 budgeted billing units.

F. Insurance for Thomson

Minnesota Power's hydro property was insured at the time of the June 2012 flood, although the dams and the forebay embankment were not. All project costs included in the customer impact analysis related to the Thomson Project in this Petition are net of expected insurance payouts.

FM Global insures Minnesota Power's property. The policy is an all-risk policy covering fire, acts of nature, and mechanical failures. Total limit on the policy is $4.5 billion; however flood coverage carries a sublimit of $100 million with a $500,000 deductible per location. Although four hydro stations were affected by the flood, the insurance company viewed the damage at the four locations as one incident and agreed to a combined deductible of $500,000 versus a separate deductible for each hydro location.

The policy covers building and associated structures, substations, power cable, clean-up of debris, removal of water, electrical equipment, mechanical equipment, as well as damage to structure and electrical equipment at the upper and lower gatehouses. The policy excludes dams, dikes, damage to land, relocation of power lines and business interruption. Removal of debris from the trash gates is also excluded. However, Minnesota Power has negotiated with the insurance company to pay 50 percent of the costs for debris removal because removal of debris is a risk reduction measure to prevent impact to insurance covered facilities.

The coverage provided is for like-kind replacement cost value. Any upgrades are not normally covered unless there is a special circumstance. Since the Thomson Project includes many changes and upgrades to meet current FERC and other regulatory criteria and standards, the claim adjustment is challenging. Estimated damages to date for the insurance company are at $14 million, but will be continually adjusted until the project is complete. The Company has received advance payments of $4 million to date from FM Global for repairs. As restoration continues there are ongoing discussions with FM Global on negotiating a settlement on various items.

G. Project Schedule (Minn. Stat. § 216B.1645, subd. 2a(b)(2))

The majority of the Thomson Project will be completed over the 2014 to 2016 timeframe, with the majority of the Project in-service in 2014 and the remaining spillway capacity project expected to be in-service at year-end 2016. Minnesota Power proposes to provide compliance filings to the Commission following the actual in-service dates of the Thomson Project.

V. THE THOMSON PROJECT IS IN THE PUBLIC INTEREST

The following discussion describes the benefits of the Thomson Project in promoting the development of renewable energy, consistent with Minn. Stat. § 216B.1645, subd. 2a(b)(5). The discussion also describes Minnesota Power's renewable resource supply and overall energy portfolio and explains the process and analysis the Company conducted to determine that the Thomson Project is in the best interest of our customers. The following appendices also include additional detail about the public interest analysis: Appendix A – Resource Planning Analysis, Appendix B – Discussion on Shutdown Analysis for Thomson, and Appendix C – Assumptions and Outlooks.

A. Overall Energy Portfolio

Minnesota Power's power supply strategy is guided by its 2013 Resource Plan[26] that incorporates a diverse set of renewable resources including hydroelectric, biomass, and wind resources to meet a growing base of customers. The Thomson Project is a foundational component of this strategy and will allow Thomson to serve Minnesota Power customers as it has for more than 100 years. Thomson is a necessary part of the Company's supply portfolio, particularly as customer and regional demand for reliable and cleaner power grows. The Thomson Project is in the best interest of customers, as it outperforms other supply alternatives Minnesota Power could implement and as it provides customers a reliable, flexible and renewable resource that aligns with the principles used in Minnesota Power's long-term resource planning.

Minnesota Power is projecting a growing need for demand and energy over the next decade. With additions by large retail customers and wholesale contract growth projected through 2019, Minnesota Power's long-term annual load growth[27] is expected to average 1.3

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[26] Docket No. E015/RP-13-53.

[27] Minnesota Power's June 2013 Annual Electric Utility Forecast report ("AFR") was used for the evaluation of the Thomson Project. The AFR contained several long-term scenarios for Minnesota Power's energy and demand requirements. The "Wholesale and Industrial Customer Addition Forecast Scenario," which contains the addition of the Essar taconite pellet facility in Nashwauk, Minnesota, was utilized as the expected outlook for the analysis.

percent. Minnesota Power's Energy***Forward*** strategy[28] will ensure a diverse set of reliable resources are available to meet the growing requirements for energy. The Thomson generating resources will be part of Minnesota Power's energy solution by continuing to provide a base of renewable generation that efficiently leverages regional resources within Minnesota.

As one of the only ponding hydro resources in Minnesota, Thomson is a unique hydroelectric system. The system is able to store water in its reservoir to maximize the generation output of the generating turbines for customer requirements. This "dispatchability" makes Thomson unlike most other hydroelectric resources in the state. From a broad market perspective, Thomson provides renewable and carbon-free energy and capacity as a flexible and efficient resource. Thomson also provides multiple Midcontinent Independent System Operator, Inc. ("MISO") market products for customers, such as dispatchable energy, capacity, and ancillary services, and is a key part of the regional system restoration plan, as Thomson Unit 6 is Minnesota Power's black start unit.[29] If Thomson was not rebuilt, additional expenditures would be necessary to replace this black start capability. These additional costs have not been considered in the economic analysis.

With these valuable characteristics, the Thomson Project allows the continuation of Thomson generation and outperforms other renewable resources such as wind and solar that do not have these unique characteristics. The customer impact analysis included in this section demonstrates that when compared to other viable alternatives Minnesota Power could deploy, the Thomson Project will bring an estimated range of $95 to $139 million savings in customer power supply costs over the 21-year study period utilized in the evaluation for this Petition (2014 to 2034). The Thomson Project will also add significant customer benefit as it extends the life of Thomson's generation resources to a 50-year project life. Given the level of savings above viable alternative power supply sources and its alignment with Minnesota Power's Energy***Forward*** resource strategy, the Thomson Project is a strong fit and in the best interest of customers.

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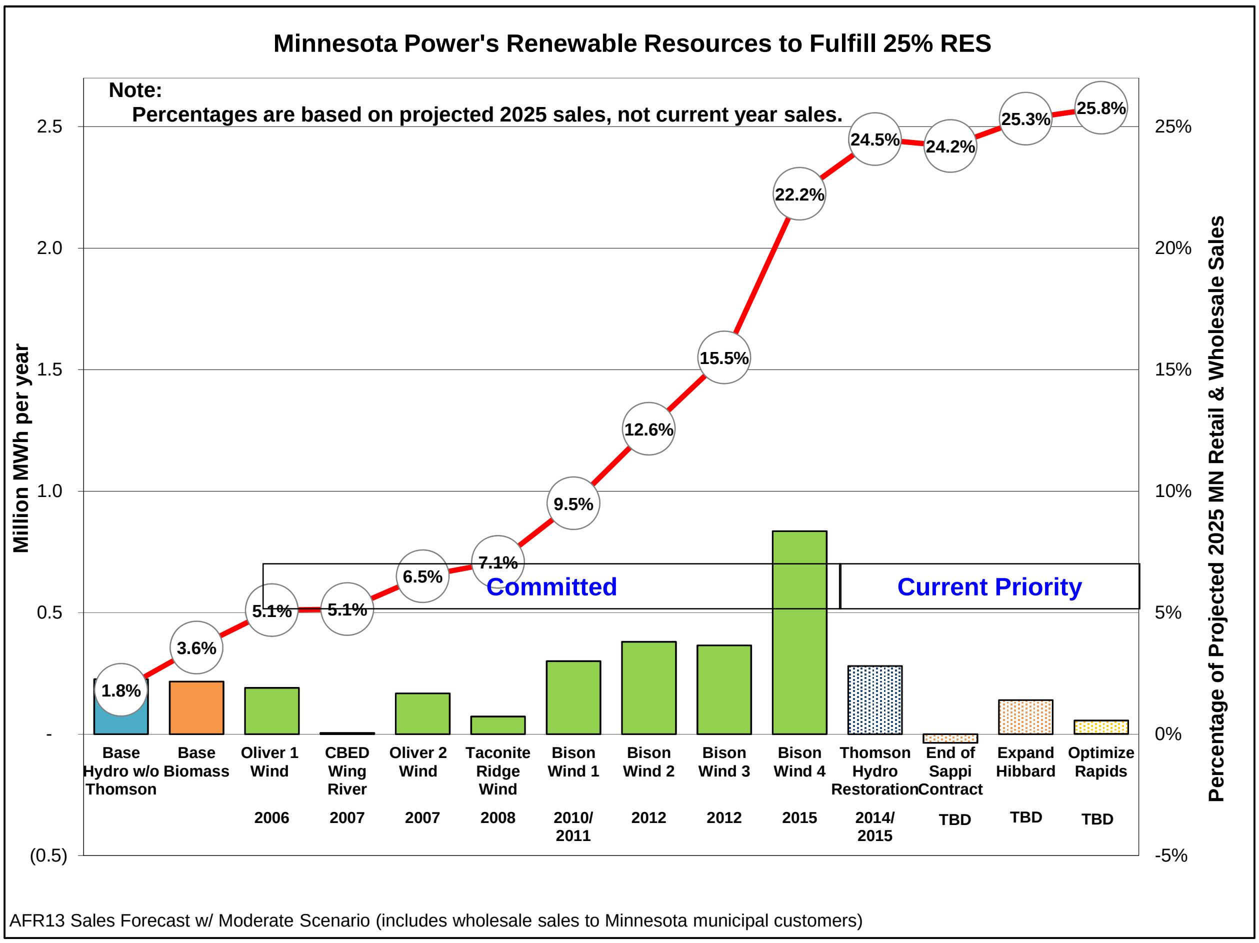
[28] Minnesota Power announced its Energy***Forward*** resource strategy in January 2013. Energy***Forward*** builds upon renewable energy investments already completed to further diversify the Company's generation mix, balancing coal, renewables and natural gas. See www.mnpower.com/Environment/EnergyForward for additional information.

[29] A black start unit is a unit which can restore a power system to operation without relying on external electric power.

B. Minnesota Renewable Energy Standard and Power Supply

With the Thomson Project, Thomson will remain an important regional resource to meet and diversify Minnesota Power's strategy to meet its Renewable Energy Standard ("RES") requirements. When it fully returns to service, Thomson generation will make up approximately two percent of Minnesota Power's retail energy supply with approximately 280,000 MWh of renewable energy per year. Figure 10 demonstrates Minnesota Power's current plan to meet its RES with Thomson generating resources playing a key role in meeting the 2025 requirement.

Figure 10 – Minnesota Power's Renewable Plan to Meet the Minnesota 25% RES

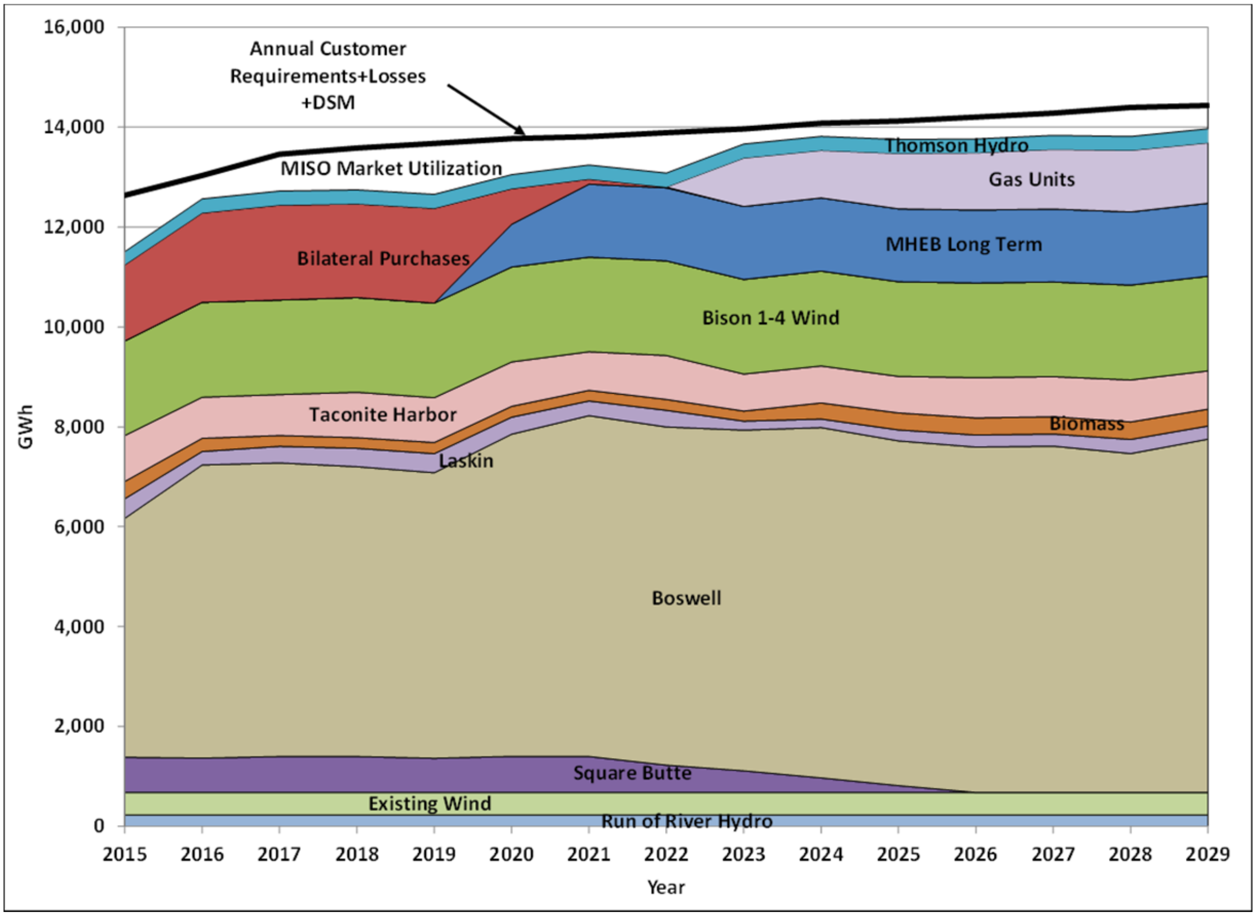


C. Thomson Project

Without Thomson's hydroelectricity, Minnesota Power is projected to attain only 23.5 percent renewable resources in 2025 for its retail customers. This means the Company would need to procure or build additional renewable resources to meet the 25 percent RES requirement in the long term. The customer impact analysis in this Petition considers this RES deficiency as other viable resource alternatives to replace Thomson's power supply are compared.

The Thomson generating station makes up a significant piece of the hydro generation in Minnesota Power's power supply. Figure 11 illustrates that Thomson is Minnesota Power's largest hydroelectric generating unit – most of Minnesota Power's owned hydro generation will be from Thomson once the Thomson Project is complete.

Figure 11 – Minnesota Power Energy Supply Position with Thomson Project



As a power supply resource, Thomson brings unique benefits to customers. Thomson is the only hydro generator in Minnesota Power's supply that has the capability to provide peaking type energy for use during periods of high demand. Thomson is a dispatchable renewable resource that can store energy (i.e., water in its reservoir) during the off-peak hours when energy prices and customer demand are lower and use that stored energy during the on-peak hours when energy prices and customer demand are higher. Furthermore, due to the flexibility of a dispatchable hydro resource, Thomson can provide ancillary services for customers such as spinning reserves.[30] The value of the spinning reserves at Thomson in the MISO ancillary services market has historically been approximately **[TRADE SECRET DATA HAS BEEN EXCISED]** per year, providing a direct benefit to customers for the generating station's flexibility.

With the Thomson Project, Minnesota Power will generate approximately 280,000 MWh per year and will restore a low-cost renewable energy resource for customers. The Thomson Project provides economic energy supply benefits, is a key piece of Minnesota Power's renewable strategy, and maintains a solid fit with the Company's long-term power supply needs. The following section outlines the quantification of these benefits.

D. Customer Impact Analysis

The Thomson Project allows the operation at Thomson to continue for another 50 years, providing long-term benefit to Minnesota Power's customers. To quantify these benefits and to ensure that the Thomson Project is the best option for Minnesota Power's customers, an analysis was performed comparing the Thomson Project to primary replacement alternatives. The analysis is broken into three parts:

1. Options after Thomson hydro damage;
2. Screening of power supply replacement alternatives for Thomson; and
3. Comparative analysis between Thomson and primary replacement alternatives.

1. Options after Thomson hydro damage

Minnesota Power considered two paths for Thomson after it was damaged and brought offline due to the June 2012 flood. The two paths considered were:

a) Repair Thomson and operate another 50-plus years – This path includes implementing the Thomson Project and restoring the generating station to full

[30] Spinning reserve is unused production capacity which can be used to provide energy to meet demand on the electric system in an emergency event, such as an unexpected loss of a generation or transmission resource.

operating condition. The expected cost of the restoration included in this analysis is $84 million.[31]

b) Shut down Thomson and replace with a reasonable generation alternative – This path includes a projected cost to shut down Thomson and the associated infrastructure which would ultimately cease hydroelectric operations at the facility. In order to replace the lost power supply, Minnesota Power would determine a reasonable alternative for the lost energy, capacity, ancillary services and renewable benefits that were provided by Thomson.

A range of replacement power supply alternatives were evaluated, including natural gas, wind, and solar resources. Each replacement alternative has its own set of characteristics and costs. A shutdown of Thomson would include extensive activities including partial or full removal of existing hydro dams and electric generating infrastructure at Thomson, and surrender of the FERC license. The estimated capital cost for a Thomson shutdown with partial removal of dam structures is approximately $55 million. However, as detailed in Appendix B – Discussion on Shutdown Analysis for Thomson, a shutdown of Thomson would entail a great deal of uncertainty regarding regulatory obligations to surrender the Company's FERC license, and may not be a feasible option.

Each path was examined in detail through Minnesota Power's resource planning process to identify the most prudent path for customers that also upholds Minnesota Power's core planning principles of securing flexible, diverse and reasonable power supply resources. The evaluation is explained in further detail in the remainder of this section.

2. Screening of power supply replacement alternatives for Thomson

The power supply screening analysis identified what type of resources could replace the 280,000 MWh of energy annually, 71 MW of capacity,[32] and environmental attributes Minnesota Power receives from Thomson, if the generating station were to be permanently shut down. Minnesota Power considered a range of alternative generation resources including renewable

[31] The $84 million project cost utilized in the customer impact analysis is net of expected insurance proceeds and excludes internal costs and AFUDC on internal costs. The $90 million project cost described in Section IV includes internal costs and AFUDC on internal costs.
[32] Refers to MISO ICAP accredited capacity.

generation, small natural gas peaking units, and larger more efficient natural gas combined cycle generating sources. The Strategist Proview software was used to compare the alternative resources and to select the lowest cost and reasonable replacement alternative(s) for Thomson.

A set of criteria representing Thomson's characteristics was established to determine the final set of replacement alternatives in narrowing down the results from the Strategist analysis. Each viable alternative would need to provide:

a) Renewable energy
b) Replacement energy
c) Replacement capacity
d) Similar energy profile (dispatchable)
e) Replacement of ancillary services

Given the unique and valuable characteristics a ponding resource such as Thomson provides, it is difficult to find a direct replacement that meets all the criteria listed above. When selecting resource alternatives the number of criteria that could be met with that resource alternative was also taken into consideration.

The screening analysis also took into consideration the power supply resource alternatives performance under both a "No CO2 Regulation Penalty" and "With CO2 Regulation Penalty" backdrop,[33] along with considering the replacement of the renewable energy credits Thomson provides for customers. Ultimately, the screening analysis demonstrated that there were four strategies – one natural gas and three renewable – that could reasonably be considered and meet the criteria as replacement alternatives for Thomson if a shutdown were to occur:

1) <u>Natural Gas Ownership Share</u>: execute a strategy to procure a 71 MW share of a large natural gas peaking combustion turbine in 2018 and utilize wholesale market energy and capacity purchases as a bridge until the turbine could be in service;

2) <u>Wind</u>: implement a large wind farm (210 MW) to gain energy to replace Thomson and utilize wholesale energy and capacity purchases to bridge additional needs;

[33] The carbon regulation penalty used in this Petition does not specifically take into account the EPA's proposed Clean Power Plan to regulate carbon emissions from the electric industry.

3) Solar: implement a large solar array (100 MW) and wholesale energy and capacity purchases to bridge additional needs; or

4) Renewable Combination: implement a medium wind farm (105 MW), a medium solar array (50 MW), along with wholesale energy and capacity purchases to bridge additional needs.

Table 3 on page 44 shows how each replacement alternative aligns with the criteria for replacing Thomson. While the table shows the ownership share of a large combustion turbine provides a direct replacement of the capacity and captures the peaking and dispatching capabilities of Thomson, it does not replace the renewable energy credits lost when Thomson is retired. The three renewable replacement alternatives of Wind, Solar and the Renewable Combination do replace nearly all or exceed the renewable energy credits created at Thomson, although not all the 71 MW of capacity is directly replaced and could require capacity market purchases.[34] The renewable alternatives also do not provide the dispatchable capabilities that would allow ancillary services to be provided and none of the alternatives provide black start capability. Although none of the alternatives directly replace all of Thomson's beneficial characteristics, Minnesota Power proceeded with these four alternatives to ensure the comparison was fully vetted in the power supply analysis.

[34] Because of the intermittent nature of wind and solar generation, the accredited capacity value is considerably lower than the nameplate capacity.

Table 3 – Criteria for Replacement Alternatives Considered

Replacement Alternative	Renewable Energy	Energy	Capacity	Energy Profile (Dispatchable)	Ancillary Services	Total Criteria Met
Thomson	Yes	Yes	Yes	Yes	Yes	**5**
Natural Gas Ownership Share	No	Yes	Yes	Yes	Yes	**4**
Wind	Yes	Yes	Yes (w/ Market Purchase)	No	No	**3**
Solar	Yes	Yes	Yes	No	No	**3**
Renewable Combination	Yes	Yes	Yes (w/ Market Purchase)	No	No	**3**

Appendix A – Resource Planning Analysis provides further details on the screening analysis.

3. Comparative analysis between Thomson and primary replacement alternatives

Minnesota Power evaluated in detail whether the Thomson Project was the best option for Minnesota Power customers. The Company performed an economic analysis comparing the cost of the Thomson Project to the cost of each of the four replacement alternatives with and without a carbon-constrained environment. Minnesota Power utilized the Strategist software to conduct the analysis comparing the alternatives. The results of the analysis shown in Table 4 on page 45 indicate that the Thomson Project provides significant benefit over the natural gas and renewable alternatives. When compared to the four replacement alternatives considered, the Thomson Project shows a benefit of approximately \$95 million to \$139 million[35] over the study period (2014 to 2034). Additionally, the results of the analysis were similar in the carbon-constrained scenario, when the midpoint of the Commission's carbon regulation planning value[36] (\$21.50 per ton in 2019) was included in the base assumptions. In this carbon-constrained case, the range of benefits of the Thomson Project was approximately \$93 million to \$143 million

[35] Reflects net present value in 2014 dollars.
[36] Docket No. E999/CI-07-1199.

over the study period. Both scenarios with and without a future carbon regulation tax confirm the customer benefit of the Thomson Project.

Table 4 – Comparison of Alternatives With and Without a Carbon Regulation Penalty

Power Supply Costs Replacement Alternative	Base Assumption with CO2 in 2019 at $21.50/ton	Base Assumption without CO2 Penalty
	($ in millions)	
Power Supply Costs With The Thomson Project	**$9,405**	**$8,225**
Change in Cost with "Natural Gas Ownership Share" Additional Cost	**$117**	**$95**
Change in Cost with "Wind " Additional Cost	**$93**	**$139**
Change in Cost with "Solar" Additional Cost	**$143**	**$133**
Change in Cost with "Renewable Combination" Additional Cost	**$123**	**$118**

In order to further enhance the comparative analysis, the Thomson Project and replacement options were then stressed under varying industry conditions. Single variables that are critical to the electric industry and consistent with Minnesota Power resource planning evaluations were increased and decreased and the power supply costs were compared between the Thomson Project and the four replacement alternatives. The stressing of variables confirmed that under varying conditions in the key variables, the Thomson Project was still the most reasonable and lowest cost option for customers. The stressed conditions were conducted both under a backdrop of no carbon regulation penalty and with the midpoint of the designated Minnesota carbon regulation planning value.[37] Under both conditions – with and without a carbon regulation penalty – the Thomson Project brought the most benefit to customers under the majority of stressed conditions. Table 5 on page 47 shows the results of the 17 sensitivities in the no carbon penalty scenario, identifying the Thomson Project as the best path forward for Minnesota Power customers.

[37] See Appendix C – Assumptions and Outlooks for more information on the Minnesota carbon regulation planning value utilized in the analysis.

Table 5 – Thomson Restoration Project Evaluation – With No Carbon Penalty

Table shows the increase/decrease in costs when the Thomson Project is replaced with natural gas or other renewable energy resources in Replacement Options 1 through 4		With No Carbon Penalty				
		***Power Supply Costs w/ The Thomson Restoration Project**	**Change in Cost with Each Option**			
			"Natural Gas Ownership Share Replacement" Option **Additional Cost**	**"Wind Replacement" Option** **Additional Cost**	**"Solar Replacement" Option** **Additional Cost**	**"Renewable Combination Replacement" Option** **Additional Cost**
0	**Base Assumption**	$8,225,246	$94,512	$138,827	$132,613	$117,733
1	**CO2 Penalty $9/ton**	$8,638,157	$101,188	$121,006	$135,615	$119,767
2	**CO2 Penalty $34/ton**	$10,139,823	$135,316	$63,998	$151,399	$126,422
3	**Low Coal Forecast (-30%)**	$7,599,704	$90,873	$144,911	$130,629	$117,640
4	**High Coal Forecast (+30%)**	$8,818,985	$99,710	$131,186	$134,550	$118,108
5	**Low Biomass (-10%)**	$8,215,652	$94,473	$138,849	$132,598	$117,739
6	**High Biomass (+10%)**	$8,234,662	$94,527	$138,826	$132,618	$117,723
7	**Lower Natural Gas (-50%)**	$7,990,121	$50,924	$140,800	$131,060	$118,139
8	**Low Natural Gas (-25%)**	$8,109,191	$78,937	$140,803	$131,632	$118,311
9	**High Natural Gas (+25%)**	$8,330,047	$107,848	$138,505	$133,804	$118,273
10	**Higher Natural Gas (+50%)**	$8,420,898	$116,407	$139,735	$134,824	$119,405
11	**Low Externality Values**	$8,000,759	$90,843	$140,484	$131,684	$117,459
12	**High Externality Values**	$8,449,734	$98,179	$137,170	$133,544	$118,008
13	**Low Wholesale Market (-50%)**	$7,874,324	$76,528	$162,957	$118,874	$107,143
14	**High Wholesale Market (+50%)**	$8,456,653	$90,661	$69,814	$153,121	$126,680
15	**No Wholesale Market**	$8,300,898	$80,498	$251,757	$217,531	$221,895
16	**Low Capital Cost (-30%)**	$8,166,022	$72,280	$36,308	$83,614	$65,411
17	**High Capital Cost (+30%)**	$8,284,469	$116,743	$241,347	$181,598	$170,051
* Power supply costs evaluated in Strategist for the 2014-2034 study period						
- Dollar amounts are shown in thousands and represent the present value of power supply cost in 2014 dollars over the study period						

The results of the carbon-constrained scenario resulted in an even greater benefit for the Thomson Project than the no carbon penalty scenario when stressed under these variables. This outcome demonstrates that under either planning assumption for carbon regulation, the Thomson Project continues to be the superior resource for Minnesota Power's customers when compared to other renewable resource alternatives. As Minnesota Power's 2013 Resource Plan identified, the best path forward is to continue to diversify the power supply along with reducing carbon emissions. Through the Thomson Project and restored operation at Thomson, Minnesota Power is able to balance the power supply cost and preserve a power supply that is reasonable, diverse, flexible and reliable for its customers.

VI. CONCLUSION

Minnesota Power believes that the Thomson Project is in the best interests of Minnesota Power customers and respectfully requests that the Commission approve eligibility of investments and expenditures related to the Thomson Project pursuant to Minn. Stat. § 216B.1645. Minnesota Power's development of this hydroelectric project will facilitate compliance with the renewable requirements under Minn. Stat. § 216B.1691. Minnesota Power looks forward to working with the Commission and other interested stakeholders to implement the Thomson Project.

Dated: July 3, 2014

Respectfully submitted,

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Appendix A – Resource Planning Analysis

Minnesota Power studied several replacement alternatives for Thomson with none of the alternatives able to completely replace the unit's valuable characteristics from both an economic and operational perspective. With the Thomson Project, Minnesota Power has the opportunity to operate Thomson for another 50-plus years and provide Minnesota Power customers an irreplaceable generation asset that is not only renewable, but capable of providing energy during periods of peak demand – a unique and valuable characteristic for renewable generation. This Appendix discusses in greater detail the replacement alternatives considered for Thomson and the results from the comparative analysis which support Minnesota Power's conclusion in the Public Interest Section of this Petition (in Section V).

I. Options Considered for Thomson Hydro Station Damage

By evaluating a wide range of replacement alternatives for Thomson in light of the damage it sustained, Minnesota Power will help to ensure a reasonable and prudent resource decision is made for its customers. Each alternative that was considered as a potential replacement for Thomson is outlined below. The detailed description of each potential replacement resource provides the key characteristics for that option and how they compare to Thomson as a generation resource. Restoration of Thomson was found to be in the best interest of customers in all cases.

A) Thomson Project

The Thomson Project returns the Thomson hydro station back to service with the annual production of 280,000 MWh of renewable energy and 71 MW of capacity[1] used to meet resource adequacy requirements. After completion, the Project will extend the life of the Thomson generating station to 50 years, providing a long-term economic resource that is free of carbon dioxide emissions, dispatchable for customer needs, that provides ancillary services to the power system and generates Renewable Energy Credits ("RECs") used for the Minnesota RES.

The Thomson Project will be completed at the end of 2016 and the total capital cost of the Project is expected to be $84 million.[2] Thomson is projected to start producing energy as early as summer 2014 from two units with the rest of the units producing energy by spring 2015. Section IV of this petition identifies additional details of the project.

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[1] Refers to MISO ICAP accredited capacity.
[2] The $84 million project cost utilized in the customer impact analysis is net of expected insurance proceeds and excludes internal costs and AFUDC on internal costs.

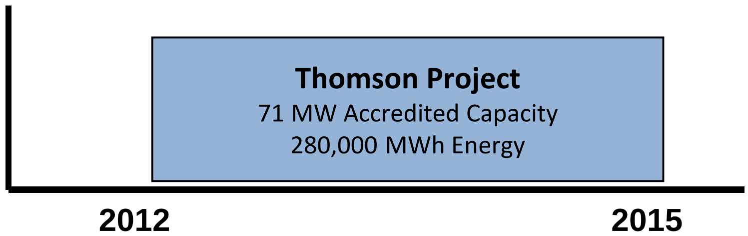

Figure 1. Thomson Project

B) Shutdown Thomson and Replace with Natural Gas or Renewable Alternative(s)

The option to not restore operations at Thomson and remove the generation from Minnesota Power's power supply would require the shutdown of the largest ponding hydro resource in Minnesota. The shutdown of Thomson would include costs for decommissioning and remaining plant balance obligations are considered as part of the economic analysis in this Petition (see Appendix B for more information on the shutdown analysis for Thomson).

A viable replacement power supply resource for Thomson would need to be able to cost-effectively provide a similar energy production schedule and contain the same renewable characteristics as Thomson. Based on results from the screening analysis described in Section V of this Petition, four viable replacement strategies were identified when Thomson was removed from the power supply: 1) Natural Gas Ownership Share, 2) Wind, 3) Solar, and 4) Renewable Combination of Solar and Wind. The characteristics of each are described in detail below.

Non-Renewable Alternatives

1) Natural Gas Ownership Share

The Natural Gas Ownership Share includes implementing a replacement strategy to procure a 71 MW (approximately 36%) ownership share of a 198 MW[3] natural gas combustion turbine. Based on the expected build and permitting schedule, the combustion turbine is assumed to be operational by January 1, 2018, with capacity and energy to be replaced by the wholesale market prior to the combustion turbine operational date. The 36% ownership share of the combustion turbine represents a direct replacement of the capacity removed when Thomson is shutdown. The energy replacement in this alternative becomes a combination of the combustion turbine output and the wholesale energy market based on economic dispatch. This option markedly does not replace the renewable attributes that Thomson brings to Minnesota Power's power supply and additional evaluation would be needed to gauge additional REC needs after 2025, depending on the status of Minnesota Power's REC portfolio.

[3] The 198 MW of capacity for the Combustion Turbine is based on summer operating capability. For economic modeling in the Strategist software, the size of the generating unit will vary each season depending on the operating conditions.

The larger peaking combustion turbine resource included in the "Natural Gas Ownership Share" alternative (198 MW) is more economic than the smaller peaking natural gas resource alternatives (typically 50 MW to 100 MW) due to a larger size that provides economies of scale and per unit cost reductions. In order to try to find the best resource alternative for Minnesota Power' s customers, the natural gas replacement option for Thomson assumed the cost for a 36% ownership share of the larger peaking combustion turbine.

Replacement Option 1 Natural Gas Ownership Share

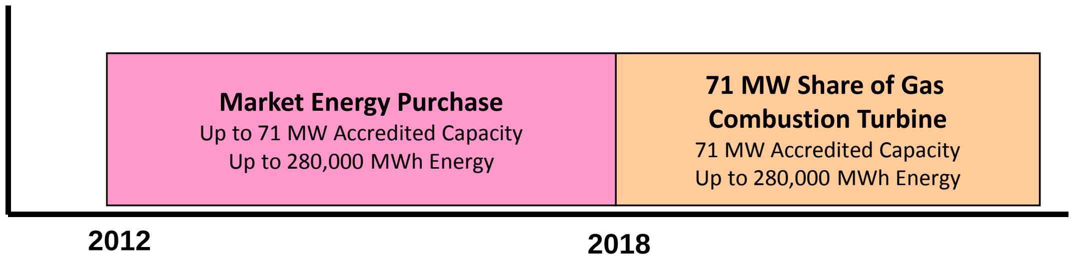

Figure 2. Combustion Turbine Replacement (Annual Energy)[4]

Based on current technology planning estimates for 2014 there is a range of capital costs for a new natural gas combustion turbine from **[TRADE SECRET DATA EXCISED]** that could be realized by customers. The operating costs of a natural gas generator also play an important role in the evaluation of this alternative due to its sensitivity to natural gas prices. The impact of fuel price variation is captured in the sensitivity analysis discussed later in this section.

There are benefits that natural gas resources can bring to Minnesota Power. Compared to a ponding hydro resource, a combustion turbine is not dependent on a variable fuel source such as water in which availability can be impacted by weather or previous hours of generation. A natural gas resource is typically available to generate at any time of the day and can provide the ancillary services that would be lost by the shutdown of Thomson. The combustion turbine does mimic Thomson's energy production and replaces all capacity, but does not replace Thomson's renewable attributes. As shown in Table 1, when replacing Thomson with a fossil fuel-based resource such as natural gas, emissions such as CO2, SO^2 and NO_x increase in the power supply; the costs associated with these increases are captured with the externality values included in the analysis.

[4] The replacement capacity and energy purchased from the market or utilized from the combustion turbine is determined by the Strategist software dispatch and varies annually depending on Minnesota Power's power supply.

Table 1. Emissions Increase with Ownership Share of Combustion Turbine

Average Annual Increase in Emissions With Ownership Share of Combustion Turbine 2018 to 2034	
Effluent	**Average Annual Increase**
Carbon (CO_2)	186,000 Tons
Sulfur Dioxide (SO_2)	72 Tons
Nitrogen Oxide (No_x)	66 Tons
Mercury (Hg)	1 lbs.

Renewable Alternatives

It is difficult to replace a ponding hydro facility like Thomson with other renewable resources. This is due to the ability to control the output of ponding hydro generation and the higher accredited capacity value Thomson has due to its ability to be counted on during times of peak load on the system – times when other intermittent renewable resources cannot be relied on. As demonstrated in the renewable resource replacement alternatives, the renewable attributes of Thomson can be replaced, but as a tradeoff, the alternatives will need to rely on the wholesale market to replace energy and/or capacity to the capability that is available with Thomson. Each renewable alternative is described in additional detail below.

2) Wind

Wind is defined as a 210 MW wind farm with an estimated accredited capacity value of 42 MW and has similar generation characteristics to Minnesota Power's North Dakota wind operations with annual generation of 790,000 MWh. Based on the expected build and permitting schedule and screening analysis results, the wind operational dates were separated into two phases with phase 1 operational by January 1, 2018, and phase 2 operational by January 1, 2019.[5]

This wind replacement option provides a tremendous amount of energy above what is required to just replace Thomson, which calls into question why this 210 MW of wind generation is included as a replacement alternative. The decision to include 210 MW of wind generation was based on the Strategist Proview expansion plan results conducted during the screening of plausible replacement alternatives. In a number of the expansion plans that were selected when Thomson was removed, there was 210 MW of wind added to replace the Thomson capacity in lieu of market energy and capacity alternatives. A Strategist Proview software constraint limits how much capacity can be procured from the market to ensure to not overburden a long-term resource portfolio with excessive market capacity purchases. The 210 MW of wind or 42 MW

[5] Up to 71 MW of replacement capacity and up to 280,000 MWh annual energy is also required prior to the operational date for the wind and is purchased from the wholesale power market for this alternative. The annual amount of replacement energy and capacity is part of the Strategist economic dispatch.

of accredited capacity was selected to satisfy the constraint and resulted in an expansion plan and plausible replacement alternative for Thomson.

The Wind replacement alternative replaces Thomson's RECs, but does not entirely replace Thomson's 71 MW of capacity; the remaining 29 MW of capacity is identified as being replaced by purchases from the wholesale capacity market. Another notable difference between the Wind replacement alternative and Thomson is the hourly generation profile, with Thomson generation having the capability to be controlled and provide energy during peak demand hours, where wind generation is only available when the wind is blowing. This difference in generation profile is captured in the Strategist software used to conduct the economic comparison of the replacement alternatives to the Thomson Project.

Replacement Option 2 Wind

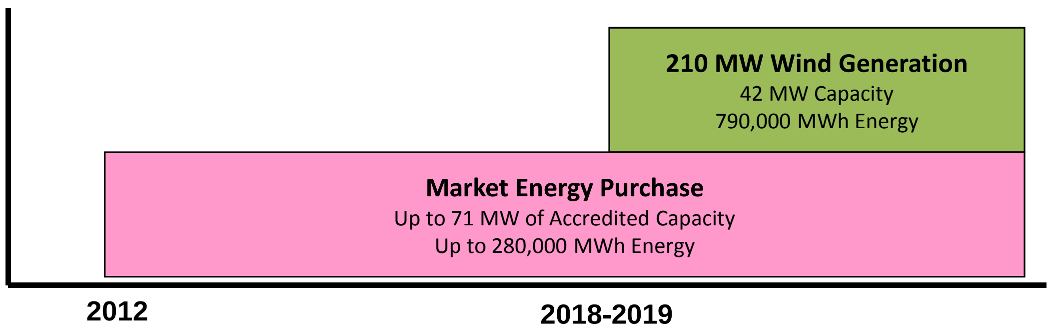

Figure 3. Wind Generation + Market Replacement (Annual Energy)

Based on current technology planning estimates for 2014 the 210 MW wind alternative has a cost range of **[TRADE SECRET DATA EXCISED]** that could be realized by customers for the resource investment.[6]

3) Solar

The Solar alternative is a 100 MW solar array with an estimated accredited capacity value of 58 MW and has similar generation characteristics to solar located in central Minnesota with an annual generation of 175,000 MWh. Based on the expected build and permitting schedule the 100 MW of solar is operational by January 1, 2017. Up to 71 MW of replacement capacity and up to 280,000 MWh of annual energy required prior to the operational date of the solar array is purchased from the wholesale power markets.

The Solar alternative replaces nearly all of Thomson's RECs, but does not entirely replace Thomson's 71 MW of capacity; the remaining 13 MW of capacity is identified as being

[6] Note that the capital cost for wind generation assumed the current federal production tax credit is not extended.

replaced by purchases from the wholesale power market when needed. Another notable difference between the Solar alternative and Thomson is the hourly generation profile, with Thomson generation having the capability to be controlled and providing energy during periods of high demand, where solar generation is more intermittent and only available when the sun is available. Although, solar generation is typically available during peak demand periods in the summer, the highest peak demand on Minnesota Power's system is during the winter months and is typically in the early evening when the sun is not available. Thomson is typically available during this peak period. This difference in the two generation profiles is captured in the Strategist software used in the economic comparison of the solar option to the Thomson Project.

Replacement Option 3 Solar

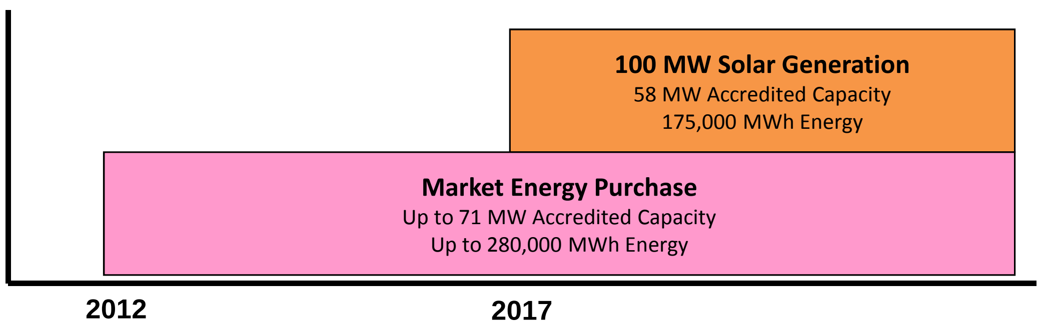

Figure 4. Solar Generation + Market Replacement (Annual Energy)

The solar resource alternative in the Solar option will require significant capital investment. Based on current technology planning estimates for 2014 the solar alternative has a cost range of **[TRADE SECRET DATA EXCISED]** that could be realized by customers for the resource investment. Note the capital cost for solar generation assumed the benefits from the current federal investment tax credit.

4) Renewable Combination

The Renewable Combination replacement alternative is a combination of solar and wind generation, including 105 MW of wind generation with an estimated accredited capacity value of 21 MW and 50 MW of solar generation with an accredited capacity value of 29 MW. The Renewable Combination option has similar generation characteristics as stated for alternatives 2 and 3. This combination was a viable alternative of two renewable resource options that were prevalent in the screening analysis.

Based on the screening evaluation and the expected build and permitting schedule, the 50 MW of solar is operational by January 1, 2017 and the 105 MW of wind is operational by January 1, 2025. Up to 71 MW of replacement capacity and up to 280,000 MWh annual energy required prior to the operational date is purchased from the wholesale power market. The Renewable Combination replacement alternative replaces all of Thomson's RECs, but does not entirely replace Thomson's 71 MW of capacity; the remaining 21 MW of capacity is identified as being replaced by purchases from the wholesale power market. Similar to alternatives 2 and 3, with Thomson generation having the capability to be controlled and providing energy during periods of high demand, Thomson's generation profile provides additional benefits for the customer when compared to the intermittent generation of solar and wind. This difference in generation profile is captured in the Strategist software used for the economic evaluation.

Replacement Alternative 4 Renewable Combination

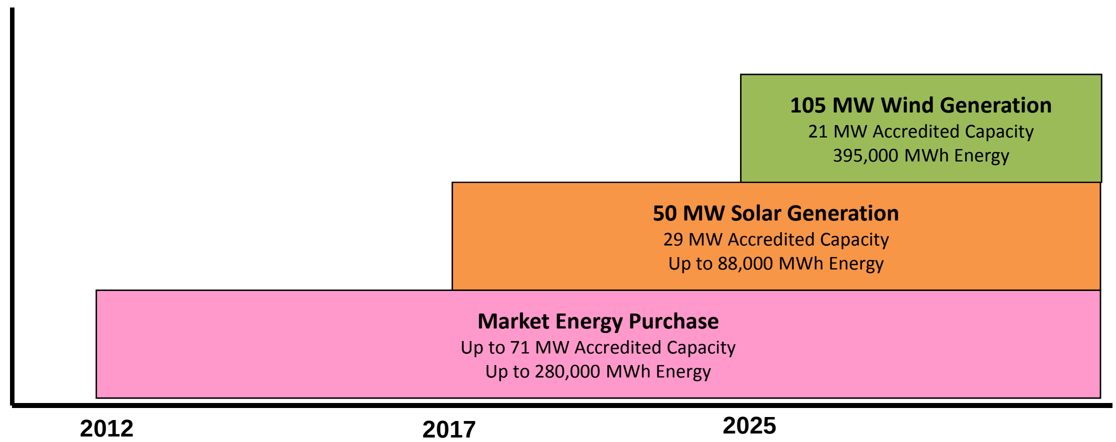

Figure 5. Wind and Solar Generation Replacement (Annual Energy)

Based on current technology planning estimates for 2014 the wind alternative has a cost range of **[TRADE SECRET DATA EXCISED]** and the solar alternative has a cost range of **[TRADE SECRET DATA EXCISED]** that could be realized by customers for the resource investments. Note the capital cost for wind generation assumed the current federal production tax credit is not extended and the capital costs for solar generation assumed the benefits from the current federal investment tax credit.

To fully evaluate the impact of integrating the replacement alternatives into Minnesota Power's system, it is necessary to go to a production cost evaluation of each option that takes into consideration more of the variables that drive a power supply implementation decision. The comparative analysis in the next section gives additional insight on how the Thomson Project continues to be in the best interest of customers compared to the natural gas and renewable alternatives.

II. Comparative Analysis Results

The Thomson Project provides a decisive range of benefits for Minnesota Power customers over the natural gas and three renewable replacement alternatives. These benefits range from $95 million to $139 million of customer savings (net present value in 2014 dollars) under the base assumptions over the 2014 to 2034 study period. Each of the alternatives were also evaluated and compared against the Thomson Project under a range of planning sensitivities. The rigorous sensitivity analysis confirmed a significant range of customer benefits, reinforcing the Thomson Project to be in the best interest of Minnesota Power customers.

The Strategist production cost software was utilized for the study period to help quantify the expected range of power supply benefits the Thomson Project would bring customers compared with the replacement alternatives. The entire cost comparison was also conducted under a "No CO2 Regulation Penalty" and a "With CO2 Regulation Penalty" condition to confirm that the Thomson Project was prudent under both resource planning assumptions.

To ensure that only the impact of the Thomson Project or the four replacement alternatives were being captured in the comparative analysis, the remaining capacity and energy requirements of Minnesota Power system over the study period were held constant in the evaluation. This assumption allowed the Thomson Project to be replaced with the replacement alternatives interchangeably so that the Present Value of Revenue Requirements ("PVRR") of the power supply costs could be directly compared to accurately analyze the effects of each.

Typical of Minnesota Power's comprehensive planning process, a range of sensitivities were also included in the comparative analysis to stress the Thomson Project and its alternatives. A complete list of the sensitivities that were stressed in both high and low conditions, and included in the comparative analysis, is included in Appendix C – Assumptions and Outlooks.

The comparative analysis results appear in the tables below and include all four replacement alternatives, Natural Gas Ownership Share, Wind, Solar and Renewable Combination. Each table demonstrates a comprehensive comparison of the Strategist power supply costs, represented by the PVRR value, with the Thomson Project and the change in cost that occurs when the four replacements alternatives are utilized. The values are provided in both the "No CO2 Regulation Penalty" outlook (Table 2 on page 10) and the "With CO2 Regulation Penalty" outlook (Table 3 on page11). A negative value in the replacement option columns indicates the alternative provides a savings to customers relative to the Thomson Project.

Overall, when the Thomson Project is compared to the resource alternatives, the Thomson Project is the lowest cost outcome for customers in a majority of the sensitivities assessed in this analysis under the "with" or "without" CO2 Regulation Penalty assumptions.

The results of the comparative evaluation under a "No CO2 Regulation Penalty" assumption identified that the Thomson Project was the lowest cost plan across all sensitivities. The customer benefit of the Thomson Project ranged from $36 million up to $252 million when compared to the replacement alternatives. The results clearly show the Thomson Project is the lowest cost path forward when compared to the other replacement alternatives.

The results of the comparative evaluation under a "With CO2 Regulation Penalty" assumption identified that the Thomson Project was the lowest cost plan across all sensitivities except for one, Low Capital Cost, where the Wind replacement option showed a benefit of $10 million over the study period. The Wind replacement option showed a benefit to the Thomson Project when the wind project cost are reduced by **[TRADE SECRET DATA EXCISED]** in the Low Capital Cost sensitivity. Otherwise, the Thomson Project showed a benefit to customers ranging up to $225 million when compared to the replacement alternatives. Similar to the comparative analysis results in the "No CO2 Regulation" assumption, the Thomson Project was again found to be the lowest-cost path forward when compared to the other replacement options.

Table 2 – Thomson Project Evaluation with "No Carbon Regulation Penalty" Assumptions

Table shows the increase/decrease in costs when the Thomson Project is replaced with natural gas or other renewable energy resources in Replacement Options 1 thru 4		With No CO2 Regulation Penalty				
		*Power Supply Costs w/ The Thomson Project	Change in Cost with "Natural Gas Ownership Share" Additional Cost (Less Cost)	Change in Cost with "Wind" Additional Cost (Less Cost)	Change in Cost with "Solar" Additional Cost (Less Cost)	Change in Cost with "Renewable Combination" Additional Cost (Less Cost)
0	**Base Assumption**	$8,225,246	$94,512	$138,827	$132,613	$117,733
1	**CO2 Penalty $9/ton**	$8,638,157	$101,188	$121,006	$135,615	$119,767
2	**CO2 Penalty $34/ton**	$10,139,823	$135,316	$63,998	$151,399	$126,422
3	**Low Coal Forecast (-30%)**	$7,599,704	$90,873	$144,911	$130,629	$117,640
4	**High Coal Forecast (+30%)**	$8,818,985	$99,710	$131,186	$134,550	$118,108
5	**Low Biomass (-10%)**	$8,215,652	$94,473	$138,849	$132,598	$117,739
6	**High Biomass (+10%)**	$8,234,662	$94,527	$138,826	$132,618	$117,723
7	**Lower Natural Gas (-50%)**	$7,990,121	$50,924	$140,800	$131,060	$118,139
8	**Low Natural Gas (-25%)**	$8,109,191	$78,937	$140,803	$131,632	$118,311
9	**High Natural Gas (+25%)**	$8,330,047	$107,848	$138,505	$133,804	$118,273
10	**Higher Natural Gas (+50%)**	$8,420,898	$116,407	$139,735	$134,824	$119,405
11	**Low Externality Values**	$8,000,759	$90,843	$140,484	$131,684	$117,459
12	**High Externality Values**	$8,449,734	$98,179	$137,170	$133,544	$118,008
13	**Low Wholesale Market (-50%)**	$7,874,324	$76,528	$162,957	$118,874	$107,143
14	**High Wholesale Market (+50%)**	$8,456,653	$90,661	$69,814	$153,121	$126,680
15	**No Wholesale Market**	$8,300,898	$80,498	$251,757	$217,531	$221,895
16	**Low Capital Cost (-30%)**	$8,166,022	$72,280	$36,308	$83,614	$65,411
17	**High Capital Cost (+30%)**	$8,284,469	$116,743	$241,347	$181,598	$170,051

* Power supply costs evaluated in Strategist for the 2014-2034 study period

- Dollar amounts are shown in thousands and represent the present value of power supply cost in 2014 dollars over the study period

Table 3 – Thomson Project Evaluation with "With CO2 Regulation Penalty" Assumption

Table shows the increase/decrease in costs when the Thomson Project is replaced with natural gas or other renewable energy resources in Replacement Options 1 thru 4		With CO2 Regulation Penalty of $21.50/ton in 2019				
		*Power Supply Costs w/ The Thomson Project	Change in Cost with "Natural Gas Ownership Share " Additional Cost (Less Cost)	Change in Cost with "Wind " Additional Cost (Less Cost)	Change in Cost with "Solar " Additional Cost (Less Cost)	Change in Cost with "Renewable Combination" Additional Cost (Less Cost)
0	Base Assumption	$9,405,833	$117,187	$92,619	$142,799	$122,789
1	CO2 Penalty $9/ton	N/A	N/A	N/A	N/A	N/A
2	CO2 Penalty $34/ton	N/A	N/A	N/A	N/A	N/A
3	Low Coal Forecast (-30%)	$8,829,707	$109,933	$98,382	$139,185	$122,075
4	High Coal Forecast (+30%)	$9,949,749	$127,191	$86,982	$147,661	$124,293
5	Low Biomass (-10%)	$9,395,484	$117,176	$92,636	$142,794	$122,784
6	High Biomass (+10%)	$9,416,061	$117,209	$92,518	$142,810	$122,770
7	Lower Natural Gas (-50%)	$9,175,840	$67,701	$95,610	$140,886	$123,067
8	Low Natural Gas (-25%)	$9,294,526	$103,791	$94,047	$141,603	$122,926
9	High Natural Gas (+25%)	$9,519,167	$127,743	$88,862	$143,548	$121,584
10	Higher Natural Gas (+50%)	$9,610,692	$137,969	$86,545	$145,629	$121,562
11	Low Externality Values	$9,319,292	$116,302	$92,662	$142,498	$122,537
12	High Externality Values	$9,492,373	$118,071	$92,574	$143,099	$123,041
13	Low Wholesale Market (-50%)	$8,822,010	$103,382	$126,990	$131,082	$109,968
14	High Wholesale Market (+50%)	$9,726,055	$111,438	$27,546	$162,177	$136,503
15	No Wholesale Market	$9,558,850	$110,191	$189,285	$224,785	$215,981
16	Low Capital Cost (-30%)	$9,346,606	$94,957	($9,899)	$93,801	$70,466
17	High Capital Cost (+30%)	$9,465,054	$139,422	$195,139	$191,785	$175,110
* Power supply costs evaluated in Strategist for the 2014-2034 study period						
- Dollar amounts are shown in thousands and represent the present value of power supply cost in 2014 dollars over the study period						

The outcome of this comparative analysis demonstrates that under a wide and robust range of planning assumptions, the Thomson Project continues to be the superior resource for Minnesota Power's customers, even when compared to other renewable resource alternatives. As Minnesota Power's 2013 Resource Plan and Energy***Forward*** resource strategy identifies, customers will benefit as Minnesota Power continues to diversify its power supply by sustaining its existing renewable resources and creatively transforming its resource portfolio by adding new resources that meet customer requirements in a reasonable and prudent manner. Through the Thomson Project and continued operation at Thomson, Minnesota Power is able to preserve a power supply that is reasonable, diverse, flexible, and reliable for its customers.

Appendix B – Discussion on Shutdown Analysis for Thomson

Minnesota Power considered two major options for Thomson after it was damaged and brought offline due to the June 2012 flood. The first option was to repair Thomson and extend the operating life by implementing the Thomson Project. The second option was to shut down Thomson and replace the energy with a reasonable generation alternative.

Soon after the June 2012 flood, Minnesota Power conducted an internal high-level analysis to determine whether it made sense for the Company to seriously pursue the option of retiring Thomson as a viable alternative. The option to simply walk away from Thomson was not considered feasible, since the Company is required to fulfill Federal Power Act obligations under the FERC license.[1] The initial high-level analysis indicated that it would be too costly and involve too much financial and regulatory risk to pursue a shutdown alternative. However, as the Thomson Project was being developed with the FERC and other stakeholders, the Company commissioned our engineering consultant, URS, to perform a more detailed study of the costs and feasibility of a potential Thomson closure in order to validate the Company's earlier high-level internal assessments. The URS study confirmed that the expected costs to close Thomson were too high to be considered a viable alternative for customers.

This Appendix provides clarification about how the Thomson shutdown analysis compares with the decommissioning assumptions used in Minnesota Power's 2014 Remaining Life Petition, provides additional details of the shutdown analysis conducted by URS, and discusses the process the Company would need to go through in order to surrender its FERC license to operate Thomson.

A. Thomson Shutdown Analysis vs. Decommissioning Assumptions

The topic of decommissioning was discussed at a Commission Hearing on April 23, 2014, in Minnesota Power's 2013 Remaining Life Petition.[2] The Commission instructed the Company to ensure consistency of assumptions used in calculations related to decommissioning across all Dockets filed by the Company. Minnesota Power agreed with the Commission's

[1] As described in Section III of the Petition, Thomson is part of the St. Louis River Hydroelectric Project, regulated by the FERC, Project No. 2360.
[2] Docket No. E015/D-13-275.

directive and promised to provide adequate explanations and support for changes in assumptions at the time we file them with the Commission.

The shutdown analysis conducted for Thomson in the wake of the June 2012 flood is different than the decommissioning assumptions provided in Minnesota Power's 2014 Remaining Life Petition.[3] The shutdown analysis for the Thomson Project considered what Minnesota Power would be required to do now, with a "broken" Thomson, should it not be repaired. The analysis was intended to provide a financial basis for the decision to proceed with reconstruction of Thomson and was not intended as a viable decommissioning plan. The Company was faced with a different situation in June 2012 than it would be in 50 or more years in the future with a normal decommissioning process of an operating dam.

In the 2014 Remaining Life Petition, it was assumed that Thomson would be reconstructed, a life extension requested for the facility, and no decommissioning costs would be included in depreciation rates. The Company has not previously collected decommissioning costs in depreciation rates for its hydro facilities due to the significant uncertainty over the timing, extent and nature of future decommissioning costs. In this Petition, the term "shutdown" analysis is used to describe the analysis of retiring a broken Thomson, rather than "decommissioning" analysis, in order to help distinguish the different purposes of these different studies.

The Company believes there is currently too much uncertainty about what Minnesota Power might do at the end of Thomson's operating life to include any decommissioning costs in depreciation rates (as is the case at all other Minnesota Power hydro facilities). Thomson has operated for more than 100 years and it is highly improbable that it will be decommissioned in the foreseeable future. When and if the time gets closer to retire Thomson, the Company will look at all possible ways to make the most prudent decisions, including a potential sale of the facility. These issues will likely be reconsidered when the current FERC license becomes due to be renewed in 2035.

[3] Docket No. E015/D-14-318.

B. URS Shutdown Analysis

As stated previously, Minnesota Power commissioned URS to develop an engineering study to evaluate a post-flood shutdown option for Thomson. This study was intended to evaluate what remediation would be required if the Company did not proceed with restoring Thomson and to provide a cost estimate for the "shutdown alternative" to use in the analysis to determine whether the Thomson Project is in the best interests of customers.

URS evaluated an option that would entail partial removal of dam structures at Thomson, and removal and stabilization of the hazardous sediments in the Thomson Reservoir. This is the option Minnesota Power believed would be necessary at a minimum in order to fulfill the regulatory requirements necessary as part of the process of surrendering the FERC license for Thomson. This option did not include costs for the full removal of all existing dam structures or removal of the St. Louis Hydro System reservoirs, which could potentially be required in an actual shutdown of the facility. The option also did not include costs for routine operation and maintenance of Thomson during the shutdown process, expected to take from 7 to 15 years to complete, and it did not include the continuing costs to operate Minnesota Power's remaining hydro facilities, which are currently operated from the Thomson control room.

The URS study concluded that this shutdown option was technically feasible and that the capital cost to complete it would be approximately $55 million.

C. Process to Surrender FERC License and Shutdown Thomson

The current 40-year FERC license to operate Thomson will expire in 2035. Minnesota Power expects and intends to retain Thomson as a valuable part of its power supply in perpetuity. However, if Minnesota Power elected not to rebuild and repair the Thomson facilities, it would be required by the FERC to submit an application to surrender its project license. Regulations regarding surrender of license are located at 18 CFR Part 6. It is important to note that a surrender application must be completed and approved prior to commencing with any project decommissioning procedures. As part of the license surrender process, Minnesota Power would be required to consult with interested parties and prepare an application that discusses how the following issues would be addressed:

- Why the project is no longer economical to operate?
- How the project will be decommissioned?
- What are the predicted environmental and social impacts of decommissioning?
- How will the predicted impacts be addressed?

For dam removal, permits are required at the federal, state and local levels. Discussions and proceedings take place as to the environmental impacts on the dam removal, from such items as sedimentation containing contaminants that have collected behind the dam and marine species that will be affected. Other agencies that have varying levels of authority for dams that may assess the impact of removal of a dam and from which permits may be required are as follows:

- Army Corps of Engineers
- National Marine Fisheries Service
- US Fish and Wildlife Service
- Environmental Protection Agency
- US Forest Service
- Bureau of Land Management
- National Parks Service
- Bureau of Indian Affairs

Additionally, the Minnesota State Historic Preservation Office ("SHPO") would need to be involved in a potential Thomson closure. All of the buildings at Thomson are eligible to be placed on the SHPO register of historical buildings and the FERC license requires us to comply with SHPO regulations.

The following is a summary of the basic steps Minnesota Power would likely take if it were to surrender the FERC license to operate Thomson. Some steps could possibly be eliminated depending on public perception of the proposed decommissioning and the FERC's assessment of the economic viability of the project and whether ownership should be transferred to another licensee.

Minnesota Power would need to coordinate with agencies and stakeholders to make preliminary determinations regarding the level of decommissioning required for the project (e.g., leaving structures in place and removing selected equipment, partial removal of structures, complete removal of structures and equipment, breaching of embankment sections, erosion control measures, etc.), as well as deciding on other alternatives if the application is opposed (e.g., recreation interests). Consultation with agencies and stakeholders would need to be documented and included in the application.

License surrender is similar to relicensing in that it requires a three-stage consultation process as described in the FERC regulations 18 CFR 16.8. The content of a surrender application is not as rigorous as for relicensing, meaning the applicant would only need to submit the environmental exhibits that are relevant to the specific surrender proposal.

- Stage One Consultation would consist of preparation and distribution of the Initial Consultation Document ("ICD") to potentially interested stakeholders. This would include the existing relicense distribution list and other local entities to be added. The ICD would consist of an overview of the potentially affected environmental resources, a project description, and a brief decommissioning proposal. Agency information or study requests obtained during this stage of consultation must be addressed in the preparation of the surrender application.

- Stage Two Consultation would commence with Minnesota Power distributing a draft surrender application for agency and stakeholder review and comment. The draft application would clarify the reason(s) for surrendering the license, provide a detailed decommissioning plan, describe any anticipated environmental effects, and incorporate the comments obtained during the stage one consultation.

- Stage Three Consultation would consist of filing of the final surrender application with the FERC. The application would be publicly noticed (30 days), giving agencies and stakeholders another comment period. If applicable, the FERC would begin Section 7 consultation as well as initiation of Section 106 consultations with the State Historic Preservation Officer. The FERC would issue a notice soliciting applications for other parties to assume the license. This step may be eliminated if there would be a settlement agreement between all interested parties that supports the project's decommissioning.

The FERC would complete a National Environmental Policy Act ("NEPA") analysis for the surrender, which usually takes the form of an environmental analysis. The FERC would consider all comments received during the NEPA process and the licensee's consultation record prior to issuing a surrender order. A surrender order would contain terms and requirements to be completed by the licensee prior to license termination.

Only after all of the specified terms of the surrender order are satisfied, would the FERC formally terminate the license and release jurisdiction over the hydroelectric facility.

There are many uncertainties in the process of surrendering a FERC license. It is possible that unknown entities could oppose the surrender application. It is also possible that Minnesota Power could spend a considerable sum to surrender its license only to have a third party file with the FERC to take over the existing license. A review by URS of case histories from decommissioning of FERC licensed dams indicates that the process may take from 7 to 15 years. The licensing surrender process would have a significant effect on the cost of the decommissioning and the facilities would have to be maintained and operated until the completion of the decommissioning.

D. Attempt to Sell Before Surrender of License and Decommissioning

Another option for Minnesota Power if it chose not to reconstruct Thomson would be for the Company to attempt to sell the facility and transfer the existing FERC license to another party rather than incur the costs associated with license surrender and decommissioning. Depending on the negotiated terms of sale, this solution could be a least-cost scenario for Minnesota Power customers. However, this option was not considered feasible in June 2012, given the inoperable condition of the Thomson facility after the flood. Any entity interested in purchasing the facility at that time would have needed to restore Thomson to meet FERC requirements in order to qualify for a transfer of the FERC license. The entity would also need to demonstrate the financial ability to maintain the facilities into the future.

Appendix C – Assumptions and Outlooks

Appendix C provides the assumptions and outlooks used in Minnesota Power's evaluation that identified the Thomson Project is in the public interest. The analysis supports the statements and data presented in Section V of this Petition that substantiates why proceeding with the Thomson Project is in the best interest of Minnesota Power customers.

The following section provides a summary of the key economic modeling assumptions and basis that Minnesota Power utilized in the Strategist Proview analysis completed for the Thomson Project. The assumptions used in the economic evaluation align with the assumptions used in Minnesota Power's 2013 Integrated Resource Plan ("2013 Plan") unless noted otherwise.

A. Base Case Economic Modeling Assumptions – a review of the base economic assumptions used in the analysis for the Petition.

B. New Asset Resources – a description of new resource additions included in the Baseline Scenario Power Supply.

C. Sensitivity Analysis Results

D. Other Changes Made for the Petition Evaluation

A. Base Case Economic Modeling Assumptions

Study Period

The focus of the Thomson Project analysis is 2014 through 2034. The power supply cost shown in the Petition are the net present value of cost from 2014 thru 2034 and are reported in 2014 dollars, unless noted otherwise.

Baseline Scenario Power Supply Assumptions

1. The Baseline Scenario Power Supply includes the generation resource decisions of the short-term and long-term action plans identified in Minnesota Power's 2013 Plan.

   a. Short-term action plan (2013-2017)

      i. 204.8 MW Bison 4 Wind Project by end of 2014

      ii. Refuel Laskin Energy Center ("LEC") Units 1 and 2 with natural gas in 2015

      iii. Shut down Taconite Harbor Energy Center ("THEC") Unit 3 ("THEC3") in 2015

      iv. 50 MW bilateral bridge purchases from 2016 thru 2019

      v. Retrofit of Boswell Energy Center ("BEC") Unit 4 ("BEC4") with environmental controls

b. Long-term action plan (2018-2027)

i. New 200 MW share of a combined cycle natural gas facility in 2023

ii. 250 MW bilateral power purchase from Manitoba Hydro starting 2020

c. New generation resources added past the long-term action plan for the purpose of ensuring resource adequacy beyond the Company's current resource plan (2028 to 2034)

i. New 54 MW Wartsilla generator in 2031

<u>Externalities, Pricing and Wholesale Market</u>

1. The base case forecasts utilized for emission externality values, natural gas prices, market energy prices, and market capacity prices over the study period:[1]

a. The base forecast utilized the Metropolitan Fringe externality values from the State Externality Docket published on June 5, 2013, under Docket Nos. E999/CI-93-583 and E999/CI-00-1636. This is a change from the 2013 Plan where the externality values were based on the externality values from the State Externality Docket published on June 13, 2012. The mid-point of the externality values is utilized in the Base Case. These value ranges are approximate representations of what is in the Strategist database.

i. Carbon externality cost range: $2.50/ton in 2014 to $3.75/ton in 2034

ii. Oxides of nitrogen ("NO_x") externality cost range: $300/ton in 2014 to $450/ton in 2034

iii. Particulate matter ("PM_{10}") externality cost range: $3,500/ton in 2014 to $5,400/ton in 2034

iv. Carbon monoxide ("CO") externality cost range: $1.50/ton in 2014 to $2.25/ton in 2034

v. Lead ("Pb") externality cost range: $2,700/ton in 2014 to $4,000/ton in 2034

b. The SO_2 allowance price assumptions utilized in the base forecast.

i. SO_2 allowance price for Clean Air Interstate Rule ("CAIR") Replacement Group 2: $202/ton in 2018 to $11/ton in 2024

ii. This assumption was not included in the base forecast in the 2013 Plan.

c. Natural Gas forecast assumptions utilized in the base forecast.

[1] Values are in nominal dollars.

i. Natural Gas at Henry Hub: $4/MMBtu in 2014 to $6.50/MMBtu in 2034

ii. The projected natural gas prices used in this Petition is a change from the projections used in the 2013 Plan. The natural gas prices were updated with Minnesota Power's most recent forecast.

ii. Natural gas supply prices reflect the projected spot market at Henry Hub. In addition a regional delivery charge of $0.42/MMBtu for the fuel supply of all new gas generation alternatives is included in the petition including the natural gas fuel switch at LEC. The delivery charges were escalated at 2.1% annually after 2014.

d. Delivered Coal price forecast assumptions utilized in the base forecast represent the attributes of each of Minnesota Power's facilities and include:

[TRADE SECRET DATA EXCISED]

e. Wholesale Market Capacity (approximate): $200/MW-month in 2014 to $11,600/MW-month in 2034. Wholesale market capacity was made available up to a maximum of 50 MW for the model during all study years.

i. The projected market capacity prices used in this Petition is a change from the projections used in the 2013 Plan. The market capacity prices were updated with Minnesota Power's most recent forecast.

f. Wholesale Market Energy (approximate): $30/MWh in 2014 to $60/MWh in 2034. Additional implementation detail provided in item 3.

i. The projected market energy prices used in this Petition is a change from the projections used in the 2013 Plan. The market energy prices were updated with Minnesota Power's most recent forecast.

g. The base forecast for energy prices assumed no cost related to the regulation of carbon dioxide ("CO_2") emissions.

2. The base case energy market interaction structure for Minnesota Power's analysis assumed that the wholesale market was available throughout the study period. The wholesale energy market structure in the modeling represents the day-ahead interaction with the Midcontinent Independent System Operator ("MISO") regional market and helps utilities optimize power supply for customers. A sensitivity called 'No Wholesale Market' was developed that assumed the wholesale energy market was unavailable as a power supply resource long term (four years beyond the study start date). The sensitivity was included to understand the impact to the planning analysis when the availability of the regional wholesale energy market is removed. A more detailed description of each market interaction structure is provided below.

a. <u>With Wholesale Energy Market</u> ("With Market") – A conservative approach was taken when creating the wholesale energy market that would be made available as a power supply resource during the study period. While the regional market is a valuable and useful piece of a utility's power supply, it should not be considered an "endless" resource. To help account for the increased risk and volatility that is present when purchasing incrementally larger amounts of energy from the short-term market, an increasing price adder was included based on the level of energy purchased. As the volume of energy purchased from the market increased, so did the price adder. This is referred to as a "Tiered Energy Market" and includes the following pricing assumptions:

i. 0 to 150 MW at base forecast price

ii. 151 to 300 MW at base forecast price plus $15/MWh premium adder

iii. 301 to 600 MW at base forecast price plus $40/MWh premium adder

iv. Greater than 600 MW at emergency energy price ($260/MWh in 2014 and escalates at approximately 2% annually)

b. <u>Without Wholesale Energy Market</u> ("No Wholesale Market") – For this scenario, the Tiered Energy Market described above was removed starting in 2018 and only emergency energy at $250/MWh in 2012 and escalates at approximately 2% annually was made available as a power supply resource. As this scenario did not provide for purchasing energy from the wholesale energy market during hours of generation unit planned and forced outages, the planned outages and forced outages for Minnesota Power's generation resources were removed from the model. Removing these outages prevents the model from burdening the customer with additional resources that are not needed for reliability, which would also increase customer cost and power supply surpluses.

The No Market scenario was included to address stakeholder feedback that identified long-term expansion plan modeling could be done with no energy procured from a regional energy market, such as MISO, effectively cutting the utility off from the region as if the utility were located on an island. While Minnesota Power does not envision a future without an effective and beneficial regional market, it conducts this scenario to help identify the long-term resource actions that align under both planning methodologies.

3. The estimated decommissioning cost for Minnesota Power's small coal units for the shutdown scenarios discussed in the 2013 Plan are from a study completed by Burns & McDonnell called 2011 Baseload Diversification Study. These costs, along with the remaining plant balances at each facility, are assumed to be recovered and depreciated for 10 years past the shutdown date.

   The estimated shutdown cost for Thomson for the shutdown scenario discussed in this Petition is from an analysis completed by URS. These costs, along with the remaining plant balance for Thomson, are assumed to be recovered and depreciated for 10 years past the shutdown date. For Thomson, the shutdown date was assumed to be 2014. In the Thomson shutdown scenario the overall O&M cost for Minnesota Power's hydro generation fleet does not decrease in proportion to the MW being removed. To account for this, after Thomson is shut down, $4.5 million of O&M is added to the remaining hydro fleet modeled in Strategist and escalated annually thereafter. The shutdown study is discussed further in Appendix B.

Minnesota Power Resources and Bilateral Power Transactions

Another important component of a utility's power supply are contracted purchases and sales that are conducted within the industry to optimize the power surpluses and deficits that occur due to industry load and supply changes. These transactions are called bilateral transactions and allow Minnesota Power to work with other entities to procure energy and capacity (see Appendix C from the 2013 Plan for a list of Minnesota Power's current bilateral transactions included in the Baseline Scenario).

A bilateral transaction is functionally different than the day-ahead regional energy and capacity markets represented by the MISO tariff construct in that bilateral transactions are typically forward, medium- to longer-term contracts with defined pricing terms. 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.

Emission Rate Modeling For Minnesota Power Generation and New Alternatives

The emission rates for the thermal generation units included in Strategist are modeled as tons or pounds per MMBtu of fuel consumed for energy production. The level of effluents emitted per MWh generated will vary depending on the output level of a generation facility. As a generator is dispatched to a lower output level because of economic conditions, the effluents emitted per MWh will increase due to the generator operating at a less optimal level when compared to running at full output. The effluents modeled with emission rates in Strategist are:

a. Carbon Monoxide

b. Carbon Dioxide

c. Lead

d. Mercury

e. Nitrogen Oxide

f. Particulate Matter 10

g. Sulfur Dioxide

Minnesota Power Load and General Economic Assumptions

1. Customer energy and demand requirements are based on the Moderate Growth Scenario – Expected Case in Minnesota Power's 2013 Annual Electric Utility Forecast Report ("AFR2013"). The energy and demand forecast is based on the AFR2013 econometric modeling results plus customer adjustments for increased energy sales to new customers and transmission losses.

Using the AFR2013 forecast is a change from the load forecast used in the 2013 Plan, which used Minnesota Power's 2012 Annual Electric Utility Forecast Report forecast.

Example of the Energy and Demand Calculation:

The Moderate Growth Scenario from Table C.i. on page 41 of Minnesota Power's AFR2013 is the base forecast for the Petition. Note the annual peak demand for the Summer Season is used for the Peak Demand in the Thomson Project evaluation. The values needed to calculate the annual energy sales and annual peak demand is the econometric forecast and the customer adjustments. Below are the values and calculations from Table C.i. of the AFR2013 used to calculate the Annual Energies and Annual Peak Demand used in the Strategist software for the Petition:

Annual Energies (Minnesota Power Delivered Load) = Econometric + Net Energy Added

Annual Summer Peak Demand (Minnesota Power Delivered Load) = Econometric Summer Peak Demand + Net Load Added

Refer to page 39 of the AFR2013 for a description of the Customer Generation Adjustments ("Net Load Added" or "Net Energy Added").

The transmission losses of 6 percent are added to the Annual Energies to capture the power supply requirements for serving Minnesota Power's customers.

2. Capacity accreditation values for generators are the installed capacity ("ICAP") and are based on MISO's Planning Year 4 (June 2012 thru May 2013) generation performance test results per the Module E Resource Adequacy program.
3. Planning reserve margin is based on MISO's required reserve margin of 11.32% based on its 2012 Loss of Load Expectation study and installed generating capability and projected energy demand in the MISO region.
4. The utility discount rate is the weighted average cost of capital for Minnesota Power based on current capital structure and allowed return on equity. The utilized discount rate is 8.18%.
5. General escalation rate of 2.1% was utilized, except for capital cost and operation and maintenance for new generation which is escalated at 3% per year.

B. New Asset Resources Included in the Baseline Scenario Power Supply

The capital costs for the new resource alternatives included in the 2013 Plan's short-term and long-term action plans that form the Base Case for the Baseline Scenario Power Supply were developed using Minnesota Power's most current planning estimates for such resources. The estimates are high level engineering projections and typically have a minimum of +/- 30% range of accuracy.

1. Partial ownership share of 408 MW (approximate) natural gas 1x1 combined cycle natural gas facility
    a. Estimated capital build cost plus a transmission upgrade cost in 2014 dollars is **[TRADE SECRET DATA EXCISED]**
2. Partial ownership share of 214 MW (approximate) natural gas combustion turbine unit
    a. Estimated capital build cost plus a transmission upgrade cost in 2014 dollars is **[TRADE SECRET DATA EXCISED]**
3. 55 MW (approximate) natural gas reciprocating engines (6 x 9.2MW engines)
    a. Estimated capital build costs in 2014 dollars is **[TRADE SECRET DATA EXCISED]**
4. 105 MW (approximate) wind farm located in North Dakota
    a. Estimated capital build costs in 2014 dollars is **[TRADE SECRET DATA EXCISED]**
    b. Assumed the federal production tax credit is not extended past 2013.
5. 50 MW (approximate) fixed tilt Polycrystalline solar facility
    a. Estimated capital build costs in 2014 dollars is **[TRADE SECRET DATA EXCISED]**
    b. In this Petition an investment tax credit is applied to builds prior to 2018.
    c. The estimated capital build cost for a solar facility used in this Petition is a change from the capital build cost used in the 2013 Plan. The capital build cost was updated to capture the decrease in solar cost realized since the 2013 Plan.

C. Variables Stressed high or low and Scenario Sensitivities utilized in the Sensitivity Analysis

The following variables were stressed low and high in the single variable sensitivity analysis.

1. Wholesale market energy
    a. A low sensitivity representing a decrease of 50% from base: **[TRADE SECRET DATA EXCISED]**
    b. A high sensitivity representing an increase of 50% from base: **[TRADE SECRET DATA EXCISED]**
2. Natural gas price forecast at Henry Hub

a. A low sensitivity representing a decrease of 50% from base: **[TRADE SECRET BEGIN** $2/MMBtu in 2014 to $3/MMBtu in 2034. **TRADE SECRET ENDS]**

b. A low sensitivity representing a decrease of 25% from base: **[TRADE SECRET BEGIN** $3/MMBtu in 2014 to $5/MMBtu in 2034. **TRADE SECRET ENDS]**

c. A high sensitivity representing an increase of 25% from base: **[TRADE SECRET BEGIN** $5/MMBtu in 2014 to $8/MMBtu in 2034. **TRADE SECRET ENDS]**

d. A high sensitivity representing an increase of 50% from base: **[TRADE SECRET BEGIN** $6/MMBtu in 2014 to $10/MMBtu in 2034. **TRADE SECRET ENDS]**

3. Carbon regulation planning value[2]

The evaluation of several carbon regulation levels gives insight into the customer impact of these potential carbon regulation prices; however, in Minnesota Power's opinion these costs should not directly impact long-term resource decisions until regulation has been defined and approved for implementation. The carbon regulation values for the sensitivities are from the 2014 Order Establishing 2014 Estimate of Future Carbon Dioxide Regulation Costs, pursuant to Minn. Stat. § 216H.06, in Docket No. E-999/CI-07-1199. This is a change from the 2013 Plan where the carbon regulation values for the sensitivities were from the 2012 Order Establishing 2012 Estimate of Future Carbon Dioxide Regulation Costs.

a. A sensitivity based on the low carbon regulation value ranging from $9/ton starting in 2019 to $12/ton in 2034.

b. A sensitivity based on the mid carbon regulation value ranging from $21.50/ton starting in 2019 to $29/ton in 2034.

c. A high sensitivity based on the high carbon regulation value ranging from $34/ton starting in 2019 to $46/ton in 2034.

The carbon regulation planning value used in this Petition does not specifically take into account the EPA's proposed Clean Power Plan that will regulate carbon emissions from the electric industry.

4. Externality costs

The values for PM_{10}, CO, NO_x, Pb, and CO_2 were stressed to the low and high levels indicated in the Metropolitan Fringe from the State Externality Docket, Docket Nos. E-999/CI-93-583 and E-999/CI-00-1636.

5. Coal fuel prices

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[2] All carbon regulation planning values reflect costs in dollars per ton.

   a. The low sensitivity reduced coal prices by approximately 30% from base.

   b. The high sensitivity increased coal prices by approximately 30% from base.

6. Biomass fuel prices

   a. The low sensitivity reduced biomass prices by approximately 10% from base.

   b. The high sensitivity increased biomass prices by approximately 10% from base.

D. Other changes made in the Thomson Project Model

The following are specific changes made to the Base Case assumptions from the 2013 Plan to the Thomson Project evaluation.

1. To align with the energy sales forecast assumptions in AFR 2013, the moving of Rapids Energy Center ("Rapids") to the regulated side of business is assumed to occur January 1, 2014. The 2013 Plan assumed Rapids would be moved to regulated in April 1, 2013.

2. The Rapids biomass expansion assumed to occur in January 2015 in the 2013 Plan was removed in the Thomson Project evaluation based on the current status of Rapids project.[3]

3. **[TRADE SECRET DATA EXCISED]**

[3] The Company did not receive Commission approval to include the Rapids biomass project in its Renewable Resources Rider; see Docket No. Docket No. E015/M-12-1349.

Appendix D – Glossary of Dam-Related Terms

Glossary of Dam-Related Terms Used in Petition	
ACRE-FOOT	The volume of one acre of surface area to a depth of one foot.
BLACK START UNIT	A generating unit which can restore a power system to operation without relying on external electric power.
BREACH	An opening or a breakthrough of a dam sometimes caused by rapid erosion of a section of earth embankment by water.
CFS	Cubic feet per second.
CONDUIT	A closed channel to convey the discharge through or under a dam. Usually pipes are constructed of concrete or steel.
CATHODIC PROTECTION (CP)	A technique used to control the corrosion of a metal surface by making it the cathode of an electrochemical cell.
CREST OF DAM	The elevation of the upper most surface of a dam.
CROSS RECEIVER	At the Thomson Development, the cross receiver, located downstream from the Lower Gatehouse, splits water flow from three flowlines into six penstocks downstream.
DAM TOE	The juncture of the downstream face of the dam with the ground surface.
EMBANKMENT	Fill material, usually earth or rock, placed with sloping sides.
EMERGENCY SPILLWAY	A secondary spillway designed to operate only during exceptionally large floods.
FLOWLINES	Pipe lines that are constructed to direct the flow of water. At the Thomson Development, three 4,400-foot long steel flowlines of 7-, 11-, and 12-foot diameter, are used to transport water from the lower gate house to the Cross Receiver, which splits the flow into six penstocks, one for each powerhouse turbine.
FOREBAY	At the Thomson Development, the forebay is a 4,000-foot portion of the power canal which is contained in soil cut on the left bank and earthfill embankment on the right bank. Water from the forebay discharges into the Lower Gatehouse.
GATE	In general, a device in which a leaf or member is moved across the waterway from an external position to control or stop the flow. (See SPILLWAY GATE, TAINTER GATE, and SLUICE GATE.)

IMPRESSED CURRENT CP SYSTEM	A Cathodic Protection system which uses a rectifier to convert alternating current to direct current. This current is sent through an insulated wire to the anodes, which are special metal bars buried in the soil near the flowline or penstock pipe. The current then flows through the soil to the pipe system and returns to the rectifier through an insulated wire attached to the pipe.
LOWER GATEHOUSE	At the Thomson Development, the Lower Gatehouse is a structure containing four sluice gates which control discharge from the Thomson Reservoir into the canal.
NORMAL HEAD	The height of water that feeds a generator.
NORMAL POOL	The normal high water operating level of a reservoir.
PENSTOCK	A pipe constructed to direct the flow of water to an individual hydraulic turbine.
POWERHOUSE	An industrial place for the generation of electric power. At the center of nearly all power stations is a generator.
SLUICE GATE	A gate that can be opened or closed by sliding in supporting guides.
SLUICEWAY	An artificial channel for water to flow through or conduit that carries a rapid flow of water controlled by a sluice gate.
SPILLWAY	A structure over or through which flood flows are discharged. If the flow is controlled by gates, it is considered a controlled spillway; if the elevation of the spillway crest is the only control, it is considered an uncontrolled spillway. (See EMERGENCY SPILLWAY and OGEE SPILLWAY.)
SPILLWAY GATE	A gate on the crest of a spillway that controls overflow or reservoir water level.
SURGE TANK	A storage reservoir at the downstream end of a dam that is used to absorb sudden rises of pressure, as well as to quickly provide extra water during a brief drop in pressure.
TAINTER GATE	A gate with a curved upstream plate and radial arms hinged to piers or other supporting structures.
TRASH RACK	A screen comprising metal or reinforced concrete bars located in the waterway at an intake so as to prevent the ingress of floating or submerged debris.
UPPER GATEHOUSE	At the Thomson Development, the Upper Gatehouse is a structure containing four sluice gates which control discharge from the forebay into three flowlines.