

Application for Resource Plan Approval 2017 - 2031

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Submitted to

**Minnesota Public Utilities Commission
Docket No. E017/RP-16-386**

**North Dakota Public Service Commission
South Dakota Public Utilities Commission**

June 1, 2016



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Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

**RE: IN THE MATTER OF OTTER TAIL POWER COMPANY'S SUBMITTAL OF ITS
2017-2031 RESOURCE PLAN
MN Docket No. E017/RP-16-386**

Dear Mr. Wolf:

Otter Tail Power Company ("Otter Tail") hereby submits its 2016 Resource Plan filing to the Minnesota Public Utilities Commission. The plan identifies how Otter Tail proposes to meet the capacity and energy needs of its customers over the 2017-2031 planning period.

Otter Tail has worked closely with stakeholders and regulators over the last year to develop a straight-forward plan that meets the requirements of these groups and at the same time keeps customer's rates as low as possible. The preferred plan includes an addition of a 248 MW simple cycle natural gas combustion turbine plus an additional 200 MW of wind as a replacement for the retiring Hoot Lake Plant. In addition, Otter Tail has included an energy efficiency goal of 1.5% and will add 30 MW of solar to meet Minnesota's Solar Energy Standard. The renewable additions included in the preferred plan will bring the nameplate rating of our current renewable energy generation to approximately 475 MW or about 30% of retail MWH sales.

Enclosed please find 15 copies of the filing and a Certificate of Service. Also enclosed is the original document as an unbound single-sided copy of the filing. Otter Tail has also provided copies to the Minnesota Department of Commerce, Division of Energy Resources, Office of the Attorney General – Anti-Trust & Utilities Division, the Minnesota Environmental Quality Board and member agencies as well as all other parties on the attached Service List pursuant to Minnesota Rule 7843.0300. The Public version will soon be posted on the Company's website at www.otpc.com.

Daniel P. Wolf
June 1, 2016
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Should you have any questions, please contact me at bhdraxten@otpc.com or (218) 739-8417.

Sincerely,

/s/ BRIAN DRAXTEN
Brian Draxten
Manager, Resource Planning

nlo
Enclosures
By electronic service and Overnight Mail Delivery
c: Service List

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Preface

TAB

1 Preface

Otter Tail Power Company (“Otter Tail” or “Company”) respectfully files this resource plan with the Minnesota Public Utilities Commission (“Commission”) for approval under Minnesota Statute §216B.2422 and Minnesota Rules Part 7843. Additionally, Otter Tail will submit this plan to the North Dakota Public Service Commission and the South Dakota Public Utilities Commission. While the Commissions in North and South Dakota are not required by law to review resource plans for pre-approval, in those states resource plans are filed and considered in certificate of need, siting, and rate recovery proceedings to demonstrate that resource additions are needed and part of a prudent and cost-effective plan. About fifty percent of Otter Tail’s load is in North and South Dakota; the remaining fifty percent is in Minnesota.

The plan presented in this filing identifies the anticipated demand and energy needs of the Company's customers. It also details specific actions that Otter Tail intends to complete within the first five years of the planning period and the potential actions that Otter Tail might take in the following ten years.

This resource plan is intended to identify Otter Tail’s likely courses of action that are designed to meet the requirements of applicable statutes and rules, satisfy the Commissions’ goals in implementing its responsibilities, and allow the Company to continue providing reliable, low-cost electricity to meet the service requirements and the desires of customers, while minimizing potential adverse environmental and socio-economic impacts in an increasingly competitive industry. Considerable unknowns and variables outside of Otter Tail’s control will impact the actual resources the Company selects and implements in the future. Any long-range plan is subject to change because it represents an optimal plan based on numerous forecasts and assumptions at a specific point in time.

This resource plan is in large part an execution of the action items authorized by the Minnesota Public Utilities Commission in its December 5, 2014 Order approving Otter Tail’s last resource plan (“the 2013 Resource Plan”).¹ In the 2013 Resource Plan, the Commission authorized several generation additions for construction in the time period covered by this new plan filing. Otter Tail’s resource needs have not materially changed since the 2013 Resource Plan was approved in December of 2014.

¹ See December 5, 2014, ORDER APPROVING PLAN WITH MODIFICATIONS AND SETTING REQUIREMENTS FOR NEXT RESOURCE PLAN, in *In the Matter of Otter Tail Power Company’s 2014-2028 Resource Plan*, Docket No. E017/RP-13-961.

Since Otter Tail's 2010 Resource Plan and related Baseload Diversification Study was approved on March 25, 2013,² Otter Tail has added 62.4 megawatts (MW) of wind generation and entered into a capacity-only purchase power agreements (PPA) for Midcontinent Independent System Operator ("Midcontinent ISO") Zone 1 capacity that will cover the bulk of Otter Tail's capacity needs until June 2021. In addition, the Company has included in this new plan an energy efficiency goal of 1.5 percent to meet Minnesota state goals.

To prepare for the Strategist modeling that forms the foundation for this resource plan, the Company conducted eight stakeholder group meetings in Fergus Falls, St. Paul, Bismarck, ND, and Pierre, SD, . Each party who was actively involved in Otter Tail's last resource plan proceeding was invited to participate in this stakeholder process. Consequently, Otter Tail believes it has developed a resource plan that addresses the concerns of stakeholders.

Details of the underlying assumptions and descriptions of significant components, activities and issues associated with this resource plan are documented within the appendices to this filing.

² March 25, 2013, ORDER APPROVING BASELOAD DIVERSIFICATION STUDY AND SETTING REQUIREMENTS FOR NEXT RESOURCE PLAN, in *In the Matter of Otter Tail Power Company's 2011-2025 Resource Plan*, Docket No. E017/RP-10-623. The Baseload Diversification Study was a study required by the Commission for the purpose of examining alternatives for decommissioning and replacing or repowering Otter Tail's Hoot Lake Power Plant. The March 25, 2013 Order authorized Otter Tail to decommission and replace Hoot Lake Plant at the end of 2020.

Non-Technical Summary TAB

2 Resource Plan Non-Technical Summary

The plan identifies the anticipated electric service needs of the Company's customers for the 2017-2031 planning period. The plan details specific action items that Otter Tail intends to complete within the first five years of the planning period.

In its Order concerning Otter Tail's initial resource plan filing in 1992, the Commission stated that it considers the characteristics of the available resource options and the proposed plan as a whole. In Minnesota Administrative Rules, Chapter 7843.0500, Subp.3, it states that "Resource options and resource plans must be evaluated on their ability to:

- A. maintain or improve the adequacy and reliability of utility service.
- B. keep the customer's bills and the utility's rates as low as practicable, given regulatory and other constraints.
- C. minimize adverse socio-economic effects and adverse effects upon the environment.
- D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations.
- E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control."

Otter Tail has incorporated these objectives into this resource plan. Otter Tail has continued to operate its existing facilities as efficiently and economically as possible, which has helped to maintain the reliability of the electric system and kept Otter Tail's rates low. The plan is designed to reduce the financial risks of future environmental regulation or taxes, to reduce adverse socio-economic effects and effects on the environment, and to position the Company to respond to change. This resource plan evaluates a blend of supply-side and demand-side resource options to meet customer needs that cannot be met with existing resources.

2.1 Synopsis

Preferred plan reflects that Otter Tail is continuing to execute on plan approved by Commission in December 2014

Our preferred 2017-2031 resource plan is consistent with the Commission's December 5, 2014 Order approving our 2013 Resource Plan filing. This 2017-2031 resource plan reflects Otter Tail's execution of the action items authorized by the Commission in that 2014 Order. In that Order, the Commission authorized several generation additions for construction in the time period covered by this new plan filing, and it set out the parameters of what was to be included in this filing. Otter Tail has followed those parameters and this filing shows that Otter Tail's resource needs have not materially changed since the time of the 2014 Order. Therefore, modifications have not been required for this new plan filing. As it was in our approved 2013 Resource Plan, our preferred plan in this filing is our least-cost option, aside from the addition of 30 MW of solar to meet Minnesota's Solar Energy Standard, *and* it meets Minnesota's energy policy and regulatory requirements. Furthermore, it minimizes issues resulting from differing

Resource Plan Summary 2-2

regulatory policies and philosophies in the three states we serve. If the price of solar continues to decline, it is quite possible that in our next resource plan, an addition of solar could be included in our least-cost plan scenario.

Otter Tail also notes that its least-cost plan scenario identifies 200 MW of wind additions, 100 MW added in 2018 and 100 MW added in 2020. The approved 2013 Resource Plan authorizes up to 300 MW of wind. Otter Tail's request in this case is for the Commission to repeat the authority granted in 2013 IRP Plan. Specifically, Otter Tail requests that the Order state as follows:

“Otter Tail is authorized to obtain up to 300 MW of wind in the 2017–2021 timeframe if cost-effective and to the extent consistent with reliable system operation” (December 5, 2014 Order in Otter Tail's 2013 IRP Plan proceeding, Ordering paragraph 1.b.).

As was recognized in that prior Order, there are scenarios where up to 300 MW of wind is cost effective and reasonable to add to the plan (for example see Sensitivity #4 from Appendix I in this current plan filing), and therefore it is reasonable to grant Otter Tail the additional authority at this time so that Otter Tail can take action if such an opportunity presents itself (and provided the conditions meet the cost-effectiveness and reliability requirements reflected in the Ordering paragraph).

As earlier indicated, Otter Tail's current wind resources are adequate to serve approximately 19 percent of its customers' total energy needs. Each additional 100 MW increment of additional wind generation increases that amount by approximately 5 percent, so with 200 MW of additional wind, Otter Tail will generate approximately 29 percent of its customer's energy needs through wind resources. With a third 100 MW added, Otter Tail would increase that amount to 34 percent.

Table 2-1 depicts a comparison of the major elements of the 2013 Resource Plan and Otter Tail's Preferred Plan in this filing. As the table depicts, the current Preferred Plan is for Otter Tail to continue to focus on executing on the Commission's December 2014 Order approving Otter Tail's 2013 Resource Plan.

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Table 2-1: Current Preferred Plan compared to last resource plan order

2013 Resource Plan Order	Current Preferred Resource Plan Scenario
Otter Tail shall obtain approximately 200 MW, subject to need, of intermediate capacity (and associated energy) in the 2019-2021 time frame	Add a 248 ³ -MW simple-cycle natural gas combustion turbine in 2021 (energy to come from wind addition below)
Otter Tail is authorized to obtain up to 300 MW of wind in the 2017–2021 timeframe if cost-effective and to the extent consistent with reliable system operation	Add 100 MW wind in 2018 Add 100 MW wind in 2020 Additional authority up to a total of 300 MW, provided cost-effective and consistent with reliable system operation
Otter Tail shall add enough solar to comply with Minnesota’s SES	Add 30 MW solar by 2020 to comply with Minnesota’s SES

- Acquisition activities relating to the Intermediate Capacity addition authorized by the 2013 Resource Plan approval: We have purchased a site and entered the MISO interconnection process simple-cycle combustion turbine located at that site. High-voltage electric transmission and a large natural-gas pipeline exist already **on the parcel**—so this turbine site will not require construction of additional transmission lines or gas pipeline. Additional pre-development activities are underway. We expect to begin site permitting by early 2017 and to issue requests for bids for turbine supply, engineering, and elements of construction beginning in late 2018.
- Acquisition activities relating to the Wind Generation addition authorized by the 2013 Resource Plan approval: We’re discussing potential wind projects in North Dakota with developers. Each of the projects will be able to achieve commercial operation in 2018. While the status of the Clean Power Plan remains uncertain, we believe that siting renewable generation in North Dakota in this timeframe best mitigates the Company’s risks under the Clean Power Plan while maximizing the value of Production Tax Credits.
- Acquisition activities relating to the solar generation addition authorized by the 2013 Resource Plan approval: We are in discussions with possible solar developers. By 2020, we plan to have sufficient solar energy procured, either through ownership or purchase, to meet Minnesota’s Solar

³ 248 MW is a proxy size. The actual size of the unit will be determined after the bidding process for turbine supply.

Resource Plan Summary 2-4

Energy standard. We believe that the capital cost of solar will continue to decline and the efficiency of those panels will continue to increase as we get closer to 2020. We are also exploring the possibility of early compliance through the purchase of Solar Renewable Energy Credits (Solar RECs) in order to best take advantage of continued cost declines of solar components and to accommodate the different requirements of Otter Tail's three state jurisdictions.

- Continued Progress on Hoot Lake Plant Transition: Consistent with the Commission's approval of the Baseload Diversification Plan, we are planning to retire Hoot Lake Plant at the end of the MISO Planning Year 2020 —coincident with commencement of operation of the large simple-cycle turbine described above (the MISO planning year ends on May 31, 2021).
- Satisfaction of the Minnesota's Greenhouse Gas Reduction Goal: Our preferred resource plan will result in Otter Tail generating approximately 30% of our energy from renewables by 2021. After the wind, solar, and natural gas additions and the Hoot Lake Plant retirement, we'll meet Minnesota's greenhouse gas reduction goal at least until 2025.
- Conservation and Renewable Energy: Minnesota Statutes §216B.2422, Subd. 2, states that "a utility shall include the least-cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources." Our preferred plan, which includes 1.5% CIP, 200 MW wind, and 30 MW solar, exceeds the 50 percent and 75 percent targets.

In summary, our preferred resource plan furthers the vision set by the Commission in its Order approving Otter Tail's 2013 Resource Plan. Consistent with that prior ruling, the preferred plan meets all legal requirements and allows the Company to continue providing reliable, low-cost electricity to meet our customers' requirements.

2.2 Stakeholder Group Meetings

As indicated, prior to filing this resource plan, Otter Tail met with various stakeholders to solicit their input into the modeling assumptions used in the resource plan. Several groups travelled to our company headquarters in Fergus Falls for the stakeholder meetings. We believe it was valuable for stakeholders to experience first-hand the small-towns and the rural areas that make up our service territory. We greatly appreciate the time these participants took to travel to our area of the state. In our opinion, this approach yielded our most effective stakeholder process to date.

Representatives from the organizations and agencies listed below participated in this stakeholder process. The list identifies the dates and locations of our meetings:

- North Dakota Public Service Commission and Staff (March 18, 2016, Bismarck, ND)
- South Dakota Public Utilities Commission and Staff (March 31, 2016, Pierre, SD)

- Minnesota Department of Commerce (April 5, 2016, St. Paul, MN)
- Clean Energy Organizations (MCEA, Sierra Club, Wind on the Wires) (April 11, 2016, Fergus Falls, MN)
- Fresh Energy (April 14, 2016, St. Paul, MN)
- Minnesota Public Utilities Commission Staff (April 18, 2016, Fergus Falls, MN)
- Great Plains Institute & Center for Energy and the Environment (April 20-21, 2016, Fergus Falls, MN)
- Minnesota Chamber of Commerce / Midwest Large Industrial Group (May 3, 2016, St. Paul, MN)

The goal of these stakeholder meetings was to make our resource plan filing as complete as possible and streamline the proceeding. We believe that the meetings were productive for both the Company and the parties. As a result of the meetings, we added several sensitivities and made adjustments to our modeling assumptions to address issues and perspectives brought forward by the parties.

2.3 Multi-State Jurisdictional Complexity

Otter Tail operates in a service territory that spans three states, and from economic and demographic perspectives, the towns and areas Otter Tail serves in these three states are very similar. Both east and west of the Red River, Otter Tail serves very small rural towns—the average population of our communities in Minnesota is approximately 630 people. Nevertheless, very different policy perspectives can be in play at times in each of these three jurisdictions. About fifty percent of Otter Tail’s load is in Minnesota, North Dakota makes up roughly forty percent and South Dakota comprises the remaining ten percent.

Continuing to operate as a single cost-effective multi-state utility is an important priority for Otter Tail’s customers. Otter Tail is already one of the smallest vertically integrated utilities in the country. To give some perspective, in terms of Minnesota customer count, Xcel Energy is approximately 20 times the size of Otter Tail. Because of this already very small size, splitting Otter Tail into multiple separate and even smaller utility systems would result in harmful inefficiencies and an increased cost of service. Therefore, we are pleased that the preferred plan presented in this filing satisfies the regulatory requirements in each of our jurisdictions, and we feel strongly that it can be supported in all the states we serve. In fact, as described above, the preferred plan is, in practical terms, just a continuation of the 2013 Resource Plan that was approved by the Commission only eighteen months ago. Otter Tail’s request in this case is for authority to continue to execute on that previously-approved plan.

2.4 Load Forecast

The process of developing this resource plan began with an econometric peak demand and energy requirements forecast, which provided base forecast, low forecast, and high forecast scenarios.

The forecast peak demand and energy requirements are detailed in Appendix B. The energy requirements forecast represents an approximate .85 percent average annual growth rate, prior to new demand side

Resource Plan Summary 2-6

management (“DSM”) programs, and is the key component in determining the type of resources to be added, whether baseload, intermediate, or peaking. Peak demands are anticipated to average an annual growth rate of 1.23 percent in the summer, prior to new DSM programs. The peak demand will determine the size of capacity resources required for the system. As a participant in the Midcontinent ISO, Otter Tail is currently required to maintain a 7.6 percent planning reserve margin on the forecasted summer peak demand coincident with the Midcontinent ISO’s peak demand, after accounting for plant accreditation ratings as defined by the Midcontinent ISO.

2.5 Future Resource Needs

Table 2-2 provides the Company’s summer season resource needs showing the Company’s projected load and capability according to Midcontinent ISO Module E rules for resource adequacy. Please see Section 3 for discussion of Midcontinent ISO Module E and further detail regarding the resource adequacy obligation calculation.⁴

The total accredited capacities, shown as Zonal Resource Credits (“ZRCs”), represent the Midcontinent ISO’s capacity ratings for the Company’s resources based on the 2016 planning year accreditation levels. Adjustments were made to the coal facilities to account for the abnormally low accreditation levels in 2016 caused by major outages in 2015. Capacities for transactions are shown separately. Resource, transaction, and demand response accreditations are based on historical summer performance and do not vary monthly.

Table 2-2: Summer 2017-2031 Base Case Projected Load and Capability Prior to Resource Plan Information

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Forecasted Load	803.6	819.0	836.2	840.4	839.0	854.5	871.9	889.3	907.6	914.6	921.6	928.6	935.6	942.6	949.6
Transmission Losses	32.1	32.8	33.4	33.6	33.6	34.2	34.9	35.6	36.3	36.6	36.9	37.1	37.4	37.7	38.0
MISO Coincident Factor	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%
Coincident Load	762.2	776.8	793.1	797.1	795.7	810.4	826.9	843.4	860.8	867.5	874.1	880.8	887.4	894.1	900.7
MISO Planning Reserve	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%
Total	820.1	835.8	853.4	857.7	856.2	872.0	889.8	907.5	926.3	933.4	940.6	947.7	954.9	962.0	969.2
Enbridge Adjustment	-25.0	-34.0	-20.0	-17.0	-8.0	-17.0	-28.0	-29.0	-31.0	-31.0	-31.0	-31.0	-31.0	-31.0	-31.0
Obligation	795.1	801.8	833.4	840.7	848.2	855.0	861.8	878.5	895.3	902.4	909.6	916.7	923.9	931.0	938.2

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal	486.4	489.4	506.2	506.2	369.8	369.8	369.8	369.8	369.8	369.8	369.8	369.8	369.8	369.8	369.8
Natural Gas	41.9	41.6	41.2	41.2	41.2	41.2	41.2	41.2	41.2	41.2	41.2	41.2	41.2	41.2	41.2
Oil	54.5	51.4	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5
Wind	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	54.6	54.6
Solar															
Hydro	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
BTMG	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Purchased	89.5	89.5	59.5	59.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Load Management	33	33	34	34	34	35	35	35	36	37	38	38	39	40	41
Total	773.2	772.8	761.3	761.3	574.9	575.9	575.9	575.9	576.9	577.9	578.9	578.9	576.3	577.3	578.3

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Net	(21.9)	(29.0)	(72.1)	(79.4)	(273.3)	(279.1)	(285.9)	(302.6)	(318.4)	(324.5)	(330.7)	(337.8)	(347.6)	(353.7)	(359.9)

⁴ The Module E resource adequacy obligation calculation is:

Reserve Obligation = (Coincident Peak Demand Forecast-Demand Response) x (1+Load Based Reserve Margin) + Transmission Losses, where the reserve margin is currently 7.6 percent. Total Accredited Capacity is the sum of Aggregate ZRCs, Local ZRCs, External ZRC’s and Net Transaction ZRCs, where ZRCs are MWs that have been converted to “Zonal Resource Credits.” Under Module E, only ZRCs are eligible for designation toward the Reserve Obligation.

The data in the tables illustrates the capacity deficits that exist prior to plan development, based on the Company’s existing resources as of May 31, 2016. The table shows that Otter Tail is capacity deficient beginning in the summer of 2017, and this deficiency grows dramatically in the summer of 2021 when Hoot Lake Plant is retired and power purchase agreements (“PPAs”) expire.

2.6 Resource Plan Development

The software model used for developing Otter Tail’s resource plan is Strategist. The long-range peak demand and energy forecasts were incorporated into the Strategist database, along with the supply-side and demand-side resources available to the Company over the course of the study period. Strategist was then executed to develop a series of least-cost resource plans. Otter Tail defined the objective function as minimizing total utility costs (zero externality scenario) or total societal costs (externality value scenario).

The Proview module within Strategist was executed to develop an optimized resource plan for each scenario for the time period 2017 through 2031. Resource plans were developed in accordance with the resource planning rules, including evaluation of sensitivities that varied load growth, applied externalities, and achieved specified renewable and conservation objectives.

2.7 Resource Alternatives

Otter Tail considers both demand-side and supply-side resources in long-term planning analysis. Appendix D provides a more detailed discussion of the resources that the Company evaluated. Table 2-3 provides a list of the alternatives evaluated within the Strategist model.

Table 2-3: List of Resource Alternatives Included in Strategist Model

Resource Alternatives Modeled	Description
Natural Gas Simple Cycle - Small	Generic 49 MW nameplate capacity aeroderivative type simple cycle unit
Natural Gas Simple Cycle - Large	Site Specific 248 MW nameplate capacity frame type simple cycle unit
Natural Gas Combined Cycle*	Generic 319 MW nameplate capacity utility-Frame type combined cycle unit
Wind	Generic 100 MW nameplate capacity utility-scale wind resource
Solar	Generic 30 MW nameplate capacity utility-scale solar resource
* This alternative was included in early modeling runs but was not selected in any of the sensitivities. This alternative was removed from the final modeling runs to allow for additional superfluous wind and solar alternatives.	

2.8 Preferred Resource Plan

The Company’s preferred resource plan (sensitivity #1 from Appendix I) includes all of the resources that are common between the two base case scenario plans (with externalities and without externalities) plus a solar resource to comply with the Minnesota Solar Energy Standard (SES). Table 2-4 shows the Company’s preferred plan which includes the addition of 200 MW of wind (100 MW in 2018 and 2020, and additional authority for up to 100 MW of wind if cost effective and reliable), 30 MW of solar in 2020 along with a 248 MW simple cycle frame unit in 2021. The preferred plan uses the 1.5 percent CIP energy goal in Minnesota.

Table 2-4: Preferred Resource Plan Summary

Resource Plan (MW) - Based on Nameplate ratings		
2017		
2018	100 MW Wind	100 MW Utility Scale Wind
2019		
2020	100 MW Wind & 30 MW Solar	100 MW Utility Scale Wind & 30 MW Utility Scale Solar
2021	248 MW Frame NG CT	248 MW Frame NG Simple-Cycle Combustion Turbine
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		

Figure 2-1 shows the capacity resource additions along with existing resources over the study period. Figure 2-2 and Figure 2-3 shows the energy contribution by fuel category for 2017-2031 for the preferred plan under the two externality scenarios. The application of externality penalties to the unit dispatch results in significant differences in the energy mix between the two scenarios even though both scenarios have the same set of resources available. In Figures 2-2 and 2-3, the Purchases category (red) is primarily comprised of day-ahead market opportunity purchases, while the Forward Purchases (yellow) represents longer term bi-lateral contractual purchases.

Figure 2-1: Preferred Plan Capacity Resources and Reserve Obligation 2017-2031 (MW)

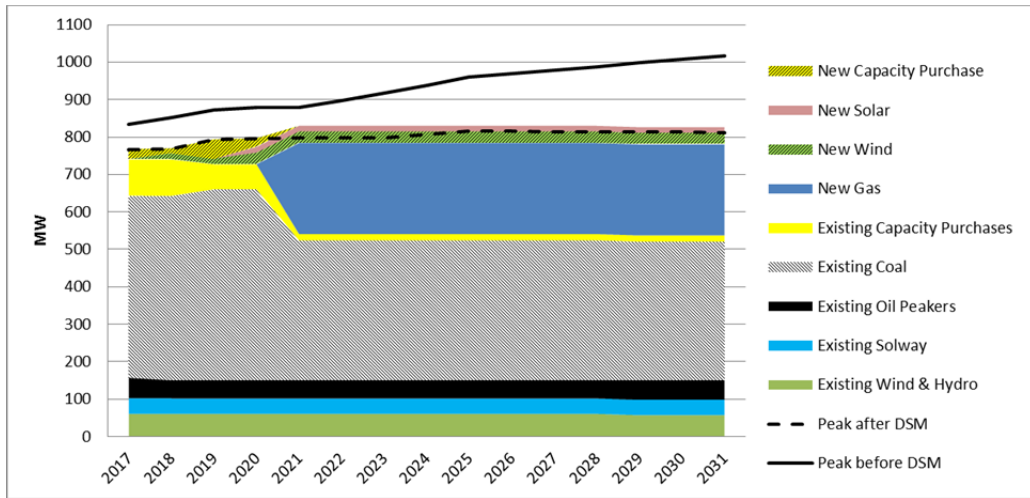
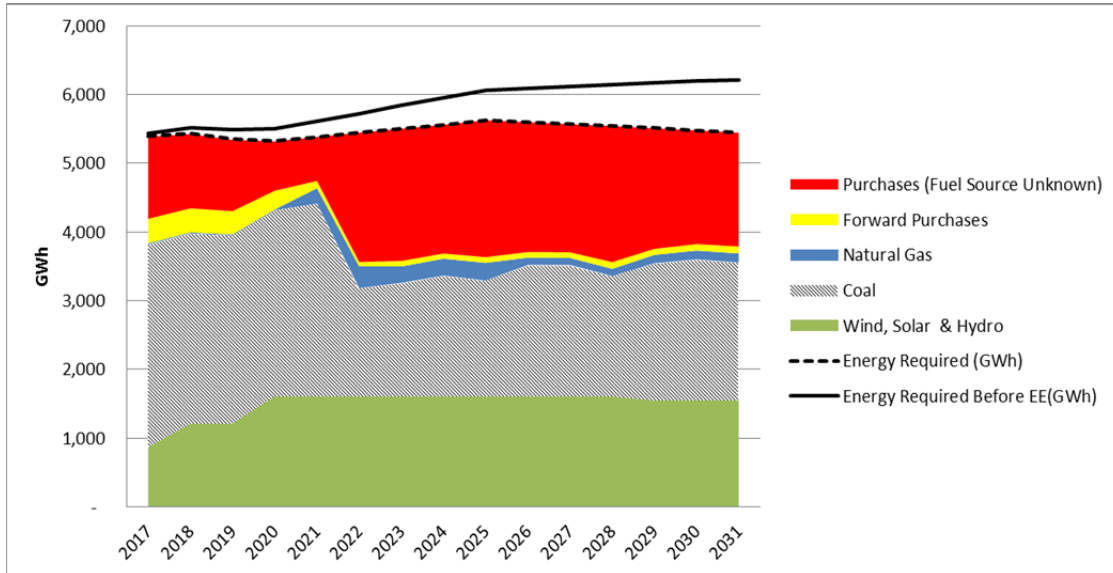


Figure 2-2: Preferred Plan Energy Resources and Requirements with Externalities Applied 2017-2031 (GWh)



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Figure 2-3: Preferred Plan Energy Resources and Requirements without Externalities Applied 2017-2031 (GWh)

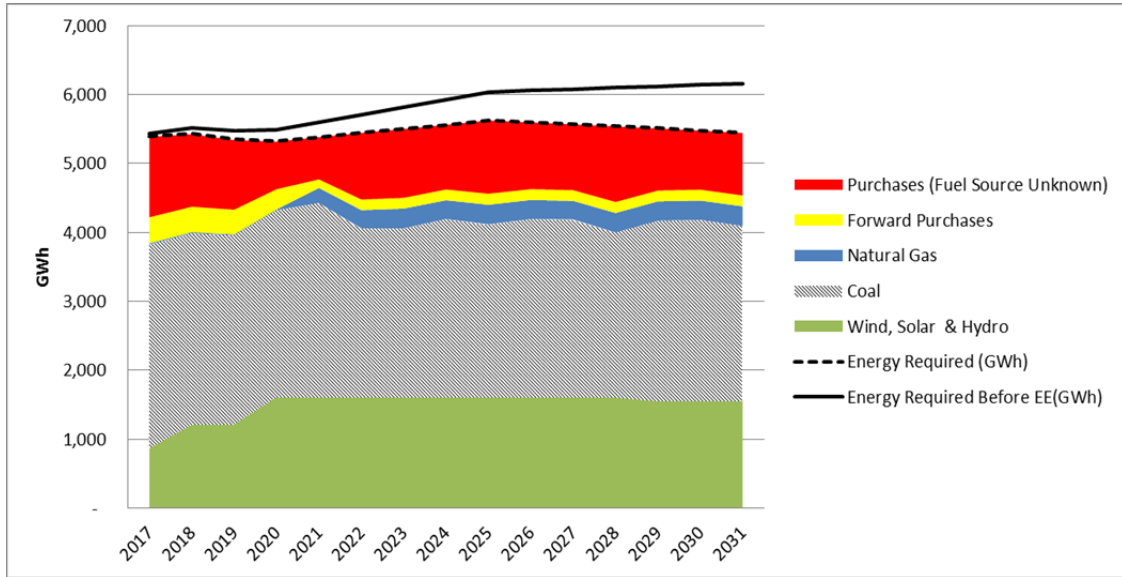


Figure 2-4 shows the projected energy contribution by fuel category for the year 2017. There is no difference between externality scenarios for the year 2017. Figure 2-5 shows the expected energy contribution by fuel category for the preferred plan for the year 2031 with externalities applied. Figure 2-6 shows the expected energy contribution by fuel category for the same preferred plan for the year 2031 without externalities applied. The preferred plan shows a reduction in percentage of coal energy and an increase in the percentage of energy from natural gas and renewable energy.

Figure 2-4: 2017 Energy by Fuel Source (same for both externality scenarios)

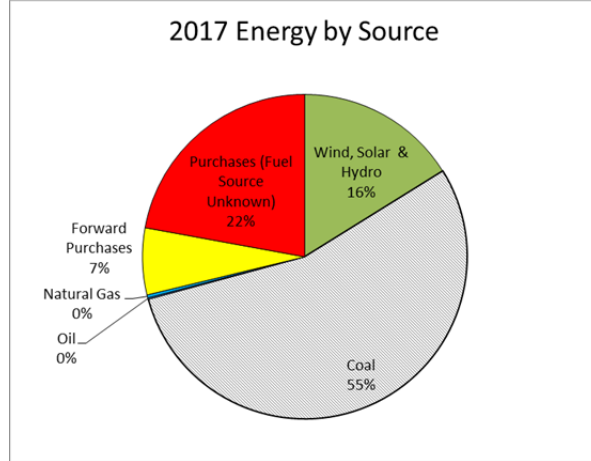
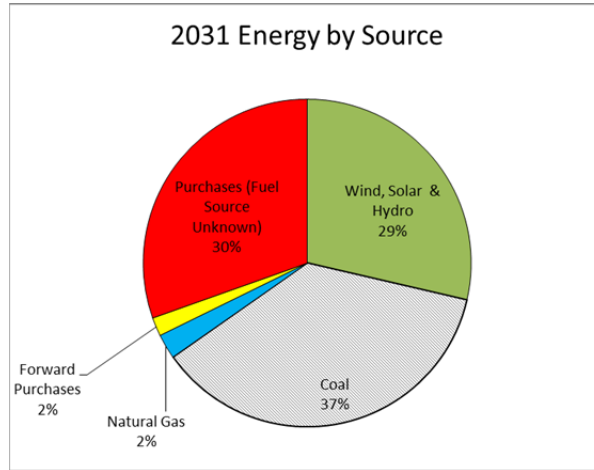
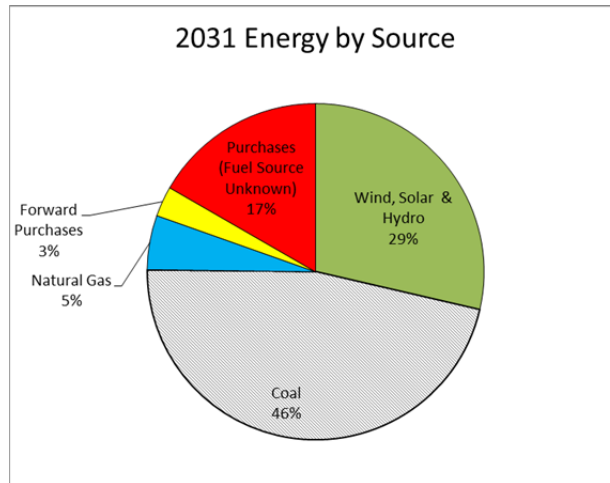


Figure 2-5: Preferred plan 2031 Energy by Fuel Source with Externalities Applied



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Figure 2-6: Preferred plan 2031 Energy by Fuel Source without Externalities Applied



2.9 Preferred Plan is in the Public Interest

Otter Tail Power Company is committed to operating its generation facilities as efficiently as practicable while minimizing adverse effects on the environment. New resources have been selected that will meet the Company's needs while maintaining flexibility and limiting the risk of exposure to changes in financial, social, and technological factors beyond its control. This resource plan satisfies the legal and regulatory requirements in the multi-state service territory and allows Otter Tail and its customers to realize the benefits of operating as a single system while satisfying requirements in all states served by Otter Tail.

The preferred resource plan represents a cost-effective plan developed with a model that successfully integrates demand-side and supply-side resource analysis. Otter Tail serves customers in three states. To provide operating efficiencies, the Company operates and plans its system as a single entity to the benefit of all customers. Maintaining compliance with the many statutes, rules, and regulations in three separate states and three separate regulatory commissions can be challenging at times. Otter Tail believes that this resource plan meets that challenge, successfully providing a plan that reasonably satisfies the needs of all three states.

In compliance with Minnesota Statutes, the Company evaluated low (sensitivity #19 from Appendix I), mid (28 sensitivities), and high (sensitivity #20 from Appendix I) externality sensitivities for this resource plan and as defined by the Commission's May 27, 2015, Notice of Updated Environmental Externality Values. Each externality case also assumed a CO₂ tax starting in 2022 and escalating annually. In addition to the externality sensitivities, the Company evaluated 27 sensitivities with zero externalities.

Minnesota Stat. §216B.2422 also requires evaluation of the resource plan for low and high load growth sensitivities and for sensitivities that evaluate meeting 50 percent and 75 percent of future resource needs using demand side management and renewable resources. Like the externality sensitivities, the load growth sensitivities also varied from the preferred plan in total cost and resource selection. The Company

plans for the most likely forecast, recognizing that this plan can adapt as time progresses to accommodate variations in actual load growth from the present long-range forecast. The preferred plan meets 216 percent of new energy requirements for Minnesota customers using renewable resources and energy efficiency and conservation.

2.10 Externality Values

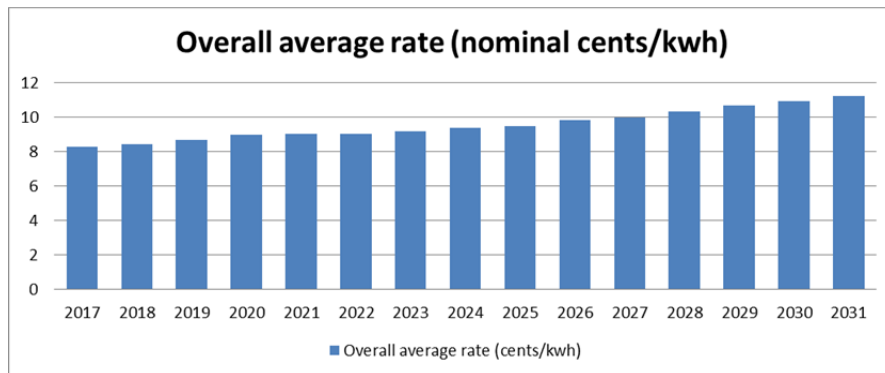
Two dockets relating to externality values are open in Minnesota. Docket No. E999/CI-13-796, deals with the estimate of the costs of future carbon regulation. Docket No. E999/CI-14-643 is evaluating proposed updates to environmental cost values. Neither of these proceedings was completed in time for Otter Tail to incorporate the results into its 2016 resource plan. However, it appears that in the docket that deals with the estimate of the future cost of carbon regulation, all parties are in agreement that the \$9-\$34 range should be continued and the year to start applying these costs should be 2022. We have incorporated this assumption into our Strategist modeling for this case. The Company does not anticipate that these proceedings would have an impact on the five year action plan. The outcome of the above listed proceedings will be incorporated in future resource plans.

2.11 Preferred Plan Rate Impacts

Figure 2-7 shows the potential estimated overall rate impact of the preferred resource plan.

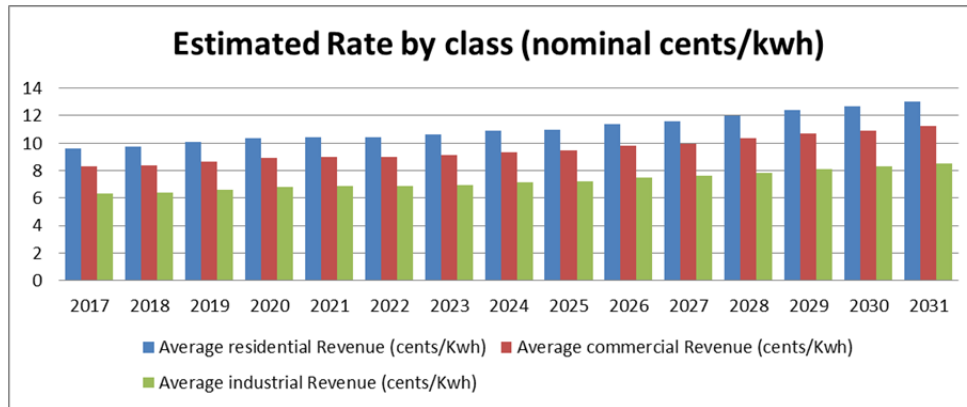
The data shown is the average annual rate based on the Strategist model for the total system and represents total revenue divided by total sales. Figure 2-8 shows the potential estimated rate impacts of the preferred resource plan by customer class. A number of parameters in the operation of the model will impact rates. The Strategist model assumes automatic rate increases each year to meet the targeted rate of return; but in reality, rate cases take place as needed and have an inherent amount of regulatory and administrative lag. The Strategist model rate impact calculation has taken into account the generation additions in the preferred plan. But it does not include all projected capital expenditures, asset based sales, or projected CO₂ costs.

Figure 2-7: Preferred Resource Plan Estimated Rate Impacts



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Figure 2-8: Preferred Resource Plan Estimated Rate Impacts by Class



2.12 Five-Year Action Plan

Table 2-5 identifies specific major items that require action in the first five years of the planning period. The five-year action plan is for the years 2017-2021; however, the action items in 2016 also are provided. As shown, the major activities during the five-year period are construction of the 248 MW CT and two 100 MW wind projects to replace Hoot Lake Plant plus the addition of 30 MW of solar generation to meet Minnesota’s solar energy standard.

Table 2-5: Five-Year Action Plan Activities

Year	Activity
2016	June 1 Triennial CIP filing for 2017, 2018, 2019 MISO interconnection process for CT Preparation for permitting effort for CT
2017	Permitting and approvals for 248 MW CT MISO interconnection process for CT Begin construction on 100 MW wind project
2018	Commercial operation of 100 MW wind project Permitting and approvals for 248 MW CT MISO interconnection process for CT Initiate work on utility-scale solar project to meet the Minnesota Solar Mandate by 2020
2019	June 1 Triennial CIP filing for 2020, 2021, 2022 Engineering and procurement for 248 MW CT Begin construction on 100 MW wind project Construct or obtain PPA for an approximate 30 MW solar installation
2020	Construction of 248 MW CT File MISO Attachment Y for retirement of Hoot Lake Plant Commercial operation of 100 MW wind project Commercial operation of 30 MW solar project
2021	Start-up and commercial operation of 248 MW CT Retirement of Hoot Lake Plant

2.13 Conclusion

Otter Tail Power Company has continued to optimize existing resources and obtain supplemental capacity and energy through bilateral contracts in the wholesale market to meet both customer needs and resource adequacy requirements. This strategy will continue while balancing risk and economics. Cost-effective energy efficiency and demand response is used throughout the study period. The preferred resource plan presented here accomplishes the goal of meeting customer needs and regulatory requirements in the three jurisdictions that Otter Tail serves.

Current Outlook TAB

3 Current Outlook

The following list provides a brief overview of the most prevalent changes that have occurred since the 2013 resource plan filing. These changes include both regulatory and economic factors that have had very tangible effects on the Company's current outlook.

3.1 Completion of the Big Stone Plant AQCS and the Hoot Lake Plant MATS

The Big Stone air quality control system (AQCS) was completed and commenced commercial operation in December 2015. The final cost of the project was over \$100 million below the original budget. The Hoot Lake Plant Mercury and Air Toxics Standards (MATS) project was completed and commenced commercial operation in September 2014.

3.2 Installation of an approximate 248 MW⁵ natural gas fired combustion turbine

As approved in the course of the 2010 IRP proceeding and related Baseload Diversification Study, Docket, No. E017/RP-10-623, Otter Tail is planning to retire the approximately 140 MW Hoot Lake Plant at the end of the MISO Planning Year 2020 (May 2021). In addition, 50 MW of capacity purchase agreements expire at the same time.

The December 5, 2014 Order in Otter Tail's 2013 Resource Plan authorized: "Otter Tail shall obtain approximately 200 MW, subject to need, of intermediate capacity (and associated energy) in the 2019-2021 timeframe ..." Furthermore, the Commission required Otter Tail to "File a proposal to replace Hoot Lake Plant, including expected dates for filing a certificate-of-need application with the Commission, an Attachment Y with MISO, and an interconnection request with MISO for its proposed new facility..."

In 2015, the Company completed an extensive internal evaluation of both combined-cycle (CC) and combustion turbine (CT)/wind projects and preferred sites. There were six sites under original consideration across our three-state service territory. We also evaluated the possibility of partnering with another utility to build a larger project. While both CT and CC have their strengths, the results of the evaluation indicated that a CT located at **[PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]** provided the most benefits at the least cost to our customers.

[PROTECTED DATA BEGINS

⁵ 248 MW is a proxy size. The actual size of the unit will be determined after the bidding process for turbine supply. This size turbine is consistent with the order in our last resource plan.

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...**PROTECTED DATA ENDS]** interconnection costs are extremely low.

The **[PROTECTED DATA BEGINS...**

ENDS]

...**PROTECTED DATA**

The North Dakota site(s) requires the construction of a natural gas lateral supply line which increases the overall cost of the project. This additional cost causes the North Dakota option to become a higher lifetime cost option. Annual property taxes in North and South Dakota are relatively close, but it is expected the Minnesota property tax would be significantly higher causing the overall lifetime costs in Minnesota to be higher.

Otter Tail has submitted a MISO interconnection request for the **[PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]** project and made the required deposit with MISO to take our place in the queue. We have established our DPP queue date and MISO currently estimates DPP studies to be complete in Nov-2016. Completion of studies and negotiation of a Generator Interconnection Agreement (GIA) is anticipated by the end of 2018. We are currently working with an engineering consultant on pre-development activities.

With the CPP, general public and regulatory policy, and the fact that our service territory is in the heart of a wind-rich region, we expect large amounts of renewables will be added to the already significant wind resources in this area. Those wind additions will contribute to increasingly volatile market prices when the wind blows versus when it doesn't blow. Our new CT project will serve to hedge customers' energy needs, so that they are not paying high market prices during periods when the wind isn't blowing. In addition, it will afford us dispatch flexibility to serve as a price hedge for our customers at times of high energy prices.

Our industry is in a time of great uncertainty. The outcome of the CPP, allowance and Emission Rate Credit (ERC) prices, and the volatility of future energy and natural gas prices all contribute to this uncertainty. Therefore, we believe that mitigating risk and maximizing future flexibility are paramount. The addition of a CT affords us that flexibility for the following reasons:

- A CT is exempt from regulation under the CPP. By contrast, a CC comes with risks if a state chooses a mass-based plan with a new source compliment. We won't know how each of our states will proceed until their State Implementation Plans (SIP) under the CPP are completed.
- A CT can be converted to CC in the future if circumstances so dictate but not vice versa. Our proposed site is large enough to handle a CC conversion and we will engineer the project to readily accept conversion to CC should it be needed.
- Compared to a CC project, a CT/wind combination results in significantly lower CO₂ emissions.

- Increased dispatch flexibility for a CT when compared to a CC. This allows us to better follow the fluctuations in wind and energy prices.
- A CT is a less complicated project when compared to a CC allowing for a shorter permitting and construction timeline.

Combining capital cost with adjusted 2015 annual operating costs throughout the plant's 30 year expected life, [PROTECTED DATA BEGINS... ..PROTECTED DATA ENDS] has the lowest overall lifetime cost estimate of all sites under consideration.

In summary, Otter Tail has taken significant actions toward installation of a new 248MW natural gas CT generation project. These actions are necessary to complete the replacement of our retiring Hoot Lake Plant and expiring capacity purchase agreements by May of 2021. Otter Tail's five year action plan reflects our intent to proceed with this project.

3.3 Midcontinent ISO Module E Resource Adequacy Obligation

Beginning in June 2013 the Midcontinent ISO revised its resource adequacy construct. The revisions included changing from a monthly construct based on non-coincident peak demand to an annual construct based on the Midcontinent ISO's coincident peak demand. In addition, the Midcontinent ISO created ten capacity pricing zones to ensure capacity and transmission investments are made in the right places. The change from a non-coincident construct to a summer coincident construct reduced the Company's reserve obligation. The Company's customer peak demand is lower in the summer than in the winter, which is offset by the loss of winter demand response resources under the revised construct. The Company's coincident peak demand diversity factor is approximately 8 percent of its non-coincident peak demand. For modeling purposes, Otter Tail used a zero cost capacity transaction within Strategist to reflect the impact of the coincident peak demand on reserve requirements.

The Midcontinent ISO's planning year 2016 resource adequacy reserve obligation is 7.6 percent. For every MW of forecasted peak demand, the Company must provide 1.076 MW of accredited capability. Otter Tail's generators are accredited based on historical plant performance. Each resource's historical performance data is used to calculate a probability that it will be available to operate when called upon. The probability is applied to the resource's demonstrated capability under defined conditions and lowers the accreditation of that resource from its demonstrated capability.

Resource accreditations change annually and are based on summer ratings. As stated previously, ratings for generators are based on historic generator availability data or, if that is unavailable, class averages.

Wind generation is accredited based on unit specific historical capacity factors. Accreditation for the 2016 planning year for the Company's wind farms varied from 27 percent at the Luverne Wind Farm to 17 percent at the Edgeley Wind Farm.

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Otter Tail has successfully registered the load management system and retail firm service level contracts under Module E as Demand Resources. The accredited capability of these resources is subtracted from the Company's forecast demand prior to calculating the planning reserve margin. Otter Tail's accredited Demand Resources for planning year 2016 totaled 32.3 MW. This accreditation is based on its summer capability, which is when Midcontinent ISO experiences its annual peak demand.

The Midcontinent ISO is discussing with stakeholders a potential transition to a two season capacity construct starting in planning year 2018. Upon initial review, the Company does not see this being a concern from a capacity perspective. Although the Company has a winter peak of roughly 100 MWs higher than its summer peak, it also has over 100 MWs of winter demand response resources available to offset the increase in winter peak load.

3.4 Market Conditions in the Midcontinent ISO

Wholesale energy prices remain low due to the increasing penetration of wind generation, and continuing low natural gas prices. Annual average Locational Marginal Prices ("LMP") at the OTP.OTP load zone in the day-ahead market remain low:

2013: \$28.23/MWh
2014: \$34.27/MWh
2015: \$21.97/MWh
2016 (YTD April 25): \$18.26/MWh

Capacity values in the Midcontinent ISO centralized market have remained low due to excess reserves. However, due to pending coal plant retirements reserve margins likely will tighten. The Midcontinent ISO has recently projected the possibility of capacity shortfalls starting in 2020. The forward capacity market has seen significant upward pressure as these uncertainties weigh on market participants.

3.5 New EPA Emission Standards for Stationary Engines

On March 3, 2010 the U.S. Environmental Protection Agency issued new national emission standards for hazardous air pollutants for existing stationary compression ignition reciprocating internal combustion engines. The new standards include emissions limitations, operating limitations, maintenance requirements, performance tests, recordkeeping requirements, and reporting requirements. By May 1, 2016 all of Otter Tail's engines affected by the RICE Rule will be considered emergency or blackstart in nature and therefore exempt from emissions limitations and performance tests. Only routine maintenance activities will be needed to comply with the rule.

3.6 Clean Power Plan Uncertainty

On October 23, 2015 the Environmental Protection Agency published the final Clean Power Plan. On February 9, 2016 the U.S. Supreme Court granted a stay of the rule pending ongoing litigation, including any eventual U.S. Supreme Court review. The stay was effective immediately and accordingly, compliance with any deadlines to file state plans and other deadlines associated with the rule are now on hold. As a result, the ultimate disposition of the Clean Power Plan remains unclear.

If the Clean Power Plan is ultimately upheld, each of Otter Tail's states will be faced with numerous decisions that could result in a wide variety of impacts. However, in any case, Otter Tail's preferred resource plan will result in additional renewable energy resources, the retirement of Hoot Lake Plant, and the addition of a simple-cycle CT unit that would be excluded from regulation under the Clean Power Plan. Thus, implementing this preferred plan – while not specifically designed to comply with the Clean Power Plan – would provide Otter Tail with several flexibilities for generating compliance credits/allowances should the rule be re-instated.

Additional discussion of the Clean Power Plan is included in Appendix E.

3.7 Renewable Energy Objectives and Standards

Otter Tail was required to make a good faith effort to comply with the state REO through 2011. In 2012 the requirement switched to an RES. To date the Company has met the REO and RES targets. The state requirements⁶ increase in a step-wise fashion, consisting of:

- 2007 – 1% of retail sales
- 2010 – 7% of retail sales
- 2012 – 12% of retail sales
- 2016 – 17% of retail sales
- 2020 – 21.5% of retail sales (1.5% from solar resources)
- 2025 – 26.5% of retail sales (1.5% from solar resources).

The Company is also obligated to meet renewable energy objectives in both North Dakota and South Dakota to generate or procure 10 percent of annual retail sales from renewable or recycled energy. Otter Tail has joined the Midwest Renewable Energy Tracking System (“M-RETS”) and uses this system to track and report compliance with REO and RES targets.

3.8 DSM and Conservation Requirements

The 2007 Next Generation Energy Act of 2007 established an ambitious goal for all Minnesota electric and natural gas utilities of achieving energy savings equal to 1.0 percent of retail energy sales. In 2013, the energy savings goal was modified to an annual goal of 1.5 percent of retail energy sales. The goal is based on a rolling three-year average of weather normalized historical retail sales. (Minnesota Statute §216B.241, Subd. 1c). On June 1, 2013, the Company made its 2014-2016 Minnesota CIP Triennial filing with the Minnesota Office of Energy Security. The plan as filed complied with all regulatory requirements, including a minimum of 1.5 percent energy savings. This resource plan reflects the 1.5 percent annual energy savings goal as filed in the Minnesota CIP Triennial filing. The Company also included modeling sensitivities of annual goals from 1.6 to 2.0 percent in .1 percent increments as ordered in our last resource plan.

⁶ These REO and RES requirements only apply to utilities like Otter Tail without nuclear generating assets. Utilities with nuclear generating assets have a more aggressive standard as detailed in Minn. Stat. §216B.1691 .

3.9 Projected Load and Capability

Appendix B provides Otter Tail’s Annual Electric Utility Report, which includes Otter Tail’s forecast in detail. Figure 3-1 below shows the historical and projected non-coincident summer peak demand by season through the study period to 2031. Figure 3-2 shows historic and forecast annual energy requirements by customer class. The historic and forecast values have existing conservation programs embedded, whereas the forecasted values exclude new conservation programs. Otter Tail’s energy requirements are driven equally by residential and commercial customers, creating an annual load factor of approximately 70 percent. Otter Tail projects that by the end of the study period, large commercial and industrial loads will increase to roughly 60 percent of the Company’s retail sales.

Figure 3-1: Historic and Forecast Unmanaged 50/50 Non-coincident Summer Peak Demand

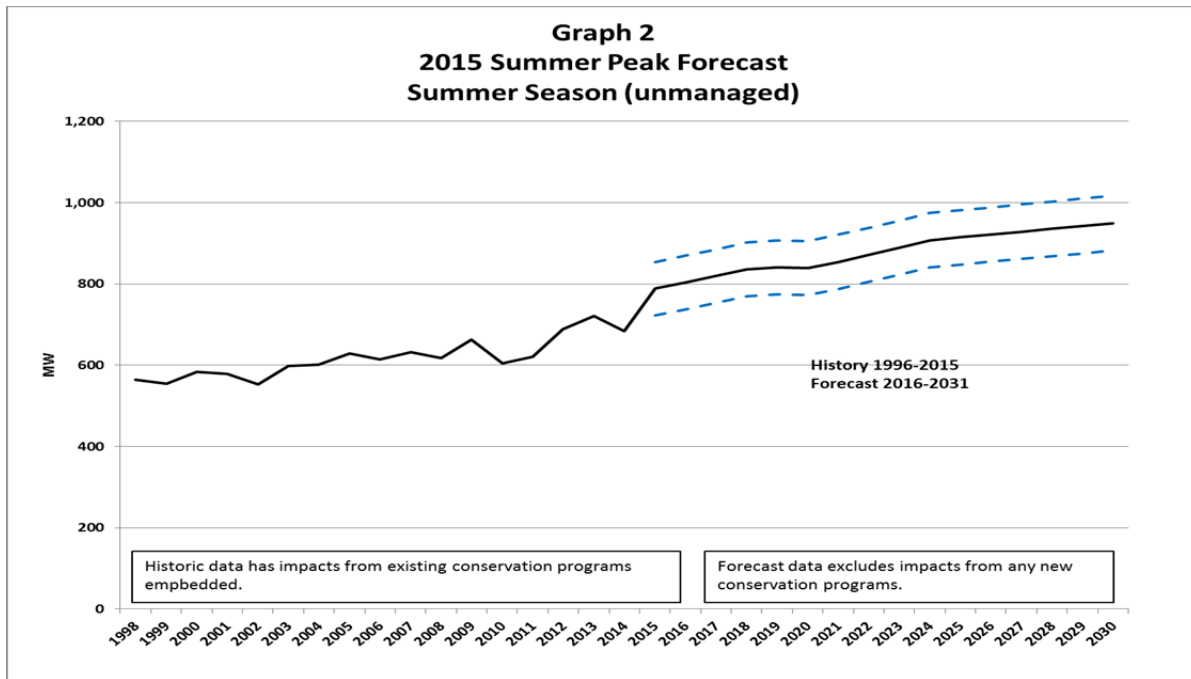
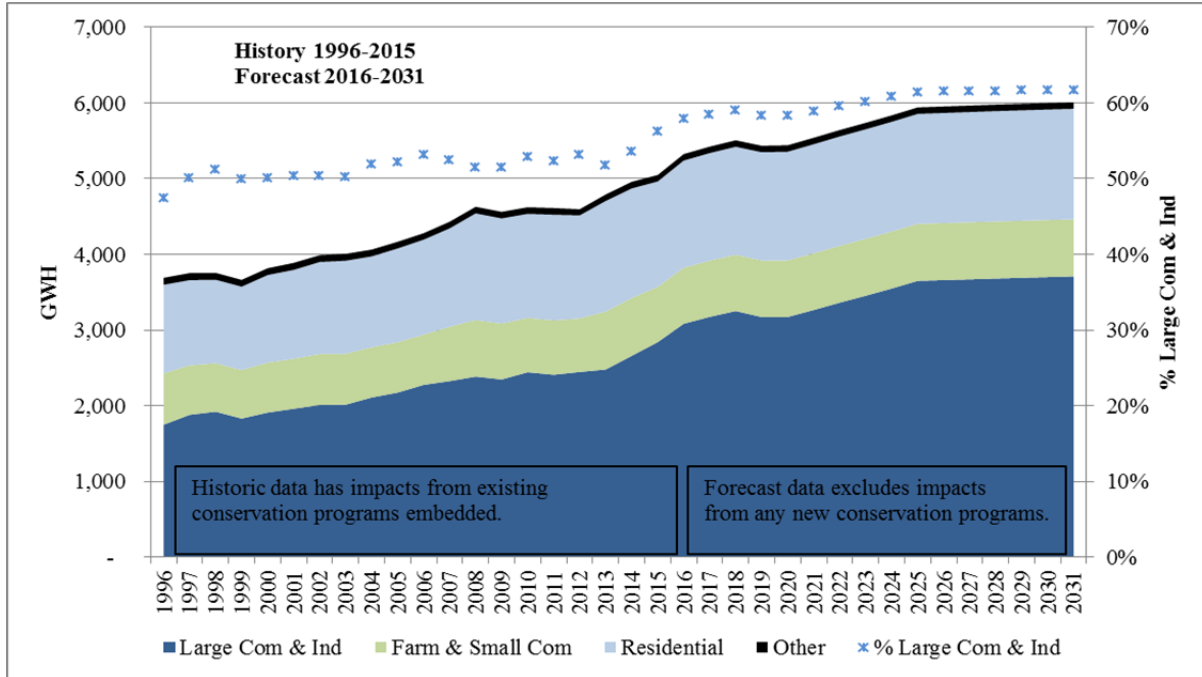


Figure 3-2: Historic and Forecast Annual Retail Sales Before EE (Losses are not included)



Otter Tail assesses capacity need through evaluation of the Company’s load and capability under Module E of the Midcontinent ISO Resource Adequacy Construct. Capacity need is calculated by taking the difference between the planning reserve obligation, which is the coincident peak demand forecast plus the planning reserve margin and transmission losses, and the sum of accredited generating capability, net transaction capacity, and demand side resources.

The Company’s projected summer capacity needs under Module E requirements are shown in Tables 3-1 and represented graphically in Figure 3-3. The Midcontinent ISO requires the Company to designate capacity to meet the 50th percentile peak demand forecast plus reserves. The supply-side resource stack is composed of capacity that is converted to zonal resource credits (“ZRCs”) for resources that are universally deliverable within the Midcontinent ISO footprint (or aggregate), as well as for resources that are locally deliverable to Otter Tail’s load, and any bilateral transactions of ZRCs.

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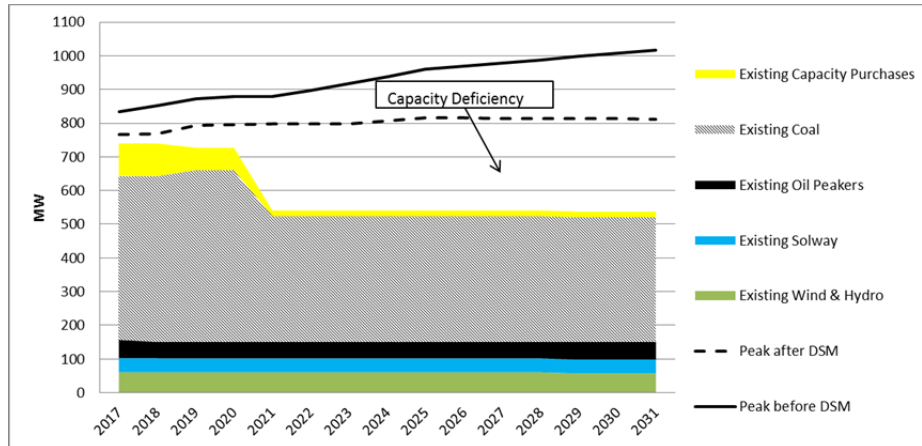
Table 3-1: Summer 2017-2031 Load and Capability Prior to Preferred Plan Information

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Forecasted Load	803.6	819.0	836.2	840.4	839.0	854.5	871.9	889.3	907.6	914.6	921.6	928.6	935.6	942.6	949.6
Transmission Losses	32.1	32.8	33.4	33.6	33.6	34.2	34.9	35.6	36.3	36.6	36.9	37.1	37.4	37.7	38.0
MISO Coincident Factor	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%	91.20%
Coincident Load	762.2	776.8	793.1	797.1	795.7	810.4	826.9	843.4	860.8	867.5	874.1	880.8	887.4	894.1	900.7
MISO Planning Reserve	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%
Total	820.1	835.8	853.4	857.7	856.2	872.0	889.8	907.5	926.3	933.4	940.6	947.7	954.9	962.0	969.2
Enbridge Adjustment	-25.0	-34.0	-20.0	-17.0	-8.0	-17.0	-28.0	-29.0	-31.0	-31.0	-31.0	-31.0	-31.0	-31.0	-31.0
Obligation	795.1	801.8	833.4	840.7	848.2	855.0	861.8	878.5	895.3	902.4	909.6	916.7	923.9	931.0	938.2

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal	486.4	489.4	506.2	506.2	369.8	369.8	369.8	369.8	369.8	369.8	369.8	369.8	369.8	369.8	369.8
Natural Gas	41.9	41.6	41.2	41.2	41.2	41.2	41.2	41.2	41.2	41.2	41.2	41.2	41.2	41.2	41.2
Oil	54.5	51.4	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5
Wind	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	54.6	54.6	54.6
Solar															
Hydro	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
BTMG	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Purchased	89.5	89.5	59.5	59.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Load Management	33	33	34	34	34	35	35	35	36	37	38	38	39	40	41
Total	773.2	772.8	761.3	761.3	574.9	575.9	575.9	575.9	576.9	577.9	578.9	578.9	576.3	577.3	578.3

Net	(21.9)	(29.0)	(72.1)	(79.4)	(273.3)	(279.1)	(285.9)	(302.6)	(318.4)	(324.5)	(330.7)	(337.8)	(347.6)	(353.7)	(359.9)
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Figure 3-3: Projected Summer Capacity Needs through 2031, by Calendar Year



As shown, the Company has a small capacity deficit beginning in the summer of 2017 and expects that deficiency to grow in 2021 when the existing capacity purchase agreements end and the Hoot Lake units 2 and 3 are planned to retire. Any remaining shortfalls for 2017/2018 and 2018/2019 will be closed once the final forecast and MISO parameters are known for each planning year. Otter Tail is a winter peaking utility but for modeling purposes bases its capacity resource need on the summer season as required by Midcontinent ISO resource adequacy rules. Although the summer season drives capacity needs, the entire year is evaluated for the Company's energy needs.

Plan Development TAB

4 Plan Development

4.1 Plan Objectives

In its Order concerning Otter Tail Power Company's initial resource plan filing in 1992, the Commission stated that it considers the characteristics of the available resource options and the proposed plan as a whole. In addition, the Commission stated that it evaluates resource plans on their ability to: (1) maintain or improve the adequacy and reliability of utility service, (2) keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints, (3) minimize adverse socio-economic effects and adverse effects upon the environment, (4) enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations, and (5) limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control. Otter Tail has worked to keep the Commission's objectives in mind while selecting resource options that will provide adequate, reliable, and reasonably priced electric power for its customers.

4.2 Planning Tools

Otter Tail Power Company uses Strategist to perform capacity expansion planning. The Strategist model is capable of providing full supply-side and demand-side integration in the optimal selection of resources, subject to a specified objective function and any imposed constraints. The objective function employed by Otter Tail was to minimize total societal cost, or revenue requirements, based on the costs incurred by both the customers and the utility, plus any externality costs, as shown in the following formula:

$$\begin{array}{r} \text{Capital Cost} \\ + \text{Base Revenue} \\ + \text{Total System Cost} \\ + \text{Emissions Externalities} \\ \hline \text{MINIMIZE Net Present Value:} \quad \text{Total Societal Costs (or Revenue Requirements)} \end{array}$$

Capital Costs include costs for engineering, procurement, and construction of a resource addition. Base Revenue includes the allowable return the Company is able to earn on rate base. Total System Costs include operations and maintenance expenses, fuel costs, or emissions charges. Emissions externalities include any imposed externality cost.

Emissions externalities were used in 31 of the 58 sensitivities. The remaining 27 sensitivities did not have emissions externalities applied.

The net present value of costs (societal/utility) evaluated by the model includes end-effects calculations. End-effects calculations are used to analyze differences between alternatives after the planning period's horizon. End effects are significant in determining the optimal rankings of plans based on long-run economic advantages. Differences among alternatives are due to different operating characteristics and lives and end-effects analysis ensures that those characteristics are adequately considered for capital intensive units that may be added late in the planning period. The end effects result is used to augment the planning period result to account for the cost of replacing the resources and for differences in

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operating cost after the planning period. In all scenarios, the end-effects period was assumed to be 15 years. Therefore, the total societal costs, or utility costs, were considered for the study period of 2017-2031, plus end effects.

4.3 Planning Process

Otter Tail's planning process is an iterative progression that includes the following primary steps:

- 1) Modeling the Company's system using Strategist – This step requires representing all components of the Company's existing fleet of generation, transactions, DSM programs, and financial structure. This is an ongoing process and many inputs are updated either annually or as changes occur.
- 2) Performing capacity expansion runs – This step requires executing the capacity expansion model to rank plans of feasible combinations of alternatives under specified constraints. The capacity expansion tool ranks the plans according to least cost. Careful review of model results for verification and validation and reasonability is essential.
- 3) Developing a preferred resource plan – The Company aims to select a least-cost preferred plan that complies with all relevant statutes and rules, resource adequacy obligations, renewable energy objectives and standards, and established environmental regulations. Additionally, the least-cost plan is weighed against scenarios that evaluate regulatory and market uncertainties in the planning horizon. The preferred plan protects the customer and the Company from unnecessary exposure to risk, while maintaining flexibility and commitment to providing electricity in an economical, reliable, and environmentally responsible manner.

Because Otter Tail's planning process is model-dependent, a more detailed explanation of the components of the Strategist model is provided here. Otter Tail uses four modules in the Strategist model called the LFA, GAF, CER, and PRV. The following section discusses some of the major inputs and the process involved in populating these modules of the database. Greater detail on model assumptions is provided in Appendix F.

Load Forecasting Module – (“LFA”)

The load-forecasting process developed three uncontrolled load forecast scenarios: low, base, and high. The Company splits the load into two components for modeling purposes to represent the Company's Minnesota load and remaining load in both North Dakota and South Dakota. The accredited load control, as registered with Midcontinent ISO under Module E as Demand Response, was also entered into the model. The load control was set up to net against the demand forecast prior to calculating the reserve obligation, it was prevented from actually dispatching. The reason for this representation was that the model is developing a capacity expansion plan based on the 50/50 or mean forecast. Load control is unlikely to occur for capacity reasons at the mean forecast level. Rather, Otter Tail aims to control for capacity reasons to protect against extreme capacity constraints during higher than anticipated load levels, more likely at the 95th percentile level or under obligation to the Midcontinent ISO for emergency conditions.

Generation and Fuel Module – (“GAF”)

Operational specifications and performance parameters of existing and potential thermal resources, hydro units, and transactions (including owned wind and power purchase agreements) were entered in the Strategist database. Capacity accreditation was based on the 2016-2017 planning year ratings by the Midcontinent ISO and any known or anticipated adjustments to accreditations in future years. The data for the thermal resources included heat rates, emissions, maintenance schedules, and maximum and minimum capability. Fuel price forecasts for oil, coal, and natural gas were also represented in the GAF. A tie line to the Midcontinent ISO energy market was represented along with a corresponding energy market price forecast. Wind generation resources were provided a profile for generation output based on historical performance. The GAF also includes cost data for fixed and variable operation and maintenance expenses and contract prices for energy and capacity.

Capital Expenditures – (“CER”)

Capital projects associated with potential resources are entered in the CER module along with an expenditure profile and specified tax life and book life.

Proview Capacity Expansion – (“PRV”)

The Proview Module in Strategist was set up to evaluate a variety of potential resource alternatives subject to the objective function to minimize total societal costs. As part of a robust planning process, the Company uses Proview to evaluate a variety of sensitivities to meet the requirements of the resource plan filing and any known or expected regulatory or economic conditions. Otter Tail ran the model from 2017 through 2031 to capture the full 15 years in the study period. Model results from the Proview runs were compared and evaluated for reasonability and compliance with all constraints.

The Company seeks to develop one preferred plan that reliably and economically meets the energy needs of its customers in all three states, while complying with all legal and regulatory obligations and managing risk. The results of the resource planning analysis are used to develop this filing as well as internal planning and evaluation.

Preferred Resource Plan TAB

5 Preferred Resource Plan

The preferred resource plan identifies resources that could be used to serve customer loads over the entire 2017 – 2031 resource planning period. It also details Otter Tail’s expected activities during the first five years of the planning period. This section first discusses details associated with the preferred resource plan. Then it presents the results for the scenarios required by the Minnesota Rules for resource plan filings, including high and low load growth sensitivities, externality sensitivities, and renewable and conservation sensitivities. The Company’s preferred resource plan, presented in Table 5-1, shows the resource additions anticipated for the planning period.

Table 5-1: Preferred Plan Resource Additions

Resource Plan (MW) - Based on Nameplate ratings		
2017		
2018	100 MW Wind	100 MW Utility Scale Wind
2019		
2020	100 MW Wind & 30 MW Solar	100 MW Utility Scale Wind & 30 MW Utility Scale Solar
2021	248 MW Frame NG CT	248 MW Frame NG Simple-Cycle Combustion Turbine
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		

As Table 5-1 shows, 100 MW of wind is added in 2018 and 2020, as well as, 30 MW of solar in 2020, and a 248 MW natural gas CT is added in 2021. The 200 MW of wind additions early in the plan is due to the impact of the production tax credit (PTC) extension. In December 2015, legislation was enacted that extended the availability of the PTC associated with wind energy through 2019. The legislation also included a phase-out of the tax incentive. The wind energy price assumptions incorporate the phasing out of the PTCs from 100 percent for projects that have started construction in 2016, to 40 percent for projects that have started construction in 2019. For projects that start construction after 2019, there are no PTCs assumed.

5-2 Preferred Resource Plan

Figure 5-1 shows the reserve obligations and the capacity resources of the Preferred Plan.

Figure 5-1: 2017-2031 Capacity Resources and Reserve Obligation for Preferred Plan (MW)

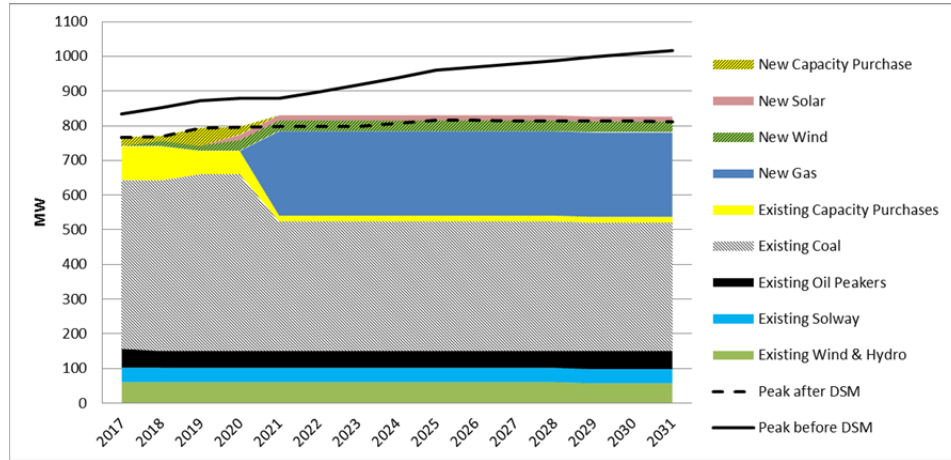
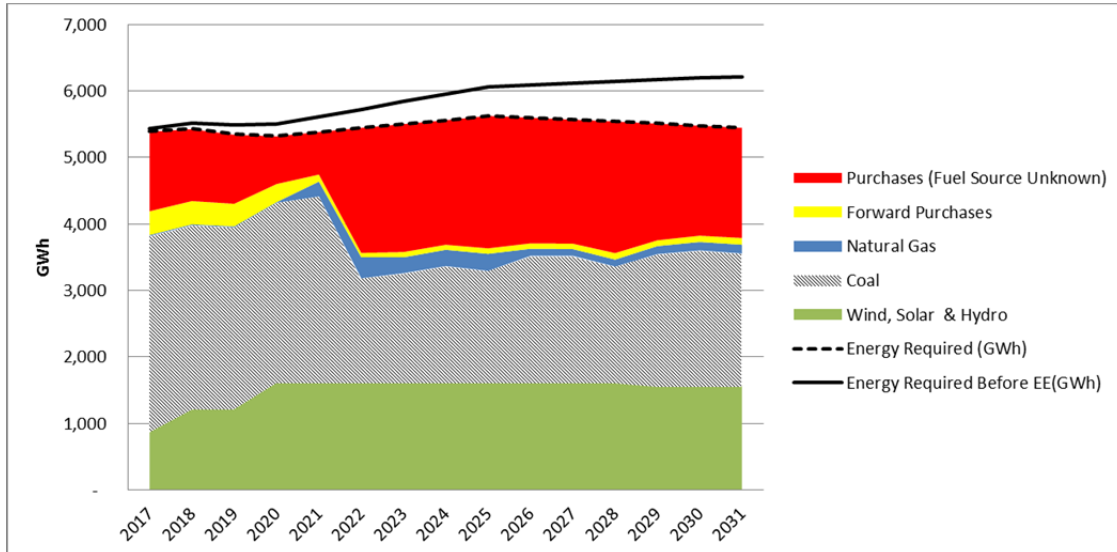


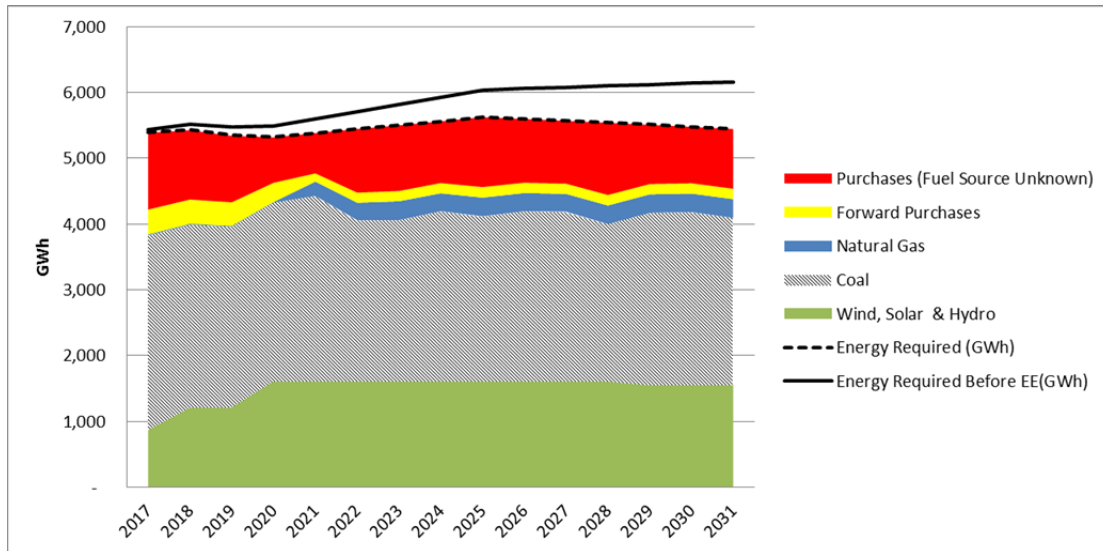
Figure 5-2 shows the energy sources in the preferred plan by fuel type with externalities applied, and figure 5-3 shows the energy sources without externalities applied. Conservation contributes a significant portion to the Company's future energy needs, as do wind generation, continued market opportunity purchases, and natural gas generation.

Figure 5-2: 2017-2031 Energy Resources and Energy Requirements for Preferred Plan with Externalities (GWh)



Preferred Resource Plan 5-3

Figure 5-3: 2017-2031 Energy Resources and Energy Requirements for Preferred Plan without Externalities (GWh)



5.1 Preferred Resource Plan Description

The Otter Tail preferred resource plan in the externality scenario has a present value of societal cost (PVSC) of 3.165B in 2017\$. The Otter Tail preferred resource plan in the zero externality scenario has a present value of utility cost (PVUC) of \$2.419B in 2017\$. The Company’s preferred plan is identified as sensitivity #1 from Appendix I. Following is a description and comment on the demand response and energy efficiency resources used in the preferred plan.

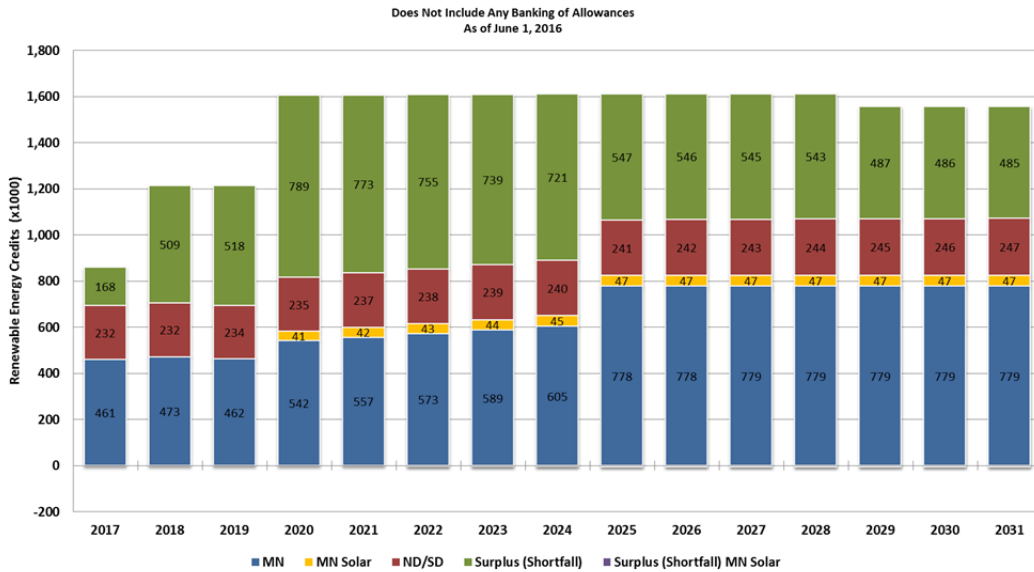
- **1.5 % CIP** – The model uses an annual energy efficiency and conservation alternative for Minnesota load that is 1.5 percent of average retail sales in Minnesota for the prior three years. In 2017 the energy efficiency for Minnesota is modeled at energy sales reduction of 39 GWh and the cumulative effect of the energy savings in the year 2031 is modeled at 658 GWh.
- **Demand Response** – Demand response includes both load management capability and customer contracts that allow load shedding to a firm service level. In the preferred plan, demand response capability is modeled at 33 MW in 2017 increasing to 41 MW in 2031

5.2 REO/RES Compliance

Figure 5-4 represents the planned compliance with REO/RES regulation in all jurisdictions under the preferred plan. Otter Tail expects to have surplus renewable energy credits throughout the study period.

5-4 Preferred Resource Plan

Figure 5-4: Compliance with REO/RES Regulation in All Jurisdictions



The solar portion of the RES is a Minnesota requirement enacted in 2013 to be effective in 2020. The preferred plan forces a solar resource as part of its compliance with the Minnesota SES. In December 2015 legislation was enacted that extended the availability of investment tax credits (ITC). Solar projects that start construction by 2019 are eligible for the 30 percent ITC. The legislation includes a step-down provision of the ITC to the 10 percent level for projects that start construction after 2021. The Company included 6 solar price sensitivities (sensitivities #4, #5, and #6 from Appendix I – With Externalities and Without Externalities), which included modeling solar purchased power agreements at different price levels to determine the resource selections at various price levels. Solar was not selected as a least-cost resource in the base case assumptions, but was selected in the following sensitivities from Appendix I:

- #4 solar with a declining price over the study period
- #15 high load growth
- #18 limited market purchases
- #30 oil peaking units retired in 2023

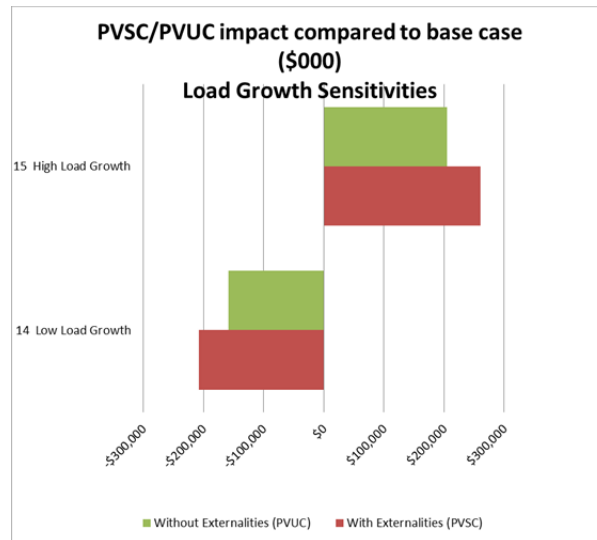
The estimate of the cost/benefit of RES compliance is contained in Appendix H.

5.3 Load Growth Scenarios

The Company included low and high load growth sensitivities (sensitivities #14 and #15 from Appendix I) As shown in Figure 5-7, the low load growth sensitivities results in lower total present value of societal cost (PVSC) and present value of utility costs (PVUC) and fewer resource additions than the base case. The high load growth sensitivities result in higher total PVSC/PVUC and more resource additions than the base case.

Preferred Resource Plan 5-5

Figure 5-5: Load Growth Sensitivities – PVSC/PVUC impact



5.4 Environmental Externalities

The Company evaluated 31 sensitivities where environmental externalities were applied. The low and high externality sensitivities (sensitivities #19 and #20 from Appendix I) use the environmental externality values from the May 27, 2015, *Notice of Revised Updated Environmental Externality Values* as provided by the Commission. The Company’s thermal units located in Minnesota (Hoot Lake and Solway) use the “rural” externality values. Big Stone plant and the proposed combustion turbine use the “within 200 miles of Minnesota” externality values. Coyote station is beyond 200 miles of Minnesota and no externality values were applied to it (except CO₂ starting in 2022). The high and low CO₂ values were \$34 and \$9 respectively starting in 2022. The mid-externality values (average of high and low values) were used in most sensitivities, including the base case. Externality values were escalated 2 percent for inflation.

5.5 Emissions and Greenhouse Gas Reduction Goal

The preferred plan (with externality values applied) shows a reduction in emissions from Otter Tail’s historical levels. Figure 5-9 shows the estimated emissions for SO₂ and NO_x. Figure 5-10 shows the estimated emissions for CO₂. Figure 5-11 shows the estimated emissions for mercury. The values to the left of the solid black line indicate historical levels of emissions (2005 to 2015) for Otter Tail-owned units. The values to right of the solid black line (2017 to 2031) indicate the estimated emissions of the preferred plan for Otter Tail-owned units.

5-6 Preferred Resource Plan

Figure 5-6: SO₂ and NO_x Emissions

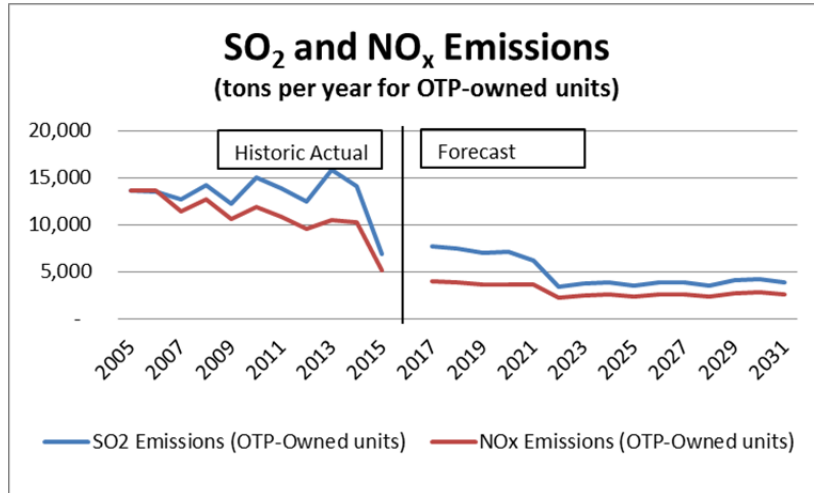
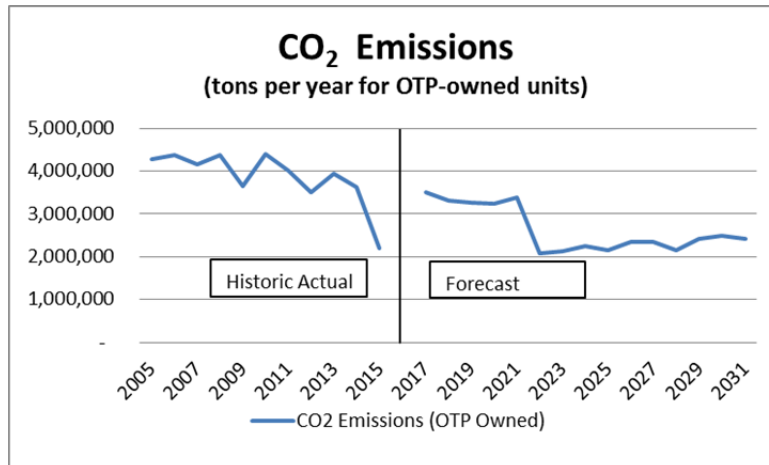
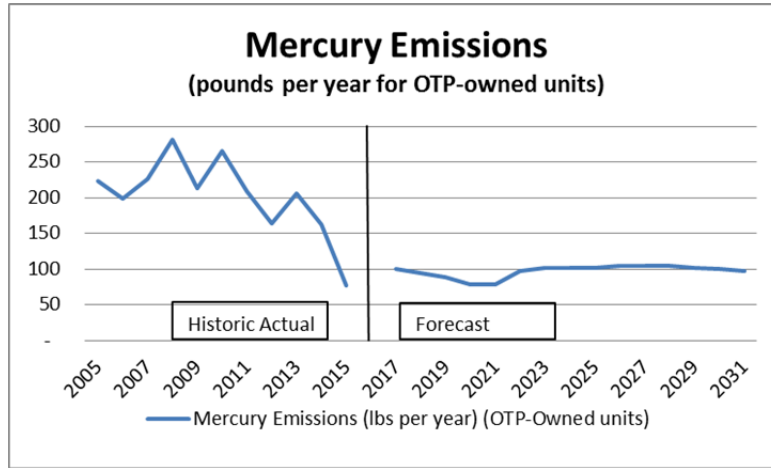


Figure 5-7: CO₂ Emissions



Preferred Resource Plan 5-7

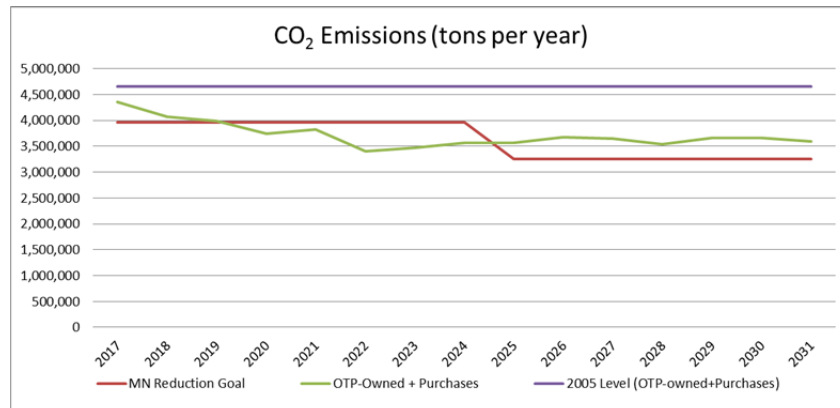
Figure 5-8: Mercury Emissions



Minnesota Statutes §216H.02 states that “It is the goal of the state to reduce greenhouse gas emissions to a level of at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050.” Sensitivity No. 22 from Appendix I shows that the preferred plan plus an additional 200 MW of wind resource addition meets the CO₂ reduction goal for Otter Tail’s system.

Figure 5-9 shows the preferred plan CO₂ emissions and how it compares with the CO₂ reduction goal and the 2005 level of CO₂ emissions. The 2005 level is estimated at 4,653,930 tons of CO₂ (3,745,676 tons from Otter Tail-owned units and 908,254 tons assumed for purchased energy based on the 2005 MRO west regional average CO₂ /MWh of 1,821.64 lbs). For market purchases in this resource plan, 1,425.15 lbs of CO₂ are applied to each MWh of energy purchased (based on the eGRID2012 MRO west sub regional emissions rate).

Figure 5-9: Preferred Plan CO₂ Emissions and the CO₂ reduction Goal



5-8 Preferred Resource Plan

5.6 50% and 75% Conservation and Renewable Scenarios

Minnesota Statutes §216B.2422, Subd. 2, states that "a utility shall include the least-cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources." The calculation is based on the energy from future conservation and renewable resources compared to the total growth in energy requirements for Otter Tail's Minnesota load.

Table 5-2 presents the energy calculation for determining whether the conservation and renewable energy target was met. The preferred plan achieves the 50 percent target and the 75 percent target. The preferred plan which includes 1.5 percent CIP, 200 MW of wind resources, and 30 MW solar resources exceed both the 50 percent target and the 75 percent target, assuming only 50 percent of new wind and solar resources are allocated to Minnesota load (Otter Tail notes that the specific jurisdictional allocation of the wind and solar resource might not be proportional among its jurisdictions if the resource addition is not able to be demonstrated to be part of a least cost resource plan).

Table 5-2: 50% and 75% Renewable and Conservation as Percent of Total New MN Energy Requirements

	Preferred Plan and the 50% and/or 75% Renewable and Conservation goal		
	1.5% Conservation (GWh)	MN 50% Share of 200 MW Wind and 30 MW of Solar (GWh)	Total (GWh)
New MN CIP	495	-	495
New Wind and Solar	-	373	373
Total	495	373	868
Percent of Total New MN Energy Requirements (= 402 GWh)	123%	93%	216%

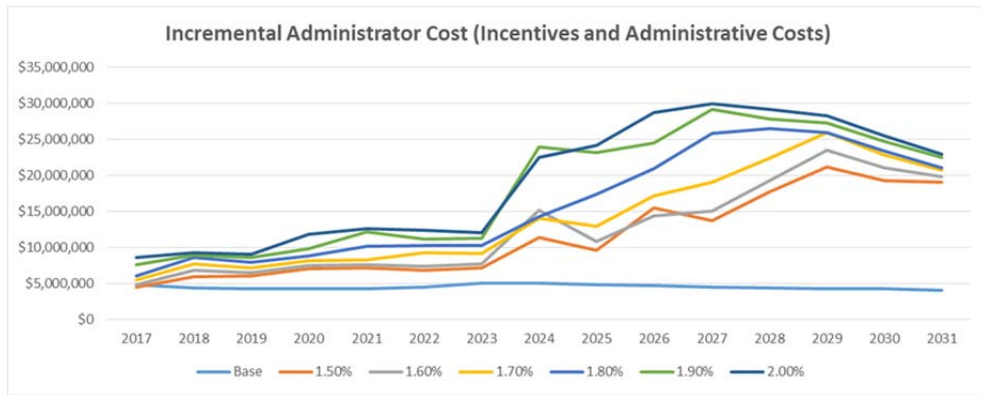
5.7 Energy Conservation Sensitivities

In Otter Tail's 2013 resource plan (MN Docket E017/RP-13-961), the Commission ordered the Company in order point 2(a) to "Evaluate additional conservation scenarios that would achieve greater energy savings beyond those in the base case and provide cost assumptions for achieving every 0.1% of savings above 1.5% retail sales, up to 2% of retail sales".

The Company engaged Navigant Consulting to conduct a DSM potential study to, among other things, evaluate the economics of energy savings at the levels ordered by the Commission. The study is contained in Appendix J. Figure 5-13 shows the incremental costs (in 2016\$) associated with the different levels of energy savings.

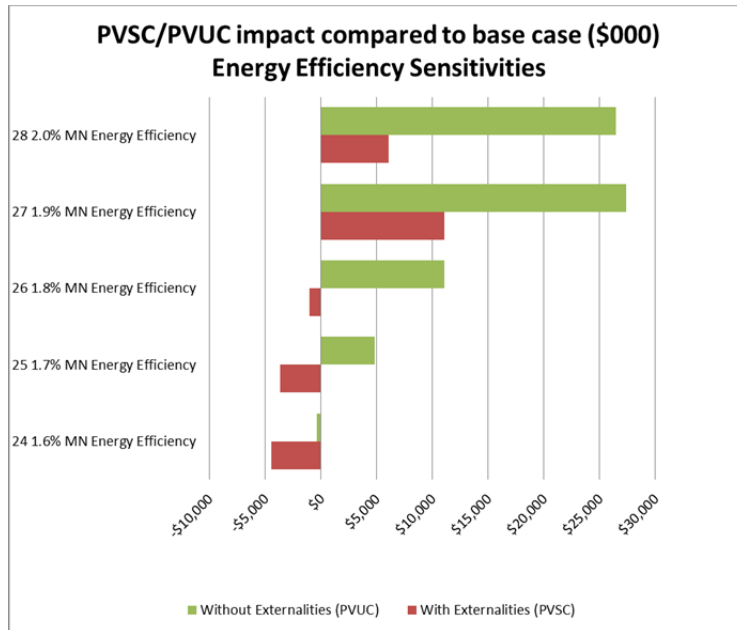
Preferred Resource Plan 5-9

Figure 5-10: Energy Efficiency Costs in 2016\$



Sensitivities #24-28 from Appendix I show the Strategist modeling results for the varying levels of energy savings. Figure 5-14 shows the impact on the PVSC/PVUC of the varying levels of conservation compared to the base case level of 1.5 percent energy savings. With externality values applied (red bars), the PVSC is lower in the 1.6 percent, 1.7 percent and 1.8 percent sensitivities, but higher in the 1.9 percent and 2.0 percent sensitivities. Without externality values applied (green bars), the PVUC of the 1.6 percent sensitivity is similar to the base case 1.5 percent, but higher in the other four sensitivities.

Figure 5-11: Energy Efficiency Sensitivities Compared to Base Case PVSC/PVUC



5.8 Oil Peaker Evaluation Sensitivities

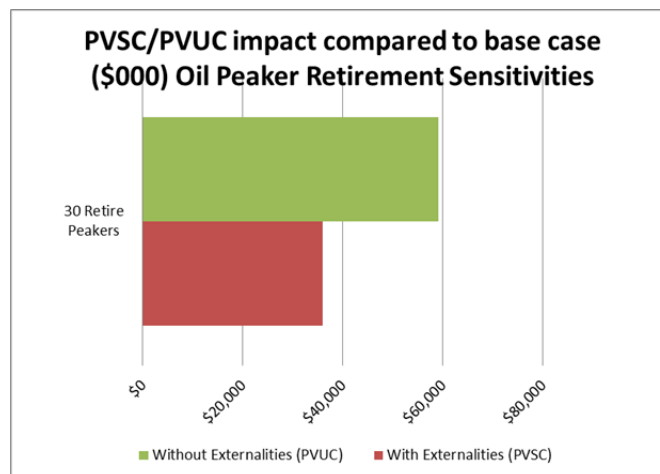
In Otter Tail’s 2013 resource plan (MN Docket E017/RP-13-961), the Commission ordered the Company in order point 2(e) to “Include an analysis of the effects of retiring the Jamestown and Lake Preston Peaking units”.

5-10 Preferred Resource Plan

When Otter Tail made the decision to install the Lake Preston unit in 1978 and Jamestown Units in 1976 and 1978, the primary reason for installing these units was not for additional generation. These units were installed in lieu of building a second high voltage transmission line (backup/supplemental source) into each of these areas. The Lake Preston unit is located in the Hetland Jct. – Toronto load pocket (15 MWs), which currently has a single transmission source, a 115 kV line from Big Stone, SD to Canby, MN. The Jamestown units are both located in the Jamestown load pocket (70 MWs), which also currently has a single high voltage source, a 345 kV line from Center, ND through Jamestown to the Bison station near Mapleton, ND. Today, all three of the peaking units continue to serve the purpose of which they were originally installed, to provide backup local load serving capability to the respective load pockets in the event there is a loss of the high voltage transmission source currently serving the load. If Otter Tail decides to retire any of these three units, a high voltage transmission line will need to be built prior to retirement of the unit in order to continue to provide reliable service to these load pockets. Otter Tail has evaluated two different build-out options for each load pocket. The costs of building new transmission into the Jamestown load pocket range from \$10.75-\$13.25 M. The costs of building new transmission into the Hetland load pocket range from \$30-\$32.75 M.

Sensitivity #30 from Appendix I shows the Strategist modeling results for retiring the oil peaking units (Jamestown #1, Jamestown #2, and Lake Preston units) at the end of their current book life of June 2023. This sensitivity assumes that \$45 million of transmission assets would be built before the peaking units are retired. Figure 5-15 shows the PVSC increases approximately \$36 million compared to the base case and the PVUC increases nearly \$60 million compared to the base case. The base case has the peaking units remaining in operation throughout the study period.

Figure 5-12: Oil Peaker Retirement in 2023 Compared to Base Case PVSC/PVUC



5.9 Limited Market Sensitivities

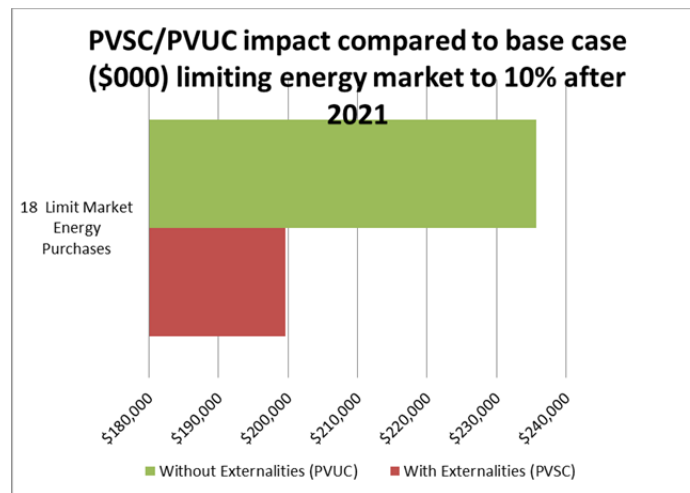
In Otter Tail’s 2013 resource plan (MN Docket E017/RP-13-961), the Commission ordered the Company in order point 2(d) to “Restrict Strategist from selecting generic, wholesale capacity purchases after the first five years of the planning period, unless a specific, known, and reasonable contract exists.” For all of the sensitivities that have externality values applied, the Company limited the use of generic capacity purchases to the first five years. For sensitivities that do not apply externality values, the generic capacity

Preferred Resource Plan 5-11

purchases are available throughout the study period. The Preferred plan does not use any generic capacity purchases after the first five years of the study.

In Otter Tail's 2013 resource plan (MN Docket E017/RP-13-961), the Commission ordered the Company in order point 2(c) to "Include a scenario which caps MISO day-ahead market energy at ten percent of Otter Tail's total energy needs after the first five years of the planning period". Sensitivity #18 from Appendix I show the Strategist results when market purchases are limited to ten percent of the energy needs after the first five years. Figure 5-16 shows the PVSC increases nearly \$200 million compared to the base case and the PVUC increases over \$235 million compared to the base case. The base case allows for unlimited market opportunity purchases to occur throughout the study period.

Figure 5-13: Limiting Market Energy Purchases Compared to Base Case PVSC/PVUC

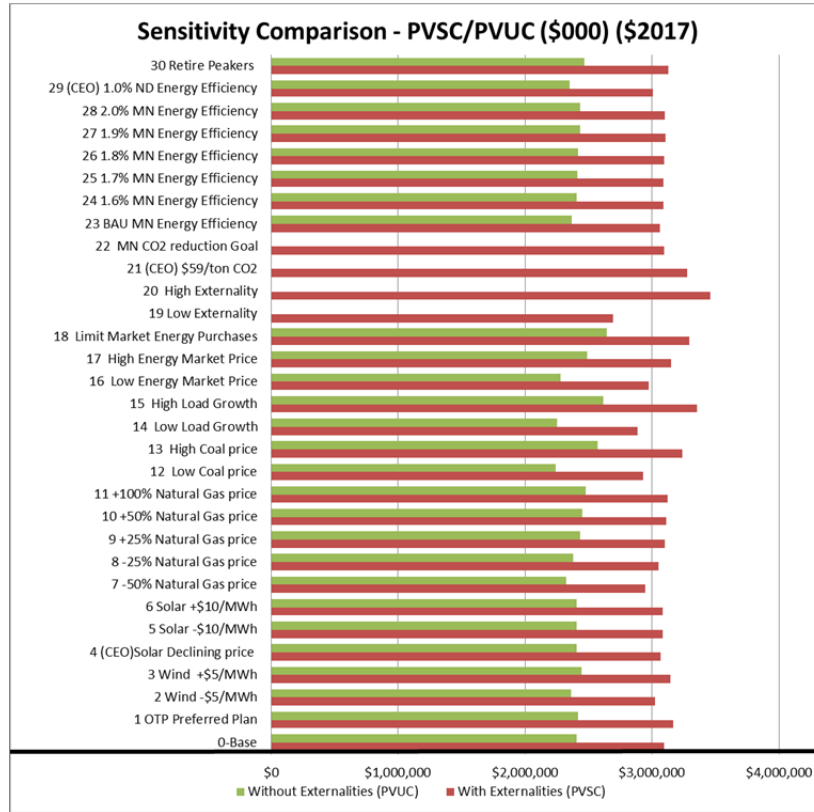


5.10 Additional Sensitivity Scenarios

Otter Tail evaluated additional sensitivities. They included variations in wind prices, solar prices, natural gas prices, coal prices, energy market prices, and CO₂ reductions. A comparison of the PVSC/PVUC for all scenarios is provided in Figure 5-17 while figure 5-18 shows the sensitivities compared to the base case.

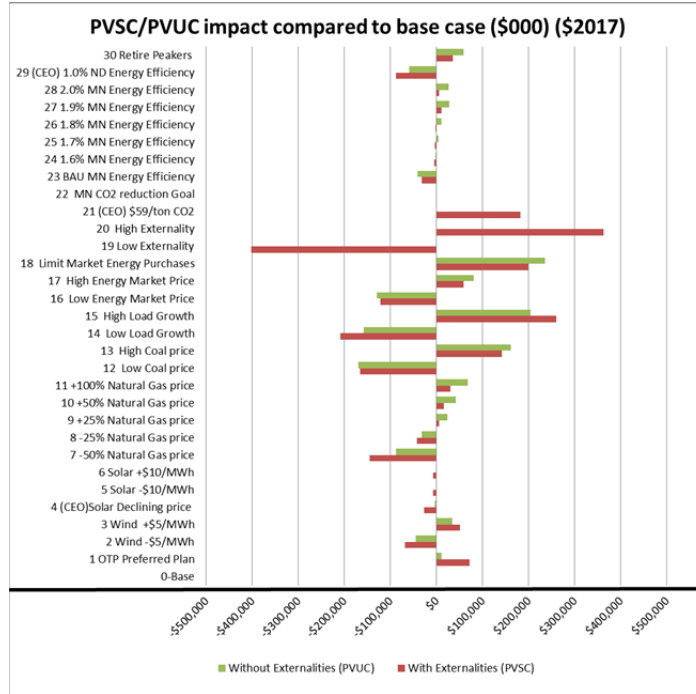
5-12 Preferred Resource Plan

Figure 5-14: Sensitivity Comparison (PVSC/PVUC)



Preferred Resource Plan 5-13

Figure 5-15: Sensitivity Comparison to Base Case (PVSC/PVUC)



Conclusion

TAB

6 Conclusion

Otter Tail Power Company's mission is to produce and deliver electricity as reliably, economically, and environmentally responsibly as possible to the balanced benefit of customers, shareholders, and employees and to improve the quality of life in the areas in which we do business. The preferred plan provides the best course of action for the Company to achieve these objectives. The preferred plan also provides flexibility to react to legislative, regulatory, and market changes that will occur during the next several years.

This resource plan results in generation additions that are nearly the same in the majority of the sensitivities: 200 MW of new wind, a new 248 MW CT, and enough solar to meet Minnesota's solar energy standard.

The preferred plan improves environmental performance through implementation of DSM, renewable resources and simple-cycle natural gas generation. The resource plan satisfies the regulatory and statutory requirements of all three jurisdictions that it serves.

6.1 Preferred Plan is in the Public Interest

The Company is committed to operating its generation facilities as efficiently as practicable while minimizing adverse effects on the environment. New resources have been selected that will meet the Company's needs while maintaining flexibility and limiting the risk of exposure to changes in financial, social and technological factors beyond its control. The plan maintains flexibility during a period of much uncertainty in the future of the electric industry. In addition, customers will be provided with increased opportunities to improve their energy efficiency. This resource plan satisfies the legal and regulatory requirements in the multi-state service territory and allows Otter Tail and its customers to realize the benefits of operating as a single system while recognizing the differing state requirements.

Our preferred resource plan will result in Otter Tail generating approximately 30% of our energy from renewables by 2021. After the wind, solar, and natural gas additions and the Hoot Lake Plant retirement, we'll meet Minnesota's greenhouse gas reduction goal at least until 2025. The preferred plan, which includes 1.5 percent CIP, 200 MW of wind resources, and 30 MW solar resources, exceeds both the target of meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources 2031. The plan satisfies all rules and requirements of the Minnesota statutes and rules, provides a clear concise report to interested parties of what Otter Tail intends to do to satisfy customer needs in the near term, and identifies the resources the Company is considering for viable options for the long term.

6.2 Socio-Economic Impacts of the Preferred Plan

The primary socio-economic impact of the preferred plan is that it is a cost-effective plan that meets all statutory and regulatory requirements, and provides reliable and affordable electricity to customers. Otter Tail supports economic development in the states we do business by keeping costs low and reliability high for commercial and industrial customers so that those customers can invest in greater productivity and growth. Likewise, Otter Tail keeps costs low and reliability high for the residential consumer, recognizing that electricity is a fundamental input to the overall health, welfare, and productivity of society.

6-2 Conclusion

The resource additions in the preferred plan will create construction jobs to develop the natural gas-fired peaking facility and new wind generation. This plan will foster greater awareness and participation in energy efficiency in the homes and businesses the Company serves, helping to meet future energy needs, and avoiding the addition of more expensive generation alternatives. Under this plan the Company will continue to develop an effective demand-side management portfolio, a successful collaboration among Otter Tail and residential, commercial, and industrial customers. These programs provide customers with economic rates that allow them to be more productive and invest in the regional economy while providing load shifting or shedding capability in times of emergency.

In summary, the socio-economic impacts from this plan include providing cost-effective, reliable electricity to all classes of customers, preserving and creating jobs in the utility industry, and reducing emissions. Greater detail regarding impacts of specific projects within the plan will be addressed as those projects are developed.

6.3 Five-Year Action Plan

The preferred plan will require considerable activity within the next five years to bring about the resources previously approved and those selected in the plan. Table 6-1 identifies the major activities and the approximate timelines for those activities, beginning with 2016. Some of these activities are already underway. There are many other related activities that will be taking place to support the major items identified in the table that will involve many stakeholders, regulatory agencies, and interested parties.

Table 6-1: Five-Year Action Plan Activities

Year	Activity
2016	June 1 Triennial CIP filing for 2017, 2018, 2019 MISO interconnection process for CT Preparation for permitting effort for CT
2017	Permitting and approvals for 248 MW CT MISO interconnection process for CT Begin construction on 100 MW wind project
2018	Commercial operation of 100 MW wind project Permitting and approvals for 248 MW CT MISO interconnection process for CT Initiate work on utility-scale solar project to meet the Minnesota Solar Mandate by 2020
2019	June 1 Triennial CIP filing for 2020, 2021, 2022 Engineering and procurement for 248 MW CT Begin construction on 100 MW wind project Construct or obtain PPA for an approximate 30 MW solar installation
2020	Construction of 248 MW CT File MISO Attachment Y for retirement of Hoot Lake Plant Commercial operation of 100 MW wind project Commercial operation of 30 MW solar project
2021	Start-up and commercial operation of 248 MW CT Retirement of Hoot Lake Plant

Appendix A

TAB

Appendix A: Plan Cross Reference

Table 1: Status of 5-year Action Plan from 2013 IRP Docket No. E017/RP-13-961

Table 2: Minnesota Public Utilities Commission Orders since 2013 IRP Docket No. E017/RP-13-961

Table 3: Minnesota Statutes and Rules on IRPs

Appendix A: Plan Cross Reference

Table 1: Status of 5-year Action Plan in 2013 IRP Docket No. E017/RP-13-961

Year	Activity	Status
2013	July 1 Triennial CIP filing for 2014,2015,2016	Was filed on June 1, 2013
	On-going construction of Big Stone Plant AQCS project	Construction complete, plant in full operation
	On-going construction of Hoot Lake MATS upgrade	Construction complete, plant in full operation
2014	On-going construction of Big Stone Plant AQCS project	Construction complete, plant in full operation
	On-going construction of Hoot Lake MATS upgrade	Construction complete, plant in full operation
2015	On-going construction of Big Stone Plant AQCS project	Construction complete, plant in full operation
2016	June 1 Triennial CIP filing for 2017, 2018, 2019	Will be filed on June 1, 2016
2017	Preliminary engineering for permit support and interconnection request (Hoot Lake replacement unit)	Expect to begin late in 2016; MISO interconnection request was filed in November 11, 2015.
2018	File interconnection request, Certificate of Need for 2021 combustion turbine (Hoot Lake replacement unit)	MISO interconnection request filed on November 11, 2015. Since project is not located in Minnesota, no Certificate of Need filing is necessary.
	Environmental permitting for 2021 combustion turbine; initiate detailed design and procurement for 248 MW turbine	Expect to begin this work during late 2017 through 2017.
	Initiate work on utility-scale solar project to meet the Minnesota Solar Mandate by 2020	Initial meetings with various solar developers are taking place currently.

Table 2: Minnesota Public Utilities Commission Orders since 2013 IRP

Docket No. E017/RP-13-961 Order Approving Plan Subject to Conditions, Requiring Further Filings, and Setting Requirements for Next Resource Plan, dated 2-9-2012		Section/Reference
1	Based on the entire record in this case, the Commission approves Otter Tail Power Company's 2014-2028 resource plan, as modified by the Company in response to the parties' comments and as further modified below. This approval does not extend to particular generation projects that are currently under review in other proceedings or will be subject to review in future proceedings, but is a general finding that the plans filed by Otter Tail appear to be reasonable in light of the entire record.	Not Applicable
a	Otter Tail shall obtain approximately 200 MW, subject to need, of intermediate capacity (and associated energy) in the 2019–2021 timeframe by constructing the resource itself, sharing in the ownership of the resource, or procuring the resource through bilateral contracts, whichever option is most cost-effective.	Otter Tail is including a 248 MW combustion turbine in 2021 and 200MW of new wind between 2018 and 2022 in its preferred plan. (See Section 5)
b	Otter Tail is authorized to obtain up to 300 MW of wind in the 2017–2021 timeframe if cost-effective and to the extent consistent with reliable system operation.	See above
c	Otter Tail's use of bilateral energy contracts shall not be limited to the first five years of the planning period, as long as the contracts are secured and a cost-effective resource.	Included in Strategist modeling assumptions
d	Otter Tail shall modify its action plan to add enough solar to comply with the Solar Energy Standard.	Included in Preferred Plan. (See Section 5)
e	Otter Tail shall explore procuring at least half of its [Solar Energy Standard] SES compliance by December 2016 to secure potentially expiring tax credits for solar resources. The Company shall report on its progress toward this December 2016 goal in each of its Annual SES Reports required under Minn. Stat. § 216B.1691, subd. 2f(g).	The IRS has extended the Solar ITC so Otter Tail has not procured any utility scale solar at this time. Sufficient solar to meet Minnesota's SES is included in its Preferred Plan. (See Section 5)
2	In its next resource plan, Otter Tail Power shall do the following:	
a	Use Strategist as its modeling program.	Strategist is used as the modeling program.
b	Evaluate additional conservation scenarios that would achieve greater energy savings beyond those in the base case and provide cost assumptions for achieving every 0.1% of savings above 1.5% retail sales, up to 2% of retail sales.	See Appendix I, page 2, Sensitivities 23-28
c	Include a scenario which caps MISO day-ahead market energy at ten percent of Otter Tail's total energy needs after the first five years of the planning period.	See Appendix I, page 2, Sensitivity 18
d	Restrict Strategist from selecting generic, wholesale capacity purchases after the first five years of the planning period, unless a specific, known, and reasonable contract exists.	See Section 5.9 of the resource plan.

e	Include an analysis of the effects of retiring its Jamestown and Lake Preston peaking units.	See Appendix I, page 2, Sensitivity 30
f	File a proposal to replace Hoot Lake Plant, including expected dates for filing a certificate-of-need application with the Commission, an Attachment Y with MISO, and an interconnection request with MISO for its proposed new facility.	This resource plan proposes a replacement for Hoot Lake Plant. Since it not located in Minnesota, a certificate of need is not required. MISO requires Attachment Y be filed 26 weeks prior to retirement. We expect to file that during second half of 2020.
g	Monitor the discussion regarding Minnesota’s greenhouse-gas reduction goal in the pending Southern Minnesota Municipal Power Agency resource-planning docket, No. 13-1104, and provide an analysis in the Company’s resource plan.	See Section 5.5
3	In all future resource plans, Otter Tail shall do the following:	
a	Provide a forecast of the market cost of SO ₂ allowances, as well as any other emissions allowances granted to the Company.	See Appendix E, Environmental Assessment, page 12
b	Provide detailed data, calculations, and written explanations supporting Heating Degree Day base.	A detailed explanation of Otter Tail’s Heating Degree Day calculation was included in the forecast pre-filing dated May 2, 2016.
c	Investigate other regressions specifications and methods to account for the change in the capacity-control set point.	Otter Tail does not control demand for capacity purposes, only for economics. All capacity-related control would be initiated by MISO.
4	Otter Tail shall file all pertinent details demonstrating the reasonableness of the energy-only bilateral purchased power agreement it entered into on October 7, 2014. The Company shall provide the price(s) of the energy under the contract, whether any resources would be replaced by the energy-only purchase, and any other information necessary for the Department and the Commission to determine whether this bilateral purchase is reasonable.	Otter Tail submitted a Compliance Report in Docket No. E017/RP-13-961 on December 31, 2014 demonstrating the reasonableness of the purchase entered into on October 7, 2014.
5	Otter Tail Power shall file its next resource plan on June 1, 2016.	Next resource plan filed on June 1, 2016 in Docket No. E017/RP-16-386
6	This order shall become effective immediately.	

Docket E-999/CI-07-1199 Order Establishing 2014 and 2015 Estimate of Future Carbon Dioxide Regulation Costs, dated 4-28-2014	
	Section/Reference
1. The Commission maintains its estimate of the range of likely costs of CO2 regulation at between \$9 and \$34 per ton of CO2 for 2014 and 2015.	See Appendix I. Otter Tail applied the mid-point of the range, \$21.50, to all sensitivities except #19 and #20 where \$9 and \$34 were applied respectively.
2. Utilities shall begin applying the above range of CO2 values in their resource planning as of 2019.	Otter Tail began applying these costs in 2022 per recommendation in Docket No. E999-DI-15-708.

Docket E-999/CI-11-852	
Minn. Statutes Sec. 216B.1691, Subd. 2e.	Section/Reference
Utilities were required to make initial report including clear narrative explanations of the modeling methods and the assumptions used in developing the cost and rate impacts.	See Appendix G
The report must be updated and submitted in subsequent resource plans.	See Appendix G

Table 3: Minnesota Statutes and Rules - IRPs

Statute	Subsection	Subject	Section/Reference
§216B.1612 Community- Based Energy Development	Subd. 5b - Priority for C- BED projects.	Utility shall include a description of its efforts to purchase energy from C-BED projects, including a list of the projects under contract and the amount of C-BED energy purchased.	See Appendix H - C-BED Report
§216B.1691 Renewable Energy Objectives	Subd. 2a - Eligible energy technology standard.	Report on renewable energy objectives and standards.	See Appendix G - REO/RES Compliance
	Subd. 2e - Rate impact of standard compliant; report.	Utility must submit a report containing an estimation of the rate impact of RES compliance.	See Figure 5-4 - Preferred Resource Plan
	Subd. 2f - Solar energy standard	(a) Utility shall generate or procure sufficient electricity generated by solar energy to serve its retail electricity customers in Minnesota so that by the end of 2020, at least 1.5 percent of the utility's total retail electric sales to retail customers in Minnesota is generated by solar energy. At least ten percent of the 1.5 percent goal must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 20 kilowatts or less.	See Section 5.2 Preferred Resource Plan - REO/RES Compliance
		(c) It is an energy goal of the state of Minnesota that by 2030, ten percent of the retail electric sales in Minnesota be generated by solar energy.	Study concludes in 2031; this will be addressed in future resource plans.
	Subd. 3 – Utility plans filed with commission.	Report on efforts toward meeting renewable energy objective/renewable energy standard.	See Appendix G
§216B.241 Energy Conservation Improvement	Subd. 1c(b) - Energy saving goals.	Utility shall have an annual energy-savings goal equivalent to at least 1.5 percent of annual retail energy sales unless modified by the commissioner. The savings goals must be calculated based on the most recent three-year weather-normalized average.	See Section 3.9 Current Outlook - 2007 MN Legislature DSM and Conservation Requirements
§216B.2422 Resource Planning; Renewable Energy	Subd. 2 - Resource plan filing and approval.	Utility shall include the least cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources.	See Section 5.5 Preferred Resource Plan - 50% and 75% Conservation and Renewable Scenarios

Appendix A: Plan Cross Reference 6

	Subd. 2a – Historical data and advance forecast.	Utility required to file a resource plan under this section shall include in the filing all applicable annual information required by section 216C.17, subdivision 2, and the rules adopted under that section. To the extent that a utility complies with this subdivision, it is not required to file annual advance forecasts with the department under section 216C.17, subdivision 2.	Otter Tail filed its energy and demand forecast with the Commission on May 2, 2016
	Subd. 3 - Environmental costs.	Utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings.	Appendix F - Externality Price Assumptions
	Subd. 4 - Preference for renewable energy facilities.	The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. The public interest determination must include whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f.	See Section 6.1 Conclusion - Preferred Plan is in the Public Interest
	Subd. 6 - Consolidation of resource planning and certificate of need.	Utility shall indicate in its resource plan whether it intends to site or construct a large energy facility.	See Section 6 Conclusion
§216B.2426 Opportunities for Distributed Generation	Distributed generation.	Report on opportunities for distributed generation.	See Appendix K - Distributed Renewable Generation
§216H.02 Greenhouse Gas Emissions Control	Minnesota CO2 Goal	It is the goal of the state to reduce statewide greenhouse gas emissions to a level of at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050.	Study concludes in 2028; 2050 requirement will be addressed in future resource plans.
§216H.03 Failure to adopt greenhouse gas control plan.		Long-term increased emissions from power plants is prohibited and includes new construction, import from source that would contribute to emissions, and long-term PPA of more than 50MW of capacity or more for a term exceeding five years.	None planned.

<p>§216H.06 Emissions consideration in resource planning.</p>	<p>Carbon values</p>	<p>The Public Utilities Commission shall establish an estimate of the likely range of costs of future carbon dioxide regulation on electricity generation. The estimate must be used in all electricity generation resource acquisition proceedings.</p>	<p>See Section 5.4 Preferred Resource Plan - Environmental Externality Scenarios and Appendix I - IRP Sensitivity Summary</p>
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Rule	Subpart	Subject	Section/Reference
7843.03 Utility Resource Planning Process	Subpart 5 - Copies of filings.	Utility shall submit 15 copies of its resource plan filing to the commission.	Sent on filing.
7843.04 Contents of Resource Plan Filings	Subpart 1 - Advance forecasts.	Utility shall include in the filing identified in subpart 2 its most recent annual submission to the Minnesota Department of Commerce and the MEQB.	Appendix B – MEQB
	Subpart 2 - Resource plan.	Utility shall file a proposed plan for meeting the service needs of its customers over the forecast period. The plan must show the resource options the utility believes it might use to meet those needs. The plan must also specify how the implementation and use of those resource options would vary with changes in supply and demand circumstances. The utility is only required to identify a resource option generically, unless a commitment to a specific resource exists at the time of the filing. The utility shall also discuss plans to reduce existing resources through sales, leases, deratings, or retirements.	Appendix I - IRP Sensitivity Summary
	Subpart 3(A) - Supporting information.	Resource plan shall include a list of resource options considered.	See Section 2.4 Resource Plan Summary -Resource Alternatives
	Subpart 3(B)	Resource plan shall include a description of the process and analytical techniques used in developing the plan.	See Section 4.2 Plan Development - Planning Tools
	Subpart 3(C)	Response plan shall include a 5-year action plan with key construction activities and regulatory filings.	See Section 6.3 Conclusion - Five- Year Action Plan
	Subpart 3(D)	Resource plan shall include a narrative and quantitative discussion of why the plan is in the public interest.	See Section 2.6 Resource Plan Summary - Preferred Plan is in the Public Interest
	Subpart 4	Response plan shall include a nontechnical summary (not exceeding 25 pages in length).	See Section 2 Resource Plan Summary Non- Technical Summary

Appendix B

TAB

Appendix B: Minnesota Electric Utility Annual Report

**PUBLIC DOCUMENT – NOT PUBLIC
DATA HAS BEEN EXCISED**

SECTION 1

Electric Utility Information Reported Annually
Under Rules 7610.0100-7610.0700

Form EN-0003 – 20

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0150 FEDERAL OR STATE DATA SUBSTITUTION

FEDERAL AGENCY	FORM NUMBER	FORM TITLE	FILING CYCLE (enter an "X" in the cell)		
			MONTHLY	YEARLY	OTHER
DOE	EIA860	ANN. ELECT. GENERATING REPORT		X	
DOE	EIA861	ANN. ELECT. UTIL. REPORT		X	
DOE	EIA923	TEAM ELECT. PLANT OPERATIONS/DESIGN		X	
DOE	EIA826	ELECT. UTIL. COMPANY. MONTHLY	X		
DOE	EIA714	ANN. ELECT. POWER SYS. REPORT		X	

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

A utility shall provide the following information for the last calendar year:

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

If applicable, the Largest Customer List must be submitted either in electronic or paper format. If information is Trade Secret, note it as such.

See "LargestCustomers" worksheet for data entry.

C. MINNESOTA SERVICE AREA MAP

The referenced map must be submitted either in electronic or paper format.

See Instructions for details of the information required on the Minnesota Service Area Map.

D. PURCHASES AND SALES FOR RESALE			RESALE ONLY	
UTILITY NAME	INTERCONNECTED UTILITY	MWH PURCHASED	MWH SOLD FOR RESALE	
American Electric Power Service	MISO			
American UE	MISO			
Ashtabula Wind III, LLC	MISO	213,010		
Badger, SD	Badger Municipal Power			361
Basin Electric Power Cooperative				
Beltrami Electric Cooperative	Minnkota Power Cooperative	86,367		
Cargill Power Markets, LLC	MISO	58,400		
Constellation Energy Commodities Group	MISO			
Dakota Valley Services		72		
DTE Energy Trading, Inc.	MISO			
EDF Trading North America	MISO			
Excel Energy Under Reported Load Adj.	MISO	-257		
Lake Region State College		4,163		
Lyon Lincoln Electric Cooperative				
MacQuarie Energy LLC	MISO			
Manitoba Hydro Electric Board	MISO	50,400		
MidAmerican Energy Company	MISO			
Minnesota Power	MISO			
Minnkota Power Cooperative	MAPP			
Missouri River Services	MISO			
Montana Dakota Utilities - Mountrail	MISO			
New Folden, MN	New Folden Municipal Power			2,335
Nextra Energy Power Marketing	MISO			
Nielsville, MN	Nielsville Municipal Power			95
Nodak Electric Cooperative	Nodak Electric Cooperative	9,928		
North Central Electric Cooperative				
Northern States Power	MISO	670,850		
NorthWestern Energy - NLE	MAPP			
PKM Electric Cooperative	PKM Electric Cooperative	10,608		
Rainbow Energy Marketing Corp	MAPP			
RBC Capital Markets Corporation	MAPP			
Red Lake Rural Electric Cooperative	MAPP	9,127		
Shelly, MN	Shelly Municipal Power			686
Southern MN Municipal Power Agency	MAPP			
The Energy Authority	MISO			
Transalta Energy Marketing	MAPP			
Western Area Power Administration	MISO	279		
Western Area Power Administration - WEC		32,158		
Willmar Municipal Utilities	MISO			
Midwest ISO		1,981,736		112,383
Non-asset based cost of sales				
OTHER NON UTILITY				
American Crystal Sugar		153		
Borderline Wind		1,936		
City of Detroit Lakes		1,000		
City of Perham				
Dakota Magic Casino				
Dakota Wind Exchacnge		161		
Energy Maintenance Service-Broadwind Srvc				
Fleet Farm				
FPL Energy North Dakota Wind II		57,287		
Hendricks Wind 1		2,357		
Kindred School				
Lac Qui Parle School		54		
Langdon Wind, LLC		75,422		
District 45 Methane		11,427		
Minnesota Small Power (Wind)		127		
North Dakota Small Power (Wind)		62		

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

A utility shall provide the following information for the last calendar year:

E. RATE SCHEDULES

The rate schedule and monthly power cost adjustment information must be submitted in electronic or paper format.

See Instructions for details of the information required on the Rate Schedules and Monthly Power Cost Adjustments.

F. REPORT FORM EIA-861

A copy of report form EIA-861 filed with the US Dept. of Energy must be submitted in electronic or paper format.

A copy of the report form EIA-861 filed with the Energy Information Administration of the US Dept. of Energy must be submitted.

G. FINANCIAL AND STATISTICAL REPORT

If applicable, a copy of the Financial and Statistical Report filed with the US Dept. of Agriculture must be submitted in electronic or paper format.

For rural electric cooperatives, a copy of the Financial and Statistical Report to the US Dept of Agriculture must be submitted.

H. GENERATION DATA

If the utility has Minnesota power plants, enter the fuel requirements and generation data on the Plant1, Plant2, etc. worksheets.

I. ELECTRIC USE BY MINNESOTA RESIDENTIAL SPACE HEATING USERS

See Instructions for details of the information required for residential space heating users.

COL. 1 NO. OF RESIDENTIAL ELECTRICAL SPACE HEATING CUSTOMERS	COL. 2 NO. OF RESIDENTIAL UNITS SERVED WITH ELECTRICAL SPACE HEATING	COL. 3 TOTAL MWH USED BY THESE CUSTOMERS AND UNITS
6,866	8,957	145,583

Comments

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

J. ITS DELIVERIES TO ULTIMATE CONSUMERS BY COUNTY FOR THE LAST CALENDAR YEAR

ENERGY DELIVERED TO ULTIMATE CONSUMERS BY COUNTY

COUNTY CODE	COUNTY NAME	MWH DELIVERED	COUNTY CODE	COUNTY NAME	MWH DELIVERED
1	Aitkin		46	Martin	
2	Anoka		47	Meeker	
3	Becker	42,145	48	Mille Lacs	
4	Beltrami	257,323	49	Morrison	
5	Benton		50	Mower	
6	Big Stone	20,678	51	Murray	
7	Blue Earth		52	Nicollet	
8	Brown		53	Nobles	
9	Carlton		54	Norman	12,417
10	Carver		55	Olmstead	
11	Cass	110,632	56	Otter Tail	493,561
12	Chippewa	4,727	57	Pennington	3,610
13	Chisago		58	Pine	
14	Clay	13,226	59	Pipestone	
15	Clearwater	237,964	60	Polk	217,363
16	Cook		61	Pope	2,410
17	Cottonwood		62	Ramsey	
18	Crow Wing		63	Red Lake	140,404
19	Dakota		64	Redwood	2,596
20	Dodge		65	Renville	
21	Douglas	40,093	66	Rice	
22	Faribault		67	Rock	
23	Fillmore		68	Roseau	14,211
24	Freeborn		69	St. Louis	
25	Goodhue		70	Scott	
26	Grant	31,905	71	Sherburne	
27	Hennepin		72	Sibley	
28	Houston		73	Stearns	
29	Hubbard	12,914	74	Steele	
30	Isanti		75	Stevens	97,413
31	Itasca		76	Swift	47,535
32	Jackson		77	Todd	766
33	Kanabec		78	Traverse	29,899
34	Kandiyohi	7,788	79	Wabasha	
35	Kittson	154,907	80	Wadena	
36	Koochiching		81	Waseca	
37	Lac Qui Parle	52,705	82	Washington	
38	Lake		83	Watonwan	
39	Lake of the Woods		84	Wilkin	21,191
40	Le Sueur		85	Winona	
41	Lincoln	21,156	86	Wright	
42	Lyon	24,201	87	Yellow Medicine	25,007
43	McLeod				
44	Mahnomen	44,155		GRAND TOTAL (Entered)	2,359,606
45	Marshall	174,704		GRAND TOTAL (Calculated)	2,359,606

<= (Should equal "Megawatt-hours" column total on ElectricityByClass worksheet)

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

J. ITS DELIVERIES TO ULTIMATE CONSUMERS BY MONTH FOR THE LAST CALENDAR YEAR

See Instructions for details of the information required concerning electricity delivered to ultimate consumers.

Past Year Entire System		A	B	C	D	E	F	G	H	I
		Non-Farm Residential	Residential With Space Heat	Farm	Small Commercial & Industrial	Irrigation	Large Commercial & Industrial	Street & Highway Lighting	Other (Include Municipals)	Total (Columns A through H)
January	No. of Customers	45,130	2,351	1,266	9,579	0	785	139	222	59,472
	MWH	62,603	7,904	4,309	28,648	0	129,007	957	1,873	235,301
February	No. of Customers	45,219	2,349	1,260	9,560	0	788	138	222	59,536
	MWH	60,366	7,596	4,313	28,441	0	130,586	1,052	1,835	234,189
March	No. of Customers	45,299	2,350	1,267	9,596	0	785	137	221	59,655
	MWH	56,407	7,080	3,795	27,245	0	118,202	880	1,807	215,416
April	No. of Customers	45,288	2,345	1,263	9,613	0	786	139	223	59,657
	MWH	42,575	4,791	3,208	22,257	0	120,232	867	1,794	195,724
May	No. of Customers	45,372	2,339	1,436	9,702	0	780	137	222	59,988
	MWH	31,455	3,006	2,403	17,876	0	110,860	839	1,624	168,063
June	No. of Customers	46,388	2,339	1,452	9,799	0	788	138	223	61,127
	MWH	31,306	2,493	2,508	18,116	0	117,832	831	1,780	174,866
July	No. of Customers	46,439	2,339	1,449	9,792	0	785	138	223	61,165
	MWH	36,029	2,570	3,540	20,170	0	109,660	817	1,682	174,468
August	No. of Customers	46,489	2,337	1,463	9,787	0	782	138	222	61,218
	MWH	38,845	2,609	4,675	20,801	0	134,932	820	1,630	204,312
September	No. of Customers	46,584	2,339	1,458	9,803	0	786	140	222	61,332
	MWH	35,329	2,410	3,680	19,776	0	139,233	831	1,526	202,785
October	No. of Customers	46,108	2,335	1,457	9,731	0	782	139	222	60,774
	MWH	31,929	2,494	3,534	18,686	0	128,234	836	1,526	187,239
November	No. of Customers	45,323	2,339	1,420	9,605	0	784	138	224	59,833
	MWH	33,245	3,204	6,957	18,762	0	126,694	884	1,421	191,167
December	No. of Customers	45,487	2,342	1,299	9,663	0	786	138	224	59,939
	MWH	497,620	5,046	1,035	22,122	0	134,174	884	1,420	662,301
Total MWH		957,709	51,203	43,957	262,900	0	1,499,646	10,498	19,918	2,845,831

Comments

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

ELECTRICITY DELIVERED TO ULTIMATE CONSUMERS IN MINNESOTA SERVICE AREA IN LAST CALENDAR YEAR

See Instructions for details of the information required concerning electricity delivered to ultimate consumers. Exclude station use, distribution losses, and unaccounted for energy losses from this table altogether.

In this column report the number of farms, residences, commercial establishments, etc., and not the number of meters, where different. This column total should equal the grand total in the worksheet labeled "ElectricityByCounty" which provides deliveries by county. This column total will be used for the Alternative Energy Assessment and should not include revenues from sales for resale (MN Statutes Sec. 216B.62, Subd. 5).

Classification of Energy Delivered to Ultimate Consumers (include energy used during the year for irrigation and drainage pumping)	Number of Customers at End of Year	Megawatt-hours (round to nearest MWH)	Revenue (\$)
Farm	1,444	43,957	4,218,371
Nonfarm-residential	48,834	548,069	55,082,595
Commercial	9,642	262,899	26,097,677
Industrial	778	1,494,944	104,023,667
Street and highway lighting	154	10,449	1,701,688
All other	228	19,936	1,628,752
Entered Total	61,080	2,380,254	192,752,750

CALCULATED TOTAL **61,080** **2,380,254** **192,752,750**

Comments

Non-farm Residential
(\$/kWh) (\$/customer)
=> 0.100503 1127.956

PLEASE CHECK THAT THE CALCULATED VALUES ABOVE ARE REALISTIC. THEY HELP YOU ENTER THE PROPER VALUES IN THE NONFARM-RESIDENTIAL CELLS TO THE LEFT.

REMEMBER TO SEND THE FOLLOWING ATTACHMENTS:

- 1 If applicable, the Largest Customer List (Attachment ELEC-1), if the separate LargestCustomers spreadsheet file was not used (pursuant to MN Rules Chapter 7610.0600 B.)
- 2 Minnesota service area map (pursuant to MN Rules Chapter 7610.0600 C.)
- 3 Rate schedules and monthly power cost adjustments (pursuant to MN Rules Chapter 7610.0600 E.)
- 4 Report form EIA-861 filed with US Dept. of Energy (pursuant to MN Rules Chapter 7610.0600 F.)
- 5 If applicable, for rural electric cooperatives, the Financial and Statistical Report filed with US Dept. of Agriculture (pursuant to MN Rules Chapter 7610.0600 G.)

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2014

INSTRUCTIONS: Complete one worksheet for each power plant
 Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
 Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA	
PLANT NAME	COYOTE STATION
STREET ADDRESS	
CITY	BEULAH
STATE	ND
ZIP CODE	58523
COUNTY	MERCER
CONTACT PERSON	Stacie Hebert
TELEPHONE	218-739-8635
PLANT ID	87009
NUMBER OF UNITS	1

B. INDIVIDUAL GENERATING UNIT DATA						
Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1981	Coal	662,451.00	
TOTAL				Plant Total	662,451.00	

C. UNIT CAPABILITY DATA						
Unit ID #	CAPACITY (MEGAWATTS)		Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
	Summer	Winter				
1	149.4	149.4	51.24	94.3	2.7	
Plant Total	149.4	149.4				

D. UNIT FUEL USED									
Unit ID #	Fuel Type ***	PRIMARY FUEL USE			SECONDARY FUEL USE				
		Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)	
1	LIG	573,148	Tons	6,888	FO2	143,277	Gals		

ALLOWABLE CODES					
Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
*** Energy Source & Fuel Type	BIT	Bituminous Coal	**** Unit of Measure	NC	Nuclear
	COAL	Coal (general)		WI	Wind
	DIESEL	Diesel		OTHER	Other - provide description
	FO2	Fuel Oil #2 (Mid Distillate)		GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS	
Forced Outage Rate = (percentage)	$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$
Operating Availability = (percentage)	100 - Maintenance percentage - Forced Outage percentage
Capacity Factor = (percentage)	$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8,760}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.
 Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2014

INSTRUCTIONS: Complete one worksheet for each power plant
 Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
 Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA	
PLANT NAME	HOOT LAKE PLANT
STREET ADDRESS	
CITY	FERGUS FALLS
STATE	MN
ZIP CODE	56537
COUNTY	OTTER TAIL
CONTACT PERSON	Stacie Hebert
TELEPHONE	218-739-8635
PLANT ID	87014
NUMBER OF UNITS	5

B. INDIVIDUAL GENERATING UNIT DATA						
Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	RET	ST	1948	Coal	0	
2	USE	ST	1959	Coal	152123	
3	USE	ST	1964	Coal	144079	
2A	STB	IC	1959	FO2		
3A	STB	IC	1964	FO2		
TOTAL						
					Plant Total	296202

C. UNIT CAPABILITY DATA						
CAPACITY (MEGAWATTS)						
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.0	0.0				
2	52.0	52.0	33.30	98.6	2.4	
3	73.0	73.0	24.60	99.2	1.5	
2A	0.2	0.2				
3A	0.2	0.2				
Plant Total	125.4	125.4				

D. UNIT FUEL USED								
PRIMARY FUEL USE					SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	Sub		Tons		FO2		Gals	
2	Sub	93,552	Tons	9,199	FO2	23,500	Gals	
3	Sub	88,801	Tons	9,201	FO2	22,643	Gals	

ALLOWABLE CODES					
Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
*** Energy Source & Fuel Type	BIT	Bituminous Coal	NC	Nuclear	
	COAL	Coal (general)	WI	Wind	
	DIESEL	Diesel	OTHER	Other - provide description	
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
SOLAR	Solar				
OTHER	Other - provide description				

DEFINITIONS	
Forced Outage Rate = (percentage)	$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$
Operating Availability = (percentage)	100 - Maintenance percentage - Forced Outage percentage
Capacity Factor = (percentage)	$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8,760}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2014

INSTRUCTIONS: Complete one worksheet for each power plant
 Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
 Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA	
PLANT NAME	BEMIDJI HYDRO
STREET ADDRESS	
CITY	BEMIDJI HYDRO
STATE	MN
ZIP CODE	56601
COUNTY	BELTRAMI
CONTACT PERSON	Stacie Hebert
TELEPHONE	218-739-8635
PLANT ID	87002
NUMBER OF UNITS	2

B. INDIVIDUAL GENERATING UNIT DATA						
Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1907	HYD	0	
2	USE	HC	1907	HYD	0	
Plant Total					0	

C. UNIT CAPABILITY DATA						
Unit ID #	CAPACITY (MEGAWATTS)		Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
	Summer	Winter				
1	0.1	0.1				
2	0.0	0.0				
Plant Total		0.1				

D. UNIT FUEL USED								
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE			
					Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	Hyd							
1	Hyd							

ALLOWABLE CODES					
Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
*** Energy Source & Fuel Type	BIT	Bituminous Coal		NC	Nuclear
	COAL	Coal (general)		WI	Wind
	DIESEL	Diesel		OTHER	Other - provide description
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS	
Forced Outage Rate = (percentage)	$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$
Operating Availability = (percentage)	$100 - \text{Maintenance percentage} - \text{Forced Outage percentage}$
Capacity Factor = (percentage)	$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8,760}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.
 Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2014

INSTRUCTIONS: Complete one worksheet for each power plant
 Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
 Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA	
PLANT NAME	DAYTON HOLLOW HYDRO
STREET ADDRESS	
CITY	FERGUS FALLS
STATE	MN
ZIP CODE	56537
COUNTY	OTTER TAIL
CONTACT PERSON	Stacie Hebert
TELEPHONE	218-739-8635
PLANT ID	87010
NUMBER OF UNITS	2

B. INDIVIDUAL GENERATING UNIT DATA						
Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1909	HYD	5026	
2	USE	HC	1919	HYD	0	
					Plant Total	5026

C. UNIT CAPABILITY DATA						
Unit ID #	CAPACITY (MEGAWATTS)		Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
	Summer	Winter				
1	0.5	0.5				
2	0.4	0.4				
		Plant Total	0.9	0.9		

D. UNIT FUEL USED								
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE			
					Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	Hyd							
1	Hyd							

ALLOWABLE CODES					
Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
*** Energy Source & Fuel Type	BIT	Bituminous Coal	NC	Nuclear	
	COAL	Coal (general)	WI	Wind	
	DIESEL	Diesel	OTHER	Other - provide description	
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
SOLAR	Solar				
OTHER	Other - provide description				

DEFINITIONS	
Forced Outage Rate = (percentage)	$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$
Operating Availability = (percentage)	100 - Maintenance percentage - Forced Outage percentage
Capacity Factor = (percentage)	$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8,760}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.
 Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

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SCHEDULE 1. IDENTIFICATION

SURVEY CONTACTS: Persons to contact with question about this form		RESPONSE DUE DATE: Please submit by April 30th following the close of calendar year	
Contact	Nathan Jensen Title: Senior Resource Planner	REPORT FOR:	Otter Tail Power Co 14232
Phone: (218) 739-8989	FAX:	REPORTING PERIOD:	2015
Supervisor	Brian Draxten Title: Manager Resource Planning	Logged By / Date: Logged In: <input type="checkbox"/> Receipt Date (mm/dd/yyyy):	
Phone: (218) 739-8417	FAX:	Email: bhdraxten@otpc.com	

1	Legal Name of Industry Participant	Otter Tail Power Co	Submission Status/Date:	<input type="text" value="Not Submitted"/>															
2	Current Address of Principal Business Office	P O Box 496215 South Cascade Street Fergus Falls MN 56538 0496																	
3	Preparer's Legal Name Operator (if different than line 1)																		
4	Current Address of Preparer's Office (if different than line 2)																		
5	Respondent Type (Check One)	<table style="width:100%; border: none;"> <tr> <td><input type="checkbox"/> Federal</td> <td><input type="checkbox"/> State</td> <td><input type="checkbox"/> Transmission</td> </tr> <tr> <td><input type="checkbox"/> Political Subdivision</td> <td><input type="checkbox"/> Municipal</td> <td><input type="checkbox"/> Behind the Meter</td> </tr> <tr> <td><input type="checkbox"/> Municipal Marketing Authority</td> <td><input checked="" type="checkbox"/> Investor-Owned</td> <td><input type="checkbox"/> Wholesale Power Marketer</td> </tr> <tr> <td><input type="checkbox"/> Cooperative</td> <td><input type="checkbox"/> Retail Power Marketer (or Energy Service Provider)</td> <td><input type="checkbox"/> DSM Administrator</td> </tr> <tr> <td><input type="checkbox"/> Independent Power Producer or Qualifying Facility</td> <td></td> <td></td> </tr> </table>			<input type="checkbox"/> Federal	<input type="checkbox"/> State	<input type="checkbox"/> Transmission	<input type="checkbox"/> Political Subdivision	<input type="checkbox"/> Municipal	<input type="checkbox"/> Behind the Meter	<input type="checkbox"/> Municipal Marketing Authority	<input checked="" type="checkbox"/> Investor-Owned	<input type="checkbox"/> Wholesale Power Marketer	<input type="checkbox"/> Cooperative	<input type="checkbox"/> Retail Power Marketer (or Energy Service Provider)	<input type="checkbox"/> DSM Administrator	<input type="checkbox"/> Independent Power Producer or Qualifying Facility		
<input type="checkbox"/> Federal	<input type="checkbox"/> State	<input type="checkbox"/> Transmission																	
<input type="checkbox"/> Political Subdivision	<input type="checkbox"/> Municipal	<input type="checkbox"/> Behind the Meter																	
<input type="checkbox"/> Municipal Marketing Authority	<input checked="" type="checkbox"/> Investor-Owned	<input type="checkbox"/> Wholesale Power Marketer																	
<input type="checkbox"/> Cooperative	<input type="checkbox"/> Retail Power Marketer (or Energy Service Provider)	<input type="checkbox"/> DSM Administrator																	
<input type="checkbox"/> Independent Power Producer or Qualifying Facility																			

For questions or additional information about the Form EIA-861 contact the Survey Manager: **Stephen Scott** Phone: (202) 586-5140 Email: stephen.scott@eia.gov Fax: (202) 287 - 1938 Email: EIA-861@eia.gov

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REPORT FOR: Otter Tail Power Co 14232
 REPORT PERIOD ENDING: 2015

SCHEDULE 2, PART A. GENERAL INFORMATION

LINE NO.

1 Regional North American Electric Reliability Council (Not applicable for power marketers)	<input type="checkbox"/> TRE (formerly ERCOT)	<input type="checkbox"/> NPCC	<input type="checkbox"/> SPP
	<input type="checkbox"/> FRCC	<input type="checkbox"/> RFC (formerly ECAR, MAIN, MAAC)	<input type="checkbox"/> WECC
	<input checked="" type="checkbox"/> MRO	<input type="checkbox"/> SERC	

2 Name of RTO or ISO	<input type="checkbox"/> California ISO	<input type="checkbox"/> Southwest Power Pool
	<input type="checkbox"/> Electric Reliability Council of Texas	<input checked="" type="checkbox"/> Midwest ISO
	<input type="checkbox"/> PJM Interconnection	<input type="checkbox"/> ISO New England
	<input type="checkbox"/> New York ISO	<input type="checkbox"/> None

3 (For EIA Use Only) Identify the North American Electric Reliability Council where you are physically located	MRO
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4 Did Your Company Operate Generating Plants(s)?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
---	---

5 Identify The Activities Your Company Was Engaged In During The Year (Check appropriate activities)	<input checked="" type="checkbox"/> Generation from company owned plant	<input type="checkbox"/> Buying distribution on other electrical system
	<input checked="" type="checkbox"/> Transmission	<input checked="" type="checkbox"/> Wholesale power marketing
	<input checked="" type="checkbox"/> Buying transmission services on other electrical system	<input type="checkbox"/> Retail power marketing
	<input checked="" type="checkbox"/> Distribution using owned/leased electric wires	<input type="checkbox"/> Bundled Services (electricity plus other services such as gas, water, etc. in addition to electric service)

6 Highest Hourly Electrical Peak System Demand	Summer (Megawatts)	716.4	Prior Year	679.0
	Winter (Megawatts)	896.7	Prior Year	874.0

7 Did Your Company Operate Alternative-Fueled Vehicles During the Year?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
Does Your Company Plan to Operate Such Vehicles During the Coming Year?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No

If "Yes", Please Provide Additional Contact Information

Name: Kyle Rich
 Title: Manager, Transportation
 Telephone: 218 - 739 - 8590 Fax: 218 - 739 - 8734 Email: krich@otpc.com

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REPORT PERIOD ENDING: 2015

SCHEDULE 2. PART B ENERGY SOURCES AND DISPOSITION

	SOURCE OF ENERGY	MEGAWATTHOURS		DISPOSITION OF ENERGY	MEGAWATTHOURS
1	Net Generation	2,305,968	11	Sales to Ultimate Consumers	4,593,604
2	Purchases from Electricity Suppliers	3,283,337	12	Sales For Resale	115,860
3	Exchanged Received (In)		13	Energy Furnished Without Charge	
4	Exchanged Delivered (Out)		14	Energy Consumed By Respondent Without Charge	11,858
5	Exchanged Net				
6	Wheeled Received (In)	116,856			
7	Wheeled Delivered (Out)	246,395	15	Total Energy Losses (positive number)	738,444
8	Wheeled Net	-129,539			
9	Transmission by Others Losses (Negative Number)				
10	Total Sources (sum of lines 1, 2, 5, 8 & 9)	5,459,766	16	Total Disposition (sum of lines 11, 12, 13, 14, & 15)	5,459,766

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REPORT PERIOD ENDING: 2015

SCHEDULE 2, PART C. ELECTRIC OPERATING REVENUE

LINE NO.	TYPE OF OPERATING REVENUE	(THOUSAND DOLLARS to the nearest 0.1)
1	Electrical Operating Revenue From Sales to Ultimate Customers (Schedule 4: Parts A, B, and D)	\$ 359,784.0
2	Revenue From Unbundled (Delivery) Customers (Schedule 4: Part C)	\$
3	Electric Operating Revenue from Sales for Resale	\$ 2,499.0
4	Electric Credits/Other Adjustments	\$
5	Revenue from Transmission	\$ 28,798.0
6	Other Electric Operating Revenue	\$ 8,455.0
7	Total Electric Operating Revenue (sum of lines 1, 2, 3, 4, 5 and 6)	\$ 399,536.0

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REPORT PERIOD ENDING: 2015

**SCHEDULE 3. PART A.
 DISTRIBUTION SYSTEM RELIABILITY DATA**

INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory MN

1	Total Number of Distribution Circuits	282.0
2	Number of Distribution Circuits that employ voltage/VAR optimization (VVO)	

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REPORT PERIOD ENDING: 2015

SCHEDULE 3. PART A.
DISTRIBUTION SYSTEM RELIABILITY DATA

INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory ND

1	Total Number of Distribution Circuits	352.0
2	Number of Distribution Circuits that employ voltage/VAR optimization (VVO)	

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REPORT PERIOD ENDING: 2015

SCHEDULE 3. PART A.
 DISTRIBUTION SYSTEM RELIABILITY DATA

INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory SD

1	Total Number of Distribution Circuits	100.0
2	Number of Distribution Circuits that employ voltage/VAR optimization (VVO)	

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REPORT FOR: Otter Tail Power Co 14232
 REPORT PERIOD ENDING: 2015

**SCHEDULE 3. PART B
 DISTRIBUTION SYSTEM RELIABILITY DATA**

Who is required to complete this schedule?

This schedule collects System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) statistics. If your organization does not compute these indexes, answer 'no' to Question 1 and then skip to Schedule 4A. You do not have to complete any other part of this schedule 3B or 3C.

Should you complete Part B or Part C?

If your organization computes the SAIFI and SAIDI indexes and determines Major Event Days using the IEEE 1366-2003 or the IEEE 1366-2012 standard, answer 'YES' to Questions 1 and 2, and complete Part B. Then skip to Schedule 4A. (You do not complete Schedule 3, Part C.)

If your organization does not use the IEEE 1366-2003 or the IEEE 1366-2012 standard but calculates SAIDI and SAIFI indexes via other method, answer 'yes' to question 1 and 'no' to question 2 and complete Part C. Then go to Schedule 4A.

- 1 Do you calculate SAIDI and SAIFI by any method? If Yes, go to Question 2. If No, go to Schedule 4, Part A. Yes No
- 2 Do you calculate SAIDI and SAIFI and determine Major Event Days using the IEEE1366-2003 standard or IEEE-2012 standard? If Yes, complete Part B. If No, go to complete Part C. Yes No

Part B: SAIDI and SAIFI in accordance with IEEE 1366-2003 standard or IEEE 1366-2012 standard

	State	MN
3a. SAIDI value including Major Event days		53.3
3b. SAIDI value excluding Major Event days		53.3
4 SAIDI value including Major Event days minus loss of supply		53.3
5a. SAIFI value including Major Event days		.8
5b. SAIFI value excluding Major Event days		.8
6. SAIFI value including Major Event days minus loss of supply		.8
7. Total number of customers used in these calculations		61,100.0
8. What is the highest voltage that you consider part of the distribution system, as opposed to the supply system? (kV)		12.5
9. Do you receive information about a customer outage in advance of a customer reporting it?		<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No

Thank You for completing this part. Skip Part C and go directly to Schedule 4 Part A.

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REPORT PERIOD ENDING:

Part C: SAIDI and SAIFI calculated by other methods

State

10a. SAIDI value including Major Events

10b. SAIDI value excluding Major Events

11a. SAIFI value including Major Events

11b. SAIFI value excluding Major Events

12. Total number of customers used in these calculations

13. Do you include inactive accounts?

Yes No

14. How do you define momentary interruptions

Less than 1 min. Less than 5 min. Other

15. What is the highest voltage that you consider part of the distribution system, as opposed to the supply system?

kv

16. Is information about customer outages recorded automatically?

Yes No

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REPORT FOR: Otter Tail Power Co
REPORT PERIOD ENDING: 2015

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SCHEDULE 4, PART - A. SALES TO ULTIMATE CUSTOMERS. FULL SERVICE - ENERGY AND DELIVERY SERVICE (BUNDLED)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	MN Balancing Authority ****				
Revenue (thousand dollars)	52,047.5	85,835.1	43,386.1	0.0	181,268.7
Megawatthours	548,043	1,073,168	766,863	0	2,388,074
Number of Customers	48,026	12,195	11	0	60,232
Are your rates decoupled?	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?	<input type="checkbox"/> N automatic	<input type="checkbox"/> N automatic	<input type="checkbox"/> N automatic	<input type="checkbox"/> N automatic	
	<input type="checkbox"/> N proceeding	<input type="checkbox"/> N proceeding	<input type="checkbox"/> N proceeding	<input type="checkbox"/> N proceeding	
Cents/Kwh	9.497	7.998	5.658		7.591
State	ND Balancing Authority ****				
Revenue (thousand dollars)	53,728.0	87,043.9	5,163.6	0.0	145,935.5
Megawatthours	609,828	1,095,592	74,255	0	1,779,675
Number of Customers	45,411	12,884	2	0	58,297
Are your rates decoupled?	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?	<input type="checkbox"/> N automatic	<input type="checkbox"/> N automatic	<input type="checkbox"/> N automatic	<input type="checkbox"/> N automatic	
	<input type="checkbox"/> N proceeding	<input type="checkbox"/> N proceeding	<input type="checkbox"/> N proceeding	<input type="checkbox"/> N proceeding	
Cents/Kwh	8.810	7.945	6.954		8.200

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SCHEDULE 4, PART - A. SALES TO ULTIMATE CUSTOMERS. FULL SERVICE - ENERGY AND DELIVERY SERVICE (BUNDLED)

		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	SD	Balancing Authority ****				
Revenue (thousand dollars)		10,503.8	22,076.0	0.0	0.0	32,579.8
Megawatthours		115,040	310,815	0	0	425,855
Number of Customers		8,689	2,768	0	0	11,457
Are your rates decoupled?		<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?		<input type="checkbox"/> N automatic	<input type="checkbox"/> N automatic	<input type="checkbox"/> N automatic	<input type="checkbox"/> N automatic	
		<input type="checkbox"/> N proceeding	<input type="checkbox"/> N proceeding	<input type="checkbox"/> N proceeding	<input type="checkbox"/> N proceeding	
Cents/Kwh		9.131	7.103			7.650
State						
Revenue (thousand dollars)						
Megawatthours						
Number of Customers						
Are your rates decoupled?						
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?						
Cents/Kwh						
Total						
Revenue (thousand dollars)		116,279.3	194,955.0	48,549.7	0.0	359,784.0
Megawatthours		1,272,911	2,479,575	841,118	0	4,593,604
Number of Customers		102,126	27,847	13	0	129,986

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SCHEDULE 4, PART -B. SALES TO ULTIMATE CUSTOMERS. ENERGY - ONLY SERVICE (WITHOUT DELIVERY SERVICE)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	Balancing Authority				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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SCHEDULE 4, PART -C. SALES TO ULTIMATE CUSTOMERS, DELIVERY – ONLY SERVICE (AND OTHER RELATED CHARGES)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	Balancing Authority				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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SCHEDULE 4, PART D. BUNDLED SERVICE BY RETAIL ENERGY PROVIDERS AND POWER MARKETERS

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	Balancing Authority				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

Total
Revenue (thousand dollars)
Megawatthours
Number of Customers

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SCHEDULE 5 MERGERS and/or ACQUISITIONS

Mergers and/or acquisitions during the reporting month

If Yes, Provide:

Date of Merger or Acquisition

Company merged with or acquired

Name of new parent company

Address

City

State, Zip

New Contact Name

Telephone No.

Email address

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SCHEDULE 6 PART A. ENERGY EFFICIENCY PROGRAMS
 Schedule 6. Part A. Adjusted Gross Energy and Demand Savings – Energy Efficiency

State/Territory	SD	Balancing Authority				Total
		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	
Reporting Year Incremental Annual Savings						
1	Energy Savings (MWh)	381	1,449	2,409	0	4,239
2	Peak Demand Savings (MW)	0	0	0	0	1
Increment Life Cycle Savings						
3	Energy Savings (MWh)	4,913	56,175	37,816	0	98,904
4	Peake Demand Savings (MW)	0	0	0	0	1
Reporting Year Incremental Costs						
5	Customer Incentives	19	89	148	0	256
6	All other costs	28	30	50	0	108
Incremental Life Cycle Costs						
7	Customer Incentives	19	89	148	0	256
8	All other costs	28	30	50	0	108
Weighted Average Life for Portfolio (Years) - Use Spreadsheet to Calculate						
9	Weighted Average Life	8	16	15	0	

Please provide website address to your energy efficiency program reports:

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Schedule 6. Part B. Energy and Demand Savings -- Demand Response

Reporting Year Savings

	State/Territory	MN	Balancing Authority	56669	(a)	(b)	(c)	(d)	(e)
					Residential	Commercial	Industrial	Transportation	Total
1	Number of Customers Enrolled								
2	Energy Savings (Mwh)								
3	Potential Peak Demand Savings (MW)								
4	Actual Peak Demand Savings (MW)								

Schedule 6. Part B. Program Costs -- Demand Responses (Thousand Dollars)

Reporting Yearly Costs

5	Customer Incentives								
6	All other costs								
7	If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?								

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Schedule 6. Part B. Energy and Demand Savings -- Demand Response

Reporting Year Savings

State/Territory	ND	Balancing Authority	56669	(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
1	Number of Customers Enrolled							
2	Energy Savings (Mwh)							
3	Potential Peak Demand Savings (MW)							
4	Actual Peak Demand Savings (MW)							

Schedule 6. Part B. Program Costs -- Demand Responses (Thousand Dollars)

Reporting Yearly Costs

5	Customer Incentives							
6	All other costs							
7	If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?							

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Schedule 6. Part B. Energy and Demand Savings -- Demand Response

Reporting Year Savings

State/Territory	SD	Balancing Authority	56669	(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
1	Number of Customers Enrolled							
2	Energy Savings (Mwh)							
3	Potential Peak Demand Savings (MW)							
4	Actual Peak Demand Savings (MW)							

Schedule 6. Part B. Program Costs -- Demand Responses (Thousand Dollars)

Reporting Yearly Costs

5	Customer Incentives							
6	All other costs							
7	If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?							

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SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.

State/Territory ND Balancing Authority 56669

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class	16,329	2,228	0	0	18,557

Types of Dynamic Pricing Programs
--

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customer are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
3	Real TimePricing	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
4	Variable Peak Pricing	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
5	Critical Peak Pricing	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
6	Critical Peak Rebate	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No

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SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS
 Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.

State/Territory MN Balancing Authority 56669

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class	18,156	2,007	33	0	20,196

Types of Dynamic Pricing Programs

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customer are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
3	Real TimePricing	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
4	Variable Peak Pricing	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
5	Critical Peak Pricing	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
6	Critical Peak Rebate	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No

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SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS
Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.
 State/Territory **SD** Balancing Authority **56669**

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class	3,640	366	0	0	4,006

Types of Dynamic Pricing Programs

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customer are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
3	Real TimePricing	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
4	Variable Peak Pricing	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
5	Critical Peak Pricing	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
6	Critical Peak Rebate	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No

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SCHEDULE 6, PART D ADVANCED METERING

Only customers from schedule 4A and 4C need to be reported on this schedule.
 AMR- data transmitted one-way, to the utility.
 AMI- data transmitted in both directions, to the utility and customer

State	MN	Balancing Authority	56669					
				Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1				0	30	11	0	41
2				0	0	0	0	0
3				0	0	0	0	0
Number of AMI Meters with home area network (HAN) gateway enabled								
4				62,817	16,276	47	0	79,140
5				62,817	16,306	58	0	79,181
Total Number of Meters (All Types), line 1+2+4								
6								
Energy Served Through AMI								
7								
Number of Customers able to access daily energy usage through a webportal or other electronic means								
8								
Number of customers with direct load control								

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SCHEDULE 6, PART D ADVANCED METERING

Only customers from schedule 4A and 4C need to be reported on this schedule.
 AMR- data transmitted one-way, to the utility.
 AMI- data transmitted in both directions, to the utility and customer

State	SD	Balancing Authority	56669				
			Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1	Number of AMR Meters		0	0	0	0	0
2	Number of AMI Meters		0	0	0	0	0
3	Number of AMI Meters with home area network (HAN) gateway enabled		0	0	0	0	0
4	Number of non AMR/AMI Meters		11,929	3,514	0	0	15,443
5	Total Number of Meters (All Types), line 1+2+4		11,929	3,514	0	0	15,443
6	Energy Served Through AMI						
7	Number of Customers able to access daily energy usage through a webportal or other electronic means						
8	Number of customers with direct load control						

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SCHEDULE 7. PART A. NET METERING

Net Metering program allow customers to sell excess power they generate back to the electrical grid to offset consumption. Provide the information about programs by Statem balancing authority, customer class, and technology for all net metering applications.

State	MN	Balancing Authority	56669	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
				0.067	0.119			0.186
Photovoltaic				9	8			17
								0
				0.081	0.099			0.180
Wind				3	7			10
								0
					0.035			0.035
Other					1			1
								0
				0.148	0.253	0.000	0.000	0.401
Total				12	16	0	0	28
				0	0	0	0	0

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SCHEDULE 7. PART A. NET METERING

Net Metering program allow customers to sell excess power they generate back to the electrical grid to offset consumption. Provide the information about programs by State balancing authority, customer class, and technology for all net metering applications.

State	SD	Balancing Authority	56669	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
		Installed Net Metering Capacity (MW)			0.040			0.040
Photovoltaic		Number of Net Metering Customers			2			2
		If Available, Enter the Electric Energy Sold Back to the Utility (Mwh)						0
		Installed Net Metering Capacity (MW)		0.003	0.002			0.005
Wind		Number of Net Metering Customers		1	1			2
		If Available, Enter the Electric Energy Sold Back to the Utility (Mwh)						0
		Installed Net Metering Capacity (MW)						0.000
Other		Number of Net Metering Customers						0
		If Available, Enter the Electric Energy Sold Back to the Utility (Mwh)						0
		Installed Net Metering Capacity (MW)		0.003	0.042	0.000	0.000	0.045
Total		Number of Net Metering Customers		1	3	0	0	4
		If Available, Enter the Electric Energy Sold Back to the Utility (Mwh)		0	0	0	0	0

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SCHEDULE 7. PART B. DISTRIBUTED AND DISPERSED GENERATION

If your company owns and/or operates a distribution system, please report information on known distributed generation capacity on the system. Such capacity must be utility or customer-owned

		Distributed Generators (Residential, Commercial and Industrial Grid Connected/Synchronized Generators) (a)	NUMBER AND CAPACITY	Dispersed Generators (Residential, Commercial and Industrial Generators Not Connected/Synchronized to the Grid) (b)	
State	SD	Balancing Authority	56669		
		< 1MW		< 1MW	
1. Number of generators		5		1. Number of generators	
2. Total combined capacity (MW)		0.065		2. Total combined capacity (MW)	
3. Capacity that consists of backup-only units				3. Capacity that consists of backup-only units	
4. Capacity owned by respondent				4. Capacity owned by respondent	
5. Nature of data reported		<input checked="" type="checkbox"/> Actual <input type="checkbox"/> Estimated		5. Nature of data reported	<input type="checkbox"/> Actual <input type="checkbox"/> Estimated

Capacity by Technology (MW)

1. Internal combustion/reciprocating engines				1. Internal combustion/reciprocating engines	
2. Combustion turbine(s)				2. Combustion turbine(s)	
3. Steam turbine(s)				3. Steam turbine(s)	
4. Hydroelectric				4. Hydroelectric	
5. Wind turbine(s)		.02		5. Wind turbine(s)	
6. Photovoltaic		.04		6. Photovoltaic	
7. Storage				7. Storage	
8. Other				8. Other	
9. Total		.07		9. Total	
10. Nature of data reported		<input type="checkbox"/> Actual <input type="checkbox"/> Estimated		10. Nature of data reported	<input type="checkbox"/> Actual <input type="checkbox"/> Estimated

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SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION

LINE NO.	(US Postal State) (a)	(COUNTY) (b)	LINE NO.	(US Postal State) (a)	(COUNTY) (b)
41	ND	Grand Forks	62	ND	Traill
42	ND	Griggs	63	ND	Walsh
43	ND	Kidder	64	ND	Ward
44	ND	LaMoure	65	ND	Wells
45	ND	Logan	66	SD	Brookings
46	ND	McHenry	67	SD	Codington
47	ND	McLean	68	SD	Day
48	ND	Mountrail	69	SD	Deuel
49	ND	Nelson	70	SD	Grant
50	ND	Pembina	71	SD	Hamlin
51	ND	Pierce	72	SD	Kingsbury
52	ND	Ramsey	73	SD	Lake
53	ND	Ransom	74	SD	Marshall
54	ND	Renville	75	SD	Moody
55	ND	Richland	76	SD	Roberts
56	ND	Rolette			
57	ND	Sargent			
58	ND	Sheridan			
59	ND	Steele			
60	ND	Stutsman			
61	ND	Towner			

US Department of Energy
 Energy Information Administration
 Form EIA-861 (2015)

ANNUAL ELECTRIC POWER
 INDUSTRY REPORT

Form Approved
 OMB No. 1905-0129
 Approved Expires 05/31/2017

REPORT FOR: Otter Tail Power Co 14232
 REPORT PERIOD ENDING: 2015

SCHEDULE 9. COMMENTS

SCHEDULE (a)	PART (b)	LINE NO. (c)	COLUMN (d)	NOTES (e)

US Department of Energy Energy Information Administration Form EIA-861 (2015)	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 05/31/2017
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REPORT FOR: Otter Tail Power Co

14232

REPORT PERIOD ENDING: 2015

EIA861 ERROR LOG

Part	State	BA ID	Error No.	Error Description/Override Comment	Type	Override
2	B	--	0	309 Wheeling-In must be greater than or equal to Wheeling-Out. This is what was submitted and approved on our FERC Form 1 filing.	W	
4	A	MN	0	416 The calculated Commercial average price (revenue/sales) falls outside the expected range compared to last year's data. The average price should be between 20% below and 30% above last year's rate. The submitted data is correct.	W	
4	A	MN	0	417 The calculated Industrial average price (revenue/sales) falls outside the expected range compared to last year's data. The average price should be between 20% below and 30% above last year's rate. The submitted data is correct.	W	
4	A	SD	0	421 The calculated Commercial average consumption per customer (sales/customers) differs by more than 40% from last year's data. If the data is correct, please provide an explanation for the change. The submitted data is correct.	W	
4	A	ND	0	421 The calculated Commercial average consumption per customer (sales/customers) differs by more than 40% from last year's data. If the data is correct, please provide an explanation for the change.	W	
4	A	MN	0	421 The calculated Commercial average consumption per customer (sales/customers) differs by more than 40% from last year's data. If the data is correct, please provide an explanation for the change. The submitted data is correct.	W	
4	A	MN	0	422 The calculated Industrial average consumption per customer (sales/customers) differs by more than 40% from last year's data. If the data is correct, please provide an explanation for the change. The submitted data is correct.	W	
4	A	ND	0	422 The calculated Industrial average consumption per customer (sales/customers) differs by more than 40% from last year's data. If the data is correct, please provide an explanation for the change.	W	
4	A	SD	0	426 The Industrial customer counts differ by more than 20% from last year. If the data is correct, please provide an explanation for the change. The submitted data is correct.	W	

US Department of Energy
 Energy Information Administration
 Form EIA-861 (2015)

ANNUAL ELECTRIC POWER
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Form Approved
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 Approved Expires 05/31/2017

REPORT FOR: Otter Tail Power Co

14232

REPORT PERIOD ENDING: 2015

Part	State	Error No.	Error Description/Override Comment	Type	Override
4	A ND	0 426	The Industrial customer counts differ by more than 20% from last year. If the data is correct, please provide an explanation for the change. The submitted data is correct.	W	
4	A MN	0 426	The Industrial customer counts differ by more than 20% from last year. If the data is correct, please provide an explanation for the change. The submitted data is correct.	W	
4	A SD	0 432	Industrial customers were reported last year but not this year. We no longer have an industrial customer in SD.	W	
6	D SD	0 6000	Advanced Meters and/or Standard Meters in Schedule 6D were reported last year, but not this year. Please provide corrected data. If correct, please provide an explanation.	W	

SECTION 2

Electric Utility Information Reporting
Forecast Section

Form EN-0005 – 20

7610.0310 CONTENT OF HISTORICAL AND FORECAST

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

INSTRUCTIONS

The individual worksheets in this spreadsheet file correspond closely to the tables in the paper forms received by the utility. The instructions provided with the paper forms also pertain to the data to be entered in each of the worksheets in this file.

PLEASE DO NOT CHANGE THE NAME OR ORDER OF ANY OF THE WORKSHEET TABS IN THIS FILE

In general, the following scheme is used on each worksheet:

- Cells shown with a light green background correspond to headings for columns, rows or individual fields.
- Cells shown with a light yellow background require data to be entered by the utility.
- Cells shown with a light brown background generally correspond to fields that are calculated from the data entered, or correspond to fields that are informational and not to be modified by the utility.

Each worksheet contains a section labeled Comments below the main data entry area.

You may enter any comments in that section that may be needed to explain or clarify the data being entered on the worksheet.

Please complete the required worksheets and save the completed spreadsheet file to your local computer.

Then attach the completed spreadsheet file to an e-mail message and send it to the following e-mail address:

rule7610.reports@state.mn.us

If you have any questions please contact:

Steve Loomis

MN Department of Commerce

steve.loomis@state.mn.us

(651) 539-1690

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

7610.0120 REGISTRATION

ENTITY ID#	87
REPORT YEAR	2014

RILS ID#	U10756
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UTILITY DETAILS	
UTILITY NAME	Otter Tail Power Co
STREET ADDRESS	215 South Cascade St
CITY	Fergus Falls
STATE	MN
ZIP CODE	56538-0496
TELEPHONE	218-739-8417
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	PRIVATE

CONTACT INFORMATION	
CONTACT NAME	BRIAN DRAXTEN
CONTACT TITLE	MANAGER, Resource Planning
CONTACT STREET ADDRESS	215 SOUTH CASCADE STREET
CITY	FERGUS FALLS
STATE	MN
ZIP CODE	56538-0496
TELEPHONE	218-739-8417
CONTACT E-MAIL	bhdraxten@otpc.com

COMMENTS

PREPARER INFORMATION	
PERSON PREPARING FORMS	Nathan Jensen
PREPARER'S TITLE	Senior Resource Planner
DATE	

ALLOWABLE UTILITY TYPES

Code
 Private
 Public
 Co-op

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item A. SYSTEM FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your entire system for the past year, your estimate for the present year and all future forecast years.

Please remember that the number of customers should reflect the number of customers at year's end, not the number of meters.

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Past Year	2015	No. of Cust.	2,816	103,307	22,080	0	1,938	414	598	131,153	131,153
		MWH	89,325	1,272,473	569,745	0	2,598,184	25,876	40,928	4,596,531	4,596,531
Present Year	2016	No. of Cust.	2,722	103,130	22,344	0	1,953	393	772	131,314	131,314
		MWH	87,312	1,316,727	601,742	0	2,868,017	26067.67	53,417	4,953,283	4,953,283
1st Forecast Year	2017	No. of Cust.	2,725	103,537	22,408	0	1,966	393	772	131,801	131,801
		MWH	87,536	1,321,791	603,538	0	2,945,886	26094.243	53,417	5,038,261	5,038,261
2nd Forecast Year	2018	No. of Cust.	2,729	103,916	22,465	0	1,979	393	772	132,254	132,254
		MWH	87,749	1,326,571	605,117	0	3,017,554	26120.855	53,417	5,116,529	5,116,529
3rd Forecast Year	2019	No. of Cust.	2,732	104,276	22,518	0	1,992	393	772	132,683	132,683
		MWH	87,956	1,331,110	606,560	0	2,944,205	26147.454	53,417	5,049,396	5,049,396
4th Forecast Year	2020	No. of Cust.	2,734	104,625	22,569	0	2,005	394	772	133,099	133,099
		MWH	88,161	1,335,545	607,943	0	2,944,307	26174.07	53,417	5,055,547	5,055,547
5th Forecast Year	2021	No. of Cust.	2,738	104,958	22,615	0	2,018	394	772	133,495	133,495
		MWH	88,357	1,339,766	609,220	0	3,030,432	26200.623	53,417	5,147,391	5,147,391
6th Forecast Year	2022	No. of Cust.	2,740	105,219	22,649	0	2,031	394	772	133,805	133,805
		MWH	88,534	1,343,174	610,120	0	3,121,136	26227.14	53,417	5,242,607	5,242,607
7th Forecast Year	2023	No. of Cust.	2,742	105,433	22,672	0	2,044	394	772	134,057	134,057
		MWH	88,699	1,346,009	610,761	0	3,206,349	26253.464	53,417	5,331,488	5,331,488
8th Forecast Year	2024	No. of Cust.	2,744	105,616	22,691	0	2,057	394	772	134,274	134,274
		MWH	88,858	1,348,479	611,236	0	3,295,021	26279.664	53,417	5,423,290	5,423,290
9th Forecast Year	2025	No. of Cust.	2,745	105,777	22,704	0	2,070	394	772	134,462	134,462
		MWH	89,008	1,350,694	611,589	0	3,389,294	26305.529	53,417	5,520,307	5,520,307
10th Forecast Year	2026	No. of Cust.	2,747	105,917	22,714	0	2,082	395	772	134,627	134,627
		MWH	89,152	1,352,641	611,825	0	3,398,873	26330.989	53,417	5,532,240	5,532,240
11th Forecast Year	2027	No. of Cust.	2,748	106,039	22,720	0	2,094	395	772	134,768	134,768
		MWH	89,290	1,354,381	611,977	0	3,408,262	26356.078	53,417	5,543,681	5,543,681
12th Forecast Year	2028	No. of Cust.	2,748	106,142	22,723	0	2,107	395	772	134,887	134,887
		MWH	89,421	1,355,892	612,028	0	3,417,462	26380.641	53,417	5,554,600	5,554,600
13th Forecast Year	2029	No. of Cust.	2,750	106,215	22,720	0	2,119	395	772	134,971	134,971
		MWH	89,545	1,357,056	611,923	0	3,426,510	26404.769	53,417	5,564,854	5,564,854
14th Forecast Year	2030	No. of Cust.	2,751	106,261	22,713	0	2,131	395	772	135,023	135,023
		MWH	89,659	1,357,892	611,683	0	3,435,347	26428.504	53,417	5,574,427	5,574,427

* MINING needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item A. MINNESOTA-ONLY FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your Minnesota service area only, for the past year, your best estimate for the present year and all future forecast years.

Please remember that the number of customers should reflect the number of customers at year's end, not the number of meters.

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	MN-ONLY TOTALS	Calculated MN-Only Totals
Past Year	2015	No. of Cust.	1,365	48,333	9,712		784	146	306	60,646	60,646
		MWH	43,908	548,267	262,508		1,493,453	10,461	27,167	2,385,764	2,385,764
Present Year	2016	No. of Cust.	1,367	48,515	9,702		793	146	307	60,829	60,829
		MWH	41,066	574,622	270,515		1,719,479	10,621	27,583	2,643,886	2,643,886
1st Forecast Year	2017	No. of Cust.	1,368	48,737	9,743		795	146	307	61,095	61,095
		MWH	41,211	577,267	271,661		1,673,298	10,633	27,583	2,601,653	2,601,653
2nd Forecast Year	2018	No. of Cust.	1,369	48,929	9,778		797	146	307	61,325	61,325
		MWH	41,353	579,561	272,655		1,631,956	10,645	27,583	2,563,753	2,563,753
3rd Forecast Year	2019	No. of Cust.	1,371	49,099	9,810		799	146	307	61,530	61,530
		MWH	41,494	581,593	273,535		1,706,123	10,657	27,583	2,640,985	2,640,985
4th Forecast Year	2020	No. of Cust.	1,372	49,260	9,839		801	146	307	61,724	61,724
		MWH	41,633	583,504	274,363		1,725,369	10,669	27,583	2,663,122	2,663,122
5th Forecast Year	2021	No. of Cust.	1,373	49,404	9,866		803	146	307	61,897	61,897
		MWH	41,769	585,214	275,107		1,821,708	10,682	27,583	2,762,062	2,762,062
6th Forecast Year	2022	No. of Cust.	1,374	49,486	9,881		805	146	307	61,998	61,998
		MWH	41,900	586,220	275,542		1,928,582	10,694	27,583	2,870,521	2,870,521
7th Forecast Year	2023	No. of Cust.	1,375	49,528	9,889		807	146	307	62,051	62,051
		MWH	42,030	586,733	275,764		1,987,459	10,706	27,583	2,930,275	2,930,275
8th Forecast Year	2024	No. of Cust.	1,376	49,544	9,892		809	146	307	62,073	62,073
		MWH	42,158	586,931	275,849		2,071,338	10,719	27,583	3,014,577	3,014,577
9th Forecast Year	2025	No. of Cust.	1,376	49,544	9,892		809	146	307	62,073	62,073
		MWH	42,283	586,897	275,835		2,154,217	10,731	27,583	3,097,546	3,097,546
10th Forecast Year	2026	No. of Cust.	1,379	49,485	9,881		815	146	307	62,011	62,011
		MWH	42,406	586,646	275,726		2,156,092	10,743	27,583	3,099,196	3,099,196
11th Forecast Year	2027	No. of Cust.	1,379	49,434	9,871		817	146	307	61,954	61,954
		MWH	42,525	586,237	275,549		2,157,965	10,756	27,583	3,100,614	3,100,614
12th Forecast Year	2028	No. of Cust.	1,380	49,358	9,858		819	146	307	61,867	61,867
		MWH	42,642	585,642	275,291		2,159,838	10,768	27,583	3,101,763	3,101,763
13th Forecast Year	2029	No. of Cust.	1,381	49,262	9,840		821	146	307	61,755	61,755
		MWH	42,758	584,752	274,905		2,161,712	10,780	27,583	3,102,490	3,102,490
14th Forecast Year	2030	No. of Cust.	1,381	49,146	9,818		823	146	307	61,621	61,621
		MWH	42,869	583,609	274,410		2,163,587	10792.56689	27,583	3,102,850	3,102,850

* MINING needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item B. FORECAST OF ANNUAL SYSTEM CONSUMPTION AND GENERATION DATA (Express in MWH)

NOTE: (Column 1 + Column 2) = (Column 3 + Column 5) - (Column 4 + Column 6)

It is recognized that there may be circumstances in which the data entered by the utility is more appropriate or accurate than the value in the corresponding automatically-calculated cell. If the value in the automatically-calculated cell does not match the value that your utility entered, please provide an explanation in the Comments area at the bottom of the worksheet.

	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	CALCULATED
	CONSUMPTION BY ULTIMATE CONSUMERS IN MINNESOTA in MWH [7610.0310 B(1)]	CONSUMPTION BY ULTIMATE CONSUMERS OUTSIDE OF MINNESOTA in MWH [7610.0310 B(2)]	RECEIVED FROM OTHER UTILITIES in MWH [7610.0310 B(3)]	DELIVERED FOR RESALE in MWH [7610.0310 B(4)]	TOTAL ANNUAL NET GENERATION in MWH [7610.0310 B(5)]	TRANSMISSION LINE SUBSTATION AND DISTRIBUTION LOSSES in MWH [7610.0310 B(6)]	TOTAL WINTER CONSUMPTION in MWH [7610.0310 B(7)]	TOTAL SUMMER CONSUMPTION in MWH [7610.0310 B(7)]	(GENERATION + RECEIVED) MINUS (RESALE + LOSSES) MINUS (CONSUMPTION) SHOULD EQUAL ZERO
Past Year 2015	2,385,764	2,216,277	3,150,377	115,860	2,305,968	738,444	2,531,123	2,070,918.601	0
Present Year 2016	2,643,886	2,309,396	3,863,388	2,209,078	3,671,800	372,828	2,724,305	2,228,977.161	0
1st Forecast Year 2017	2,601,653	2,436,609	3,824,170	2,253,493	3,846,808	379,224	2,771,044	2,267,217.539	0
2nd Forecast Year 2018	2,563,753	2,552,776	3,752,076	2,253,493	4,003,061	385,115	2,814,091	2,302,438.205	0
3rd Forecast Year 2019	2,640,985	2,408,411	3,700,786	2,253,493	3,982,165	380,062	2,777,168	2,272,228.172	0
4th Forecast Year 2020	2,663,122	2,392,425	3,354,157	2,253,493	4,335,408	380,525	2,780,551	2,274,995.930	0
5th Forecast Year 2021	2,762,062	2,385,330	3,142,961	2,253,493	4,645,362	387,438	2,831,065	2,316,326.056	0
6th Forecast Year 2022	2,870,521	2,372,086	3,568,263	2,253,493	4,322,443	394,605	2,883,434	2,359,173.371	0
7th Forecast Year 2023	2,930,275	2,401,213	3,642,696	2,253,493	4,343,580	401,295	2,932,318	2,399,169.606	0
8th Forecast Year 2024	3,014,577	2,408,713	3,620,889	2,253,493	4,464,098	408,205	2,982,810	2,440,480.530	0
9th Forecast Year 2025	3,097,546	2,422,761	3,789,645	2,253,493	4,399,662	415,507	3,036,169	2,484,137.981	0
10th Forecast Year 2026	3,099,196	2,433,044	3,732,675	2,253,493	4,469,463	416,405	3,042,732	2,489,507.860	0
11th Forecast Year 2027	3,100,614	2,443,068	3,758,988	2,253,493	4,455,453	417,266	3,049,025	2,494,656.638	0
12th Forecast Year 2028	3,101,763	2,452,837	3,944,271	2,253,493	4,281,910	418,088	3,055,030	2,499,570.064	0
13th Forecast Year 2029	3,102,490	2,462,364	3,786,428	2,253,493	4,450,779	418,860	3,060,670	2,504,184.386	0
14th Forecast Year 2030	3,102,850	2,471,577	3,784,725	2,253,493	4,462,776	419,581	3,065,935	2,508,492.328	0

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item C. PEAK DEMAND BY ULTIMATE CONSUMERS AT THE TIME OF ANNUAL SYSTEM PEAK (in MW)

		FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Last Year Peak Day	2015	17.4	248.2	111.1	0	506.9	5.1	8	896.7	896.7

7610.0310 Item D. PEAK DEMAND BY MONTH FOR THE LAST CALENDAR YEAR (in MW)

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
Last Year	2015	896.7	842.4	805.0	646.9	566.8	628.2	683.2	716.4	717.1	631.6	695.5	844.9

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item E. PART 1: FIRM PURCHASES (Express in MW)

NAME OF OTHER UTILITY =>										
Past Year	2015	Summer								
		Winter								
Present Year	2016	Summer								
		Winter								
1st Forecast Year	2017	Summer								
		Winter								
2nd Forecast Year	2018	Summer								
		Winter								
3rd Forecast Year	2019	Summer								
		Winter								
4th Forecast Year	2020	Summer								
		Winter								
5th Forecast Year	2021	Summer								
		Winter								
6th Forecast Year	2022	Summer								
		Winter								
7th Forecast Year	2023	Summer								
		Winter								
8th Forecast Year	2024	Summer								
		Winter								
9th Forecast Year	2025	Summer								
		Winter								
10th Forecast Year	2026	Summer								
		Winter								
11th Forecast Year	2027	Summer								
		Winter								
12th Forecast Year	2028	Summer								
		Winter								
13th Forecast Year	2029	Summer								
		Winter								
14th Forecast Year	2030	Summer								
		Winter								

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item E. PART 2: FIRM SALES

(Express in MW)

NAME OF OTHER UTILITY =>									
Past Year	2015	Summer							
		Winter							
Present Year	2016	Summer							
		Winter							
1st Forecast Year	2017	Summer							
		Winter							
2nd Forecast Year	2018	Summer							
		Winter							
3rd Forecast Year	2019	Summer							
		Winter							
4th Forecast Year	2020	Summer							
		Winter							
5th Forecast Year	2021	Summer							
		Winter							
6th Forecast Year	2022	Summer							
		Winter							
7th Forecast Year	2023	Summer							
		Winter							
8th Forecast Year	2024	Summer							
		Winter							
9th Forecast Year	2025	Summer							
		Winter							
10th Forecast Year	2026	Summer							
		Winter							
11th Forecast Year	2027	Summer							
		Winter							
12th Forecast Year	2028	Summer							
		Winter							
13th Forecast Year	2029	Summer							
		Winter							
14th Forecast Year	2030	Summer							
		Winter							

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item F. PART 1: PARTICIPATION PURCHASES

(Express in MW)

NAME OF OTHER UTILITY =>		GRE							
Past Year	2015	Summer	100						
		Winter	100						
Present Year	2016	Summer	100						
		Winter	100						
1st Forecast Year	2017	Summer	0						
		Winter	100						
2nd Forecast Year	2018	Summer	80						
		Winter	80						
3rd Forecast Year	2019	Summer	80						
		Winter	80						
4th Forecast Year	2020	Summer	50						
		Winter	50						
5th Forecast Year	2021	Summer	0						
		Winter	50						
6th Forecast Year	2022	Summer	0						
		Winter	0						
7th Forecast Year	2023	Summer	0						
		Winter	0						
8th Forecast Year	2024	Summer	0						
		Winter	0						
9th Forecast Year	2025	Summer	0						
		Winter	0						
10th Forecast Year	2026	Summer	0						
		Winter	0						
11th Forecast Year	2027	Summer	0						
		Winter	0						
12th Forecast Year	2028	Summer	0						
		Winter	0						
13th Forecast Year	2029	Summer	0						
		Winter	0						
14th Forecast Year	2030	Summer	0						
		Winter	0						

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item F. PART 2: PARTICIPATION SALES

(Express in MW)

NAME OF OTHER UTILITY =>		EDF	MMPA	MRES	NEPM				
Past Year	2015	Summer	0	15	25	8			
		Winter	100	0	0	0			
Present Year	2016	Summer	0	15	0	0			
		Winter	0	15	25	8			
1st Forecast Year	2017	Summer	0	0	0	0			
		Winter	0	15	0	0			
2nd Forecast Year	2018	Summer	0	0	0	0			
		Winter	0	0	0	0			
3rd Forecast Year	2019	Summer	0	0	0	0			
		Winter	0	0	0	0			
4th Forecast Year	2020	Summer	0	0	0	0			
		Winter	0	0	0	0			
5th Forecast Year	2021	Summer	0	0	0	0			
		Winter	0	0	0	0			
6th Forecast Year	2022	Summer	0	0	0	0			
		Winter	0	0	0	0			
7th Forecast Year	2023	Summer	0	0	0	0			
		Winter	0	0	0	0			
8th Forecast Year	2024	Summer	0	0	0	0			
		Winter	0	0	0	0			
9th Forecast Year	2025	Summer	0	0	0	0			
		Winter	0	0	0	0			
10th Forecast Year	2026	Summer	0	0	0	0			
		Winter	0	0	0	0			
11th Forecast Year	2027	Summer	0	0	0	0			
		Winter	0	0	0	0			
12th Forecast Year	2028	Summer	0	0	0	0			
		Winter	0	0	0	0			
13th Forecast Year	2029	Summer	0	0	0	0			
		Winter	0	0	0	0			
14th Forecast Year	2030	Summer	0	0	0	0			
		Winter	0	0	0	0			

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item G. LOAD AND GENERATION CAPACITY (Express in MW)

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	Column 14	Column 15	
		SEASONAL MAXIMUM DEMAND	SCHEDULE L PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND	SEASONAL SYSTEM DEMAND	ANNUAL SYSTEM DEMAND	SEASONAL FIRM PURCHASES (TOTAL)	SEASONAL FIRM SALES (TOTAL)	SEASONAL ADJUSTED NET DEMAND (3 - 5 + 6)	ANNUAL ADJUSTED NET DEMAND (4 - 5 + 6)	NET GENERATING CAPABILITY	PARTICIPATION PURCHASES (TOTAL)	PARTICIPATION SALES (TOTAL)	ADJUSTED NET CAPABILITY (9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (7 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (12 - 14)	
Past Year	2015	Summer	717	33	684	684	0	0	684	684	678	100	48	730	0	684	46
		Winter	897	100	797	797	0	0	797	797	678	100	100	678	0	797	-119
Present Year	2016	Summer	788	33	755	797	0	0	755	797	678	100	15	763	0	755	8
		Winter	915	100	815	815	0	0	815	815	678	100	48	730	0	815	-85
1st Forecast	2017	Summer	804	33	771	815	0	0	771	815	678	80	0	758	0	771	-13
		Winter	931	105	826	826	0	0	826	826	678	80	15	743	0	826	-83
2nd Forecast	2018	Summer	819	33	786	826	0	0	786	826	678	80	0	758	0	786	-28
		Winter	946	106	840	840	0	0	840	840	678	80	0	758	0	840	-82
3rd Forecast	2019	Summer	836	34	802	840	0	0	802	840	678	50	0	728	0	802	-74
		Winter	963	107	856	856	0	0	856	856	678	50	0	728	0	856	-128
4th Forecast	2020	Summer	840	34	806	856	0	0	806	856	678	50	0	728	0	806	-78
		Winter	967	108	859	859	0	0	859	859	678	50	0	728	0	859	-131
5th Forecast	2021	Summer	839	34	805	859	0	0	805	859	736	0	0	736	0	805	-69
		Winter	966	109	857	857	0	0	857	857	736	0	0	736	0	857	-121
6th Forecast	2022	Summer	854	35	819	857	0	0	819	857	736	0	0	736	0	819	-83
		Winter	981	110	871	871	0	0	871	871	736	0	0	736	0	871	-135
7th Forecast	2023	Summer	872	35	837	871	0	0	837	871	736	0	0	736	0	837	-101
		Winter	999	111	888	888	0	0	888	888	736	0	0	736	0	888	-152
8th Forecast	2024	Summer	889	35	854	888	0	0	854	888	736	0	0	736	0	854	-118
		Winter	1016	113	903	903	0	0	903	903	736	0	0	736	0	903	-167
9th Forecast	2025	Summer	908	36	872	903	0	0	872	903	736	0	0	736	0	872	-136
		Winter	1034	115	919	919	0	0	919	919	736	0	0	736	0	919	-183
10th Forecast	2026	Summer	915	37	878	919	0	0	878	919	736	0	0	736	0	878	-142
		Winter	1042	117	925	925	0	0	925	925	736	0	0	736	0	925	-189
11th Forecast	2027	Summer	922	38	884	925	0	0	884	925	736	0	0	736	0	884	-148
		Winter	1049	119	930	930	0	0	930	930	736	0	0	736	0	930	-194
12th Forecast	2028	Summer	929	38	891	930	0	0	891	930	736	0	0	736	0	891	-155
		Winter	1056	122	934	934	0	0	934	934	736	0	0	736	0	934	-198
13th Forecast	2029	Summer	936	39	897	934	0	0	897	934	736	0	0	736	0	897	-148
		Winter	1063	124	939	934	0	0	939	934	736	0	0	736	0	939	-203
14th Forecast	2030	Summer	943	40	903	934	0	0	903	934	736	0	0	736	0	903	-155
		Winter	1070	127	931	934	0	0	931	934	736	0	0	736	0	931	-210

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item H. ADDITIONS AND RETIREMENTS (Express in MW)

		ADDITIONS	RETIREMENTS
Past Year	2015		
Present Year	2016		
1st Forecast Year	2017		
2nd Forecast Year	2018		
3rd Forecast Year	2019		
4th Forecast Year	2020		
5th Forecast Year	2021	248	128.5
6th Forecast Year	2022		
7th Forecast Year	2023		
8th Forecast Year	2024		
9th Forecast Year	2025		
10th Forecast Year	2026		
11th Forecast Year	2027		
12th Forecast Year	2028		
13th Forecast Year	2029		
14th Forecast Year	2030		

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

Please use the appropriate code for the fuel type as shown in the list at the bottom of the worksheet.

		FUEL TYPE 1		FUEL TYPE 2		FUEL TYPE 3		FUEL TYPE 4		FUEL TYPE 5		FUEL TYPE 6	
		Name of Fuel	SUB	Name of Fuel	HYDRO	Name of Fuel	GAS	Name of Fuel		Name of Fuel		Name of Fuel	
		Unit of Measure	Tons	Unit of Measure	Gal	Unit of Measure	MMBTU	Unit of Measure		Unit of Measure		Unit of Measure	
		QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED
Past Year	2015	1291459	1795134	na	20010	184681	17660						
Present Year	2016	1597741	2216500	na	22000	69100	6800						
1st Forecast Year	2017	1690693	2328700	na	22000	111300	10700						
2nd Forecast Year	2018	1738243	2400000	na	22000	116400	11400						
3rd Forecast Year	2019	1635853	2274400	na	22000	109600	10600						
4th Forecast Year	2020	1726719	2381300	na	22000	114200	11100						
5th Forecast Year	2021	1498179	2027600	na	22000	2396000	221000						
6th Forecast Year	2022	1198000	2440000	na	22000	2890000	265000						
7th Forecast Year	2023	1254000	2439000	na	22000	3143000	287000						
8th Forecast Year	2024	1325000	2570000	na	22000	2974000	272000						
9th Forecast Year	2025	1294000	2489000	na	22000	3105000	294000						
10th Forecast Year	2026	1417000	2575000	na	22000	3028000	277000						
11th Forecast Year	2027	1418000	2569000	na	22000	2952000	269000						
12th Forecast Year	2028	1295000	2381000	na	22000	3108000	283000						
13th Forecast Year	2029	1469000	2608000	na	22000	3071000	281000						
14th Forecast Year	2030	1505000	2621000	na	22000	3072000	280000						

- LIST OF FUEL TYPES
- BIT - Bituminous Coal
 - COAL - Coal (general)
 - DIESEL - Diesel
 - FO2 - Fuel Oil #2 (Mid-distillate)
 - FO6 - Fuel Oil #6 (Residual fuel oil)
 - LIG - Lignite
 - LPG - Liquefied Propane Gas
 - NG - Natural Gas
 - NUC - Nuclear
 - REF - Refuse, Bagasse, Peat, Non-woi
 - STM - Steam
 - SUB - Sub-bituminous coal
 - HYD - Hydro (water)
 - WIND - Wind
 - WOOD - Wood
 - SOLAR - Solar

COMMENTS