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September 1, 2021



Mr. Steve Kahl  
Director of Administration/Executive Secretary  
North Dakota Public Service Commission  
State Capitol  
600 East Boulevard, Dept. 408  
Bismarck, ND 58505-0408

**PUBLIC DOCUMENT – NOT PUBLIC (OR  
PRIVILEGED) DATA HAS BEEN EXCISED**

**RE: In the Matter of Otter Tail Power Company’s Submittal of its  
2022–2036 Integrated Resource Plan**

Dear Mr. Kahl:

Enclosed for filing with the North Dakota Public Service Commission is Otter Tail Power Company’s (Otter Tail) 2021 Integrated Resource Plan (IRP). The IRP identifies a Preferred Plan for meeting the capacity and energy needs of our customers over the 2022-2036 planning period.

The modeling analysis supporting the selection of the Preferred Plan includes the input of numerous stakeholders and has been refined over the course of two years. In the aggregate, the Preferred Plan allows us to reduce costs and maintain and improve resiliency, while having greater control over whether or not to dispatch resources based on market conditions.

To achieve these ends the Preferred Plan includes a request for authority to add dual fuel capability at Astoria Station, add 150 MW solar generation in 2025, and to commence the process of withdrawing from our 35 percent ownership interest in Coyote Station, with the completion of that process expected by the end of 2028.

Please note that Otter Tail deems the following attachments marked as NOT PUBLIC to be trade secrets, valuable or sensitive commercial or financial information, or information that is otherwise confidential or proprietary and subject to restrictions against disclosure and unauthorized use under North Dakota law and the Parties’ Confidentiality Agreement.

An original and seven (7) copies have been sent to you via USPS.

1 PU-21-380 Filed 09/01/2021 Pages: 316  
Integrated Resource Plan 2022 - 2036 - redacted  
Otter Tail Power Company  
Nathan Jensen

Mr. Kahl  
September 1, 2021  
Page 2

An electronic copy of this filing is being sent to you at [ndpsc@nd.gov](mailto:ndpsc@nd.gov). Should you have any questions, please contact me at [njensen@otpc.com](mailto:njensen@otpc.com) or (218) 739-8989.

Sincerely,

*/s/ NATHAN JENSEN*  
Nathan Jensen  
Manager, Resource Planning

kaw  
Enclosures  
By electronic service and USPS

# Application for Resource Plan Approval 2022-2036

**PUBLIC DOCUMENT — NOT PUBLIC (OR PRIVILEGED)**  
Data has been excised

SUBMITTED TO

**Minnesota Public Utilities Commission: Docket No. E017/RP-21-339**

**North Dakota Public Service Commission**

**South Dakota Public Utilities Commission**

**September 1, 2021**



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## **1 Statement of Preferred Plan**

Otter Tail Power Company (Otter Tail or Company) has developed a Preferred Plan that will allow us to reduce costs while maintaining and enhancing resiliency and giving the Company greater control over whether or not to dispatch resources based on market conditions.

Accordingly, we are requesting authority to carry out the following key aspects of the plan within the next five years:

- the addition of dual fuel capability at Astoria Station;
- the addition of 150 MW of solar generation in 2025; and
- the commencement of the process of withdrawal from our 35 percent ownership interest in Coyote Station.

This plan, the analysis supporting it, and its various components are discussed in greater detail throughout this filing.<sup>1</sup>

## **2 Preface**

Otter Tail has prepared this resource plan for concurrent filings with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (ND PSC), and the South Dakota Public Utilities Commission (SD PUC).

### **Resource Plan Requirements and Policy Considerations**

In Minnesota, this plan is filed to satisfy the requirements of Minnesota Statute § 216B.2422 and Minnesota Rules, Part 7843. In North Dakota, the plan is filed pursuant to North Dakota Century Code §§ 49-05-04.4 and 49-05-17. In South Dakota, the plan is filed to keep the SD PUC apprised of the Company's plans; however, there is not any statute or rule requiring the SD PUC to review or approve resource plans.

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<sup>1</sup> In addition to the foregoing, Otter Tail's five-year plan also includes taking the initial steps to necessary to bring 100 MW of additional wind resources into service in 2027.

The legal and regulatory requirements regarding resource plan approval thus differ from state to state, as does the significance of approval (where required). However, regardless of the specific differing statutory and regulatory provisions, integrated resource plan analysis plays an important role in all three Otter Tail states when the necessity and prudence of resource additions are considered, including certificate of need matters, certificate of public convenience and necessity cases, and rate recovery matters.

Otter Tail is quite small for a vertically integrated utility. Despite that small size, we have succeeded over the years in keeping our rates low. Customers have benefitted from our efficiency and economies of scale we have been able to achieve in spite of our limited customer base. If, however, the requirements of our regulators in Minnesota, North Dakota, and South Dakota were to diverge to the point that we had to operate state-specific systems in each jurisdiction, the increase in administrative expenses and the loss of economies of scale would increase our costs and, necessarily, our retail rates. It is important, therefore, that the Company be able to maintain a single integrated system pursuant to an integrated resource plan acceptable to all three jurisdictions. Obviously, there can be (and are) some differences in the regulatory treatment of certain resources, but there is also, just as obviously, a point at which Otter Tail could not reasonably accommodate such differences. Fortunately, we are confident that the Commissions in all three states will support the integrated resource plan presented in this filing, as was the case with our most recent resource plan.

### **Execution of the 2016 Plan**

Resource planning is a continuous and iterative process. Accordingly, the resource plan submitted with this filing is based on the Company's most recent resource plan, which was submitted in 2016 (2016 Plan),<sup>2</sup> with appropriate adjustments for changing conditions in the market and our industry. In the 2016 Plan, various actions were scheduled for the 2017 to 2022 planning period. For the most part, the Company has completed its planned actions. In

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<sup>2</sup> *In the Matter of Otter Tail Power Company's 2017-2031 Integrated Resource Plan*, in Minnesota Docket No E-017/RP-16-386 and North Dakota Case No. PU-16-308.

particular, two major resource additions authorized as part of the 2016 Plan<sup>3</sup> are now in service: the 150 MW Merricourt Wind Energy Center, located near Merricourt, North Dakota, went into service in late 2020, and the 245 MW Astoria Station simple-cycle natural gas generator, located near Astoria, South Dakota, went into service in early 2021. The Company added those two generation resources in response to the May 2021 retirement of the Hoot Lake Plant<sup>4</sup> and the expiration of certain capacity contracts.

In addition to the new generation resources now in service, the Company is also working to develop the MPUC-approved Hoot Lake Solar project, a 49.9 MW solar installation using the Hoot Lake Plant interconnection.<sup>5</sup> The facility is currently anticipated to be in service in 2023. The Hoot Lake Solar opportunity emerged quickly, and Otter Tail responded effectively to secure interconnection rights, investment tax credits, and the necessary permits. The Hoot Lake Solar project matched a need identified in Minnesota for solar generation with a unique opportunity at the site of the retiring Hoot Lake Plant. Once in service it will provide significant ratepayer benefits, including reductions to market purchases during the most expensive hours of the year.<sup>6</sup> Table 2-1 summarizes Otter Tail's execution of the 2016 Plan.

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<sup>3</sup> *In the Matter of Otter Tail Power Company's 2017-2031 Integrated Resource Plan*, Order Approving Plan with Modifications and Setting Requirements for Next Resource Plan, April 26, 2017, MPUC Docket No E-017/RP-16-386.

<sup>4</sup> The Hoot Lake Plant was a 140 MW coal-fired facility originally constructed in the 1950s that used coal from the Powder River Basin. It was retired from service on May 31, 2021.

<sup>5</sup> *In the Matter of Otter Tail Power Company's Petition for Approval of the Hoot Lake Solar Project*, Order Approving Petition, Authorizing Allocation of Output and Costs, Authorizing Cost Recovery, And Requiring Compliance Filings, April 29, 2021, MPUC Docket No. E-017/M-20-844. The Company is currently undergoing vendor requests for proposals and negotiations.

<sup>6</sup> *Id.* at 7.

**Table 2-1: Execution of 2016 IRP Order**

<b>2016 Resource Plan Order</b>	<b>Execution of 2016 IRP</b>
The addition of 200 MW of wind in the 2018-2020 timeframe	The 150 MW Merricourt Wind Farm became commercially operational in December 2020. <sup>7</sup>
The addition of 30 MW of solar in about 2020	Received MPUC approval to construct the 49.9 MW Hoot Lake Solar Project beginning in 2021.
The addition of up to 250 MW of peaking capacity in 2021	The 245 MW Astoria Station was completed and became operational during Q1 2021
Average annual energy savings of 46.8 GWh (1.6 percent of sales).	Average annual energy savings of 1.86%, which exceeds the newly established 1.75% goal in Minnesota’s ECO Act. <sup>8</sup>

The Company has performed well in carrying out the 2016 Plan. The Astoria and Merricourt projects were completed on time and under budget despite substantial labor availability challenges and supply chain disruptions caused by the COVID-19 pandemic. In fact, final Merricourt costs were nearly 20 percent<sup>9</sup> lower than the estimated costs presented in the 2016 Plan, and the final Astoria costs are expected to be about seven percent<sup>10</sup> lower than the estimated costs presented in the 2016 Plan. The Hoot Lake Plant was retired on-schedule, on May 31, 2021. The Company mitigated the community and worker impacts that are inherent in any facility retirement through thoughtful planning, communication, and coordination.

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<sup>7</sup> The 150 MW Merricourt Project with its approximately 50 percent net capacity factor is basically equivalent to the 200 MW addition of wind resource with an approximately 40 percent capacity factor assumed in the 2016 Resource Plan Order.

<sup>8</sup> On May 25, 2021, Minnesota Governor Tim Walz signed the Energy Conservation and Optimization (ECO) Act of 2021. This legislation modernized Minnesota conservation policy by adding new opportunities and setting higher conservation goals. The ECO Act increased the annual energy savings goal for public electric utilities, from 1.5 percent of retail sales to 1.75 percent of retail sales, based on a rolling three-year average of weather normalized sales.

<sup>9</sup> The 2016 Resource Plan wind resource selected was \$30/MW. Otter Tail expects the levelized cost of the Merricourt project to be less than \$24/MWh.

<sup>10</sup> The 2016 Resource Plan new thermal alternative selected was \$599/kW (2017\$), escalated to \$674/kW (2021\$) / \$167.2 million and the current estimate at completion is \$628/kW / \$153.8 million.

The Company has also been successful with its demand-response initiatives, including Minnesota’s approved Conservation Incentive Program (CIP), South Dakota’s Energy Efficiency Program (EEP), and other conservation and demand-response initiatives. These programs benefit customers in all three states served by Otter Tail. Since the MPUC approved the 2016 Plan in 2017, Otter Tail has achieved energy savings of 78,583 MWh in 2018, 82,466 MWh in 2019, and 81,559 MWh in 2020. Combined, these achievements have significantly reduced our energy needs by 242,609 MWh, which has resulted in a substantial reduction in the cost of providing service to our customers.

As a result of both the Company’s successful management of the costs of the generation resource additions and favorable market conditions for purchased power, the Company has been able to keep its costs lower than contemplated in the 2016 Plan. Table 2-2 provides a comparison between the prices forecasted in the 2016 Plan and the actual market prices for 2017 to 2020.

**Table 2-2: Comparison of 2017-2020 Forecasted to Actual Market Prices**

\$/MWh	2016 Resource Plan	Actual LMPs	\$ Change	% Change
<b>2017</b>	29.99	23.00	-6.99	-23.3%
<b>2018</b>	27.94	27.28	-0.66	-2.4%
<b>2019</b>	27.81	22.99	-4.82	-17.3%
<b>2020</b>	28.10	16.60	-11.50	-40.9%
<b>2017 -2020 Average</b>	<b>28.46</b>	<b>22.47</b>	<b>-5.99</b>	<b>-21.0%</b>

Otter Tail’s all-in rates (including base rates, riders, and fuel charges) continue to be among the very lowest of all electric utilities in each of our states. We are proud of that, and we recognize that collaboration with our state Commissions and other stakeholders has been an important part of our success in keeping rates low. Our new resource plan is designed to keep our rates low, while maintaining reliability and responding to the realities of current and projected market conditions.

### **The Preferred Plan**

Our preferred 2022-2036 resource plan (Preferred Plan) takes account of the anticipated demand and energy needs of the Company's customers. Based on those forecasted needs, we have set forth both specific actions that Otter Tail plans to complete during the first five years of the planning period and potential actions that Otter Tail may take during the subsequent ten years. In our plan, Otter Tail presents actions that: (a) will ensure that Otter Tail has the resources necessary to continue to provide reliable, low-cost electricity to meet customers' needs, while avoiding adverse impacts; (b) comply with the requirements of applicable statutes and rules; and (c) take account of the sometimes-differing goals of the commissions in all three states.

The Company has determined that it can best satisfy those goals by: (1) beginning the process of withdrawal from our ownership interest in Coyote Station; (2) modifying the Astoria Station so that it can use fuel oil in addition to natural gas (dual fuel capability); and (3) adding solar and wind resources, including a 150 MW solar facility and a 100 MW wind facility. Our analysis indicates that this combination of actions will maintain and enhance the resiliency of our system and reduce costs.

In fact, the economic analyses supporting the Preferred Plan is compelling. In almost every scenario and permutation analyzed, the results are clear: It is no longer in customers' best interest for Otter Tail to continue to participate as an owner in Coyote Station. This outcome is true regardless of any future compliance obligation<sup>11</sup> or potential change in law. Should significant investments need to be made at Coyote Station for environmental compliance purposes, the economic analysis is even more compelling. Consequently, Otter Tail is proposing to commence the process of withdrawing from its ownership interest in Coyote Station upon approval of this Preferred Plan with the consummation of that process expected by the end of

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<sup>11</sup> This possibility arises from the EPA's Regional Haze Rule. In its planning, the Company is treating the need for capital investments to comply with that rule as a possibility; however, to be clear, Otter Tail is not taking the position that such capital investments should be required, nor are we providing an estimate of the likelihood of such an outcome.

2028.

Withdrawing from Otter Tail's ownership interest in Coyote Station will not be without challenges, however. Coyote Station is a key baseload resource for the plant's co-owners.<sup>12</sup> Additionally, Otter Tail is the current operator of the plant and is relied upon by the co-owners for the plant's safe and efficient operation. Further, Coyote Station is a mine-mouth lignite plant, which is fully integrated with the mine adjacent to the plant. The mine is owned by Coyote Creek Mining Company, LLC, a subsidiary of the North American Coal Corporation, which is not affiliated with any of the Coyote Station co-owners. Finally, Coyote Station is a key source of union jobs and tax base in Mercer County and North Dakota. Consequently, in addition to considering customer impact we must also consider the impacts to our Coyote Station co-owners and these other stakeholders. While these challenges are not insurmountable, they will require thoughtful consideration and management. We have sought to be measured and deliberate in our approach to withdrawing from Coyote Station. Through this resource planning process, we are seeking Commission acknowledgement and understanding of these challenges and risks, recognizing that Otter Tail's withdrawal from Coyote Station is demonstrated as the most reasonable course of action from a resource planning and customer perspective.

Otter Tail's withdrawal from Coyote Station is justified by our modeling and will also help to shift the Company's generation portfolio into a more flexible one, allowing Otter Tail to better match its operations with the ongoing trends in the MISO market. Shifting the generation fleet's focus to dispatchable gas resources and away from coal will help to improve operational flexibility while hedging market risk. That said, it is also necessary to ensure fuel-secure generation is available for those times when self-generation is necessary to maintain reliability of the system. Obtaining gains in reliability is a necessary component of prudent resource planning

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<sup>12</sup> Ownership shares in Coyote are: 35% Otter Tail; 30% Northern Municipal Power Agency; 25% Montana-Dakota Utilities Co.; and 10% NorthWestern Energy. Minnkota Power Cooperative, Inc., serves as the agent for Northern Municipal Power Agency. NorthWestern's share of the plant is dispatched into the SPP Market with the remainder of Coyote Station dispatched into MISO.

and, to that end, we intend to make key system investments to enable Astoria Station to run on fuel oil in addition to natural gas. By making an investment in on-site fuel oil storage, Otter Tail will actually have more generation capacity than we currently have, while providing greater flexibility to decide whether to dispatch the resource depending on fuel costs and market conditions. Our analysis supports dual fuel at Astoria Station regardless of the course of action on Coyote Station.

Otter Tail’s Preferred Plan will make the Otter Tail system more flexible in its ability to respond to market signals. Flexibility in this context includes the ability to start and stop generation quickly and less reliance on long term fuel supply commitments. The Preferred Plan provides sufficient resources to meet our customers’ needs and hedges overall exposure while enhancing the Company’s ability to take advantage of favorable market dynamics that accrue to our customers’ short-and long-term benefit. In light of current market dynamics and as a hedge against the future, Otter Tail’s Preferred Plan also includes the addition of 150 MW of solar and 100 MW of wind as economic resources for the system.

Table 2-3 demonstrates the economic benefits of the Company’s Preferred Plan.

**Table 2-3: Coyote Withdrawal NPVRR Comparison\***

	No Externalities		With Externalities	
	Base Case	Preferred Plan	Base Case	Preferred Plan
Continued Operation (\$000)	\$2,515,096	\$2,530,668	\$2,971,847	\$2,991,608
2028 Withdrawal (\$000)	\$2,466,554	\$2,479,385	\$2,864,875	\$2,909,334
<b>Difference (\$000)</b>	<b>-\$48,542</b>	<b>-\$51,283</b>	<b>-\$106,972</b>	<b>-\$82,274</b>

\* Tables 3-5 and 3-6 detail the resource additions included for the plans in Table 2-3.

The figures presented above are the result of EnCompass modeling that forms the foundation for this resource plan. To prepare for this modeling, the Company conducted numerous virtual stakeholder group meetings in the states we serve. Otter Tail considered input from those stakeholders in developing this resource plan. 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.

Historically, the Company has advocated for what we describe as a “least cost” resource plan. However, the selection of such a plan has always involved more than just selecting the lowest cost option under a single forecasted scenario. Instead, Otter Tail analyzes numerous potential scenarios in a range of possible “futures.” By considering a variety of scenarios, the Company’s goal has always been to go beyond a single “least cost” consideration to also consider the various *risks* that are inherent in any plan so that we can arrive at a plan that has the greatest likelihood of being “least cost” under the broadest range of possible futures. It might therefore be more accurate to say that Otter Tail’s resource planning has been focused on finding the “least cost/least risk” plan. The Preferred Plan is such a plan.

As with any planning based on forecasts, considerable unknowns and variables outside of any stakeholder’s control will impact the actual resulting costs. Any long-range plan is subject to change because it is based on forecasts and assumptions from a specific point in time. As we continue into this rapidly evolving period influenced by technological advances, efficiency gains, fuel economics and, not least of all, regulatory influences, speculating on what the “least-cost plan” looks like using current assumptions carries significant opportunities and risk. These opportunities and risks relate mostly to actual fuel and market prices, capital costs for construction, and the future volatility of prices and costs. In this resource plan we have attempted to present information that our Commissions and other stakeholders can use to give careful consideration of how best to balance least-cost principles and the cost-related risks and opportunities inherent in planning.

There is no doubt there will be differences of opinion based upon stakeholders’ various perspectives. Otter Tail’s goal is to keep customers’ interests in the forefront of this analysis. We know we share this goal with each of our three Commissions. With this in mind, our Preferred Plan strikes a balance between several planning objectives - including arriving at a diversified mix of generation resources that assures reliability, rate stability, stewardship of

resources, and the flexibility to respond to risks and opportunities in this rapidly changing environment. Table 2-4 below summarizes the key actions in the Preferred Plan. Each of the items listed is discussed in greater detail in subsequent sections of this filing.

**Table 2-4: Otter Tail 2022-2028 Detailed Action Plan**

<b>Year</b>	<b>Actions</b>
2022	<p><u>Pursue Withdrawal from Coyote:</u>                      Fulfill contractual and legal obligations; assess opportunity to sell ownership interest in plant</p> <p><u>150 MW Solar (in-service 2025):</u>                      Development Activities: Secure land, MISO interconnection, Preliminary Design Permitting</p> <p><u>Dual Fuel at Astoria:</u>                      Development Activities: Engage engineering firm for studies to refine cost estimates and the combustion turbine supplier to develop preliminary schedule including environmental study for permitting process</p>
2023	<p><u>Pursue Withdrawal from Coyote:</u>                      Fulfill contractual and legal obligations; assess opportunity to sell ownership interest in plant; assess other actions necessary to withdraw from plant ownership by end of 2028</p> <p><u>150 MW Solar (in-service 2025):</u>                      Secure necessary equipment and contracting for construction</p> <p><u>Dual Fuel at Astoria:</u>                      Enter into agreements for equipment, begin detailed design, seek construction bids</p>
2024	<p><u>Pursue Withdrawal from Coyote:</u>                      Fulfill contractual and legal obligations; assess opportunity to sell ownership interest in plant; assess other actions necessary to withdraw from plant ownership by end of 2028</p> <p><u>150 MW Solar (in-service 2025):</u>                      Construction</p>

	<p><u>Dual Fuel at Astoria:</u>                  Manufacture equipment and start construction</p> <p><u>100 MW Wind (in-service 2027):</u>                  Commencing development activities: secure land, MISO interconnection, preliminary design permitting</p>
2025	<p><u>Pursue Withdrawal from Coyote:</u>                  Fulfill contractual and legal obligations; assess opportunity to sell ownership interest in plant; assess other actions necessary to withdraw from plant ownership by end of 2028.</p> <p><u>150 MW Solar:</u>                  2025 commercial operation</p> <p><u>Dual Fuel at Astoria:</u>                  Construction and 2026 commercial operation.</p> <p><u>100 MW Wind (in-service 2027):</u>                  Secure necessary equipment and contracting for construction</p>
2026	<p><u>Pursue Withdrawal from Coyote:</u>                  Fulfill contractual and legal obligations; assess opportunity to sell ownership interest in plant; assess other actions necessary to withdraw from plant ownership by end of 2028.</p> <p><u>Dual Fuel at Astoria:</u>                  2026 Commercial operation</p> <p><u>100 MW Wind (in-service 2027):</u>                  Construction</p>
2027	<p><u>Pursue Withdrawal from Coyote:</u>                  Fulfill contractual and legal obligations; assess opportunity to sell ownership interest in plant; assess other actions necessary to withdraw from plant ownership by end of 2028</p> <p><u>100 MW Wind:</u>                  2027 Commercial operation</p>
2028	<p><u>Pursue Withdrawal from Coyote:</u>                  Otter Tail expected withdraw from Coyote Station end of 2028</p>

### **3 The Factors Considered in our Planning Analysis.**

Otter Tail’s overall rates for electric service are among the lowest in the nation. The Table below reflects an Otter Tail Total System blended cost of energy paid by Otter Tail’s customers since 2010.<sup>13</sup> It shows that our customers have benefitted from our consistent and cost-effective portfolio of resources over that period. It is important that we continue to be able to operate as one system, with a generation mix serving all our customers.

**Table 3-1: Otter Tail Total System Average Cost of Energy  
Paid by Otter Tail Customers since 2010**

<b>Calendar Year</b>	<b>Estimated Total System Cost of Energy (\$/MWh)</b>
2010	21.64
2011	22.04
2012	23.43
2013	23.54
2014	26.46
2015	25.18
2016	22.45
2017	23.73
2018	24.68
2019	23.25
2020	18.54

The Preferred Plan identifies the anticipated electric service needs of our customers for the 2022-2036 planning period, and it includes aspects that are aimed at the emergence of new opportunities presented by low market prices, low market price forecasts, and low costs for generation alternatives. It details specific action items that we intend to complete within the first six years of the planning period.

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<sup>13</sup> Recovery of fuel costs vary by jurisdiction including the treatment of true-up amounts. For the purposes of this estimation Otter Tail utilized actual fuel costs per MWh by jurisdiction and weighted them: Minnesota – 50%, North Dakota 40%, and South Dakota 10% to arrive at an approximate average cost of energy across all our states.

In its Order concerning Otter Tail's initial resource plan filing in 1992, the MPUC stated that it considers the characteristics of the available resource options and the proposed plan as a whole.<sup>14</sup> The MPUC has continued this approach in Otter Tail's subsequent resource plans. 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.”

While this list is taken from Minnesota Administrative Rules, it provides a useful set of factors from which to consider Otter Tail's plan in all states; the plan's success in any state will depend on how it will maintain and improve reliability, keep rates low, manage the potential for adverse effects, maintain flexibility, and mitigate risk. These factors could be a simple report card for any utility and for any resource plan. Therefore, we have incorporated these objectives into the evaluation of our Preferred Plan.

### **3.1 Plan Synopsis**

Our Preferred Plan is consistent with our 2016 Plan, and it positions the Company well to manage customer costs, risks, and other negative impacts while maintaining reliable electric service. At the same time, the resulting diversified, balanced generation portfolio will give us the

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<sup>14</sup> *In the Matter of the Petition of Otter Tail Power Company for Approval of its 1992 Resource Plan*, Order Approving 1992 Resource Plan and Requiring Additions To 1994 Resource Plan, May 19, 1993, MPUC Docket No. E-017/RP-92-484.

flexibility to respond to industry changes and MISO market conditions. The Preferred Plan better manages risks than would the base case scenario or other scenarios, and it is therefore the most favorable of the plan scenarios considered.

### **Otter Tail's request regarding its interest in Coyote Station**

The most notable aspect of the Preferred Plan is Otter Tail's request for authority to meet customers' generation needs through resources that are more flexible in their dispatch and less likely to require large capital expenditures at Coyote Station. Otter Tail owns a 35 percent interest in Coyote Station, and it was designed as a baseload generating resource. It therefore has limitations to its dispatch flexibility. Current and forecasted market conditions present opportunities to utilities that have greater flexibility in the dispatch of their resources and, therefore, as part of this filing, we are requesting authority to commence the process of withdrawing from Coyote Station so that we can increase the flexibility of our portfolio and reduce costs for our customers. Also, we anticipate Coyote Station may require significant capital investment to maintain compliance with the Environmental Protection Agency's (EPA) Regional Haze Rule and possibly other environmental regulatory requirements.

To be clear, Coyote Station has performed at least as well as it was expected to perform in previous resource plans, and the costs of Coyote Station have not materially increased from what was expected at the time of the 2016 Plan. Its costs have been stable, and the results of this analysis are, therefore, not due to unexpected increases to the costs of operating the plant (with the exception of the possible costs anticipated to comply with the Regional Haze Rule).

The results of our analysis, and our request, are instead due to market price forecasts and demand forecasts now being much lower than previous forecasts. Otter Tail has taken advantage of these low market conditions within the limits of its existing resource portfolio, but current forecasts reflect that we can lower costs further by increasing the flexibility of our generation portfolio. Commencing withdrawal from ownership will include monitoring changes to our capacity needs and other assumptions to ensure withdrawal from Coyote Station will remain prudent.

Again, the details of the factors affecting Coyote Station and the evolving market conditions are considered more fully throughout this filing, and they provide insight on the question of whether it is preferable to maintain or withdraw from our current interest in Coyote Station to pursue favorable market opportunities for our customers through more advantageous resources. This requested authority is not typical of resource plans, but it is also not unique. In Otter Tail's 2010 IRP,<sup>15</sup> a thorough examination was made of the question whether Otter Tail should maintain its Hoot Lake Plant or retire it to pursue more advantageous alternatives. For purposes of this resource plan, we have conducted significant comparative scenario analysis in our modeling. Later in this filing, we also consider factors relating to this decision that go beyond the modeling.

### **The Preferred Plan**

This filing provides an explanation of our analysis, the data and inputs into the analysis and its results. With this filing we request Commission authority within the legal framework of each particular state to commence the following key actions in furtherance of the Preferred Plan:

- To add of dual fuel capability at Astoria Station;
- To add of 150 MW of solar generation in 2025; and
- To commence of the process to withdraw from our ownership interest in Coyote Station.

### **3.2 Load Forecast**

The process of developing this resource plan began with an econometric peak demand and energy requirements forecast, which was used as our Base forecast scenario.

The forecast peak demand and energy requirements are detailed in Appendix B. The energy requirements forecast represents an approximately 0.46 percent average annual growth rate, prior to new demand side management (DSM) programs, and it is the key component in determining

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<sup>15</sup> *In the Matter of Otter Tail Power Company's 2011-2025 Resource Plan*, Order Approving Baseload Diversification Study and Setting Requirements for Next Resource Plan, March 25, 2013, MPUC Docket No. E017/RP-10-623. The Baseload Diversification Study was a study required by the MPUC for the purpose of examining alternatives for decommissioning or 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.

the type of resources to be added, whether baseload, intermediate, or peaking. Peak demands are anticipated to average an annual growth rate of 0.57 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 Independent System Operator, Inc. (MISO), Otter Tail is currently required to maintain a 9.4 percent planning reserve margin on the forecasted summer peak demand coincident with the MISO's peak demand, after accounting for plant accreditation ratings as defined by the MISO.<sup>16</sup>

When comparing the load forecast from our 2016 IRP to the updated forecast used in this IRP there is a noticeable reduction in the current forecast. This reduction is a result of energy efficiency programs. Otter Tail has seen significant demand and energy savings, in excess of three percent in some years. Another factor contributing to our forecast reductions is a decrease to firm demand requirements from our large industrial customers.

### **3.3 Future Resource Needs**

Table 3-2 and Figure 3-1 provide the Company's summer season resource needs showing the Company's projected load and capability according to the MISO Module E rules for resource adequacy. Section 4.4 provides discussion of the MISO Module E and further detail regarding the resource adequacy obligation calculation.<sup>17</sup>

The total accredited capacities, shown as Zonal Resource Credits (ZRCs), represent the MISO's capacity ratings for the Company's resources based on the 2021 planning year accreditation levels. Resource, forward purchase, and demand response accreditations are based on historical summer performance and do not vary monthly.

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<sup>16</sup> As noted below MISO is considering changes to its compacity construct.

<sup>17</sup> 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.

**Table 3-2: Summer 2022-2036 Base Case Projected Load and Capability Prior to Preferred Resource Plan**

Line No.		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1	<b>Forecasted Load</b>	672.0	675.6	679.2	682.8	686.4	690.0	693.6	697.3	700.9	704.6	708.3	712.0	715.7	719.5	723.2
2	<b>Transmission Losses</b>	39.0	38.8	38.6	38.6	38.6	38.6	38.5	38.4	38.4	38.5	38.6	38.4	39.0	39.5	40.0
3	<b>Net CIP Demand Reduction</b>	12.3	23.1	32.8	38.7	44.7	51.4	58.2	64.9	70.9	74.2	77.4	89.2	80.1	72.6	66.2
4	<b>Total Forecasted Load</b>	698.8	691.4	685.1	682.7	680.3	677.1	674.0	670.8	668.4	668.9	669.5	661.2	674.6	686.3	697.1
5	<b>MISO Coincident Factor</b>	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%
6	<b>Coincident Load</b>	635.9	629.2	623.4	621.3	619.1	616.2	613.3	610.4	608.2	608.7	609.2	601.7	613.9	624.6	634.3
7	<b>MISO Planning Reserve</b>	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%
8	<b>Total Obligation</b>	695.6	688.3	682.0	679.6	677.3	674.1	671.0	667.8	665.4	666.0	666.5	658.2	671.6	683.3	694.0
9	<b>Coal</b>	365.5	365.5	365.5	365.5	365.5	365.5	365.5	365.5	365.5	365.5	365.5	365.5	365.5	365.5	365.5
10	<b>Natural Gas / Oil</b>	344.3	344.3	344.3	344.3	344.3	344.3	344.3	344.3	344.3	344.3	344.3	286.7	286.7	286.7	286.7
11	<b>Wind</b>	82.3	82.3	82.3	82.3	82.3	82.3	82.3	78.7	78.7	78.7	78.7	74.0	74.0	74.0	74.0
	<b>Solar</b>	0.0	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3
	<b>Hydro</b>	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
12	<b>Purchased*</b>	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
13	<b>Load Management</b>	16.0	16.0	16.0	17.0	18.0	19.0	20.0	21.0	22.0	23.0	24.0	25.0	26.0	27.0	28.0
14	<b>Total ZRCs</b>	819.1	831.4	831.4	832.4	833.4	834.4	835.4	832.8	833.8	834.8	835.8	774.4	775.4	776.4	777.4
<i>*Co-generation, Co-Op Shared, and WAPA</i>																
15	<b>Net (Line 14 - Line 8)</b>	123.5	143.0	149.3	152.7	156.1	160.2	164.4	164.9	168.3	168.8	169.3	116.2	103.9	93.2	83.5

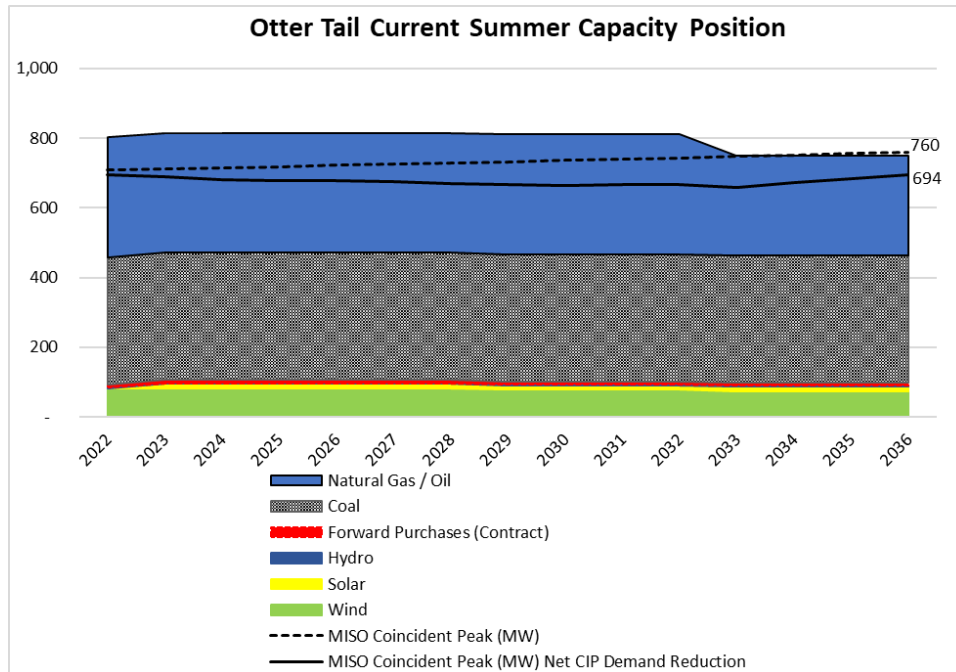
### Implementation Information

The data in Table 3-2 above and Figure 3-1 below illustrate Otter Tail’s capacity position prior to plan development in 2021.<sup>18</sup> The decrease in Total ZRCs in 2033 is due to the end of depreciable lives for a number of our peaking plants. The table shows that we have adequate capacity for the planning period.

Figure 3-1 depicts the Table 3-2 data and includes a solid black line representing Otter Tail’s current forecast obligation to customers, which incorporates energy efficiency savings. Figure 3-1 also includes a dotted black line that shows what Otter Tail’s forecast obligation would be if we recognized no new energy efficiency.

<sup>18</sup> Based on the existing resources as of May 31, 2021.

**Figure 3-1: Current Capacity Resources and Reserve Obligation 2022-2036 (MW)**



As shown in Figure 3-1, for 2036, forecasted CIP Demand Reduction is expected to reduce Otter Tail’s 2036 summer capacity position from 760 MW to 694 MW, approximately nine percent.

### 3.4 Resource Plan Development

The software model we use for resource plan modeling is EnCompass, which replaced the Strategist model used for our 2016 Plan.<sup>19</sup> Otter Tail’s long-range peak demand and energy forecasts were incorporated into the EnCompass database, along with the supply-side and demand-side resources available to the Company over the course of the study period.

EnCompass was then used to develop a series of least-cost resource plans. We defined the objective function as minimizing total utility costs (i.e., a zero externality scenario) and, for Minnesota, minimizing total societal costs (i.e., an externality value scenario).

<sup>19</sup> Otter Tail first used the EnCompass software in previous Minnesota proceedings that were approved by the Commission including its forecasted 2021 Energy Adjustment Rider rates in Docket No. E017/AA-20-462.

The EnCompass software develops an optimized resource plan for each scenario for the time period 2022 through 2036. Scenarios were developed, including evaluation of sensitivities that varied load growth, altered natural gas and energy market prices, adjusted the MISO capacity requirement, and applied externalities.

### 3.5 New 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 new resources we evaluated. Table 3-3 provides a list of the alternatives evaluated within the EnCompass model.

**Table 3-3: List of Resource Alternatives Included in EnCompass 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	Generic 248 MW nameplate capacity frame type simple cycle unit
Wind	50 MW nameplate capacity utility-scale wind resource. Generic options as well as specific replacement and surplus interconnection options are available.
Solar	25 MW nameplate capacity utility-scale solar resource. Generic options as well as specific replacement and surplus interconnection options are available.
Stand Alone Battery Storage	Generic 25 MW lithium-ion battery storage resource
Paired Battery Storage	10 MW lithium-ion battery storage resource paired with a 25 MW solar installation

### 3.6 Preferred Resource Plan

Table 3-4 shows preferred 15-year resource plan which includes a request for authority to add dual fuel capability at Astoria by 2026, add 150 MW of solar in 2025, add 100 MW of wind in 2027, start the process of withdrawing from ownership in Coyote Station, and add 50 MW of solar in 2033. The Preferred Plan appropriately addresses customer needs and balances other objectives described in this filing, including, most importantly, low-cost and reliable service for our customers.

**Table 3-4: Preferred Resource Plan Summary<sup>20</sup>**

Resource Plan (MW) - Based on Nameplate ratings	
2022	
2023	
2024	
2025	150 MW Surplus Interconnection Solar
2026	Dual Fuel at Astoria
2027	100 MW Surplus Interconnection Wind
2028	Anticipated Withdrawal from Coyote 149 MW
2029	
2030	
2031	
2032	
2033	50 MW Replacement Solar
2034	
2035	
2036	

Figure 3-2 below shows the capacity resource additions along with existing resources over the study period. Figures 3-3 (with externalities) and 3-4 (no externalities) below show the energy contributions by fuel category for 2022-2036 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 3-3 and 3-4, the Purchases category (light blue) is primarily comprised of day-ahead market opportunity purchases (where we can take advantage of market prices that are lower than our generation costs), while the Forward Purchases (yellow) represents longer term bilateral contractual purchases.

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<sup>20</sup> Otter Tail includes three categories for wind and solar projects: (1) generic wind resources require a new generation site, (2) surplus interconnection wind may be added alongside an existing generating facility where the generation of both resources does not exceed the existing interconnection amount of the original facility, and (3) replacement interconnection wind resources reuse the existing interconnection rights of an existing resource that is retiring.

Figures 3-2 through 3-8 below note the significant demand and energy contributions from Otter Tail’s DSM and energy efficiency programs, which reduce our capacity requirements by 54 MW in 2025 and by 94 MW in 2036. These reductions have saved our customers significant costs. We have approved energy efficiency and DSM programs in Minnesota and South Dakota, and all customers in our three-state service area have benefitted from cost reductions driven by DSM energy efficiency efforts.

**Figure 3-2: Preferred Plan Capacity Resources and Reserve Obligation 2022-2036 (MW)**

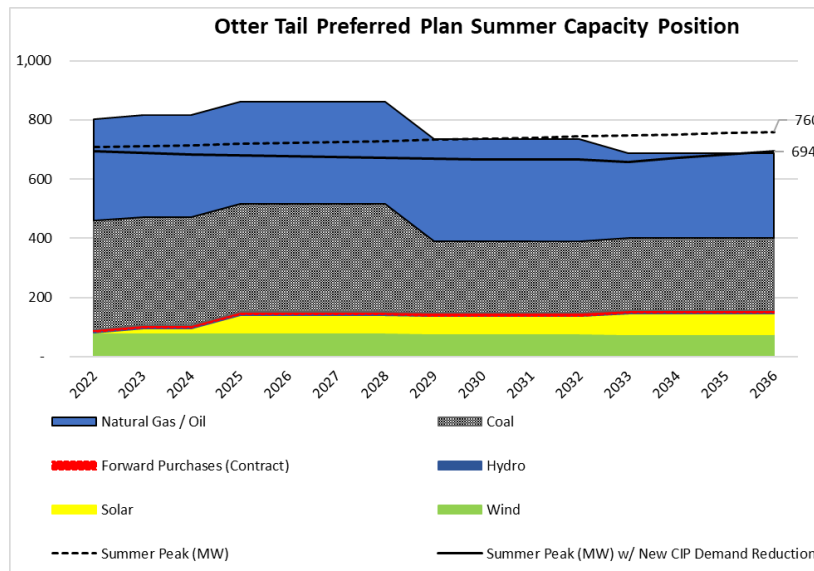


Figure 3-3: Preferred Plan Energy Resources and Requirements with Externalities Applied 2022-2036 (GWh)

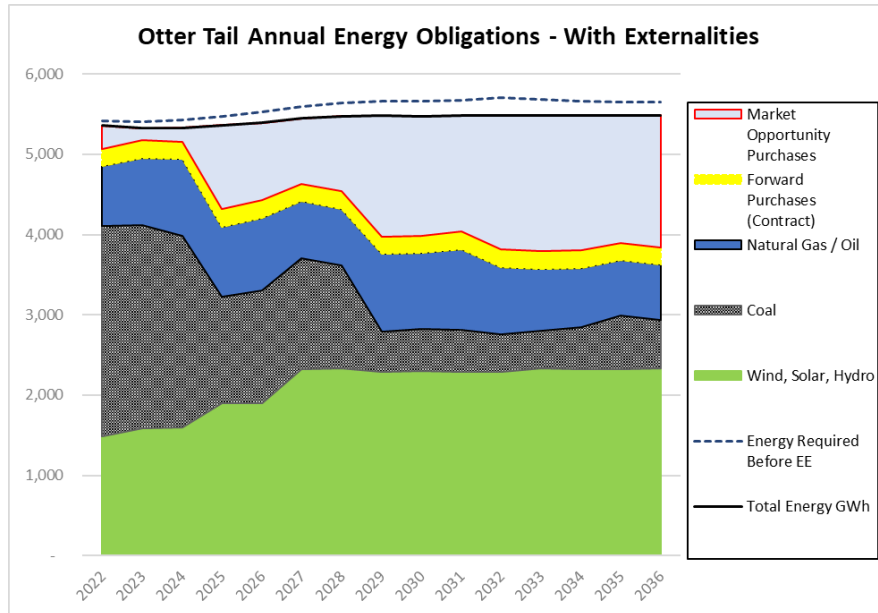
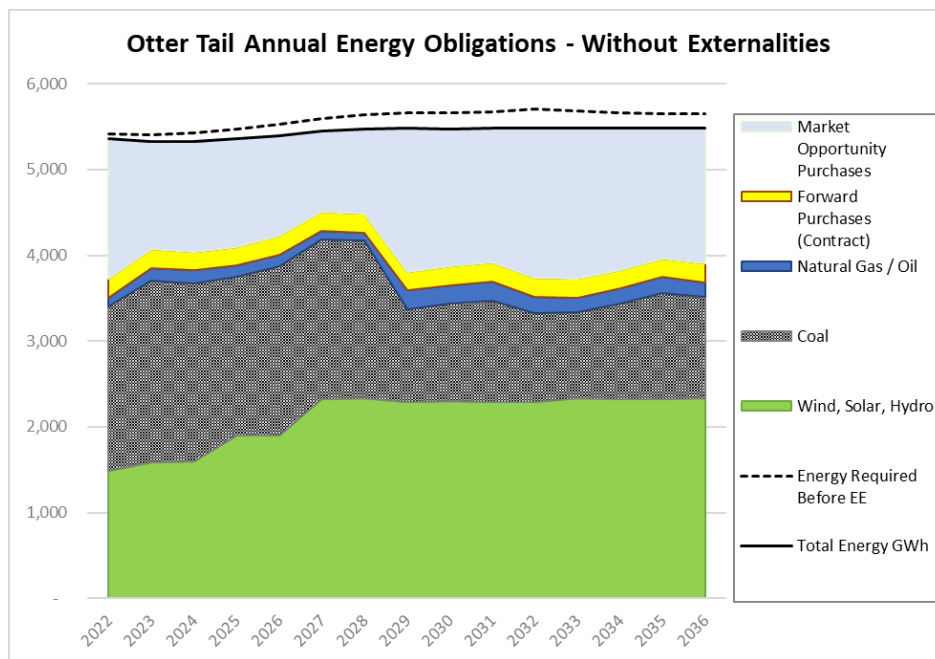
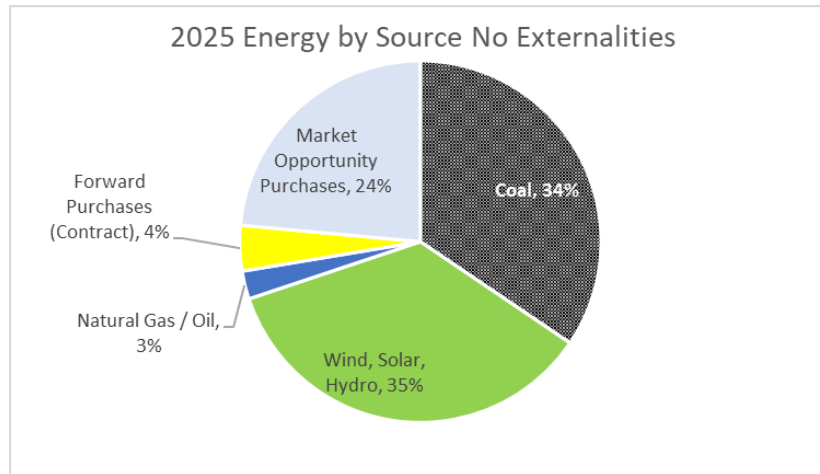


Figure 3-4: Preferred Plan Energy Resources and Requirements without Externalities Applied 2022-2036 (GWh)

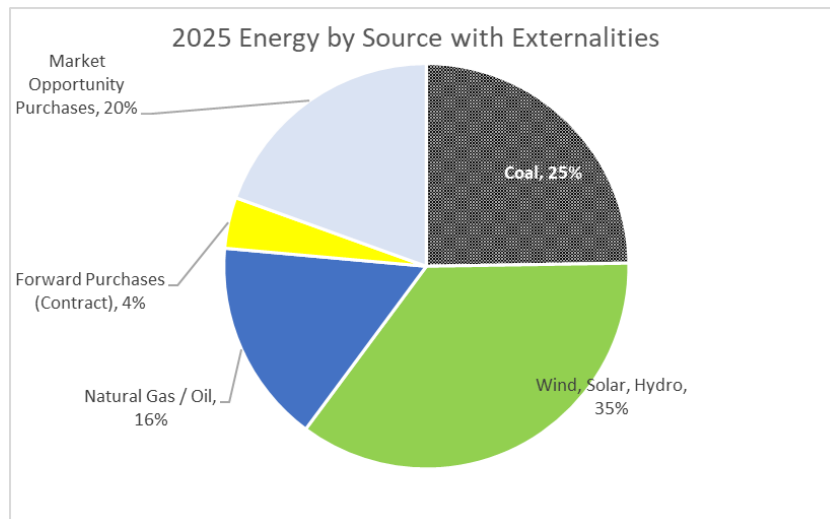


Figures 3-5 and 3-6 shows the projected energy contribution by fuel category for the year 2025.

**Figure 3-5: 2025 Energy by Fuel Source No Externalities**



**Figure 3-6: 2025 Energy by Fuel Source with Externalities**



Figures 3-7 and 3-8 provide the forecasted energy contribution by fuel category for the Preferred Plan for the year 2036 with and without externalities.

Figure 3-7: Preferred plan 2036 Energy by Fuel Source No Externalities

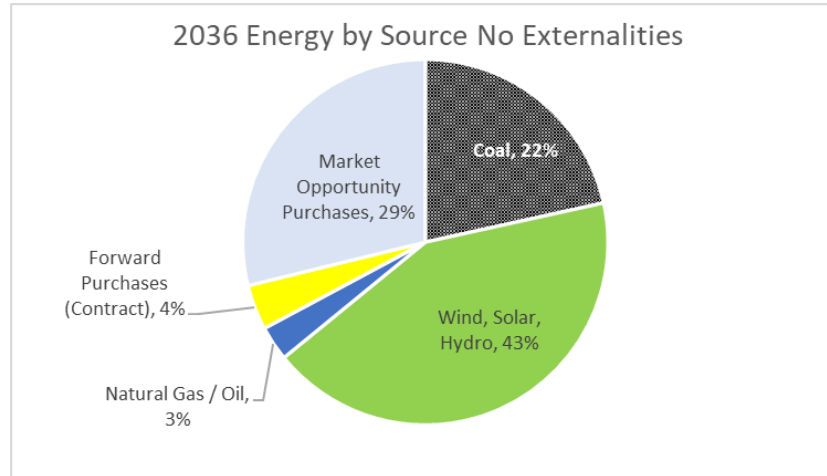
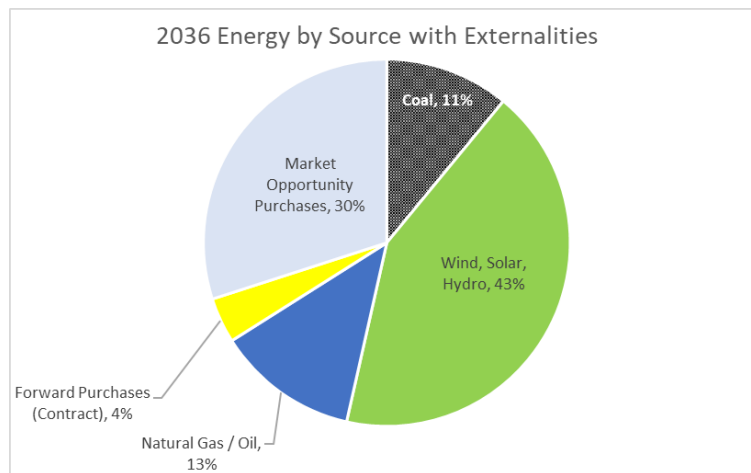


Figure 3-8: Preferred plan 2036 Energy by Fuel Source with Externalities



For each sensitivity, this filing includes six EnCompass modeling runs to provide insight into the impacts of Otter Tail continuing with its interest in Coyote Station and the impacts of Otter Tail pursuing alternatives to Coyote Station:

- 1) Withdraw from Coyote Station December 31, 2040: Otter Tail maintaining its interest in Coyote Station until 2041 (the plant's assumed retirement date based on its remaining depreciable life):

- 2) Withdraw from Coyote Station December 31, 2028: Otter Tail withdrawing from Coyote at the end of 2028 (the end date for the second Regional Haze planning period): and
- 3) Withdraw from Coyote Station December 31, 2026: Otter Tail withdrawing from Coyote at the end of 2026 (for analysis purposes only -- this date assumes the earliest possible date the Company could conceivably withdraw under the plant ownership agreement among the Coyote Station co-owners – a decision that would need to be made prior to the issuance of any Commission order).

Each of these sensitivities were modeled both with and without environmental externalities. In all but two<sup>21</sup> of 82 of the withdrawal sensitivities, the least cost strategy is withdrawal from Coyote Station before the end of the plant’s current depreciable life in 2041.

**Table 3-5: Base Case with and without Externalities**

	Base Case - no externalities			Base Case - with externalities		
	Withdraw 2040	Withdraw 2028	Withdraw 2026	Withdraw 2040	Withdraw 2028	Withdraw 2026
2022						
2023						
2024						
2025						
2026	25 MW Sur Solar	100 MW Sur Solar	100 MW Sur Solar	125 MW Sur Solar	125 MW Sur Solar	125 MW Sur Solar
2027						
2028						
2029						
2030						
2031						
2032						
2033						
2034						
2035		50 MW Rep Wind 50 MW Sur Wind	50 MW Rep Wind 50 MW Sur Wind	100 MW Sur Solar 50 MW Gen Wind 50 MW Gen Wind 50 MW Sur Wind	100 MW Sur Solar 50 MW Gen Wind 50 MW Gen Wind 50 MW Sur Wind	100 MW Sur Solar 50 MW Gen Wind 50 MW Gen Wind 100 MW Sur Wind
2036						
NPVRR	\$ 2,515,096	\$ 2,466,554	\$ 2,460,904	\$ 2,971,847	\$ 2,864,875	\$ 2,855,293

<sup>21</sup> In the 2028 and 2026 withdrawal from Coyote sensitivity with natural gas and market energy prices 100 percent above forecast, the model calculates a net present value revenue requirement that are approximately \$2.4 million and \$1.1 million respectively more expensive than Otter Tail maintaining its interest in Coyote until its assumed retirement date.

**Table 3-6: NPV Revenue Requirement Base Case and Preferred Plan**

	Withdrawal from Coyote in 2028			
	No Externalities		With Externalities	
	Base Case	Preferred Plan	Preferred Plan	Base Case
2022				
2023				125 MW Sur Solar
2024				
2025		150 MW Sur Solar	150 MW Sur Solar	100 MW Sur Solar 50 MW Gen Wind
2026	100 MW Sur Solar			50 MW Gen Wind
2027		100 MW Sur Wind	100 MW Sur Wind	
2028				50 MW Sur Wind
2029				100 MW Sur Wind
2030				
2031				
2032				
2033		50 MW Rep Solar	50 MW Rep Solar	25 MW Rep Solar
2034				25 MW Rep Solar 100 MW Rep
2035	50 MW Rep Wind 50 MW Sur Wind			
2036				
NPVRR	\$ 2,466,554	\$ 2,479,385	\$ 2,909,334	\$ 2,864,875

Based on this analysis, the Preferred Plan is for Otter Tail to withdraw from its ownership interest in Coyote Station by the end of 2028. The only resource addition entering service during the Five-Year Action Plan is 150 MW of solar in 2025 (assuming use of a surplus interconnection at existing generating facility, further described in Section 6 below). This amount of solar is *less* than the sensitivities including environmental externality costs would indicate and *more* than the sensitivities not including environmental externality costs would indicate.

The Preferred Plan represents a balanced and reasonable approach to the challenging task of addressing the concerns of our regulators and varied stakeholders. The Preferred Plan meets all legal requirements and allows the Company to continue providing reliable, low-cost electricity to meet our customers’ requirements.<sup>22</sup>

<sup>22</sup> This includes satisfaction of Minnesota’s Greenhouse Gas Reduction Goals. *See* Appendix A.

### **3.7 Multi-State Jurisdictional Complexity**

Otter Tail is very small, serving just 137,000 customers in its three states. The percentage of Otter Tail’s utility service delivered to each state varies depending on whether demand, energy or the number of customers is measured. Overall our service is approximately 50 percent Minnesota, 40 percent North Dakota and 10 percent South Dakota. Table 3-7 provides approximate 2021 figures for of demand, energy and customer count in each state.

**Table 3-7: Percentage of Otter Tail operations in each of its three states**

	Minnesota	North Dakota	South Dakota
Demand	50%	39%	11%
Energy	54%	36%	10%
Customer count	47%	44%	9%

In all three states Otter Tail serves very small rural towns—the average population of our communities in the three-state region is approximately 400 people.

Continuing to operate as a single, cost-effective multi-state utility is important for our customers and these small communities. Otter Tail is already one of the smallest vertically integrated utilities in the country. To give some perspective, Xcel Energy’s NSP Minnesota subsidiary, through which Xcel serves Minnesota, North Dakota, and South Dakota, is approximately 10 times the size of Otter Tail. Because of this already very small size, splitting Otter Tail into separate and even smaller utility systems would result in harmful inefficiencies and an increased cost of service. The Preferred Plan presented in this filing meets resource planning objectives in each of our jurisdictions, and we feel strongly that it can be supported in all the states we serve, and it has the additional benefit of providing a path for Otter Tail to continue operating with a single integrated system. This current resource plan reflects the execution of the projects approved in our most recent plan and continues the Company down the path of reliable, affordable, and environmentally responsible electric service.

### 3.7.1 Multiple ISOs (SPP & MISO)

Otter Tail has a partial interest in each of Big Stone Plant and Coyote Station. Each of these baseload plants are co-owned and they each operate in two Independent System Operators (ISOs): Southwest Power Pool (SPP) and MISO.

Each of these units was constructed before the time of Regional Transmission Organizations (RTOs), ISOs and centrally dispatched energy markets. They were constructed as “baseload units,” which means that they were conceived, designed, and constructed with the expectation that they would form the “base” of the owners’ generation portfolios and run consistently for long periods of time without frequent or material variation in output. At that time, each utility expected to operate its generation portfolio as a single unit and only vary the portfolio’s output generally with variation in its customers’ energy usage. There were occasional utility-to-utility sales, and there were also planning pools within regions, but there were no coordinated energy markets and there were no moment-by-moment energy market prices upon which a utility could base its unit dispatch decisions. Most importantly, customers’ usage levels did not vary unpredictably or dramatically and, therefore, managing a portfolio that could match customers’ collective “load shape” was the goal. Baseload units ran most of the time between “minimum” and full output (following customers’ usage from high to low) and peaking units filled in as needed during periods of particularly high usage.

Now, however, with the advent of coordinated region-wide energy markets, there are times when units with greater flexibility can take advantage of changes to regional energy market prices. For example, if a generating unit has the ability to turn on and off, and ramp up and down quickly, the owner can take advantage of rapidly evolving pricing variations—when prices are high, it can dispatch the unit and use it to prevent high market prices from being passed to its customers, or it can sell the off-take into the market for the benefit of its customers; when prices are low, the owner can ramp down the plant and buy low cost energy from the market for its customers’ use. In the markets, the dispatch of units occurs through the coordinated “commitment” and “dispatch” constructs. The unit commitment determines whether the unit is

on or off-line—and can be driven by a market-based signal or determined by the owner. The unit dispatch determines the amount of generation from a unit at a given time in response to whether the unit’s offered cost is above or below the market price. If the market price is above unit cost, the unit is dispatched higher. If the market price is below unit cost, the unit is dispatched lower.

As indicated, baseload units like Big Stone Plant and Coyote Station were not conceived or designed with the intent of flexibly dispatching into rapidly variable energy markets. Their design requires that when they run, they run at a minimum level, which historically was often something close to half of their full output. Since original operation, plant staff has worked to safely reduce the minimum load levels to approximately 25-35 percent of full load level. From their minimum level of output up to their full output potential, they are relatively flexible, but starting and stopping such units takes substantial lead time and therefore owners have generally “committed” these generators in times when they perceive exposure to energy market prices. These design limitations have not historically been a concern (again, due to there not being a coordinated energy market and due to energy prices being higher than the price of operating these units), but, with the advent of energy markets, and periods of low prices, increased flexibility would give the owners of such units greater market opportunities to lower costs for their customers. With this in mind, Otter Tail, other owners of baseload plants, and other stakeholders have been considering ways to increase the flexibility of baseload units.<sup>23</sup>

Because baseload units require long lead times to “turn on” and to recover when they “turn off,” they have generally been “self-committed” to their minimum load levels. This means that they would run at their minimum levels even when market prices were below their cost of running. This strategy has been intended to prevent their unavailability if market prices were to increase faster than they could be dispatched to respond. By running at minimum, they could serve as a

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<sup>23</sup> For example Otter Tail has discussed this issue and associated challenges in MPUC Docket No. E-999/CI-19-704, *In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities*.

hedge against price volatility. In recent years, however, the owners of some baseload units have been able to remove any “self-commitments” and allow the units to “economically dispatch,” that is, be called upon to run if and when prices exceed their operating costs. This can pose some risk of their unavailability should prices rise unexpectedly, but when markets and loads are relatively low and expected to stay low, this can be a reasonable strategy that may lower overall costs for customers. These strategies for baseload units are relatively new, and Otter Tail and the owners of Big Stone and Coyote have recently moved the units to economic dispatch in many hours. It is an example of how strategies for increasing baseload flexibility are considered in response to new market opportunities.

In addition to the technical and mechanical limitations that affect the flexibility of baseload units, Otter Tail’s partial interests in Coyote Station and Big Stone Plant are also subject to additional coordination-related limitations because the plants are jointly owned. Those limitations are described below. While this section focuses on operational limitations due to co-ownership, it is also important to keep in mind that Otter Tail’s customers have benefitted substantially from co-ownership of these two baseload plants. For example, the co-ownership has allowed Otter Tail and the other owners to achieve significant economies of scale that would not have been possible if they had each built their own separate stand-alone generating units.

### **Coyote Station**

Coyote Station is co-owned by Otter Tail (35 percent), Northern Minnesota Municipal Power Agency (represented by Minnkota Power Cooperative) (30 percent), Montana-Dakota Utilities Co. (MDU) (25 percent), and Northwestern Energy (10 percent). Coyote Station was constructed between the years 1980 and 1983, and it had a depreciable life that assumed retirement in 2016.<sup>24</sup> The depreciable life was extended at various times during the life of the plant, the last time being in 2013, when the depreciable life was extended by nine years, from

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<sup>24</sup> See MPUC MN Docket E017/D-83-2.

2032 to 2041.<sup>25</sup>

Otter Tail, Minnkota, and MDU operate within the MISO market; Northwestern Energy operates within the SPP market. The SPP and MISO markets do not have mechanisms for inter-ISO coordination of commitment status of jointly owned units that partially operate in each ISO. Furthermore, both markets model partial shares of jointly owned units as individual, separate, and distinct generators. If each partner share of the unit were to be offered on an economic commitment basis, in many hours only a portion of the entire unit would be dispatched. From a practical standpoint, however, since the plant is one physical generator, dispatch of a single owner's share of the plant will result in the dispatch of all owners' shares of the plant. Furthermore, from a co-owner contractual standpoint, if one owner calls on its share of the plant, all owners are required to take their share of the total minimum output.

### **Big Stone Plant**

Big Stone is co-owned by Otter Tail (53.9 percent), Montana Dakota Utilities Co. (22.7 percent), and Northwestern Energy (23.4 percent). Big Stone Plant, located near Milbank, South Dakota, is a 475 MW coal plant burning sub-bituminous coal from the Powder River Basin. It was retrofitted with an Air Quality Control System (AQCS) in 2015. The AQCS is comprised of state-of-the-art controls for SO<sub>2</sub>, NO<sub>x</sub>, and mercury. Big Stone has similar market operating complexities as Coyote. Big Stone straddles both the MISO and SPP wholesale energy markets and can be dispatched by either ISO. Big Stone contractual obligations require partners to take their minimum share of the plant whenever another owner calls for dispatch.

Both Big Stone and Coyote Station are currently capable of being placed on economic commitment. The Big Stone co-owners meet periodically to determine if Big Stone should be placed into economic commitment or must-run status based on market conditions. Our intention

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<sup>25</sup> *In the Matter of Otter Tail Power Company's Request for Approval of its Five Year Depreciation Study*, MPUC Docket No. E017/D-13-795, Order (Apr. 7, 2014).

is to keep it on economic commitment in the future. The EnCompass sensitivities included in this IRP generally have the Big Stone capacity factor from around 20 percent to 60 percent depending on the sensitivity. This range is far below the 85-90 percent capacity factor of traditional baseload coal plants.

There are several differences between Coyote Station and Big Stone Plant. Big Stone is a delivered fuel plant where we only pay for coal that we take—as contrasted with Coyote where we have a fixed component in the fuel cost. Big Stone’s AQCS, with capital intensive state-of-the-art SO<sub>2</sub> and NO<sub>x</sub> controls, is already in place. While the Company would have sufficient capacity resources after withdrawal from Coyote Station, replacing Otter Tail’s interest in Big Stone would require the addition of another large dispatchable resource (likely a gas CT). Also, Big Stone has recently been operated more frequently on economic dispatch, which reduces the hours it operates in a market below its production costs.

### **3.8 Resilience**

Historically, resource plans have been focused on energy and capacity metrics to assess a utility’s ability to produce electricity cost-effectively and reliably for its customers. With changes in the marketplace, however, concepts of resilience have grown in significance. These concepts were highlighted during events such as the 2014 Polar Vortex and the 2021 Winter Storm Uri, where renewable generation was at times not available, natural gas availability was at times limited, and electricity market prices and natural gas prices were at times extremely high. While Otter Tail had limited exposure during these events, some other utilities experienced very concerning service interruptions and high fuel and electricity bills.

While resiliency is not a defined term as applied to generation resources, in the context of cold or hot weather events (mentioned above) we identify three characteristics of a resilient resource:

1. Dispatchability – A generation resource is dispatchable if it can reasonably be expected to generate when called upon.

2. **Reliable Fuel Supply** – A generation resource has a more reliable fuel supply when fuel is available onsite, when onsite fuel storage is possible or there is more than one reasonable means for fuel delivery.
3. **Energy Price Protection** – A generation resource has more energy price protection if the availability and cost of fuel for generation can be managed during volatile market conditions.

Table 3-8 below provides a high-level summary of what resiliency factors Otter Tail’s current and potential future generation resources possess. The resources are also listed in order of most resilient to least resilient.

**Table 3-8: Generation Resources and Resiliency Factors**

<b>Generation Resource</b>	<b>Dispatchable</b>	<b>Reliable Fuel Supply</b>	<b>Energy Price Protection</b>	<b>Ranking Factors</b>
1. Coal Generation	Yes	Yes	Yes	Fuel storage capability and low volatility in fuel price
2. Dual Fuel Simple Cycle	Yes	Yes	Yes	Fuel oil storage capabilities, multiple fuel sources, fuel oil storage protects from volatility in natural gas market
3. Fuel Oil Simple Cycle	Yes	Yes	Yes	Fuel oil storage capability protects from volatility in natural gas market
4. Natural Gas Simple Cycle	Yes	No	No	Without dual fuel capabilities, no storage capability, dependence on single natural gas supply pipeline, no protection from volatile natural gas markets and relatively close correlation in gas and electricity markets
5. Solar	No	No	No	Ranked higher than wind due to generation occurring during peak loads, and while not dispatchable, no significant correlation to energy and natural gas markets
6. Wind	No	No	No	No fuel storage and relatively close inverse correlation between wind generation operating and energy and gas market prices

In addition to considering individual resource resiliency, Otter Tail also considers the resiliency of its entire generation portfolio. This includes the diversity of its portfolio and the portfolio's ability to withstand significant unforeseen events. One question at the heart of resiliency is the extent to which wind and solar generation may be relied upon during a significant event. As shown in Table 3-8 above, from an individual generation resource level, wind and solar are not dispatchable and have other features considered less resilient than dispatchable resources.

Therefore, the analysis of market exposure detailed below conservatively assumes no contribution from wind and solar resources. From an overall generation portfolio perspective, however, it is reasonable to expect solar and wind resources to provide some generation in many of the hours of high loads. In terms of our expectations for actual operation, some portion, if not all, of the "market exposure" identified below is expected to be covered by Otter Tail's variable resources. The addition of new resources and the removal of other resources, namely Coyote Station in the Preferred Plan, requires Otter Tail to look at what opportunities it is taking advantage of and whether it is creating potential resiliency problems for the portfolio.

While our portfolio has performed exceptionally well, even during significant events, maintaining and enhancing the overall resiliency of the portfolio is an important consideration. One cost effective option to maintain and enhance resiliency is adding dual fuel capability at Astoria Station, which would allow Otter Tail to use natural gas supplied by the current pipeline as the main source of fuel and use stored fuel oil during rare instances of pipeline unavailability or volatile natural gas markets. Otter Tail currently operates its Solway combustion turbine in similar fashion.

The capital cost for the addition of dual fuel capability at Astoria is preliminarily estimated at **[PROTECTED DATA BEGINS... ..PROTECTED DATA ENDS]** with a corresponding annual O&M cost of **[PROTECTED DATA BEGINS... ..PROTECTED DATA ENDS]**

A reasonable schedule would be to add dual fuel capability in conjunction with Astoria’s first inspection in 2026. This would allow for replacement of any combustion turbine components necessary for potential use of fuel oil in parallel with the inspection. Other necessary equipment could be installed independent of plant operations either before or after the scheduled 2026 minor inspection. Otter Tail is moving forward with engaging an engineering firm and initiating dialogue with the combustion turbine supplier to develop a more refined cost estimate and preliminary schedule. This information will be used to support any decisions on moving forward with the addition of dual fuel capability.

Given the three criteria listed above for assessing resiliency, Table 3-9 compares Otter Tail’s total current resilient generation resources to what the Preferred Plan resilient generation would be in 2030, assuming dual fuel capability is added at Astoria. Controllable load is also included in the list of resilient resources because the net result of a reliable load control system and a resilient generator is similar in terms of reducing market exposure during peak load situations. Two separate values have been given for summer and winter generation capabilities since Otter Tail’s combustion turbines and load control resource have varying output capabilities depending on the season.

**Table 3-9: Resilient Generation**

	<b>Current Winter</b>	<b>Current Summer</b>	<b>Preferred Plan Winter</b>	<b>Preferred Plan Summer</b>
Big Stone	256	256	256	256
Coyote	149	149	0	0
Astoria	0	0	285	245
Solway	46	43	46	43
Oil Peakers	74	69	74	69
Controllable Load	115	20	115	20
<b>Total (MW)</b>	<b>640</b>	<b>537</b>	<b>776</b>	<b>633</b>

Figures 3-9 and 3-10 compare the resilient generation levels listed in Table 3-9 to the forecasted hourly load in 2022 and 2030. The hourly load has been sorted by season and then sorted from

high to low to show the quantity of hours during which load would be expected to exceed dispatchable/fuel secure/price-protected generation capabilities.

In 2022 the forecasted market exposure is roughly 130,000 MWh, or 10.6 percent of Otter Tail's total load. Looking ahead to 2030, Otter Tail anticipates total market exposure to decrease to just 29,500 MWh, or 2.4 percent. As noted above it is reasonable to expect solar and wind resources to provide some generation in many of the times total load exceeds resilient generation. In terms of our expectations for actual operation, some portion, if not all, of the forecasted market exposure is expected to be covered by Otter Tail's variable resources.

The forecasted market exposure is not a ceiling for Otter Tail's market purchases. Actual market purchases will likely be higher due to Otter Tail's ability to take advantage of low market prices as those opportunities arise.

Taking advantage of market opportunity is an important tool that has allowed Otter Tail to keep rates low. The distinction between market exposure and market opportunity is an important point that must be understood. *Market exposure* can be thought of as the times when total load exceeds total resilient generation potential. *Market opportunity* is the times when market energy prices are lower than the variable energy costs of our dispatchable resources. In times of market opportunity most of our dispatchable resources can be ramped down or completely curtailed, which reduces customer cost. The important factor to remember is that just because the dispatchable units are ramped down to minimums or offline completely does not mean they are unavailable to cover Otter Tail's load, should market conditions change.

Figure 3-9 (below) compares Otter Tail's 2022 forecasted hourly load to existing resilient generation capabilities. The blue line in Figure 3-9 depicts OTP's winter and summer load duration curves. A load duration curve illustrates the total amount of load in each hour of the season arranged in order of magnitude. From it, we can consider the maximum amount of load we need to be prepared to serve over the course of a year. The grey line in Figure 3-9 is drawn

to show the level of our resilient generation resources. The purpose of this figure is to show the relationship between resilient generation capabilities and forecasted hourly load and potential market exposure if variable resources were not generating at the time load exceeded the resilient generation capabilities. As shown in the figure, Otter Tail projects that 10.6 percent of its overall load will be exposed to market energy prices assuming no variable resource generation in 2022.

**Figure 3-9: 2022 Forecasted Load Relationship with Resilient Generation**

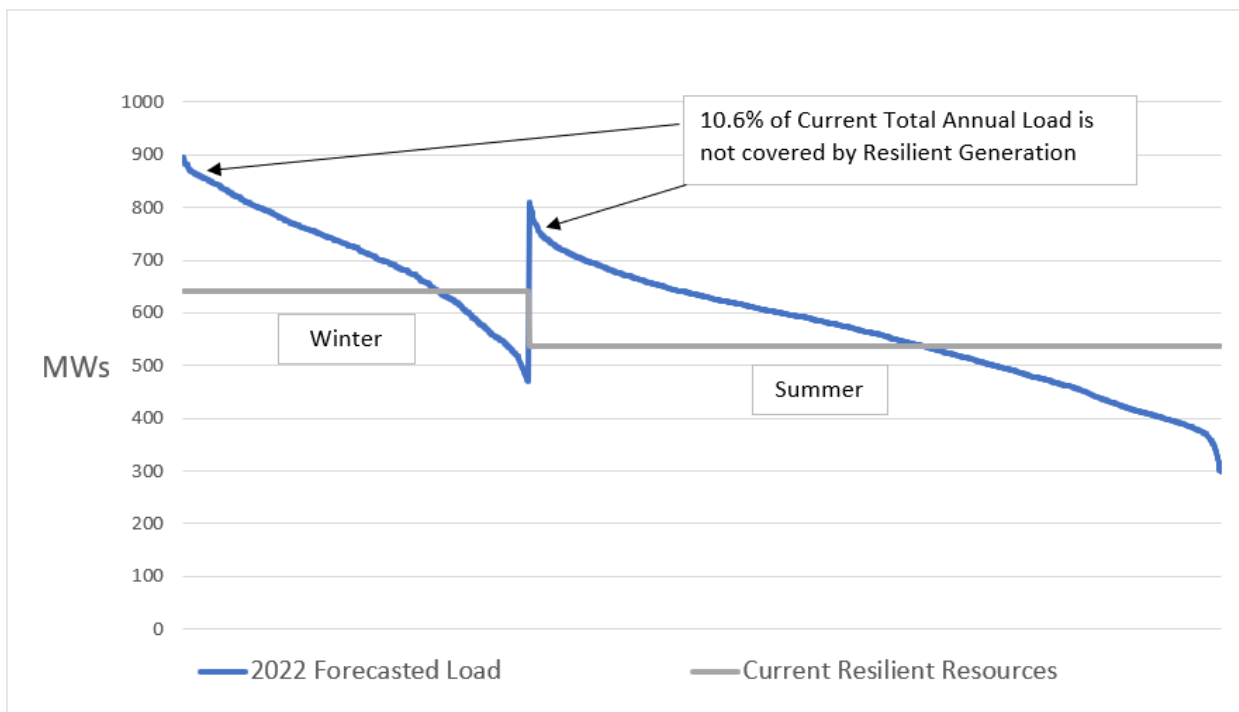
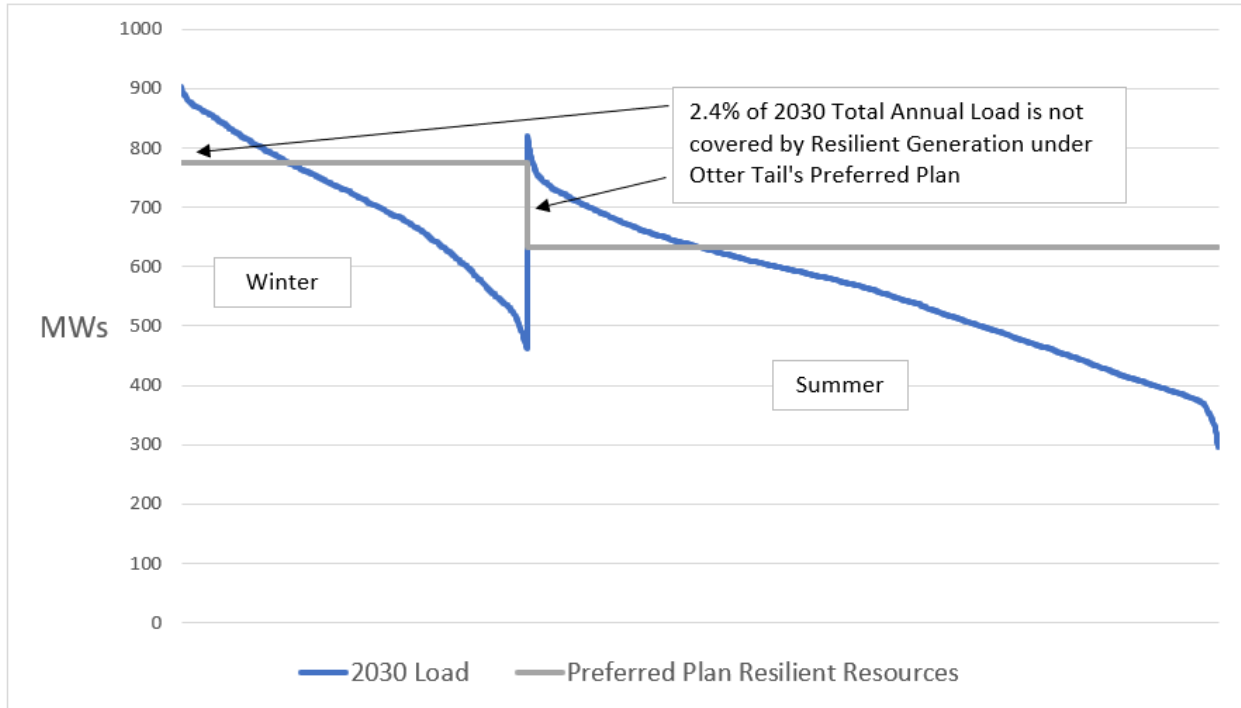


Figure 3-10 similarly compares Otter Tail’s 2030 forecasted hourly load with the resilient generation available under the Preferred Plan. As noted by Figure 3-10 the Preferred Plan reduces the amount of load not backed by resilient generation from 10.6 percent to only 2.4 percent.

Figure 3-10: 2030 Forecasted Load Relationship with Resilient Generation (Preferred Plan)



Assuming for analysis that Otter Tail did not add dual fuel at Astoria Station then Figure 3-10 does not fully capture the total market risk associated with the Preferred Plan. The reason for this is because natural gas units tend to be the marginal units in the MISO energy market. This means that they set the price based on their variable energy cost. High market price situations are usually accompanied (or caused) by high natural gas prices. Relying on natural gas units to serve load during volatile market situations will not provide adequate price protection for customers unless those units have the ability and fuel on hand to switch to an alternate fuel source when natural gas prices are elevated. There is also the potential in extreme situations that natural gas might not be available, in which case the unit would be forced offline and unable to generate when it is needed most. This makes the addition of dual fuel capability at Astoria a particularly attractive resiliency enhancement.

If Astoria Station is removed from the list of Preferred Plan resilient resources in Table 3-9, total market risk exposure increases from 2.4 percent to 30.4 percent in 2030. To reduce the risk associated with natural gas generation, Otter Tail currently uses forward energy purchases to hedge against the potential for high natural gas prices in the winter months. Recently the forward energy purchase price points have been competitive due to the low market prices seen in the last handful of years. This is an adequate solution for the time being but adding dual fuel capability at Astoria would mitigate the need for forward energy hedge which Otter Tail finds desirable to reduce exposure to the forward energy purchase market.

### **3.9 Coyote Station**

#### **Withdrawing From Coyote Station: Process and Key Considerations**

Otter Tail is requesting approval to commence the process of withdrawing from its ownership interest in Coyote Station with the intent to complete withdrawal by 2028. By withdrawal, the Company means that it is seeking to end its ownership and role in operating the facility in a manner that is both least-cost to Otter Tail's customers and least-impactful to other plant stakeholders, including the co-owners. Withdrawing from Coyote Station will be complex. The Company must address the concerns of other stakeholders, including its co-owners, the owner of the adjacent lignite coal mine, our employees, and the community in and around Beulah, North Dakota for whom the power plant is such an important source of good jobs and tax revenue.<sup>26</sup> There are also uncertainties. Nevertheless, it is Otter Tail's commitment to plan for and pursue courses of action that benefit our customers through low-cost reliable electricity. Our analysis shows that the customer benefits of Otter Tail's withdrawal are compelling. For this reason, the Company is seeking permission to begin the withdrawal process with the intent of ending its involvement in Coyote Station by 2028. Our proposal provides us with sufficient lead time to obtain clarity on many issues necessary to prudently withdraw from Coyote Station.

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<sup>26</sup> The Company notes that decisions involving the future of other jointly-owned coal plants around the country have been difficult. Notable examples include Public Service Company of New Mexico's proposed departure from the Four Corners facility in New Mexico and litigation between co-owners of the Colstrip plant in Montana.

### Coyote Station Overview

Coyote Station is a 428 MW, lignite fueled, mine-mouth generating facility located near Beulah, North Dakota.<sup>27</sup> Since entering service in 1981, Coyote Station has been a co-owned generation plant with each co-owner owning an undivided interest in the entire plant as provided in Table 3-10 below:

**Table 3-10: Coyote Station Ownership Percentage**

<b>Coyote Owners</b>	<b>Ownership Percentage</b>	<b>ISO Membership<sup>28</sup></b>
Otter Tail Power Company	35%	MISO
Northern Municipal Power Agency (Minnkota Power Cooperative)	30%	MISO
Montana Dakota Utilities Co.	25%	MISO
Northwestern Energy	10%	SPP

The joint ownership of Coyote Station is governed by the Agreement for Sharing Ownership of Generating Unit No. 1 (Plant Ownership Agreement) and subsequent amendments, which define the co-owners' rights and responsibilities and the processes by which decisions are made. Otter Tail is the operating agent for the Plant and our employees operate the plant for Otter Tail and the other co-owners.<sup>29</sup> Generally, the Plant Ownership Agreement provides that decisions concerning the plant require the concurrence of (a) owners having ownership shares of more than 50 percent of the plant *and* (b) at least three owners, although some major decisions require concurrence of all the owners. Necessarily, this structure has promoted collaborative decision-making. Importantly, as of January 1, 2022, the Plant Ownership Agreement also permits an owner to terminate the agreement upon five years written notice.

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<sup>27</sup> There are six mine mouth generation facilities operating in North Dakota. Coyote Station is the only mine-mouth generating facility that falls under MPUC's regulation.

<sup>28</sup> As noted above the SPP and MISO markets do not coordinate the commitment nor the dispatch of jointly owned units.

<sup>29</sup> Otter Tail has been the operating agent for Coyote Station since July 1, 1998. In that capacity it provides all the personnel necessary to operate the plant. There are currently 80 Otter Tail employees working at Coyote Station.

Coyote Station is a mine mouth generating facility, meaning that it was conceived, sited, designed, and constructed to have a long-term, integrated relationship with an immediately adjacent mine serving the plant. In that regard, Coyote Station obtains all of its fuel requirements under a Lignite Sales Agreement (LSA) with Coyote Creek Mining Company, L.L.C, a subsidiary of The North American Coal Corporation.<sup>30</sup> The LSA recognizes that Coyote Station and the mine are integrated, with the mine existing to serve Coyote Station. Importantly, because of this structure the LSA is designed to ensure an equitable relationship between buyer and seller. The term of the agreement extends to the end of 2040, unless terminated earlier, and therefore, for rate making purposes, the depreciable life of Coyote Station has been extended as well.<sup>31</sup>

Coyote Station has served Otter Tail well. Although market conditions have changed and there are now significant advantages to having greater control over when a generation resource is dispatched, the development of jointly owned coal generation plants was once common in the electric utility industry (particularly in this region) and co-ownership of Coyote Station provided Otter Tail with many advantages over the years. Through co-ownership, Otter Tail and its co-owners have achieved better economies of scale than if each utility had built its own separate, smaller generation plant. Otter Tail has also benefited from knowledge sharing and collaboration with its co-owners, and from its successful operation of Coyote Station. Otter Tail's balanced portfolio of rail-delivered coal (Big Stone Plant and the recently retired Hoot Lake Plant) and mine-mouth lignite coal (Coyote Station) have provided fuel diversity important to reliable and affordable electric service. Otter Tail is now seeking to obtain fuel security and system resiliency consistent with the changing marketplace. To that end, Otter Tail is seeking Commission approval to commence the withdrawal from its ownership interest in Coyote Station.

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<sup>30</sup> North American Coal employs approximately 110 personnel at the mine.

<sup>31</sup> *In the Matter of Otter Tail Power Company's Request for Approval of its Five Year Depreciation Study*, MPUC Docket No. E017/D-13-795, Order (Apr. 7, 2014).

### **Withdrawal from Coyote Station**

By withdrawing from its ownership interest in Coyote Station, Otter Tail is ultimately seeking to end its obligations<sup>32</sup> to the co-owners of the plant and the owners of the mine. This includes financial and contractual obligations to these counterparties as well as ending Otter Tail's role as operator of the plant. To accomplish this, Otter Tail must either (1) divest its ownership shares in the plant to another co-owner or third-party who will take on Otter Tail's current obligations, and secure releases from those obligations as necessary in favor of the acquiring party; or (2) terminate the co-tenancy in the plant under the ownership agreement and any contractual obligations that survive the termination of that co-tenancy. Neither option is without risk or potential cost to Otter Tail and its customers. In this section, Otter Tail discusses the overall process and identifies some of the complexities of withdrawal from its 35 percent ownership interest in Coyote Station. Our goal is to withdraw from Coyote Station in a manner that minimizes the impact on stakeholders (including the other co-owners, the community that has hosted the plant for decades and our employees) to the extent reasonably possible. Otter Tail believes that divesting its shares would be the preferred path to take, if a willing and qualified acquirer can be found. That said, Otter Tail will explore termination of the Plant Ownership Agreement if necessary. Otter Tail is seeking the authority to commence its withdrawal from Coyote Station because the two paths of withdrawal present several challenges that will take time to address.

As noted, Otter Tail's preference is to divest its ownership in Coyote to a co-owner or third party, with the acquiring party participating in the plant in conjunction with the existing co-owners and as a counterparty to the LSA, provided that certain necessary consents were secured and conditions met.<sup>33</sup> In this way, all the stakeholders in Coyote Station will have an opportunity to continue operations of the plant and/or plan for an orderly wind down sometime after 2028.

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<sup>32</sup> As noted above Otter Tail serves as the operating agent of the plant. Until and unless Otter Tail withdraws as operating agent, or the owners agree otherwise, this obligation remains.

<sup>33</sup> If the other owners were also interested in selling their interests such that the entire plant could be sold to a third-party, Otter Tail would be open to such a possibility.

However, the market for ownership interests in coal plants is not robust. Consequently, Otter Tail will need time to identify potential acquirers for its ownership share in Coyote Station. In light of market conditions, any divestiture may be at pricing below its undepreciated net book value. If a buyer is found, Otter Tail intends to be creative in structuring a divestiture transaction; Otter Tail, however, would need regulatory support and assurance that it would be able to recover the costs and liabilities that such a divestiture transaction would require Otter Tail to undertake. Having until 2028 to withdraw will provide Otter Tail with the time it needs to seek out buyers or pursue alternative paths to withdrawal.

Absent a willing and qualified buyer, and withdrawal from Coyote Station continuing to be the most prudent course of action, Otter Tail could give notice by the end of 2023 to terminate the Plant Ownership Agreement in late 2028. Termination of the Plant Ownership Agreement is permitted by (a) agreement among *all* the co-owners, with a mutually agreed-upon termination date, or (b) by Otter Tail (or any co-owner) upon not less than five years advance written notice. Otter Tail notes, however, that co-ownership agreements of this type and vintage never truly contemplated the details of cessation of operation of these large baseload plants since at the time they were some of the most economic sources of generation available. Consequently, the Plant Ownership Agreement provides relatively few details on how to wind down operations to cease operating by the end of 2028 should the agreement be terminated.

As discussed further below, there may be additional clarity on Regional Haze Rule compliance obligations that could impact the plans of each of the co-owners. If material capital investments are required to comply with the Regional Haze Rule by 2028, it is conceivable that the co-owners could mutually agree to terminate the Plant Ownership Agreement and provide for an orderly wind-down of plant operations and disposition of plant assets. A withdrawal date in 2028 helps provide sufficient time to gain clarity on this approach. This time frame also recognizes that the other Coyote Station owners each have their own resource needs and planning cycles, and that there may be other regulatory compliance issues to consider.

If there is no co-owner consensus on termination of plant operations, Otter Tail could unilaterally initiate termination of the Plant Ownership Agreement upon five years advance notice. To be clear, Otter Tail's termination of the Plant Ownership Agreement would depend on several factors discussed in this resource plan, the status of which is subject to future developments. Such unilateral termination could impact the other co-owners, given post closure obligations of the parties to each other, the community, and the state of North Dakota along with the potential that the co-owners may choose to continue to rely on the plant for their own load serving needs. Without an orderly process for implementing termination of Otter Tail's participation in the plant, there is some potential for disputes amongst the co-owners to arise. Otter Tail is hopeful that a mutually agreeable path can be found, but if it is not, Otter Tail would need sufficient assurances that it could recover any prudently incurred costs of terminating the Plant Ownership Agreement that could occur.

Last, termination of the Plant Ownership Agreement does not cause the automatic termination of the LSA. The LSA and applicable law contain provisions allowing for early termination under certain conditions. If the LSA is terminated early, the agreement provides for the co-owners to buy the membership interests in the mine entity (Coyote Creek Mining Company, L.L.C.) and thereby assume certain of its obligations. Otter Tail currently projects that in the event of a 2028 buy-out, it would be obligated to pay approximately \$21.7 million. That figure was used in the Company's modeling, and is a conservative forecast based on current assumptions. Any actual buy-out amount would be calculated in the future based on the actual termination date of the LSA and would depend on conditions at the time. As with any contractual termination, there is always the potential for disputes.<sup>34</sup> These costs would need to be recoverable should Otter Tail move forward with a withdrawal.

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<sup>34</sup> As is the case in any situation involving the early termination of a contract there is a risk of litigation. Otter Tail has not included the costs of potential litigation in its modeling.

### Cost Impacts of Withdrawal from Coyote Station

For its economic analysis, Otter Tail developed a conservative estimate of the reasonably foreseeable costs of withdrawing from Coyote Station at the end of 2028 of \$68.5 million, estimated as follows:

**Table 3-11: Coyote Station Estimated Foreseeable Withdrawal Costs**

OTP Share	Forecast (in millions)		
Coyote Station	YE 2040	YE 2028	YE 2026
Book Value (non-land accts 311-316)	(13.4)	\$33.4	\$41.2
2041 Decommissioning/Salvage*	\$13.4	\$13.4	\$13.4
LSA Early Termination Costs	\$0	\$21.7	\$33.3
<b>Total For Withdrawal</b>	<b>\$0.0</b>	<b>\$68.5</b>	<b>\$87.9</b>
*This is the Coyote End of Life book value collected and accumulated in our current depreciation rates for the decommissioning of the plant.			
Note: Does not include any: (1) ancillary costs of withdrawal such as loss of plant related transmission rights or other operational matters; (2) any potential costs of disputes; (3) any unforeseen liabilities.			
Project Book Balances in 2021: August 31, 2021: \$62.1M YE 2021: \$60.7M			

The \$68.5 million potential cost of withdrawal assumes as a modeling baseline the termination of the Plant Ownership Agreement (whether by the co-owners or by Otter Tail) and subsequent retirement of Coyote Station at the end of 2028. This amount does not consider: (1) ancillary impacts to Otter Tail’s costs due to withdrawal; (2) any costs related to disputes between the co-owners and Otter Tail or between North American Coal or Otter Tail; and (3) any unforeseen or retained liabilities other than undepreciated net book value of the Plant. As Otter Tail commences the process of withdrawing from Coyote Station, we expect to obtain more clarity on these costs and refine our economic assessment as part of the process of withdrawal. That said, our modeling suggests that even if Otter Tail should prudently incur additional costs or liabilities from its withdrawal from Coyote Station that withdrawal would still be the most prudent course of action. Consequently, the \$68.5 million is a reasonable baseline of known and quantifiable

costs from which to assess the prudence of Otter Tail's commencement of the process of withdrawal from its ownership interest in Coyote Station.

There are two general cost categories to Otter Tail's withdrawal: (1) undepreciated net book value, and (2) early termination costs under the LSA. The undepreciated net book value is based on Coyote Station's remaining depreciable life which currently extends to 2041.<sup>35</sup>

As noted above, Otter Tail's remaining net plant balance of approximately \$62.0 million is being depreciated over the current remaining life of the plant. Otter Tail's planned withdrawal, if approved, requires consideration of how (and when) to recover the undepreciated balance. In addition to the undepreciated plant balance there are LSA early termination costs to consider. Otter Tail proposes that LSA termination costs and the undepreciated plant balance be placed within a regulatory asset account, which can serve as a vehicle for recovery. The cost impact to customers would then depend on the amortization schedule by which these expenses are recovered over time. One option is a schedule that aligns with Coyote Station's current retirement date of 2041 notwithstanding the Company's exit from the plant by 2028. This option would have the least impact on ratepayers and would be the Company's preferred option. A similar mechanism was used by the MPUC for the abandonment of Xcel Energy's Prairie Island nuclear facility EPU project. The second option would be to accelerate recovery of the regulatory asset account balance to match the early exit date, which would have greater customer impacts. Additional options would fall on a date between these bookends. However, as Otter Tail considers options for its withdrawal (sale or notice, etc.), reducing the depreciable life of the plant may be premature. It is not Otter Tail's intent to reduce the plant's remaining life if, for example, there is another potential owner. The paramount issue is that the Commissions authorize recovery, including a return on the undepreciated regulatory asset.

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<sup>35</sup> As noted earlier, the original depreciable life of Coyote Station assumed retirement in 2016. The depreciable life was extended at various times during the life of the plant, the last time being in 2013, when the depreciable life was extended by nine years, from 2032 to 2041.

### **Other Factors that Could Impact Withdrawal**

In addition to the contractual issues discussed above, there are additional factors that could influence the ultimate process and form of any withdrawal from Coyote Station. These variables are dynamic and difficult to predict, especially in combination, and they may affect the prospects for a sale of Otter Tail's ownership interest in Coyote Station or the willingness of the co-owners to agree on Coyote Station's future. Regulatory approvals will be a precondition to Otter Tail's withdrawal from Coyote Station. Further, Otter Tail's capacity needs and capacity position will also impact our ability to withdraw. Additionally, the ancillary impacts of withdrawal on Otter Tail's transmission rights will need to be further studied.<sup>36</sup> Last, use of the Coyote Plant site and impacts to the community stemming from withdrawal will all have to be considered.

Environmental compliance requirements such as the Regional Haze Rule will have to be assessed and could impact the overall approach to a withdrawal. Together, these factors could impact the timing, costs, and method of withdrawing from ownership in Coyote Station. The Company's modeling forecasts benefits from withdrawal under the scenarios and sensitivities it has considered; however, we cannot rule out the possibility that some combination of factors, including developments that are not currently contemplated, could produce different results in the future. If that were to occur, the Company and its Commissions might need to revisit the issue.

### **Regulatory Approvals**

Otter Tail's plan to withdraw from Coyote Station is premised and conditioned on the support of the Company's regulators, particularly the state commissions regulating Otter Tail's rates. Regardless of whether a formal framework for review and approval of an IRP exists, it is essential that the Commissions in Minnesota, North Dakota, and South Dakota each support withdrawal and allow Otter Tail to recover the resulting costs in rates. Each state has a different regulatory construct and Otter Tail will work to obtain appropriate guidance from each

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<sup>36</sup> Upon withdrawal, Otter Tail may need to have alternative transmission arrangements in place, the cost of which are difficult to predict. Our resource planning model does not account for these costs.

Commission at the appropriate time. The Company also anticipates that it may need to seek further approval from one or more Commissions once it has a clearer plan for its method of withdrawal.

### **Environmental Compliance**

In 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the Clean Air Act (CCA) establishing the Regional Haze Rule as the comprehensive visibility protection program for Federal Class I areas.<sup>37</sup> States are required to submit Regional Haze Rule state implementation plans (SIPs) that evaluate reasonable progress in approximately 10-year increments. The first Regional Haze planning period covered the years 2008-2018, while the second planning period covers the timeframe ending in 2028. The EPA has designated five Regional Planning Organizations (RPOs) to assist with the coordination and cooperation needed to address visibility. North Dakota is a member of the Western Regional Air Partnership, which serves as the RPO in 15 western states.<sup>38</sup>

SIPs for the second planning period were originally due to EPA on July 31, 2018; however, in early 2017 EPA provided an extension until July 31, 2021.<sup>39</sup> In view of this schedule change the MPUC granted Otter Tail's request to extend the filing date of this IRP to September 1, 2021, in part to allow for additional time to conduct modeling needed to comply with the SIP being prepared by the North Dakota Department of Environmental Quality (North Dakota DEQ).<sup>40</sup> The North Dakota SIP is delayed (as are all the SIPs within the Western Air Partnership).<sup>41</sup> At

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<sup>37</sup> These areas include national parks, memorial parks, and wilderness areas over a certain size. The Regional Haze Rule did not mandate specific milestones or rates of progress, but instead called for states to establish goals that provide for reasonable progress towards achieving natural visibility conditions by the year 2064.

<sup>38</sup> Minnesota is a member of the Central Regional Air Planning Association.

<sup>39</sup> 82 Federal Register 3078.

<sup>40</sup> *In the Matter of Otter Tail Power Company's 2017-2031 Resource Plan*, Order Extending Deadline for Filing Resource Plan, Requiring Supplemental Filing, And Completing Competitive Bidding Process, December 30, 2019, MPUC Docket No. E-017/RP-16-386.

<sup>41</sup> The change in timing relates to delays in the efforts by the Western Regional Air Partnership to develop build out a Technical Support System (TSS) website modeling tool.

this time, Otter Tail anticipates that the North Dakota DEQ will provide a draft SIP for public review in late 2021 or early 2022.

The base assumption in Otter Tail’s IRP modeling analysis is that the North Dakota DEQ will not propose a SIP requiring additional controls on Coyote Station. However, Otter Tail recognizes there is a risk that the EPA may not accept that approach;<sup>42</sup> therefore, Otter Tail also included sensitivities in its modeling for the possibility that the Coyote Station owners will be required to make significant upgrades. If significant upgrades are required, they will likely need to be made before 2028 so that they can be operational by the time of the compliance deadline of December 2028. Otter Tail’s analysis shows that even at a “no controls” SIP, where no capital investments are required at Coyote Station, withdrawing from Coyote Station would be a financial benefit for Otter Tail customers. Not surprisingly, this is particularly true when including externality costs required by Minnesota. Even in the no externality analysis, in all cases except when natural gas and market energy prices double, the analysis shows that Otter Tail’s withdrawal from Coyote Station would benefit customers. However, the Coyote Station owners each have their own cost structures, generation fleets, and modeling, and Otter Tail anticipates that more clarity will be available prior to a final determination on environmental compliance costs.

### **Otter Tail Capacity Needs**

As noted, the prudence of Otter Tail’s withdrawal from Coyote Station is premised on the load forecasting that forms the basis of this IRP. However, as the future is uncertain, changes to Otter Tail’s capacity needs could impact the prudence of a withdrawal from Coyote Station. As part of commencing the process of withdrawing from Coyote Station, Otter Tail will continue to monitor its needs to ensure it has sufficient generation to meet its obligation of reliable service to its customers.

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<sup>42</sup> Otter Tail is not quantifying that risk, nor is it taking a position in this filing with regard to what action the EPA should or should not take.

Load growth is certainly a possibility. Otter Tail’s low prices can be attractive for new forms of high load customers. For example in August 2021, we filed for the ND PSC’s approval an electric service agreement with a new, “super-large load” customer.<sup>43</sup> Should additional customers such as this one emerge on our system, we will need to evaluate the least cost way to serve this new load. That said, our current analysis indicates that (1) we have sufficient capacity to meet our current needs with sufficient margin; and (2) that Coyote Station may not be the least cost or most beneficial resource to serve emerging load.

An additional emerging issue that has the potential to impact Otter Tail’s withdrawal from Coyote is the possibility of MISO changing its capacity construct. The issue has been under consideration, and it is possible that MISO will change its capacity requirements so that Load Serving Entities (LSEs) must account capacity needs using something different than the current annual requirement method. Otter Tail is a winter peaking utility and MISO is a summer peaking organization which provides material benefits to Otter Tail since Otter Tail must have enough capacity to meet its load obligation during MISO’s summer peak, when the Otter Tail system is not at peak. A shift to a seasonal construct to meet both a summer and winter peak could increase Otter Tail’s capacity needs without any changes to its actual load profile. Otter Tail understands that MISO may make a filing with FERC in the near future to implement a new seasonal capacity construct. Until that filing is made, the actual details of MISO’s proposal will not be known with certainty. Our Preferred Plan is based on a resource planning analysis that assumes no change to the MISO capacity construct. However, an initial assessment of what our current understanding of what MISO could potentially propose for a changed capacity construct indicates that even with a possible change to the MISO capacity construct, withdrawal from Coyote Station would still be financially beneficial. Otter Tail is monitoring this issue and notes that it could be a material factor in the future.

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<sup>43</sup> *In the Matter of Otter Tail Power Company’s Application for Super Large General Service Rate & Electric Service Agreement Approval*, August 9, 2021, ND PSC Case No. PU-21-366.

### **Operational Matters**

While the resource planning analysis in this IRP indicates that withdrawal from Coyote Station is a prudent path, during the time from commencement of withdrawal to actual withdrawal, Otter Tail will need to consider the operational matters involved. Different withdrawal paths will impose different operational outcomes and needs. As Otter Tail seeks to implement withdrawal, additional operational considerations are likely to arise.

Further, if Coyote Station is closed, there are other potential uses for the site. Solar or natural gas generation (two natural gas pipelines are in the vicinity) are two possibilities given the existing transmission interconnection. However, while Otter Tail is open to the concept, there is no agreement among the Coyote Station owners regarding re-use of the site, and such consensus would be necessary for any such development. In addition, state and local preferences and policies would need to be considered. Accordingly, our Preferred Plan does not incorporate any predictions or assumptions regarding re-development, and the Company is simply noting the possibility here as it may be relevant to stakeholders and Commissions.

### **Mitigation of Impacts on the Community**

The Company understands the importance of Coyote Station and the adjacent mine to the local community and will endeavor to mitigate the impacts of any withdrawal. However, the magnitude of impacts will depend on factors discussed above, including whether the Company is able to sell its ownership share in Coyote Station, and, if not, whether other uses for the site are developed. As the future of the plant becomes clearer, we anticipate that any plans for mitigation will be determined through consultation with community members and elected officials.

Included in these impacts will be Otter Tail's need to appropriately transition our workforce currently operating the plant. The transition will depend on the path for withdrawal that will ultimately be chosen. Consequently, we are not able to present any concrete plans in this regard at this time.

### **Otter Tail’s Proposed Plan to Withdraw from Coyote**

Should the Commission approve Otter Tail’s Preferred Plan – with such approval recognizing the complexities of Otter Tail’s potential paths to withdrawal from Coyote Station – we intend to promptly: (1) offer the Company’s ownership interest to the other co-owners and qualified third parties, and (2) continue working with the Coyote Station co-owners regarding a possible consensus decision on Coyote Station’s future. If no buyer for Otter Tail’s ownership interest is found, and the co-owners are not able to reach a consensus, Otter Tail would then propose to exercise its right to terminate the Plant Ownership Agreement on five years advance notice, provided other factors noted in this resource plan did not call for reassessment.

Assuming no intervening issues create circumstances in which withdrawal is no longer prudent, Otter Tail’s intent is to withdraw from Coyote Station by the end of 2028. We understand that different stakeholders will have different views on this timing. Some stakeholders may focus on the cost of Coyote Station operations in a low MISO market and the continued routine capital spending pending withdrawal. Other stakeholders may focus on exhausting options that might keep Coyote Station viable before retiring a baseload generation facility. While the timing is unlikely to satisfy all of the involved stakeholders, Otter Tail believes this proposal is reasonable and appropriately balances competing concerns.

### **Summary**

Otter Tail’s Preferred Plan requests authority to begin the process of withdrawal from Coyote Station with a goal of withdrawing by 2028 as described above.

## **3.10 Adding Dual Fuel Capabilities at Astoria Station**

### **Plant Description**

Astoria Station, located near Astoria, South Dakota, is a wholly owned 245 MW natural gas peaking unit that was an approved resource addition as part of our 2016 Plan and came online in early 2021.

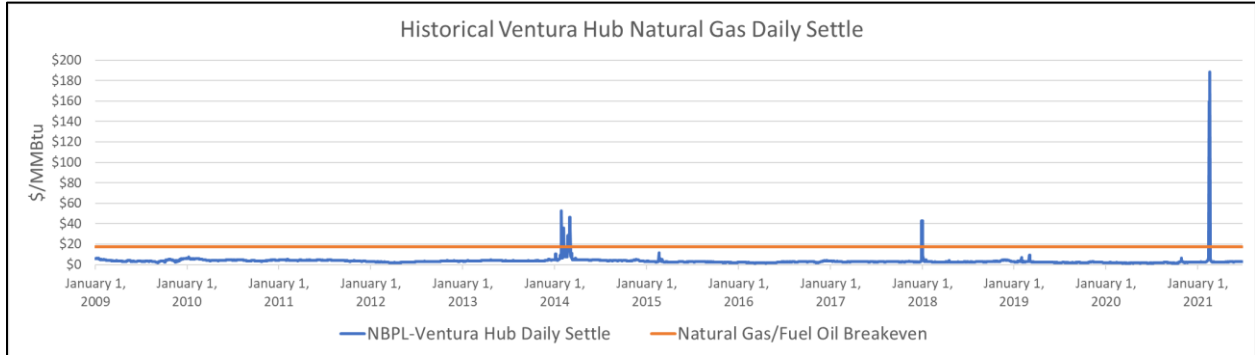
### **Dual Fuel Capabilities**

Astoria Station was designed, permitted, and constructed with natural gas as the sole source of fuel. Prior to selecting a combustion turbine, Otter Tail confirmed that any one of the potential combustion turbines selected could be converted to dual fuel. To be clear, MISO does not currently require dual fuel capabilities for capacity accreditation. Prior to MISO, it is our understanding that MAPP (the Midwest Area Power Pool) required fuel oil backup for natural gas fired units which is why we have fuel oil backup at our Solway Power plant. The natural gas transmission lines are very reliable. In fact, even during Winter Storm Uri in February 2021, natural gas would have been available for Astoria Station if it would have needed to operate. What Winter Storm Uri highlighted more so than any time before is natural gas volatility and intra-day price risk; risk that dual fuel capabilities at a peaker would protect against. The volatility seen during Winter Storm Uri demonstrates that installation of dual fuel capability at Astoria would be justified and would have inherent reliability benefits, as discussed below.

### **Natural Gas Price Volatility**

The natural gas transmission lines, where the Otter Tail natural gas peakers are located, are very reliable. The extraordinary pricing variability during the 2021 Winter Storm Uri event generated our internal review of the intra-day pricing variability exposure of a natural gas generator without a secondary fuel source backup. Over the past decade, there have been three events that caused high gas prices, the most recent of which was Winter Storm Uri. Figure 3-11 below depicts the gas market prices since January 2009.

Figure 3-11: Historic Ventura Hub Natural Gas Prices



With increased reliance on variable renewable resources and natural gas generation to fill short term electrical demand needs, history has shown that natural gas prices can be volatile, and we expect that to continue. But the advent of fracking has made the long-term price of gas more stable.

When analyzing the economic benefits of dual fuel (or on-site backup fuel oil) at Astoria when considering the intra-day pricing risk has focused on three primary factors:

- *Protection against intraday natural gas pricing deltas* – During extreme and volatile pricing conditions, like what was seen in February 2021, the natural gas market can vary dramatically between the time a generation offer is given to MISO and when MISO clears the offer. If the quantity of MWs cleared varies from expectations, and the price to procure or liquidate additional natural gas fuel supply varies from expectations, the generator can be exposed to significant pricing risk. Dual fuel capability mitigates if not eliminates this risk by providing a known and stable fuel supply during extreme natural gas pricing events.

- *Energy hedge value* – Without the ability to call on Astoria Station for dual fuel capability (and therefore run the facility at a pre-determined energy price), Otter Tail has utilized energy purchases at the Otter Tail load zone to hedge against high priced, natural gas-driven markets during the winter months of December, January, and February. This winter energy hedge purchase could likely be significantly reduced or eliminated with installation of dual fuel. While not directly related to intraday pricing risk, this value can be considered in the analysis.
- *Possibility of a changing MISO capacity construct* – It is not yet certain if a change to the capacity construct within MISO will occur, but the issue is being seriously considered.

Using Winter Storm Uri as an example, Otter Tail has been able to back cast the value of having dual fuel available at Astoria Station.<sup>44</sup> The data below provides insight on the likely financial implications. The following analysis assumes the value of avoiding intraday natural gas forecasting uncertainty. This includes intraday pricing deltas, and timing challenges associated with procurement of natural gas, offering generation, and commitment/dispatch by the MISO market.

The analysis is based on historical energy and natural gas pricing data during Winter Storm Uri. Despite the historical data, numerous assumptions were required, complicating the analysis, including timely gas nominations, intraday purchase pricing and liquidation pricing, and changing market conditions. Sensitivity analysis was completed based on varied natural gas timely nominations and energy market pricing.

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<sup>44</sup> During Winter Storm Uri Otter Tail had not yet retired Hoot Lake and Astoria Station was still in the testing phase. As such, these costs were not incurred by Otter Tail or its customers.

**Table 3-12: February 2021 LMP Pricing Scenario**

LMP Pricing Scenario	Timely Gas Purchase: % of Daily Capacity	Timely MMBtu Purchase (MMBTu)	Intraday Purchase (MMBTu)	Gas Only		Duel Fuel Integration			Net Benefit Delta	
				Net Benefit: Average Gas Case	Net Benefit: Worst Gas Case	Fuel Oil Dispatch (MWh)	Net Benefit: Average Gas Case	Net Benefit: Worst Gas Case	Net Benefit: Average Gas Case	Net Benefit: Worst Gas Case
Historical Astoria LMPs	0%	0	43,696	(\$545,053)	(\$2,388,478)	20,825	\$2,736,879	\$2,736,879	\$3,281,932	\$5,125,357
	10%	72,098	(28,402)	(\$2,158,476)	(\$5,394,416)	20,825	\$2,801,247	\$2,710,305	\$4,959,723	\$8,104,721
	15%	108,148	(64,452)	(\$3,016,393)	(\$7,449,380)	20,825	\$2,833,431	\$2,697,018	\$5,849,825	\$10,146,398
	25%	180,246	(136,550)	(\$4,834,641)	(\$12,663,298)	20,825	\$2,897,799	\$2,670,444	\$7,732,440	\$15,333,742
	50%	360,492	(316,796)	(\$9,391,184)	(\$25,720,761)	20,825	\$3,047,796	\$2,581,341	\$12,438,980	\$28,302,102
Historical Astoria LMPs X2	0%	0	281,293	(\$3,059,285)	(\$16,700,630)	35,525	\$8,991,457	\$8,868,562	\$12,050,742	\$25,569,192
	25%	180,246	101,047	(\$6,509,090)	(\$18,603,269)	35,525	\$9,326,478	\$9,244,548	\$15,835,568	\$27,847,817
MISO LMP Price Cap \$3,500/MWh	0%	0	720,984	\$173,912,028	\$95,423,088	64,680	\$216,278,628	\$216,114,768	\$42,366,600	\$120,691,680
	25%	180,246	540,738	\$172,612,885	\$113,746,180	64,680	\$216,613,650	\$216,490,755	\$44,000,764	\$102,744,574
Historical SPP Big Stone LMPs	0%	0	494,311	\$35,155,620	(\$13,818,038)	38,710	\$66,852,204	\$66,708,827	\$31,696,585	\$80,526,865
	25%	180,246	314,065	\$33,105,452	(\$4,972,881)	38,710	\$67,187,226	\$67,084,813	\$34,081,774	\$72,057,694

The possible benefits of having dual fuel at Astoria Station varied significantly based on the given sensitivity. In the cases where February 2021 historical Astoria LMP data was utilized, the net benefit of dual fuel capability ranged from \$3.2 million to \$21.8 million, depending on the amount of timely gas nominations. The net benefit nearly doubles under a “worst” natural gas scenario where natural gas is either purchased at the high trading mark of the day or liquidated at the low trading mark of the day.

Additional scenarios considered the possibility of increased LMP prices above and beyond what was historically experienced during Winter Storm Uri. Under these scenarios, the net benefit ranged from \$12.1 million - \$44.0 million. While some of these scenarios have a very remote possibility of occurrence, it is prudent to mitigate these risks and increase our fleet resiliency by adding dual fuel capability at Astoria Station.

Astoria Station’s location on the Norther Border Pipeline is advantageous. It is located between the Canadian and North Dakota supplier injection points and the higher load centers to the southeast. It is important to note that natural gas was always available for Astoria Station during Winter Storm Uri in February 2021. However, while the deliverability risk of gas was low, the

price risk for the delivered gas was high. Dual fuel capability at Astoria Station would mitigate the risk of intraday pricing volatility and overall energy pricing risks that were experienced by some other utilities during the February 2021 event.

It is important to note that dual fuel capability at Astoria Station is justified regardless of any decision on Coyote Station. Dual fuel at Astoria Station addresses the risk of intra-day pricing volatility and overall energy pricing risks. The benefit of addressing these risks is apparent regardless of when or how (or even whether) Otter Tail withdraws from ownership in Coyote Station.

Otter Tail is asking for Commission approval to advance with the project with the understanding the preliminary estimated cost is [PROTECTED DATA BEGINS...  
...PROTECTED DATA ENDS].

### **3.11 Preferred Plan is in the Public Interest**

The Preferred Plan aligns with and supports Otter Tail's commitment to operate its generation facilities as efficiently as practicable while minimizing adverse effects on the environment. The Preferred Plan identifies new resources that will meet our customers' needs while maintaining flexibility and minimizing the risk of exposure to changes in financial, social, and technological factors beyond our control.

The Preferred Plan is cost-effective. It was developed with a model that integrates demand-side and supply-side resource analysis. The Preferred Plan allows our customers to realize the benefits of Otter Tail operating as a single system, which is essential to securing operating efficiencies.

The Preferred Plan satisfies the legal and regulatory requirements in our multi-state service territory. Complying with the standards and expectations administered by three Commissions can be challenging at times. Otter Tail believes that the Preferred Plan meets that challenge,

satisfying the requirements and prerogatives of each jurisdiction we serve.

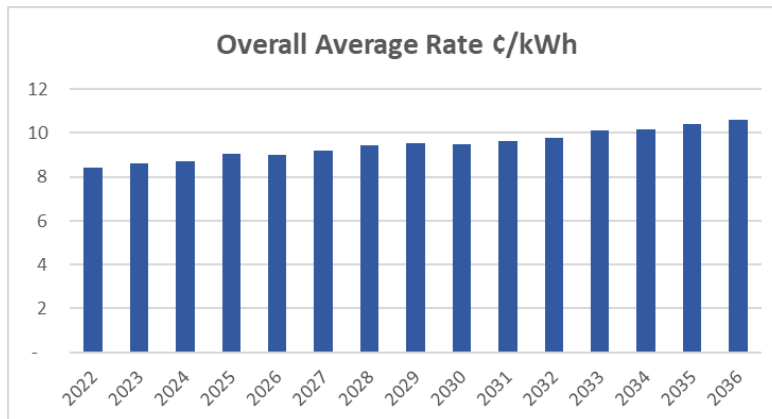
In response to discussions with stakeholders and in compliance with rules detailed in Appendix A, the Company evaluated numerous sensitivities for this resource plan and provides the resulting net present value revenue requirement and annual resource addition in Appendix I.

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 considers resilience of the system and includes renewable resources for new energy additions and energy efficiency and conservation.

### 3.12 Preferred Plan Rate Impacts

Figure 3-12 shows the potential estimated overall rate impact of the Preferred Plan.

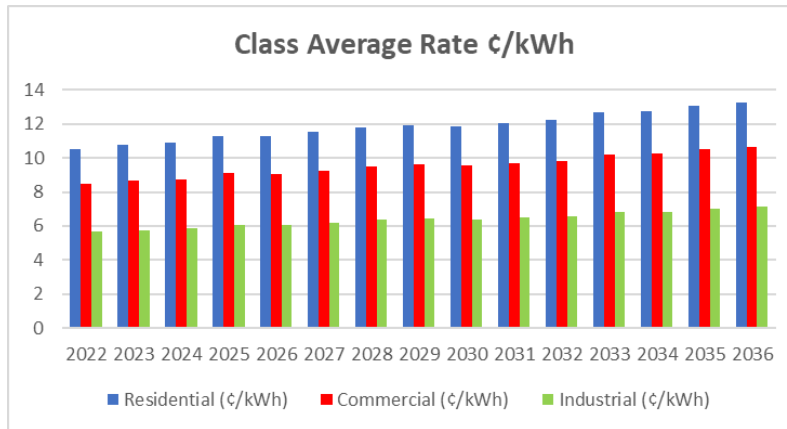
**Figure 3-12: Preferred Resource Plan Estimated Rate Impacts**



The data shown is the average annual rate based on the EnCompass model for the total system and represents total revenue divided by total sales. Figure 3-13 shows the potential estimated rate impacts of the Preferred Plan by customer class. A number of parameters in the operation of the model will impact rates. The EnCompass model assumes automatic rate increases each year to

meet the targeted rate of return; but in reality, recovery proceedings take place as needed and have an inherent amount of regulatory and administrative lag. The EnCompass model rate impact calculation takes into account the generation additions in the Preferred Plan but it does not include all projected capital expenditures, asset-based sales, or projected CO<sub>2</sub> costs.

**Figure 3-13: Preferred Resource Plan Estimated Rate Impacts by Class**



### 3.13 Five-Year Action Plan

Table 3-13 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 2022-2036; however, the action items in 2021 also are provided. As shown, the major activities during the five-year period are construction of the 49.9 MW Hoot Lake Solar, addition of 150 MW of surplus interconnected solar in 2025, completion of dual fuel at Astoria in 2026, and activities related to the addition of 100 MW of surplus interconnected wind in 2027 and withdrawal from Coyote in 2028.

**Table 3-13: Five-Year Action Preferred Plan Activities**

Year	Activity
2021	Engineering and procurement for 49.9 MW Hoot Lake Solar. Purchase SRECs for compliance with MN Solar Energy Standard.
2022	June 1 Triennial CIP filing for 2023, 2024, 2025. Anticipated construction of Hoot Lake Solar.
2023	MISO interconnection process for 150 MW surplus solar projects. Anticipated Commercial Operation Hoot Lake Solar.
2024	Engineering and procurement for 150MW surplus solar projects. Depending on developments provide five year advance notice of termination of Coyote Station Plant Ownership Agreement by January 1, 2024.
2025	June 1 Triennial CIP filing for 2026, 2027, 2028. Construction and commercial operation of 150 MW solar projects. MISO interconnection process for 100 MW surplus wind project.
2026	Construction and commercial operation of Dual Fuel Astoria project. Engineering and procurement for 100 MW surplus wind project.

### **3.14 Conclusion**

Otter Tail has continued to optimize existing resources 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 least-cost, least-risk preferred resource plan presented here accomplishes the goal of meeting customer needs and regulatory requirements in the three jurisdictions that Otter Tail serves.

## 4 Current Outlook

The following list provides a brief overview of the most prevalent changes that have occurred since the 2016 Plan. These changes include the tangible effects of both regulatory and economic factors on the Company's current outlook.

### 4.1 Retirement of Hoot Lake Plant

As approved in the course of the 2010 IRP proceeding and related Baseload Diversification Study,<sup>45</sup> Otter Tail's Hoot Lake Plant retirement and decommissioning of the facility began in May 2021. Hoot Lake's capacity is not included in the current MISO Module E for Planning Year 2021-2022. As discussed in other sections of this Petition, Otter Tail will use the transmission interconnection from the retired Hoot Lake Plant for its Hoot Lake Solar facility.

### 4.2 Completion of Astoria Station, a 245 MW simple-cycle natural gas combustion turbine in South Dakota

The 2016 IRP indicated that Otter Tail had taken significant actions to proceed with installation of a new, 245 MW<sup>46</sup> simple cycle natural gas combustion turbine. Astoria Station was one of two projects, the other being the Merricourt Wind Facility, to replace the retiring Hoot Lake Plant.

Otter Tail successfully executed the Astoria Station project at costs below budget and on schedule. The generating facility became operational in February 2021. MISO has dispatched Astoria regularly since April 30, 2021, one month prior to retirement of Hoot Lake Plant, and the unit has operated well.

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<sup>45</sup> MPUC Docket No. E017/RP-10-623.

<sup>46</sup> The 245 MW is a summer rating, the winter rating is 285 MW.

### **4.3 Completion of the 150 MW Merricourt Wind generation facility in North Dakota**

Otter Tail successfully executed the Merricourt Wind Energy Facility project which became commercially operational in December 2020. This project, along with Astoria Station, serve to replace the now retired Hoot Lake Plant.

### **4.4 MISO Module E Resource Adequacy Obligation**

Beginning in June 2013 the MISO 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 MISO's coincident peak demand. In addition, the MISO 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 since Otter Tail's summer peak is less than its winter peak. Otter Tail's summer coincident peak demand diversity factor is approximately nine percent of its summer peak demand. This means that Otter Tail's capacity requirement is equal to 91 percent of its summer peak plus transmission losses and a required reserve margin which was set at 9.4 percent for planning year 2021-2022.

MISO is currently in the design phase of a new capacity construct that seeks to set capacity requirements on a seasonal basis rather than the current annual construct. At the current time there are still many unknowns that make it difficult to model the future seasonal construct. For this reason, Otter Tail has decided to continue with the annual construct in its modeling. Also, Otter Tail includes a sensitivity with an additional 10 percent MISO capacity requirement as a reference point to consider if Otter Tail's capacity requirements were to increase due to the seasonal construct. This is an estimate of a possible impact from such a change to the construct, as it is currently in development and Otter Tail doesn't have sufficient information to precisely estimate its possible impact.

#### 4.5 Market Conditions in the MISO

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:

2018: \$27.28/MWh  
2019: \$22.99/MWh  
2020: \$16.60/MWh  
2021 (YTD May 13): \$30.81/MWh<sup>47</sup>

Capacity values in the MISO centralized market have remained low due to excess reserves. However, pending coal plant retirements may tighten reserve margins.

#### 4.6 MPUC Approval of the 49.9 MW Hoot Lake Solar generation facility

Otter Tail's Hoot Lake Solar project is a solar generating facility that will be located at the site of Otter Tail's recently retired coal-fueled Hoot Lake Plant, on approximately 450 acres of Company-owned property in Fergus Falls, Minnesota. The project consists of approximately 110,000 solar panels with total capacity of 49.9 MW and expected energy output of 105,000 megawatt hours, at a projected net capacity factor of 24 percent. This project will utilize several components of the Hoot Lake Plant, including the land, existing infrastructure, and existing interconnection rights associated with the Hoot Lake Plant.

The MPUC recently approved Otter Tail's petition made pursuant to Minn. Stat. § 216B.1691 (Renewable Energy Standard Statute) and § 216B.1645 (Renewables Cost Recovery Statute).<sup>48</sup> In its Order, the MPUC authorized future cost recovery of 100 percent of Hoot Lake Solar's

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<sup>47</sup> The large increase seen in 2021 was caused in large part by Winter Storm Uri.

<sup>48</sup> *In the Matter of Otter Tail Power Company's Petition for Approval of the Hoot Lake Solar Project*, Order Approving Petition, Authorizing Allocation of Output and Costs, Authorizing Cost Recovery, and Requiring Compliance Filings, April 29, 2021, MPUC Docket No. E-017/M-20-844.

output and costs to Otter Tail's Minnesota jurisdiction through its Renewable Resource Cost Recovery Rider.<sup>49</sup>

#### **4.7 Renewable Energy Objectives (REO) and Standards (RES)**

Otter Tail includes a discussion on REO and RES in Appendix G. The Preferred Plan includes the addition of 100 MW of surplus interconnected wind in 2027. 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. The Company fulfills its obligation 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 assessed the appropriate resources to include in this resource plan including incremental levels of new wind that could be reasonably procured and worked into the system while maintaining reliability of service. Further, Otter Tail relied on the MISO developed Renewable Integration Impact Assessment (RIIA) study<sup>50</sup> to help identify inflection points associated with increasing levels of renewable generation. The RIIA study identified five risks to address as more renewables are integrated into the generation portfolio: (1) stability risk, (2) shifting periods of grid stress, (3) shifting periods of energy shortage risk, (4) shifting flexibility risk, and (5) insufficient transmission. Otter Tail sees these risks in its own resource planning and in particular views the transmission queue for new interconnection of wind as a significant hurdle to introducing new wind resources outside of utilizing surplus interconnection at existing plants. In addition to the MISO transmission queue, the EnCompass modeling does lean towards selecting solar resources.

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<sup>49</sup> *Id.* Order point 8.

<sup>50</sup> MISO Renewable Integration Impact Assessment: <https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment>.

## 4.8 DSM and Conservation Requirements

### Demand Side Management

Otter Tail contracted with Brattle in 2020 to perform a Demand Response (DR) Potential Study for Otter Tail's system. This study is included as Appendix H. To perform the study, Brattle used its LoadFlex model which was also used in Brattle's 2019 load flexibility potential study prepared for Xcel Energy. Brattle studied the potential to increase Otter Tail's existing DR portfolio along with adding new DR products to its portfolio. Brattle evaluated each DR measure dispatched against an hourly forecast of marginal costs to determine value.

At a high-level Brattle found Otter Tail to have a large existing demand response portfolio which is actively utilized. Brattle states, "OTP's existing DR capability is in the top 10 percent of U.S. IOUs." Based on 2019 EIA-861 data Brattle found Otter Tail to be ranked at the 90<sup>th</sup> percentile in Peak Reduction Capability, 95<sup>th</sup> percentile in Residential Customer Enrolled in a DR program, and 90<sup>th</sup> percentile in Non-Residential Customers enrolled in a DR program.

### Technical Potential

Page 17 of Brattle's study describes Incremental Technical Potential by 2036. Brattle defines Technical Potential as, "the maximum achievable potential irrespective of cost-effectiveness. It is incremental to OTP's existing DR portfolio." Brattle identified incremental technical potential for both summer and winter seasons. Most technical potential identified was by expanding Otter Tail's existing direct load control for Commercial and Industrial (C&I) customers. Other areas of large technical potential included offering more dynamic pricing to all classes of customers. These areas include, adding critical peak pricing rates (CPP) for residential, increasing C&I customer participation in the Company's existing CPP rate, and also increasing C&I participation in Otter Tail Time of Use (TOU) rates. As a reminder, Technical Potential does not take cost-effectiveness into account.

### **Economic Potential**

Brattle’s modeling used for the “Base Case” assumes current Otter Tail resources and a 2020 forecast of MISO energy and capacity values. For evaluation of economic potential, Brattle set incentive levels at maximum cost-effective levels. The Base Case modeling found that system conditions do not appear to support the cost-effective addition of new DR programs. Avoided generation capacity investments are the primary DR value proposition but based on current resources Otter Tail does not forecast a need for new capacity until 2033.<sup>51</sup> Regarding Economic Potential, the Brattle study concludes:

- Generation capacity avoidance is the key driver of DR value, and it is not currently an opportunity for Otter Tail
- There may be isolated opportunities for geo-targeted distribution deferral; requires detailed analysis of distribution plan
- Time-varying rates may be desirable as an option regardless, as they provide other benefits beyond avoided costs (e.g., equity, fairness, facilitating electrification).

Brattle also modeled a “High Value Sensitivity Case.” The High Value Sensitivity Case assumes a need for capacity on the Otter Tail system and assumes higher capacity prices. This scenario was not based on any Otter Tail forecast, but instead an analysis to what strategies Otter Tail would target if there was a capacity need and if capacity prices were higher. Based on these assumptions the analysis did identify several cost-effective new DR opportunities. The opportunities identified mostly consisted of Otter Tail utilizing its CPP and TOU rate offerings to enroll a greater number of large and medium C&I customers. Lesser opportunities identified included expansion of its large C&I interruptible program and CPP for residential customers. While the Brattle study did not identify any cost-effective DR opportunities, the Company continues to have a strong commitment to DR. The Company understands its existing and robust DR portfolio is important to system planning and providing low-cost energy and capacity to its

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<sup>51</sup> See Table 2-2, Line 9.

customers. Otter Tail continues to actively market its DR programs to its customers to recruit new customers, and to also maintain the existing customers' controllable loads.

Otter Tail is excited about the future possibilities of DR. The Company's ongoing multi-year Automated Metering Infrastructure project combined with its plan to update its aging load management system will prepare the Company for the future when it will better equipped to strategically control DR loads and thoroughly evaluate and offer additional dynamic pricing plans.

### **Conservation**

The Minnesota Next Generation Energy Act of 2007 established a goal for all Minnesota electric and natural gas utilities of achieving energy savings equal to one 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.<sup>52</sup> On July 1, 2019, the Company made its 2021-2023 Minnesota CIP Triennial filing with the Minnesota Department of Commerce's Division of Energy Resources. The CIP plan as filed complied with all regulatory requirements, including annual energy savings goals at or above 2.4 percent. This resource plan reflects an average annual energy savings of 1.86 percent, which exceeds the newly established 1.75 percent goal in the Minnesota Energy Conservation and Optimization Act of 2021. In November 2020, the SD PUC approved the Company's 2021-2023 Energy Efficiency Partnership Triennial Plan (EEP). The EEP set forth a number of conservation projects with an estimated 4.6 million kWh in annual savings. As noted above the programs benefit customers in all three states served by Otter Tail by reducing our energy needs and reducing the costs of providing service to our customers.

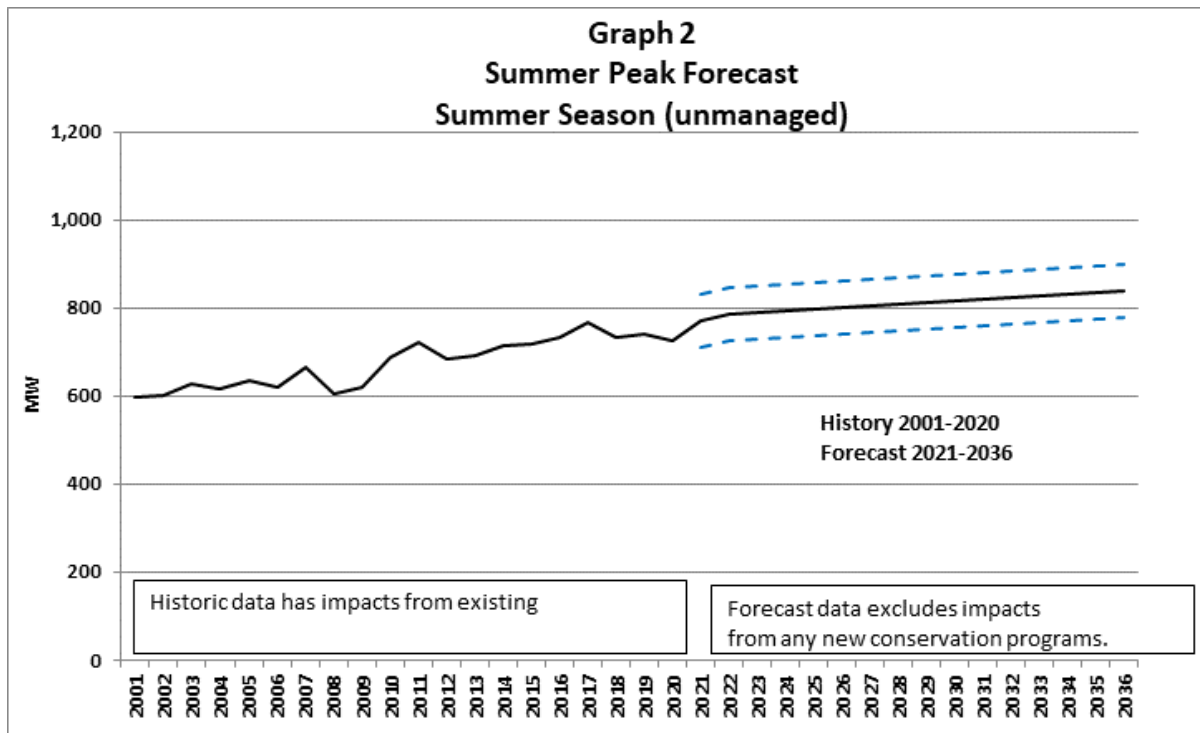
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<sup>52</sup> On May 25, 2021, Minnesota Governor Tim Walz signed the Energy Conservation and Optimization (ECO) Act of 2021. This legislation modernized Minnesota conservation policy by adding new opportunities and setting higher conservation goals. The ECO Act increased the annual energy savings goal for public electric utilities, from 1.5 percent of retail sales, to 1.75 percent of retail sales, based on a rolling three year average of weather normalized sales.

## 4.9 Projected Load and Capability

Otter Tail’s submits its energy and demand forecasts and forecast documentation used in its 2022-2036 Plan as part of this filing.<sup>53</sup> Otter Tail’s forecast documentation consists of a detailed summary of the processes used to create its energy and peak demand forecasts. Figure 4-1 below shows the historical and projected non-coincident summer peak demand by season through the study period to 2036.

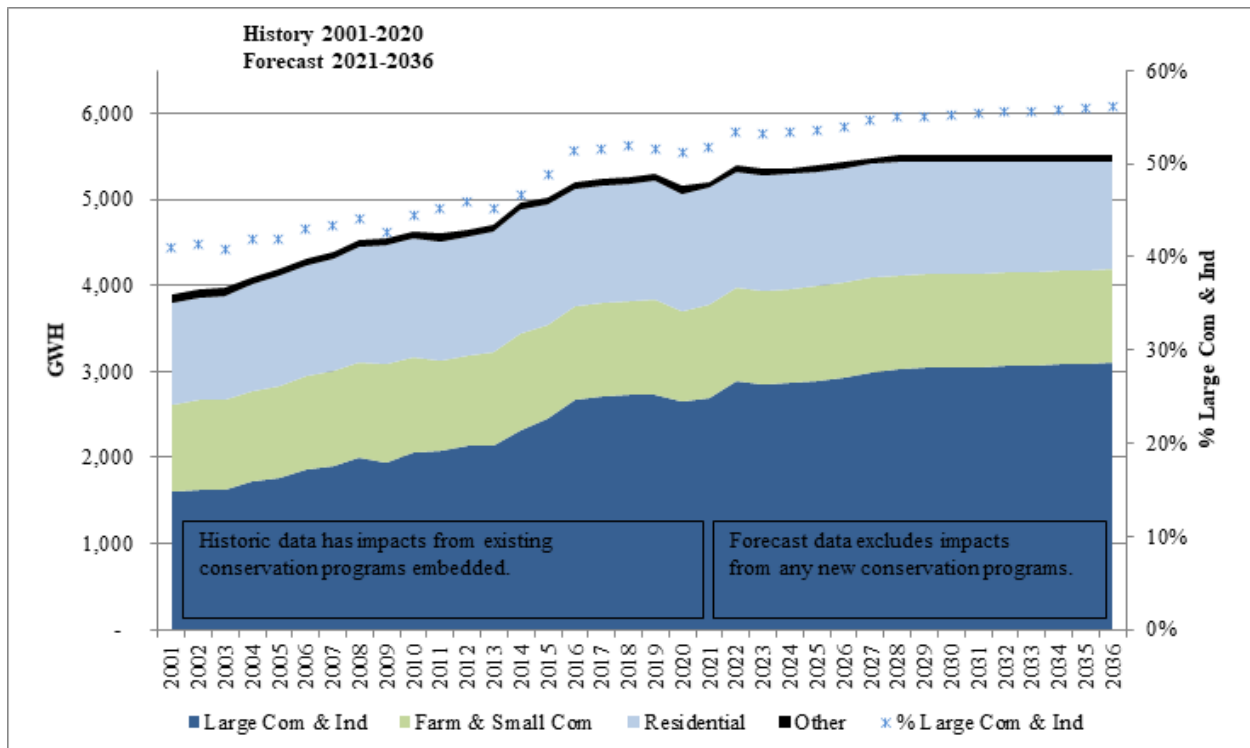
**Figure 4-1: Historic and Forecast Unmanaged 50/50 Non-coincident Summer Peak Demand**



<sup>53</sup> The energy and demand forecast is included in our September 1, 2021 IRP filings for the ND PSC and SD PUC. We previously provided the MPUC the energy and demand forecast on August 2, 2021 as part a pre-filing obligation. See, *In the Matter of Otter Tail Power Company’s 2022-2036 Resource Plan*, Energy and Demand Forecast Models Information Filing, August 2, 2021, MPUC Docket No. E017/RP-21-339.

Figure 4-2 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 nearly 60 percent of the Company’s retail sales.

**Figure 4-2: 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 MISO 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.

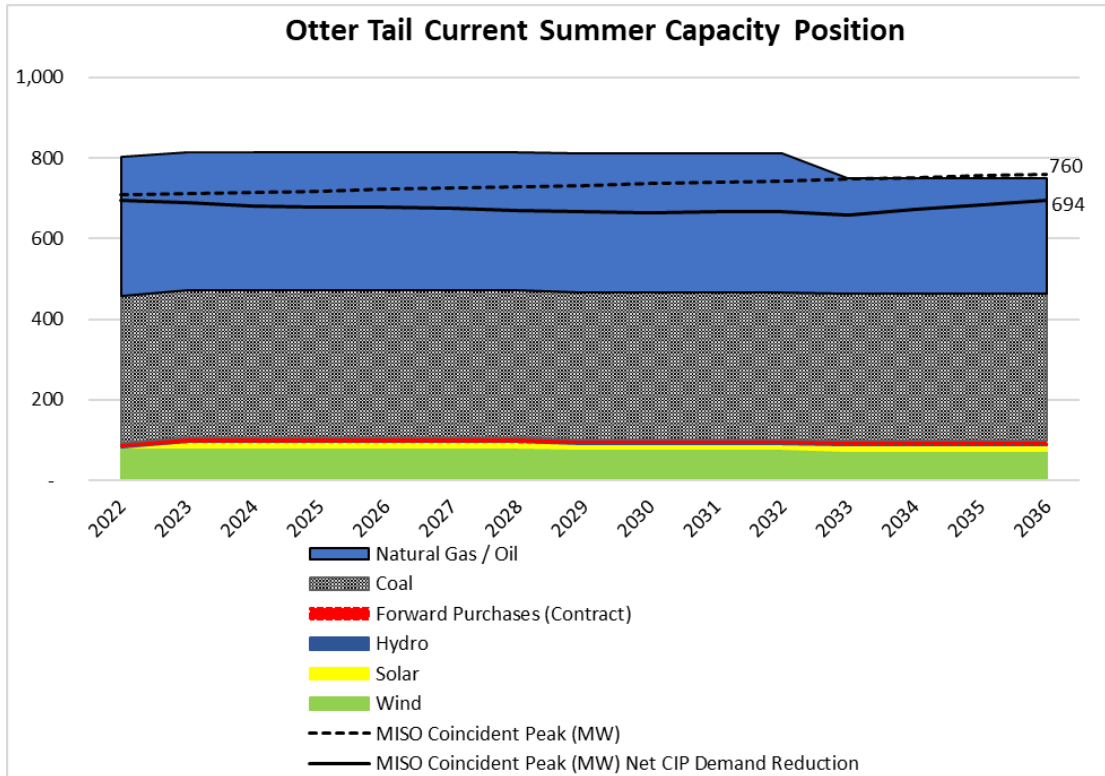
**PUBLIC DOCUMENT – NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED**  
**Resource Plan 71**

The Company’s projected summer capacity needs under Module E requirements are shown in Tables 4-1 and represented graphically in Figure 4-3. The MISO 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 MISO footprint (or aggregate), as well as for resources that are locally deliverable to Otter Tail’s load, and any bilateral transactions of ZRCs.

**Table 4-1: Summer 2022-2036 Base Case Projected Load and Capability Prior to Preferred Resource Plan**

Line No.		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1	<b>Forecasted Load</b>	672.0	675.6	679.2	682.8	686.4	690.0	693.6	697.3	700.9	704.6	708.3	712.0	715.7	719.5	723.2
2	<b>Transmission Losses</b>	39.0	38.8	38.6	38.6	38.6	38.6	38.5	38.4	38.4	38.5	38.6	38.4	39.0	39.5	40.0
3	<b>Net CIP Demand Reduction</b>	12.3	23.1	32.8	38.7	44.7	51.4	58.2	64.9	70.9	74.2	77.4	89.2	80.1	72.6	66.2
4	<b>Total Forecasted Load</b>	698.8	691.4	685.1	682.7	680.3	677.1	674.0	670.8	668.4	668.9	669.5	661.2	674.6	686.3	697.1
5	<b>MISO Coincident Factor</b>	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%
6	<b>Coincident Load</b>	635.9	629.2	623.4	621.3	619.1	616.2	613.3	610.4	608.2	608.7	609.2	601.7	613.9	624.6	634.3
7	<b>MISO Planning Reserve</b>	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%
8	<b>Total Obligation</b>	695.6	688.3	682.0	679.6	677.3	674.1	671.0	667.8	665.4	666.0	666.5	658.2	671.6	683.3	694.0
9	<b>Coal</b>	365.5	365.5	365.5	365.5	365.5	365.5	365.5	365.5	365.5	365.5	365.5	365.5	365.5	365.5	365.5
10	<b>Natural Gas / Oil</b>	344.3	344.3	344.3	344.3	344.3	344.3	344.3	344.3	344.3	344.3	344.3	286.7	286.7	286.7	286.7
11	<b>Wind</b>	82.3	82.3	82.3	82.3	82.3	82.3	82.3	78.7	78.7	78.7	78.7	74.0	74.0	74.0	74.0
	<b>Solar</b>	0.0	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3
	<b>Hydro</b>	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
12	<b>Purchased*</b>	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
13	<b>Load Management</b>	16.0	16.0	16.0	17.0	18.0	19.0	20.0	21.0	22.0	23.0	24.0	25.0	26.0	27.0	28.0
14	<b>Total ZRCs</b>	819.1	831.4	831.4	832.4	833.4	834.4	835.4	832.8	833.8	834.8	835.8	774.4	775.4	776.4	777.4
<i>*Co-generation, Co-Op Shared, and WAPA</i>																
15	<b>Net (Line 14 - Line 8)</b>	123.5	143.0	149.3	152.7	156.1	160.2	164.4	164.9	168.3	168.8	169.3	116.2	103.9	93.2	83.5

**Figure 4-3: Summer 2022-2036 Capacity Needs Prior to Preferred Plan Information**



Otter Tail is a winter peaking utility but for modeling purposes bases its capacity resource need on the summer season as required by the MISO resource adequacy rules. Although the summer season drives capacity needs, the entire year is evaluated for the Company’s energy needs. As shown, the Company has a small capacity deficit beginning in the summer of 2033 corresponding to the current end of life for certain peaking plant facilities.

## **5 Plan Development**

### **5.1 Plan Objectives**

In its Order concerning Otter Tail’s initial resource plan filing in 1992, the MPUC stated that it considers the characteristics of the available resource options and the proposed plan as a whole. In addition, the MPUC provided evaluation considerations that Otter Tail has used to guide its total system resource plans. This framework 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 keeps these objectives in mind while selecting resource options that will provide adequate, reliable, and reasonably priced electric power for its customers.

### **5.2 Planning Tools**

Otter Tail uses EnCompass to perform capacity expansion planning. The EnCompass model optimizes future resource selections while ensuring capacity and energy needs are met within the bounds set. The model selects a least-cost resource plan based on the net present value of revenue requirements (NPVRR) of all possible alternatives.

This will be the first complete IRP that Otter Tail has filed using the EnCompass modeling software. Prior to EnCompass, Otter Tail used Strategist for all capacity expansion modeling. The decision to begin the transition from Strategist to the newly developed EnCompass software occurred in 2018. EnCompass was selected based on a multitude of factors including functionality, ease of use, and cost.

### 5.3 Planning Process

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

- 1) Modeling the Company's system using EnCompass – 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 – As noted above, the Company aims to select a least cost/least risk preferred plan that complies with all relevant statutes and rules, resource adequacy obligations, renewable energy objectives and standards, and established environmental regulations. Additionally, the 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.

## 6 Preferred Resource Plan

The Preferred Plan identifies resources that could be used to serve customer loads over the entire 2022 – 2036 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 Plan. The Company’s Preferred Plan, presented in Table 6-1, shows the resource additions anticipated for the planning period.

**Table 6-1: Preferred Plan Resource Summary**

<b>Resource Plan (MW) - Based on Nameplate ratings</b>	
2022	
2023	
2024	
2025	150 MW Surplus Interconnection Solar
2026	Dual Fuel at Astoria
2027	100 MW Surplus Interconnection Wind
2028	Anticipated Withdrawal from Coyote 149 MW
2029	
2030	
2031	
2032	
2033	50 MW Replacement Solar
2034	
2035	
2036	

Table 6-1 shows the addition of 150 MW of surplus interconnection solar in 2025 followed by the completion of dual fuel capability at Astoria Station in 2026, 100 MW of surplus interconnection wind in 2027, withdrawal from our ownership interest in Coyote Station in 2028, and the addition of 50 MW of replacement interconnection solar in 2033. The solar resource selected in 2025 qualifies for a 26 percent investment tax credit (ITC.) The additional wind and solar resources selected in 2027 and 2033 are not expected to qualify for any tax incentives according to the rules as they are written today.

Due to the current congestion in the MISO interconnection queue, transmission interconnection costs for new resources are very high and impact the economic feasibility of adding new generation units of all types. Recently the MISO has provided two alternative methods for

interconnecting new resources without having to go through the traditional queue process. These two new interconnection methods are replacement interconnection and surplus interconnection. Replacement interconnection resources reuse the existing interconnection rights of a resource that is retiring. Existing interconnection rights for an existing resource that is retiring have a shelf-life of three years. If not used within that time frame the interconnection rights expire. This is the approach that Otter Tail used for the Hoot Lake Solar project. Surplus interconnection resources are built alongside an existing resource and share the interconnection rights. The total output of both resources cannot exceed the existing interconnection amount of the original unit.

Figure 6-1 shows the reserve obligations and the capacity resources of the Preferred Plan.

**Figure 6-1: 2022-2036 Capacity Resources and Reserve Obligation for Preferred Plan (MW)**

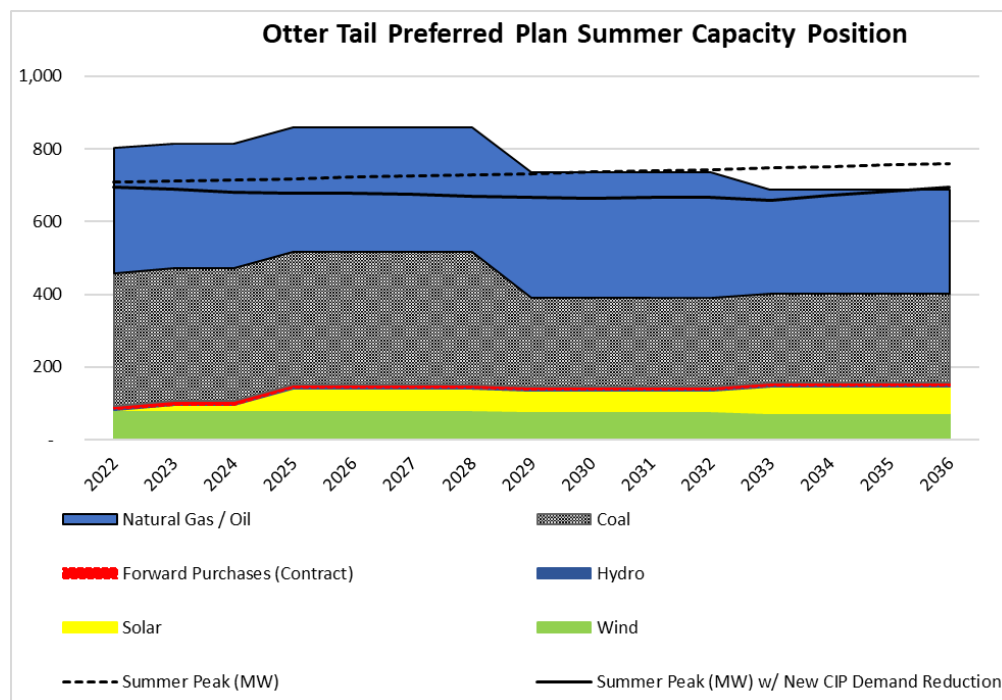
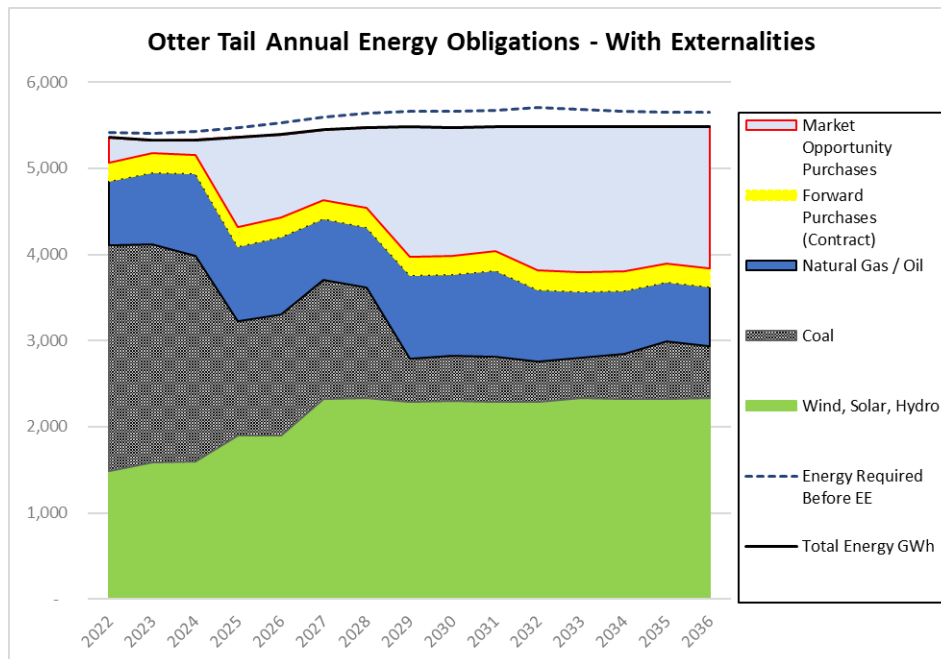
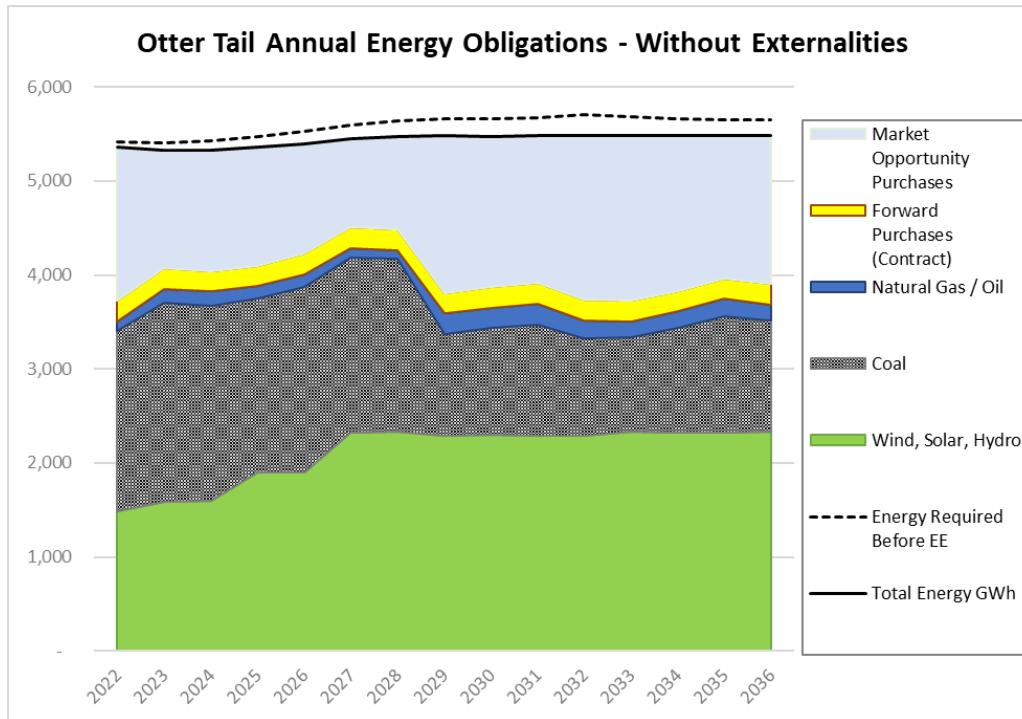


Figure 6-2 shows the energy sources in the Preferred Plan by fuel type with externalities applied, and Figure 6-3 shows the energy sources without externalities applied. Conservation contributes a significant reduction to the Company’s future energy needs (as depicted in the difference between the solid and dotted black lines), as do wind generation, continued market opportunity purchases, and natural gas generation.

**Figure 6-2: 2022-2036 Energy Resources and Energy Requirements for Preferred Plan with Externalities (GWh)**



**Figure 6-3: 2022-2036 Energy Resources and Energy Requirements for Preferred Plan without Externalities (GWh)**



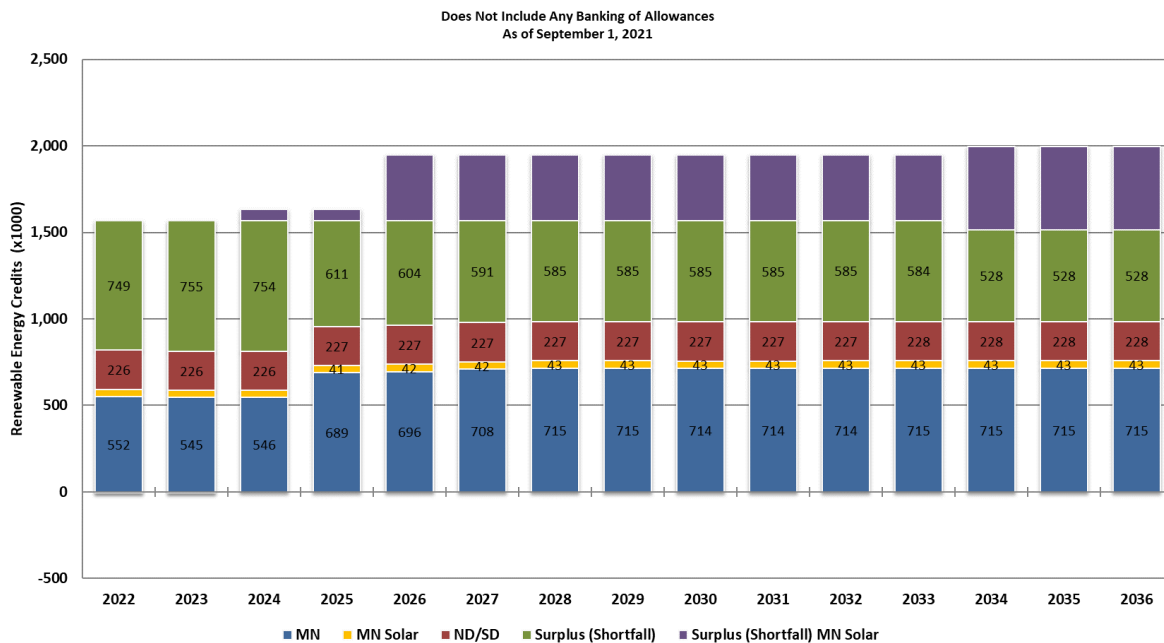
### 6.1 Preferred Resource Plan Description

Otter Tail’s Preferred Plan in the externality scenario has a present value of societal cost (PVSC) of \$2.91B in 2022\$. The Otter Tail Preferred Plan in the zero-externality scenario has a present value of utility cost (PVUC) of \$2.48B in 2022. Otter Tail believes that this plan reduces risk for customers in all three of its jurisdictions. The plan takes advantage of available federal tax credits that incentivize carbon free generation while also maintaining a level of dispatchable generation comparable with the Company’s historic levels.

### 6.2 REO/RES/SES Compliance

Figure 6-4 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. The estimate of the cost/benefit of RES compliance is contained in Appendix G.

**Figure 6-4: Compliance with REO/RES Regulation in All Jurisdictions**



### 6.3 Load Growth Scenarios

The Company included two load growth sensitivities to capture the potential impact of significant load growth across its system. The first sensitivity increased total system sales and demand by 10 percent and the second sensitivity used an increase of 25 percent. These two sensitivities are included as Sensitivities *Q* and *R* in Appendix I. This was done in the EnCompass model by applying a multiplying factor to the base case sales and demand forecast time series inputs. The Company is aware of potential new large loads that are not included in the base forecast due to uncertainty of the loads at this time. One of these loads is the new, “super-large load” customer referenced above.<sup>54</sup> We model sensitivities with large amounts of load growth to address load growth uncertainty.

<sup>54</sup> Otter Tail’s request for approval of an electric service agreement for this load is pending before the ND PSC in Case No. PU-21-366.

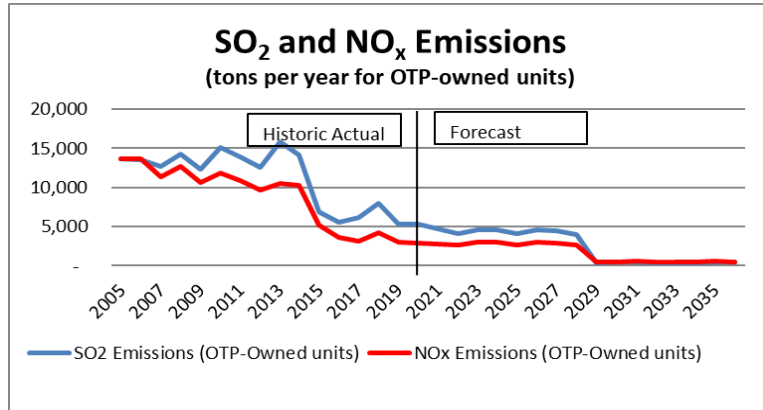
## **6.4 Environmental Externalities**

Otter Tail includes all modeling runs with and without externalities in Appendix I and compliance with specific dockets is provided in Appendix A.

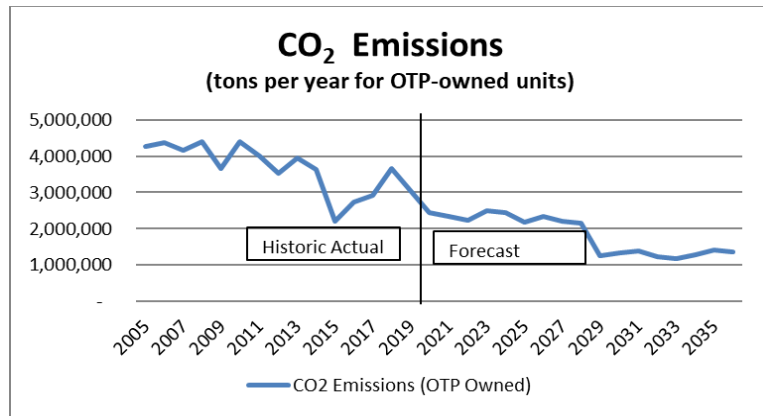
## **6.5 Emissions and Greenhouse Gas Reduction Goal**

The Preferred Plan (with externality values applied) shows a reduction in emissions from Otter Tail's historical levels. Figure 6-5 shows the estimated emissions for SO<sub>2</sub> and NO<sub>x</sub>. Figure 6-6 shows the estimated emissions for CO<sub>2</sub>. Figure 6-7 shows the estimated emissions for mercury. The values to the left of the solid black line indicate historical levels of emissions (2005 to 2020) for Otter Tail-owned units. The values to right of the solid black line (2022 to 2036) indicate the estimated emissions of the Preferred Plan for Otter Tail-owned units.

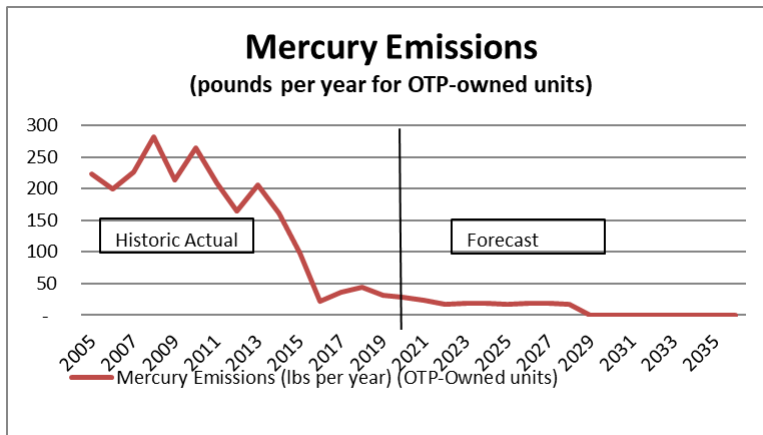
**Figure 6-5: SO<sub>2</sub> and NO<sub>x</sub> Emissions**



**Figure 6-6: CO<sub>2</sub> Emissions**



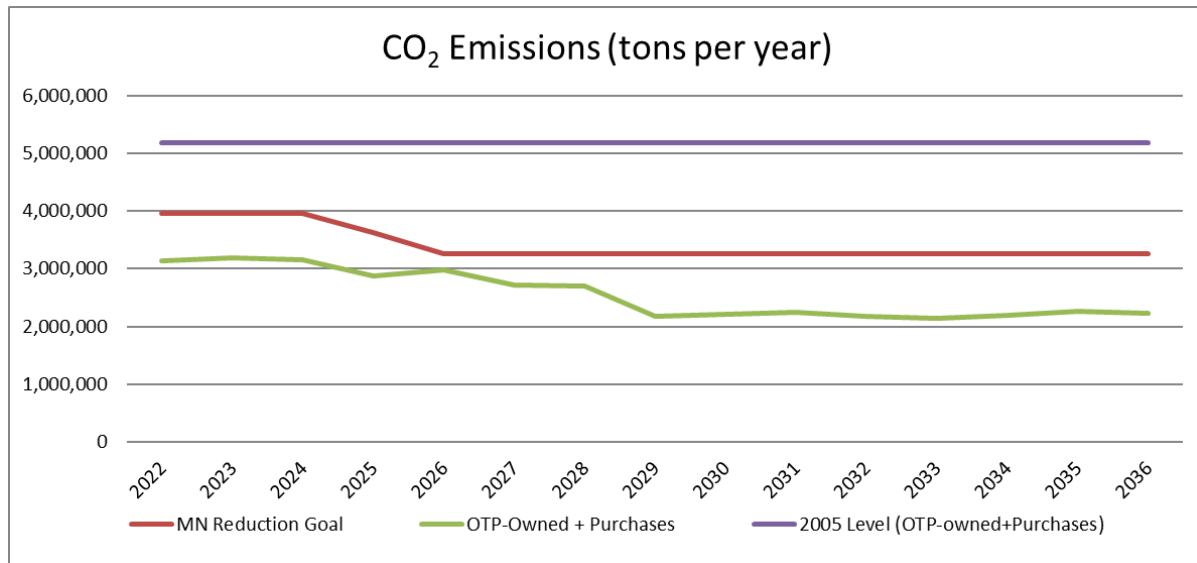
**Figure 6-7: Mercury Emissions**



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.” Otter Tail’s Preferred Plan meets the CO<sub>2</sub> reduction goal for Otter Tail’s system.

Figure 6-8 shows the Preferred Plan CO<sub>2</sub> emissions and how it compares with the CO<sub>2</sub> reduction goal and the 2005 level of CO<sub>2</sub> emissions. The 2005 level is estimated at 5,179,034 tons of CO<sub>2</sub> (4,270,780 tons from Otter Tail-owned units and 908,254 tons assumed for purchased energy based on the 2005 MRO west regional average CO<sub>2</sub> /MWh of 1,821.64 lbs). For market purchases in this resource plan, 1,098.40 lbs. of CO<sub>2</sub> are applied to each MWh of energy purchased (based on the eGRID2019<sup>55</sup> MRO west sub regional emissions rate).

**Figure 6-8: Preferred Plan CO<sub>2</sub> Emissions and the CO<sub>2</sub> reduction Goal**



<sup>55</sup> Available at: [https://www.epa.gov/sites/production/files/2021-02/documents/egrid2019\\_summary\\_tables.pdf](https://www.epa.gov/sites/production/files/2021-02/documents/egrid2019_summary_tables.pdf).

## 6.6 Oil Peaker Evaluation Sensitivities

Otter Tail includes three oil peaker plants in its resource plan: (1) at Jamestown, North Dakota, Units 1 and 2; and (2) Lake Preston, South Dakota. The peaking units are currently scheduled to be retired in 2033, as approved in Otter Tail’s 2020 Annual Depreciation Filing,<sup>56</sup> in all modeling runs.

When Otter Tail made the decision to install the Lake Preston unit in 1978 and Jamestown Units in 1976 and 1978, the primary reason 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 Junction – Toronto load pocket (15 MWs), which, until recently, had a single transmission source, a 115 kV line from Big Stone, South Dakota to Canby, Minnesota. The Jamestown units are both located in the Jamestown load pocket (70 MWs), which currently has a single high voltage source, a 345 kV line from Center through Jamestown to the Bison station near Mapleton, all in North Dakota. Today, the Jamestown Units continue to serve the purpose for 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. The Lake Preston Unit continues to provide similar backup source for its area; however, due to an increase of load in the area, Otter Tail recently installed a second transmission source that can also serve as a backup source, providing critical local transmission reliability for this load pocket.

If Otter Tail decides to retire the Jamestown 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 its load pocket. Otter Tail has evaluated two different build-out options for this load pocket. The costs of building new transmission into the Jamestown load pocket range from \$11.25 - \$14.7 million.

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<sup>56</sup> *In the Matter of the Petition of Otter Tail Power Company for Approval of its 2020 Annual Review of Depreciation Certification*, Order Approving Petition with Modifications, April 21, 2021, MPUC Docket No. E-017/D-20-703.

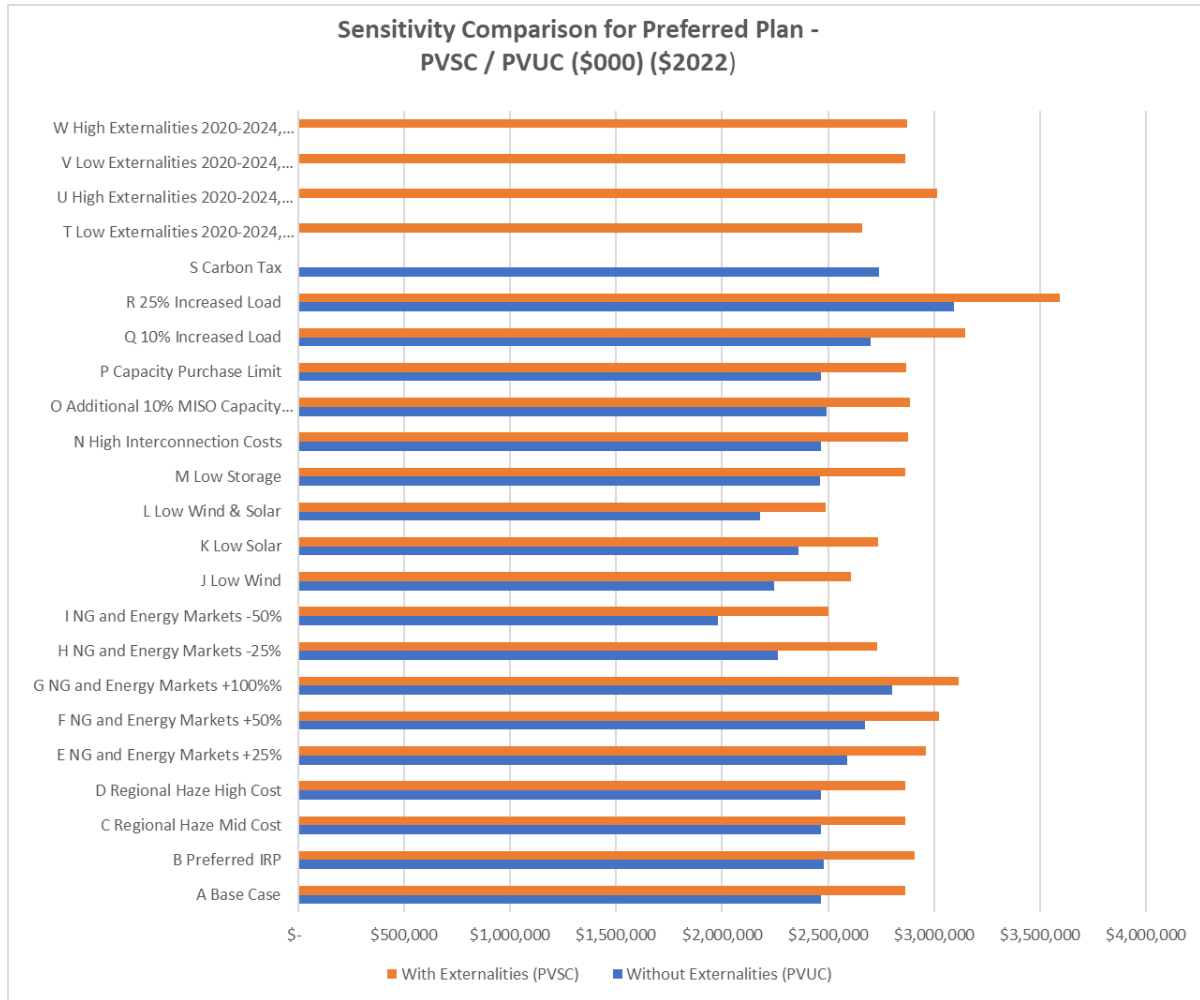
Otter Tail will be assessing the retirement of the Lake Preston unit now that a secondary transmission source has been installed in the area. The process of retiring the Lake Preston Unit will require a study and approval by MISO to determine if any additional equipment will be needed to support the area in the event the Lake Preston Unit is retired. At the same time Otter Tail will also assess the resiliency value Lake Preston continues to provide as a dispatchable generation resource with onsite fuel storage.

Generally, these units are viewed as low-cost to maintain in the fleet of resources: they are not capital or expense intensive, they rarely operate, and they are available for service if needed. However, as these units age, even though they are rarely called into service, at some point it will be prudent to plan for their retirement.

## **6.7 Additional Sensitivity Scenarios**

Otter Tail evaluated additional sensitivities. They included variations in wind prices, solar prices, natural gas prices, energy market prices, and CO<sub>2</sub> reductions. A comparison of the PVSC/PVUC for all sensitivities we evaluated based on Otter Tail's Preferred Plan, which includes withdrawal from Coyote Station in 2028, is provided in Figure 6-9. Each sensitivity is shown in orange (the PVSC) and blue (PVUC). Numeric detail of the NPVRR results of these sensitivities, as well as resources selected, are provided in Appendix I.

**Figure 6-9: Sensitivity Comparison (PVSC/PVUC)**



## 7 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.

Specifically, we request authority for the following:

- the addition of dual fuel capability at Astoria Station;
- the addition of 150 MW of solar generation in 2025; and
- the commencement of the process of withdrawal from our 35 percent ownership interest in Coyote Station, with an anticipated completion date by the end of 2028.

The Preferred Plan improves environmental performance through implementation of DSM, renewable resources as well as keeping customer rates low. The resource plan satisfies the regulatory and statutory requirements of all three jurisdictions that it serves.

### 7.1 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.

The Preferred Plan maintains and enhances system resiliency, the importance of which has been demonstrated by events such as the recent Winter Storm Uri. Specifically adding dual fuel

capability at Astoria Station substantially increases the level resilient generation provided by Otter Tail’s generation portfolio during all seasons.

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 35 percent of our energy from renewables by 2022. The Preferred Plan, which includes average annual energy savings of 1.86 percent, authority to pursue withdrawal from Otter Tail’s ownership in Coyote effective at the end of 2028, 150 MW of surplus interconnection solar in 2025, the addition of dual fuel capabilities at Astoria Station in 2026, 100 MW of surplus interconnection wind in 2027, and 50 MW of replacement interconnection solar in 2033, satisfies all rules and requirements of each jurisdictions statutes and 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.

## **7.2 Socio-Economic Impacts of the Preferred Plan**

The Preferred Plan is a least cost/least-risk plan that meets all statutory and regulatory requirements while providing reliable and affordable electricity to customers. The Preferred Plan 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.

The resource additions in the Preferred Plan will create construction jobs to develop Hoot Lake Solar and other generation resources. We acknowledge that our withdrawal from ownership in Coyote Station under the Preferred Plan has the potential for adverse socio-economic impacts for

employees working at Coyote Station, the adjacent mine, and the community in and around Beulah, North Dakota. The Preferred Plan provides opportunities to mitigate those potential impacts.

The Preferred 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, in terms of socio-economic impact the Preferred Plan provides cost-effective, reliable electricity to all classes of customers, preserves and creates jobs in the utility industry, and reduces emissions, all while being responsive to the varied concerns of our stakeholders. Greater detail regarding impacts of specific projects within the plan will be addressed as those projects are developed.

### **7.3 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; these significant activities are provided in greater detail in Section 2 above and throughout the Petition. Table 7-1 identifies some of the more major activities and the approximate timelines for those activities. 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 7-1: Five-Year Action Preferred Plan Activities**

Year	Activity
2021	Commence engineering and procurement for 49.9 MW Hoot Lake Solar Purchase SRECs for compliance with MN Solar Energy Standard
2022	June 1 Triennial CIP filing for 2023, 2024, 2025. Anticipated construction of Hoot Lake Solar. Seek sale of Coyote Station ownership interest.
2023	MISO interconnection process for 150 MW surplus interconnection solar. Anticipated commercial operation of Hoot Lake Solar.
2024	Engineering and procurement for 150MW surplus interconnection solar projects. Depending on developments provide five year advance notice of termination of Coyote Station Plant Ownership Agreement by January 1, 2024.
2025	June 1 Triennial CIP filing for 2026, 2027, 2028, Construction and commercial operation of 150 MW surplus interconnection solar projects. MISO interconnection process for 100 MW surplus interconnection wind project.
2026	Construction and commercial operation of Dual Fuel Astoria project. Engineering and procurement for 100 MW surplus interconnection wind project.

## **Appendix A: Plan Cross Reference**

*Table 1: Status of 5-year Action Plan from 2016 Integrated Resource Plan*

*Table 2: Minnesota Public Utilities Commission Orders since 2016 IRP Docket No. E017/RP-16-386*

*Table 3: North Dakota Century Code*

*Table 4: Minnesota Orders from Other Dockets*

*Table 5: Minnesota Statutes and Rules on IRPs*

## Appendix A: Plan Cross Reference

Table 1: Status of 5-year Action Plan in 2016 Integrated Resource Plan<sup>1</sup>

Year	Activity	Status
<b>2016</b>	June 1 Triennial CIP filing for 2017, 2018, 2019	Filed on June 1, 2016 (MN Docket CIP-16-116) July 1, 2019, we filed to extend the three year plan to include four years 2017, 2018, 2019, and 2020
	MISO interconnection process and preparation for permitting effort for Astoria CT	Construction complete, plant in full operation Q1 2021
<b>2017</b>	Permitting and approvals for 248 MW Astoria CT including ongoing MISO interconnection process	Construction complete, plant in full operation Q1 2021
	Begin construction on 100 MW wind project	150 MW Merricourt Wind Energy Facility construction complete, plant in full operation Q4 2020
<b>2018</b>	Commercial operation of 100 MW wind project <sup>2</sup>	150 MW Merricourt Wind Energy Facility construction complete, plant in full operation Q4 2020
	Ongoing permitting and approvals for 248 MW Astoria CT including MISO interconnection process	Construction complete, plant in full operation Q1 2021
	Initiate work on utility-scale solar project to meet the Minnesota Solar Mandate by 2020	OTP purchased SRECs to meet its 2020 and 2021 SES requirements.  OTP received approval to construct a 49.9 MW Hoot Lake Solar project in March 2021, currently expected to be operational by end of 2022.
<b>2019</b>	June 1 Triennial CIP filing for 2020, 2021, 2022	Was filed July 1, 2020, for 2021, 2022, 2023 (MN Docket CIP-20-475)
	Engineering and procurement for 248 MW Astoria CT	Construction complete, plant in full operation Q1 2021
	Begin construction on 100 MW wind project	150 MW Merricourt Wind Energy Facility construction complete, plant in full operation Q4 2020
	Construct or obtain PPA for an approximate 30 MW solar installation	OTP purchased SRECs to meet its 2020 and 2021 SES requirements.  OTP received approval to construct a 49.9 MW Hoot Lake Solar project in March 2021, currently expected to be operational by end of 2022.

<sup>1</sup> Minnesota Docket No. E017/RP-16-386, North Dakota Case No. PU-16-308, South Dakota non-docketed item provided to South Dakota Public Utility Commission on June 15, 2016.

<sup>2</sup> The 150 MW Merricourt Project with its approximately 50 percent net capacity factor is basically equivalent to the 200 MW addition of wind resource with an approximately 40 percent capacity factor in the Order due to the difference of the net capacity factor assumed.

<b>2020</b>	Construction of 248 MW Astoria CT	Construction complete, plant in full operation Q1 2021
	File MISO Attachment Y for retirement of Hoot Lake Plant	Plant retired and decommissioning began Q2 2021
	Commercial operation of 100 MW wind project	150 MW Merricourt Wind Energy Facility construction complete, plant in full operation Q4 2020
	Commercial operation of 30 MW solar project	OTP purchased SRECs to meet its 2020 and 2021 SES requirements.  OTP received approval to construct a 49.9 MW Hoot Lake Solar project in March 2021, currently expected to be operational by end of 2022.
<b>2021</b>	Start-up and commercial operation of 248 MW Astoria CT	Construction complete, plant in full operation Q1 2021
	Retirement of Hoot Lake Plant	Plant retired and decommissioning began Q2 2021

Table 2: Minnesota Public Utilities Commission Orders since 2016 IRP

<b>Docket No. E017/RP-16-386 Order Approving Plan with Modifications and Setting Requirements for Next Resource Plan, dated April 26, 2017</b>		<b>Section/Reference</b>
1.	The Commission hereby approves Otter Tail Power Company's 2017-2031 Integrated Resource Plan, as modified below.	
2.	The Commission finds that the Company's demand and net energy forecasts are acceptable for planning purposes.	
3.	Otter Tail shall file its next integrated resource plan no later than June 3, 2019.	The Minnesota Commission's December 30, 2019, Order approved the September 1, 2021, filing date for this IRP in Docket No. E-017/RP-16-386.
4.	The Commission hereby approves a five-year action plan that includes the addition of:	
	a. 200 MW of wind in the 2018 to 2020 timeframe;	Petition Section 4, Merricourt Wind Energy Facility
	b. 30 MW of solar in about 2020;	Petition Section 4, Hoot Lake Solar
	c. Up to 250 MW of peaking capacity in 2021; and	Petition Section 4, Astoria Station simple-cycle natural gas combustion turbine

	d. Average annual energy savings of 46.8 GWh (1.6 percent of retail sales)	Petition Section 4, DSM and Conservation Requirements
5.	The Commission hereby modifies Otter Tail’s integrated resource plan to include 100 MW to 200 MW of wind in the 2022 to 2023 timeframe. This does not preclude additional wind during the five-year action plan period.	Petition Section 6, Preferred Plan covers 2022-2026 time frame
6.	The Commission hereby finds that Otter Tail is adequately tracking environmental regulations that might impact its operations.	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 Petition Section 6 and Appendix F)
7.	7. Otter Tail must include in its next resource plan filing:	
	a. A transparent methodology to reflect forecasted load associated with pipelines or pipeline replacements.	Energy and Demand Forecast Models Information Filing
	b. A discussion of how incremental levels of new wind could be reasonably procured and worked into the system while maintaining reliability of service.	Petition Section 4, Renewable Energy Objectives and Standards
	c. An evaluation of capacity savings the Company could achieve via demand-response programs, including more from its existing direct load control programs. The Company must also study reliability, price, and technology-based demand-response products.	Petition Section 4, DSM and Conservation Requirements
	d. A detailed discussion of how the identified technical and economic potential for direct load control programs can be integrated into its supply-side and demand-side resource mix. The Company must also provide its strategies to improve on its installed kilowatt as a percentage of technical potential and include any overall specific benchmarks.	Petition Section 4, DSM and Conservation Requirements
	e. An analysis of the cost-effectiveness of its oil peaker plants (at Jamestown, North Dakota, Units 1 and 2; and Lake Preston, South Dakota) relative to other supply and demand-side alternatives as it relates to transmission constraints.	Petition Section 6, Oil Peaker Evaluation Sensitivities
	f. The status of Clean Power Plan compliance plans in the states included in Otter Tail’s service territory.	Appendix E
8.	This order shall become effective immediately.	
<b>Docket No. E017/RP-16-386</b>		
<b>Order Extending Deadline for Filing Resource Plan, Requiring Supplemental Filing, and Completing Competitive Bidding Process December 30, 2019</b>		
		<b>Section/Reference</b>
1.	The Commission approves Otter Tail’s request to delay the filing date for its next Integrated Resource Plan from June 1, 2020, to September 1, 2021.	
2.	Otter Tail shall make a supplemental filing by December 31, 2020, which shall include a Base case with low, mid, and high scenarios for Regional Haze compliance options, as well as a Coyote Station 2028 retirement scenario. The Company shall also run a reasonable number of sensitivities for each scenario including Minnesota environmental externalities and carbon regulatory costs. The compliance filing will be limited to Otter	Otter Tail’s December 31, 2020, Supplemental Filing <i>In the Matter of Otter Tail Power Company’s 2017-2031 Resource Plan</i> in Minnesota Docket No. E017/RP-16-386.

	Tail's EnCompass modeling results and is not subject to all items required by Minn. R. 7843.0400 and Minn. Stat. § 216B.2422	
3.	By June 1, 2020, Otter Tail shall complete a competitive-bidding process to procure approximately 30 MW or more of installed solar capacity. The process shall allow for the option of solar plus storage. The bidding process and timeline must be filed by April 15, 2020. By July 1, 2020, the Company shall make a compliance filing detailing the process and its proposed next steps for contract negotiations and filing with the Commission.	Addressed <i>In the Matter of Otter Tail Power Company's Petition for Approval of the Hoot Lake Solar Project</i> , Minnesota Docket No. E-017/M-20-844
4.	This order shall become effective immediately.	

Table 3: North Dakota Century Code

North Dakota Century Code 49-05-17 Resource Planning		Section/Reference
1.	An integrated resource plan must include: <ul style="list-style-type: none"> <li>a. The electric public utility's forecast of demand for electric generation supply over the planning period with recommended plans for meeting the forecasted demand plus an additional planning reserve margin for ensuring adequate and sufficient reliability of service; and</li> <li>b. Any additional information the commission requests related to how an electric public utility intends to provide sufficient electric generation service for sue by retail customers within the state over the planning period.</li> </ul>	Energy and Demand Forecast Models Information Filing
2.	An electric public utility shall include a least cost plan for providing adequate and reliable service to retail customers which is consistent with the provisions of this title and the rules and orders adopted and issued by the commission.	Petition, Section 6 Preferred Resource Plan
3.	The commission may consider the qualitative benefits and provide value to a base-load generation and load-following generation resource and its proximity to load.	
4.	The commission may contract or consult with an expert to evaluate qualitative benefits of resources and to review reliability planning. The commission may require an electric public utility to pay a fee necessary for completion of an evaluation in an amount not to exceed two hundred fifty thousand dollars. <ul style="list-style-type: none"> <li>a. If additional funds are necessary for completion of the evaluation, upon approval of the emergency commission, the electric public utility shall pay the additional fees reasonably necessary for the completion.</li> <li>b. If the evaluation applies to more than one electric public utility, the commission may assess each electric public utility the proportionate share of the fee</li> </ul>	
5.	An electric public utility shall report annually to the commission on cybersecurity preparedness, including an assessment of emerging threats and efforts taken by the electric public utility to implement cybersecurity measures. The commission may limit access to records and portions of a meeting relating to cybersecurity preparedness.	Otter Tail will comply with this requirement as part of an annual filing that is separate from the Integrated Resource Plan.

Table 4: Minnesota Orders from Other Dockets

<b>Docket E-999/CI-07-1199 &amp; E-999/DI-19-406 Order Establishing Estimate of the Costs of Future Carbon Dioxide Regulation Costs, dated September 30, 2020</b>		<b>Section/Reference</b>
6. The Commission hereby quantifies and establishes the range of regulatory costs of carbon dioxide emissions as \$5 to \$25 per short ton effective 2025 and thereafter.		Appendix I, <i>Externalities Included</i> . Otter Tail applied the mid-point of the range, \$15, to all with externalities sensitivities except <i>T</i> and <i>U</i> where \$5 and \$25 were applied respectively.
7. Scenarios that incorporate, for all years, the low end of the range of environmental costs for carbon dioxide as approved by the Commission in its January 3, 2018, Order Updating Environmental Costs in Docket No. E-999/CI-14-643, In the Matter of the Further investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3, and set forth in Attachment A.		Appendix I, <i>Externalities Included</i> . Sensitivity <i>V</i> uses the Attachment A Low CO2 Externality Values for 2020-2024 and the median Regulatory Cost of Carbon thereafter.
8. Scenarios that incorporate, for all years, the high end of the range of environmental costs for CO2 as approved by the Commission in its January 3, 2018, order, and set forth in Attachment A.		Appendix I, <i>Externalities Included</i> . Sensitivity <i>W</i> uses the Attachment A High CO2 Externality Values for 2020-2024 and the median Regulatory Cost of Carbon thereafter.
9. Scenarios that incorporate the low end of the range of environmental costs for CO2 but substituting, for planning years after 2024, the low end of the range of regulatory costs for CO2 regulations (\$5 per short ton) in lieu of environmental costs.		Appendix I, <i>Externalities Included</i> . Sensitivity <i>T</i> uses the Attachment A Low CO2 Externality Values for 2020-2024 and the Low Regulatory Cost of Carbon thereafter.
10. Scenarios that incorporate the high end of the range of environmental costs for CO2 but substituting, for planning years after 2024, the high end of the range of regulatory costs for CO2 regulations (\$25 per short ton) in lieu of environmental costs.		Appendix I, <i>Externalities Included</i> . Sensitivity <i>U</i> uses the Attachment A High CO2 Externality Values for 2020-2024 and the High Regulatory Cost of Carbon thereafter.
11. A reference case scenario incorporating the Commission's middle or high values of the established environmental and regulatory cost ranges.		Appendix I, <i>Externalities Included</i> . Sensitivity <i>A</i> uses the middle values of the established cost ranges.

Table 5: Minnesota Statutes and Rules – IRPs

<b>Statute</b>	<b>Subsection</b>	<b>Subject</b>	<b>Section/Reference</b>
<b>§216B.1691 Renewable Energy Objectives</b>	Subd. 2a - Eligible energy technology standard.	Report on renewable energy objectives and standards.	Appendix G

	Subd. 2e - Rate impact of standard compliant; report.	Utility must submit a report containing an estimation of the rate impact of RES compliance.	Appendix G
	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.	Petition Section 4, Renewable Energy Objectives and Standards
		(e) 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.	With the addition of Hoot Lake Solar and our Preferred IRP, Otter Tail is on track to meet this requirement
	Subd. 3 – Utility plans filed with commission.	Report on efforts toward meeting renewable energy objective/renewable energy standard.	Appendix G
<b>§216B.241 Energy Conservation Improvement</b>	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.	Petition, Section 4 – DSM and Conservation Requirements
<b>§216B.2422 Resource Planning; Renewable Energy</b>	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.	Petition, Preferred IRP meets capacity needs entirely through conservation and renewable energy resources.
	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 August 2, 2021
	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

	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.	Petition, Sections 3 and 7 - 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.	Throughout Petition, Summarized in Section 7
<b>§216B.2426 Opportunities for Distributed Generation</b>	Distributed generation.	Report on opportunities for distributed generation.	Appendix J
<b>§216H.02 Greenhouse Gas Emissions Control</b>	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.	Otter Tail's Preferred Plan meets the Emissions and Greenhouse Gas Reduction CO2 reduction Goal
<b>§216H.03 Failure to adopt greenhouse gas control plan.</b>		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.
<b>§216H.06 Emissions consideration in resource planning.</b>	Carbon values	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.	Appendix F and Appendix I, <i>Externalities Included</i>

<b>Rule</b>	<b>Subpart</b>	<b>Subject</b>	<b>Section/Reference</b>
<b>7843.03 Utility Resource Planning Process</b>	Subpart 5 - Copies of filings.	Utility shall submit 15 copies of its resource plan filing to the commission.	Included with filing
<b>7843.04 Contents of Resource Plan Filings</b>	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
	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.	Throughout Petition and Appendix I
	Subpart 3(A) - Supporting information.	Resource plan shall include a list of resource options considered.	Petition, Section 3 - Resource Alternatives and Appendix D
	Subpart 3(B)	Resource plan shall include a description of the process and analytical techniques used in developing the plan.	Petition, Section 5 - Planning Tools
	Subpart 3(C)	Response plan shall include a 5-year action plan with key construction activities and regulatory filings.	Petition, Section 7 - 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.	Petition, Section 3 - Preferred Plan is in the Public Interest
	Subpart 4	Response plan shall include a nontechnical summary (not exceeding 25 pages in length).	Petition, Section 2 - Preface

**Appendix B: Minnesota Electric Utility Annual Report**

**PUBLIC DOCUMENT –  
NOT PUBLIC (OR PRIVILEGED) 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 (please spell out acronyms)	FORM NUMBER	FORM TITLE	FILING CYCLE (enter an "X" in the cell)		
			MONTHLY	YEARLY	OTHER
US Dept of Energy, Energy Information Administration	EIA-826	Monthly Electric Utility Report	X		
US Dept of Energy, Energy Information Administration	EIA-860	Annual Electric Generator Report		X	
US Dept of Energy, Energy Information Administration	EIA-861	Annual Electric Utility Report		X	
US Dept of Energy, Energy Information Administration	EIA-923	Power Plant Operations Report		X	
US Dept of Energy, Federal Energy Regulatory Commission	Form 714	Annual Electric Control and Planning Area 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 in electronic 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 in electronic 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 (please spell out acronyms)	INTERCONNECTED UTILITY (please spell out acronyms)	MWH PURCHASED	MWH SOLD FOR RESALE
American Electric Power Service	Midcontinent Independent System Operator, Inc. (MISO)		
American UE	Midcontinent Independent System Operator, Inc. (MISO)		
Ashtabula Wind III, LLC	Midcontinent Independent System Operator, Inc. (MISO)	218,467	
Badger, SD	Badger Municipal Power		249
Basin Electric Power Cooperative			
Beltrami Electric Cooperative	Minnkota Power Cooperative	108,042	
Cargill Power Markets, LLC	Midcontinent Independent System Operator, Inc. (MISO)		
Constellation Energy Commodities Group	Midcontinent Independent System Operator, Inc. (MISO)		
Dakota Valley Services			
DTE Energy Trading, Inc.	Midcontinent Independent System Operator, Inc. (MISO)		
EDF Trading North America	Midcontinent Independent System Operator, Inc. (MISO)		
Excel Energy Under Reported Load Adj.	Midcontinent Independent System Operator, Inc. (MISO)		
Exelon			
Lake Region State College		3,724	
Lyon Lincoln Electric Cooperative			
MacQuarie Energy LLC	Midcontinent Independent System Operator, Inc. (MISO)		
Manitoba Hydro Electric Board	Midcontinent Independent System Operator, Inc. (MISO)		
MidAmerican Energy Company	Midcontinent Independent System Operator, Inc. (MISO)		
Minnesota Power	Midcontinent Independent System Operator, Inc. (MISO)		
Minnkota Power Cooperative	MAPP		
Missouri River Energy Services (MRES)	Midcontinent Independent System Operator, Inc. (MISO)		
Montana Dakota Utilities - Mountrail	Midcontinent Independent System Operator, Inc. (MISO)		
New Folden, MN	New Folden Municipal Power		1,797
Nextra Energy Power Marketing	Midcontinent Independent System Operator, Inc. (MISO)		
Nielsville, MN	Nielsville Municipal Power		27
Nodak Electric Cooperative	Nodak Electric Cooperative	7,636	
North Central Electric Cooperative			
Northern States Power	Midcontinent Independent System Operator, Inc. (MISO)	205,600	
NorthWestern Energy - NLE	MAPP		
P.K.M. Electric Co-operative, Inc.	P.K.M. Electric Co-operative, Inc.	6,064	
Rainbow Energy Marketing Corp	MAPP		
RBC Capital Markets Corporation	MAPP		
Red Lake Rural Electric Cooperative	MAPP	5,439	
Shelly, MN	Shelly Municipal Power		626
Southern Minnesota Municipal Power Agency (SMMPA)	MAPP		
The Energy Authority	Midcontinent Independent System Operator, Inc. (MISO)		
Transalta Energy Marketing	MAPP		
Western Area Power Administration (WAPA)	Midcontinent Independent System Operator, Inc. (MISO)	3	
Western Area Power Administration (WAPA) - WEC		29,972	
Willmar Municipal Utilities	Midcontinent Independent System Operator, Inc. (MISO)		
Midwest ISO			239,677
Southwest Power Pool ISO			
Non-asset based cost of sales			
OTHER NON UTILITY			



# 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 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 Department of Energy must be submitted in electronic format.

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

### G. FINANCIAL AND STATISTICAL REPORT

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

For rural electric cooperatives, a copy of the Financial and Statistical Report to the US Department 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.

COLUMN 1 NUMBER OF RESIDENTIAL ELECTRICAL SPACE HEATING CUSTOMERS	COLUMN. 2 NUMBER OF RESIDENTIAL UNITS SERVED WITH ELECTRICAL SPACE HEATING	COLUMN 3 TOTAL MWH USED BY THESE CUSTOMERS AND UNITS
na	na	188,019

### COMMENTS

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# 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 IN 2020

COUNTY CODE	COUNTY NAME	MWH DELIVERED	COUNTY CODE	COUNTY NAME	MWH DELIVERED
1	Aitkin		46	Martin	
2	Anoka		47	Meeker	
3	Becker	35646	48	Mille Lacs	
4	Beltrami	232977	49	Morrison	
5	Benton		50	Mower	
6	Big Stone	19,689	51	Murray	
7	Blue Earth		52	Nicollet	
8	Brown		53	Nobles	
9	Carlton		54	Norman	11434
10	Carver		55	Olmstead	
11	Cass	169632	56	Otter Tail	488358
12	Chippewa	4761	57	Pennington	2761
13	Chisago		58	Pine	
14	Clay	14661	59	Pipestone	
15	Clearwater	282576	60	Polk	190284
16	Cook		61	Pope	2,436
17	Cottonwood		62	Ramsey	
18	Crow Wing		63	Red Lake	194990
19	Dakota		64	Redwood	2857
20	Dodge		65	Renville	
21	Douglas	49,916	66	Rice	
22	Faribault		67	Rock	
23	Fillmore		68	Roseau	13618
24	Freeborn		69	St. Louis	
25	Goodhue		70	Scott	
26	Grant	33313	71	Sherburne	
27	Hennepin		72	Sibley	
28	Houston		73	Stearns	
29	Hubbard	13976	74	Steele	
30	Isanti		75	Stevens	93,029
31	Itasca		76	Swift	46,320
32	Jackson		77	Todd	49
33	Kanabec		78	Traverse	29171
34	Kandiyohi	9391	79	Wabasha	
35	Kittson	229235	80	Wadena	
36	Koochiching		81	Waseca	
37	Lac Qui Parle	59227	82	Washington	
38	Lake		83	Watonwan	
39	Lake of the Woods		84	Wilkin	17728
40	Le Sueur		85	Winona	
41	Lincoln	20880	86	Wright	
42	Lyon	24053	87	Yellow Medicine	25505
43	McLeod				
44	Mahnomen	37378		GRAND TOTAL (Entered)	2548449
45	Marshall	192598		GRAND TOTAL (Calculated)	2548449

### 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 (2020) 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	47,205	1,763	1,361	9,991	0	707	0	500	61,527
	MWH	58,787	7,090	5,059	37,927	0	157,440	176	2,836	269,315
February	No. of Customers	47,182	1,760	1,350	9,975	0	710	0	502	61,479
	MWH	51,407	6,135	4,188	33,259	0	154,386	130	2,655	252,158
March	No. of Customers	46,929	1,751	1,355	9,934	0	713	0	500	61,182
	MWH	46,056	5,436	3,944	31,272	0	143,894	112	2,504	233,219
April	No. of Customers	47,226	1,762	1,352	10,015	0	716	0	504	61,575
	MWH	42,658	4,604	3,635	27,489	0	147,798	109	2,462	228,757
May	No. of Customers	46,708	1,745	1,692	9,817	0	687	0	498	61,147
	MWH	33,387	3,109	3,253	20,991	0	116,136	75	2,169	179,119
June	No. of Customers	47,975	1,763	1,696	10,151	0	714	0	502	62,801
	MWH	31,776	2,302	3,441	20,423	0	110,542	74	2,057	170,615
July	No. of Customers	47,042	1,749	1,712	9,792	0	687	0	484	61,466
	MWH	42,202	2,623	4,773	24,204	0	129,826	77	1,889	205,595
August	No. of Customers	48,044	1,762	1,714	10,174	0	721	0	506	62,921
	MWH	41,080	2,423	4,902	24,921	0	131,989	78	2,075	207,468
September	No. of Customers	48,094	1,767	1,716	10,172	0	720	0	507	62,976
	MWH	35,780	2,372	4,093	24,138	0	120,835	95	1,951	189,264
October	No. of Customers	47,848	1,765	1,731	10,135	0	716	0	507	62,702
	MWH	31,780	3,614	3,578	24,792	0	107,381	105	2,058	173,306
November	No. of Customers	47,374	1,760	1,725	10,068	0	717	0	504	62,148
	MWH	37,043	3,921	4,743	27,351	0	112,491	116	1,951	187,615
December	No. of Customers	46,982	1,742	1,347	9,936	0	704	0	499	61,210
	MWH	42,990	4,746	3,945	28,928	0	169,279	113	2,118	252,019
<b>Total MWH</b>		<b>494,946</b>	<b>48,373</b>	<b>49,555</b>	<b>325,595</b>	<b>0</b>	<b>1,601,997</b>	<b>1,260</b>	<b>26,725</b>	<b>2,548,449</b>

**COMMENTS**

Street & Highway Lighting customers are counted as part of other classes. Including Street & Highway Lighting customers would be double counting as a customer would show up twice.

# 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.

	This column reports 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 (Minnesota Statutes, Section 216B.62, Subd. 5).
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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	1,347	49,555	\$4,955,634.00
Non-Farm Residential	48,724	543,318	\$58,638,894.00
Commercial	9,936	325,595	\$33,293,866.00
Industrial	704	1,601,997	\$103,564,946.00
Street & Highway Lighting	0	1,260	\$128,106.00
All other	499	26,725	\$1,825,038.00
<b>Entered Total</b>	<b>61,210</b>	<b>2,548,449</b>	<b>\$202,406,484.00</b>

^ should match ElectricityByCounty Tab, cell G55)

<b>CALCULATED TOTAL</b>	<b>61,210</b>	<b>2,548,449</b>	<b>202,406,484</b>
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^ should match ElectricityByCounty Tab, cell G55)

<b>COMMENTS</b>	Street & Highway Lighting customers are counted as part of other classes. Including number of Street & Highway Lighting customers would be double counting as a customer would show up twice.
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**REMEMBER TO SEND/UPLOAD THE FOLLOWING ATTACHMENTS:**

**DO NOT INSERT THE ATTACHMENT INTO THIS WORKBOOK**

- 1 If applicable, the Largest Customer List (Attachment ELEC-1), if the separate LargestCustomers workbook 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 Department 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 Department of Agriculture (pursuant to MN Rules Chapter 7610.0600 G)

When submitting this workbook and attachments, please following the file naming format of:

ELEC\_###\_2020 Annual Report (*this workbook*)

ELEC\_###\_2020 Largest Customer List

ELEC\_###\_2020 MN Service Area Map

ELEC\_###\_2020 Rate Schedules

ELEC\_###\_2020 Monthly Power Cost Adjustments

ELEC\_###\_2020 USDOE EIA-861

ELEC\_###\_2020 USDOA Financial and Statistical Report

NOTE: ### is your Utility Entity number found in Cell C5 on the Registration Tab













**MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)**

**7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE**  
**POWER PLANT AND GENERATING UNIT DATA REPORT 2020**

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.

<b>A. PLANT DATA</b>	
PLANT NAME	Dayton Hollow Hydro
STREET ADDRESS	
CITY	Fergus Falls
STATE	MN
ZIP CODE	56537
COUNTY	Otter Tail
CONTACT PERSON	Nathan Jensen
TELEPHONE	218-739-8989
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	7,789.00		
2	USE	HC	1919	HYD			
					<b>Plant Total</b>	<b>7,789.00</b>	

C. UNIT CAPABILITY DATA							
CAPACITY (MEGAWATTS)							
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments	
1	0.55	0.55					
2	0.40	0.40					
					<b>Plant Total</b>	<b>0.95</b>	<b>0.95</b>

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 ****
1	HYD						
2	HYD						

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

DEFINITIONS	
<b>Forced Outage Rate = (percentage)</b>	Hours Unit Failed to be Available X 100 Hours Unit Called Upon to Produce
<b>Operating Availability = (percentage)</b>	100 - Maintenance percentage - Forced Outage percentage
<b>Capacity Factor = (percentage)</b>	Total Annual MWH of Production X 100 Accredited Capacity Rating (MW) of the Unit X 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 2020**

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.

<b>A. PLANT DATA</b>	
PLANT NAME	Jamestown Turbine Plant
STREET ADDRESS	
CITY	Jamestown
STATE	ND
ZIP CODE	58401
COUNTY	Stutsman
CONTACT PERSON	Nathan Jensen
TELEPHONE	218-739-8989
PLANT ID	87015
NUMBER OF UNITS	2

<b>B. INDIVIDUAL GENERATING UNIT DATA</b>							
Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments	
1	STB	IC	1976	OIL	120.80		
2	STB	IC	1978	OIL	62.90		
					<b>Plant Total</b>	<b>183.70</b>	

<b>C. UNIT CAPABILITY DATA</b>							
CAPACITY (MEGAWATTS)			Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments	
Unit ID #	Summer	Winter					
1	20.60	20.60					
2	20.40	20.40					
<b>Plant Total</b>			<b>41.00</b>	<b>41.00</b>			

<b>D. UNIT FUEL USED</b>								
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	FO2	31,777.00	GAL					
2	FO2	23,617.00	GAL					

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

DEFINITIONS	
<b>Forced Outage Rate = (percentage)</b>	Hours Unit Failed to be Available X 100 Hours Unit Called Upon to Produce
<b>Operating Availability = (percentage)</b>	100 - Maintenance percentage - Forced Outage percentage
<b>Capacity Factor = (percentage)</b>	Total Annual MWH of Production X 100 Accredited Capacity Rating (MW) of the Unit X 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.







US Department of Energy Energy Information Administration Form EIA-861	<b>ANNUAL ELECTRIC POWER                  INDUSTRY REPORT</b>	Form Approved OMB No. 1905-0129 Approved Expires 05/31/2023
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**SCHEDULE 1. IDENTIFICATION**

<b>SURVEY CONTACTS:</b> Persons to contact with question about this form	<b>RESPONSE DUE DATE:</b> Please submit by April 30th following the close of calendar year
<b>Contact</b> Tina Eberle Title: Financial Reporting Accountant  Phone: (218) 739-8933 FAX: Email: teberle@otpco.com	REPORT FOR: Otter Tail Power Co 14232 REPORTING PERIOD: 2020
<b>Supervisor</b> Heather Johnson Title: Manager, Financial Reporting  Phone: (218) 739-8681 FAX: Email: hjohnson@otpco.com	Logged By / Date: Logged In: <input type="checkbox"/> Receipt Date (mm/dd/yyyy):

1	Legal Name of Industry Participant	Otter Tail Power Co	<b>Submission Status/Date:</b>	Submitted	08/11/2021															
2	Current Address of Principal Business Office	P O Box 496, 215 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><input type="checkbox"/> Community Choice Aggregator</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"/> Community Choice Aggregator	
<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"/> Community Choice Aggregator																			

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

US Department of Energy Energy Information Administration Form EIA-861	<b>ANNUAL ELECTRIC POWER          INDUSTRY REPORT</b>	Form Approved OMB No. 1905-0129 Approved Expires 05/31/2023								
REPORT FOR: Otter Tail Power Co 14232 REPORT PERIOD ENDING: 2020										
<b>SCHEDULE 2. PART A. GENERAL INFORMATION</b>										
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								
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	<table style="width:100%; border-collapse: collapse;"> <tr> <td style="width:30%; border-bottom: 1px solid black;">Summer (Megawatts)</td> <td style="width:10%; text-align: center;">690.7</td> <td style="width:10%; border-bottom: 1px solid black;">Prior Year</td> <td style="width:10%; text-align: center;">742.3</td> </tr> <tr> <td style="border-bottom: 1px solid black;">Winter (Megawatts)</td> <td style="text-align: center;">865.1</td> <td style="border-bottom: 1px solid black;">Prior Year</td> <td style="text-align: center;">924.0</td> </tr> </table>	Summer (Megawatts)	690.7	Prior Year	742.3	Winter (Megawatts)	865.1	Prior Year	924.0
Summer (Megawatts)	690.7	Prior Year	742.3							
Winter (Megawatts)	865.1	Prior Year	924.0							
7	Did Your Company Operate Alternative-Fueled Vehicles During the Year?  Does Your Company Plan to Operate Such Vehicles During the Coming Year?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No  <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 FOR: Otter Tail Power Co 14232  
REPORT PERIOD ENDING: 2020

SCHEDULE 2. PART B. ENERGY SOURCES AND DISPOSITION					
	SOURCE OF ENERGY	MEGAWATTHOURS		DISPOSITION OF ENERGY	MEGAWATTHOURS
1	Net Generation	2,514,831	11	Sales to Ultimate Consumers	4,776,688
2	Purchases from Electricity Suppliers	2,875,162	12	Sales For Resale	242,376
3	Exchanged Received (In)		13	Energy Furnished Without Charge	
4	Exchanged Delivered (Out)		14	Energy Consumed By Respondent Without Charge	7,500
5	Exchanged Net				
6	Wheeled Received (In)				
7	Wheeled Delivered (Out)	263,017	15	Total Energy Losses (positive number)	100,412
8	Wheeled Net	-263,017			
9	Transmission by Others Losses (Negative Number)				
10	Total Sources (sum of lines 1, 2, 5, 8 & 9 )	5,126,976	16	Total Disposition (sum of lines 11, 12, 13, 14, & 15)	5,126,976

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REPORT FOR: Otter Tail Power Co

14232

REPORT PERIOD ENDING: 2020

**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) \$	386,364.4
2	Revenue From Unbundled (Delivery) Customers (Schedule 4: Part C) \$	
3	Electric Operating Revenue from Sales for Resale \$	4,857.3
4	Electric Credits/Other Adjustments \$	
5	Revenue from Transmission \$	43,520.1
6	Other Electric Operating Revenue \$	6,805.1
7	Total Electric Operating Revenue (sum of lines 1, 2, 3, 4, 5 and 6) \$	441,546.9

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REPORT FOR: Otter Tail Power Co 14232

REPORT PERIOD ENDING: 2020

**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	290.0
2	Number of Distribution Circuits that employ voltage/VAR optimization (VVO)	.0

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REPORT FOR: Otter Tail Power Co 14232

REPORT PERIOD ENDING: 2020

**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	354.0
2	Number of Distribution Circuits that employ voltage/VAR optimization (VVO)	.0

US Department of Energy  
 Energy Information Administration  
 Form EIA-861

ANNUAL ELECTRIC POWER  
 INDUSTRY REPORT

Form Approved  
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 Approved Expires 05/31/2023

REPORT FOR: Otter Tail Power Co 14232  
 REPORT PERIOD ENDING: 2020

**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 91.0
2	Number of Distribution Circuits that employ voltage/VAR optimization (VVO) .0

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**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		107.660
3b. SAIDI value excluding Major Event days		107.660
4 SAIDI value including Major Event days minus loss of supply		
5a. SAIFI value including Major Event days		1.400
5b. SAIFI value excluding Major Event days		1.400
6. SAIFI value including Major Event days minus loss of supply		
7. Total number of customers used in these calculations		63,290.0
8. What is the highest voltage that you consider part of the distribution system, as opposed to the supply system? (kV)		25.0
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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**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	SD
3a. SAIDI value including Major Event days		79.200
3b. SAIDI value excluding Major Event days		79.200
4 SAIDI value including Major Event days minus loss of supply		
5a. SAIFI value including Major Event days		1.100
5b. SAIFI value excluding Major Event days		1.100
6. SAIFI value including Major Event days minus loss of supply		
7. Total number of customers used in these calculations		11,930.0
8. What is the highest voltage that you consider part of the distribution system, as opposed to the supply system? (kV)		25.0
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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**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	ND
3a. SAIDI value including Major Event days		105.900
3b. SAIDI value excluding Major Event days		105.900
4 SAIDI value including Major Event days minus loss of supply		
5a. SAIFI value including Major Event days		1.700
5b. SAIFI value excluding Major Event days		1.700
6. SAIFI value including Major Event days minus loss of supply		
7. Total number of customers used in these calculations		59,761.0
8. What is the highest voltage that you consider part of the distribution system, as opposed to the supply system? (kV)		25.0
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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**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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**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)
<b>State MN Balancing Authority</b> 56669					
Revenue (thousand dollars)	56,414.7	88,868.6	56,723.9	0.0	202,007.2
Megawatthours	545,911	1,032,208	981,838	0	2,559,957
Number of Customers	49,403	13,051	11	0	62,465
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	10.334	8.610	5.777		7.891
<b>State ND Balancing Authority</b> 56669					
Revenue (thousand dollars)	58,408.3	87,957.3	1,456.7	0.0	147,822.3
Megawatthours	602,118	1,115,223	20,545	0	1,737,886
Number of Customers	45,673	13,613	3	0	59,289
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	9.700	7.887	7.090		8.506

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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)
<b>State</b>	<b>SD</b>	<b>Balancing Authority</b>	56669				
Revenue (thousand dollars)			11,753.6	24,781.3	0.0	0.0	36,534.9
Megawatthours			118,203	360,642	0	0	478,845
Number of Customers			8,858	2,879	0	0	11,737
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			9.944	6.871			7.630

<b>State</b>						
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						

<b>Total</b>							
Revenue (thousand dollars)			126,576.6	201,607.2	58,180.6	0.0	386,364.4
Megawatthours			1,266,232	2,508,073	1,002,383	0	4,776,688
Number of Customers			103,934	29,543	14	0	133,491

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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)
<b>State</b>	<b>Balancing Authority</b>				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
<b>State</b>					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

<b>Total</b>
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)
<b>State</b>	<b>Balancing Authority</b>				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
<b>State</b>					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

<b>Total</b>
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)
<b>State</b>	<b>Balancing Authority</b>				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
<b>State</b>					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

<b>Total</b>
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**  
**Adjusted Gross Energy and Demand Savings -- Energy Efficiency**

If you have a non utility DSM administrator that reports your DSM activity for you please select them from the list

State/Territory	MN	Balancing Authority				Total
		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	
<b>Reporting Year Incremental Annual Savings</b>						
1	Energy Savings (MWh)	22,388.486	26,937.536	21,323.590		70,649.612
2	Peak Demand Savings (MW)	18.734	5.836	3.061		27.631
<b>Increment Life Cycle Savings</b>						
3	Energy Savings (MWh)	284022.194	399,158.409	311,060.311		994,240.914
4	Peake Demand Savings (MW)	18.734	5.836	3.061		27.631
<b>Reporting Year Incremental Costs</b>						
5	Customer Incentives	1,488.950	2,536.920	1,851.078		5,876.948
6	All other costs	2,030.831	1,062.461	673.442		3,766.734
<b>Incremental Life Cycle Costs</b>						
7	Customer Incentives	1,488.950	2,536.920	1,851.078		5,876.948
8	All other costs	2,030.831	1,062.461	673.442		3,766.734
<b>Weighted Average Life for Portfolio (Years) - Use Spreadsheet to Calculate</b>						
9	Weighted Average Life	12.686	14.818	14.588		42.000

Please provide website address to your energy efficiency program reports:

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**SCHEDULE 6. PART A. ENERGY EFFICIENCY PROGRAMS**  
**Adjusted Gross Energy and Demand Savings -- Energy Efficiency**

State/Territory	SD	Balancing Authority				Total
		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	
<b>Reporting Year Incremental Annual Savings</b>						
1	Energy Savings (MWh)	894.303	10,014.878			10,909.181
2	Peak Demand Savings (MW)	0.540	1.684			2.224
<b>Increment Life Cycle Savings</b>						
3	Energy Savings (MWh)	15587.770	151,484.149			167,071.919
4	Peake Demand Savings (MW)	0.540	1.684			2.224
<b>Reporting Year Incremental Costs</b>						
5	Customer Incentives	106.030	521.177			627.207
6	All other costs	29.044	104.340			133.384
<b>Incremental Life Cycle Costs</b>						
7	Customer Incentives	106.030	521.177			627.207
8	All other costs	29.044	104.340			133.384
<b>Weighted Average Life for Portfolio (Years) - Use Spreadsheet to Calculate</b>						
9	Weighted Average Life	17.430	15.725			33.000

Please provide website address to your energy efficiency program reports:

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**SCHEDULE 6. PART A. ENERGY EFFICIENCY PROGRAMS**

DMS Administration only. List all utilities that you provide service for.

State	Utility Name
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**Schedule 6. Part B. Yearly 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		16,745	1,756		0	18,501
2		Energy Savings (Mwh)		0.000	0.000	0.000	0.000	0.000
3		Potential Peak Demand Savings (MW)		17.000	35.000	0.000	0.000	52.000
4		Actual Peak Demand Savings (MW)		17.000	35.000	0.000	0.000	52.000

**Schedule 6. Part B. Program Cost -- Demand Response (Thousand Dollars)**  
Reporting Year Costs

5		Customer Incentives		34.492	23.005	0.000	0.000	57.497
6		All other costs		25.365	16.918	0.000	0.000	42.283

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. Yearly Energy and Demand Savings - Demand Response**

Reporting Year Savings

State/Territory	ND	Balancing Authority	56669	(a)	(b)	(c)	(d)	(e)
				Residential	Commercial	Industrial	Transportation	Total
1		Number of Customers Enrolled		15,414	1,958	0	0	17,372
2		Energy Savings (Mwh)		0.000	0.000	0.000	0.000	0.000
3		Potential Peak Demand Savings (MW)		16.000	16.000	0.000	0.000	32.000
4		Actual Peak Demand Savings (MW)		16.000	16.000	0.000	0.000	32.000

**Schedule 6. Part B. Program Cost -- Demand Response (Thousand Dollars)**

Reporting Year Costs

5		Customer Incentives		227.702	111.315	0.000	0.000	339.017
6		All other costs		179.137	87.573	0.000	0.000	266.710

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. Yearly Energy and Demand Savings - Demand Response**

Reporting Year Savings

State/Territory	SD	Balancing Authority	56669	(a)	(b)	(c)	(d)	(e)
				Residential	Commercial	Industrial	Transportation	Total
1		Number of Customers Enrolled		3,448	367	0	0	3,815
2		Energy Savings (Mwh)		0.000	0.000	0.000	0.000	0.000
3		Potential Peak Demand Savings (MW)		4.000	8.000	0.000	0.000	12.000
4		Actual Peak Demand Savings (MW)		4.000	8.000	0.000	0.000	12.000

**Schedule 6. Part B. Program Cost -- Demand Response (Thousand Dollars)**

Reporting Year Costs

5		Customer Incentives		8.120	15.550	0.000	0.000	23.670
6		All other costs		5.579	10.864	0.000	0.000	16.443

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 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	17,634	1,902	11	0	19,547

**Types of Dynamic Pricing Programs**

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customers 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-Time 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
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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 Energy Information Administration  
 Form EIA-861

ANNUAL ELECTRIC POWER  
 INDUSTRY REPORT

Form Approved  
 OMB No. 1905-0129  
 Approved Expires 05/31/2023

REPORT FOR: Otter Tail Power Co 14232  
 REPORT PERIOD ENDING: 2020

**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	15,881	2,276	0	0	18,157

**Types of Dynamic Pricing Programs**

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customers 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 type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
3	Real-Time 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
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 type="checkbox"/> Yes <input checked="" 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	3,405	370	0	0	3,775

**Types of Dynamic Pricing Programs**

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customers 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 type="checkbox"/> Yes <input checked="" type="checkbox"/> No	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
3	Real-Time 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
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 type="checkbox"/> Yes <input checked="" 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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REPORT FOR: Otter Tail Power Co 14232  
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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	145	23	0	168
2				253	261	5	0	519
3				0	0	0	0	0
4				66,910	14,258	22	0	81,190
5				67,163	14,664	50	0	81,877
6				3,710	142,539	12,379	0	158,628
7								
8								

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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	ND	Balancing Authority	56669				
			Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1		Number of AMR Meters	0	162	1	0	163
2		Number of AMI Meters	355	376	1	0	732
3		Number of AMI Meters with home area network (HAN) gateway enabled	0	0	0	0	0
4		Number of non AMR/AMI Meters	60,552	15,454	1	0	76,007
5		Total Number of Meters (All Types), line 1+2+4	60,907	15,992	3	0	76,902
6		Energy Served Through AMI	6,948	930,425	102	0	937,475
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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REPORT FOR: Otter Tail Power Co 14232  
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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	46	0	0	46
2		Number of AMI Meters	71	74	0	0	145
3		Number of AMI Meters with home area network (HAN) gateway enabled	0	0	0	0	0
4		Number of non AMR/AMI Meters	12,545	3,079	0	0	15,624
5		Total Number of Meters (All Types), line 1+2+4	12,616	3,199	0	0	15,815
6		Energy Served Through AMI	1,239	106,747	0	0	107,986
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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REPORT FOR: Otter Tail Power Co 14232

REPORT PERIOD ENDING: 2020

**SCHEDULE 7. PART A. NET METERING**

**Net Metering** programs allow customers to sell excess power they generated 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	MN	Balancing Authority	56669	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
				0.168	0.919	0.000	0.000	1.087
				21	21	0	0	42
<b>Photovoltaic</b>								
				123.026	160.531	0.000	0.000	283.557
				0.044	0.214	0.000	0.000	0.258
<b>Wind</b>				3	9	0	0	12
				0.228	4.614	0.000	0.000	4.842
				0.000	0.035	0.000	0.000	0.035
<b>Other</b>				0	1	0	0	1
				0.000	0.000	0.000	0.000	0.000
				0.212	1.168	0.000	0.000	1.380
<b>Total</b>				24	31	0	0	55
				123.254	165.145	0.000	0.000	288.399

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**SCHEDULE 7. PART A. NET METERING**

**Net Metering** programs allow customers to sell excess power they generated 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	ND	Balancing Authority	56669	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
					0.107			0.107
					4			4
<b>Photovoltaic</b>								
					7.680			7.680
				0.002	0.030			0.032
<b>Wind</b>				1	1			2
				0.000	0.000			0.000
<b>Other</b>								
								0.000
								0
								0.000
				0.002	0.137	0.000	0.000	0.139
<b>Total</b>				1	5	0	0	6
				0.000	7.680	0.000	0.000	7.680

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REPORT FOR: Otter Tail Power Co	14232							
REPORT PERIOD ENDING: 2020								
<b>SCHEDULE 7. PART A. NET METERING</b>								
<b>Net Metering</b> programs allow customers to sell excess power they generated 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)
					0.040			0.040
					2			2
<b>Photovoltaic</b>								
					28.721			28.721
				0.003	0.112			0.115
<b>Wind</b>				1	3			4
				0.000	80.239			80.239
								0.000
<b>Other</b>								0
								0.000
				0.003	0.152	0.000	0.000	0.155
<b>Total</b>				1	5	0	0	6
				0.000	108.960	0.000	0.000	108.960
<b>Grand Total All States</b>				.217	1.457	0	0	1.674
				26	41	0	0	67
				123.254	281.785	0	0	405.039

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REPORT FOR Otter Tail Power Co

REPORT PERIOD ENDING:

**SCHEDULE 7. PART B. NON NET-METERED DISTRIBUTED GENERATORS**

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

**NUMBER AND CAPACITY**

State	Balancing Authority	< 1MW
1. Number of generators		3. Capacity that consists of backup-only units
2. Total combined capacity (MW)		4. Capacity owned by respondent

**Capacity by Technology and Sector (MW)**

	Residential	Commercial	Industrial	Transportation	Direct Connected	Total
5. Internal combustion						
6. Combustion turbine(s)						
7. Steam turbine(s)						
8. Fuel Cell(s)						
9. Hydroelectric						
10. Photovoltaic						
11. Storage						
12. Wind turbine(s)						
13. Other						
14. Total						

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**SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION**

If your company owns a distribution system, please identify the names of the counties (parish, etc.) by State in which the electric wire/equipment are located.

LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)	LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)
1	MN	Becker	21	MN	Polk
2	MN	Beltrami	22	MN	Pope
3	MN	Big Stone	23	MN	Red Lake
4	MN	Cass	24	MN	Redwood
5	MN	Chippewa	25	MN	Roseau
6	MN	Clay	26	MN	Stevens
7	MN	Clearwater	27	MN	Swift
8	MN	Douglas	28	MN	Todd
9	MN	Grant	29	MN	Traverse
10	MN	Hubbard	30	MN	Wilkin
11	MN	Kandiyohi	31	MN	Yellow Medicine
12	MN	Kittson	32	ND	Barnes
13	MN	Lac Qui Parle	33	ND	Benson
14	MN	Lincoln	34	ND	Bottineau
15	MN	Lyon	35	ND	Burleigh
16	MN	Mahnomen	36	ND	Cass
17	MN	Marshall	37	ND	Cavalier
18	MN	Norman	38	ND	Dickey
19	MN	Otter Tail	39	ND	Eddy
20	MN	Pennington	40	ND	Foster

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**SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION**

If your company owns a distribution system, please identify the names of the counties (parish, etc.) by State in which the electric wire/equipment are located.

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

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SCHEDULE 9. COMMENTS				
SCHEDULE (a)	PART (b)	LINE NO. (c)	COLUMN (d)	NOTES (e)

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**EIA861 ERROR LOG**

Part	State	BA ID	Error No.	Error Description/Override Comment	Type	Override	
2	B	--	0	309	Schedule 2B lines 6 (Wheeling In) must be greater than line 7 (Wheeling Out). Please review the data and provide revisions.  Prior to WAPA joining SPP, this calculation was made up of Received Interchange (various points of interconnect with WAPA and East River loads), (Delivered Interchange) (various points of interconnect with WAPA, East River loads, and CPEC loads), (Wheeling Delivered), and (Line Loss) allowance. Which could also be referred to as OTP load in WAPA balancing authority (BA) and (WAPA load in OTP BA). When WAPA joined SPP effective October 2015, the various points of interconnect are now settled within SPP (like MISO) and all that remains in this calculation is tribal allocation delivery (WAPA load in OTP BA), wheeling deliveries (WAPA load in OTP BA and MPC wheeling in OTP BA) and line loss allowance.	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

These worksheet tabs correspond closely to the tables in the forecast instructions received by the utility. The forecast instructions pertain to the data to be entered in each of the worksheet tabs.

**PLEASE DO NOT CHANGE THE NAME OR ORDER OF ANY OF THE WORKSHEET TABS OR CHANGE THE NAME OF THIS WORKBOOK.**

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

Cells shown with a light green background correspond to headings for sections, columns, row, or individual fields on each worksheet tab.

**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 tab contains a section labeled "Comments" below the main data entry area.

You may enter any comments in that section to provide an explanation or clarification on the data entered; OR why data IS NOT being entered on the worksheet tab (for example: cells left blank).

Cells with automatic calculations (typically totals) are provided on some worksheets to assist with the accuracy of the data provided by the utility. 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 tab.

Please complete the required worksheet tabs and save the completed workbook to your local computer.

Then attach the completed workbook to an email message, include your contact information, and send it to the following email address:

[rule7610.reports@state.mn.us](mailto:rule7610.reports@state.mn.us)

If you have any questions please contact:

Anne Sell

MN Department of Commerce

[rule7610.reports@state.mn.us](mailto:rule7610.reports@state.mn.us)

651-539-1851

**MINNESOTA ELECTRIC UTILITY ANNUAL REPORT - FORECAST SECTION**

**7610.0120 REGISTRATION**

<b>ENTITY ID#</b>	87
<b>REPORT YEAR</b>	2020

<b>RILS ID#</b>	
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<b>UTILITY DETAILS</b>	
UTILITY NAME	Otter Tail Power Company
STREET ADDRESS	215 S Cascade St, PO Box 496
CITY	Fergus Falls
STATE	MN
ZIP CODE	56538-0496
TELEPHONE	218-739-8635
Scroll down to see allowable UTILITY TYPES	
* UTILITY TYPE	PRIVATE

<b>CONTACT INFORMATION</b>	
CONTACT NAME	Nathan Jensen
CONTACT TITLE	Manager, Resource Planning
CONTACT STREET ADDRESS	215 S Cascade St
CITY	Fergus Falls
STATE	MN
ZIP CODE	56538-0496
TELEPHONE	218-739-8989
CONTACT E-MAIL	<a href="mailto:njensen@otpc.com">njensen@otpc.com</a>

<b>COMMENTS</b>

<b>PREPARER INFORMATION</b>	
(do not type "Same as Above")	
PERSON PREPARING FORMS	Bryce Haugen
PREPARER'S TITLE	Senior Resource Planner
DATE	6/21/2021
PREPARER'S EMAIL ADDRESS	<a href="mailto:bhaugen@otpc.com">bhaugen@otpc.com</a>

**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	2020	No. of Customers	2,639	99,450	20,581	0	1,003	0	951	124,624	124,624
		MWH	108,037	1,269,198	879,229	0	2,463,339	20,047	58,826	4,798,675	4,798,675
Present Year	2021	No. of Customers	2,667	100,103	20,985	0	995	0	966	125,716	125,716
		MWH	100,660	1,259,736	903,404	0	2,510,155	17037.87	55,113	4,846,106	4,846,106
1st Forecast Year	2022	No. of Customers	2,695	100,509	21,178	0	996	0	975	126,353	126,353
		MWH	104,543	1,255,052	908,322	0	2,680,220	15859.2	55,847	5,019,844	5,019,844
2nd Forecast Year	2023	No. of Customers	2,710	100,809	21,313	0	997	0	981	126,810	126,810
		MWH	105,936	1,251,160	907,682	0	2,652,926	14880.4	56,232	4,988,815	4,988,815
3rd Forecast Year	2024	No. of Customers	2,723	101,040	21,444	0	998	0	985	127,190	127,190
		MWH	107,313	1,246,427	906,741	0	2,661,859	14592.78	56,472	4,993,405	4,993,405
4th Forecast Year	2025	No. of Customers	2,737	101,231	21,575	0	1,000	0	987	127,530	127,530
		MWH	108,700	1,241,182	905,685	0	2,694,830	14570.8	56,647	5,021,615	5,021,615
5th Forecast Year	2026	No. of Customers	2,752	101,399	21,706	0	1,001	0	990	127,848	127,848
		MWH	110,099	1,235,637	904,567	0	2,728,827	14548.82	56,790	5,050,469	5,050,469
6th Forecast Year	2027	No. of Customers	2,766	101,554	21,837	0	1,003	0	993	128,153	128,153
		MWH	111,507	1,229,899	903,279	0	2,786,845	14526.84	56,916	5,102,973	5,102,973
7th Forecast Year	2028	No. of Customers	2,779	101,695	21,967	0	1,005	0	995	128,441	128,441
		MWH	112,922	1,223,987	901,791	0	2,819,865	14504.86	57,033	5,130,102	5,130,102
8th Forecast Year	2029	No. of Customers	2,793	101,822	22,097	0	1,007	0	998	128,717	128,717
		MWH	114,340	1,217,911	900,151	0	2,826,869	14482.88	57,145	5,130,898	5,130,898
9th Forecast Year	2030	No. of Customers	2,806	101,935	22,227	0	1,009	0	1,000	128,977	128,977
		MWH	115,759	1,211,671	898,435	0	2,830,853	14460.9	57,254	5,128,434	5,128,434
10th Forecast Year	2031	No. of Customers	2,819	102,039	22,357	0	1,011	0	1,001	129,227	129,227
		MWH	117,179	1,205,277	896,590	0	2,839,808	14438.92	57,362	5,130,655	5,130,655
11th Forecast Year	2032	No. of Customers	2,833	102,131	22,487	0	1,013	0	1,004	129,468	129,468
		MWH	118,591	1,198,754	894,572	0	2,848,701	14416.94	57,468	5,132,503	5,132,503
12th Forecast Year	2033	No. of Customers	2,847	102,210	22,616	0	1,015	0	1,006	129,694	129,694
		MWH	119,993	1,192,117	892,389	0	2,857,511	14394.96	57,574	5,133,979	5,133,979
13th Forecast Year	2034	No. of Customers	2,860	102,285	22,744	0	1,017	0	1,008	129,914	129,914
		MWH	121,392	1,185,403	890,019	0	2,866,288	14372.98	57,680	5,135,154	5,135,154
14th Forecast Year	2035	No. of Customers	2,872	102,350	22,872	0	1,019	0	1,010	130,123	130,123
		MWH	122,781	1,178,635	887,543	0	2,874,988	14351	57,785	5,136,084	5,136,084

\* 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

Street &amp; Highway Lighting customers are counted as part of other classes. Including the number of Street &amp; Highway Lighting customers would be double counting as a customer would show up twice.

## 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 **actual number of customers** the utility has in that category 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	2020	No. of Customers	1,330	47,344	8,835	0	602	0	417	58,528	58,528
		MWH	50,237	544,380	328,639	0	1,602,559	6,622	26,891	2,559,329	2,559,329
Present Year	2021	No. of Customers	1,361	47,746	9,012	0	589	0	422	59,130	59,130
		MWH	49,957	538,386	347,017	0	1,632,226	5512.45	27,753	2,600,851	2,600,851
1st Forecast Year	2022	No. of Customers	1,373	47,979	9,107	0	590	0	428	59,477	59,477
		MWH	51,085	536,389	350,784	0	1,789,142	4355.76	28,295	2,760,051	2,760,051
2nd Forecast Year	2023	No. of Customers	1,379	48,128	9,167	0	591	0	431	59,696	59,696
		MWH	51,722	533,253	353,073	0	1,756,296	3398.94	28,492	2,726,234	2,726,234
3rd Forecast Year	2024	No. of Customers	1,385	48,234	9,225	0	592	0	433	59,869	59,869
		MWH	52,366	529,605	355,298	0	1,759,694	3133.3	28,594	2,728,690	2,728,690
4th Forecast Year	2025	No. of Customers	1,391	48,313	9,283	0	594	0	434	60,015	60,015
		MWH	53,015	525,645	357,520	0	1,787,096	3133.3	28,663	2,755,072	2,755,072
5th Forecast Year	2026	No. of Customers	1,397	48,377	9,341	0	595	0	435	60,145	60,145
		MWH	53,668	521,498	359,742	0	1,815,507	3133.3	28,719	2,782,267	2,782,267
6th Forecast Year	2027	No. of Customers	1,403	48,431	9,399	0	597	0	436	60,266	60,266
		MWH	54,321	517,227	361,964	0	1,867,900	3133.3	28,770	2,833,314	2,833,314
7th Forecast Year	2028	No. of Customers	1,409	48,474	9,457	0	599	0	437	60,376	60,376
		MWH	54,974	512,833	364,186	0	1,895,277	3133.3	28,817	2,859,220	2,859,220
8th Forecast Year	2029	No. of Customers	1,415	48,505	9,515	0	601	0	438	60,474	60,474
		MWH	55,621	508,302	366,408	0	1,896,615	3133.3	28,864	2,858,943	2,858,943
9th Forecast Year	2030	No. of Customers	1,420	48,522	9,573	0	603	0	439	60,557	60,557
		MWH	56,261	503,632	368,630	0	1,894,904	3133.3	28,911	2,855,471	2,855,471
10th Forecast Year	2031	No. of Customers	1,426	48,530	9,631	0	605	0	439	60,631	60,631
		MWH	56,893	498,848	370,852	0	1,898,140	3133.3	28,957	2,856,823	2,856,823
11th Forecast Year	2032	No. of Customers	1,432	48,526	9,689	0	607	0	440	60,694	60,694
		MWH	57,510	493,949	373,074	0	1,901,293	3133.3	29,003	2,857,963	2,857,963
12th Forecast Year	2033	No. of Customers	1,437	48,511	9,747	0	609	0	441	60,745	60,745
		MWH	58,110	488,944	375,296	0	1,904,352	3133.3	29,049	2,858,884	2,858,884
13th Forecast Year	2034	No. of Customers	1,442	48,490	9,805	0	611	0	442	60,790	60,790
		MWH	58,697	483,868	377,518	0	1,907,340	3133.3	29,095	2,859,651	2,859,651
14th Forecast Year	2035	No. of Customers	1,447	48,460	9,862	0	613	0	443	60,825	60,825
		MWH	59,267	478,718	379,740	0	1,910,243	3133.3	29,141	2,860,243	2,860,243

\* 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

Street & Highway Lighting customers are counted as part of other classes. Including the number of Street & Highway Lighting customers would be double counting as a customer would show up twice.

**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 tab.

	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	CALCULATED (GENERATION + RECEIVED) MINUS (RESALE + LOSSES) MINUS (CONSUMPTION) SHOULD EQUAL ZERO
	CONSUMPTION BY ULTIMATE CONSUMERS IN MINNESOTA MWH [7610.0310 B(1)]	CONSUMPTION BY ULTIMATE CONSUMERS OUTSIDE OF MINNESOTA MWH [7610.0310 B(2)]	RECEIVED FROM OTHER UTILITIES MWH [7610.0310 B(3)]	DELIVERED FOR RESALE MWH [7610.0310 B(4)]	TOTAL ANNUAL NET GENERATION MWH [7610.0310 B(5)]	TRANSMISSION LINE SUBSTATION AND DISTRIBUTION LOSSES MWH [7610.0310 B(6)]	TOTAL WINTER CONSUMPTION MWH [7610.0310 B(7)]	TOTAL SUMMER CONSUMPTION MWH [7610.0310 B(7)]	
Past Year 2020	2,559,329	2,239,346	2,873,290	233,830	2,514,831	355,616	2,639,271	2,159,404	0
Present Year 2021	2,600,851	2,245,255	2,294,509	142,873	3,047,011	352,540	2,665,358	2,180,748	0
1st Forecast Year 2022	2,760,051	2,259,792	2,741,358	175,212	2,820,800	367,102	2,760,914	2,258,930	0
2nd Forecast Year 2023	2,726,234	2,262,581	2,402,727	96,041	3,041,445	359,315	2,743,848	2,244,967	0
3rd Forecast Year 2024	2,728,690	2,264,715	2,425,401	137,580	3,068,159	362,575	2,746,373	2,247,032	0
4th Forecast Year 2025	2,755,072	2,266,543	2,576,611	95,451	2,902,046	361,591	2,761,888	2,259,727	0
5th Forecast Year 2026	2,782,267	2,268,201	2,571,472	115,510	2,959,554	365,048	2,777,758	2,272,711	0
6th Forecast Year 2027	2,833,314	2,269,659	2,627,687	115,510	2,959,554	368,758	2,806,635	2,296,338	0
7th Forecast Year 2028	2,859,220	2,270,882	2,656,733	115,510	2,959,554	370,675	2,821,556	2,308,546	0
8th Forecast Year 2029	2,858,943	2,271,955	2,657,585	115,510	2,959,554	370,731	2,821,994	2,308,904	0
9th Forecast Year 2030	2,855,471	2,272,963	2,654,947	115,510	2,959,554	370,557	2,820,639	2,307,795	0
10th Forecast Year 2031	2,856,823	2,273,832	2,657,325	115,510	2,959,554	370,714	2,821,860	2,308,795	0
11th Forecast Year 2032	2,857,963	2,274,540	2,659,304	115,510	2,959,554	370,845	2,822,877	2,309,626	0
12th Forecast Year 2033	2,858,884	2,275,095	2,660,884	115,510	2,959,554	370,949	2,823,688	2,310,291	0
13th Forecast Year 2034	2,859,651	2,275,503	2,662,142	115,510	2,959,554	371,032	2,824,335	2,310,819	0
14th Forecast Year 2035	2,860,243	2,275,841	2,663,137	115,510	2,959,554	371,098	2,824,846	2,311,238	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 2020	19.02	223.44	154.79	0.00	433.67	3.53	10.36	844.80	844.8

**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 2020	844.8	820.1	758.7	643.8	575.0	679.5	661.9	690.3	593.3	724.3	714.2	783.1

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

NAME OF OTHER UTILITY =>										
Past Year	2020	Summer								
		Winter								
Present Year	2021	Summer								
		Winter								
1st Forecast Year	2022	Summer								
		Winter								
2nd Forecast Year	2023	Summer								
		Winter								
3rd Forecast Year	2024	Summer								
		Winter								
4th Forecast Year	2025	Summer								
		Winter								
5th Forecast Year	2026	Summer								
		Winter								
6th Forecast Year	2027	Summer								
		Winter								
7th Forecast Year	2028	Summer								
		Winter								
8th Forecast Year	2029	Summer								
		Winter								
9th Forecast Year	2030	Summer								
		Winter								
10th Forecast Year	2031	Summer								
		Winter								
11th Forecast Year	2032	Summer								
		Winter								
12th Forecast Year	2033	Summer								
		Winter								
13th Forecast Year	2034	Summer								
		Winter								
14th Forecast Year	2035	Summer								
		Winter								

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item E. PART 2: FIRM SALES

(Express in MegaWatts)

NAME OF OTHER UTILITY =>									
Past Year	2020	Summer							
		Winter							
Present Year	2021	Summer							
		Winter							
1st Forecast Year	2022	Summer							
		Winter							
2nd Forecast Year	2023	Summer							
		Winter							
3rd Forecast Year	2024	Summer							
		Winter							
4th Forecast Year	2025	Summer							
		Winter							
5th Forecast Year	2026	Summer							
		Winter							
6th Forecast Year	2027	Summer							
		Winter							
7th Forecast Year	2028	Summer							
		Winter							
8th Forecast Year	2029	Summer							
		Winter							
9th Forecast Year	2030	Summer							
		Winter							
10th Forecast Year	2031	Summer							
		Winter							
11th Forecast Year	2032	Summer							
		Winter							
12th Forecast Year	2033	Summer							
		Winter							
13th Forecast Year	2034	Summer							
		Winter							
14th Forecast Year	2035	Summer							
		Winter							

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item F. PART 1: PARTICIPATION PURCHASES (Express in MegaWatts)

PROTECTED DATA BEGINS...

NAME OF OTHER UTILITY =>									
Past Year	2020	Summer							
		Winter							
Present Year	2021	Summer							
		Winter							
1st Forecast Year	2022	Summer							
		Winter							
2nd Forecast Year	2023	Summer							
		Winter							
3rd Forecast Year	2024	Summer							
		Winter							
4th Forecast Year	2025	Summer							
		Winter							
5th Forecast Year	2026	Summer							
		Winter							
6th Forecast Year	2027	Summer							
		Winter							
7th Forecast Year	2028	Summer							
		Winter							
8th Forecast Year	2029	Summer							
		Winter							
9th Forecast Year	2030	Summer							
		Winter							
10th Forecast Year	2031	Summer							
		Winter							
11th Forecast Year	2032	Summer							
		Winter							
12th Forecast Year	2033	Summer							
		Winter							
13th Forecast Year	2034	Summer							
		Winter							
14th Forecast Year	2035	Summer							
		Winter							

...PROTECTED DATA ENDS

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item F. PART 2: PARTICIPATION SALES (Express in MegaWatts)

NAME OF OTHER UTILITY =>										
Past Year	2020	Summer								
		Winter								
Present Year	2021	Summer								
		Winter								
1st Forecast Year	2022	Summer								
		Winter								
2nd Forecast Year	2023	Summer								
		Winter								
3rd Forecast Year	2024	Summer								
		Winter								
4th Forecast Year	2025	Summer								
		Winter								
5th Forecast Year	2026	Summer								
		Winter								
6th Forecast Year	2027	Summer								
		Winter								
7th Forecast Year	2028	Summer								
		Winter								
8th Forecast Year	2029	Summer								
		Winter								
9th Forecast Year	2030	Summer								
		Winter								
10th Forecast Year	2031	Summer								
		Winter								
11th Forecast Year	2032	Summer								
		Winter								
12th Forecast Year	2033	Summer								
		Winter								
13th Forecast Year	2034	Summer								
		Winter								
14th Forecast Year	2035	Summer								
		Winter								

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

	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 (Column 7, 8 + 6)	ANNUAL ADJUSTED NET DEMAND (Column 8, 9 + 6)	NET GENERATING CAPABILITY	PARTICIPATION PURCHASES (TOTAL)	PARTICIPATION SALES (TOTAL)	ADJUSTED NET CAPABILITY (Column 9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (Column 12 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (Column 14 - 15)
Past Year 2020	Summer	662	16	625	738	0	608	738	752	50	0	802	0	826	174
	Winter	845	90	738	738	0	738	738	752	50	0	802	0	738	64
Present Year 2021	Summer	771	16	737	737	0	737	737	834	0	0	834	0	737	97
	Winter	830	90	722	737	0	722	737	834	0	0	834	0	722	112
1st Forecast 2022	Summer	785	16	751	796	0	751	796	819	0	0	819	0	751	68
	Winter	905	90	796	796	0	796	796	819	0	0	819	0	796	23
2nd Forecast 2023	Summer	789	16	754	798	0	754	798	819	0	0	819	0	754	65
	Winter	908	90	798	798	0	798	798	819	0	0	819	0	798	21
3rd Forecast 2024	Summer	783	16	758	801	0	758	801	819	0	0	819	0	758	61
	Winter	912	90	801	801	0	801	801	819	0	0	819	0	801	18
4th Forecast 2025	Summer	796	17	761	803	0	761	803	820	0	0	820	0	761	59
	Winter	916	91	803	803	0	803	803	820	0	0	820	0	803	17
5th Forecast 2026	Summer	800	18	764	805	0	764	805	821	0	0	821	0	764	57
	Winter	920	92	805	805	0	805	805	821	0	0	821	0	805	16
6th Forecast 2027	Summer	804	19	767	807	0	767	807	822	0	0	822	0	767	55
	Winter	924	93	807	807	0	807	807	822	0	0	822	0	807	15
7th Forecast 2028	Summer	808	20	770	808	0	770	808	823	0	0	823	0	770	53
	Winter	927	94	808	808	0	808	808	823	0	0	823	0	808	15
8th Forecast 2029	Summer	812	21	774	809	0	774	809	821	0	0	821	0	774	47
	Winter	931	95	809	809	0	809	809	821	0	0	821	0	809	12
9th Forecast 2030	Summer	816	22	777	811	0	777	811	822	0	0	822	0	777	45
	Winter	935	96	811	811	0	811	811	822	0	0	822	0	811	11
10th Forecast 2031	Summer	819	23	779	812	0	779	812	823	0	0	823	0	779	44
	Winter	939	97	812	812	0	812	812	823	0	0	823	0	812	11
11th Forecast 2032	Summer	823	24	782	813	0	782	813	824	0	0	824	0	782	42
	Winter	943	99	813	813	0	813	813	824	0	0	824	0	813	11
12th Forecast 2033	Summer	827	25	785	814	0	785	814	824	0	0	824	0	785	39
	Winter	947	101	814	814	0	814	814	824	0	0	824	0	814	10
13th Forecast 2034	Summer	831	26	788	815	0	788	815	824	0	0	824	0	788	36
	Winter	951	103	815	815	0	815	815	824	0	0	824	0	815	9
14th Forecast 2035	Summer	835	27	791	816	0	791	816	824	0	0	824	0	791	33
	Winter	955	105	816	816	0	816	816	824	0	0	824	0	816	8

COMMENTS

**MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)**

**7610.0310 Item H. ADDITIONS AND RETIREMENTS (Express in MegaWatts)**

		ADDITIONS	RETIREMENTS
Past Year	2020	150	
Present Year	2021	248	128.5
1st Forecast Year	2022		
2nd Forecast Year	2023		
3rd Forecast Year	2024		
4th Forecast Year	2025		
5th Forecast Year	2026		
6th Forecast Year	2027		
7th Forecast Year	2028		
8th Forecast Year	2029		
9th Forecast Year	2030		
10th Forecast Year	2031		
11th Forecast Year	2032		
12th Forecast Year	2033		
13th Forecast Year	2034		
14th Forecast Year	2035		

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 this worksheet tab.

		FUEL TYPE 1		FUEL TYPE 2		FUEL TYPE 3		FUEL TYPE 4		FUEL TYPE 5		FUEL TYPE 6	
		Name of Fuel	Coal	Name of Fuel	HYD	Name of Fuel	NG	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	QUANTITY OF FUEL USED	NET MWH GENERATED
Past Year	2020	1,428,408	1,931,612	na	22592	526,540	51,999						
Present Year	2021	1,285,116	1,782,949	0	20000	1,052,744	117,248						
1st Forecast Year	2022	1,080,007	1,488,626	0	20000	1,674,356	186,480						
2nd Forecast Year	2023	1,140,100	1,560,805	0	20000	1,964,881	221,064						
3rd Forecast Year	2024	1,144,896	1,567,052	0	20000	2,150,037	239,458						
4th Forecast Year	2025	1,040,840	1,429,417	0	20000	1,944,154	216,529						
5th Forecast Year	2026	1,074,222	1,461,857	0	20000	2,172,681	241,980						
6th Forecast Year	2027	1,074,222	1,461,857	0	20000	2,172,681	241,980						
7th Forecast Year	2028	1,074,222	1,461,857	0	20000	2,172,681	241,980						
8th Forecast Year	2029	1,074,222	1,461,857	0	20000	2,172,681	241,980						
9th Forecast Year	2030	1,074,222	1,461,857	0	20000	2,172,681	241,980						
10th Forecast Year	2031	1,074,222	1,461,857	0	20000	2,172,681	241,980						
11th Forecast Year	2032	1,074,222	1,461,857	0	19999.99928	2,172,681	241,980						
12th Forecast Year	2033	1,074,222	1,461,857	0	19999.99928	2,172,681	241,980						
13th Forecast Year	2034	1,074,222	1,461,857	0	19999.99928	2,172,681	241,980						
14th Forecast Year	2035	1,074,222	1,461,857	0	19999.99928	2,172,681	241,980						

LIST OF FUEL TYPES

- |                                       |   |                     |
|---------------------------------------|---|---------------------|
| BIT - Bituminous Coal                 | LPG - Liquefied Propane Gas                 | HYD - Hydro (Water) |
| COAL - Coal (General)                 | NG - Natural Gas                            | WIND - Wind         |
| DIESEL - Diesel                       | NUC - Nuclear                               | WOOD - Wood         |
| FO2 - Fuel Oil #2 (Mid-Distillate)    | REF - Refuse, Bagasse, Peat, Non-wood waste | SOLAR - Solar       |
| FO6 - Fuel Oil #6 (Residual Fuel Oil) | STM - Steam                                 |                     |
| LIG - Lignite                         | SUB - Sub-bituminous coal                   |                     |

COMMENTS



**MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)**

**7610.0600, item A. 24 - HOUR PEAK DAY DEMAND**

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

A table of the demand in megawatts by the hour over a 24-hour period for:

1. the 24-hour period during the summer season when the megawatt demand on the system was the greatest; and
2. the 24-hour period during the winter season when the megawatt demand on the system was the greatest.

	DATE OF PEAK DAY DEMAND	DATE OF PEAK DAY DEMAND	
	8/13/20	1/16/20	<b>&lt;= ENTER DATES</b>
TIME OF DAY	MW USED ON SUMMER PEAK DAY	MW USED ON WINTER PEAK DAY	
0100	448	768	
0200	435	741	
0300	425	729	
0400	420	733	
0500	420	737	
0600	423	740	
0700	451	771	
0800	494	795	
0900	534	835	
1000	557	845	
1100	576	830	
1200	608	816	
1300	637	797	
1400	659	793	
1500	670	786	
1600	680	775	
1700	690	771	
1800	682	779	
1900	669	811	
2000	647	819	
2100	616	814	
2200	596	811	
2300	558	775	
2400	513	788	

COMMENTS

SECTION 3

Electric Utility Information Reporting  
Forecast Section

Form EN-0005 – 20

7610.0320 FORECAST DOCUMENTATION

## 7610.0320 FORECAST DOCUMENTATION.

**Subpart 1. Forecast methodology.** *An applicant may use the forecast methodology that yields the most useful results for its system. However, the applicant shall detail in written form the forecast methodology employed to obtain the forecasts provided under parts 7610.0300 to 7610.0315, including:*

**A. the overall methodological framework that is used;**

Aggregate econometric models of use-per-meter and number of meters were developed for each customer class, using historical data on monthly sales, number of meters, economic activity, and weather conditions. Monthly use-per-meter and number of meters forecasting models were estimated as a function of these explanatory variables, plus month-specific variables to capture any seasonal patterns that are not related to the other explanatory variables. Monthly sales forecasts for most classes were developed by multiplying use-per-meter forecasts by meter forecasts for each customer class. The exception to this is the Large Commercial class, which forecasts kWh directly, and Street Lights, which incorporates knowledge of switchover to LED fixtures. To forecast system peak demand, an econometric model was developed that explains monthly system peak demands as a function of weather, economic conditions, and month-specific variables.

**B. the specific analytical techniques that are used, their purpose, and the components of the forecast to which they have been applied;**

1. **Econometric Analysis.** Otter Tail Power Company used econometric analysis to develop jurisdictional MWh sales forecasts for the following classes: Residential, Farm, Small Commercial, Large Commercial, Other Public Authority, and Unclassified. The Street Light forecast is created using historical sales and knowledge of changes currently occurring in the change to LED fixtures.
2. **Judgment.** Judgment is inherent to the development of any forecast. Whenever possible, Otter Tail Power Company tries to use appropriate statistical tests of quantitative models to structure its judgment in the forecasting process.
3. **Loss Factor Methodology.** Loss factors were applied to convert the sales forecasts into system energy requirements.
4. **Peak Demand Forecast.** Econometric analysis was used to produce a total system MW demand forecast for each month of the forecast period.

A MWh sales forecast was developed for each customer class and jurisdiction. Summing the various jurisdictional class forecasts yields the total system sales forecast.

A monthly loss factor is applied to convert MWh sales to MWh native energy requirements.

For the sales forecasting models and system demand forecasting model, we used a standard ordinary least squares (OLS) regression model. The purpose of this model is to estimate the relationship between a dependent variable and explanatory variables (e.g., heating degree days, or GDP).

***C. the manner in which these specific techniques are related in producing the forecast;***

The econometric techniques described in Section B are applied to historical data to produce estimated effects of weather, economic factors, and demographic factors on class usage or system demand. Forecast values for the explanatory values (derived either from Woods and Poole forecasts or based on weather normal conditions) are then inserted into the estimated equations to produce forecast values of class-level sales and system demand.

***D. where statistical techniques have been used, the purpose of the technique, typical computations (e.g., computer printouts, formulas used) specifying variables and data, and the results of appropriate statistical tests;***

***Models used***

The basic structure for the use-per-meter models estimates monthly use-per-meter as a function of economic conditions, weather conditions, and month-specific variables. The economic variables that are most often used are Gross Regional Product and Total Personal Income. Weather conditions are represented using monthly heating degree days and cooling degree days. In some cases, indicator variables were included in the equation to account for events in the historical time period.

The basic form of the use-per-meter models is represented by the equation below. In this equation “m2” equals one in February and zero in all other months.

$$\text{Use-per-meter} = a + b_1 * \text{Economic Variable} + b_2 * \text{CDD/day} + b_3 * \text{HDD/day} + b_4 * m_2 + \dots + b_{14} * m_{12}$$

The basic structure for the meter models estimates monthly meters as a function of economic conditions and month-specific variables. The economic variables that are most often used are Number of Households and Total Population. The meter model is shown in the equation below.

$$\text{Meters} = a + b_1 * \text{Economic Variable} + b_2 * \text{CDD/day} + b_3 * \text{HDD/day} + b_4 * m_2 + \dots + b_{14} * m_{12}$$

The system peak demand model uses the equation below.

$$kW = a + b_1 * \text{Winter} * \text{HDD Buildup} + b_2 * \text{Summer} * \text{Temperature Humidity Index Buildup} + b_3 * \text{Swing Month} * \text{CDD \& HDD Buildup} + b_4 * \text{Gross Regional Product} + b_5 * m_2 + \dots + b_{15} * m_{12}$$

The weather buildup variables are constructed as follows:  $40/75 * X_t + 20/75 * X_{t-1} + 10/75 * X_{t-2} + 5/75 * X_{t-3}$ , where X is the weather variable in question, t is the peak day and t-3 is three days prior to the peak day. The CDD & HDD variable used in the swing months (May and September) is constructed by adding the HDD value to three times the CDD value.

The models use information from Woods and Poole Economics, Inc. for its forecasts of economic demographic variables.

The table under Subp. 2 (data base for forecasts) shows the variables that are included in each model. Specifications that included more variables were also tested to determine the final model used.

***E. forecast confidence levels or ranges of accuracy for annual peak demand and annual electrical consumption; and***

The estimated effect of each variable in the equations above (e.g., the effect of heating degree days on system peak demand) has a standard error associated with it that is used to generate a confidence interval around the forecasted demand value (e.g., there is some probability that the “true” value of the parameter is actually larger than the estimated value, which would imply that the effect of weather on demand would be larger, leading to a higher peak demand for a given assumed weather condition). In calculating the confidence intervals around the demand forecast, the values of the explanatory variables, such as weather, economic growth, and demographics are all maintained at fixed assumed or expected levels. TABLE 1 (below) shows the results of the confidence levels in 5 year increments.

**Table 1**  
**Forecast Confidence Levels**  
**2021 Econometric Forecast**  
**Percent Deviation from Base**

Year	Low Scenario		High Scenario	
	Peak	Sales	Peak	Sales
2021	(7.7%)	(9.4%)	7.6%	9.2%
2026	(7.4%)	(9.7%)	7.5%	9.5%
2031	(7.3%)	(10.3%)	7.4%	10.2%
2036	(7.2%)	(11.1%)	7.3%	11.1%

***F. a brief analysis of the methodology used, including its strengths and weaknesses, its suitability to the system, cost considerations, data requirements, past accuracy, and any other factors considered significant by the utility.***

**Methodology** As discussed in A the Company uses Econometric models to forecast energy sales requirements and system peak demand. This method is used as it is a standard methodology in the industry and thus facilitates review.

**Strengths and Weaknesses** As mentioned above, one of the main strengths is the ability of the econometric model to be understood because as mentioned above, the econometric model is an industry standard. The model is reasonably easy to fine tune as it was developed in-house. One of the weaknesses is that the data it uses is not as detailed as the data used in an end-use forecast.

**Suitability to the system** The econometric methodology is a very good fit to Otter Tail Power Company's system. Serving three states with distinct economic differences, using the econometric model makes it easy to utilize the different economic data for each state and determine whether particular variables are drivers for each state.

**Cost Considerations** The econometric approach, relative to an end-use model approach, is inexpensive to maintain while being very reliable.

**Data Requirements**

The forecast utilizes about 20 years of monthly historical energy data and demand data along with their corresponding weather and econometric variables. As described in detail in subpart 2, the sources of data for the explanatory variables was Otter Tail Power Company weather monitoring stations for weather data; the Otter Tail Power Company Customer Information System for meter counts; Woods and Poole Economics, Inc. for econometric data; and the High Plains Regional Climatic Center for weather data that was not available from Otter Tail Power Company weather monitoring stations.

**Past Accuracy**

Otter Tail Power Company does look back to see how the model predicts past energy and demand. If the model predicts backwards well, there is a reasonable confidence that it will predict well in the future. We've looked at the 20 year backcast for the energy and demand forecasts models. The energy model has an Average Absolute Error of 1.73 percent over the past ten years. The demand model has an Average Absolute Error of 3.00 percent over the past ten years.

***Subp. 2. Data base for forecasts. The utility shall discuss in written form the data base used in arriving at the forecast presented in part 7610.0310, including:***

- A. a complete list of all data sets used in making the forecast, including a brief description of each data set and an explanation of how each was obtained, (e.g., monthly observations, billing data, consumer survey, etc.) or a citation to the source (e.g., population projection from the state demographer); and***
- B. a clear identification of any adjustments made to raw data to adapt them for use in forecasts, including the nature of the adjustment, the reason for the adjustment, and the magnitude of the adjustment.***

Sales Forecast

Table 2

Independent Variables Used in the Sales Forecast Models													
		State	CDD65	HDD65	Mean Household Income	Number Of Households	Gross Regional Product	Total Employment	Billing Days	AR Terms	Trend Variable	Miscellaneous Binaries	
Residential	Use Per Meter	MN	X	X					X	X	X	X	
		ND	X	X					X	X	X	X	
		SD	X	X	X				X	X		X	
	Meters	MN				X							X
		ND								X	X	X	X
		SD								X	X	X	X
Farm	Use Per Meter	MN	X	X			X			X		X	
		ND		X			X		X	X		X	
		SD		X						X	X		X
	Meters	MN					X			X			X
		ND								X	X		X
		SD								X	X		X
Small Commercial	Use Per Meter	MN	X	X					X	X		X	
		ND	X	X					X	X	X	X	
		SD	X	X				X	X	X	X		X
	Meters	MN								X	X		X
		ND								X	X		X
		SD						X					X
Large Commercial	KWH	MN	X	X			X		X	X		X	
		ND		X			X		X	X		X	
		SD							X	X	X		X
		MN											
		ND											
		SD											
Other Public Authority	Use Per Meter	MN		X					X	X		X	
		ND		X					X			X	
		SD		X					X	X		X	
	Meters	MN								X	X		X
		ND								X	X		X
		SD								X	X		X

Database: Otter Tail Power Company's Customer Information System (CIS)

**Variables Used:**

Use-per-meter: kwh sales divided by the number of meters

Meters: number of meters

**Description/Source:**

KWH and the number of meters were read from SAS CISA data sets. The SAS data sets were created from extracts of the CIS taken the last day of each month. Each record was assigned to one of 40 rate groups within each state based on rate and revenue class combinations. Records were summed to the rate group level within each state. Each rate group was then assigned to one of the eight classes used in the forecast. The variable *Use-per-meter* was calculated by dividing the monthly KWH by the monthly number of meters.

**Adjustments Made:**

Each record was checked to be sure it was assigned a rate group. Any record not assigned a rate group had its rate and/or revenue class corrected so a rate group was properly assigned. Monthly group KWH data was graphed and values were reviewed for errors due to meters not being billed, being billed twice one month, etc. In most cases the data used for corrections was taken from a second CIS download that was run later the following month after billing corrections had been made. In some cases judgment was used.

**Database:** DEGREE DAYS**Variables Used:**

*cdd65*: average cooling degree days for each month with a 65 degree base

*hdd55*: average heating degree days for each month with a 55 degree base

**Description/Source:**

Hourly temperature data was obtained from 14 monitoring stations throughout Minnesota, North Dakota and South Dakota. The data comes from Schneider Electric, who does multiple data "cleansing" processes to ensure the data is correct and that missing values are filled. Scheduled billing cycle start and stop dates were obtained from the Customer Information System (CIS). Daily heating degree days (*hdd*) and cooling degree days (*cdd*) were calculated based on 65 degree base and the rounded average of the twenty-four hourly temperatures. Daily degree days were then averaged and weighted for each state and added to calculate billing month and calendar month heating degree days and cooling degree days. Average monthly *hdd* and *cdd* were calculated over a 20 year period to calculate normal billing month and calendar month *hdd* and *cdd*. Billing month *hdd* and *cdd* were used for the historical period and calendar month *hdd* and *cdd* were used for the forecast period.

**Adjustments Made:**

Hourly monitoring station temperatures are graphed each month after the data is downloaded. Any missing or obviously bad temperatures are corrected based on temperatures from other nearby monitoring points or by judgment when necessary.

**Database:** WOODS AND POOLE**Variables Used:**

*Total Personal Income*  
*Number of Households*  
*Gross Regional Product*  
*Farm Employment*  
*Total Employment*  
*Net Earnings*  
*Farm Earnings*  
*Total Population*

**Description/Source:**

2020 state profile econometric data for Minnesota, North Dakota and South Dakota was purchased from Woods and Poole Economics, Inc., 4910 Massachusetts Avenue NW Ste 208, Washington, DC 20016-4368 ([www.woodsandpoole.com](http://www.woodsandpoole.com)). The 2020 state profile data contains annual historical data for 1969-2018 and annual forecast data for 2020-2050 at the county level.

**Adjustments Made:**

Otter Tail Power Company does not serve all of the load in the counties within its service territory. This is especially problematic when Otter Tail Power Company does not serve a large city that has a significant impact on the economy of the county. Some examples are Fargo, Grand Forks and Minot in North Dakota and Moorhead, Minnesota. To reflect this, a decision was made to not use econometric data from counties where Otter Tail Power Company served less than 10 percent of the population of the county. County population data was downloaded from [www.census.gov](http://www.census.gov). The percentage of the population served by Otter Tail Power Company in each county was determined by dividing the sum of populations of towns served by Otter Tail Power Company in each county by the population of the county. Counties with a percentage of less than 10 percent were not included. Town populations were obtained from an internal database of towns served. The data was then summed to the state level and graphed as a reasonability check. Annual Woods and Poole data was converted from annual data to monthly by interpolating between annual values with a flat line.

## Demand Forecast

**Table 3**

Independent Variables Used in the Peak Demand Forecast Model					
	Monthly Binaries	w hdd55 buildup	sth buildup	swcdd65 hdd55 buildup	Gross Regional Product
System Peak Demand	X	X	X	X	X

**Database:** Otter Tail Power Company's System Load Data

**Variables Used:** *System Peak Demand*

**Description/Source:** Annual hourly system load (MAPP) files and annual hourly net controlled load (NCL) files were obtained from System Operations. System load data was combined with the net controlled load data to give hourly system demands without control.

**Adjustments Made:** The hourly system load files are graphed and reviewed by System Operations personnel each month.

**Database:** WOODS AND POOLE

**Variables Used:** *Gross Regional Product*

**Description/Source:** 2020 state profile econometric data for Minnesota, North Dakota and South Dakota was purchased from Woods and Poole Economics, Inc., 4910 Massachusetts Avenue NW Ste 208, Washington, DC 20016-4368 ([www.woodsandpoole.com](http://www.woodsandpoole.com)). The 2019 state profile data contains annual historical data for 1969-2017 and annual forecast data for 2020-2050 at the county level.

**Adjustments Made:** Otter Tail Power Company does not serve all of the load in the counties within its service territory. This is especially problematic when Otter Tail Power Company does not serve a large city that has a significant impact on the economy of the county. Some examples are Fargo, Moorhead, Grand Forks and Minot. To reflect this, a decision was made to not use econometric data from counties where Otter Tail Power Company served less than 10 percent of the population of the county. County population data was downloaded from [www.census.gov](http://www.census.gov). The percentage of the population served by Otter Tail Power Company in each county was determined by dividing the sum of populations of towns served by Otter Tail Power Company in each county by the population of the

county. Counties with a percentage of less than 10 percent were not included. Town populations were obtained from an internal database of towns served. The data was then summed to the state level and graphed as a reasonability check. Annual Woods and Poole data was converted from annual data to monthly by interpolating between annual values with a flat line.

**Database:** FARGO WEATHER DATA

**Variables Used:** *sthibuildup*: summer temperature humidity index buildup

**Description/Source:** Hourly weather data files were obtained from the High Plains Regional Climatic Center ([www.hprcc.unl.edu](http://www.hprcc.unl.edu)) for Fargo, North Dakota. Fargo is used as a proxy for the system average weather data (other than temperatures which come from Otter Tail Power Company division weather stations). The hourly temperature humidity index (*thi*) was calculated from the hourly dry bulb temperatures and the hourly relative humidity ( $thi=db-(.55-.55*rh/100)*(db-58)$ ). The average daily temperature humidity index (*thi*) was calculated from the hourly values. The variable *thibuildup* was calculated from *thi* for the day of monthly system peak and *thi* from the previous three days so that each previous day has half the influence of following day  $((40/75)*thi+(20/75)*lag1thi+(10/75)*lag2thi+(5/75)*lag3thi)$ . The variable *sthibuildup* has the value of *thibuildup* for the months of June, July and August and zero for all other months. The forecast period *sthibuildup* variable was calculated by determining the value of *thi* for each monthly system peak day and the three days previous to the peak for the last 20 years.

**Adjustments Made:** High Plains Climatic Center data was used rather than NOAA data because the High Plains Climatic Center data has been reviewed and edited where necessary and the NOAA data has not.

**Database:** DEGREE DAYS

**Variables Used:**

*Whdd65buildup*: winter heating degree day buildup

*swcdd65hdd65buildup*: swing month cooling and heating degree day buildup

**Description/Source:** Average hourly temperature data was obtained by averaging hourly temperatures across 14 monitoring stations throughout Minnesota, North Dakota and South Dakota. Daily heating degree days (*hdd*) and cooling degree days (*cdd*) were calculated based on a 65 degree base and the rounded average of the twenty-four hourly temperatures. The variables *hddbuidup* and *cddbuidup* were calculated from the degree days for the day of monthly system peak and the degree days from the previous three days so that each previous day has half the influence of following day (for example,  $(40/75)*hdd+(20/75)*lag1hdd+(10/75)*lag2hdd+(5/75)*lag3hdd$ ). The variable *whdd65buildup* has the value of *hddbuidup* for the months of January, February, March, April, October, November and December and zero for all other months. The variable *cddhdd* was calculated by adding three times *cdd* to one times *hdd* ( $3*cdd+1*hdd$ ). The variable *swcdd65hdd65buildup* has the value *cddhdd* for the months of May and September and zero for all other months. Forecast period *whdd65buildup* and *swcdd65hdd65buildup* variables were calculated by determining

the value of *hdd* and *cdd* for each monthly system peak day and the three days previous to the peak for the last 20 years.

**Adjustments Made:** Hourly monitoring station temperatures are graphed each month after the data is downloaded. Any missing or obviously bad temperatures are corrected based on temperatures from other nearby monitoring points or by judgment when necessary.

***Subp. 3. Discussion. The utility shall discuss in writing each essential assumption made in preparing the forecasts, including the need for the assumption, the nature of the assumption, and the sensitivity of forecast results to variations in the essential assumptions.***

Some assumptions should be listed individually for emphasis.

**1). No load management:**

Need: Load management is used at Otter Tail Power during peak conditions, summer, and winter. The use of the control is not always predictable. To build a forecast to match a load subject to load management is not practical.

Assumption: The forecast is made to match uncontrolled load. Therefore, to match forecast to load, the observed load must have the estimated load management added. This simplifies the process of reconciling the forecast.

Sensitivity: There is nothing to test.

**2). Woods and Poole Economics, Inc.**

Need: Economic forecasts are needed to provide projections of population and employment. The forecasts must be consistent among county, state, and national projections, so the forecasts need to be from similar sources or be based on similar assumptions. For this reason, these elements of the forecast are taken from a single source.

Assumption: Woods and Poole data provides a consistent scenario of the future that connects national, state and county projections. Population and employment follow this story of the future economy.

Sensitivity: No consistent alternatives are provided.

See also the above discussions and the discussion below regarding subject of assumption.

***Subp. 4. Subject of assumption. The utility shall discuss the assumptions made regarding the availability of alternative sources of energy, the expected conversion from other fuels to electricity or vice versa, future prices of electricity for customers in the utility's system and the effect that such price changes will likely have on the utility's system demand, the assumptions made in arriving at***

**any data requested in part 7610.0310 that is not available historically or not generated by the utility in preparing its own internal forecast, the effect of existing energy conservation programs under federal or state legislation on long term electrical demand, the projected effect of new conservation programs that the utility deems likely to occur through future state and federal legislation on long term electrical demand, and any other factor considered by the utility in preparing the forecast. In addition the utility shall state what assumptions were made, if any, regarding current and anticipated saturation levels of major electric appliances and electric space heating within the utility's service area. If a utility makes no assumptions in preparing its forecast with regard to current and anticipated saturation levels of major electrical appliances and electric space heating it shall simply state this in its discussion of assumptions.**

Otter Tail Power Company's forecast assumes availability of alternative sources of energy will continue in similar patterns as have been historically.

Otter Tail Power Company did not assume any changes in the availability of alternative sources of energy, the expected conversions from other fuels to electricity or vice versa, future prices of electricity for customers in the utility's system and the effect that such price changes will have on the utility's system demand. The current forecast by default assumes any prices changes would be in small increments that demand is not noticeably impacted. While price changes due to rate cases are not necessarily smooth in the short-term (reality), for the purposes of the long-term forecast any price changes smooth out over time. This reality is due to the long-term planning process. The utility itself and regulatory bodies are involved in the integrated resource planning process in part to mitigate significant price changes.

Otter Tail Power Company's forecast does not make any explicit assumptions about current and anticipated saturation levels of major electric appliances and electric space heating within the utility's service area.

**Subp. 5. Coordination of forecasts with other systems.**

***The utility shall provide in writing:***

- A. a description of the extent to which the utility coordinates its load forecasts with those of other systems, such as neighboring systems, associate systems in a power pool, or coordinating organizations; and***
- B. a description of the manner in which such forecasts are coordinated, and any problems experienced in efforts to coordinate load forecasts.***

Otter Tail Power Company does not coordinate its long-term load forecasts with those of other systems.

STAT AUTH: MS s 216C.10

HIST: L 1987 c 312 art 1 s 9; 16 SR 1400

# Appendix C: Existing Resources

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## Existing Resources

Otter Tail Power Company has a variety of existing resources available to meet the energy needs of its customers, both reliably and economically. These resources consist of existing generating facilities, the radio load management system, the Midcontinent Independent System Operator (MISO), purchases from other utilities, customer owned generation, the transmission and distribution network, and current Company sponsored conservation programs.

Figure 1-1 shows the composition of the 2021 Planning Year capacity by fuel source for the Company.

**Figure 1-1: 2021 Planning Year Accredited Capacity Resources Fuel Source Percent of Total = 807 MW**

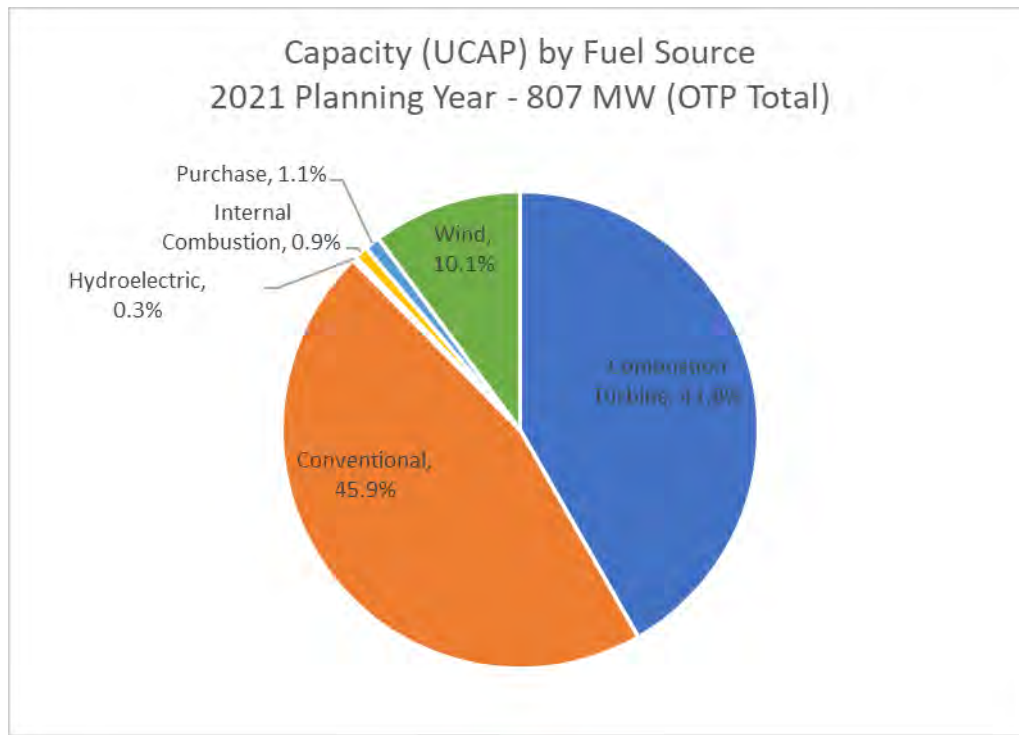


Table 1-1 shows a listing of the Company’s resources and their capacity ratings for the 2021 Planning Year. The capacity ratings data provided is based on current MISO ratings under Module E’s resource adequacy requirements in effect for the Planning Year June 1, 2021, through May 31, 2022.

**Table 1-1: 2021 Otter Tail Capacity Resources**

<b>Capacity - Owned Resources</b>	<b>ICAP (MW)</b>	<b>UCAP (MW)</b>
<b>Coal</b>		
Big Stone Plant	257.7	252.8
Coyote	149.1	131.3
<b>Gas CT</b>		
Astoria	249.7	237.8
Solway 1	42.4	41.6
<b>Wind</b>		
Ashtabula	48.0	8.2
Langdon	40.5	7.7
Luverne	49.5	9.8
Merricourt	150.0	24.5
<b>Hydro</b>		
Garrison Hydro	4.3	4.3
Garrison Hydro 2	4.4	4.4
Dayton Hollow Hydro 1	0.5	0.5
Dayton Hollow Hydro 2	0.4	0.4
Hoot Lake Hydro	0.5	0.5
Pisgah Hydro	0.7	0.7
Taplin Gorge Hydro	0.5	0.5
Wright Hydro		
<b>Oil</b>		
Lake Preston	19.4	18.4
Jamestown 1	20.6	20.2
Jamestown 2	20.4	20.4
<b>Load Control</b>		
Otter Tail Load Control	16.0	18.5
<b>Total Owned:</b>	1074.6	802.5

<b>Capacity Purchased Resources</b>	<b>ICAP (MW)</b>	<b>UCAP (MW)</b>
<b>Wind</b>		
Edgeley (ND Wind II)	21.0	2.8
Langdon	19.5	3.9
Ashtabula III	62.4	11.7
Customer Owned	4.3	4.1
<b>Total Purchased:</b>	107.2	22.5

## 1.1 Hydroelectric Facilities

Otter Tail Power Company has 6 units located at five dams on the Otter Tail River near Fergus Falls, MN and 2 units located at a dam on the outlet of Lake Bemidji at Bemidji, MN. These hydro units were constructed in the early 1900's and were the backbone of the generating resources for Otter Tail for many years in the early days of the Company. The total capability of all of the hydro units is about 3.7 MW.

The hydro units located on the Otter Tail River are under FERC jurisdiction and were licensed for the first time in 1991. All of these units were built prior to licensing requirements. The units are predominantly operated in run of river mode without pondage capability except for Hoot Lake and Wright Lake behind the Hoot Lake Hydro. Prior to the FERC licensing, there was a small amount of pondage and cycling capability with these units that increased the amount of energy obtained from the water flow. The FERC license required a change to strict run of river operation.

All of the hydro units in run of river mode have had updated reservoir level monitoring systems installed to aid in complying with the operating requirements of the FERC license. Automatic level control systems have also been installed at a number of the units to control the reservoir level using the signal from the reservoir level monitoring system. Significant other equipment upgrades were completed in the past 15 years, to upgrade electrical control and protection equipment.

The FERC re-licensing process is approximately 5 years and OTP has been preparing for submission for license renewal. This submission known as the Notice of Intent (NOI) and Project Application Document (PAD) is being prepared and the process through FERC will begin officially in the summer of 2016.

### **Bemidji Hydro**

The Bemidji Hydro units were built in 1907. These units were authorized by Congress and are not subject to FERC jurisdiction. Otter Tail acquired ownership of these units in the 1940's. The Unit #1 generator stator and rotor field was rewound in 2008.

### **Dayton Hollow Hydro**

Dayton Hollow Dam was built in 1909 with two generators installed. A third generator was added in 1917. One of the original generators was retired and removed in 1964. The Unit #2 turbine and generator were refurbished in 2006 and the turbine also had a major repair in 2008 – 2009. Annual generation from the Dayton Hollow units is about 5,000 – 7,000 MWh.

### **Hoot Lake Hydro**

The Hoot Lake Hydro was built in 1914. The hydro originally had two units, but one unit was retired with the addition of the Hoot Lake #3 steam unit in 1964. The Hoot Lake Hydro is part of a system that was developed to make further use of the Otter Tail River. Diversion Dam was built on the Otter Tail River and part of the water from the river is diverted through an underground tunnel to Hoot Lake that flows into Wright Lake. The two lakes were created from the diverted water. The water from Wright Lake flows through the Hoot Lake structure, and is used in the hydro unit and for cooling water for the Hoot Lake steam units. Hoot Lake Hydro has been generating about 3,000 - 4,000 MWh annually. The City of Fergus Falls also makes use of the Diversion Dam system as water supply for the city.

**Pisgah Hydro**

Pisgah Hydro was built in 1918. The generator stator and rotor was rewound in 2001. The turbine was rebuilt in 2005. This unit provides about 3,500 – 4,500 MWh during normal years.

**Taplin Gorge (Friberg) Hydro**

Taplin Gorge, also known as Friberg, was constructed in 1925. The structure is well known in the Fergus Falls area because the powerhouse is a replica of the tomb of the former Italian ruler, Theodoric. The generator was rewound in 1999. Annual generation is in the 3,000 – 4,200 MWh range.

**Wright (Central) Hydro**

Wright Dam (also called Central) is located in downtown Fergus Falls, and has been the location of a dam since the 1880's. It originally provided power via drive belts to industries located nearby. The current structure was built in 1922. The turbine was rebuilt and the generator cleaned and rewedged in 2002 – 2003. Annual generation is in the range of 2,000 – 3,000 MWh.

## 1.2 Peaking Facilities

Otter Tail Power Company has a number of peaking units on the system. Some are internal combustion units, but most of the capacity is comprised of combustion turbines. Astoria and Solway are frequently dispatched by the MISO centralized market. Otter Tail's other peaking units operate on a very limited basis annually, either for emergency or extreme peak times, or for testing purposes.

**Astoria Station**

Astoria Station is natural gas fired, Mitsubishi 501GAC, combustion turbine that was placed into service in 2021. Astoria Station's summer rating is 245 MW. At colder ambient temperatures, the Unit can generate up to its transmission interconnection limit of 286 MW. Astoria Station was designed with fast start capability; allowing it to achieve 80% load within 10 minutes from the initiation of a start command.

**Jamestown Combustion Turbines**

Otter Tail has two fuel oil-fired combustion turbines located at Jamestown, ND. These units are of 1976 and 1978 vintage. These units are operated for emergency, peaking, and testing situations, as well as for economy during periods when market prices support it. The Frame 5 units at Jamestown operate a very limited number of hours during the year.

**Lake Preston Combustion Turbine**

Lake Preston is a third combustion unit, identical to the Jamestown units, located at Lake Preston, SD. This unit was installed in 1978. This unit is also fired with fuel oil and has limited operation. The unit usually operates for emergencies, peak loads, and testing, but is also used for area voltage support under certain transmission line switching and outage scenarios. The Frame 5 unit at Lake Preston operates a very limited number of hours during the year.

**Solway Combustion Turbine Plant**

Otter Tail brought on-line a General Electric LM6000 dual-fuel combustion turbine just prior to the 2003 summer season. The unit includes inlet chilling to improve the summer rating and efficiency, as well as water injection for NOX control and increased output. Interruptible natural gas is the primary fuel with

fuel oil as the back-up fuel supply. The combustion turbine also includes a clutch to allow synchronous condensing service to support the transmission system. The LM6000 is an aeroderivative machine, powered by a Boeing 747 engine.

#### **Big Stone Diesel**

The Big Stone Plant has an internal combustion emergency diesel unit. This unit operates only for extreme emergency or testing purposes, but can synchronize with the system and is submitted as a capacity resource. The unit was installed in 1975 with the construction of the Big Stone Plant.

#### **Fergus Control Center Diesel**

A 2,000 kW diesel unit was installed at Otter Tail's System Control Center to serve as a standby generator for the facility, in accordance with NERC reliability criteria. The System Control Center was added to an existing Company building that contains the main business computers for Otter Tail. The system is staffed 24 hours per day and must have firm electric service to keep the System Control Center in operation during outages. The standby generator will supply emergency power, when required, to the total System Control Center and to the computer facilities.

#### **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 minimal efforts will be needed to comply with the rule.

### **1.3 Baseload Resources**

Otter Tail Power has partial or full ownership of three coal-fired generators, all at different locations. Until 1988 Otter Tail's coal-fired units had burned primarily North Dakota lignite. Some early units, long since retired, had used eastern coals, but lignite had been the fuel of choice for many years. Following a fuel switch in 1995 at Big Stone Plant to low-sulfur western sub-bituminous coal, Coyote is the only plant still burning lignite coal. The coal-fired units also use fuel oil for startup, and flame stabilization at times. The use of fuels at each facility is discussed in the following sections.

Otter Tail is always reviewing opportunities to improve the efficiency and operation of its units. The improvements and conservation efforts within the generating stations have helped Otter Tail maintain some of the lowest system heat rates in its history.

#### **Big Stone Plant**

The Big Stone Plant, of which Otter Tail owns 53.9 percent, became commercial on May 1, 1975. Improvements have come about as the result of conservation, operational efforts, and equipment updates within the plant. The current output rating for the Big Stone Plant is 475,000 kw (total plant).

The switch to sub-bituminous coal in late 1995 helped to reduce the plant net heat rate. Other efficiency improvements, and the installation of a new low-pressure rotor in 1996, have also helped to lower the heat

rate level at Big Stone Plant. A new high-pressure/intermediate pressure rotor was installed in 2005 and improved efficiency by about two percent.

The POET Bio-refining ethanol plant (formerly Northern Lights Ethanol) is located on the Big Stone Plant site. Big Stone Plant supplies steam for ethanol production. The steam is extracted part of the way through the electrical production process, so by serving the ethanol plant, Big Stone is truly a cogeneration plant involving the sequential use of the energy for two different purposes. The cogeneration operation does not impact the plant's ability to generate electricity.

In 2015, the largest capital project in Otter Tail Power history, at that time, was undertaken as the AQCS project was installed at Big Stone Plant to meet the regional haze rule requirements. The AQCS project was a project to install controls for NO<sub>x</sub> (SCR and SOFA), SO<sub>2</sub> (circulating dry fluidized bed scrubber), particulate (baghouse) and Hg control (activated carbon injection to meet MATS rule). The original budget for the AQCS project was \$491 million, and through efforts related to project team management and overall project timing, the final cost of the project was about \$384 million.

### **Coyote Station**

The Coyote Station, located near Beulah, ND is a lignite-fired mine mouth facility. Otter Tail owns 35 percent of this unit. The Coyote Station was declared commercial on May 1, 1981 and is equipped with a flue gas desulfurization unit and a baghouse. Otter Tail became the operating agent of the facility on July 1, 1998. The other co-owners of this facility are Northern Municipal Power Agency, Montana-Dakota Utilities, and Northwestern Public Service. Minnkota Power Cooperative acts as the agent for Northern Municipal Power Agency.

The Coyote Station is a sister unit to Big Stone, but six years newer. The Coyote Station approved outlet rating is limited to 427,000 kW due to transmission limitations. The facility also has two emergency diesel generators that are not accredited in MISO due to the transmission limitations.

Coyote completed a high-pressure/intermediate pressure rotor replacement in 2009 that resulted in about a two percent increase in efficiency. It also increased the UCAP rating of the plant by about 6,000 kW.

Coyote completed the installation of activated carbon injection for Hg control in 2015 as well as a SOFA (separated over-fire air) system for NO<sub>x</sub> reduction during 2016.

Additionally, the Owners of Coyote Station entered into a 25-year lignite supply agreement with Coyote Creek Mining Company to supply the Coyote Station with lignite from a new, efficient mine.

## **1.4 Demand Resources**

Otter Tail Power Company has two demand resources that can be registered under Module E with the MISO. Both resources are load modifying resources (LMR) that are netted from the demand forecast and available to MISO in emergency events. These resources are obligated to provide sustained load reduction for up to 4 hours at a time and be available ten times a year to the MISO in the event of an emergency. This obligation does not preclude the Company from relying on these resources to control for capacity events or economic reasons outside of a MISO emergency event.

**Direct Load Control – The Radio Load Management System**

The first resource, “Direct Load Control” represents the Company’s extensive radio load management system that is used to control customer load during economic or capacity events. This resource was accredited at 16 MW for MISO planning year 2021/2022 based on summer capability but has proven capability as high as 130 MW during the winter months. Otter Tail has approximately 129,800 customers and approximately 42,000 of those customers have some type of load control. The level of control that is available can vary with temperature, customer behavior, and load control responsiveness. For example, more load control is available during extremely cold temperatures in the winter than during moderate temperatures and customers with dual-fuel load may choose to switch to an alternate fuel, particularly during a period of lower prices.

Winter season manageable loads are in several categories and can reach as high as 130 MW. These manageable loads include water heaters, thermal storage, residential demand controllers, commercial time of use rates, small dual fuel heating systems, and large dual fuel (industrial and bulk interruptible loads). The radio load management system also has the capability of interrupting as much as 15 MW of peak load in the summer-season months, June through September. These summer loads consists primarily of water heaters, large dual fuel industrials, small dual fuel and deferred load heat pumps used for cooling, and standard air conditioning. Otter Tail continues to add customers to the direct load control rates to maintain and grow manageable loads.

Although measurement data shows the load management system as able to achieve higher levels than the level accredited, those higher levels related to peak control levels during a minimum number of hours and were impacted by weather and load diversity. Those higher levels do not represent the typical levels of control that Otter Tail is confident can be sustained. The measurement and verification requirements for continued accreditation and the risk of potential penalties were also significant factors in the lower accreditation level registered by the Company.

**Firm Service Level – Customer Contracts**

The second demand resource registered with MISO is a “Firm Service Level” resource that represents Otter Tail’s contract with a large industrial customer to shed load to a firm service level in the event of a capacity event. Unlike the “Direct Load Control” resource that reduces load when called upon by our load management system, this resource must demonstrate that it did not exceed the registered load level during a capacity event.

## 1.5 Transactions

Otter Tail has a number of large commercial customers that are shared loads with local rural electric cooperatives. These loads are in areas that may be in one utility's service territory, but are located where the other utility already had the necessary facilities to handle the load. In order to reduce costs and avoid duplication of facilities, these loads have been shared. In the accounting process, these loads are usually served as if they are Otter Tail customers, and then 50 percent of the energy is purchased wholesale from the other utility at the retail rate used to serve the customer. All of the retail energy shows up as Otter Tail energy with a 50 percent wholesale energy purchase, even though Otter Tail only served half of the load.

**WAPA Allocation to Native American Tribes**

The Western Area Power Administration (WAPA) is a federal Power Marketing Agency that provides capacity and energy from hydroelectric facilities located on the Missouri River to preference customers. Otter Tail does not qualify as a preference customer. Native American tribes are preference customers eligible to receive the federal power. The tribes, however, are not utilities in the same manner as typical WAPA preference customers such as municipals and rural electric cooperatives. The tribal lands are typically served by a combination of existing utilities.

In order to facilitate the delivery of the electricity to the tribes, or the economic benefits of the low-cost federal electricity, WAPA developed a process in which the electricity is delivered to the utilities providing electric service on tribal lands. Each tribe has the right to determine which tribal entities receive the benefits. For the customers designated by the tribe as receiving the benefits, WAPA delivers the electricity to Otter Tail at the WAPA rate, and then Otter Tail provides a bill credit to the customer. The bill credit is essentially equal to the difference in cost between the WAPA power and the embedded Otter Tail cost of generation, less expenses to administer the program. Otter Tail has filed the appropriate information with and received approval from the state regulatory commissions in the states involved.

Otter Tail has five tribes that receive the benefits of the WAPA power. The current capacity amount varies monthly from a low of 4.3 MW to a high of 5.6 MW, with annual energy of 32,158,236 kWh. Otter Tail also receives the load based reserve margin benefit with the capacity. Because the tribes have the right to change who receives the benefit and such changes may move benefits from tribal customers served by Otter Tail to tribal customers served by another utility, the amount of capacity and energy received for the tribal loads may vary over time. The current amount of tribal allocation that is received through Otter Tail is included in all analysis scenarios. None of the WAPA power qualifies for compliance with the Minnesota Renewable Energy Objective, as all of the WAPA hydroelectric facilities are greater than 100 MW when considering all units at a specific location.

**Customer Owned Generation**

Otter Tail has worked with several customers who desired to install small diesel generators for back-up emergency power. These units are owned by the customers and capable of being interconnected to Otter Tail's system. The capacity from these units is purchased by Otter Tail and submitted as behind the meter capacity resources registered with MISO. Currently the NDC rating of these units is 4,300 kW in total and the UCAP rating is 4,100 kW in total.

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. Effective May 1, 2016 all of Otter Tail's engines affected by the RICE Rule are considered emergency or blackstart in nature and therefore exempt from emissions limitations and performance tests.

Otter Tail also has power purchase agreements with several wind generation facilities as described in the following section.

**1.6 Wind and Solar Generation Resources**

Otter Tail has more than 405 MW of wind/solar generation on the system, including utility owned and

contracted generation. The Company owns 288 MW of wind generation. This wind generation accounted for 18 percent of the Company’s energy needs in 2020.

**Langdon Wind Energy Center**

Otter Tail owns 40.5 MW of wind generation located south of Langdon, ND consisting of 27 1.5MW GE wind turbines. This facility began operation in January 2008.

**Ashtabula Wind Energy Center**

Otter Tail owns 48.0 MW of wind generation located in Barnes County, ND consisting of 32 1.5MW GE wind turbines. This facility began operation in November 2008.

**Luverne Wind Energy Center**

Otter Tail owns 49.5 MW of wind generation located in Steele County, ND consisting of 33 1.5MW GE wind turbines. This facility began operation in September 2009.

**Merricourt Wind Energy Center**

Otter Tail owns 150 MW of wind generation located approximately fifteen miles south of Edgeley, North Dakota in McIntosh and Dickey Counties, consisting of 75 2 MW Vestas wind turbines. This facility became commercially operational in December 2020.

Approximately 117 MW of wind/solar generation is purchased by Otter Tail from customers or other entities and is identified in Table 1-2. Customer owned units do not have the ownership name included to protect customer information. Often generation from smaller, customer owned units is used to serve the customer and only the surplus generation is sold to Otter Tail.

Otter Tail is in the early stages of analyzing the potential purchase of the Ashtabula III wind facility from NextEra. This purchase would likely occur in the 2023 timeframe.

**Table 1-2: Contracted Wind Generation Facilities**

Name and Owner	State	kW Rating
FPL Energy ND Wind II - NextEra	ND	21,000
Langdon Wind Energy Center – NextEra	ND	19,500
Ashtabula III – NextEra	ND	62,400
Various Small Wind/solar Producers	ND	3,318
Various Small Wind/solar Producers	MN	10,620
Various Small Wind/solar Producers	SD	154

**1.7 Energy Efficiency Programs**

Otter Tail Power Company operates a number of Demand-Side Management Programs in its service territory. In Minnesota, some of these projects are part of the Company’s Conservation Improvement Program (CIP) filing, Docket No. E017/CIP-20-475. The Company also operates an energy efficiency

program in South Dakota; Otter Tail's 2021 Energy Efficiency Plan (EEP) status report and annual filing was filed in Docket No. EL21-015. North Dakota does not have a formal energy efficiency program. The Company's Minnesota and South Dakota energy efficiency results have been on target with the energy efficiency goals in historical integrated resource plan filings.

This resource plan reflects an average annual energy savings of 1.86 percent, which exceeds the newly established 1.75 percent goal in Minnesota's Energy Conservation and Optimization Act of 2021.

## **1.8 Midcontinent Independent System Operator, Inc. (MISO)**

Otter Tail continues to play an active role in the regional transmission planning efforts. While Otter Tail still leads and conducts studies to ensure the adequacy of the transmission system to serve its customers, all transmission planning activities related to regional transmission are coordinated with the MISO and the surrounding non-MISO transmission owners.

Transmission planning occurs through the course of performing transmission studies at several different levels, from individual utility plans, to joint utility plans with utility neighbors, to broad regional studies. Regardless of the type of studies, the forum for which these studies are discussed is through a regional transmission planning process. Otter Tail actively participates in several MISO study groups, such as the West Subregional Planning Meetings (WSPM) and the West Technical Study Task Force meetings (WTSTF). These groups provide forums for regional transmission planners to discuss the needs and projects related to the transmission system in the Otter Tail and surrounding area that are within the western footprint of the MISO region.

Otter Tail closely coordinates its transmission planning efforts with the MISO. For transmission planning purposes, MISO performs three primary functions. The first two are federally mandated processes established by FERC, generator interconnection and delivery service, and the third process is related to expansion planning.

MISO administers and processes requests to use the transmission system of the MISO transmission owners. MISO has established procedures for processing generation interconnection and delivery service transmission requests of generators and market participants. Through this FERC mandated process, MISO offers the area utilities opportunities to participate in "ad-hoc" study groups to provide input and review of the technical studies completed for generation interconnection or delivery service. In addition to these FERC mandated requirements, MISO also performs expansion planning studies on an annual basis. These expansion planning studies are referred to as the MISO Transmission Expansion Plan (MTEP) and focuses on a variety of studies, from reliability assessments to targeted studies focused on a particular issue or item. Otter Tail's transmission system falls within the MISO West region. Through the MTEP process, MISO completes a reliability analysis assessing the transmission system performance against transmission owner's reliability criteria. In the event that reliability criteria is not met, additional analysis is completed to find mitigation to a particular system issue. Otter Tail actively participates in the MTEP, generator interconnection, and delivery service efforts by attending meetings, reviewing study results and providing input into the study process.

MISO has also sponsored targeted studies in the region as part of the MTEP process. Otter Tail actively participates in many of these targeted studies, including the Long-Range Transmission Plan (LRTP) and

Joint Targeted Interconnection Queue (JTIQ) studies, as well as other targeted studies. Through these various study efforts, Otter Tail attends meetings, reviews study results and provides input into the study processes.

In addition to the specific study opportunities, the MISO conducts meetings of several stakeholder groups, which include the Planning Subcommittee (PSC), the Planning Advisory Committee (PAC), the Regional Expansion Criteria and Benefits Working Group (RECB WG), the Interconnection Process Working Group (IPWG), among several others. These meetings are attended by various representatives of the different stakeholder groups at MISO. These meetings act as a forum between MISO staff and the stakeholders to provide input into the processes of the MISO. Otter Tail regularly attends several of these meetings to stay engaged within the MISO transmission planning process as well as provide input and feedback to the MISO.

All of these transmission planning activities are then combined into, and are consistent with, the MN state transmission planning process.

### **Transmission Interconnections**

On May 9, 2002, the Commission gave conditional authority to Otter Tail to transfer operating control of certain transmission facilities to the MISO. Since joining MISO and transferring operational control of its high voltage transmission facilities to MISO, Otter Tail has seen positive benefits in this relationship regarding the generator interconnection processes.

Since Otter Tail joined MISO, numerous generators have successfully interconnected to the Otter Tail electric system under MISO's generator interconnection procedures. Under MISO's Open Access Transmission and Energy Markets Tariff (TEMT), all generator interconnection requests (regardless of generator size or interconnecting voltage level) are required to abide by the MISO generator interconnection process if the generator intends on engaging in wholesale transactions. The MISO, as an independent system operator, ensures comparable treatment for all customers and it is staffed to provide and administer this service. Otter Tail receives value and efficiencies from the MISO process given that MISO is staffed to administer its procedures and, as an independent organization, ensures comparable treatment to all parties involved. Additionally, Otter Tail stays actively engaged in several MISO studies and provides information regarding the transmission system when reviewing study results and giving direction for future studies. This is an efficient process and a benefit to all parties since Otter Tail has ultimate knowledge and familiarity with its system and most efficiently and effectively provides this service. Project coordination, administration, and filing requirements fall upon MISO, thus freeing up Otter Tail's resources to focus on its key priority of providing clean, efficient, and low cost energy to its customers.

In the recent years, an unprecedented amount of renewable generation has been requested to be added to the MISO system. The increase in requests and generators interconnecting to the MISO system has caused congestion that has been reflected in the MISO interconnection queue. Due to the large amount of requests and recent generator interconnections, transmission interconnection costs for new resources are very high and impact the economic feasibility of adding new generation units of all types. Some of the challenges include additional uncertainties, large queue cycles, delayed studies, and very high interconnection costs. Recently the MISO has provided two alternative methods for interconnecting new resources. The two new interconnection methods are replacement interconnection and surplus interconnection. Both alternatives prevent having to go through the traditional MISO interconnection

queue process. Replacement interconnection resources reuse the existing interconnection rights of an existing resource that is retiring. Surplus interconnection resources are built alongside an existing resource and share the interconnection rights while not exceeding the total output of the existing interconnection. Both interconnection methods are studied to confirm that there are no reliability impacts to the transmission system, and if issues are identified, the request goes to the standard queue.

### **Locational Marginal Pricing (LMP) Energy Market and Ancillary Services Market (ASM)**

The MISO Locational Marginal Pricing (LMP) energy market was introduced on April 1, 2005. The MISO subsequently introduced the Ancillary Services Market (ASM) on January 6, 2009. Both market introductions went well, but utility operations and market functions have changed significantly.

Many of the key preparations and day-to-day activities since commencement of the markets include:

- Development of software interfaces and procuring or developing new software systems.
- Training of employees.
- Developing after-the-fact data flows to ensure a seamless transition in the accounting and regulatory areas.
- Active involvement in filings related to the Energy Market at the Federal Energy Regulatory Commission (FERC) and state commissions. This includes settlement proceedings for the non-MISO Load Serving Entities located within the Otter Tail Power Company Control Area.
- Nominating and receiving Auction Revenue Rights (ARRs) and Financial Transmission Rights (FTR) allocations to safeguard Otter Tail's native load.
- Developing business practices, strategies and risk management policies to accommodate an LMP and ASM Market.
- Actively participating in the numerous MISO committees seeking to ensure that Otter Tail's best interests and the interests of its customers were not adversely impacted by decisions and policies resulting out of these committees.

Market operations continue to go smoothly, and the company is generally pleased with the transition to the centralized energy and ancillary services markets.

### **MISO Resource Adequacy (Module E)**

Otter Tail's reserve requirements are established by MISO under Module E of the MISO Tariff. For planning year 2021 (June 2021 – May 2022) the MISO reserve margin requirement is 9.4 percent.

MISO currently operates in an annual construct with a system wide coincident peak occurring in the summer months. The Company's coincident peak demand diversity factor is approximately 9 percent of its non-coincident peak demand.

Resource accreditations change annually and are based on summer ratings. Ratings for non-wind generators are based on historic generator availability data or, if that is unavailable, class averages are used.

Wind generation is accredited based on unit specific historical capacity factors. Accreditation for the 2021 planning year for the Company's wind farms varied from 20 percent at the Langdon Wind Farm to 16 percent (MISO average) at the Merricourt Wind Farm. The accredited capacity rating is expected to increase at Merricourt in the future as historic generation data becomes available.

## 1.9 Transmission Facilities

Otter Tail serves many very small communities located in a geographical area about the size of the State of Wisconsin. The characteristics of the customer loads and locations have required an extensive transmission system. When compared to many investor-owned utilities, Otter Tail's customer count per mile of transmission facilities is quite small. To minimize cost, Otter Tail has become party to several integrated transmission agreements. The Company participates in many shared networks with other investor owned utilities, municipals, G & T cooperatives, and rural electric cooperatives. In many cases, a 41.6 kV or 69 kV transmission line will serve an equal number of non-Otter Tail and Otter Tail distribution substations.

These agreements have resulted in over 200 points of interconnection with other utilities. Such a network adds to the complexity of operating the electrical system, but also adds the capability for the facilities of one utility to provide either full time or emergency service to another utility. The ultimate result is reduced cost and increased reliability for the customer. Table 1-4 lists the mileage of various voltage classes of transmission lines. All of these lines are overhead lines except for less than one mile of underground cable in the 41.6 kV class.

**Table 1-3: Circuit Miles of Transmission by Voltage**

<b>Voltage (kilovolts)</b>	<b>Circuit length</b>
345 kV	*875 miles
230 kV	*496 miles
115 kV	*916 miles
69 kV	209 miles
41.6 kV	3796 miles

*\*Mileage includes Otter Tail Power Company joint ownership in CapX2020 transmission projects. See CapX2020.com for more information.*

# Appendix D: Potential Resources

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## Potential Resources

This appendix provides a description of the resources that were evaluated in the development of the 2021 Integrated Resource Plan by Otter Tail. The development of the resource plan focused on the evaluation of resources that are available to the Company, taking into account a number of factors. These factors include available size increments of the technology, the maturity and commercial availability of the technology, the availability of interested co-owners of large facilities, operational parameters, and available data. Not every resource that was evaluated was included in the Company's model. In order to reduce run time of the EnCompass software, an initial screening was performed to limit the number of potential new resources that would be made available for the model to select.

Specific cost and performance data used for modeling came from a variety of sources and is provided in detail in Appendix F: Assumptions for EnCompass Modeling Assumptions.

### Supply-Side Generation

A discussion of each of the coal- and gas-fired technologies and other supply-side technologies is included in the following pages. The technologies are grouped into the following two categories:

#### Generation Alternatives in the Model

- Simple Cycle Combustion Turbine (Large and Small)
- Wind
- Solar Photovoltaic
- Battery Storage

#### Pre-screened Generation Alternatives Not in the Model

- Nuclear
- Pulverized Coal - Subcritical
- Atmospheric Circulating Fluidized Bed Coal (ACFB)
  - Integrated Gasification Combined Cycle (IGCC)
  - Phosphoric Acid Fuel Cell (PAFC)
- Pulverized Coal – Supercritical and Ultra-supercritical (green field site)
- Supercritical Coal, using a brown field site
- Reciprocating Engine Plants
- Hydro (owned projects)
- Heat Recovery
- Anaerobic Digestion
- Landfill Gas
- Microturbines
- Biomass
- Geothermal

Whether a technology was pre-screened or included in the model for capacity expansion evaluation is indicated in the text. The effort on screening resources was necessary to develop a useful modeling tool that was practical in terms of run-time while simultaneously comprehensive in evaluating the forward-

looking resource mix. It is important to note that any resource used as a potential future addition in the EnCompass model was intended to be generic and representative of the Company's needs. In no way do the alternatives selected for modeling purposes exclude future consideration of competing options in similar generation categories.

## 1.1 Technology options included in the model

### **Simple Cycle Combustion Turbine - Large**

The model was given the preferred combustion turbine option. This is a heavy-duty frame unit with an ISO rating of about 248 MW. The heavy-duty frame units are characterized by a lower capital cost per kW and lower maintenance cost.

### **Aeroderivative Simple Cycle Combustion Turbine – Small**

The 49 MW ISO-rated alternative is based on the existing GELM6000 aeroderivative technology that Otter Tail currently owns and operates at Solway, MN. As the name implies, aero derivative electric generation units were derived from gas turbine development for the aircraft industry. The traits of aeroderivative units compared to the frame-style gas turbines are typically, faster starts, higher efficiency, smaller overall size, and higher capital cost in \$/kw. However, frame CT technology has advanced, and it should be noted that starts times and efficiency have dropped in recent years, as now some frame CT suppliers are offering units that can meet the 10 minute start time that was the hallmark of aero derivative units in the past.

### **Wind Generation**

Wind generation was made available to the model in 50 MW blocks throughout the study period modeled as a purchased power transaction.

### **Solar Generation**

Solar generation was made available to the model in 25 MW blocks throughout the study period modeled as a purchased power transaction.

### **Battery Storage**

4-hour battery storage was made available to the model in 25 MW blocks throughout the study period modeled as a purchased power transaction.

### **Paired Battery Storage**

4-hour paired battery storage was made available to the model in 10 MW blocks throughout the study period modeled as a purchased power transaction. This resource could only be selected in combination with a 25 MW solar resource.

## 1.2 Technology options not allowed in the model

### **Combined Cycle Gas Turbine (CCGT)**

The basic principle of the Combined Cycle Gas Turbine is to use a gaseous fuel such as natural gas, or a liquid fuel such as no. 2 fuel oil, to produce power in a gas turbine and to use the hot exhaust gases from the gas turbine to produce steam in a Heat Recovery Steam Generator (HRSG). The steam is used to

generate electric power with a steam driven turbine-generator set. Typical CCGT units operate with natural gas as the operating fuel, but often dual-fuel capability with oil as a backup is used to increase the availability of the generation when natural gas supplies are curtailed. Given the size of Otter Tail's system and the lack of a significant capacity need during the planning period it was decided that a large CCGT unit would not be a reasonable option and was removed from the model.

### **Nuclear**

Electricity from a nuclear power plant remains a very clean and safe form of electrical generation in the United States and the world. In 1994, the Minnesota Legislature passed a law that created a moratorium on the construction of new nuclear generation facilities in Minnesota (216B.243, subd. 3b). Nuclear energy was not considered as a resource alternative because of the law listed above, and what appear to be very high costs related to siting, permitting, and construction. Additionally, the Company is not aware of any nuclear project under development soliciting joint ownership. Due to the factors listed above, the addition of nuclear generation was not included in the model.

### **Carbon Capture and Sequestration (CCS)**

There is significant research and development underway related to carbon dioxide capture and sequestration from fossil-fuel electric generating units; however, currently only two commercial power plants have been equipped with this technology worldwide. While there is much information in the public domain about development work, demonstration projects, and future-looking analysis for resource planning purposes, it is the position of Otter Tail that CCS development needs to continue to develop to understand cost certainty and feasibility. Additionally, it is Otter Tail's understanding that the current CCS technologies require very high levels of control of sulfur-dioxide prior to routing the flue gas to the CCS equipment. Therefore, the Coyote Station sulfur-dioxide scrubber would first need to be upgraded to the high-control scenario being considered by the Regional Haze Rule, which would result in additional capital and operational costs, before employing carbon capture technology (if the addition of CCS became viable). Due to these increased scrubber costs and due to the uncertainties around CCS, since the base assumption in the resource planning modeling analysis is that no Regional Haze Rule upgrades are necessary, and since that analysis supports that Coyote is uneconomic and planning for withdrawal is prudent, Otter Tail has not included CCS as an option to the resource planning model. If MISO requirements, or the MISO market changes, and if CCS cost estimates and operational efficiencies are proven acceptable, the Company will reconsider this position.

### **Pulverized Coal - Subcritical**

Pulverized coal boiler technology is a mature and reliable energy producing technology around the world. The operating pressure of conventional coal-fired power plants can be classified as sub-critical and super-critical. Sub-critical and super-critical technologies refer to the state of the water that is used in the steam generation process. The critical point of water is 3208.2 psia and 705.47° F. At this critical point, there is no difference in the density of water and steam. At pressures of about 3208.2 psia, heat addition no longer results in the typical boiling process in which there is an exact division between steam and water. The fluid becomes a composite mixture throughout the heating process. A sub-critical pulverized coal unit was eliminated from consideration as an option because of higher emissions and a less efficient heat rate.

**Pulverized Coal – Supercritical and Ultra-Supercritical**

The current Minnesota Next Generation Act of 2007 eliminates any reasonable chance of construction of coal-fired generation for Minnesota and was not made available to the model. Super-critical pulverized coal units have been part of the U.S. power generation mix since the mid-1950's. Since the 1980's, the development of high strength materials and Distributed Control Systems (DCS) have helped to make supercritical units easier to control and operate. Supercritical units typically operate at 3500 psig and up to 1050° F or 1080° F. at the steam turbine inlet. In addition, while there is no current technical definition of an ultra-supercritical unit, it seems to be generally accepted that units designed to operate at 1100° F or higher are ultra-supercritical. There is currently at least one new unit that is being constructed in the United States where the design steam temperatures are above 1100° F. Heat rates for supercritical or ultra-supercritical units can be lower than 9,000 btu/kWh. If the average heat rate of the current coal fleet is 11,500 btu/kWh, use of a modern supercritical or ultra-supercritical unit would result in over 20% less coal being burned per MWh or 20% less CO<sub>2</sub> emissions per MWh.

**Atmospheric Circulating Fluidized Bed Coal (ACFB)**

The consideration of a baseload coal-fired unit at the Big Stone Plant (BSP) site included evaluation of a large ACFB facility. The combustion within a fluidized bed boiler occurs in a suspended bed of solid particles in the lower section of the boiler. Combustion within the bed occurs at a slower rate and lower temperature than a conventional pulverized coal-fired boiler. Deviations in fuel type, size, or Btu content have minimal effect on the furnace performance characteristics. The bed allows for re-injection of a sorbent, such as fly ash or limestone, to reduce SO<sub>2</sub> emissions. This type of operation requires approximately 1.5 times the quantity of limestone to achieve a reduction in SO<sub>2</sub> similar to that of a wet limestone scrubber.

One of the benefits of an ACFB facility would have been an increased ability to use biomass fuels. The BSP unit already has an alternative fuels handling facility and the capability to burn alternate fuels. There has been difficulty in expanding the use of biomass fuels at BSP due to cost and availability. The benefit of being able to use biomass fuels was outweighed by a number of other factors, and a large fluidized bed unit was eliminated from consideration. The Minnesota Next Generation Energy Act of 2007 requires new coal-based generation to offset CO<sub>2</sub> emissions. Any ACFB alternative would require CCS to be installed in order to serve load in Minnesota. Otter Tail Power's view of CCS is that it is a promising technology but not currently commercial.

**Integrated Gasification Combined Cycle (IGCC)**

IGCC technology produces a low energy value syngas from coal or solid waste, for firing in a conventional combined cycle plant. The gasification process in itself is a proven technology having been previously used extensively for production of chemical products such as ammonia for use in fertilizer. The U.S. Department of Energy (DOE) has jointly funded several power plant facilities through the U.S. The majority of the DOE test facilities use entrained flow gasification design with coal as feedstock. In that process, coal is fed in conjunction with water and oxygen from an air separation unit, into the gasifier at around 450 psig where the partial oxidation of the coal occurs. The raw syngas produced by the reaction in the gasifier exists at around 2400° F. and is then cooled to less than 400° F. in a gas cooler, which produces additional steam for both the steam turbine and the gasification process. Particulate, ammonia (NH<sub>3</sub>), hydrogen chloride, and sulfur are then removed from the raw syngas stream. The cooled and treated syngas then feeds into a modified combustion chamber of a gas turbine specifically designed to accept the low calorific value syngas. Exhaust heat from the gas turbine then generates steam in a HRSG which in turn powers a steam turbine.

It is recognized that IGCC, in theory, shows potential to become a reliable, low emission source of electrical energy in the future that more easily adapts to the potential of CCS. Compared to supercritical pulverized coal, IGCC projects appear to have higher upfront capital costs, variable O&M, and fixed O&M. The Minnesota Next Generation Energy Act of 2007 requires new coal-based generation to offset CO<sub>2</sub> emissions. Any IGCC alternative would require CCS to be installed. Otter Tail Power's view of CCS is that it is a promising technology but appear to not be economically viable today. Based on all of these considerations, Otter Tail did not include IGCC as an option in the planning model.

### **Reciprocating Engine Plants**

Large-scale reciprocating engine power plants have begun to gain in popularity in some areas of the country in recent years. A reciprocating engine plant is constructed of incrementally sized engines (2 MW – 16 MW each). Most large-scale reciprocating engine plants are fueled with natural gas only. However, some systems may be dual fuel (natural gas and fuel oil). Typically speaking, the construction costs of a reciprocating engine plant are more expensive than a simple cycle combustion turbine (perhaps 10 percent – 20 percent higher). However, on a unit-to-unit comparison, the reciprocating engine is more efficient than a typical aeroderivative combustion turbine. If you consider partial load operation, the overall fuel savings can be considerable. Some energy providers have viewed the installation of reciprocating engine plants as a good fit to a region with high wind or other intermittent energy resources. A generation resource that is capable of high efficiency through a wide range of output may become attractive enough to overcome initial higher installation costs. Through the prescreening process, reciprocating engines were excluded from the alternatives made available to EnCompass, largely due to the higher O&M and capital costs.

### **Phosphoric Acid Fuel Cell (PAFC)**

The model evaluation excluded the option to select fuel cells due to the resource's higher costs compared to other units of similar technology. Fuel cells function by converting hydrogen-rich fuel sources directly to electricity through an electrochemical reaction. Fuel cells can sustain high efficiency operation even under partial load conditions and they have a rapid response to load changes. The construction of fuel cells is inherently modular, making it easy to size facilities according to power requirements. One of the most significant benefits to fuel cells is the lack of emissions. The only significant emissions are water and carbon dioxide.

### **Hydro**

For past resource plan filings Otter Tail has reviewed the potential for cost-effective small hydro development within its service territory. A Minnesota Department of Natural Resources (DNR) survey of potential sites within the state served as a basis for that review. The DNR conclusion was that the existing economic sites had already been developed. For that reason, Otter Tail did not include any potential development of small hydro within the model.

Even if potential sites existed within the Company's service territory, it is unlikely that they would be economic for development if the sites were under FERC jurisdiction. If a waterway has a designation as a navigable stream, then it falls under FERC jurisdiction. Otter Tail's small hydros on the Otter Tail River near Fergus Falls were all built prior to FERC licensing requirements. The Otter Tail River was designated as a navigable stream because in the 1800's it was used for transportation and to float logs to the sawmill. In the late 1980's and early 1990's, Otter Tail was ordered to obtain FERC licensing on these units. The licensing process took several years and cost about \$400/kW, for existing units. The

licensing cost for developing a new site is likely to be so high as to make the process uneconomic.

### **Anaerobic Digestion**

Previous study work within Otter Tail concluded the amount of potential generation from anaerobic digestion within Otter Tail's system may result in minimal (less than 5 MW) opportunity and too small to be of consequence to this resource plan filing. Anaerobic digestion was not included as a generation option within the model.

### **Landfill Gas**

According to an EPRI report completed in the late 1990's, the Otter Tail Service territory does not include any landfills of sufficient size to support a landfill gas generating facility. The only two landfills in the area that were identified as having sufficient size are located at Fargo and Grand Forks, both served by another utility. Fargo now has a unit installed. Each of those landfills was identified as having the potential to support two 2 MW generators. Landfill gas was not included as an option within the model.

### **Microturbines**

Microturbines are miniature combustion turbines, similar in concept to the large combustion turbines used in conventional utility power plants. Whereas large combustion turbines range from 20,000 to over 330,000 kW, microturbines fit into the 25 to 400 kW range. The waste heat from the turbine exhaust can be collected to supply a useful thermal load, which improves the overall cycle efficiency and the economics. However, the capital costs are still higher than the cost of a standard utility size combustion turbine and the efficiencies are much worse. At this point in time, potential economic applications are somewhat limited. The model did not include consideration of microturbines due to their small size, limited application at this time, and high cost.

### **Biomass**

Since the early 1990's Otter Tail has made an effort to use renewable fuels in its existing coal-fired plants. The Big Stone Plant has burned a number of renewable and alternate fuels over the years and has an alternative fuels handling facility to aid in blending such fuels in with coal. Some of the renewable fuels that have been tried or researched over the years include spoiled or research corn seed, wood waste in various types, soybeans, sunflower hulls, and similar agricultural wastes. Some of these materials caused significant problems in test burns by either plugging fuel handling systems (bark wood waste) or plugging boilers (soybeans). Sunflower hulls and soybeans have proven to be problematic due to their high content of potassium. As of January 1, 2010, Big Stone Plant has stopped the alternative fuel program. The primary reasons were the limited availability of fuel and the high cost of maintenance of the handling facilities.

Otter Tail did not include any other additional biomass alternatives in the model. As the cost of fossil fuels increases, other markets develop for biomass fuels such as wood waste. In many cases, the wood products companies that create the waste use it as fuel in their own process. Otter Tail has worked with customers on potential wood waste-fired biomass facility investigations. The fuel supply is limited, and the costs of such facilities are high. The development potential of these facilities is limited and very site specific. To date, Otter Tail has not found other opportunities for development of such facilities with costs being close to economic.

**Geothermal**

Otter Tail has worked with the Geology Dept. at the University of North Dakota on investigating the potential for geothermal energy. Western North Dakota has geothermal resources in temperature ranges that would be suitable for binary cycle geothermal technologies. A binary cycle facility typically pumps natural water or brine from underground that has been heated by the earth to moderate temperature ranges of 200° F. - 500° F. The heat in the fluid is transferred to another working fluid such as iso-pentane which is used in place of water in a normal vaporization/condensation cycle. The brine is then reinjected back into the earth. The extraction and reinjection wells are typically from 1,000 – 3,000 feet deep and require significant horsepower to extract the fluid and then reinject it. The resources in western North Dakota are located much too deep to be economic for binary cycle operation, typically in the 10,000 – 12,000 foot range. Otter Tail did not include any geothermal options as potential generating resources in the model.

Otter Tail does have geothermal heat pumps as programs within its CIP process.

**Appendix E: Assessment of Federal and State  
Environmental Regulations**

# **Assessment of Federal and State Environmental Regulations**

## **I. GREENHOUSE GAS REGULATION**

In 2009 the Environmental Protection Agency (EPA) began addressing greenhouse gas (GHG) emissions using the Clean Air Act (CAA). The first step in the EPA rulemaking process was the publication of an endangerment finding in the Federal Register on December 15, 2009. The EPA found that carbon dioxide (CO<sub>2</sub>) and five other GHGs – methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride – threatened public health and welfare. These findings did not themselves impose any requirements to control GHG emissions, but they were a prerequisite to finalizing GHG standards for vehicles. Additionally, since the motor vehicle standard regulated GHG emissions for the first time under the CAA, GHG emissions were included in the pollutants subject to the requirements of the New Source Review program of the CAA.

### **A. Existing Source Guidelines**

#### **1. Background**

The EPA has twice embarked upon developing GHG performance standards for existing power plants under CAA Section 111(d). Under Section 111(d), the EPA promulgates emission guidelines, and the states are then given a period of time to develop plans to implement the standard. The EPA reviews each state-developed standard and then approves it if the state's plan comports with the federal emission guidelines; if the state does not submit a plan or the EPA finds that the plan is inadequate, the EPA will prescribe a plan for that state.

A “standard of performance,” is defined as:

...a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the [EPA] Administrator determines has been adequately demonstrated.

Additionally, for existing sources, Section 111(d) requires the EPA to consider, “among other factors, remaining useful lives of the sources in the category of sources to which such standard applies.”

#### **2. Clean Power Plan**

On August 3, 2015 EPA announced existing source guidelines under Section 111(d) of the CAA, termed the Clean Power Plan (“CPP”). The CPP set state-specific goals to limit CO<sub>2</sub> emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve

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the goals. EPA applied three building blocks to each grid interconnection that resulted in final rule national uniform emission rate standards. On February 9, 2016 the United States Supreme Court granted emergency applications seeking a stay of the rule.

### 3. Affordable Clean Energy Rule

On June 19, 2019 EPA announced the Affordable Clean Energy Rule (“ACE Rule”). The rule established guidelines for states to use in developing plans to address greenhouse gas emissions from existing coal fired power plants. The final rule established heat rate improvements as the best system of emissions reductions (BSER) for reducing carbon dioxide emissions.

Simultaneous with the final ACE Rule, EPA took action to repeal the CPP, and EPA also finalized revisions to the timing and content requirements of Section 111(d) state implementation plan submissions.

Several petitioners filed challenges to the ACE Rule, and on January 19, 2021 the United States Court of Appeals for the District of Columbia vacated the rule and the repeal of the CPP, and remanded the record back to EPA. Since the ruling, EPA has clarified states do not have any obligations to submit plans under the ACE Rule or CPP. EPA has suggested that it will likely propose new rules to replace the CPP and ACE Rule in the near future.

## **B. New Source Performance Standards**

On October 23, 2015 the EPA published final New Source Performance Standards (NSPS) under section 111(b) of the CAA that requires certain new units (as well as modified and reconstructed units) to meet CO<sub>2</sub> emission standards. New natural gas combustion turbines are required to meet a standard of 1,000 lbs. of CO<sub>2</sub> per gross megawatt hour averaged over a 12-month period if they meet the definition of a baseload unit. New natural gas combined cycle units are anticipated to fit into this category. Simple cycle combustion turbines are regulated in a non-baseload category that is required to meet a heat input based standard that can be met by primarily burning clean fuels such as natural gas.

### **II. CRITERIA AIR POLLUTANTS**

The CAA requires EPA to set standards for six common air pollutants known as “criteria” pollutants. The criteria pollutants are: nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), particulate matter (PM), ozone, carbon monoxide and lead. These emissions are sometimes regulated under CAA programs when they are a precursor to other types of air pollution. NO<sub>x</sub>, for example, is regulated because it is a precursor to fine particle formation, ozone formation, acid deposition and regional haze. Similarly, SO<sub>2</sub> is a precursor to fine particle formation, acid deposition and regional haze. Particulate matter is a precursor to regional haze. This section describes the effect of anticipated regulations to limit criteria pollutant emissions from power plants, with a specific focus on OTP’s generating facilities.

#### **A. Acid Deposition and National Ambient Air Quality Standards**

##### **Acid Deposition**

The Acid Rain Program (ARP) was created under Title IV of the 1990 amendments to the CAA. Under the ARP, emissions of SO<sub>2</sub> and NO<sub>x</sub> from the electric utility industry have been reduced substantially.

##### **1. ARP SO<sub>2</sub> Program**

The SO<sub>2</sub> program sets a permanent cap on the total amount of SO<sub>2</sub> that may be emitted by electric generating units greater than 25 megawatts in the contiguous United States. The program was phased in, with the final 2010 SO<sub>2</sub> cap set at 8.95 million tons, which represents a level of about one-half of the emissions from the power sector in 1980.

Under this program, EPA allocates allowances to each source for use in or after a specified year. Each allowance permits a unit to emit one ton of SO<sub>2</sub>. At the end of the year, if a source’s emissions are less than its annual allowance allocation, it can bank the extra allowances forward for use in future years. If a source’s annual emissions are more than its annual allocation, the source can then either use banked allowances from previous years, transfer allowances from another facility, or purchase allowances on the open market.

Otter Tail’s compliance strategy has always been, and continues to be, to work within our free allowance allocation and use banked allowances when necessary to avoid having to purchase allowances on the open market.

##### **2. ARP NO<sub>x</sub> Program**

Title IV requires NO<sub>x</sub> emission reductions for certain coal-fired electric generating units (EGUs) by limiting the NO<sub>x</sub> emission rate (expressed in lb/mmBtu) in lieu of having an emissions allowance trading program. Congress applied these rate-based emission limits based on a unit's boiler type. The goal of the program is to limit NO<sub>x</sub> emission levels from the affected coal-fired

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boilers so that their emissions are at least two million tons less than the projected level for the year 2000 without implementation of Title IV. Otter Tail is able to maintain compliance with the Title IV NO<sub>x</sub> emission rates by operating existing NO<sub>x</sub> control equipment at Big Stone Plant and Coyote Station.

### **National Ambient Air Quality Standards**

The CAA requires EPA to set two types of National Ambient Air Quality Standards (NAAQS). Primary standards provide public health protection, while secondary standards provide public welfare protection.

In general, compliance with NAAQS is achieved through development of State Implementation Plans (SIPs) that limit emissions from sources located in areas designated as non-attainment.

To help states attain the NAAQS in local areas, the EPA evaluates whether certain regional or nationally applicable emission limitations should be put into place in order to assist the states in attaining the NAAQS, or states may petition EPA to impose reductions in upwind states. Additionally, federal regulations require that any permit issued under the Prevention of Significant Deterioration (PSD) provisions of the CAA must contain a demonstration of source compliance with the NAAQS.

#### **1. NO<sub>2</sub> and SO<sub>2</sub> NAAQS**

In 2010, the EPA promulgated new NAAQS for nitrogen dioxide (NO<sub>2</sub>) and SO<sub>2</sub> averaged over one hour. In 2018 for NO<sub>2</sub> and in 2019 for SO<sub>2</sub>, EPA completed another review and decided to retain the 2010 standards without modification.

For the 2010 NO<sub>2</sub> NAAQS, the States of Minnesota, North Dakota, and South Dakota recommended that their entire states be designated as attainment based on multiple years of air sampling data. The EPA reviewed the recommendations, and on January 20, 2012, EPA determined that no area in the United States is violating the 2010 NO<sub>2</sub> NAAQS. Therefore, EPA designated all areas of the country as “unclassifiable/attainment”.

For the 2010 SO<sub>2</sub> NAAQS, EPA proceeded with different rounds of designations. In one round of designations, EPA promulgated SO<sub>2</sub> designations for areas that either 1) had newly monitored violations of the 2010 SO<sub>2</sub> standard, and 2) areas that contain any stationary source that emitted more than 16,000 tons of SO<sub>2</sub> in 2012 or emitted more than 2,600 tons of SO<sub>2</sub> and had an emission rate of at least 0.45 lb/mmbtu in 2012. Based on that criteria, the areas surrounding Big Stone Plant and Coyote Station were subject to review. Air dispersion modeling was completed for each site, and based on that analysis, in July 2016 EPA designated the areas surrounding Coyote Station in Central Mercer County, ND and Big Stone Plant in Grant County, SD as “unclassifiable/attainment”.

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### 2. Ozone and PM NAAQS

In the electric power industry, the rule currently being used to assist with attainment of the NAAQS for ozone and particulate matter from regional sources is EPA's Cross-State Air Pollution Rule (CSAPR) that first went into effect on January 1, 2015. CSAPR requires SO<sub>2</sub> and NO<sub>x</sub> emission reductions from fossil fuel-fired power plants located in the eastern portion of the United States. The Rule establishes two new types of SO<sub>2</sub> allowances (Group 1 and Group 2) and two new types of NO<sub>x</sub> allowances (Annual and Ozone). Minnesota is classified as a Group 2 SO<sub>2</sub> state (along with six other states - Alabama, Georgia, Kansas, Nebraska, South Carolina and Texas) and an Annual NO<sub>x</sub> state (along with 22 other states). South Dakota and North Dakota are not included in CSAPR. On March 15, 2021, EPA finalized revisions to CSAPR for the 2008 ozone NAAQS; however, the revised CSAPR update does not impact Minnesota, North Dakota, or South Dakota.

Similar to the Acid Rain Program, under CSAPR, EPA allocates allowances to each source for use in or after a specified year. At the end of the year, if a source's emissions are less than its annual allowance allocation, it can bank the extra allowances forward for use in future years. If a source's annual emissions are more than its annual allocation, the source can then either use banked allowances from previous years, transfer allowances from another facility, or purchase allowances on the open market. However, a Group 2 SO<sub>2</sub> unit can only use Group 2 SO<sub>2</sub> allowances. Since Hoot Lake Plant has retired and Big Stone Plant and Coyote Station are not subject to CSAPR, this rule does not currently significantly impact OTP.

On October 1, 2015, the EPA announced that it tightened the primary and secondary NAAQS for ozone from 75 parts per billion (ppb) to 70 ppb. Minnesota, North Dakota, and South Dakota do not have any nonattainment areas at the 70 ppb level.

For particulate matter, EPA has established both an annual and a 24-hour standard for fine particulates (PM<sub>2.5</sub>), and a 24-hour standard for coarse particulate (PM<sub>10</sub>). The PM<sub>2.5</sub> standards were last revised in 2012, and in December 2020 EPA announced its decision to retain the standards without revision. However, in June 2021 EPA announced it will reconsider the December 2020 decision and that it expects to issue a final rule in Spring 2023. The states of Minnesota, North Dakota, and South Dakota are all currently in compliance with the particulate matter NAAQS.

### **B. Regional Haze Program**

Section 169A of the 1977 Amendments to the Clean Air Act (CAA) sets forth a program for protecting visibility in Federal Class I areas which calls for the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Federal Class I areas which

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impairment results from manmade air pollution.” Federal Class I areas include 156 national parks, memorial parks, and wilderness areas.

In 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the CAA, establishing the Regional Haze Rule (RHR) as the comprehensive visibility protection program for Federal Class I areas. The RHR did not mandate specific milestones or rates of progress, but instead called for states to establish goals that provide for reasonable progress towards achieving natural visibility conditions by the year 2064.

States are required to submit RHR state implementation plans (SIPs) that evaluate reasonable progress in approximately 10-year increments. The first Regional Haze planning period covered the years 2008-2018, while the second planning period will focus on the next timeframe ending in 2028.

For the first Regional Haze planning period, Big Stone Plant installed selective catalytic reduction in conjunction with separated over-fire air for control of nitrogen oxides, a scrubber for reducing SO<sub>2</sub>, and a baghouse to control particulate matter. The equipment began commercial operation on December 29, 2015. No additional emission reductions are anticipated to be required at Big Stone Plant for the second planning period.

At Coyote Station for the first planning period, separated overfire air equipment to reduce nitrogen oxide emissions was installed during a Spring 2016 outage. For the second planning period, Otter Tail, as operating agent for the co-owned Coyote Station, has provided the North Dakota Department of Environmental Quality (ND DEQ) with an analysis of technically feasible RHR control measures. When evaluating these potential control measures, the ND DEQ must consider four statutory factors:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected source.

Additionally, as described by an EPA August 2019 guidance document, states may choose to consider visibility benefits along with the four required statutory factors. The ND DEQ is part of a 15-state Western Regional Air Partnership (WRAP) that worked collaboratively to evaluate visibility conditions for the 118 Class I Areas in the WRAP region. As part of this evaluation, WRAP conducted two rounds of visibility modeling scenarios of “Potential Additional Controls” to allow states to weigh the projected visibility benefits of emission controls. The ND DEQ provided the following Coyote Station scenarios to WRAP:

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- An emissions-controls case consistent with either a new dry scrubber or significant upgrades for sulfur dioxide control, and a new selective non-catalytic reduction system for nitrogen oxides control (both of which would require significant capital investment in emissions controls equipment at Coyote Station, and associated annual operation and maintenance costs).
- An emissions-controls case consistent with operational improvements for sulfur dioxide control, and no additional controls for nitrogen oxides (neither of which would require additional capital investment in emissions controls equipment at Coyote Station, but the first of which would require additional operation and maintenance costs).

Otter Tail anticipates that the ND DEQ will provide a draft SIP for public review in late 2021 or early 2022. Ultimately, EPA is responsible for final review and approval of the ND DEQ SIP, or alternatively disapproval and promulgation of a Federal Implementation Plan (FIP). The duration of the EPA review process is uncertain; for example, for the first 10-year reasonable progress increment, several SIPs were rejected by EPA and FIPs were proposed, resulting in several years of administrative proceedings and subsequent judicial review.

### **C. New Source Review**

Under the New Source Review Program, the Prevention of Significant Deterioration (PSD) program applies to areas of the country that attain (or are unclassifiable) the National Ambient Air Quality Standards (NAAQS), such as the areas in which Otter Tail's facilities are located. PSD review requires persons constructing new major air pollution sources or implementing significant modifications to existing air pollution sources that constitute a significant net emissions increase to obtain a permit prior to such construction or modification. In order to obtain a PSD permit, the owner or operator of an affected facility must undergo a review which requires the identification and implementation of best-available control technology (BACT) for the regulated air pollutants for which there is a significant net emissions increase, and an analysis of the ambient air quality impacts of the facility.

Otter Tail's existing facilities are not contemplating any changes that would result in PSD review.

### **III. HAZARDOUS AIR POLLUTANTS**

#### **Mercury and Other Hazardous Air Pollutant Emissions Rulemaking**

The 1990 Amendments to the CAA required EPA to study the effects of emissions of listed hazardous air pollutants (HAPs) by electric steam generating plants. On March 16, 2011, EPA proposed Section 112 air toxics standards for all coal- and oil-fired EGUs that reflect the application of the maximum achievable control technology consistent with the requirements of the CAA. EPA signed a final rulemaking, termed the mercury and air toxics standards (MATS) rule, on December 16, 2011.

Coyote Station is meeting MATS by utilizing activated carbon injection in combination with its existing spray dryer and fabric filter. Big Stone Plant is meeting MATS through the installation activated carbon injection in conjunction with its existing selective catalytic reduction, circulating dry scrubber, and baghouse. Emissions monitoring equipment and stack testing is being utilized to verify compliance with the standards at each facility.

On June 29, 2015, the U.S. Supreme Court held that EPA must consider cost, including cost of compliance, before deciding whether regulation of mercury emissions is appropriate and necessary. The MATS rule, however, remained in effect while the case was remanded to the D.C. Circuit for further proceedings. On December 15, 2015, the D.C. Circuit ordered that the MATS rule be remanded to EPA without vacating the rule. On April 25, 2016, EPA issued a final supplemental finding that concludes that a consideration of cost does not change their determination that regulation of HAPs from coal and oil-fired EGUs is appropriate and necessary. On April 16, 2020, EPA finalized a rule that revises the 2016 cost finding, and now concludes MATS is not appropriate and necessary. However, even with this revision, EPA left MATS in place because electric generating units remain subject to regulation under Section 112 of the Clean Air Act. EPA also concluded that based on a risk and technology review, no changes to the current MATS emission standards are necessary. Challenges to these rulemakings are ongoing, and the current EPA Administration has announced they intend to review the MATS related actions of the prior Administration.

## **IV. COAL COMBUSTION RESIDUALS REGULATION**

On December 19, 2014, EPA signed a final rule to further regulate coal combustion residuals (CCR) as non-hazardous waste under subtitle D of the Resource Conservation and Recovery Act (RCRA).

The final subtitle D rule required OTP to meet several new requirements, including installing additional groundwater monitoring wells, publishing data on our CCR units on a website, conduct structural integrity assessments, determine compliance with location restrictions, and develop and implement plans for fugitive dust, hydrologic capacity, run-on & run-off control, and closure & post-closure care.

The Hoot Lake Plant operates a dry ash disposal site that is regulated, permitted and inspected by the Minnesota Pollution Control Agency (“MPCA”). The existing operating site is lined with a synthetic liner with a leachate collection system, and it will be closed with a synthetic cover and an engineered soil cover following plant demolition activities. The site has a groundwater monitoring system and annual reports have been provided to the MPCA.

Big Stone Plant operates a dry disposal site that is regulated, permitted, and inspected by the South Dakota Department of Agriculture and Natural Resource (“DANR”). The site is underlain with native clay, and each portion of the designated disposal area is covered with clay and topsoil once it is filled to capacity. Monitoring of groundwater is ongoing and annual reports are provided to the DANR. In accordance with the CCR rule, during a fall 2018 outage, Big Stone Plant closed a surface impoundment via removal of all CCR and replaced it with new ash handling technology. Boiler slag is either dry disposed in the permanent disposal site or beneficially reused.

Coyote Station has one active dry disposal site that is regulated, permitted, and inspected by the ND DEQ. The site has an engineered clay liner for acceptance of flue gas desulfurization product and boiler slag. The site has a groundwater monitoring system and annual reports have been provided to the ND DEQ. Similar to Big Stone, in 2019 Coyote Station closed its surface impoundments via removing the CCR and installed new ash handling technology. Boiler slag is either dry disposed in the permanent disposal site or beneficially reused.

### **V. WATER REGULATION**

#### **A. 316(b)**

Section 316(b) of the Clean Water Act (CWA) requires facilities with cooling water intake structures to ensure that the location, design, construction and capacity of the structures reflect the best technology available to minimize harmful impacts on the environment. EPA first promulgated regulations to implement section 316(b) in 1976. In 1977 the U.S. Court of Appeals for the Fourth Circuit remanded these regulations to EPA, which withdrew them and left in place a provision that directed permitting authorities to determine best technology available for each facility on a case-by-case basis. After numerous years of proceedings, on May 9, 2014, EPA signed the final rule setting national standards for cooling water intake structures at existing facilities with National Pollutant Discharge Elimination System (NPDES) permits that withdraw at least 2 million gallons of water per day (MGD) and use at least 25% of that water for cooling purposes.

Under the final rule, all affected facilities need to comply with one of seven Best Technology Available (BTA) alternatives for reducing impingement, while site-specific BTA for reducing entrainment will be up to the states. However, in addition to the seven BTA options for impingement, another option identified as “*de minimus*” impingement is provided in the rule. In this option, facilities with very low levels of impingement are not required to use any additional impingement controls. In any case, new requirements will be incorporated into NPDES permits to achieve 316(b) compliance “as soon as practicable according to the schedule of requirements set by the Director.”

Both Big Stone Plant and Coyote Station use closed cycle cooling, and thus have not been significantly impacted by the 316(b) rule.

#### **B. Effluent Limit Guidelines**

The Clean Water Act establishes a structure for regulating discharges of pollutants to surface waters of the United States. As part of the implementation, EPA issues effluent limit guidelines (ELG) for industrial dischargers. EPA first issued ELG for steam electric power plants in 1974, with subsequent revisions in 1977 and 1982. EPA announced its decision to proceed with further possible revisions on September 15, 2009 and published a proposed rulemaking on June 7, 2013. On November 3, 2015, the EPA published the final rule that sets technology-based effluent limitations on certain types of discharges. Generally, the final rule establishes “no discharge” requirements for waste water discharge streams from wet flue gas desulfurization, fly ash transport, and bottom ash transport.

## **Appendix E: Environmental Assessment 12**

Effluent limits specific to Coyote Station is incorporated into its NPDES permits. Big Stone Plant is a zero-discharge facility and therefore does not have a NPDES permit Coyote Station's permit limits are based on a combination of state water quality standards, the Federal ELG, and best professional judgment. Coyote Station's primary effluent discharge is cooling tower blowdown. Moreover, by recently installing new ash handling technology and utilizing existing dry flue gas desulfurization technology, neither Coyote Station nor Big Stone Plant discharge any ash transport water or flue gas desulfurization wastewater.

## Appendix E: Environmental Assessment 13

### SUMMARY

#### Environmental Regulatory Assessment Summary

Legend:

Air related

Solid Waste related

Water related

Rule	Status	Anticipated Big Stone Plant Impact	Anticipated Coyote Station Impact	Anticipated Compliance Timeframe
Greenhouse Gas Regulation – 111(d)	Remanded	Unknown	Unknown	Unknown
Greenhouse Gas Regulation – NSPS	Final	N/A – Applicable to New Plants Only	N/A – Applicable to New Plants Only	New plants
Acid Rain Program	Final	Low impact. Maintain banked allowances (SO <sub>2</sub> ); Operate existing SCR and overfire air	Low impact. Maintain banked allowances (SO <sub>2</sub> ); Operate existing separated overfire air	Ongoing
2010 NO <sub>2</sub> and SO <sub>2</sub> NAAQS	Final	Low impact. Based on SO <sub>2</sub> modeling, EPA has classified the area around Big Stone as attainment/unclassifiable.	Low impact. Based on SO <sub>2</sub> modeling, EPA has classified the area around Coyote as attainment/unclassifiable.	Ongoing
Cross-State Air Pollution Rule	Final	None -- Rule does not apply to SD	None -- Rule does not apply to ND	N/A
Regional Haze Program Round 1	Final	Selective Catalytic Reduction and separated overfire air for NO <sub>x</sub> , scrubber for SO <sub>2</sub> , and baghouse for PM	Separated overfire air for NO <sub>x</sub>	Ongoing
Regional Haze Program Round 2	SIP under development	Low	TBD. Possible SO <sub>2</sub> and NO <sub>x</sub> reductions	2028
Mercury and other Hazardous Air Pollutants (MATS)	Final	Existing pollution control equipment plus activated carbon injection	Existing pollution control equipment plus activated carbon injection	Ongoing
Coal Combustion Residuals	Final	CCR was removed from one surface impoundment and new ash handling technology installed. BSP manages an active dry ash disposal site. Future horizontal disposal site sequences may require a synthetic liner and leachate collection.	CCR was removed from three surface impoundments and new ash handling technology was installed. Coyote manages an active dry ash disposal site. Future horizontal disposal site sequences may require a synthetic liner and leachate collection.	Ongoing
Clean Water Act Section 316(b)	Final	Big Stone uses cooling ponds that qualify as closed cycle cooling	Coyote Station uses a cooling tower that qualifies as closed cycle cooling	Ongoing
Effluent Guidelines	Final	Big Stone does not generate ash transport or FGD wastewater.	Coyote does not generate ash transport or FGD wastewater.	Ongoing

**Appendix F: EnCompass Modeling Assumptions**

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# 1 Sensitivities Evaluated

Otter Tail produced 123 modeling runs for this resource plan. Figure 1 shows a grid of sensitivities evaluated in this resource plan. As further described in the Petition, for each sensitivity, this filing includes EnCompass modeling runs to provide insight into the impacts of Otter Tail continuing with its interest in Coyote Station through 2041, 2028, and 2026. This results in 57 modeling runs without externalities and 66 modeling runs with externalities. Otter Tail includes all modeling runs with and without externalities in Appendix I.

**Figure 1: Sensitivities Evaluated**

Sensitivity	Description		
A	Base Case	Zero Externalities	Externality Values Applied
B	Preferred IRP		
C	Regional Haze Mid Cost		
D	Regional Haze High Cost		
E	NG and Energy Markets +25%		
F	NG and Energy Markets +50%		
G	NG and Energy Markets +100%		
H	NG and Energy Markets -25%		
I	NG and Energy Markets -50%		
J	Low Wind		
K	Low Solar		
L	Low Wind & Solar		
M	Low Storage		
N	High Interconnection Costs		
O	Additional 10% MISO Capacity Requirement		
P	Capacity Purchase Limit		
Q	10% Increased Load		
R	25% Increased Load		
S	Carbon Tax		
T	Low Externalities 2020-2024, Low Cost of Carbon 2025-2050		
U	High Externalities 2020-2024, High Cost of Carbon 2025-2050		
V	Low Externalities 2020-2024, Median Cost of Carbon 2025-2050		
W	High Externalities 2020-2024, Median Cost of Carbon 2025-2050		

## 2 Wind Energy Assumptions

Figure 2 shows the wind energy assumptions used in the resource plan. Otter Tail evaluated wind energy resource alternatives as purchased power agreements (PPA) with a 35-year term and fixed pricing over that term. Wind integration costs are included in the fixed price assumptions.

The wind energy price assumptions for 2023 through 2026 include current legislation and Internal Revenue Service (IRS) guidance provided in IRS Notice 2020-41 which allows for 60 percent production tax credit (PTC) for projects that meet certain criteria. The wind energy price assumptions after 2026 do not include PTCs.

Wind project sizes are assumed to be 50 MW in size with a 50 percent net capacity factor and an accredited capacity of 16 percent. Otter Tail models wind projects as purchased power agreements with a fixed levelized cost of energy.

Otter Tail includes three categories for these wind projects: (1) Generic wind resources require a new generation site, (2) Surplus interconnection wind may be added alongside an existing generating facility where the generation of both resources does not exceed the existing interconnection amount of the original facility, and (3) Replacement interconnection wind resources reuse the existing interconnection rights of an existing resource that is retiring. Otter Tail includes Figure 2 below with the wind project alternatives included in the base model.

**Figure 2: Base Wind Energy Assumptions**

		Base Case \$/MWh						
Year available	Wind Project Alternatives	Size (MW)	Accredited capacity (% of Nameplate)	LCOE modeled as a fixed price PPA	PTC adjustment	Inconnection adder assuming \$500/kW	Congestion adder	Base Case (\$/MWh)
2022-2036	Generic	50	16%	\$35.00	\$0.00	\$10.00	\$3.50	\$48.50
2023-2026	Generic - 60% PTC	50	16%	\$30.00	(\$8.00)	\$10.00	\$3.50	\$35.50
2027-2036	Surplus Interconnection	50	0%	\$35.00	\$0.00	\$0.00	\$0.00	\$35.00
2033-2036	Replacement Interconnection	50	16%	\$35.00	\$0.00	\$0.00	\$0.00	\$35.00

Figure 3 provides the assumptions included in the Low Sensitivity wind energy assumptions. The low wind price sensitivities are included in sensitivities *J* and *L* in Appendix I.

**Figure 3: Low Sensitivity Wind Energy Assumptions**

		Low Sensitivity \$/MWh						
Year available	Wind Project Alternatives	Size (MW)	Accredited capacity (% of Nameplate)	LCOE modeled as a fixed price PPA	PTC adjustment	Inconnection adder assuming \$500/kW	Congestion adder	Low Wind (\$/MWh)
2022-2036	Generic	50	16%	\$26.00	(\$10.00)	\$10.00	\$3.50	\$29.50
2023-2026	Generic - 60% PTC	50	16%	\$26.00	(\$10.00)	\$10.00	\$3.50	\$29.50
2027-2036	Surplus Interconnection	50	0%	\$26.00	(\$10.00)	\$0.00	\$0.00	\$16.00
2033-2036	Replacement Interconnection	50	16%	\$26.00	(\$10.00)	\$0.00	\$0.00	\$16.00

### 3 Solar Energy Assumptions

Otter Tail evaluated solar energy resource alternatives as purchased power agreements (PPA) with a 35-year term and fixed pricing over that term. Solar integration costs are included in the fixed price assumptions.

Similar to wind, the solar energy price assumptions for 2023 through 2026 include current legislation and Internal Revenue Service (IRS) guidance provided in IRS Notice 2020-41 which allows for 26 percent investment tax credit (PTC) for projects that meet certain criteria. The solar energy price assumptions after 2026 include a 10 percent ITC.

Solar project sizes are assumed to be 25 MW in size with 24 percent net capacity factor and an accredited capacity of 30 percent. Otter Tail includes Figure 4 below with the solar project alternatives included in the base model.

**Figure 4: Base Case Solar Energy Assumptions**

		Base Case \$/MWh						
Year available	Solar Project Alternatives	Size (MW)	Accredited capacity (% of Nameplate)	LCOE modeled as a fixed price PPA	ITC adjustment	Inconnection adder assuming \$200/kW	Congestion adder	Base Case (\$/MWh)
2023-2026	Generic - 26% ITC	25	30%	\$42.00	(\$7.00)	\$7.00	\$0.00	\$42.00
2023-2026	Surplus Interconnection - 26% ITC	25	0%	\$42.00	(\$7.00)	\$0.00	\$0.00	\$35.00
2023-2026	Surplus Interconnection - 26% ITC w/ Capacity	25	30%	\$42.00	(\$7.00)	\$0.00	\$0.00	\$35.00
2023-2026	Replacement Interconnection - 26% ITC	25	30%	\$42.00	(\$7.00)	\$0.00	\$0.00	\$35.00
2022-2036	Generic	25	30%	\$39.00	(\$2.25)	\$7.00	\$0.00	\$43.75
2027-2036	Surplus Interconnection	25	0%	\$39.00	(\$2.25)	\$0.00	\$0.00	\$36.75
2026-2036	Surplus Interconnection	25	30%	\$39.00	(\$2.25)	\$0.00	\$0.00	\$36.75
2033-2036	Replacement Interconnection	25	30%	\$39.00	(\$2.25)	\$0.00	\$0.00	\$36.75

Similar to wind, Otter Tail includes three categories for solar projects: (1) Generic solar resources require a new generation site, (2) Surplus interconnection solar may be added alongside an existing generating facility where the generation of both resources does not exceed the existing interconnection amount of the original facility, and (3) Replacement interconnection

solar resources reuse the existing interconnection rights of an existing resource that is retiring.

Figure 5 provides the assumptions included in the Low Sensitivity solar energy assumptions.

The low solar price sensitivities are *K* and *L* in Appendix I.

**Figure 5: Low Sensitivity Solar Energy Assumptions**

		Low Sensitivity \$/MWh						
Year available	Solar Project Alternatives	Size (MW)	Accredited capacity (% of Nameplate)	LCOE modeled as a fixed price PPA	ITC adjustment	Inconnection adder assuming \$200/kW	Congestion adder	Low Solar (\$/MWh)
2023-2026	Generic - 26% ITC	25	30%	\$30.00	(\$7.00)	\$7.00	\$0.00	\$30.00
2023-2026	Surplus Interconnection - 26% ITC	25	0%	\$30.00	(\$7.00)	\$0.00	\$0.00	\$23.00
2023-2026	Surplus Interconnection - 26% ITC w/ Capacity	25	30%	\$30.00	(\$7.00)	\$0.00	\$0.00	\$23.00
2023-2026	Replacement Interconnection - 26% ITC	25	30%	\$30.00	(\$7.00)	\$0.00	\$0.00	\$23.00
2022-2036	Generic	25	30%	\$27.00	(\$7.00)	\$7.00	\$0.00	\$27.00
2027-2036	Surplus Interconnection	25	0%	\$27.00	(\$7.00)	\$0.00	\$0.00	\$20.00
2026-2036	Surplus Interconnection	25	30%	\$27.00	(\$7.00)	\$0.00	\$0.00	\$20.00
2033-2036	Replacement Interconnection	25	30%	\$27.00	(\$7.00)	\$0.00	\$0.00	\$20.00

## 4 Battery Storage Assumptions

Otter Tail evaluated battery storage resource alternatives as purchased power agreements (PPA) with a 30-year term and fixed pricing over that term. Battery storage costs are included in the fixed price assumptions.

The battery storage price assumptions included below are based on Otter Tail's industry knowledge and estimates specific to Otter Tail. The low price storage costs include a 25 percent reduction from the base assumptions.

**Figure 6: Battery Storage Assumptions**

Year available	Battery Storage Alternative	Size (MW)	Accredited capacity (% of Nameplate)	Base Cost Fixed Cost (\$/Year)	Low Cost Fixed Costs (\$/Year)
2022-2036	10 MW Paired Battery	10	95%	\$828,000	\$621,000
2022-2036	25 MW Battery	25	95%	\$3,000,000	\$2,250,000

## 5 Natural Gas Fuel Price Assumptions

Figure 7 shows the forecasted monthly natural gas fuel prices used in the 2021 resource plan.

Otter Tail used the Wood Mackenzie March 2021 North American Power Service for determining the natural gas fuel prices used in the resource plan. Otter Tail evaluated natural gas

prices at +/- 25percent of the base case and +/- 50 percent of the base case and at +100 percent of the base case. The natural gas price sensitivities are *E, F, G, H,* and *I* in Appendix I.

**Figure 7: Natural Gas Fuel Price Assumptions**

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## **6 Coal Price Assumptions**

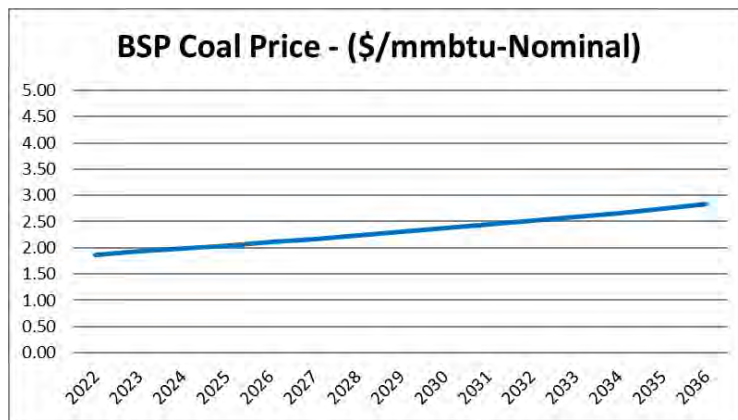
Otter Tail’s coal price forecasts for its two coal-fired thermal units are developed using existing coal and freight contracts. For modeling purposes in this resource plan coal fuel prices are broken into two portions: fixed fuel costs and variable fuel costs. The 2021 fixed fuel costs modeled for Big Stone reflect the rail car lease costs of [PROTECTED DATA BEGINS...

...PROTECTED DATA ENDS] (OTP portion) annually. The 2021 fixed fuel costs modeled for Coyote station are modeled at [PROTECTED DATA BEGINS...

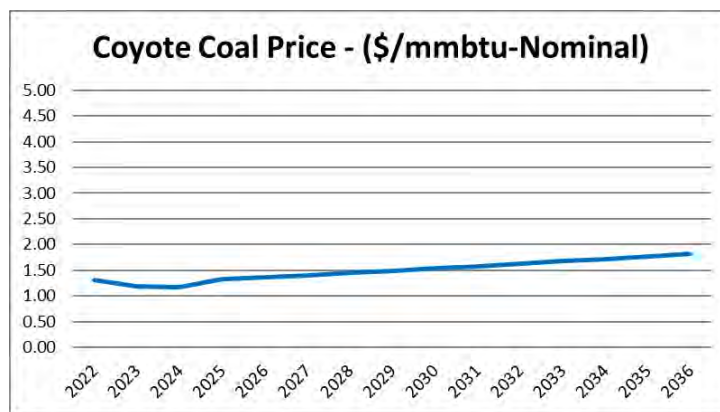
...PROTECTED DATA ENDS] (OTP portion) annually and represent the non-variable portion of the fuel supply agreement.

The variable cost portion of fuel costs are shown in Figure 8 (Big Stone Plant) and Figure 9 (Coyote Station.)

**Figure 8: Big Stone Plant Variable Portion Coal Price Assumptions**



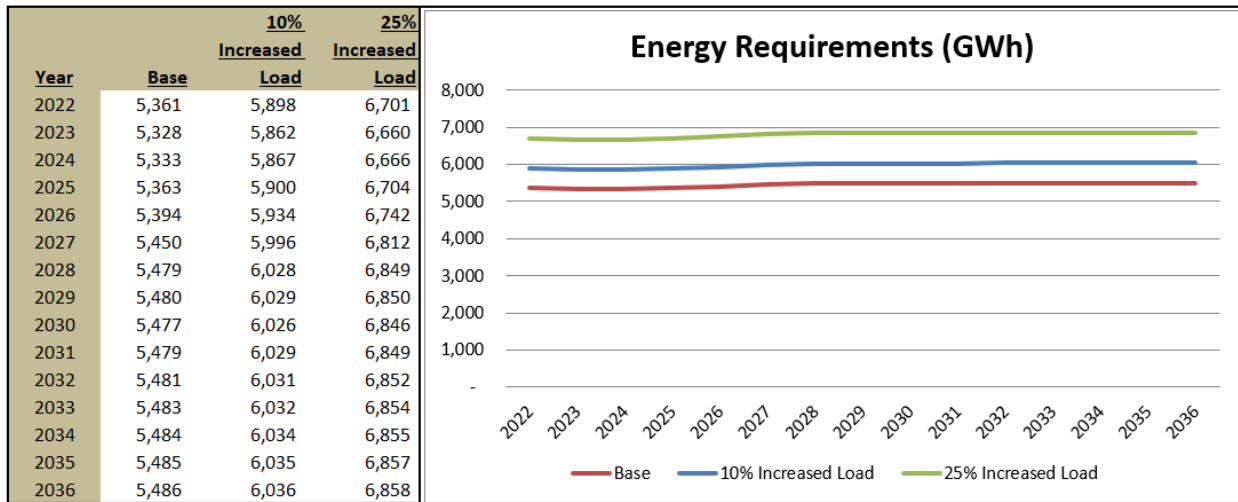
**Figure 9: Coyote Station Variable Portion Coal Price Assumptions**



## 7 Increased Load Assumptions

Figure 10 shows the energy requirement assumptions used in the resource plan. The increased load sensitivities are provided in Appendix I as Sensitivity *Q* and *R*, respectively.

**Figure 10: Increased Load Assumptions**

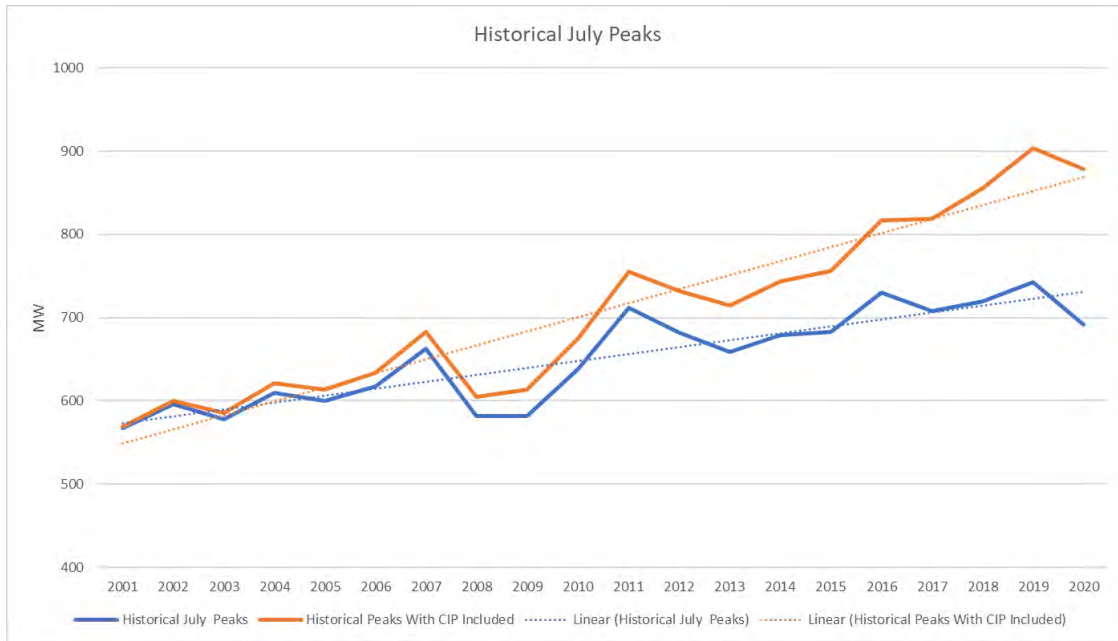


## 8 Energy Efficiency Assumed in Forecast

Otter Tail has been actively incorporating energy efficiency and Demand Side Management (DSM) programs since 1992. As time goes on and energy efficiency programs grow, a portion of future energy efficiency is included in the energy and demand forecasts. This conclusion was reached based on the fact that our historical load growth has been incrementally lowered by the existing energy efficiency programs which will translate to a lower future load growth through the forecasting process. In other words, the forecast assumes additional new energy efficiency to maintain the reduced load growth rates caused by the historical energy efficiency programs.

Figure 11 shows the historical DSM for 2001 through 2020 where the solid blue line provides the actual historical July peaks, and the solid orange line provides the historical July peak had Otter Tail not had any demand reductions. The dotted blue line provides the actual historical slope of 8.36 compared to the orange dotted line slope of 16.84 if Otter Tail had not had any demand reductions.

**Figure 11: DSM Assumptions**



The values for each year are listed in Figure 12.

**Figure 12: Built-In DSM/EE**

<b>Year</b>	<b>Historical CIP Demand Reduction</b>	<b>12-Year Cumulative Total</b>	<b>Historical July Peaks</b>	<b>Historical Peaks With CIP Included</b>
2001	2.2	2.2	567	569.2
2002	1.9	4.2	596	600.2
2003	3.0	7.2	578	585.2
2004	3.6	10.7	610	620.7
2005	2.9	13.6	600	613.6
2006	3.2	16.8	617	633.8
2007	3.0	19.8	663	682.8
2008	3.4	23.2	582	605.2
2009	8.2	31.4	582	613.4
2010	5.8	37.2	638	675.2
2011	6.3	43.5	712	755.5
2012	6.4	49.9	682	731.9
2013	7.7	55.4	659	714.4
2014	10.6	64.0	679	743.0
2015	12.3	73.3	683	756.3
2016	17.3	87.1	730	817.1
2017	26.7	110.9	708	818.9
2018	28.1	135.8	719	854.8
2019	28.5	161.3	742	903.3
2020	29.9	187.8	691	878.8

SLOPE	8.36	16.84
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Otter Tail forecasts expected demand reductions for the resource planning period. Figure 13

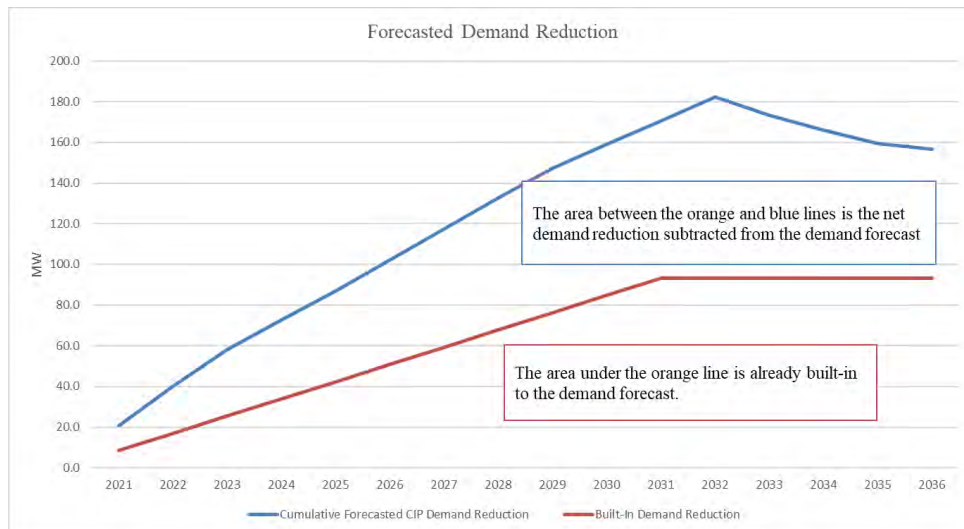
below provides those forecasted demand reductions and utilizes the historical data provided above to determine the amount of those forecasted demand reductions already built-in to the forecast. This amount assumed to already be part of the forecast is removed from the annual forecasted demand reduction to arrive at the Net Demand Reduction that Otter Tail includes in the forecast for CIP demand reduction.

**Figure 13: Net CIP Demand Reduction to Forecast**

<u>Year</u>	<u>Forecasted CIP Demand Reduction</u>	<u>Cumulative Forecasted CIP Demand Reduction</u>	<u>Built-In Demand Reduction</u>	<u>Net CIP Demand Reduction</u>
2021	20.8	20.8	8.5	12.3
2022	19.2	40.0	17.0	23.1
2023	18.2	58.2	25.4	32.8
2024	14.4	72.7	33.9	38.7
2025	14.5	87.1	42.4	44.7
2026	15.2	102.3	50.9	51.4
2027	15.2	117.5	59.4	58.2
2028	15.2	132.7	67.8	64.9
2029	14.5	147.3	76.3	70.9
2030	11.7	159.0	84.8	74.2
2031	11.7	170.7	93.3	77.4
2032	11.7	182.4	93.3	89.2
2033	11.7	173.4	93.3	80.1
2034	11.7	165.9	93.3	72.6
2035	11.8	159.4	93.3	66.2
2036	11.8	156.8	93.3	63.5

Figure 14 below shows the growth of these demand reductions included in Otter Tail’s forecast.

**Figure 14: Forecast Demand Reduction**



## **9 Market Energy Price Assumptions**

Otter Tail used the Wood Mackenzie March 2021 North American Power Service as the basis for the market energy prices used in this resource plan. Otter Tail applied the Wood Mackenzie forecasted monthly on-peak and off-peak energy prices to an hourly profile to reflect the hourly variability/volatility of the energy market. Otter Tail evaluated market energy at +/- 25 percent, +/- 50 percent, and +100 percent of the base case. Figure 15 shows the market energy price basis for the assumptions used in the resource plan. The market energy price sensitivities are provided in Appendix I as Sensitivity *E*, *F*, *G*, *H*, and *I*, respectively.

**Figure 15: Market Energy Price Assumptions**

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## **10 Externality Price Assumptions**

Otter Tail includes all modeling runs with and without externalities in Appendix I. For the modeling runs with externalities Figure 16 provides the application of the externalities for Otter Tail Generating Resources.

**Figure 16: Application of Externalities for Otter Tail Generating Resources**

	<b>Regulatory Cost of Carbon</b>	<b>CO2 Externality Values</b>	<b>Criteria Values</b>
Big Stone	<b>X</b>		<b>X</b>
Coyote	<b>X</b>		
Astoria	<b>X</b>		<b>X</b>
Solway	<b>X</b>	<b>X</b>	<b>X</b>

As identified in Appendix A, in compliance with Minnesota Docket Nos. CI-07-1199, CI-14-643, and DI-19-406, Otter Tail includes externality sensitivities. For these sensitivities, Otter Tail includes the criteria values for PM2.5, NOX, and SO2 defined in Minnesota Docket No. CI-14-643 and the CO2, for 2020-2024, and Regulatory Cost of Carbon values determined in Minnesota Docket Nos CI-07-1199 and DI-19-406. These values are provided in Figure 17 below.

**Figure 17: Externality Values**

<b>CO2 Externality Values (2020-2024)</b>			
	<b>Low</b>	<b>Median</b>	<b>High</b>
2020	\$9.05	\$25.76	\$42.46
2021	\$9.25	\$26.31	\$43.36
2022	\$9.46	\$26.86	\$44.26
2023	\$9.66	\$27.41	\$45.16
2024	\$9.87	\$27.97	\$46.06

<b>Regulatory Cost of Carbon (2025-2050)</b>			
	<b>Low</b>	<b>Median</b>	<b>High</b>
2025+	\$5.00	\$15.00	\$25.00

<b>Criteria Values (2020-2050)</b>			
	<b>Low</b>	<b>Median</b>	<b>High</b>
PM2.5	\$3,437	\$6,220	\$8,441
NOX	\$1,985	\$4,762	\$6,370
SO2	\$3,427	\$6,159	\$8,352

## 11 New Thermal Alternative Assumptions

Figure 18 shows key assumptions used for new thermal alternatives in the resource plan.

**Figure 18: New Thermal Alternatives**

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## 12 Existing Unit Input Assumptions

Figure 19 shows key input assumptions used for existing baseload units.

**Figure 19: Existing Baseload Unit Assumptions**

Existing Baseload Units		
Name	Big Stone Plant	Coyote Station
Coal Type	sub-bituminous	lignite
Retirement Date	2046	2041
Nameplate Capacity (MW)	255.8	149.8
Firm Capacity (MW)	244.1	121.4
Heat Rate at Minimum (Btu/kwh)	11,770	12,786
Heat Rate at Maximum (Btu/kwh)	10,286	11,011
O&M Escalation	2%	2%
Fixed O&M (2022\$/kw-yr)	\$57.69	\$70.52
Variable O&M (2022\$/MWh)	\$1.71	\$1.51

Figure 20 shows key input assumptions used for existing peaking units.

**Figure 20: Existing Peaking Unit Assumptions**

Existing Peaking Units					
Name	Astoria Station	Solway	Lake Preston	Jamestown 1	Jamestown 2
Fuel	natural gas	natural gas	fuel oil	fuel oil	fuel oil
Retirement Date	2056	2038	2033	2033	2033
Nameplate Capacity(MW)	248	42.5	20.4	20.7	21.1
Firm Capacity(MW)	241.0	41.5	18.7	19.7	19.3
Heat Rate at Minimum (Btu/kwh)	11,513	14,023	27,156	25,135	25,339
Heat Rate at Maximum (Btu/kwh)	9,120	9,293	14,629	13,507	13,845
O&M Escalation	2%	2%	2%	2%	2%
Fixed O&M (2022\$/kw-yr)	\$3.56	\$21.43	\$3.35	\$3.42	\$3.35
Variable O&M (2022\$/MWh)	\$0.77	\$3.68	\$18.82	\$24.18	\$24.18

Figure 21 shows key input assumptions used for existing wind purchased power agreements.

**Figure 21: Existing Wind Energy Purchases**

Existing Wind Purchased Power Transactions			
Name	ND Wind II (Edgeley)	Langdon PPA	Ashtabula III
Transaction End Date	Nov-2028	Nov-2032	Sep-2038
Nameplate Capacity(MW)	21	19.5	62.4
Firm Capacity(MW)	3.6	4.7	15.4
Net Capacity Factor	26%	41%	39%

Figure 22 shows key input assumptions used for Otter Tail owned wind facilities.

**Figure 22: Existing Otter Tail-Owned Wind Facilities**

Existing Otter Tail-Owned Wind				
Name	Langdon	Ashtabula	Luverne	Merricourt
End of Life Date	Dec-2042	Dec-2043	Dec-2044	Dec-2055
Nameplate Capacity(MW)	40.5	48	49.5	150
Firm Capacity(MW)	9.5	11.5	13.5	24.0
Net Capacity Factor	40%	36%	41%	50%

Figure 23 shows key input assumptions used for Otter Tail’s owned Hoot Lake Solar facility which is expected to be in commercial operation in 2023.

**Figure 23: Existing Otter Tail-Owned Solar Facility**

Existing Otter Tail Owned Solar	
Name	Hoot Lake Solar
Expected Commission Date	Jan-2023
Nameplate Capacity(MW)	49
Firm Capacity(MW)	12.3
Net Capacity Factor	24%

## **13 Other Assumptions**

General Inflation Rate – 2%

Capital Cost Escalation Rate – 1%

Debt Rate – 4.77%

Debt Ratio – 47.50

Discount Rate – 7.51%

Composite Tax Rate – 26.26%

# Appendix G: Otter Tail’s REO/RES Compliance Strategy

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## **REO/RES Compliance Strategy**

This document identifies and discusses the renewable energy requirements of the three states in which Otter Tail Power Company (Otter Tail or the Company) operates. The Company has developed significant wind generation resources and is currently developing the 49.9 MW Hoot Lake Solar Project. These renewable energy resources comprise a substantial percentage of the Company's total energy resources.

Renewable energy used for compliance with state requirements must be tracked through the Midwest Renewable Energy Tracking System (M-RETS) through the use of renewable energy credits. The discussion leads to a strategy for managing the renewable energy credits to the benefit of customers and Otter Tail while simultaneously complying with renewable energy requirements.

### **1. Jurisdictional Requirements**

Otter Tail serves retail customers in Minnesota, North Dakota, and South Dakota. All three state jurisdictions have a renewable energy objective (REO) or renewable energy standard (RES.) Discussion of compliance efforts with any single jurisdiction also requires a discussion of the other two jurisdictions so that a complete understanding of the Company's compliance efforts can be obtained. Table 1 describes the requirements in each of the state jurisdictions. Additional detail regarding the state rules follows.

	<b>Minnesota</b>	<b>North Dakota</b>	<b>South Dakota</b>
REO	2007-2009 1% 2010-2011 7% <i>(as percentage of retail sales after conservation)</i>	Prior to 2015 0% 2015 10% <i>(as percentage of retail sales with an adjustment for hydro energy that cannot be counted toward compliance)</i>	Prior to 2015 0% 2015 and on 10% <i>(as percentage of retail sales with an adjustment for hydro energy that cannot be counted toward compliance)</i>
RES <sup>1</sup>	2012-2015 12% 2016-2019 17% 2020-2024 21.5% (1.5% solar)  2025 and on 26.5% (1.5% solar)	N/A	N/A

### Minnesota

Eligible energy technologies for compliance include solar, wind, hydroelectric with a capacity of less than 100 MW, hydrogen,<sup>2</sup> or biomass. Biomass includes landfill gas, anaerobic digestion, and mixed municipal solid waste or refuse-derived-fuel from mixed municipal solid waste as a primary fuel. Electricity generated by the combustion of biomass through co-firing with other fuels can be used for compliance, up to the percentage amount of biomass fuel relative to total fuel, only if the generating facility was constructed in compliance with new source performance standards promulgated under the federal Clean Air Act or if the facility employs the maximum achievable or best available control technology (MACT or BACT) for that type of facility.

The Minnesota Public Utility Commission (MPUC) has ruled that RECs will have a shelf life for compliance with the REO/RES requirements of the year in which they are created plus four more calendar years. The PUC has also ruled that kWh sold under green pricing programs do not count toward REO/RES requirements.

The solar portion of the RES is a Minnesota requirement enacted in 2013 to be effective in 2020. The addition of the Hoot Lake Solar facility will be sufficient to meet the utility scale portion of the solar

<sup>1</sup> These MN REO and RES requirements only apply to utilities without nuclear generating assets. Utilities with nuclear generating assets have a more aggressive standard as detailed in Minn. Stat. §216B.1691.

<sup>2</sup> After January 1, 2010, the hydrogen must be generated from the other eligible energy technologies listed.

energy standard. Otter Tail's preferred plan includes the 49.9 MW Hoot Lake Solar project as well as 150 MW of solar in 2025; these two solar projects in the five year action window move Otter Tail closer to the energy goal of the state of Minnesota that by 2030, ten percent of the retail electric sales in Minnesota be generated by solar energy.<sup>3</sup>

#### North Dakota

The North Dakota REO is 10 percent of retail sales in 2015 and includes both renewable energy and recycled energy. The calculation contains a provision to reduce the amount of retail sales by any hydroelectric energy that cannot be counted toward the REO.<sup>4</sup> Renewable electricity and recycled energy includes electricity generated from solar, wind, biomass,<sup>5</sup> geothermal, hydrogen,<sup>6</sup> hydroelectric (must be from a facility with an in-service date of no earlier than January 1, 2007 or from efficiency improvements to a hydroelectric facility existing as of August 1, 2007), and recycled energy systems producing electricity from currently unused waste heat resulting from combustion or other processes and which do not use an additional combustion process for the electricity. Recycled energy does not include any system whose primary purpose is the generation of electricity.

The North Dakota Public Service Commission (ND PSC) has not made a determination of the shelf life of RECs for compliance purposes. The ND PSC has not ruled in any manner on whether kWh sold under green pricing programs count toward REO compliance. Until such a determination is made it is being assumed that North Dakota green pricing electricity will count toward the REO as long as the source of the electricity is a qualifying technology.

#### South Dakota

The South Dakota REO is 10 percent of retail sales which started in year 2015 and includes both renewable energy and recycled energy. The legislation is very similar to the North Dakota requirements. The calculation contains a provision to reduce the amount of retail sales by any hydroelectric energy from a facility with an in-service date prior to July 1, 2008.<sup>7</sup> Renewable electricity

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<sup>3</sup> Minnesota Statute §216B.1691, Subd. 2f(e)

<sup>4</sup> North Dakota Century Code §49-02-30.

<sup>5</sup> Including agricultural crops and wastes and residues, wood and wood wastes and residues, animal wastes, and landfill gas.

<sup>6</sup> Provided that the hydrogen is generated from a source listed in this section of North Dakota Century Code §49-02-25.

<sup>7</sup> South Dakota Codified Laws §49-34A-103.

and recycled energy include electricity generated from solar, wind, biomass,<sup>8</sup> geothermal, hydrogen,<sup>9</sup> hydroelectric (statutes seem to imply it must be from a facility with an in-service date of no earlier than July 1, 2008), and recycled energy systems producing electricity from currently unused waste heat resulting from combustion or other processes which do not use an additional combustion process to produce the electricity. Recycled energy does not include any system whose primary purpose is the generation of electricity.

The South Dakota PUC has not made a determination of the shelf life of RECs for REO compliance. The PUC has not ruled in any manner whether kWh sold under a green pricing program count toward REO compliance. Until the PUC makes a determination it is assumed that green pricing electricity does count toward the REO as long as the source of the electricity is a qualifying technology.

## **2. Midwest Renewable Energy Tracking System (M-RETS)**

Otter Tail has registered renewable energy resources within the M-RETS. There are small customer-owned wind units, generally less than 50 kW each, which the Company has not registered. These customers self-serve a portion of their own load with Otter Tail receiving the remaining surplus energy. Otter Tail does pay the cost, both initial and annual fees, to register a facility in M-RETS.

Otter Tail has developed an account structure within M-RETS to help segregate RECs by type and usage. For customer-owned facilities that self-serve customer load, all of the generation is reported within M-RETS. Otter Tail then transfers RECs associated with the energy used to self-serve load into an account in the customer's name, for their use as they deem appropriate. The RECs associated with energy purchased by Otter Tail will remain in the Company account.

The Otter Tail M-RETS accounts include a retirement account by state jurisdiction by year. Thus it will be easy to verify the amount of RECs retired annually for compliance with each state's requirements. RECs associated with *TailWinds*, the Company's green pricing program, are retired into separate state jurisdiction accounts to ensure proper accounting for the green pricing tracker balance.

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<sup>8</sup> Includes agricultural crops and wastes and residues, wood and wood wastes and residues, animal and other degradable organic wastes, and landfill gas.

<sup>9</sup> Provided that the hydrogen is generated from a source listed in this section of South Dakota Codified Laws §49-34A-94.

Retired RECs are tracked on a calendar year basis. The M-RETS system became operational in the last half of 2007. While Otter Tail began recording renewable energy within M-RETS late in 2007, the Company began full use of the M-RETS system for reporting compliance verification beginning with the first full calendar year commencing January 1, 2008. Otter Tail retired its first Solar RECs in 2021 for compliance with 2020 Solar Energy Standard (SES.)

Renewable energy used for REO-RES compliance must be tracked through M-RETS. The states are relying on the system to verify and track renewable energy to ensure that the renewable energy is not double counted and that a company's actual compliance performance can be readily tracked.

### **3. Jurisdictional Ownership of RECs**

Retail customers pay for resources through the ratemaking cost allocation process. All existing generating resources are used to serve all customers, so the customers in each jurisdiction are paying a portion of the cost of each resource. The Company allocates the RECs to each jurisdiction based on a load/ratio share in the month the RECs are generated. For the Hoot Lake Solar project, Otter Tail has received MN PUC approval for 100 percent of the project costs and benefits to be attributed to Minnesota customers. So all of the Hoot Lake Solar RECs will be allocated to MN.

### **4. Allowance Banking**

Otter Tail can and should bank some allowances for future use. There are several reasons for maintaining a bank balance of RECs including:

- Provide a compliance safety margin for years in which renewable energy generation may be lower than expected.
- Provide a construction safety margin in case planned future renewable energy resources are delayed or canceled.
- Provide a supplemental balance to be used in those years when there is a step increase in the REO-RES compliance levels.
- Provide a reserve for the time when Otter Tail may become deficit for its REO/RES compliance needs.

A number of RECs should be banked, only as long as Otter Tail has surplus RECs to bank for contingencies and future use. Once a jurisdiction is required to purchase RECs for REO/RES compliance, it does not make sense to purchase RECs simply to maintain a bank balance, unless it is expected that RECs will not be available for purchase in the future or if a particularly economic REC purchase opportunity arises.

While the prior discussion identifies the various purposes for banking RECs, the current Otter Tail situation becomes very simple. All RECs in the Minnesota jurisdiction that qualify for compliance in Minnesota should be banked as long as there is not a risk of those RECs exceeding the allowable shelf life for MN compliance.

In all cases, the oldest RECs possible should be used for compliance as newer RECs will tend to have a higher value and a longer remaining shelf life for MN compliance.

In summary:

- All MN jurisdiction RECs eligible for MN compliance should be banked.
- Wherever possible, non-eligible jurisdictional RECs should be swapped between MN and the Dakotas to make optimum use of these RECs (which are all non-wind), for compliance purposes.
- All surplus Dakotas jurisdiction RECs should be sold.

## **5. RES/SES Rate Impacts**

As ordered by the Minnesota Commission, each utility that files a Resource Plan must calculate the cost of complying with Minn. Stat. §216B.1691. Utilities are required to do the following:

- Analyze costs for the period 2005 until the last reported year.
- Analyze costs from the year following the last reported year, and for the following 15 years.
- Include all facilities used to comply with the Renewable Energy Standard and the Solar Energy Standard, regardless of when the facilities were constructed.
- Calculate direct costs to include payments under power purchase agreements and revenue requirements associated with utility-owned renewable energy projects.

- Provide a narrative discussion about the impact that adding generators powered by renewable sources may have on the utilities indirect costs, such as the cost for ancillary services and base load cycling.
- Include transmission improvement costs.
- Calculate Energy and Capacity savings arising from avoiding costs that the utility would have incurred directly in the absence of the RES and SES.
- Calculate past and future emission compliance savings arising from avoiding costs that the utility would have incurred indirectly in the absence of the RES and SES.
- Report estimated annualized and estimated levelized costs.
- Calculate the costs of complying with the RES and SES separately.
- Calculate the ultimate rate impact of Minn. Stat. §216B.1691 to reflect the fact that renewable energy comprises only a fraction of a utility's total energy costs, and consequently most of a utility's energy costs are unaffected by the RES and SES.



**Table 4**  
**Future RES Rate Impacts**

RES Generation	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Total RES Generation (GWh)	1484	1584	1595	1899	1897	2323	2336	2291	2300	2292	2287	2329	2324	2322	2335
<b>RES Generation Costs</b>															
PPA + Owned Generation Costs (millions)	\$29.0	\$33.2	\$33.7	\$44.6	\$44.8	\$60.1	\$60.6	\$59.5	\$60.0	\$60.0	\$60.0	\$57.8	\$58.0	\$58.3	\$58.8
RES Transmission Costs (millions)	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	
Total RES Costs (millions)	\$29.0	\$33.2	\$33.7	\$44.6	\$44.8	\$60.1	\$60.6	\$59.5	\$60.0	\$60.0	\$60.0	\$57.8	\$58.0	\$58.3	\$58.8
RES Costs (\$/MWh)	\$19.56	\$20.99	\$21.11	\$23.51	\$23.61	\$25.89	\$25.94	\$25.99	\$26.08	\$26.19	\$26.25	\$24.83	\$24.96	\$25.09	\$25.19
<b>Avoided Costs Due to RES</b>															
Avoided Energy Costs (millions)	\$41.6	\$44.4	\$41.7	\$41.2	\$41.6	\$54.5	\$58.0	\$60.8	\$63.8	\$67.1	\$69.5	\$68.9	\$70.6	\$76.9	\$83.6
Avoided Capacity Costs (millions)	\$0.2	\$0.2	\$2.3	\$6.2	\$7.4	\$7.5	\$7.6	\$7.7	\$7.8	\$7.8	\$7.9	\$8.1	\$8.2	\$8.0	\$8.2
Avoided Transmission Costs (millions)	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	
Avoided Emission Costs (millions)	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	
Total Avoided Costs (millions)	\$41.8	\$44.6	\$44.0	\$47.4	\$49.0	\$62.0	\$65.6	\$68.5	\$71.6	\$74.9	\$77.5	\$76.9	\$78.9	\$84.9	\$91.7
Total Avoided Costs (\$/MWh)	\$28.17	\$28.18	\$27.58	\$24.98	\$25.85	\$26.69	\$28.10	\$29.90	\$31.15	\$32.68	\$33.88	\$33.04	\$33.93	\$36.57	\$39.29
Total RES Premium/Discount (millions)	(\$12.8)	(\$11.4)	(\$10.3)	(\$2.8)	(\$4.2)	(\$1.9)	(\$5.0)	(\$9.0)	(\$11.7)	(\$14.9)	(\$17.5)	(\$19.1)	(\$20.8)	(\$26.7)	(\$32.9)
Total RES Premium/Discount (\$/MWh)	(\$8.61)	(\$7.19)	(\$6.48)	(\$1.47)	(\$2.24)	(\$0.81)	(\$2.16)	(\$3.91)	(\$5.07)	(\$6.49)	(\$7.63)	(\$8.21)	(\$8.97)	(\$11.49)	(\$14.10)
<b>Annualized RES Rate Impacts</b>															
Total Company Sales (GWh)	5361	5328	5333	5363	5394	5450	5479	5480	5477	5479	5481	5483	5484	5485	5486
Rate Impact (\$/MWh)	(\$2.38)	(\$2.14)	(\$1.94)	(\$0.52)	(\$0.79)	(\$0.34)	(\$0.92)	(\$1.63)	(\$2.13)	(\$2.72)	(\$3.19)	(\$3.49)	(\$3.80)	(\$4.86)	(\$6.00)
Rate impact (¢/kWh)	(0.24)	(0.21)	(0.19)	(0.05)	(0.08)	(0.03)	(0.09)	(0.16)	(0.21)	(0.27)	(0.32)	(0.35)	(0.38)	(0.49)	(0.60)

**Table 5**  
**Future SES Impacts**

SES Generation	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Total SES Generation (GWh)	0	104	104	416	415	415	416	416	416	416	416	519	519	520	521
<b>SES Generation Costs</b>															
PPA + Owned Generation Costs (millions)	\$0.0	\$4.1	\$4.1	\$15.0	\$15.0	\$15.0	\$15.0	\$15.0	\$15.0	\$15.0	\$15.0	\$15.0	\$15.0	\$15.0	\$15.0
SES Transmission Costs (millions)	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Total SES Costs (millions)	\$0.0	\$4.1	\$4.1	\$15.0	\$15.0	\$15.0	\$15.0	\$15.0	\$15.0	\$15.0	\$15.0	\$15.0	\$15.0	\$15.0	\$15.0
SES Costs (\$/MWh)	\$0.00	\$39.29	\$39.29	\$36.07	\$36.07	\$36.07	\$36.07	\$36.07	\$36.07	\$36.07	\$36.07	\$28.85	\$28.85	\$28.84	\$28.85
<b>Avoided Costs Due to SES</b>															
Avoided Energy Costs (millions)	\$0.0	\$3.1	\$2.9	\$11.6	\$11.7	\$11.9	\$12.6	\$13.5	\$14.1	\$14.9	\$15.5	\$19.8	\$20.3	\$22.2	\$24.0
Avoided Capacity Costs (millions)	\$0.0	\$0.0	\$0.0	\$1.0	\$1.2	\$1.2	\$1.3	\$1.3	\$1.3	\$1.3	\$1.3	\$1.3	\$1.4	\$1.4	\$1.4
Avoided Transmission Costs (millions)	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Avoided Emission Costs (millions)	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Total Avoided Costs (millions)	\$0.0	\$3.1	\$2.9	\$12.6	\$12.9	\$13.1	\$13.8	\$14.8	\$15.4	\$16.2	\$16.8	\$21.1	\$21.7	\$23.6	\$25.4
Total Avoided Costs (\$/MWh)	\$0.00	\$29.99	\$27.94	\$30.29	\$31.07	\$31.58	\$33.27	\$35.51	\$37.02	\$38.89	\$40.34	\$40.64	\$41.77	\$45.34	\$48.78
Total SES Premium/Discount (millions)	\$0.0	\$1.0	\$1.2	\$2.4	\$2.1	\$1.9	\$1.2	\$0.2	(\$0.4)	(\$1.2)	(\$1.8)	(\$6.1)	(\$6.7)	(\$8.6)	(\$10.4)
Total SES Premium/Discount (\$/MWh)	\$0.00	\$9.30	\$11.35	\$5.78	\$5.01	\$4.49	\$2.80	\$0.56	(\$0.95)	(\$2.82)	(\$4.28)	(\$11.80)	(\$12.92)	(\$16.49)	(\$19.94)
<b>Annualized SES Rate Impacts</b>															
Total Company Sales (GWh)	5361	5328	5333	5363	5394	5450	5479	5480	5477	5479	5481	5483	5484	5485	5486
Rate Impact (\$/MWh)	\$0.00	\$0.18	\$0.22	\$0.45	\$0.39	\$0.34	\$0.21	\$0.04	(\$0.07)	(\$0.21)	(\$0.32)	(\$1.12)	(\$1.22)	(\$1.56)	(\$1.89)
Rate impact (¢/kWh)	0.00	0.02	0.02	0.04	0.04	0.03	0.02	0.00	(0.01)	(0.02)	(0.03)	(0.11)	(0.12)	(0.16)	(0.19)

**Table 6**  
**Levelized RES Rate Impacts**

Levelized RES Generation	Historic	Future
Total RES Generation (GWh)	632	2106

**Levelized RES Generation Costs**

PPA + Owned Generation Costs (millions)	\$40.6	\$22.1
RES Transmission Costs (millions)	\$0.0	\$0.0
Total RES Costs (millions)	\$40.6	\$22.1
RES Costs (\$/MWh)	\$64.24	\$10.50

**Levelized Avoided Costs Due to RES**

Avoided Energy Costs (millions)	\$30.2	\$32.3
Avoided Capacity Costs (millions)	\$1.9	\$3.3
Avoided Transmission Costs (millions)	\$0.0	\$0.0
Avoided Emission Costs (millions)	\$0.0	\$0.0
Total Avoided Costs (millions)	\$32.1	\$35.6
Total Avoided Costs (\$/MWh)	\$50.74	\$16.91

Total RES Premium/Discount (millions)	\$8.5	(\$13.5)
Total RES Premium/Discount (\$/MWh)	\$13.50	(\$6.42)

**Levelized RES Rate Impacts**

Total Company Sales (GWh)	4454	5438
Rate Impact (\$/MWh)	\$1.92	(\$2.49)
Rate impact (¢/kWh)	0.19	(0.25)

**Table 7**  
**Levelized SES Rate Impacts**

Levelized SES Generation	Historic	Future
Total SES Generation (GWh)	-	374

**Levelized SES Generation Costs**

PPA + Owned Generation Costs (millions)	-	\$7.2
SES Transmission Costs (millions)	-	\$0.0
Total SES Costs (millions)	-	\$7.2
SES Costs (\$/MWh)	-	\$19.12

**Levelized Avoided Costs Due to SES**

Avoided Energy Costs (millions)	-	\$7.0
Avoided Capacity Costs (millions)	-	\$0.6
Avoided Transmission Costs (millions)	-	\$0.0
Avoided Emission Costs (millions)	-	\$0.0
Total Avoided Costs (millions)	-	\$7.6
Total Avoided Costs (\$/MWh)	-	\$20.33

Total SES Premium/Discount (millions)	-	(\$0.5)
Total SES Premium/Discount (\$/MWh)	-	(\$1.21)

**Levelized SES Rate Impacts**

Total Company Sales (GWh)	-	5438
Rate Impact (\$/MWh)	-	(\$0.08)
Rate impact (¢/kWh)	-	(0.01)

**Indirect Costs**

As a member of the Midcontinent Independent System Operator, Inc. (MISO), Otter Tail is required to offer its generation units into the day-ahead energy market. Recently, energy prices have been very low due to the addition of renewable resources as well as low fuel costs for existing thermal units. Up until 2020, Otter Tail offered in its co-owned baseload thermal units as “must-run” units to prevent them from cycling on and off with fluctuating energy prices. This means that if the day-ahead price of energy dips below the cost of the unit, the unit will still clear at minimums in order to keep the unit online. Because these units stay online regardless of energy prices, there is no increase in cycling charges. In April 2020, the owners of Big Stone Plant agreed to a methodology to allow the operation of Big Stone Plant to be offered into the MISO/Southwest Power Pool (SPP) markets on an economic dispatch basis. This methodology includes weekly, bi-weekly, or as-needed meetings with all Co-Owners (Otter Tail, Montana-Dakota Utilities Co., and NorthWestern Energy) to review the economic dispatch or self-commitment status of Big Stone Plant. For the time periods agreed to by the Co-Owners, this unit is offered into the market economically meaning the day-ahead energy price has to be higher than the unit’s cost for long enough to justify bringing the unit online. As a result, it could be argued that this unit cycles more because of the additional renewable resources on the system. The Co-Owners of Coyote Station have developed the capability to offer the plant under an economic offer. As with Big Stone Plant, each Coyote Co-Owner maintains the contractual right to request self-commitment. At the time of this filing, one of the plant’s Co-Owners, not Otter Tail, has requested ongoing self-commitment. As a result, the plant has not been offered into the market on an economic dispatch basis.

In terms of ancillary services, Otter Tail has not identified any impacts which can be attributed to the implementation of the RES requirements so far. That being said, as the amount of renewable resources increases, so does the need for ancillary services. Eventually there will be a tipping point where the amount of renewable resources increases and the amount of available spinning reserves decreases to a level which causes the cost of ancillary services to rise.

**Avoided Permitting and Emission Cost Impacts**

All historical avoided permitting and emission costs are factored in when calculating the avoided energy and capacity costs. For the future avoided carbon dioxide (CO<sub>2</sub>) costs, Otter Tail used the Commission approved value of \$15.00/ton CO<sub>2</sub> penalty starting in 2025.

## Transmission Costs

For the purpose of simplifying our modeling, all transmission costs for future RES/SES projects are built into the project energy price. It is also assumed that all avoided energy and capacity costs (both past and future) will be purchased from the market resulting in no added transmission costs.

## 6. Summary

The following strategy is being used to optimize the usage of RECs:

- Otter Tail allocates RECs from resources used to serve all customers based on a monthly energy allocation.
- Otter Tail banks all MN jurisdiction RECs which are eligible for MN compliance to be used for current and future REO/RES compliance.
- Otter Tail swaps MN jurisdiction RECs which cannot be used for MN compliance but can be used for Dakotas compliance for Dakotas jurisdiction RECs which cannot be used for ND or SD compliance but can be used for MN compliance. Equivalent monetary value will be maintained for all swaps.
- Otter Tail expects to transfer enough Dakotas RECs to Minnesota, as necessary, to maintain a bank balance for MN REO/RES compliance, but without risking shelf life expiration of RECs for compliance purposes.
- Otter Tail sells the surplus ND and SD allocated RECs.
- Otter Tail evaluates opportunities to purchase/use lower value RECs for compliance and banking, while selling higher value RECs. All benefits and costs flow to customers.
- When possible, sell higher value MN RECs and acquire older and lower value Dakotas RECs for compliance in MN. MN REC sales revenues, net of replacement purchase costs, will be treated in accordance with MN Commission Orders. Dakotas REC revenues from sales to the MN jurisdiction will be treated in accordance with the Commission Orders in those two states.
- The oldest RECs possible should be used for compliance or for sales in order to keep the REC inventory as fresh as possible and at as high a value as possible.
- Seek opportunities to sell wind generation energy either with or without RECs if lower cost replacement energy purchases can be made to reduce energy costs.

## **Appendix H: 2020 Otter Tail Power DR Potential Study**

# 2020 Otter Tail Power DR Potential Study

FINAL REPORT

PREPARED BY

Ryan Hledik

Maria Castaner

PREPARED FOR

Otter Tail Power

DECEMBER 15, 2020



## In this presentation

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- Introduction
  - Overview
  - OTP's existing DR portfolio
- Approach
  - Modeling methodology
  - Key assumptions
- Findings
  - Base Case
  - High Value Sensitivity Case
- Conclusions
- Appendices



## INTRODUCTION

# Overview

---

This study summarizes the **cost-effective, achievable DR potential** in OTP's service territory

All estimates of potential are **incremental** to OTP's existing DR capability

The analysis considers a broad range of DR programs, including **traditional options** like air-conditioning direct load control as well as **emerging options** like dynamic pricing and smart water heating

The study spans the period from **2021 through 2036**, consistent with the upcoming IRP

Estimates are not a forecast of what will happen, but rather represent the potential cost-effective impacts that could be achieved from an expansion of OTP's existing DR portfolio



INTRODUCTION

# OTP's existing DR programs span a range of offerings

Program Name	Type	Class (primary application)	Description
<b>Residential Demand Control</b>	DLC (Whole home)	Residential	25% rate discount. During a control event, end-uses are curtailed according to customer priorities to reach desired demand level. Effectively a demand subscription rate with automation. Focus on winter peak.
<b>CoolSavings</b>	DLC (A/C)	Residential	\$33 annual bill credit (residential). 15-minute A/C cycling program.
<b>Water Heating Control</b>	DLC (Water heating)	Residential	25% rate discount for water heating load, or \$8 monthly credit. Water heating service interruptions during control events (up to 14 hrs, typically much less).
<b>Dual Fuel – Small</b>	DLC (Heating)	Residential	Event-based switching to backup heating source. Roughly 40% rate discount with penalties for non-compliance.
<b>EV Rate</b>	TOU (EVs)	All	Discounted electricity for nighttime EV charging (10 pm to 6 am). Penalty rate for daytime charging (not intended as buy-through rate). Minnesota only
<b>Deferred Load</b>	DLC (Thermal storage)	All	25% rate discount for thermal storage systems. Event-based interruption
<b>Fixed Time of Delivery</b>	TOU (Thermal storage)	All	>50% rate discount for heating load during off-peak hours. Service only during off-peak hours.

INTRODUCTION

# OTP’s existing DR programs span a range of offerings (cont’d)

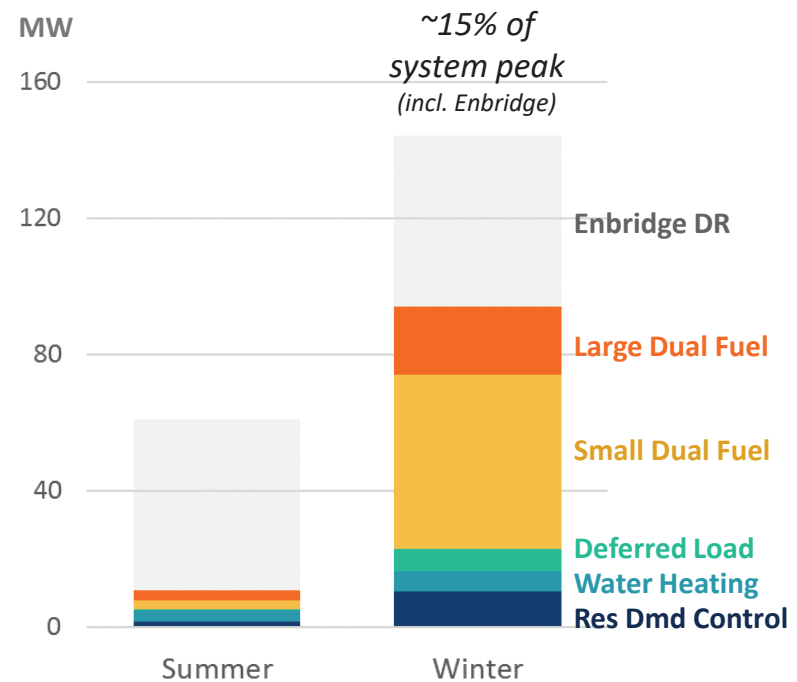
Program Name	Type	Class (primary application)	Description
Dual Fuel – Large	DLC (Heating)	Non-residential	Event-based switching to backup heating source.
General Time-of-Use	CPP (Whole facility)	Non-residential	TOU rate with day-ahead notification of critical peak pricing events.
Irrigation Time-of-Use	TOU	Non-residential	TOU rate with optional “courtesy” control for participants with ratio receivers
Enbridge contract	DLC	Non-residential	Contract with a single large customer that reduces peak coincident demand by between 40 and 60 MW during curtailment events

## INTRODUCTION

# OTP's existing DR programs represent 15% of its system peak

- **OTP has a large existing DR portfolio**
  - 15% peak reduction capability (winter)
  - Primarily from residential heating load & Enbridge contract
- **The programs are actively utilized**
  - Portfolio is dispatched both for economic and reliability reasons
  - DR event frequency higher than many other utilities, indicating that the portfolio is an active resource

### System Peak Reduction Capability (2019)

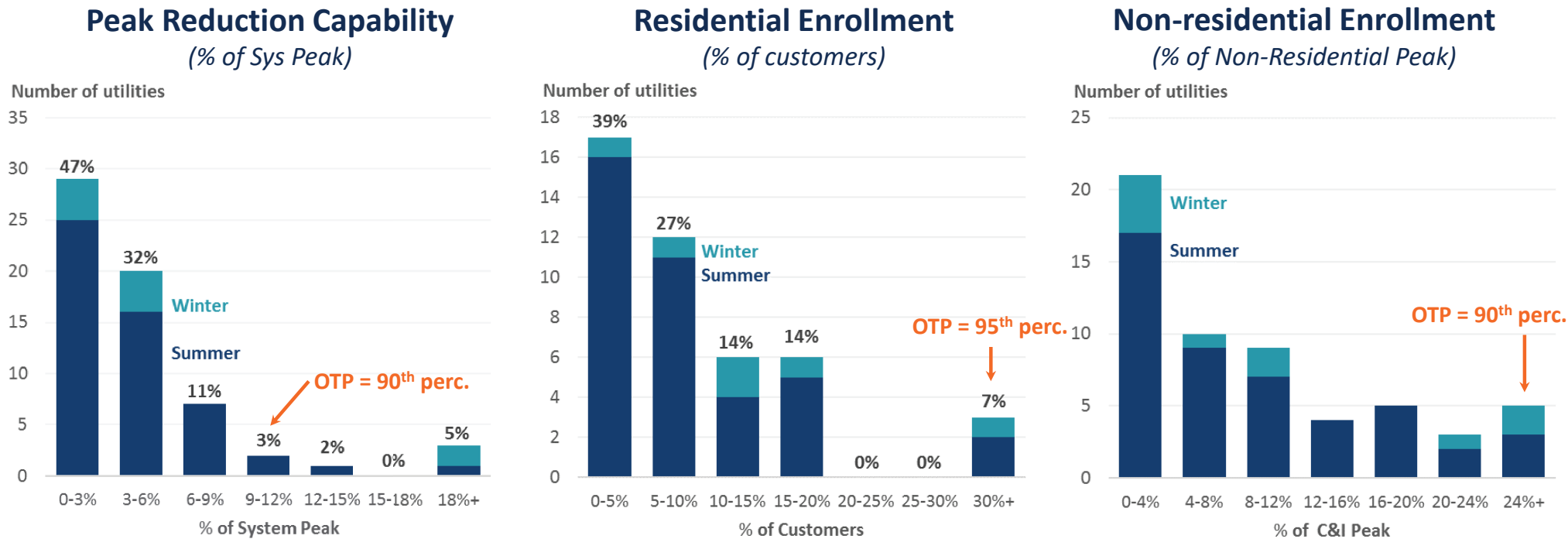


INTRODUCTION

# OTP's existing DR capability is in the top 10% of U.S. IOUs



## The Distribution of U.S. Investor Owned Utility DR Portfolios



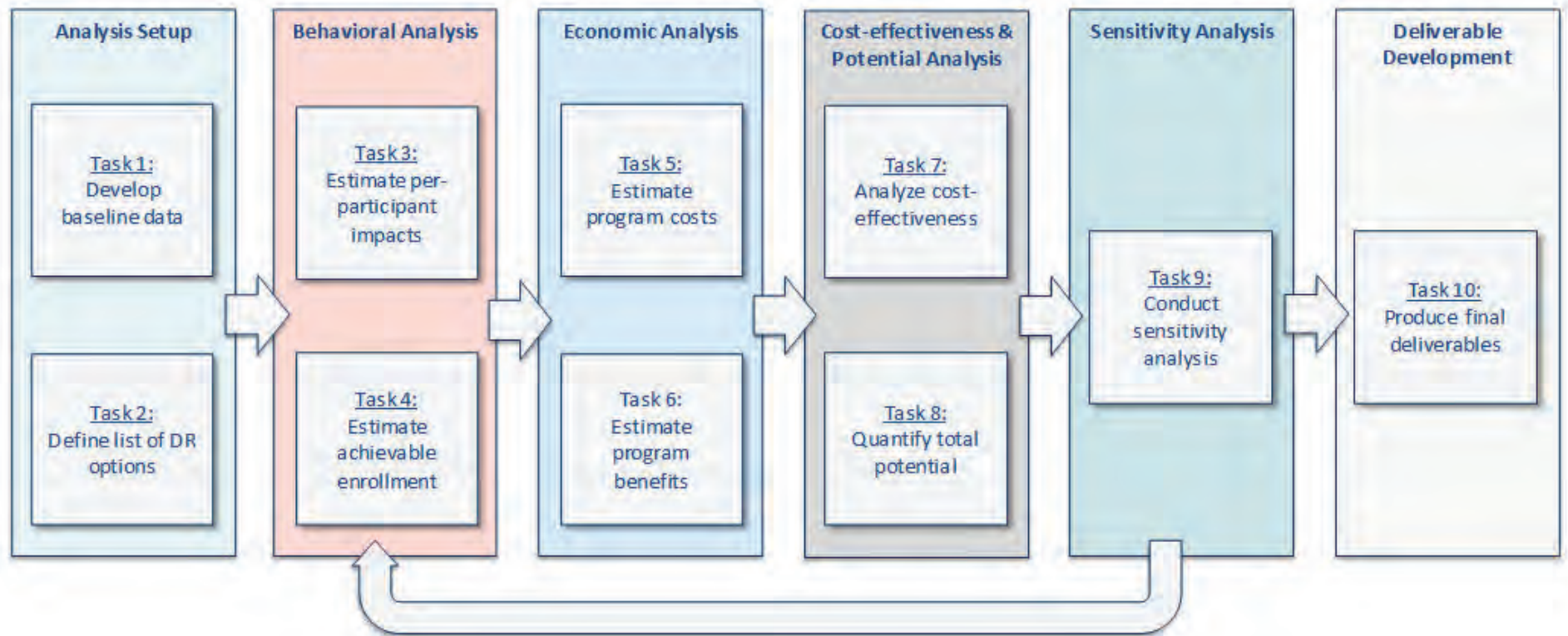
Source: Brattle analysis of 2019 Early Release EIA-861 data, and DR program data provided by OTP.

# Modeling Approach



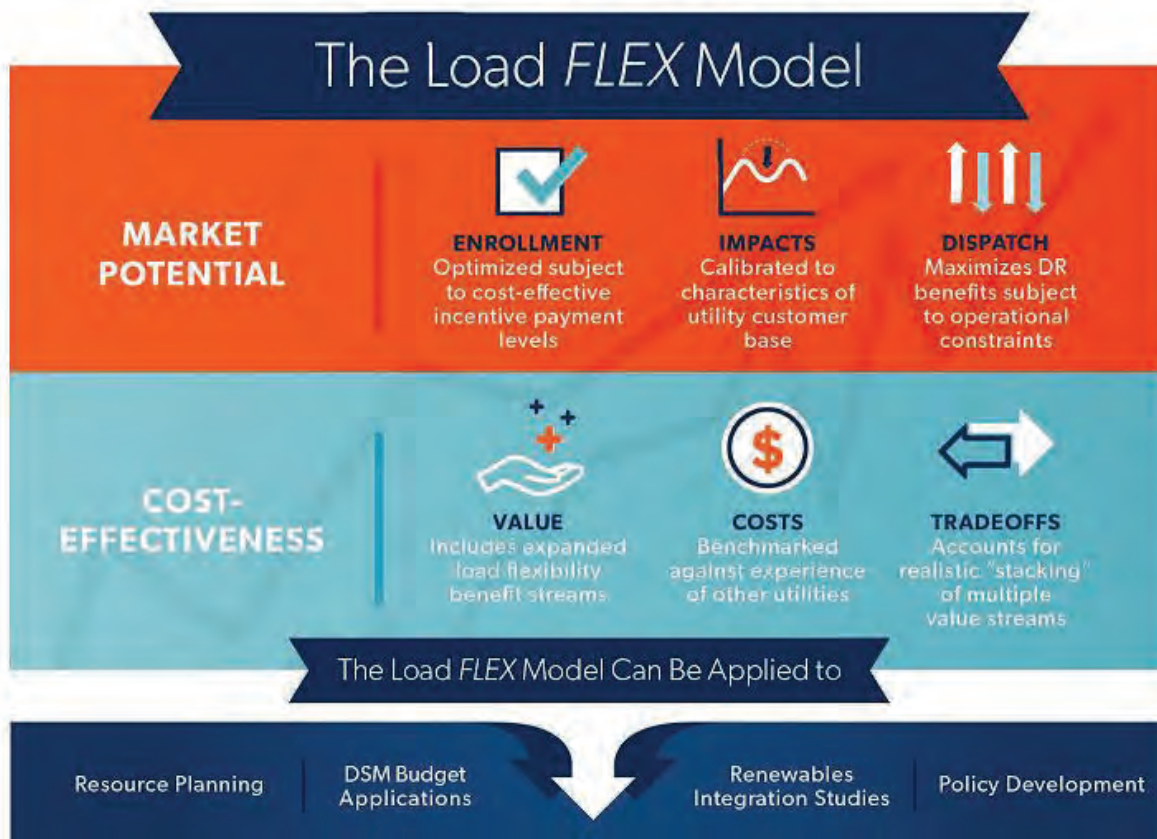
APPROACH

# Methodology overview



## APPROACH

# The LoadFlex model



- Brattle’s LoadFlex model was used to assess OTP’s DR potential in this study
- The model was used in Brattle’s 2019 load flexibility potential study for Xcel Energy, a study on the national potential for load flexibility, and is currently being used in a similar study for DOE
- Each DR measure is dispatched against an hourly forecast of marginal costs to determine value
- Enrollment is estimated based on the maximum cost-effective incentive level that can be offered

APPROACH

# The modeled DR programs

- Our review of OTP’s existing programs indicates that enrollment in space heating load control / thermal storage programs has reached maximum achievable levels of adoption; no additional potential is modeled for these programs
- Other programs vary in their applicability to customer classes and are modeled accordingly

Program	Residential	Small C&I	Med/Large C&I
<b>Existing programs</b>			
Heating load control/storage	<i>Maxed</i>	<i>Maxed</i>	<i>Maxed</i>
Water heating load control	✓		
A/C load control	✓	<i>Maxed</i>	
<b>New programs</b>			
Smart thermostat (A/C)	✓		
TOU (opt-in)	✓	✓	✓
TOU (opt-out)	✓	✓	✓
CPP (opt-in)	✓	✓	✓
CPP (opt-out)	✓	✓	✓
Smart water heating	✓		
Behavioral DR	✓		
EV managed charging (home)	✓		
EV managed charging (work)	✓		
Interruptible		✓	✓
Auto-DR (lighting)		✓	✓

APPROACH

# Achievable participation

Achievable participation assumptions were developed based on a review of DR potential studies from a variety of jurisdictions, which use the following methods to establish participation rates:

- Primary market research (customer surveys)
- Review of achieved participation in successful DR programs
- Interviews with customer account managers
- Review of utility DR plans
- Expert judgement

These “base” participation rates are then adjusted in our modeling based on the cost-effectiveness of the program

- Participation is increased for highly cost-effective programs, given the potential to offer higher incentives
- The opposite is true for marginally cost-effective programs

Participation rates are inclusive of existing DR participants

- E.g., If existing participation in A/C DLC is 5% and total potential participation is 30%, then incremental potential participation is 25%

See Appendix B for further detail.

Base Participation Rate Assumptions

Class	Program	Participation (% of eligible)
Residential	A/C DLC	30%
	Smart thermostat (A/C)	30%
	TOU (opt-in)	30%
	TOU (opt-out)	80%
	CPP (opt-in)	20%
	CPP (opt-out)	80%
	Behavioral DR	80%
	Timed water heating	30%
	Smart water heating	30%
	EV managed charging (home)	20%
EV managed charging (work)	20%	
Small C&I	TOU (opt-in)	10%
	TOU (opt-out)	80%
	CPP (opt-in)	20%
	CPP (opt-out)	80%
Med/Large C&I	Interruptible	25% - 45%
	Auto-DR (lighting)	5%
	TOU (opt-in)	20%
	TOU (opt-out)	80%
	CPP (opt-in)	15% - 20%
	CPP (opt-out)	80%

## APPROACH

# Scenarios

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The analysis includes a Base Case and a Sensitivity Case

### Base Case

- Consistent with OTP's current outlook for its system
- In particular, this reflects no anticipated need for new capacity during the study horizon

### High Value Sensitivity Case

- Explores an illustrative scenario in which there is a need for new capacity during the study horizon
- Also assumes a higher MISO capacity price (based on analysis of historical data)

Specific assumptions behind each scenario are described on the next slide



APPROACH

# Avoided costs

The analysis accounts for several possible DR value streams

Value stream	Avoided cost estimate	Source/notes
<b>OTP system generation capacity (winter)</b>	Base Case: \$0/kW-yr High Case: \$75/kW-yr	Base Case: IRP forecasts no need for new capacity High Case: Alternative case based on new capacity need
<b>MISO capacity market (summer)</b>	Base Case: \$1.7/kW-yr High Case: \$7.2/kW-yr	Base Case: 2013-19 historical <i>average</i> MISO auction price High Case: 2013-19 historical <i>maximum</i> MISO auction price
<b>Energy</b>	Top 10 <sup>th</sup> percentile: \$33/MWh Bottom 10 <sup>th</sup> percentile: \$14/MWh	2019 OTP MISO day-ahead energy prices scaled for consistency with OTP peak/off-peak price forecast through 2036
<b>Ancillary services</b>	Historical frequency regulation prices	Assume requirement equal to 0.5% of system peak (3 MW); Only smart water heating and Auto-DR are eligible
<b>Transmission capacity</b>	\$15/kW-yr	Based on OTP CIP filing, avoided through reductions in top 100 OTP system load hours
<b>Distribution capacity</b>	\$40/kW-yr (limited to 3.3 MW of benefit)	Avoided through geo-targeted DR deployment; based on reductions in top 300 OTP system load hours (reflecting diversity of distribution load)

See Appendix A for further detail.

APPROACH

# Per-participant impacts

- Based on OTP experience and a review of impacts achieved through full scale deployments and pilots in other jurisdictions
- Winter impacts assumed to be the same as summer impacts on a percentage basis, unless inapplicable (e.g., A/C load control)
- Base Case TOU/CPP pricing program impacts reflect rates with low peak-to-off-peak price ratio due to low OTP system capacity costs; High Case impacts are 2-2.5x based on higher price ratios
- A/C DLC impacts reflect potential higher per-participant impacts achieved in other jurisdictions

## Per-participant Impact Assumptions

Class	Program	Winter Impact (% of peak)	Summer Impact (% of peak)
Residential	A/C DLC	0%	27%
	Smart thermostat (A/C)	0%	50%
	TOU (opt-in)	4%	4%
	TOU (opt-out)	2%	2%
	CPP (opt-in)	10%	10%
	CPP (opt-out)	6%	6%
	Behavioral DR	3%	3%
	Timed water heating	11%	11%
	Smart water heating	11%	11%
	EV managed charging (home)	23%	40%
EV managed charging (work)	3%	5%	
Small C&I	TOU (opt-in)	0.2%	0.2%
	TOU (opt-out)	0.1%	0.1%
	CPP (opt-in)	0.5%	0.5%
	CPP (opt-out)	0.3%	0.3%
Med/Large C&I	Interruptible	20%	20%
	Auto-DR (lighting)	10% - 30%	10% - 30%
	TOU (opt-in)	2.5% - 3%	2.5% - 3%
	TOU (opt-out)	1.5% - 1.8%	1.5% - 1.8%
	CPP (opt-in)	6% - 6.5%	6% - 6.5%
	CPP (opt-out)	3.6% - 3.9%	3.6% - 3.9%

Note: Impacts in table are represented as a percentage of the average customer's seasonal peak-coincident demand.

## APPROACH

# Program costs

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Cost assumptions are based on a review of utility program data and DR studies from other jurisdictions, as well as OTP's experience with its existing DR portfolio

Reflects all costs incurred by the utility (i.e., the "Utility Cost Test" perspective)

Example – Residential smart water heating:

- Variable equipment cost: \$600/participant
- Other initial costs: \$30/participant (includes recruitment & churn)
- Base annual incentive level (\$/participant-yr): \$96

*See Appendix C for details*



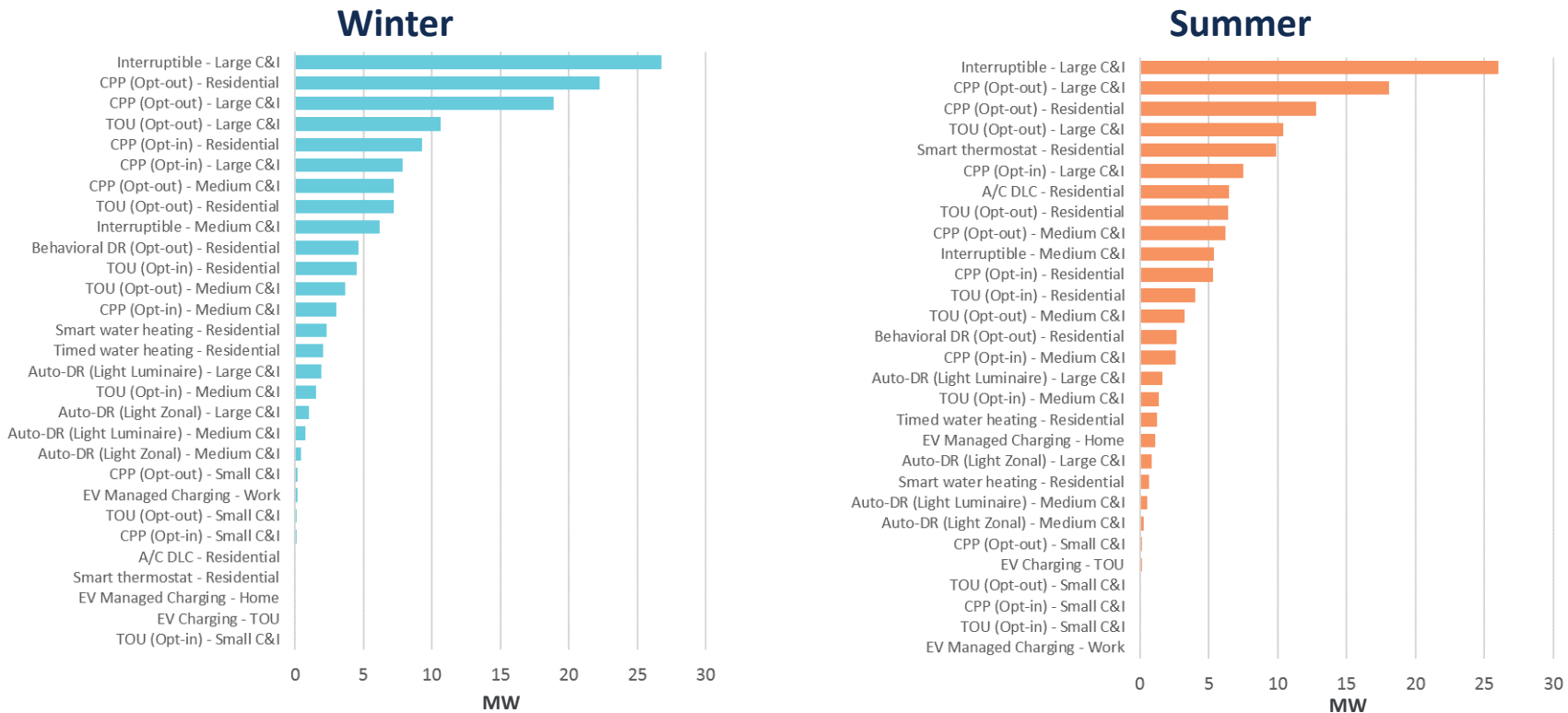
# Findings



FINDINGS

# Incremental technical potential by 2036

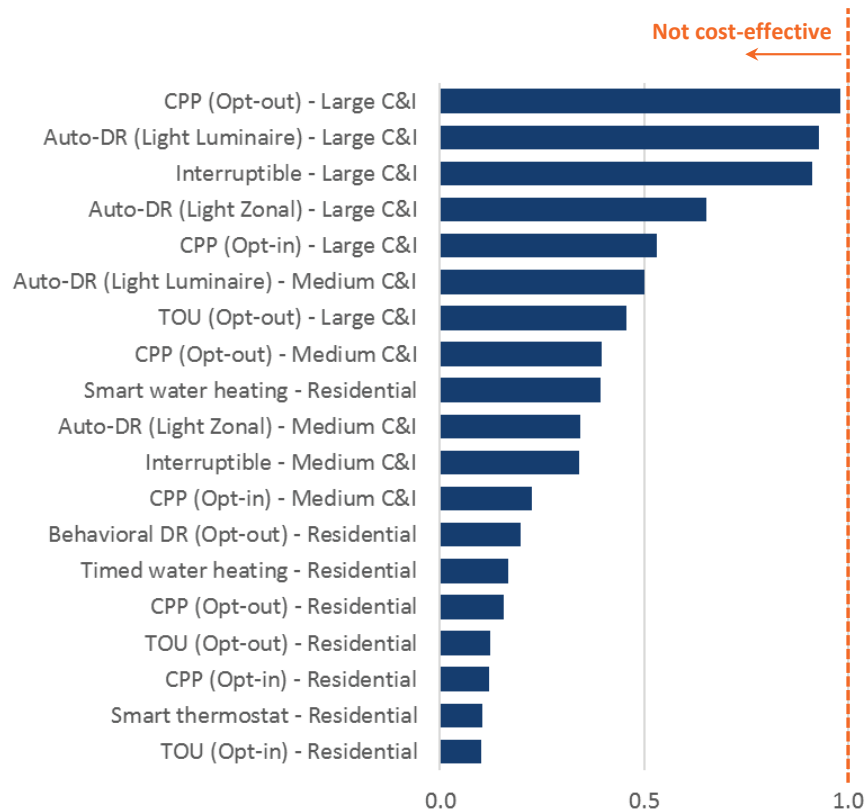
In this study, “technical potential” is defined as the maximum achievable potential irrespective of cost-effectiveness. It is incremental to OTP’s existing DR portfolio.



Note: Measure impacts shown here are not additive to each other; some are mutually exclusive options for enrollment.

FINDINGS

# Cost-effectiveness of DR options: Base Case

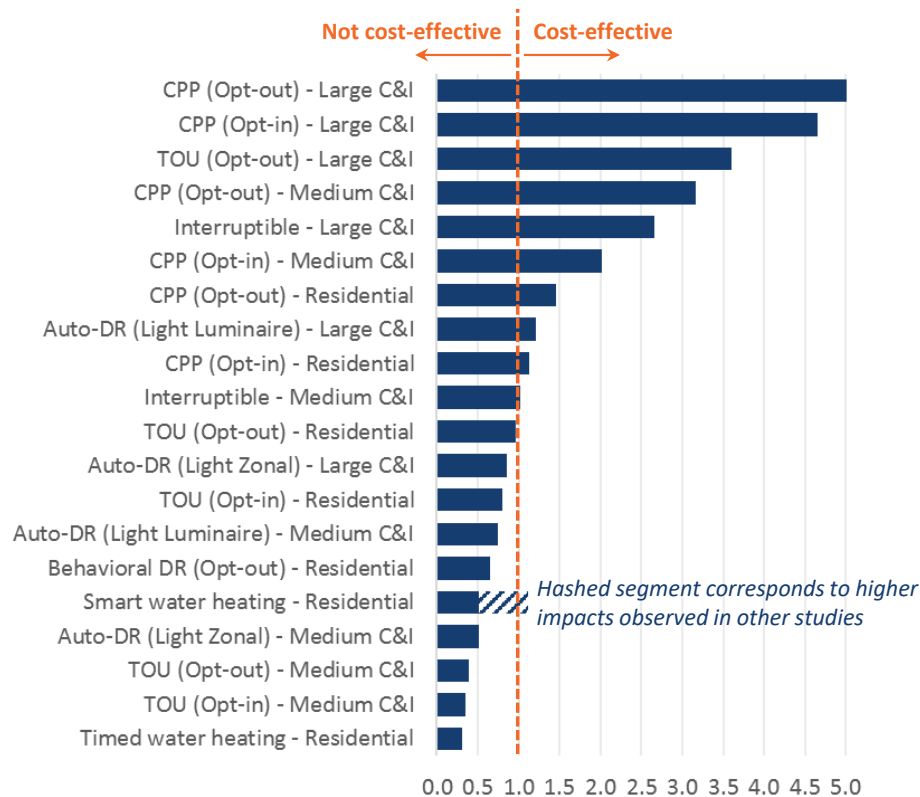


Note: DR programs with a benefit-cost ratio of <0.1 are not shown

- **Base Case system conditions do not appear to support the cost-effective addition of new DR programs**
- Avoided generation capacity investment is the primary DR value proposition, but OTP does not forecast a need for new capacity
- Other value streams can be meaningful sources of benefit for some of the DR programs analyzed, but not enough to outweigh costs
- Pricing programs (CPP, TOU) may be an attractive option regardless of cost-effectiveness, since cost-reflective rates provide other benefits (i.e., improvements in fairness, equity)
- There may be opportunities for geographically targeted DR to cost-effectively defer the need for specific distribution investments; detailed analysis of distribution resource plans would be needed

FINDINGS

# Cost-effectiveness of DR options: High Value Sensitivity Case

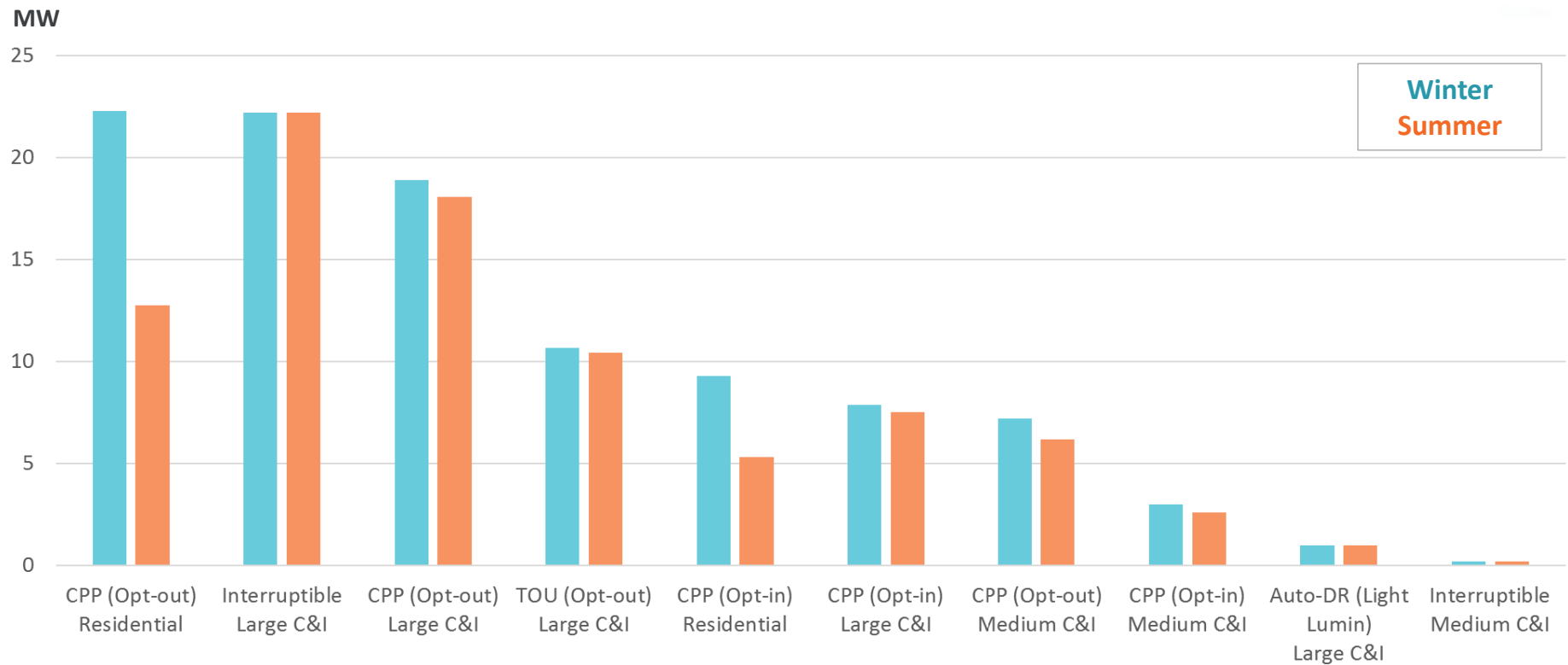


- In the High Value Sensitivity Case, the assumed need for capacity on the OTP system and higher capacity prices in MISO lead to cost-effective new DR opportunities
- Dynamic pricing programs would be a cost-effective opportunity to leverage OTP’s AMI rollout
- Interruptible tariffs could potentially engage larger customers not enrolled in a heating control/storage program
- Smart water heating is not found to be cost-effective. However, if OTP’s per-participant impacts were to reach levels estimated in other studies (roughly 3x OTP’s current impacts), the program would be cost-effective

Note: DR programs with a benefit-cost ratio of <0.3 are not shown. B/C ratio capped at 5.0 in chart.

FINDINGS

# Cost-effective achievable potential: High Value Sensitivity Case

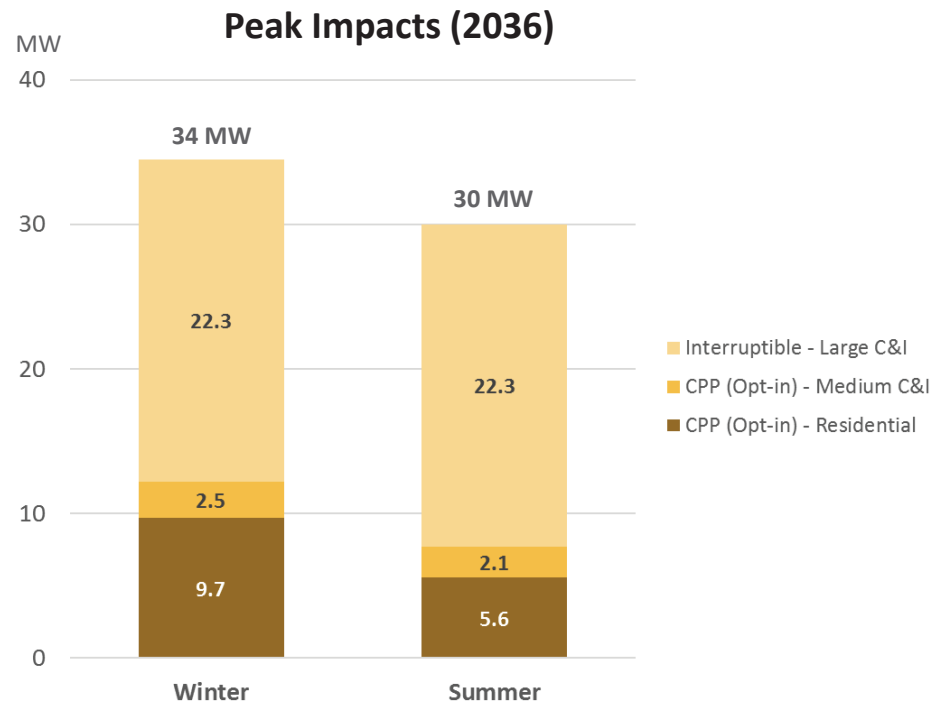


Note: Measure impacts shown here are not additive to each other; some are mutually exclusive options for enrollment.

FINDINGS

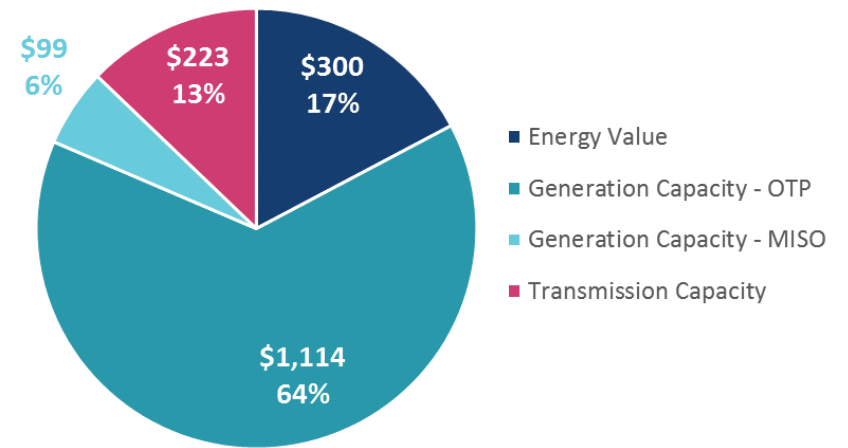
# Illustrative DR Portfolio: High Value Sensitivity Case

An illustrative cost-effective portfolio of new DR programs was created for the High Value Sensitivity Case. Alternative portfolios could be created using other combinations of cost-effective DR measures.



### Annual Program Benefits (2036, thousand \$)

Total = \$1.7 million/yr



# Conclusions



## CONCLUSIONS

# Key observations

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### **OTP has a robust existing DR portfolio**

- The portfolio is regularly utilized to provide system value and is embedded in the company's resource adequacy planning

### **Base system conditions do not support new DR additions**

- Generation capacity avoidance is the key driver of DR value, and it is not currently an opportunity for OTP
- There may be isolated opportunities for geo-targeted distribution deferral; requires detailed analysis of distribution plan
- Time-varying rates may be desirable as an option regardless, as they provide other benefits beyond avoided costs (e.g., equity, fairness, facilitating electrification)

### **If there is an unexpected need for capacity in the future, some DR programs will have value**

- "Behavioral" options (rates, interruptible tariffs) for customers that have not opted into heating load control & storage could tap into interested customers that do not want a technology-based option
- Water heating load control may also be cost-effective if per-participant impacts can be increased
- There may also be room to grow C&I heating load control; while enrollment has reached best practices levels, market research could help to identify additional interested customer segments

### **Targeted program development/recruiting may improve program economics**

- Specifically, further customer segmentation to focus on largest customers not currently enrolled in DR programs

Appendix A:

## **Additional Detail on OTP System Conditions**

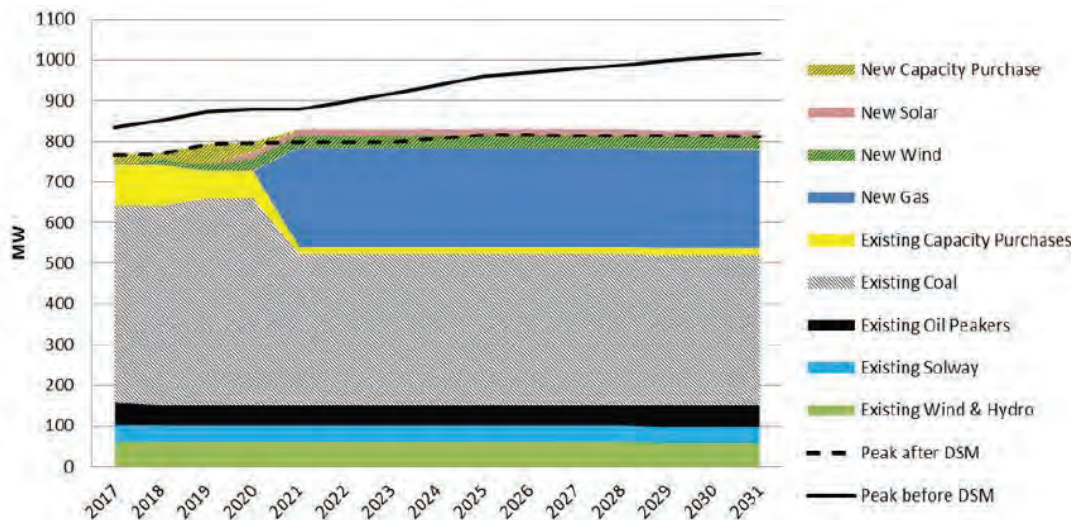


APPENDIX A

# Generation capacity value



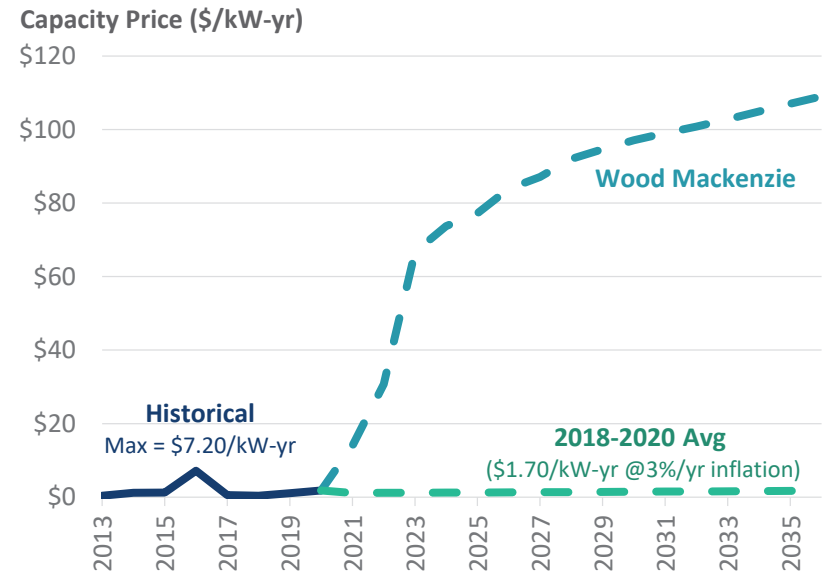
## OTP Online Capacity vs Reserve Obligation



Source: 2017 - 2031 OTP IRP.

**OTP does not forecast a need for additional capacity for at least the next decade due to new gas capacity that is under construction and will come online in 2021**

## MISO (Zone 1) Capacity Market Prices



**MISO capacity market prices are very low. While Wood Mackenzie projects that the prices will eventually rise to Net CONE, market experience does not support this projection**

## APPENDIX A

# MISO capacity market price outlook

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Historically, MISO capacity market prices have been very low. The fundamentals of the market suggest that prices will remain low for the study horizon:

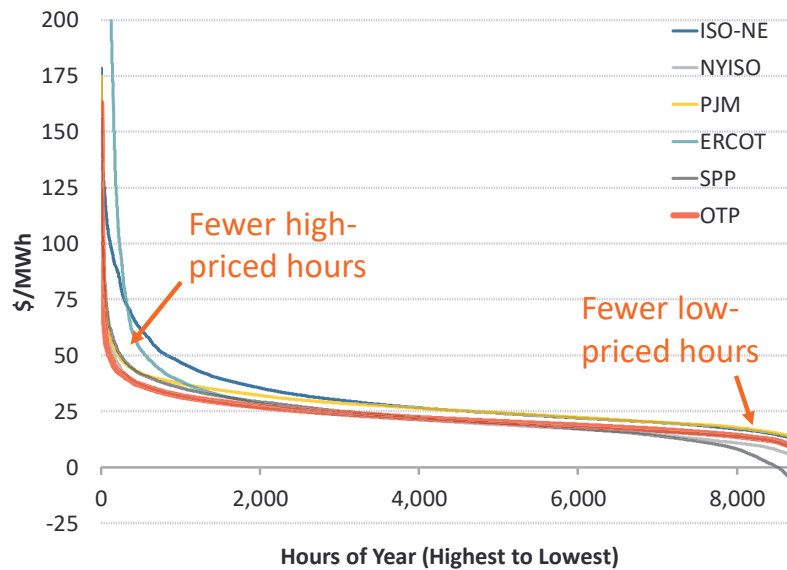
- Utilities in MISO are responsible for maintaining sufficient resource adequacy on their systems. Due to the “lumpy” nature of generation capacity investments, MISO utilities typically invest in new capacity when their reserve margin begins to approach the minimum required level. Utilities often are long on capacity as a result.
- The MISO capacity auction is just a one-year forward auction where load serving entities can purchase capacity if they are short on supply for that one-year forward timeframe. When participants are long on capacity, the price drops all the way to zero (i.e., the demand curve for capacity is vertical).
- Generally, retailers create some demand for capacity in the auction, but their impact on the market is small and not expected to create large revenue opportunities for DR that is selling into the auction

APPENDIX A

# Energy value



Day Ahead Energy Price Duration Curves



*Recent OTP day ahead LMPs are relatively low and flat compared to some other regions. Ample existing flexible generation and transmission does not suggest likelihood of significant future divergence in peak/off-peak energy price differentials for OTP due to renewables growth.*

Energy Value of Load Curtailment and Shifting  
 (\$/kW-yr)

	2017	2018	2019
Value of reducing load during highest-priced 100 hours of year	\$5.5	\$9.7	\$7.1
Value of shifting load from 4 highest-priced hours to 4 lowest-priced hours each day	\$25.2	\$26.9	\$20.2

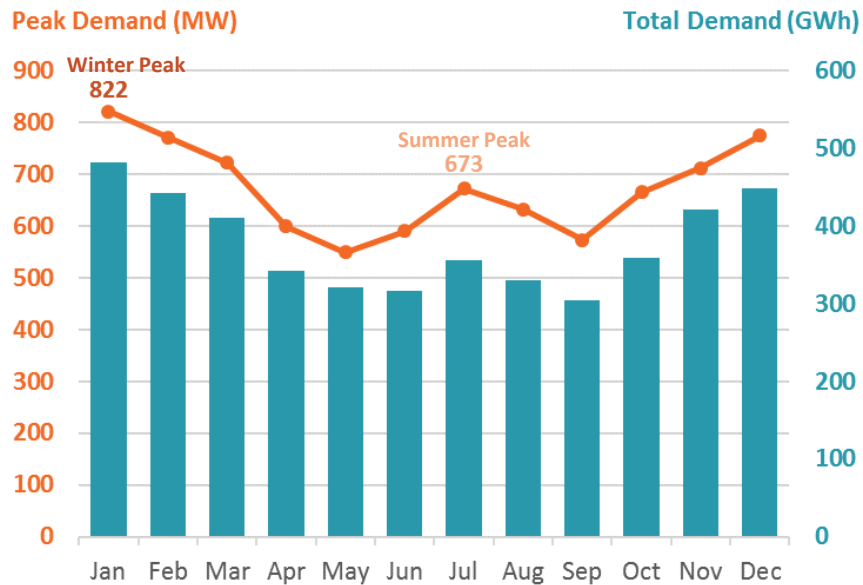
*The energy value of DR programs is modest, representing only a fraction of the total value that many DR programs have provided historically (e.g., \$100/kW-yr)*

APPENDIX A

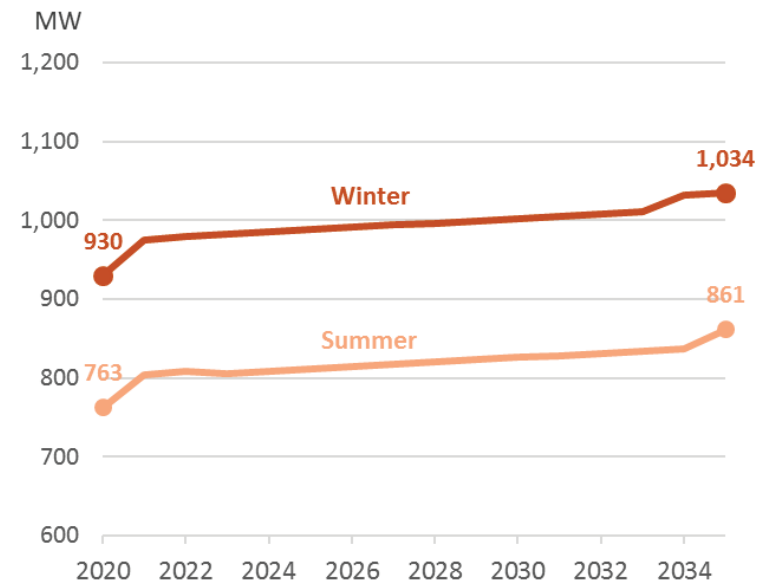
# OTP Load Summary

OTP is expected to remain winter peaking across the study horizon, with 0.7% average annual growth in system peak demand

2019 Peak and Total Energy Demand



OTP Peak Demand Forecast



# Appendix B:

## **Adoption Rates**



## APPENDIX B

# DR adoption rates: Methodology overview

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## DR measure adoption is based on a review of recent DR potential studies

The reviewed DR potential studies use a variety of methods to establish **maximum achievable** adoption rates, for different jurisdictions across North America:

- Primary market research (customer surveys)
- Review of achieved participation in successful DR programs
- Interviews with customer account managers
- Review of utility DR plans
- Expert judgement

## Notes on the adoption assumptions

- Consistent with typical incentive payments in utility/aggregator DR programs
- Expressed as a % of the eligible customer base
- Reflects steady state enrollment (i.e., after ramping up to “full” adoption)



APPENDIX B

# The reviewed DR potential studies

We analyzed 7 studies with a significant focus on DR, mostly conducted in the past 5 years

Study	Geographic Coverage	Year	Author
The Potential for Load Flexibility in Xcel Energy’s Northern States Power Service Territory	MN, WI, ND, SD	2019	The Brattle Group
Nova Scotia Energy Efficiency and Demand Response Potential Study for 2021-2045	Nova Scotia, Canada	2019	Navigant Consulting
Demand Response Potential in Bonneville Power Administration’s Public Utility Service Area	Primarily OR, WA, MT, ID	2018	The Cadmus Group
2017 IRP Demand-Side Resource Conservation Potential Assessment Report	Washington	2017	Navigant Consulting
State of Michigan Demand Response Potential Study	Michigan	2017	Applied Energy Group
Demand Response Market Research: Portland General Electric, 2016 to 2035	Oregon	2016	The Brattle Group
Estimating Xcel Energy’s Public Service Company of Colorado Territory Demand Response Market Potential	Colorado	2013	The Brattle Group

*Note: Additional studies were reviewed but did not report participation assumptions or otherwise included only a very narrow set of DR measures.*

APPENDIX B

# Residential DR adoption

Generally, studies assume **20%-30%** at the lower end of the adoption range, and **50-60%** at the upper end of the range, regardless of end-use

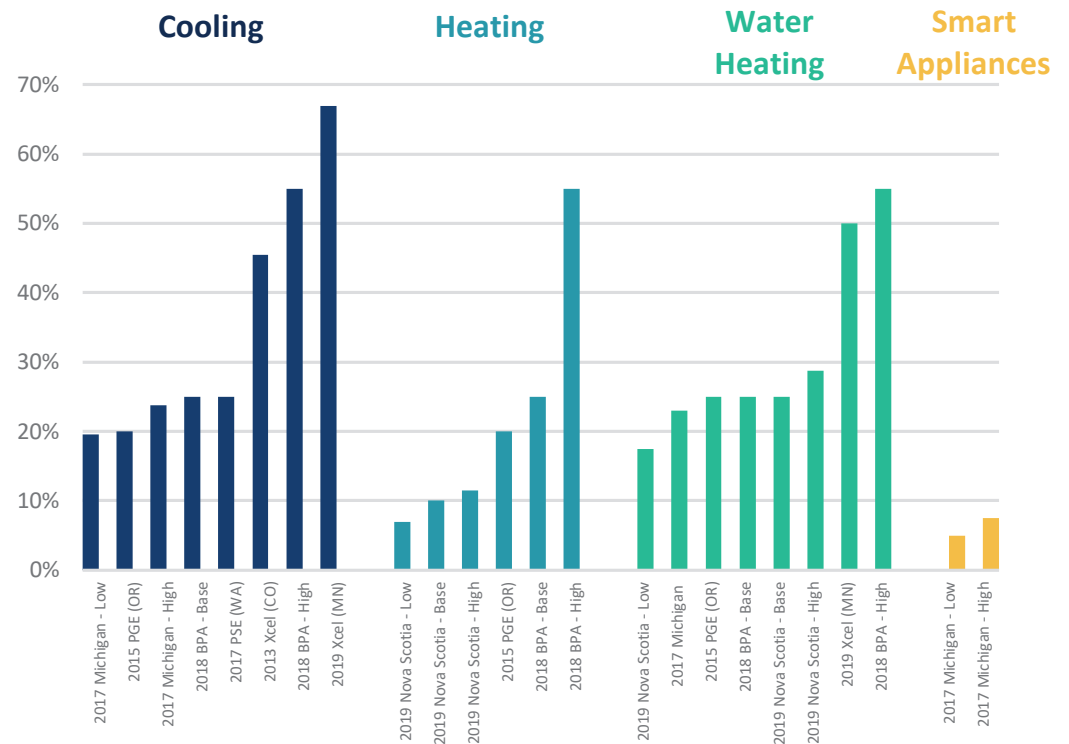
This range is supported by historical data

- According to historical FERC data, a few *states* have achieved DLC enrollment rates of 20% or more
- At the upper end, Xcel Energy has achieved roughly 50% enrollment in its A/C DLC program

Research on smart appliances is limited, but suggests lower adoption than for cooling, heating, and water heating (due to low experience with the technology)



Residential Load Control Adoption Potential



APPENDIX B

# Residential DR adoption (cont'd)

Participation in time-varying rate offerings also can be a useful indication of customer willingness to participate in DR opportunities

Research supports the observation that **more than 20% adoption** is achievable on a voluntary (opt-in) basis

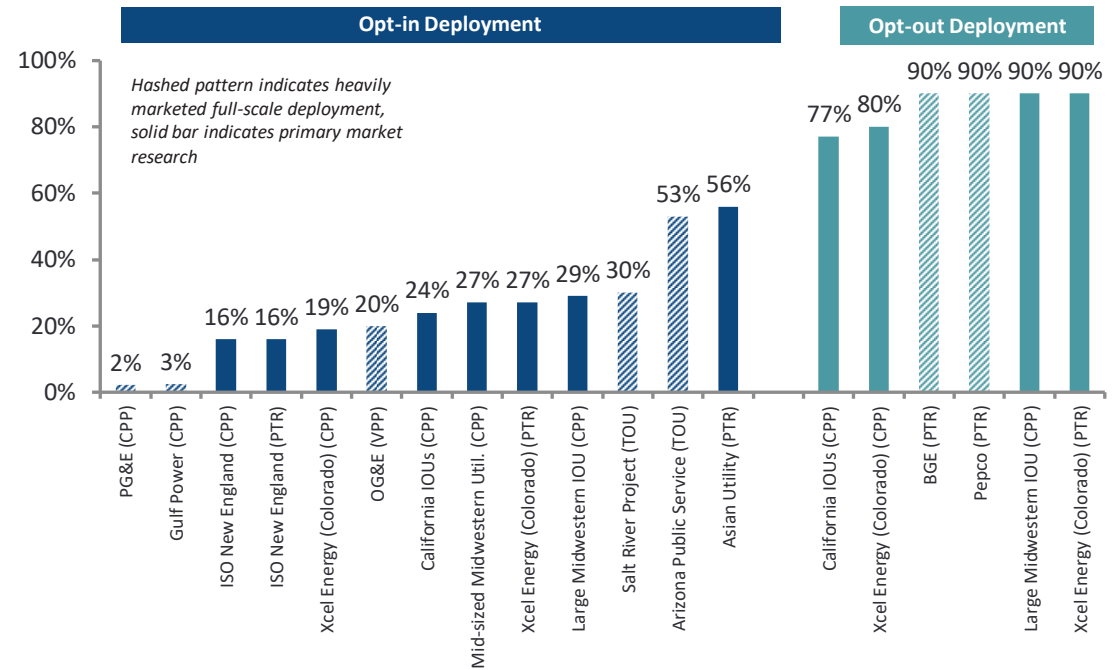
- In fact, APS has enrolled more than half of its residential customers on voluntary TOU rates

Time-varying rates can also be offered on a default (opt-out) basis, with enrollment rates that **exceed 80%**

- BGE and Pepco have achieved this level of enrollment in full-scale peak time rebates deployed on an opt-out basis
- However, opt-out deployment would be without precedent for technology-based load control programs



## Residential Time-Varying Rate Enrollment Estimates



APPENDIX B

# Commercial DR adoption

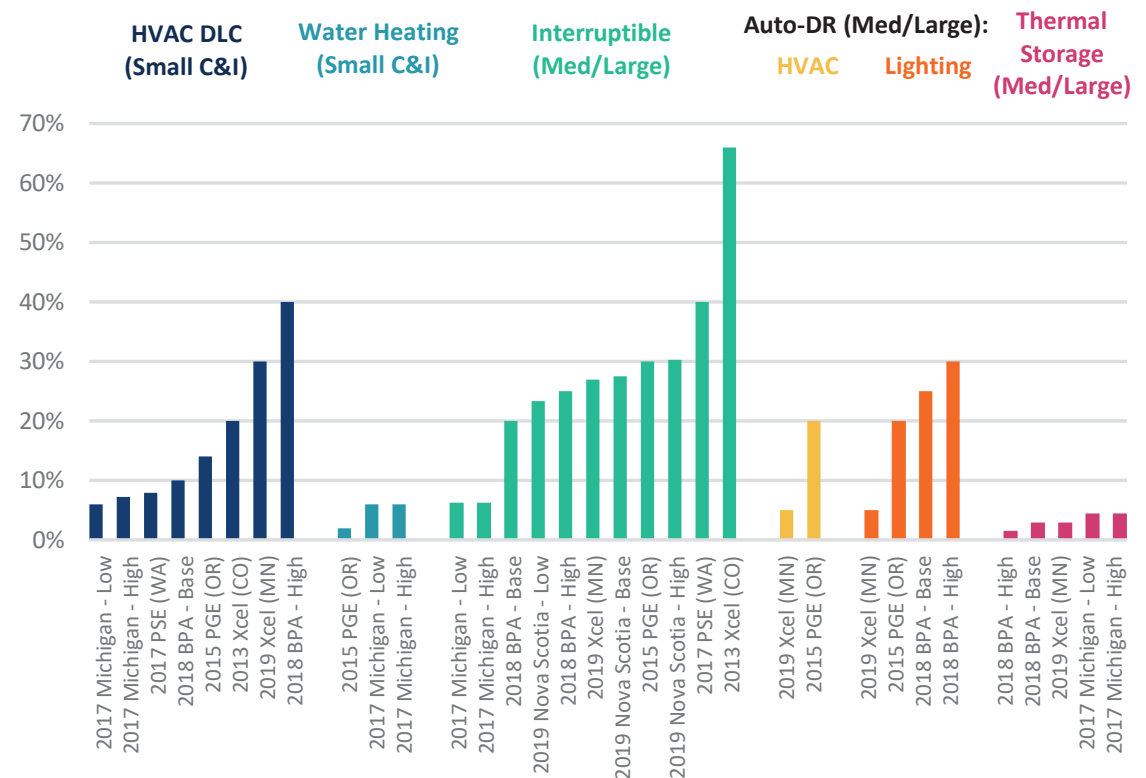
More diversity in DR adoption rate estimates is observed for commercial customers than for residential

Generally, adoption rates can range from **less than 10%** to around **30% to 40%**

### Observations

- Larger customers tend to have higher adoption potential than smaller customers, though the differences are not as stark as one may think
- Interruptible tariffs have the highest adoption potential and typically do not require advanced technology deployment (though may involve partnering with an aggregator)
- Estimates of Auto-DR adoption potential are varied and the data is fairly limited

Commercial DF Adoption Potential



## APPENDIX B

# References

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### The following studies were reviewed to establish achievable participation rates

- *“The Potential for Load Flexibility in Xcel Energy’s Northern States Power Service Territory”*, prepared by The Brattle Group for Xcel Energy, June 2019.
- *“Nova Scotia Energy Efficiency and Demand Response Potential Study for 2021-2045”*, prepared by Navigant for EfficiencyOne, August 2019.
- *“Demand Response Potential in Bonneville Power Administration’s Public Utility Service Area – Final Report”*, prepared by The Cadmus Group for Bonneville Power Administration, March 2018.
- *“2017 IRP Demand-Side Resource Conservation Potential Assessment Report”*, prepared by Navigant Consulting for Puget Sound Energy, September 2017.
- *“State of Michigan Demand Response Potential Study”*, prepared by Applied Energy Group for the State of Michigan, September 2017.
- *“Demand Response Market Research: Portland General Electric, 2016 to 2035”*, prepared by The Brattle Group for Portland General Electric, January 2016.
- *“Estimating Xcel Energy’s Public Service Company of Colorado Territory Demand Response Market Potential”*, prepared by The Brattle Group for Xcel Energy, June 2013.

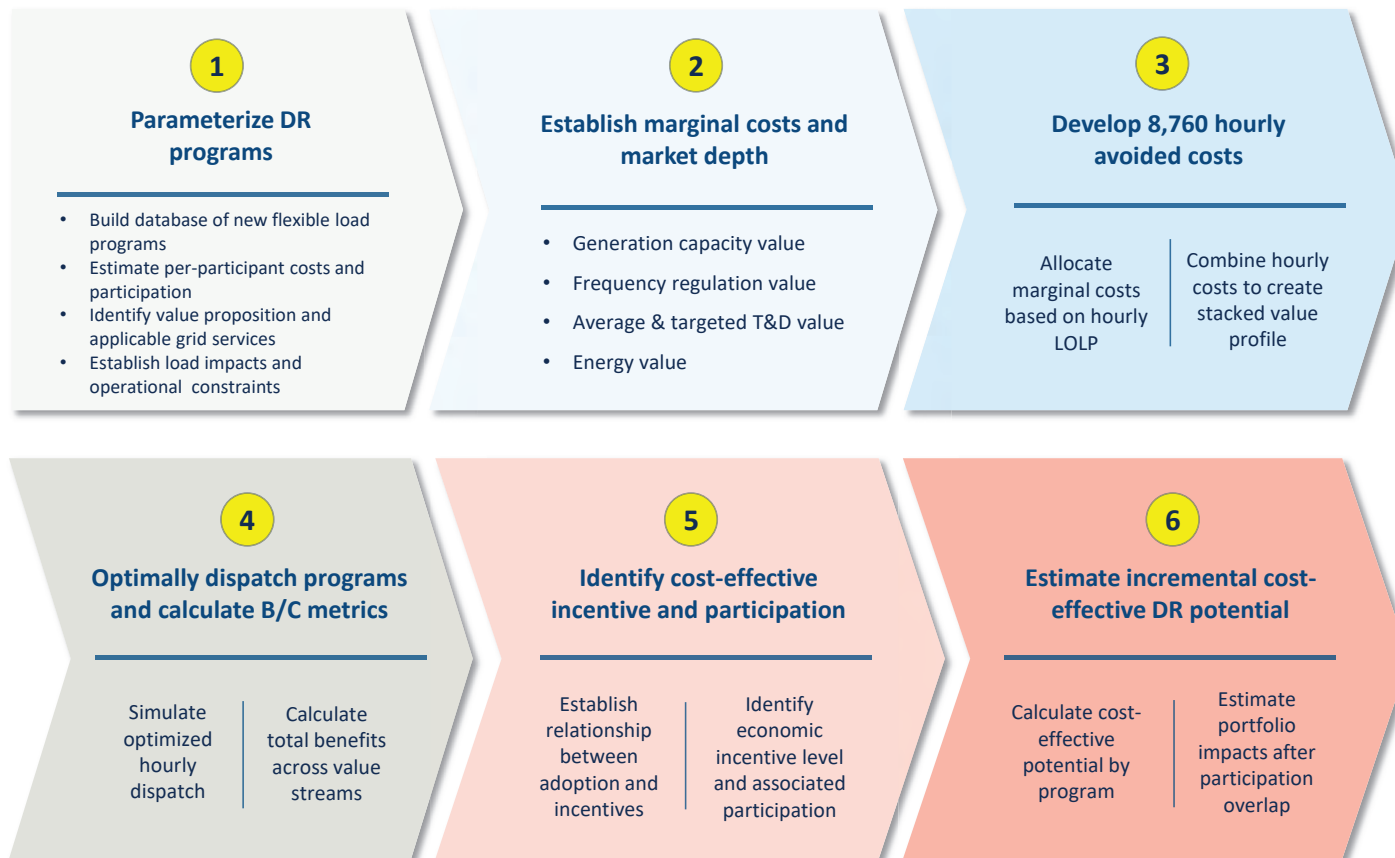
# Appendix C:

## **Additional Analysis Details**



APPENDIX C

# The LoadFlex modeling framework



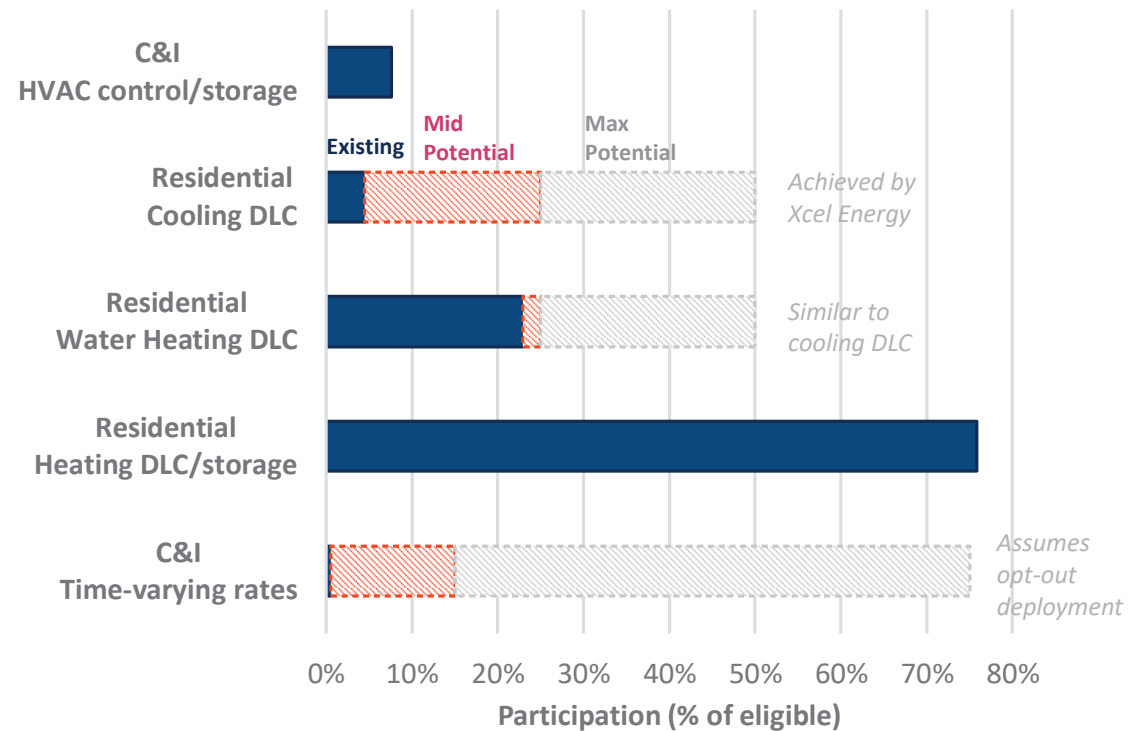
## FINDINGS

# The potential to expand participation in existing programs

### OTP's existing programs are mature and have mostly reached maximum achievable participation levels

- There is room for increased participation in Residential Cooling DLC, based on observed enrollment rates of other utilities (not accounting for cost-effectiveness)
- Non-residential TOU participation could be increased significantly through default (opt-out deployment), though there likely is room for growth in an expanded voluntary program as well
- There may be modest room for growth in Residential Water Heating programs
- Current participation in C&I HVAC and Residential Heating has effectively reached estimates of maximum achievable potential

### Enrollment in Existing OTP's DR Programs



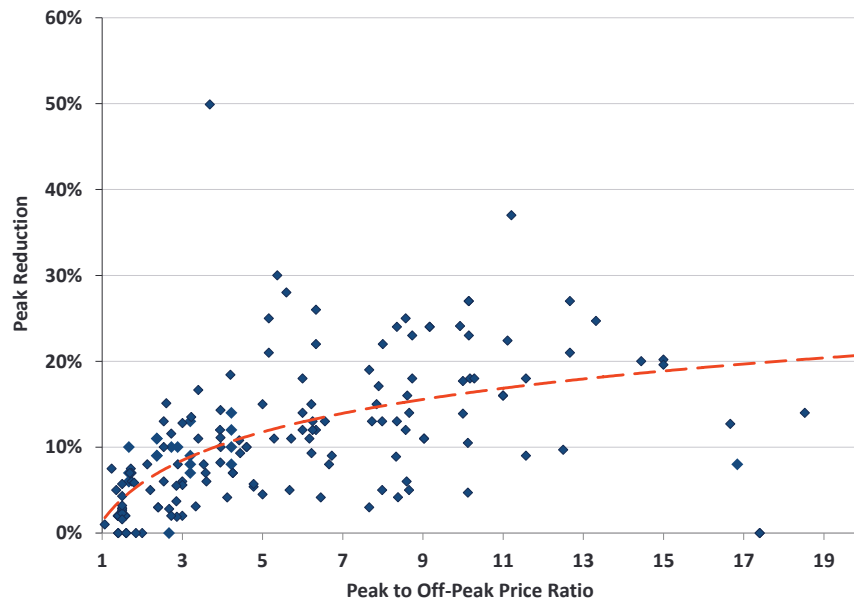
Note: Incremental participation rates shown here are based on typical program incentive payment levels and do not account for cost-effectiveness. As shown in this report, depending on system conditions, expansion of the programs in the chart may not be cost-effective.

## APPENDIX C

# Estimating per-participant impacts

Per-participant impacts are derived from OTP program experience, the experience of programs in other jurisdictions, and a review of engineering studies that identify theoretical load flexibility potential

### Relationship Between Price Ratio and Response



Results shown only for price ratios less than 20-to-1 and for treatments that did not include automating technology such as smart thermostats.

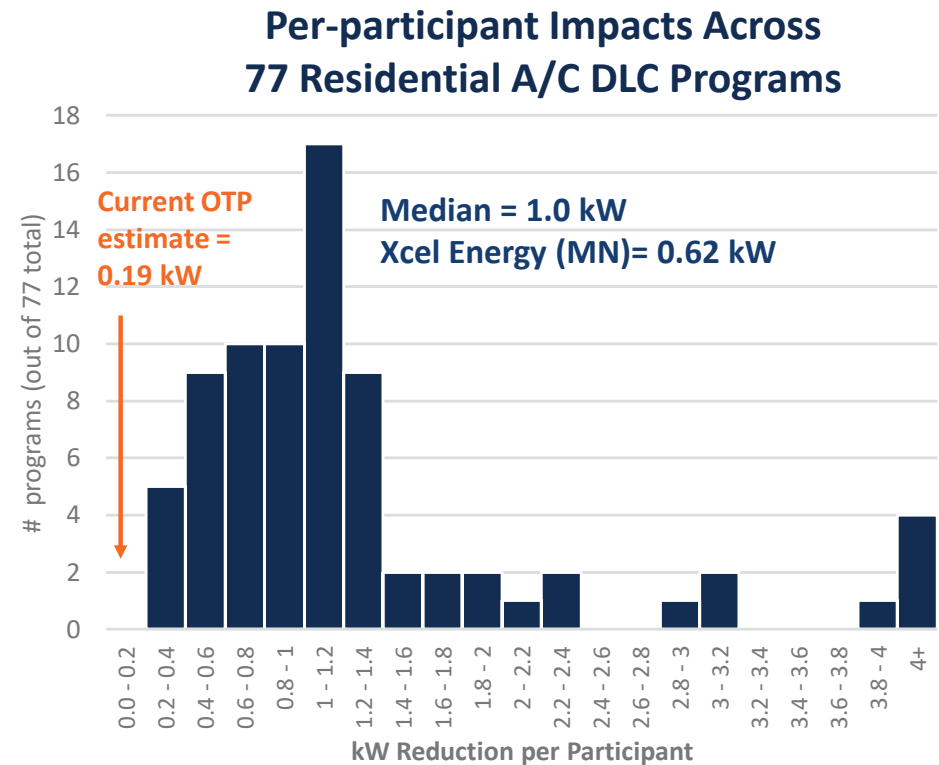
For example, the impacts of time-varying pricing programs are based on a review of more than 300 experimental and non-experimental pricing treatments across over 60 pilot programs. Price response is expressed as a function of the assumed peak-to-off-peak price ratio in the time-varying rates

APPENDIX C

# Impacts of the CoolSavings program

It appears possible to increase the per participant impacts in the CoolSavings program

- A/C DLC programs commonly achieve impacts of 1.0 kW per participant
- OTP’s current assumption of 0.19 kW is significantly lower and likely could be increased, either through revised analysis or modifications to the cycling strategy
- Smart thermostat-based programs can potentially achieve deeper load reductions through more sophisticated pre-cooling strategies



Source: Brattle analysis of 2012 FERC DR Program Database.

## APPENDIX C

# The cost-effectiveness test

We use the Utility Cost Test\* (UCT) to determine the cost-effectiveness of the incremental DR portfolio

The UCT determines whether a given DR program will increase or decrease the utility's revenue requirement

This is the same perspective that utilities take when deciding whether or not to invest in a supply-side resource (e.g., a combustion turbine) through the IRP process

Since the purpose of this DR potential study is to determine the amount of DR that should be included in the IRP, the UCT was determined to be the appropriate perspective

According to the National Action Plan for Energy Efficiency:

*"The UCT is the appropriate cost test from a utility resource planning perspective, which typically aims to minimize a utility's lifecycle revenue requirements"*

\* Also sometimes known as the Program Administrator Cost Test (PACT)

## UCT Costs & Benefits

### Benefits

- Avoided generation capacity
- Avoided peak energy
- Avoided transmission capacity
- Avoided distribution capacity

### Costs

- Incentive payments
- Utility equipment & installation
- Administration/overhead
- Marketing/promotion

APPENDIX C

# DR Program Costs

DR program costs are based on a review of experience and studies in other jurisdictions, and conversations with vendors. The costs in the table below are in 2018 dollars.

Segment	Program	One-Time Costs			Recurring Costs			Economic Life (years)
		Fixed Cost (\$)	Variable Equipment Cost (\$/participant)	Other Initial Costs (\$/participant)	Fixed Admin & Other (\$/year)	Variable Admin & Other (\$/participant-year)	Base Annual Incentive Level (\$/participant-year)	
Residential	A/C DLC - Residential	\$0	\$150	\$80	\$0	\$12	\$33	15
Residential	Smart thermostat - Residential	\$0	\$110	\$80	\$0	\$10	\$25	10
Residential	Timed water heating - Residential	\$0	\$400	\$30	\$0	\$0	\$96	10
Residential	Smart water heating - Residential	\$0	\$600	\$30	\$0	\$0	\$96	10
Residential	Behavioral DR (Opt-out) - Residential	\$0	\$0	\$0	\$0	\$4	\$0	15
Residential	TOU (Opt-in) - Residential	\$50,000	\$0	\$50	\$75,000	\$1	\$0	15
Residential	TOU (Opt-out) - Residential	\$50,000	\$0	\$25	\$75,000	\$1	\$0	15
Residential	CPP (Opt-in) - Residential	\$50,000	\$0	\$70	\$75,000	\$2	\$0	15
Residential	CPP (Opt-out) - Residential	\$50,000	\$0	\$35	\$75,000	\$2	\$0	15
Residential	EV Managed Charging - Home	\$0	\$200	\$0	\$0	\$15	\$40	15
Residential	EV Managed Charging - Work	\$0	\$200	\$0	\$0	\$15	\$40	15
Residential	EV Charging - TOU	\$0	\$0	\$0	\$75,000	\$0	\$0	15
Small C&I	CPP (Opt-in) - Small C&I	\$16,667	\$0	\$70	\$25,000	\$1	\$0	15
Small C&I	CPP (Opt-out) - Small C&I	\$16,667	\$0	\$35	\$25,000	\$1	\$0	15
Small C&I	TOU (Opt-in) - Small C&I	\$16,667	\$0	\$50	\$18,750	\$2	\$0	15
Small C&I	TOU (Opt-out) - Small C&I	\$16,667	\$0	\$25	\$18,750	\$2	\$0	15

Note: Assumed 2.20% annual inflation rate to convert 2018 dollars to 2036 dollars. Used a discount rate of 7.53% to annualize fixed costs.

APPENDIX C

# DR Program Costs (cont'd)



Segment	Program	One-Time Costs			Recurring Costs			Economic Life (years)
		Fixed Cost (\$)	Variable Equipment Cost (\$/participant)	Other Initial Costs (\$/participant)	Fixed Admin & Other (\$/year)	Variable Admin & Other (\$/participant-year)	Base Annual Incentive Level (\$/participant-year)	
Medium C&I	Interruptible - Medium C&I	\$0	\$0	\$0	\$251,000	\$0	\$431	15
Medium C&I	CPP (Opt-in) - Medium C&I	\$16,667	\$0	\$70	\$25,000	\$6	\$0	15
Medium C&I	CPP (Opt-out) - Medium C&I	\$16,667	\$0	\$35	\$25,000	\$6	\$0	15
Medium C&I	TOU (Opt-in) - Medium C&I	\$16,667	\$0	\$1,000	\$18,750	\$20	\$0	15
Medium C&I	TOU (Opt-out) - Medium C&I	\$16,667	\$0	\$500	\$18,750	\$20	\$0	15
Medium C&I	Auto-DR (Light Luminaire) - Medium C&I	\$0	\$0	\$2,969	\$0	\$20	\$399	15
Medium C&I	Auto-DR (Light Zonal) - Medium C&I	\$0	\$0	\$2,209	\$0	\$20	\$399	15
Large C&I	Interruptible - Large C&I	\$0	\$0	\$0	\$283,000	\$0	\$7,042	15
Large C&I	CPP (Opt-in) - Large C&I	\$16,667	\$0	\$1,000	\$25,000	\$20	\$0	15
Large C&I	CPP (Opt-out) - Large C&I	\$16,667	\$0	\$500	\$25,000	\$20	\$0	15
Large C&I	TOU (Opt-out) - Large C&I	\$16,667	\$0	\$1,000	\$18,750	\$20	\$0	15
Large C&I	Auto-DR (Light Luminaire) - Large C&I	\$0	\$0	\$44,681	\$0	\$20	\$8,020	15
Large C&I	Auto-DR (Light Zonal) - Large C&I	\$0	\$0	\$33,170	\$0	\$20	\$8,020	15

Note: Assumed 2.20% annual inflation rate to convert 2018 dollars to 2036 dollars. Used a discount rate of 7.53% to annualize fixed costs.

**Appendix I: Integrated Resource Plan**  
**Sensitivity Summary**



Appendix I - 2021 Integrated Resource Plan Sensitivity Summary

NPVRR Comparison			J	K	L	M	N	O	P	Q	R	S
<b>No Externalities Included</b>			Low Wind	Low Solar	Low Wind & Solar	Low Storage	High Interconnection Costs	Additional 10% MISO Capacity Requirement	Capacity Purchase Limit	10% Increased Load	25% Increased Load	Median Cost of Carbon Tax
1	Withdraw from Coyote 12/31/2040	NPVRR (\$000)	\$2,313,186	\$2,420,794	\$2,267,486	\$2,508,819	\$2,516,554	\$2,538,457	\$2,515,612	\$2,743,014	\$3,103,670	\$2,856,648
2	Withdraw from Coyote 12/31/2028	NPVRR (\$000)	\$2,243,321	\$2,358,296	\$2,178,450	\$2,461,628	\$2,467,223	\$2,492,654	\$2,466,747	\$2,698,837	\$3,093,980	\$2,739,964
	2028 Difference from 2040 Exit NPVRR (\$000)		-\$69,865	-\$62,498	-\$89,036	-\$47,191	-\$49,331	-\$45,803	-\$48,865	-\$44,177	-\$9,690	-\$116,684
3	Withdraw from Coyote 12/31/2026	NPVRR (\$000)	\$2,236,963	\$2,348,150	\$2,165,189	\$2,456,132	\$2,461,577	\$2,486,887	\$2,461,105	\$2,693,597	\$3,096,629	\$2,726,702
	2026 Difference from 2040 Exit NPVRR (\$000)		-\$76,223	-\$72,644	-\$102,297	-\$52,687	-\$54,977	-\$51,570	-\$54,507	-\$49,417	-\$7,041	-\$129,946
<b>Annual Resource Additions - Withdraw from Coyote 12/31/2040</b>												
			Low Wind	Low Solar	Low Wind & Solar	Low Storage	High Interconnection Costs	Additional 10% MISO Capacity Requirement	Capacity Purchase Limit	10% Increased Load	25% Increased Load	Median Cost of Carbon Tax
4	2022											
5	2023			150 MW Sur Solar	150 MW Sur Solar							
6	2024											
7	2025										50 MW Sur Solar	
8	2026						100 MW Sur Solar	75 MW Sur Solar		100 MW Sur Solar	100 MW Sur Solar	175 MW Sur Solar
9	2027	300 MW Sur Wind	200 MW Sur Solar		50 MW Sur Solar 250 MW Sur Wind							
10	2028				50 MW Sur Wind							
11	2029											
12	2030											
13	2031											100 MW Sur Wind
14	2032											
15	2033	100 MW Rep Wind	50 MW Rep Solar	50 MW Rep Wind							25 MW Rep Solar	25 MW Rep Solar 50 MW Rep Wind
16	2034		25 MW Rep Solar	25 MW Rep Solar							50 MW Rep Solar	25 MW Rep Solar 50 MW Sur Wind
17	2035			25 MW Rep Solar	25 MW Rep Solar	50 MW Rep Wind 50 MW Sur Wind			25 MW Rep Solar	50 MW Sur Wind	100 MW Rep Wind	25 MW Rep solar
18	2036	50 MW Rep Wind	25 MW Rep Solar								50 MW Rep Wind	50 MW Rep Wind
<b>Annual Resource Additions - Withdraw from Coyote 12/31/2028</b>												
			Low Wind	Low Solar	Low Wind & Solar	Low Storage	High Interconnection Costs	Additional 10% MISO Capacity Requirement	Capacity Purchase Limit	10% Increased Load	25% Increased Load	Median Cost of Carbon Tax
19	2022											
20	2023			150 MW Sur Solar	150 MW Sur Solar							
21	2024											
22	2025										50 MW Sur Solar	
23	2026					50 MW Sur Solar	100 MW Sur Solar	150 MW Sur Solar	100 MW Sur Solar	150 MW Sur Solar	100 MW Sur Solar 25 MW Gen Solar 10 MW Paired Batt	175 MW Sur Solar
24	2027	300 MW Sur Wind	200 MW Sur Solar		75 MW Sur Solar 250 MW Sur Wind							
25	2028		25 MW Sur Solar	50 MW Sur Wind								
26	2029										50 MW Gen Solar 20 MW Paired Batt	
27	2030											100 MW Sur Wind
28	2031											100 MW Sur Wind
29	2032											
30	2033	150 MW Rep Wind	125 MW Rep Solar	100 MW Rep Wind				100 MW Rep Solar		100 MW Rep Solar	250 MW Rep Solar	75 MW Rep Solar
31	2034		25 MW Rep Solar	50 MW Rep Wind	25 MW Rep Solar	25 MW Rep Solar	50 MW Rep Wind 50 MW Sur Wind	25 MW Rep Solar		25 MW Rep Solar	100 MW Rep Wind	50 MW Rep Wind 25 MW Rep Solar
32	2035	25 MW Rep Solar			50 MW Rep Wind 50 MW Sur Wind		50 MW Rep Wind 50 MW Sur Wind	100 MW Rep Wind	50 MW Sur Wind	150 MW Rep Wind	50 MW Rep Wind	50 MW Rep Wind
33	2036	25 MW Rep Solar						25 MW Rep Solar			25 MW Gen Solar 10 MW Paired Batt	
<b>Annual Resource Additions - Withdraw from Coyote 12/31/2026</b>												
			Low Wind	Low Solar	Low Wind & Solar	Low Storage	High Interconnection Costs	Additional 10% MISO Capacity Requirement	Capacity Purchase Limit	10% Increased Load	25% Increased Load	Median Cost of Carbon Tax
34	2022											
35	2023			150 MW Sur Solar	150 MW Sur Solar							
36	2024											
37	2025										50 MW Sur Solar	
38	2026					50 MW Sur Solar	100 MW Sur Solar	150 MW Sur Solar	100 MW Sur Solar	150 MW Sur Solar	100 MW Sur Solar 75 MW Gen Solar 30 MW Paired Batt	175 MW Sur Solar
39	2027	300 MW Sur Wind	250 MW Sur Solar		100 MW Sur Solar 300 MW Sur Wind							
40	2028											
41	2029											
42	2030											100 MW Sur Wind
43	2031											100 MW Sur Wind
44	2032											
45	2033	150 MW Rep Wind	100 MW Rep Solar	100 MW Rep Wind	25 MW Rep Solar			100 MW Rep Solar		100 MW Rep Solar	250 MW Rep Solar	75 MW Rep Solar
46	2034		25 MW Rep Solar	50 MW Rep Wind	25 MW Rep Solar			25 MW Rep Solar		25 MW Rep Solar	100 MW Rep Wind	50 MW Rep Wind
47	2035	25 MW Rep Solar			25 MW Rep Solar 50 MW Rep Wind 50 MW Sur Wind		50 MW Rep SWind 50 MW Sur Wind	100 MW Rep Wind	50 MW Sur Wind	150 MW Rep Wind	50 MW Rep Wind	25 MW Rep Solar 50 MW Rep Wind
48	2036	25 MW Rep Solar						25 MW Rep Solar				

Appendix I - 2021 Integrated Resource Plan Sensitivity Summary  
EnCompass Version 5.0.7.0

NPVRR Comparison		A	B	C	D	E	F	G	
Externalities Included		Base Case	Preferred IRP	Regional Haze Mid Cost	Regional Haze High Cost	NG and Energy Markets +25%	NG and Energy Markets +50%	NG and Energy Markets +100%	
1	Withdraw from Coyote 12/31/2040	NPVRR (\$000)	\$2,971,847	\$2,991,608	\$3,017,977	\$3,029,243	\$3,043,411	\$3,097,960	\$3,174,178
2	Withdraw from Coyote 12/31/2028	NPVRR (\$000)	\$2,864,875	\$2,909,334	\$2,864,875	\$2,864,875	\$2,959,187	\$3,022,602	\$3,113,119
	2028 Difference from 2040 Exit NPVRR (\$000)		-\$106,972	-\$82,274	-\$153,102	-\$164,368	-\$84,224	-\$75,358	-\$61,059
3	Withdraw from Coyote 12/31/2026	NPVRR (\$000)	\$2,855,293	\$2,895,349	\$2,855,293	\$2,855,293	\$2,948,319	\$3,011,247	\$3,103,710
	2026 Difference from 2040 Exit NPVRR (\$000)		-\$116,554	-\$96,259	-\$162,684	-\$173,950	-\$95,092	-\$86,713	-\$70,468

Annual Resource Additions - Withdraw from Coyote 12/31/2040		A	B	C	D	E	F	G
		Base Case	Preferred IRP	Regional Haze Mid Cost	Regional Haze High Cost	NG and Energy Markets +25%	NG and Energy Markets +50%	NG and Energy Markets +100%

4	2022							
5	2023	125 MW Sur Solar		125 MW Sur Solar	125 MW Sur Solar	200 MW Sur Solar	200 MW Sur Solar 50 MW Gen Wind	200 MW Sur Solar 100 MW Gen Wind
6	2024							
7	2025	100 MW Sur Solar 50 MW Gen Wind	150 MW Sur Solar	75 MW Sur Solar 100 MW Gen Wind	100 MW Sur Solar 50 MW Gen Wind	50 MW Sur Solar 150 MW Gen Wind	75 MW Sur Solar 100 MW Gen Wind	75 MW Sur Solar 100 MW Gen Wind
8	2026	50 MW Gen Wind		50 MW Gen Wind	50 MW Gen Wind		50 MW Gen Wind	
9	2027	50 MW Sur Wind	100 MW Sur Wind					
10	2028	50 MW Sur Wind		50 MW Sur Wind	50 MW Sur Wind	50 MW Sur Wind		50 MW Sur Wind
11	2029							
12	2030			50 MW Sur Wind				
13	2031				50 MW Sur Wind			
14	2032						50 MW Sur Wind	
15	2033	50 MW Rep Wind	50 MW Rep Solar	50 MW Rep Solar		50 MW Rep Wind		
16	2034	25 MW Rep Solar		25 MW Rep Solar	50 MW Rep Solar			
17	2035			50 MW Rep Wind				50 MW Rep Wind
18	2036							

Annual Resource Additions - Withdraw from Coyote 12/31/2028		A	B	C	D	E	F	G
		Base Case	Preferred IRP	Regional Haze Mid Cost	Regional Haze High Cost	NG and Energy Markets +25%	NG and Energy Markets +50%	NG and Energy Markets +100%

19	2022							
20	2023	125 MW Sur Solar		125 MW Sur Solar	125 MW Sur Solar	200 MW Sur Solar	200 MW Sur Solar 50 MW Gen Wind	175 MW Sur Solar 100 MW Gen Wind
21	2024							25 MW Sur Solar
22	2025	100 MW Sur Solar 50 MW Gen Wind	150 MW Sur Solar	100 MW Sur Solar 50 MW Gen Wind	100 MW Sur Solar 50 MW Gen Wind	50 MW Sur Solar 150 MW Gen Wind	75 MW Sur Solar 150 MW Gen Wind	75 MW Sur Solar 100 MW Gen Wind
23	2026	50 MW Gen Wind		50 MW Gen Wind	50 MW Gen Wind	50 MW Gen Wind		
24	2027		100 MW Sur Wind					
25	2028	50 MW Sur Wind		50 MW Sur Wind	50 MW Sur Wind			25 MW Sur Wind
26	2029	100 MW Sur Wind						25 MW Sur Solar
27	2030							100 MW Sur Wind
28	2031							
29	2032							
30	2033	25 MW Rep Solar	50 MW Rep Solar	25 MW Rep Solar	25 MW Rep Solar	50 MW Rep Solar	50 MW Rep Wind	25 MW Rep Solar 25 MW Battery
31	2034	25 MW Rep Solar 100 MW Rep Wind		25 MW Rep Solar 100 MW Rep Wind	25 MW Rep Solar 100 MW Rep Wind		25 MW Rep Solar	50 MW Rep Wind
32	2035							
33	2036							

Annual Resource Additions - Withdraw from Coyote 12/31/2026		A	B	C	D	E	F	G
		Base Case	Preferred IRP	Regional Haze Mid Cost	Regional Haze High Cost	NG and Energy Markets +25%	NG and Energy Markets +50%	NG and Energy Markets +100%

34	2022							
35	2023	125 MW Sur Solar		125 MW Sur Solar	125 MW Sur Solar	225 MW Sur Solar	200 MW Sur Solar 50 MW Gen Wind	150 MW Sur Solar 100 MW Gen Wind
36	2024							50 MW Sur Solar
37	2025	100 MW Sur Solar 50 MW Gen Wind	150 MW Sur Solar	100 MW Sur Solar 50 MW Gen Wind	100 MW Sur Solar 50 MW Gen Wind	25 MW Sur Solar 150 MW Gen Wind	75 MW Sur Solar 100 MW Gen Wind	75 MW Sur Solar 100 MW Gen Wind
38	2026	50 MW Gen Wind		50 MW Gen Wind	50 MW Gen Wind			25 MW Sur Solar
39	2027	100 MW Sur Wind	100 MW Sur Wind	100 MW Sur Wind	100 MW Sur Wind	100 MW Sur Wind	150 MW Sur Wind	150 MW Sur Wind
40	2028							
41	2029	50 MW Sur Wind		50 MW Sur Wind	50 MW Sur Wind	50 MW Sur Wind		
42	2030							
43	2031							
44	2032							
45	2033	50 MW Rep Solar	50 MW Rep Solar	50 MW Rep Solar	50 MW Rep Solar	25 MW Rep Solar	50 MW Rep Wind	
46	2034	50 MW Rep Wind		50 MW Rep Wind	50 MW Rep Wind	25 MW Rep Solar		
47	2035					50 MW Rep Wind		50 MW Rep Solar
48	2036						25 MW Rep Solar	25 MW Battery

Appendix I - 2021 Integrated Resource Plan Sensitivity Summary  
EnCompass Version 5.0.7.0

NPVRR Comparison		H	I	J	K	L	M	N	
Externalities Included		NG and Energy Markets -25%	NG and Energy Markets -50%	Low Wind	Low Solar	Low Wind & Solar	Low Storage	High Interconnection Costs	
1	Withdraw from Coyote 12/31/2040	NPVRR (\$000)	\$2,849,110	\$2,642,896	\$2,709,607	\$2,848,076	\$2,609,792	\$2,967,662	\$2,974,927
2	Withdraw from Coyote 12/31/2028	NPVRR (\$000)	\$2,731,585	\$2,503,367	\$2,606,536	\$2,737,058	\$2,486,826	\$2,861,538	\$2,874,953
	2028 Difference from 2040 Exit NPVRR (\$000)		-\$117,525	-\$139,529	-\$103,071	-\$111,018	-\$122,966	-\$106,124	-\$99,974
3	Withdraw from Coyote 12/31/2026	NPVRR (\$000)	\$2,706,529	\$2,475,659	\$2,576,239	\$2,716,959	\$2,470,288	\$2,855,648	\$2,859,743
	2026 Difference from 2040 Exit NPVRR (\$000)		-\$142,581	-\$167,237	-\$133,368	-\$131,117	-\$139,504	-\$112,014	-\$115,184

Annual Resource Additions - Withdraw from Coyote 12/31/2040		H	I	J	K	L	M	N
		NG and Energy Markets -25%	NG and Energy Markets -50%	Low Wind	Low Solar	Low Wind & Solar	Low Storage	High Interconnection Costs

4	2022							
5	2023			125 MW Sur Solar	300 MW Sur Solar	300 MW Sur Solar	125 MW Sur Solar	125 MW Sur Solar
6	2024							
7	2025	50 MW Sur Solar		25 MW Sur Solar			100 MW Sur Solar 50 MW Gen Wind	100 MW Sur Solar
8	2026	100 MW Sur Solar						
9	2027			300 MW Sur Wind	125 MW Sur Solar 50 MW Sur Wind	300 MW Sur Wind	50 MW Sur Wind	100 MW Sur Wind
10	2028						50 MW Sur Wind	50 MW Sur Wind
11	2029							
12	2030							
13	2031	50 MW Sur Wind						
14	2032				50 MW Sur Wind			
15	2033	25 MW Rep Solar 50 MW Rep Wind		150 MW Rep Wind	25 MW Rep Solar	100 MW Rep Wind	50 MW Rep Wind	50 MW Sur Wind
16	2034	50 MW Rep Solar 50 MW Sur Wind			50 MW Rep Wind		25 MW Rep Solar	25 MW Rep Solar
17	2035					50 MW Rep Wind		
18	2036					25 MW Rep Solar		

Annual Resource Additions - Withdraw from Coyote 12/31/2028		H	I	J	K	L	M	N
		NG and Energy Markets -25%	NG and Energy Markets -50%	Low Wind	Low Solar	Low Wind & Solar	Low Storage	High Interconnection Costs

19	2022							
20	2023			125 MW Sur Solar	300 MW Sur Solar	300 MW Sur Solar		125 MW Sur Solar
21	2024							
22	2025	50 MW Sur Solar		25 MW Sur Solar	50 MW Gen Wind			100 MW Sur Solar
23	2026	100 MW Sur Solar	25 MW Sur Solar					
24	2027			300 MW Sur Wind	150 MW Sur Solar	300 MW Sur Wind		100 MW Sur Wind
25	2028					25 MW Sur Solar		50 MW Sur Wind
26	2029	50 MW Sur Wind		50 MW Gen Wind	100 MW Sur Wind	25 MW Sur Solar		100 MW Sur Wind
27	2030	50 MW Sur Wind						
28	2031	50 MW Sur Wind						
29	2032							
30	2033	75 MW Rep Solar 50 MW Rep Wind		150 MW Rep Wind	50 MW Rep Solar	25 MW Rep Solar 150 MW Rep Wind		50 MW Rep Solar
31	2034		25 MW Rep Solar		50 MW Rep Wind			50 MW Rep Wind
32	2035		50 MW Rep Solar			25 MW Rep Solar		
33	2036		25 MW Rep Solar					

Annual Resource Additions - Withdraw from Coyote 12/31/2026		H	I	J	K	L	M	N
		NG and Energy Markets -25%	NG and Energy Markets -50%	Low Wind	Low Solar	Low Wind & Solar	Low Storage	High Interconnection Costs

34	2022							
35	2023			100 MW Sur Solar 50 MW Gen Wind	300 MW Sur Solar	300 MW Sur Solar	125 MW Sur Solar	125 MW Sur Solar
36	2024							
37	2025	50 MW Sur Solar		50 MW Sur Solar			125 MW Sur Solar 50 MW Gen Wind	100 MW Sur Solar
38	2026	100 MW Sur Solar	25 MW Sur Solar		50 MW Gen Wind			
39	2027			300 MW Sur Wind	150 MW Sur Solar 50 MW Sur Wind	300 MW Sur Wind	100 MW Sur Wind	200 MW Sur Wind
40	2028					50 MW Sur Solar	50 MW Sur Wind	
41	2029	50 MW Sur Wind			50 MW Sur Wind			50 MW Sur Wind
42	2030	50 MW Sur Wind						
43	2031	50 MW Sur Wind						
44	2032							
45	2033	75 MW Rep Solar		150 MW Rep Wind	50 MW Rep Solar	25 MW Rep Solar 150 MW Rep Wind	50 MW Rep Solar 50 MW Rep Wind	50 MW Rep Solar
46	2034	50 MW Rep Wind	25 MW Rep Solar		50 MW Rep Wind			50 MW Rep Wind
47	2035	25 MW Rep Solar	50 MW Rep Solar		50 MW Rep Wind	25 MW Rep Solar		
48	2036		25 MW Rep Solar				50 MW Rep Wind	

NPVRR Comparison			O	P	Q	R	T	U	V	W
Externalities Included			Additional 10% MISO Capacity Requirement	Capacity Purchase Limit	10% Increased Load	25% Increased Load	Low Externalities 2020-2024, Low Cost of Carbon 2025-2050	High Externalities 2020-2024, High Cost of Carbon 2025-2050	Low Externalities 2020-2024, Median Cost of Carbon 2025-2050	High Externalities 2020-2024, Median Cost of Carbon 2025-2050
1	Withdraw from Coyote 12/31/2040	NPVRR (\$000)	\$2,979,416	\$2,976,297	\$3,247,652	\$3,680,849	\$2,718,105	\$3,156,787	\$2,963,754	\$2,974,804
2	Withdraw from Coyote 12/31/2028	NPVRR (\$000)	\$2,883,950	\$2,868,515	\$3,147,845	\$3,593,323	\$2,660,195	\$3,012,644	\$2,862,582	\$2,872,352
	2028 Difference from 2040 Exit NPVRR	(\$000)	-\$95,466	-\$107,782	-\$99,807	-\$87,526	-\$57,910	-\$144,143	-\$101,172	-\$102,452
3	Withdraw from Coyote 12/31/2026	NPVRR (\$000)	\$2,865,661	\$2,854,019	\$3,135,452	\$3,572,003	\$2,648,162	\$2,985,027	\$2,844,688	\$2,853,201
	2026 Difference from 2040 Exit NPVRR	(\$000)	-\$113,755	-\$122,278	-\$112,200	-\$108,846	-\$69,943	-\$171,760	-\$119,066	-\$121,603

Annual Resource Additions - Withdraw from Coyote 12/31/2040			O	P	Q	R	T	U	V	W
			Additional 10% MISO Capacity Requirement	Capacity Purchase Limit	10% Increased Load	25% Increased Load	Low Externalities 2020-2024, Low Cost of Carbon 2025-2050	High Externalities 2020-2024, High Cost of Carbon 2025-2050	Low Externalities 2020-2024, Median Cost of Carbon 2025-2050	High Externalities 2020-2024, Median Cost of Carbon 2025-2050

4	2022									
5	2023	125 MW Sur Solar	125 MW Sur Solar	200 MW Sur Solar	300 MW Sur Solar	50 MW Gen Wind		175 MW Sur Solar		125 MW Sur Solar
6	2024									25 MW Sur Solar
7	2025	75 MW Sur Solar 50 MW Gen Wind	100 MW Sur Solar 50 MW Gen Wind	25 MW Sur Solar 100 MW Gen Wind	150 MW Gen Wind	50 MW Gen Wind	150 MW Sur Solar	75 MW Sur Solar 150 MW Gen Wind	225 MW Sur Solar 50 MW Gen Wind	75 MW Sur Solar 50 MW Gen Wind
8	2026	50 MW Gen Wind	50 MW Gen Wind	50 MW Gen Wind	50 MW Gen Wind	50 MW Gen Wind		50 MW Gen Wind	50 MW Gen Wind	50 MW Gen Wind
9	2027					50 MW Sur Wind				
10	2028	50 MW Sur Wind	50 MW Sur Wind	100 MW Sur Wind					50 MW Sur Wind	
11	2029									50 MW Sur Wind
12	2030									
13	2031	50 MW Sur Wind								
14	2032									
15	2033	50 MW Rep Wind	50 MW Rep Wind		25 MW Rep Solar 50 MW Rep Wind	25 MW Rep Solar 50 MW Rep Wind	50 MW Sur Wind	50 MW Sur Wind	50 MW Sur Wind	50 MW Rep Wind
16	2034	25 MW Rep Solar	25 MW Rep Solar	50 MW Rep Solar	25 MW Rep Solar	50 MW Rep Wind	50 MW Sur Wind	25 MW Rep Solar	25 MW Rep Solar	25 MW Rep Solar
17	2035					50 MW Rep Wind				
18	2036									

Annual Resource Additions - Withdraw from Coyote 12/31/2028			O	P	Q	R	T	U	V	W
			Additional 10% MISO Capacity Requirement	Capacity Purchase Limit	10% Increased Load	25% Increased Load	Low Externalities 2020-2024, Low Cost of Carbon 2025-2050	High Externalities 2020-2024, High Cost of Carbon 2025-2050	Low Externalities 2020-2024, Median Cost of Carbon 2025-2050	High Externalities 2020-2024, Median Cost of Carbon 2025-2050

19	2022									
20	2023	125 MW Sur Solar	125 MW Sur Solar	200 MW Sur Solar	250 MW Sur Solar	50 MW Gen Wind		175 MW Sur Solar		125 MW Sur Solar
21	2024			25 MW Sur Solar						25 MW Sur Solar
22	2025	50 MW Sur Solar 100 MW Gen Wind	100 MW Sur Solar 50 MW Gen Wind	150 MW Gen Wind	150 MW Gen Wind	50 MW Gen Wind	150 MW Sur Solar	100 MW Sur Solar 150 MW Gen Wind	225 MW Sur Solar 50 MW Gen Wind	75 MW Sur Solar 50 MW Gen Wind
23	2026	50 MW Gen Wind	50 MW Gen Wind	50 MW Gen Wind	150 MW Gen Wind	150 MW Gen Wind	150 MW Sur Solar	50 MW Gen Wind	50 MW Gen Wind	50 MW Gen Wind
24	2027									
25	2028		50 MW Sur Wind						50 MW Sur Wind	50 MW Sur Wind
26	2029	100 MW Sur Wind	100 MW Sur Wind	100 MW Sur Wind				100 MW Sur Wind	100 MW Sur Wind	50 MW Sur Wind
27	2030									50 MW Sur Wind
28	2031						50 MW Sur Wind			
29	2032									
30	2033	100 MW Rep Solar	50 MW Rep Solar	75 MW Rep Solar	200 MW Rep Solar 50 MW Rep Wind	50 MW Sur Wind	25 MW Rep Solar	50 MW Rep Solar	50 MW Rep Solar	25 MW Rep Solar
31	2034	50 MW Rep Wind	25 MW Rep Solar 50 MW Rep Wind		25 MW Rep Solar 50 MW Rep Wind	50 MW Rep Wind	50 MW Rep Wind	50 MW Rep Wind		25 MW Rep Solar 50 MW Rep Wind
32	2035			100 MW Rep Wind		25 MW Rep Solar		25 MW Rep Solar 50 MW Rep Wind		50 MW Rep Wind
33	2036				25 MW Battery					

Annual Resource Additions - Withdraw from Coyote 12/31/2026			O	P	Q	R	T	U	V	W
			Additional 10% MISO Capacity Requirement	Capacity Purchase Limit	10% Increased Load	25% Increased Load	Low Externalities 2020-2024, Low Cost of Carbon 2025-2050	High Externalities 2020-2024, High Cost of Carbon 2025-2050	Low Externalities 2020-2024, Median Cost of Carbon 2025-2050	High Externalities 2020-2024, Median Cost of Carbon 2025-2050

34	2022									
35	2023	125 MW Sur Solar	125 MW Sur Solar	200 MW Sur Solar	225 MW Sur Solar	50 MW Gen Wind		175 MW Sur Solar		125 MW Sur Solar
36	2024			25 MW Sur Solar						25 MW Sur Solar
37	2025	50 MW Sur Solar 100 MW Gen Wind	100 MW Sur Solar 100 MW Gen Wind	200 MW Gen Wind	200 MW Gen Wind	50 MW Gen Wind	150 MW Sur Solar	100 MW Sur Solar 150 MW Gen Wind	225 MW Sur Solar 50 MW Gen Wind	100 MW Sur Solar 50 MW Gen Wind
38	2026	50 MW Gen Wind		50 MW Gen Wind	25 MW Gen Solar 200 MW Gen Wind 10 MW Paired Batt	150 MW Sur Solar			50 MW Gen Wind	50 MW Gen Wind
39	2027	50 MW Sur Wind	100 MW Sur Wind					100 MW Sur Wind	150 MW Sur Wind	100 MW Sur Wind
40	2028	50 MW Sur Wind		50 MW Sur Wind						
41	2029							50 MW Sur Wind		
42	2030		50 MW Sur Wind				50 MW Sur Wind			50 MW Sur Wind
43	2031						100 MW Sur Wind			
44	2032									
45	2033	100 MW Rep Solar	50 MW Rep Solar	75 MW Rep Solar	125 MW Rep Solar 50 MW Rep Wind	100 MW Rep Solar 50 MW Rep Wind	50 MW Rep Solar	50 MW Rep Solar		25 MW Rep Solar
46	2034	50 MW Rep Wind	25 MW Rep Wind	50 MW Rep Wind	50 MW Rep Solar		50 MW Rep Wind	75 MW Rep Solar 50 MW Rep Wind		50 MW Rep Wind
47	2035				50 MW Rep Solar					
48	2036				25 MW Rep Solar					

## **Appendix J: Distributed Renewable Generation**

## **Distributed Renewable Generation**

### **Existing Distributed Renewable Generation Projects**

Otter Tail currently has 69 interconnected facilities with over 1.7 MW of installed nameplate capacity of distributed renewable generation (DG) on its system. The majority of these facilities are customer owned units that are utilizing the small power producer tariffs that exist in all three jurisdictions that Otter Tail operates.

### **New Distributed Renewable Generation Projects**

Otter Tail expects new small customer owned DG facilities to continue to grow over time. Otter Tail does not expect that the increase in distributed generation facilities on its system will have an impact on the current preferred resource plan.

In order for DG facilities to have an impact on Otter Tail's resource plan, the facilities will need to be competitive with other generation facilities available to Otter Tail including the cost of capacity and energy in the Midcontinent ISO market. That is a difficult hurdle in today's energy market.

Wholesale energy prices remain low following 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:

2016: \$20.22/MWh  
2017: \$23.00/MWh  
2018: \$27.28/MWh  
2019: \$22.99/MWh  
2020: \$16.60/MWh  
2021 (YTD May 13): \$30.81/MWh

While it can be argued that there are transmission and distribution loss savings to be realized, the magnitude of those savings will not come close to offsetting the additional cost of the energy.

Otter Tail will continue to analyze renewable distributed generation projects that are submitted for consideration. However, with its RES/REO obligations met in all three states, Otter Tail will only consider projects that are competitive with the Midcontinent ISO energy market or are needed to meet renewable objectives or the solar mandate in the service territory that it serves.

In order to keep customers bills as low as possible, it is prudent for Otter Tail to enter into only projects that are cost competitive with the Midcontinent ISO market.