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December 2, 2013

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

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

RE: IN THE MATTER OF OTTER TAIL POWER COMPANY'S SUBMITTAL OF ITS 2014–2028 RESOURCE PLAN
MN Docket No. E017/RP-13-961

Dear Dr. Haar:

Otter Tail Power Company ("Otter Tail") hereby submits its 2013 Resource Plan filing to the Minnesota Public Utilities Commission. The plan identifies how Otter Tail proposes to meet the capacity and energy needs of its customers over the 2014-2028 planning period.

Otter Tail has worked closely with stakeholders and regulators over the last year to develop a straight-forward plan that meets the requirements of these groups and at the same time keeps customer's rates as low as possible. The preferred plan does not include any resource additions during the first five years of the planning period. In addition, Otter Tail has included an energy efficiency goal of 1.5% and has already added 62.4 MW of wind energy in 2013 to bring our current renewable energy percentage to about 19% of retail sales.

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

Should you have any questions, please contact me at bhdraxten@otpco.com or (218) 739-8417.

Sincerely,

/s/ BRIAN DRAXTEN
Brian Draxten
Manager, Resource Planning

wao
Enclosures
By electronic service and U.S. Mail
c: Service List

Application for Resource Plan Approval 2014 - 2028

PUBLIC DOCUMENT – TRADE SECRET DATA HAS BEEN EXCISED

Submitted to
Minnesota Public Utilities Commission

December 2, 2013
Docket No. E017/RP-13-961

OTTER TAIL
POWER COMPANY

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1 Preface

Otter Tail Power Company ("Otter Tail" or "Company") respectfully files this resource plan with the Minnesota Public Utilities Commission ("Commission") for approval under Minnesota Statute §216B.2422 and Minnesota Rules Part 7843. The plan presented in this filing identifies the anticipated demand and energy needs of the Company's customers and details specific action items that Otter Tail intends to complete within the first five years of the planning period, as well as potential resources that might be used in the following 10 years.

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

This resource plan may be one of the most straight-forward resource plans that the Commission has recently reviewed. No new resources are proposed for addition during the first five years of the plan. In the period after the first five years, the only questions are those regarding the specific type and timing of resources to replace Hoot Lake Plant and expiring capacity purchase contracts. As is detailed in this plan, a natural gas resource is the first resource selected in almost all of the 78 Strategist runs submitted in this plan. The timing (2019 -2021), type (simple-cycle vs. combined-cycle), and size of the natural gas resource are the only attributes that vary among the different Strategist runs. While it may be useful to discuss and consider the attributes of this resource in this plan proceeding, because this addition occurs several years into the future, the specific timing, type, and size of the gas addition can be better addressed in the Company's next resource plan, which will likely be filed in mid-2016.

Since the 2010 resource plan and the subsequent Baseload Diversification Study, Otter Tail has added 62.4 MW of wind generation and entered into a capacity-only PPA for Midcontinent Independent System Operator ("Midcontinent ISO") Zone 1 capacity that will cover Otter Tail's capacity needs until June 2021. In addition, the Company has included in this plan an energy efficiency goal of 1.5 percent to meet Minnesota state mandates, which is an increase from 1.2 percent included in Otter Tail's previous resource plan.

To prepare for the studies that form the foundation for this resource plan, the Company convened a stakeholder group meeting in St. Paul on September 26, 2013. Each party who was actively involved in the Baseload Diversification Study also participated in this meeting. At this stakeholder meeting, no participant objected to the assumptions being used in the modelling, and meeting participants requested several new sensitivity runs, which were incorporated in the Strategist modeling. Consequently, Otter Tail believes it has developed a resource plan that addresses the concerns of stakeholders.

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

2 Resource Plan Non-Technical Summary

The plan identifies the anticipated electric service needs of the Company's customers for the 2014-2028 planning period. The plan details specific action items that Otter Tail intends to complete within the first five years of the planning period.

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

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

Otter Tail has worked diligently to keep these objectives in mind while developing this resource plan. Otter Tail continues to make existing facilities as efficient and economical as is cost-effective. These efforts should help to maintain low rates and customer bills, reduce the financial risks of future environmental regulation or taxes, reduce environmental effects, and keep the Company well positioned to respond to change. This resource plan provides a blend of supply-side and demand-side resource options to meet customer needs that cannot be met with existing resources.

2.1 Load Forecast

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

The forecast peak demand and energy requirements are detailed in Appendix B. The energy requirements forecast represents an approximate 1.5 percent average annual growth rate, prior to new demand side management ("DSM") programs, and is the key component in determining the type of capacity resources to be added, whether baseload, intermediate, or peaking. Peak demands are anticipated to average an annual growth rate of 1.8 percent in the summer, prior to new DSM programs. The peak demand will determine the size of capacity resources required for the system. As a participant in the Midcontinent ISO, Otter Tail is currently required to maintain a 6.2 percent planning reserve margin on the forecasted summer peak demand coincident with the Midcontinent ISO's peak demand, after accounting for plant accreditation ratings as defined by the Midcontinent ISO.

2.2 Future Resource Needs

Table 2-1 provides the Company's summer season resource needs showing the Company's projected load and capability according to Midcontinent ISO Module E rules for resource adequacy. Please see Section 3 for discussion of Midcontinent ISO Module E and further detail regarding the resource adequacy obligation calculation. [1]

The 50th percentile demand forecast is adjusted for accredited demand response capability, and a 6.2 percent planning reserve margin is calculated on this net demand forecast to determine the expected reserve obligation. The total accredited capacities, shown as Zonal Resource Credits ("ZRCs"), represent the Midcontinent ISO's capacity ratings for the Company's resources based on the 2013 planning year accreditation levels (including wind resource capacity credit as ordered in Otter Tail's 2010 resource plan). Aggregate ZRCs are the accreditation of those resources that have deliverability anywhere within the Midcontinent ISO footprint. Local ZRCs are the accreditation of those resources that are Behind-the-Meter-Generation, or locally deliverable to the Company's load. Capacities for transactions are shown separately. Resource, transaction, and demand response accreditations are based on historical summer performance and do not vary monthly.

Table 2-1: Summer 2014-2028 Base Case Projected Load and Capability Prior to Resource Plan Information

Planning Year	Coincident 50/50 Forecasted Demand (MW)	Accredited Demand Response (MW)	Planning Reserve Margin (6.2%)	Transmission Losses	Reserve Obligation Net of Accredited Demand Response (MW)	Aggregate Capacity (ZRCs)	Local Capacity (ZRCs)	External Capacity (ZRCs)	Net Transaction Capacity (ZRCs)	Total Accredited Capacity (ZRCs)	Projected Summer Deficiency (-MW)
2014	603.6	-26.0	35.8	28.2	641.6	608.5	64.8	4.5	100.0	777.8	136.2
2015	628.5	-30.0	37.1	29.2	664.8	608.5	64.8	4.5	100.0	777.8	113.0
2016	657.0	-41.0	38.2	30.1	684.2	608.5	64.8	4.5	100.0	777.8	93.6
2017	658.5	-39.0	38.4	30.2	688.2	608.5	64.8	4.5	25.0	702.8	14.6
2018	664.7	-39.0	38.8	30.5	695.1	608.5	64.8	4.5	25.0	702.8	7.7
2019	687.2	-43.0	39.9	31.4	715.6	608.5	64.8	4.5	50.0	727.8	12.2
2020	695.4	-43.0	40.4	31.8	724.7	608.5	64.8	4.5	50.0	727.8	3.1
2021	708.2	-50.0	40.8	32.1	731.1	473.1	64.8	4.5	0.0	542.4	-188.7
2022	722.9	-51.0	41.7	32.8	746.4	473.1	64.8	4.5	0.0	542.4	-204.0
2023	730.5	-51.0	42.1	33.2	754.8	473.1	64.8	4.5	0.0	542.4	-212.4
2024	738.2	-51.0	42.6	33.5	763.4	473.1	64.8	4.5	0.0	542.4	-221.0
2025	746.0	-51.0	43.1	33.9	772.0	473.1	64.8	4.5	0.0	542.4	-229.6
2026	754.0	-56.0	43.3	34.1	775.3	473.1	64.8	4.5	0.0	542.4	-232.9
2027	762.0	-56.0	43.8	34.5	784.3	473.1	64.8	4.5	0.0	542.4	-241.9
2028	770.2	-56.0	44.3	34.9	793.4	473.1	64.8	4.5	0.0	542.4	-251.0

The data in the tables illustrates the capacity deficits that exist prior to plan development, based on the Company's existing resources as of December 1, 2013. The table shows that Otter Tail is capacity deficient beginning in the summer of 2021 when Hoot Lake Plant is retired and power purchase agreements ("PPAs") expire and that the deficiency grows from that point throughout the study period as demand continues to grow.

[1] 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 6.2 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.

2.3 Resource Plan Development

The software model used for developing Otter Tail's resource plan is Strategist. The long-range peak demand and energy forecasts are incorporated into the Strategist database, along with the supply-side and demand-side resource alternatives available to the Company over the course of the study period. Strategist was then executed to develop a series of least-cost resource plans. Otter Tail defined the objective function as minimizing total revenue requirements or total societal costs.

The Proview module within Strategist was executed to develop an optimized resource plan for each scenario for the time period 2014 through 2028. Resource plans were developed in accordance with the resource planning rules, including evaluation of scenarios that varied load growth, applied externalities, and achieved specified renewable and conservation objectives.

2.4 Resource Alternatives

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

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

Resource Alternatives Modeled	Description
Natural Gas Combined Cycle	Generic 311 MW nameplate capacity frame type combined cycle unit
Natural Gas Simple Cycle - Small	Generic 49 MW nameplate capacity Aeroderivitive type simple cycle unit
Natural Gas Simple Cycle - Medium	Generic 101 MW nameplate capacity Aeroderivitive type simple cycle unit
Natural Gas Simple Cycle - Large	Generic 211 MW nameplate capacity frame type simple cycle unit
Natural Gas Combined Heat/Power	Generic 96 MW nameplate capacity frame type combined cycle unit
Natural Gas conversion of Hoot Lake units 2 and 3	122 MW nameplate capacity conversion of units 2 and 3 at Hoot Lake plant from coal to natural gas
Solar Photovoltaic	Generic 1 MW nameplate capacity utility-scale solar photovoltaic resource
Wind	Generic 50 MW nameplate capacity utility-scale wind resource
Conservation	1.5% energy efficiency/conservation resource (MN load only)
Load Control (DSM)	15 MW of additional load control by the end of the 15 year study period

2-4 Resource Plan Summary

2.5 Preferred Resource Plan

The Company's preferred resource plan (Energy Market On sensitivity 22 from Appendix I) as developed by the Strategist Proview optimization analysis calls for the addition of a 211 MW simple cycle frame unit in 2021 as shown in Table 2-3. The preferred resource plan is the least cost plan developed by the Strategist model without the consideration of environmental externalities, CO_2 values, or other proposed environmental regulation and using base case assumptions for load growth, fuel prices (natural gas and coal), solar, wind, market energy prices, capacity prices, and capital costs. The preferred plan is expected to cost $3.376B, a net present value in 2014$ of revenue requirements ("NPVRR"). The preferred plan uses the 1.5 percent CIP energy goal in Minnesota and 15 MW of new incremental summer demand response by 2028.

Table 2-3: Preferred Resource Plan Summary

Resource Plan (MW) - Based on Nameplate ratings		
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021	211 MW frame NG CT	Commercial Operation of frame, natural gas-fired, simple cycle combustion turbine.
2022		
2023		
2024		
2025		
2026		
2027		
2028		

Figure 2-1 shows the capacity resource addition along with existing resources over the study period and Figure 2-2 shows the energy contribution by fuel category for 2014-2028 under the preferred plan. In Figure 2-2, the Purchases category (red) is primarily comprised of day-ahead market opportunity purchases, while the Forward Purchases (yellow) represents longer term bi-lateral contractual purchases.

Figure 2-1: Preferred Plan Capacity Resources and Reserve Obligation 2014-2028 (MW)

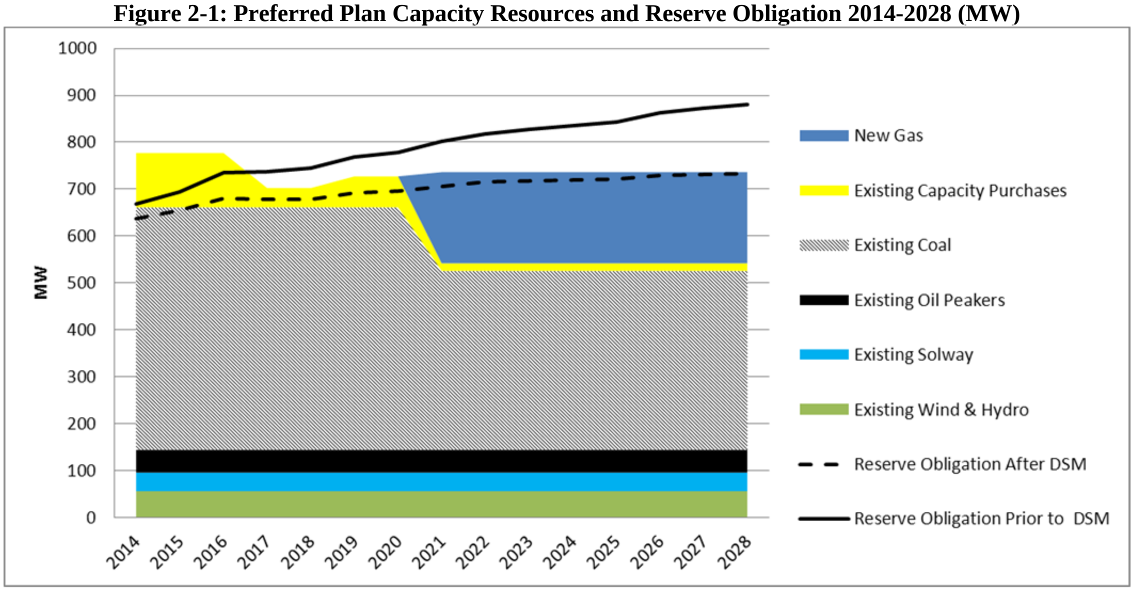
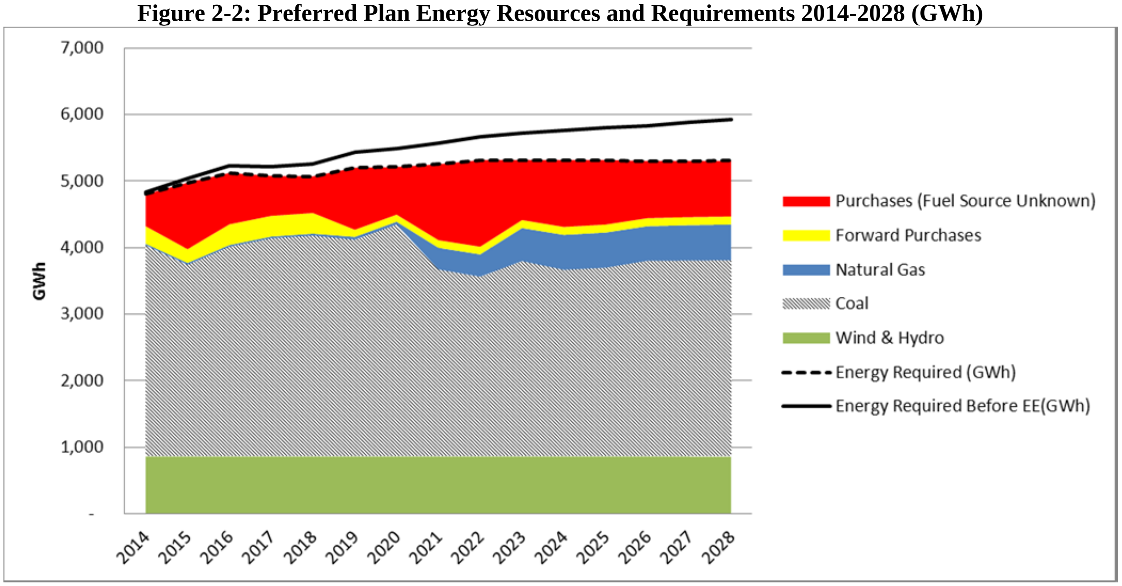


Figure 2-2: Preferred Plan Energy Resources and Requirements 2014-2028 (GWh)



2-6 Resource Plan Summary

Figure 2-3 shows the current energy contribution by fuel category for the year 2012. Figure 2-4 shows the expected energy contribution by fuel category for the preferred plan for the year 2028. The preferred plan shows a reduction in percentage of coal energy and market purchases and an increase in the percentage of energy from natural gas and renewable energy.

Figure 2-3: 2012 Energy by Fuel Source

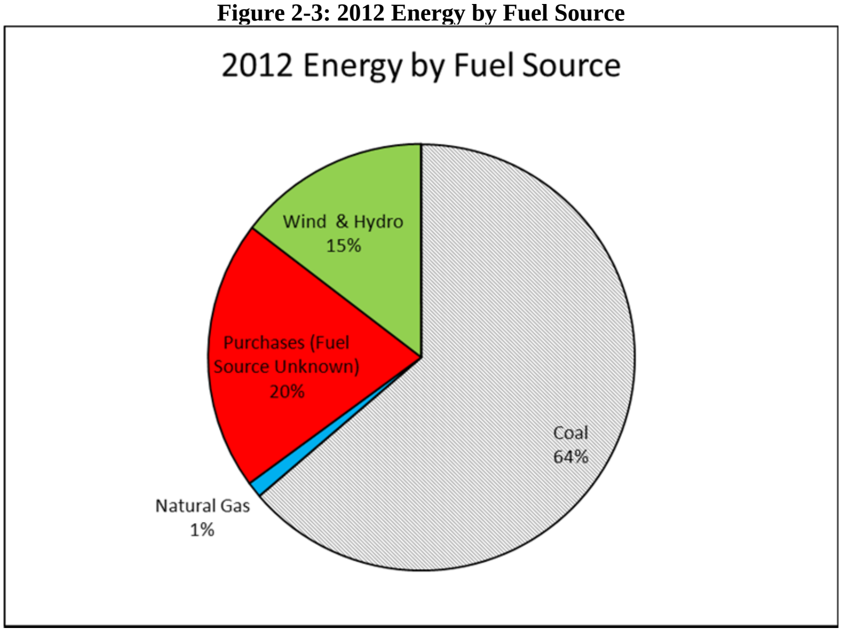
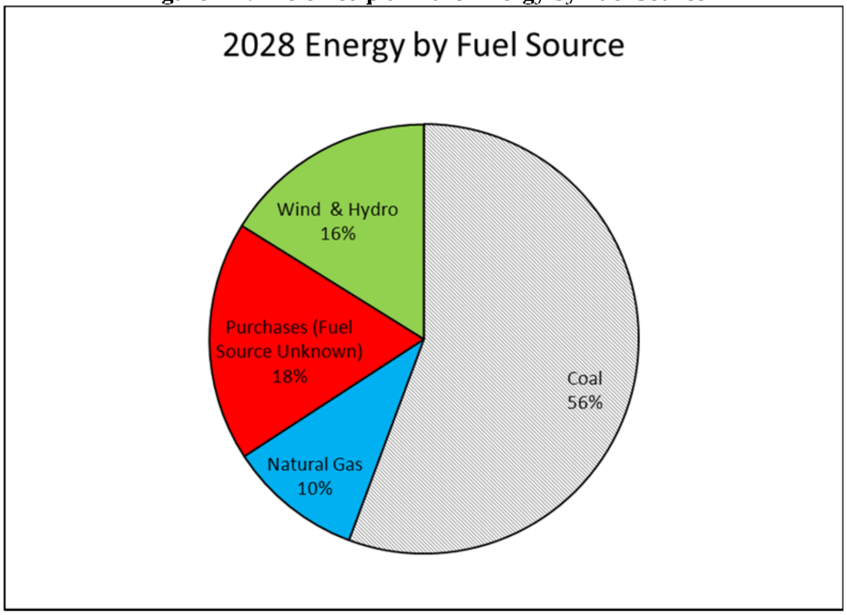


Figure 2-4: Preferred plan 2028 Energy by Fuel Source

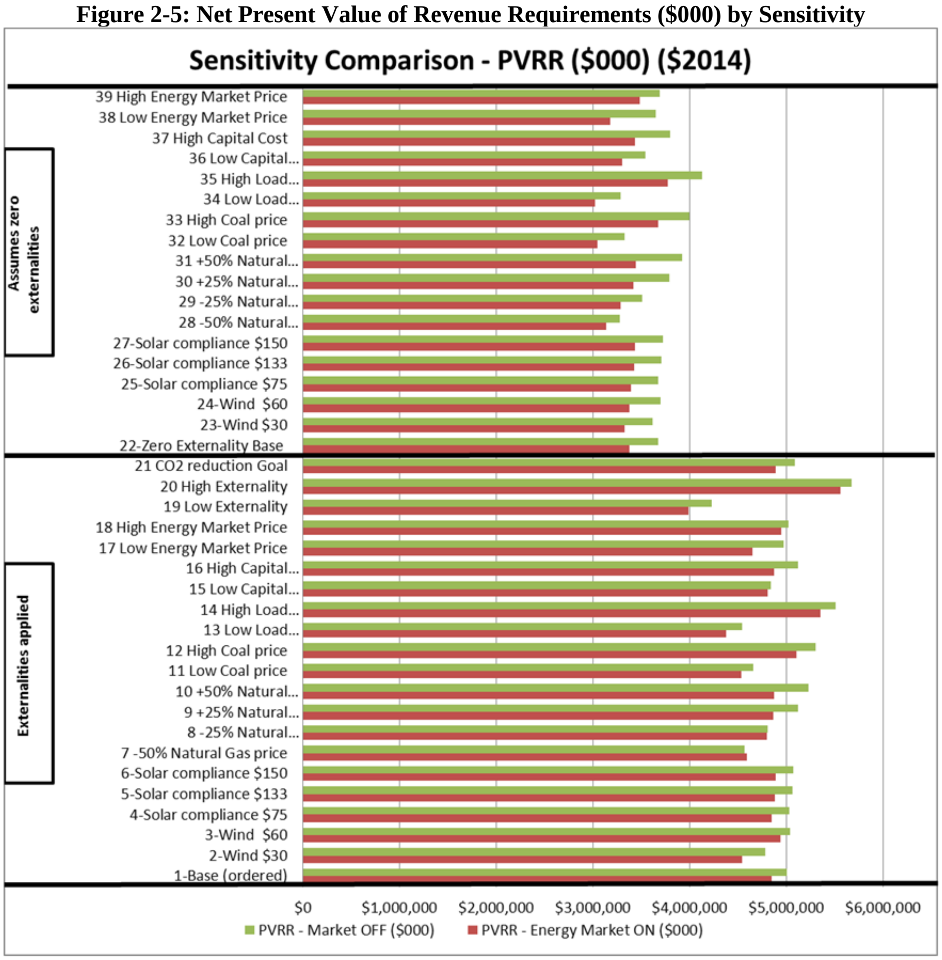


2.6 Preferred Plan is in the Public Interest

Otter Tail Power Company is committed to operating its generation facilities as efficiently as practicable while minimizing adverse effects on the environment. New resources have been selected that will meet the Company's needs while maintaining flexibility and limiting the risk of exposure to changes in financial, social, and technological factors beyond its control. With no resource additions during the initial five-year period, the plan maintains flexibility during a period of much uncertainty including recession impacts and rebound, climate change proposals, and other factors that can have a material impact on the industry. In addition, customers will be provided with more opportunities to improve their energy efficiency. This resource plan satisfies the legal and regulatory requirements in the multi-state service territory and allows Otter Tail and its customers to realize the benefits of operating as a single system while satisfying requirements in all states served by Otter Tail.

Figure 2-5 shows a summary of the Net Present Value of Revenue Requirements for all sensitivities evaluated for this resource plan.

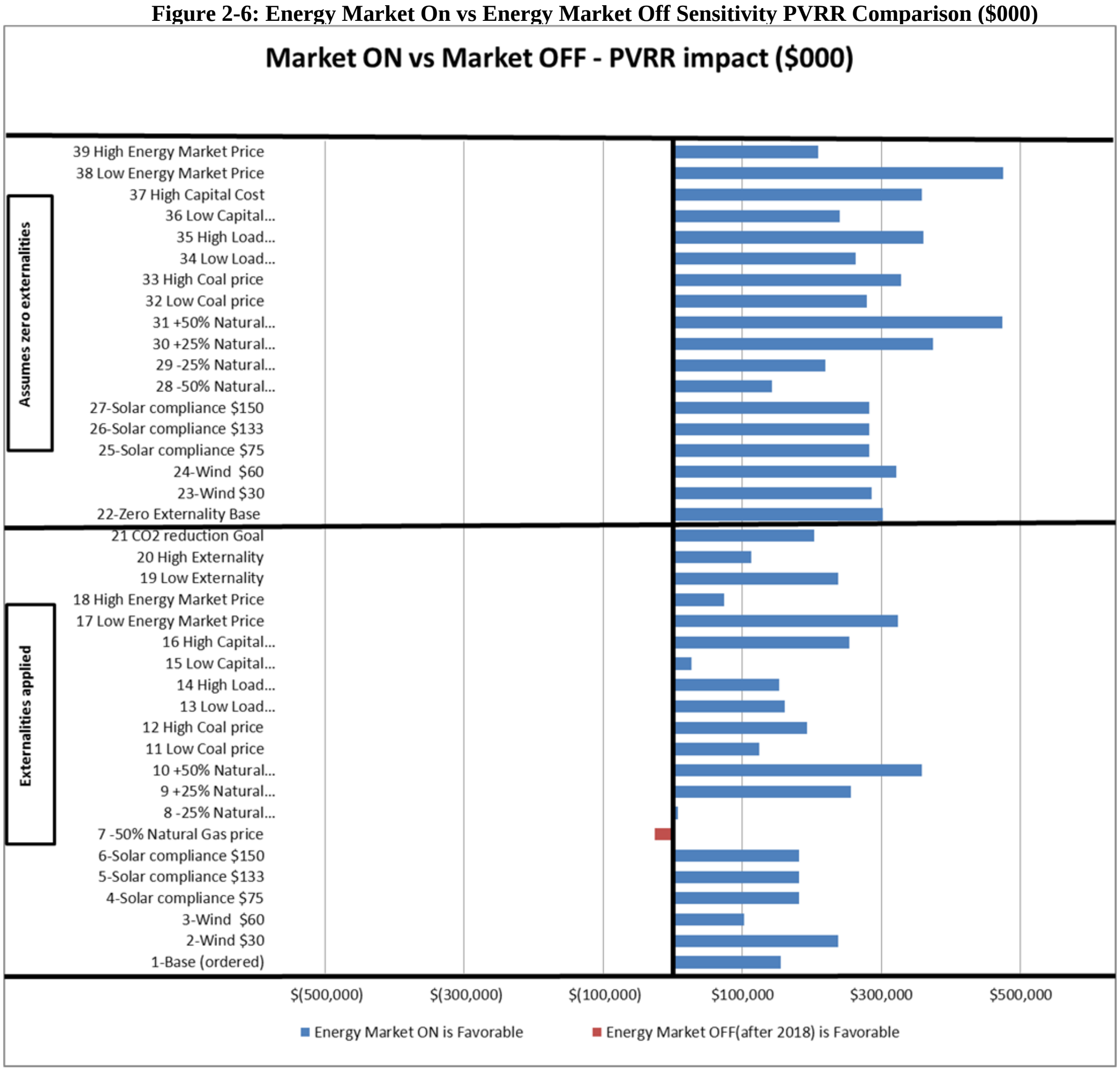
Figure 2-5: Net Present Value of Revenue Requirements ($000) by Sensitivity



2-8 Resource Plan Summary

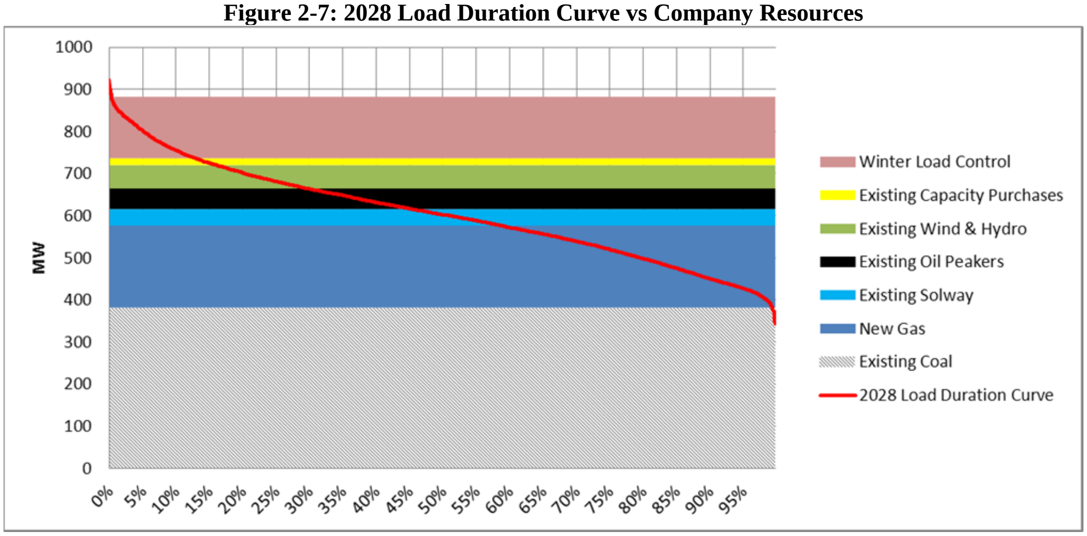
Otter Tail uses two scenarios related to interaction with the energy market in this resource plan. The Energy Market Off scenario turns the energy market opportunity purchases off after five years as required by the Commission's Order in Otter Tail's last resource plan (Docket No. E017/RP-10-623). The Energy Market On scenario allows energy market opportunity purchases throughout the study period. This plan evaluates 39 sensitivities for each scenario, a total of 78 sensitivities. The Company believes that the Energy Market On scenarios more accurately reflect the current operations and interactions with the energy market while providing significant benefit to our customers. Figure 2-6 displays the difference in the Net Present Value of Revenue Requirements of the Energy Market On and Energy Market Off for each sensitivity. Only 1 of the 39 sensitivities shows the Energy Market Off as favorable to Energy Market On.

Figure 2-6: Energy Market On vs Energy Market Off Sensitivity PVRR Comparison ($000)



Market energy opportunity purchases should not be considered market reliance because market opportunity purchases would occur when market energy prices are more favorable to the customer than running an Otter Tail-owned facility. Figure 2-7 shows the expected load duration curve for the year 2028 compared to the resources planned for that year. The resources could be considered a "price backstop", in which the resource would run when the variable cost of the resource (fuel and variable operations & maintenance expenses) is less than the market energy price.

Figure 2-7: 2028 Load Duration Curve vs Company Resources



In the Energy Market Off scenarios, a capacity build takes place in 2019, the year the energy market is turned off. The capacity build is in excess of the planned capacity reserve requirements. Figure 2-8 displays the capacity expansion for the Energy Market On scenario (Energy Market On 22 from Appendix I). Figure 2-9 displays the capacity expansion plan for the Energy Market Off scenario, depicting the excess capacity build in the year 2019 (Energy Market Off 22 from Appendix I). The increase in PVRR for the figures displayed was over $301 million. For all 39 sensitivities, the average increase in PVRR of the Energy Market Off scenarios compared to the Energy Market On scenarios was over $230 million.

2-10 Resource Plan Summary

Figure 2-8: Energy Market On Capacity Resources and Reserve Obligation 2014-2028

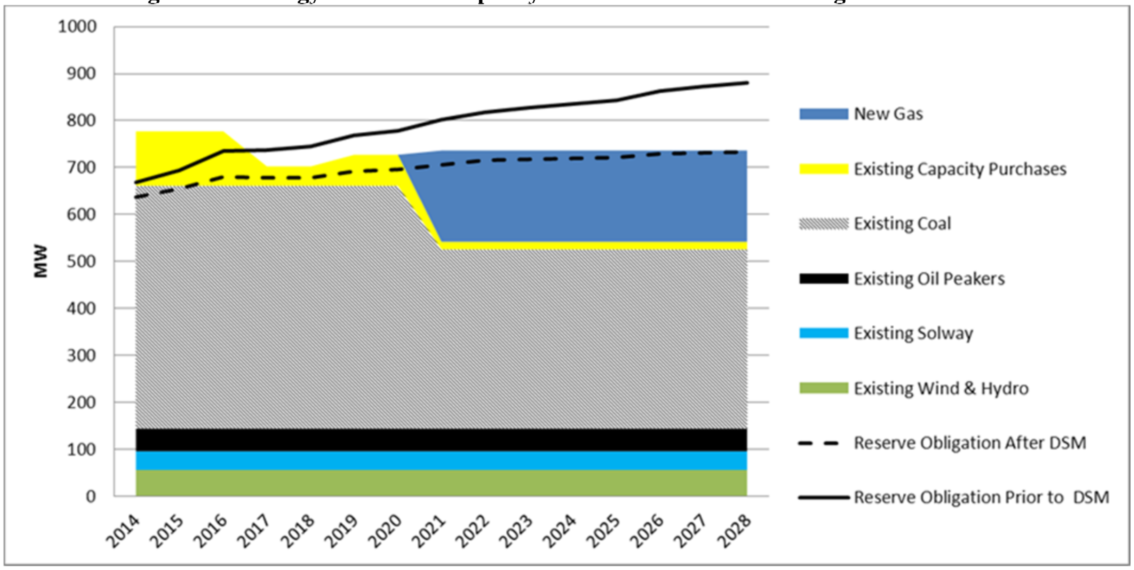
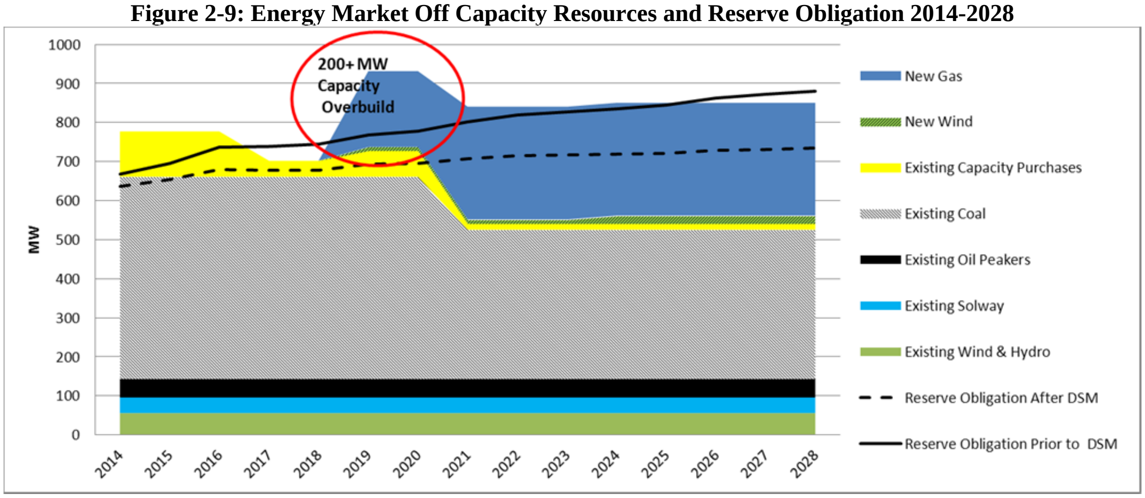


Figure 2-9: Energy Market Off Capacity Resources and Reserve Obligation 2014-2028



This resource plan satisfies all rules and requirements of the Minnesota statutes and rules, provides a clear concise report to interested parties of how Otter Tail will satisfy customer needs in the near term, and identifies the resources the Company is considering for viable options for the long term.

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

In compliance with Minnesota Statutes, the Company evaluated low (2 sensitivities), mid (38 sensitivities), and high (2 sensitivities) externality sensitivities for this resource plan and as defined by the Commission's June 5, 2013, Notice of Updated Environmental Externality Values. Each externality case also assumed a CO_2 tax starting in 2017 and escalating annually. In addition to the externality sensitivities, the Company evaluated 36 sensitivities with zero externalities.

Minnesota Stat. §216B.2422 also requires evaluation of the resource plan for low and high load growth sensitivities and for sensitivities that evaluate meeting 50 percent and 75 percent of future resource needs using demand side management and renewable resources. Like the externality sensitivities, the load growth sensitivities also varied from the preferred plan in total cost and resource selection. The Company plans for the most likely forecast, recognizing that this plan can adapt as time progresses to accommodate variations in actual load growth from the present long-range forecast. The preferred plan meets 65 percent of new energy requirements for Minnesota customers using renewable resources and energy efficiency and conservation.

2.7 Externality Values

Two dockets relating to externality values are open in Minnesota. Docket No. E999/CI-13-796, deals with the estimate of the costs of future carbon regulation. In Docket No. E999/CI-00-1636 a motion is pending before the Commission which requests an update to environmental cost values. Neither of these proceedings will be completed in time for Otter Tail to incorporate the results into its 2013 resource plan. The company does not anticipate that these proceedings would have an impact on the five year action plan since the preferred plan does not call for any resource additions in the first five years of the planning period. The outcome of the above listed proceedings would be incorporated in future resource plans.

2.8 Preferred Plan Rate Impacts

Figure 2-10 shows the potential estimated overall rate impact of the preferred resource plan. The data shown is the average annual rate based on the Strategist model for the total system and represents total revenue divided by total sales. Figure 2-11 shows the potential estimated rate impacts of the preferred resource plan by customer class. A number of parameters in the operation of the model will impact rates. The Strategist model assumes automatic rate increases each year to meet the targeted rate of return; but in reality, rate cases take place as needed and have an inherent amount of regulatory and administrative lag. The Strategist model rate impact calculation has taken into account the generation additions in the preferred plan. But it does not include all projected capital expenditures, asset based sales, or projected CO_2 costs.

2-12 Resource Plan Summary

Figure 2-10: Preferred Resource Plan Estimated Rate Impacts

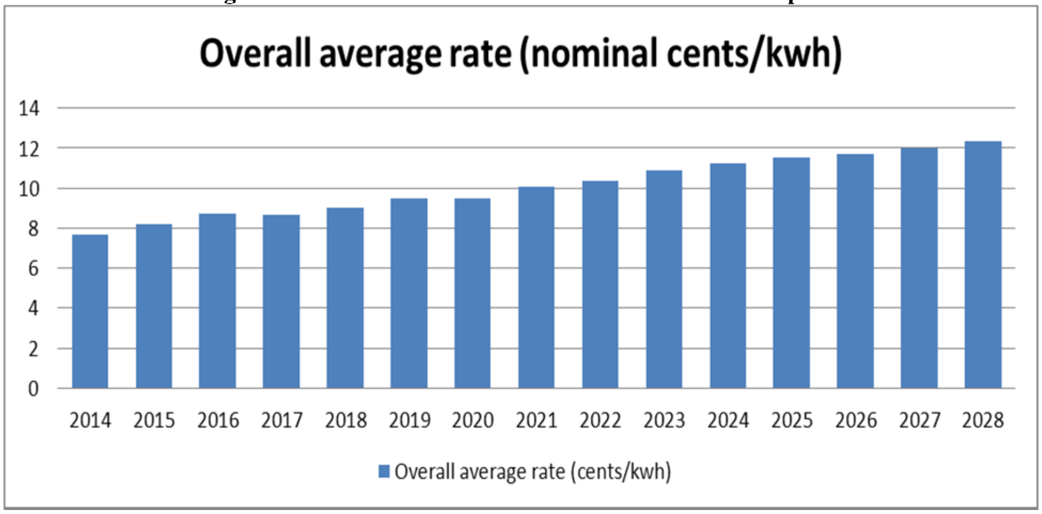
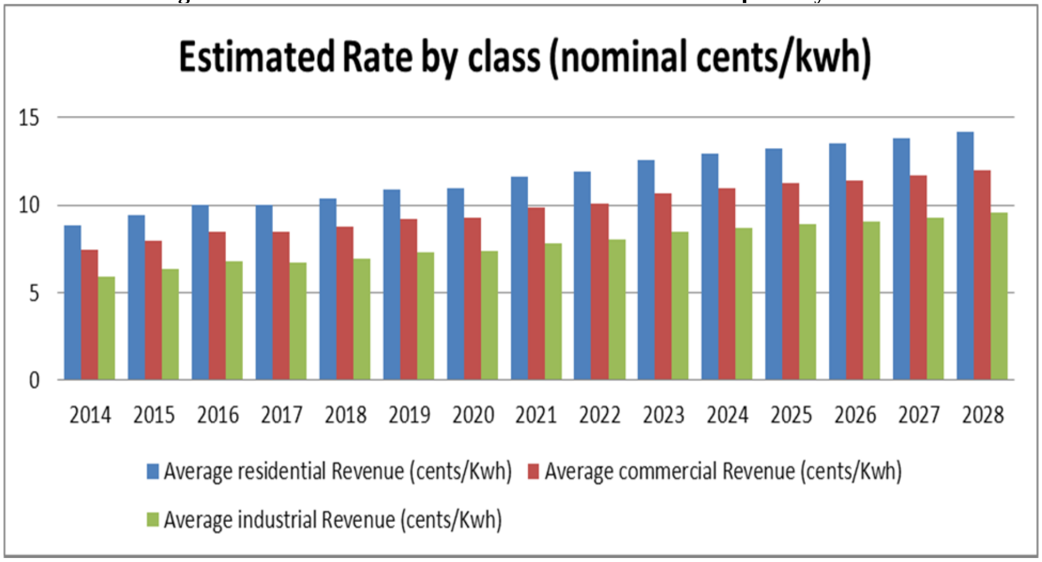


Figure 2-11: Preferred Resource Plan Estimated Rate Impacts by Class



2.9 Five-Year Action Plan

Table 2-4 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 2014-2018; however, the action items in 2013 also are provided. As shown, the major construction activities for the Big Stone Plant AQCS project and the Hoot Lake Plant MATS upgrade comprise a large portion of the five-year action plan. In 2017, the company likely will begin preliminary engineering for the planned resource addition to be operational in 2021.

Table 2-4: Five-Year Action Plan Activities

Year	Activity
2013	June 1 Triennial CIP filing for 2014, 2015, 2016 On-going construction of Big Stone Plant AQCS Project On-going construction of Hoot Lake MATS upgrade
2014	On-going construction of Big Stone Plant AQCS Project On-going construction of Hoot Lake MATS upgrade
2015	On-going construction of Big Stone Plant AQCS Project
2016	June 1 Triennial CIP filing for 2017, 2018, 2019
2017	Preliminary engineering for permit support and interconnection request (Hoot Lake replacement unit)
2018	File interconnection request, Certificate of Need for 2021 combustion turbine (Hoot Lake replacement unit) Environmental permitting for 2021 combustion turbine; initiate detailed design and procurement for 194 MW turbine (Hoot Lake replacement unit) Initiate work on utility-scale solar project to meet the Minnesota Solar Mandate by 2020

2.10 Conclusion

Otter Tail Power Company has continued to optimize existing resources and obtain supplemental capacity and energy through the wholesale market to meet both customer needs and resource adequacy requirements. This strategy will continue while balancing risk and economics. Cost-effective energy efficiency and demand response is used throughout the study period. The majority of the 78 Sensitivities show no new generation resource additions during the first five years. In the 2014-16 time period, construction on the Big Stone Plant Air Quality Control System ("AQCS") takes place. During 2014, construction on the precipitator upgrades and activated carbon injection system at Hoot Lake Plant Units No. 2 and No. 3 will be completed a full year in advance of the MATS requirement. The preferred resource plan presented here accomplishes the goal of meeting customer needs in the three jurisdictions that Otter Tail serves.

3 Current Outlook

The following underlined list provides a brief overview of the most prevalent changes that have occurred since the 2010 resource plan filing and the subsequent Baseload Diversification Study. These changes include both regulatory and economic factors that have had very tangible effects on the Company's current outlook.

3.1 Big Stone Plant Air Quality Control System (AQCS)

The AQCS project at Big Stone Plant is well underway. Engineering is 75 percent complete and ahead of schedule per the tracking index. The project's cumulative cash flow through September 2013 is $109,225,839 (27 percent) out of a total project budget of $405,175,000. Of the equipment, construction and service contracts, 27 out of 31 have been awarded. The total value of these contracts is $284,183,046. The foundations are nearly complete. The structural steel for the scrubber and baghouse, as well as the selective catalytic reduction system is being erected. The project remains on-track for cutover to the Big Stone Plant in 2015, with startup and testing to follow. See Appendix L for photographs of progress on the Big Stone AQCS Project.

3.2 Hoot Lake Plant MATS (Mercury and Air Toxics Standard) Upgrade

The MATS Upgrade project also is on schedule. The Activated Carbon Injection ("ACI") system is being installed and the ACI silo has been set on the foundation. The components for the electrostatic precipitator ("ESP") upgrade are being fabricated in Cleveland, Ohio. The new transformer/rectifier sets are on order for shipping to the site in early 2014. The Hoot Lake maintenance outage for installation of the ESP components is scheduled for April/May 2014. Beginning in June 2014, testing will begin and the system will be operational for the MATS compliance deadline of April 2015. The current projected final cost of the project remains at $8,600,000. See Appendix L for photographs of progress on the Hoot Lake Plant MATS Project.

The Hoot Lake Plant replacement is the main focus of the current resource plan. Strategist modeling runs show new gas generation being added in 2019 in the Energy Market Off sensitivities or 2021 in the Energy Market On sensitivities. The replacement in the majority of the sensitivities is a large simple-cycle combustion turbine. Permitting would begin about four years in advance of the commercial operation date.

3.3 Coordination with Midcontinent ISO with regards to outage scheduling

All outages are scheduled with the Midcontinent ISO. The Company has communicated with the Midcontinent ISO well in advance for the planned outage at Hoot Lake to install the MATS upgrade, as well as the planned outage at Big Stone Plant to install the AQCS. No potential reliability issues have been brought forward by Midcontinent ISO or are anticipated by the Company.

3.4 Midcontinent ISO Module E Resource Adequacy Obligation

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

The Midcontinent ISO's planning year 2013 resource adequacy reserve obligation is 14.2 percent. The 14.2 percent reserve obligation under Module E is implemented through two components: a load-based reserve margin (planning reserve margin) and generation accreditation. For the 2013 planning year, the planning reserve margin applied to the load forecast is 6.2 percent. For every MW of forecasted peak demand, net of accredited demand response, the Company must provide 1.062 MW of accredited capability. For the 2013 planning year, the Company's aggregate equivalent forced outage rate is roughly 5.9 percent. Otter Tail's generators are accredited based on historical plant performance. Each resource's historical performance data is used to calculate a probability that it will be available to operate when called upon. The probability is applied to the resource's demonstrated capability under defined conditions and lowers the accreditation of that resource from its demonstrated capability. Because the accreditation of resources is specific to each market participant and each resource, the effective reserve margin for each market participant can vary. Module E rules result in an effective reserve obligation specific to Otter Tail that is lower than the 14.2 percent regional reserve obligation due to the accreditations of the Company's units. Otter Tail's effective reserve obligation is closer to 12.1 percent for the 2013 planning year. This 12.1 percent is comprised of the 6.2 percent planning reserve margin on the peak demand forecast and an estimated aggregate equivalent forced outage rate of roughly 5.9 percent applied to the generation resources, excluding wind. The Module E resource adequacy construct provides incentive to improve plant performance and availability to maximize generator accreditation under Module E.

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

Wind generation is accredited based on unit specific historical capacity factors. Accreditation for the 2013 planning year for the Company's wind farms varied from 27 percent at the Luverne Wind Farm to 15 percent at the Edgeley Wind Farm.

Otter Tail has successfully registered the load management system and retail firm service level contracts under Module E as Demand Resources. The accredited capability of these resources is subtracted from the Company's forecast demand prior to calculating the planning reserve margin. Otter Tail's accredited Demand Resources for planning year 2013 totaled 30 MW. This accreditation is based on its summer capability, which is when Midcontinent ISO experiences its annual peak demand.

3.5 Market Conditions in the Midcontinent ISO

Otter Tail has added 62.4MW of additional wind capability to its resource mix since 2010. The Midcontinent ISO continues to see even more wind resources in the region. Additional projects are moving forward to take advantage of the soon to expire Production Tax Credit ("PTC"). Wholesale energy prices remain low following the economic recession, and also 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:

2010: $28.00/MWh
2011: $24.80/MWh
2012: $23.84/MWh
2013 (YTD September 30): $27.33/MWh

Capacity values in the Midcontinent ISO centralized market have remained at or near zero since 2010 due to excess reserves. However, due to pending coal plant retirements as we approach the compliance deadline for the Mercury and Air Toxics Standards ("MATS"), reserve margins likely will tighten. The forward capacity market has seen significant upward pressure as these uncertainties weigh on market participants. The Midcontinent ISO has recently projected the possibility of capacity shortfalls ranging from 3GW to 7GW starting in 2016. Otter Tail Power Company was able to purchase capacity to fulfill its currently anticipated capacity requirements through May 2021 at prices well below the cost of new construction.

3.6 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 with a compliance date of May 3, 2013. The new standards include varying combinations of emissions limitations, operating limitations, maintenance requirements, performance tests, recordkeeping requirements, and reporting requirements depending on the size and use of the engine. Otter Tail currently contracts for roughly 7.5 MW of accredited capacity with customers who own generators that are impacted by these standards. Otter Tail also owns several small units, totaling about 4 MW, affected by the rule. The rule in its current form allows us to continue to use customer-owned and company-owned engines as we have in the past. However, several parties are challenged to prohibit the use of engines for demand-response programs unless expensive emissions control equipment is installed. Should the challengers be successful, it may not be economical for engines to continue participating in the accreditation program. For now, the Company is assuming this capacity will be available in the future.

3.7 Climate Change Legislation Uncertainty

The Minnesota legislature has a state CO_2 reduction goal of 15 percent by 2015, 30 percent by 2025, and 80 percent by 2050. The Minnesota Commission uses a CO_2 value of $9-$34 per ton for evaluation of all future resource additions. There is currently no federal climate change legislation. The Environmental Protection Agency issued an endangerment finding on December 7, 2009, that paves the way for regulation of greenhouse gases under the existing Clean Air Act, regardless of whether Congress takes action.

3.8 Renewable Energy Objectives and Standards

Otter Tail was required to make a good faith effort to comply with the state REO through 2011. In 2012 the requirement switched to an RES. To date the Company has met the REO and RES targets. The state requirements[2] increase in a step-wise fashion, consisting of:

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

The Company is also obligated to meet an REO beginning in 2015 in both North Dakota and South Dakota to generate or procure 10 percent of annual retail sales from renewable or recycled energy. Otter Tail has joined the Midwest Renewable Energy Tracking System ("M-RETS") and uses this system to track and report compliance with REO and RES targets.

3.9 DSM and Conservation Requirements

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

3.10 Projected Load and Capability

Appendix B provides Otter Tail's Annual Electric Utility Report, which includes Otter Tail's forecast in detail. Figure 3-1 below shows the historical and projected non-coincident summer peak demand by season through the study period to 2028. Figure 3-2 shows historic and forecast annual energy requirements by customer class. The historic and forecast values have existing conservation programs embedded, whereas the forecasted values exclude new conservation programs. Otter Tail's energy requirements are driven equally by residential and commercial customers, creating an annual load factor of approximately 70 percent. Otter Tail projects that by the end of the study period, large commercial and industrial loads will increase to roughly 60 percent of the Company's retail sales.

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

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

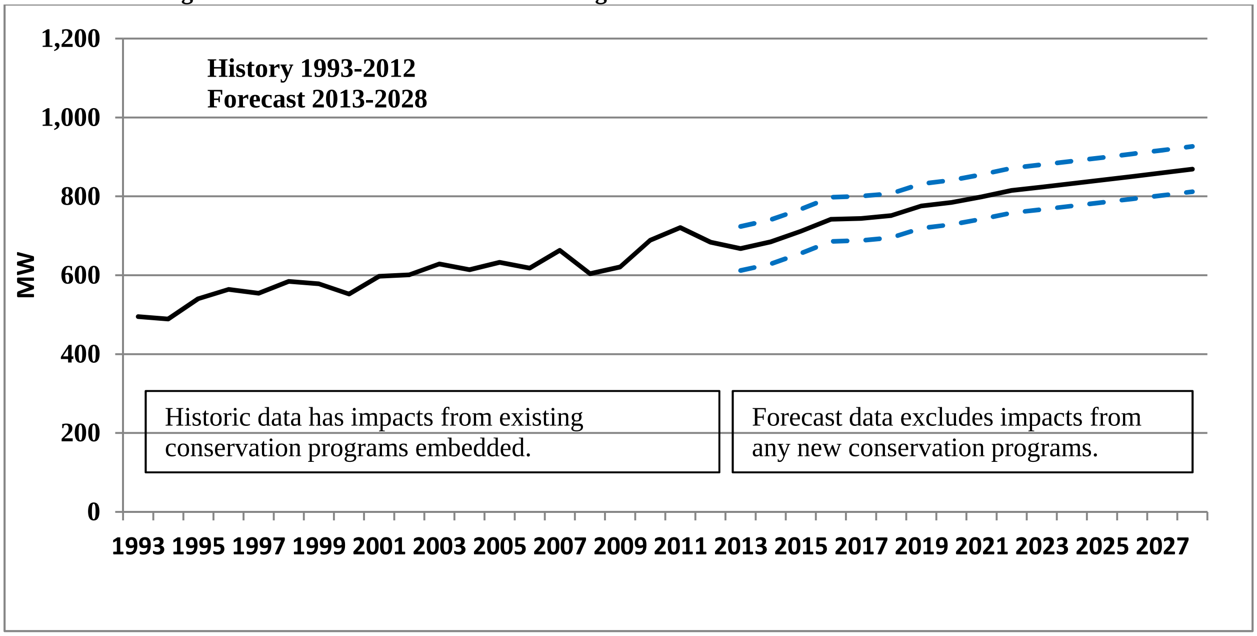
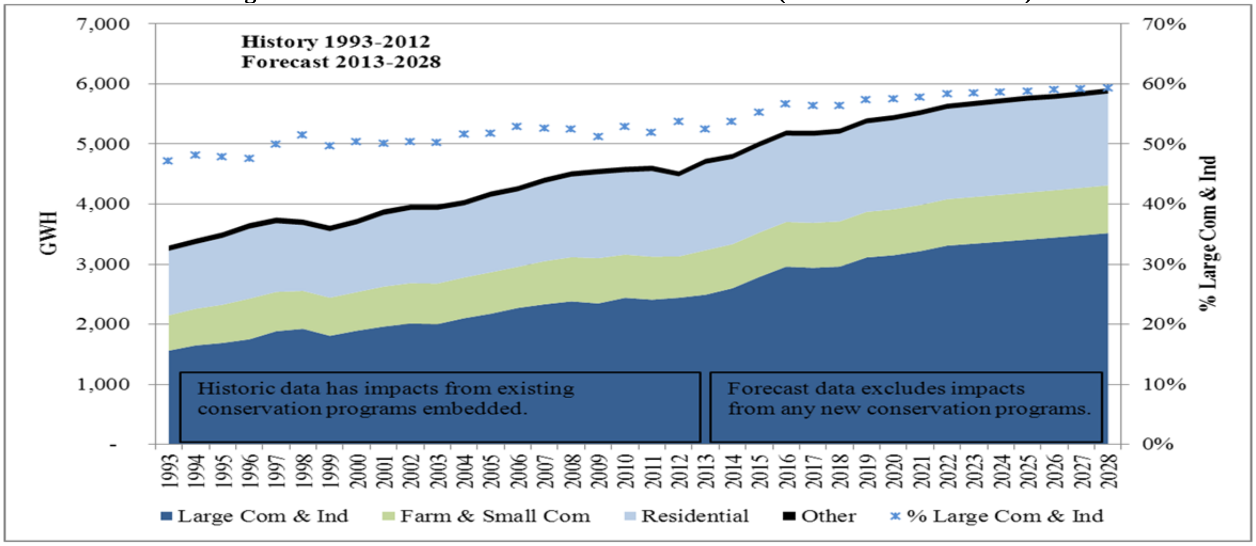


Figure 3-2: Historic and Forecast Annual Retail Sales (Losses are not included)



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

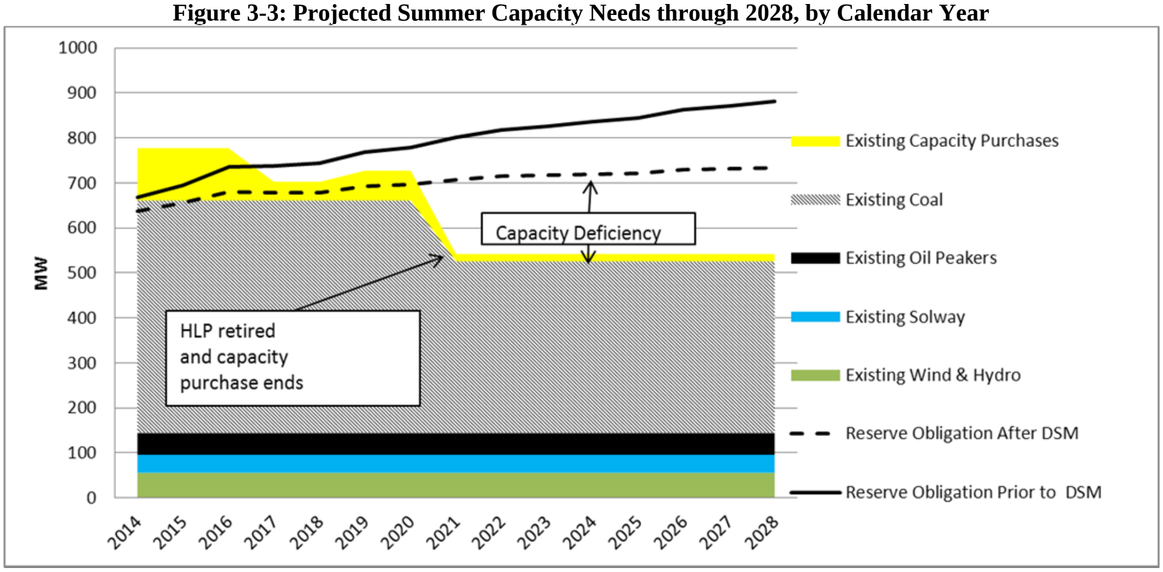
Current Outlook 3-6

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

Table 3-1: Summer 2014-2028 Load and Capability Prior to Preferred Plan Information

Planning Year	Coincident 50/50 Forecasted Demand (MW)	Accredited Demand Response (MW)	Planning Reserve Margin (6.2%)	Transmission Losses	Reserve Obligation Net of Accredited Demand Response (MW)	Aggregate Capacity (ZRCs)	Local Capacity (ZRCs)	External Capacity (ZRCs)	Net Transaction Capacity (ZRCs)	Total Accredited Capacity (ZRCs)	Projected Summer Deficiency (-MW)
2014	603.6	-26.0	35.8	28.2	641.6	608.5	64.8	4.5	100.0	777.8	136.2
2015	628.5	-30.0	37.1	29.2	664.8	608.5	64.8	4.5	100.0	777.8	113.0
2016	657.0	-41.0	38.2	30.1	684.2	608.5	64.8	4.5	100.0	777.8	93.6
2017	658.5	-39.0	38.4	30.2	688.2	608.5	64.8	4.5	25.0	702.8	14.6
2018	664.7	-39.0	38.8	30.5	695.1	608.5	64.8	4.5	25.0	702.8	7.7
2019	687.2	-43.0	39.9	31.4	715.6	608.5	64.8	4.5	50.0	727.8	12.2
2020	695.4	-43.0	40.4	31.8	724.7	608.5	64.8	4.5	50.0	727.8	3.1
2021	708.2	-50.0	40.8	32.1	731.1	473.1	64.8	4.5	0.0	542.4	-188.7
2022	722.9	-51.0	41.7	32.8	746.4	473.1	64.8	4.5	0.0	542.4	-204.0
2023	730.5	-51.0	42.1	33.2	754.8	473.1	64.8	4.5	0.0	542.4	-212.4
2024	738.2	-51.0	42.6	33.5	763.4	473.1	64.8	4.5	0.0	542.4	-221.0
2025	746.0	-51.0	43.1	33.9	772.0	473.1	64.8	4.5	0.0	542.4	-229.6
2026	754.0	-56.0	43.3	34.1	775.3	473.1	64.8	4.5	0.0	542.4	-232.9
2027	762.0	-56.0	43.8	34.5	784.3	473.1	64.8	4.5	0.0	542.4	-241.9
2028	770.2	-56.0	44.3	34.9	793.4	473.1	64.8	4.5	0.0	542.4	-251.0

Figure 3-3: Projected Summer Capacity Needs through 2028, by Calendar Year



As shown, Otter Tail expects deficiencies to begin in 2021 when the existing capacity purchase agreements end and the Hoot Lake units 2 and 3 are planned to retire. Otter Tail is a winter peaking utility but for modeling purposes bases its capacity resource need on the summer season as required by Midcontinent ISO resource adequacy rules. Although the summer season drives capacity needs, the entire year is evaluated for the Company's energy needs.

4 Plan Development

4.1 Plan Objectives

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

4.2 Planning Tools

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

	Capital Cost
	+ Base Revenue
	+ Total System Cost
	<u>+ Emissions Externalities</u>
MINIMIZE Net Present Value:	**Total Societal Costs (or Revenue Requirements)**

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

Emissions externalities were used in 42 of the 78 sensitivities. The remaining 36 sensitivities did not have emissions externalities applied.

The net present value of revenue requirements evaluated by the model includes end-effects calculations. End-effects calculations are used to analyze differences between alternatives after the planning period's horizon. End effects are significant in determining the optimal rankings of plans based on long-run economic advantages. Differences among alternatives are due to different operating characteristics and lives and end-effects analysis ensures that those characteristics are adequately considered for capital intensive units that may be added late in the planning period. The end effects result is used to augment the planning period result to account for the cost of replacing the resources and for differences in operating cost after the planning period. In all scenarios, the end-effects period was assumed to be infinite. Therefore, the total societal costs, or revenue requirements, were considered for the study period of 2014-2028, plus end effects.

4.3 Planning Process

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

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

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

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

Generation and Fuel Module – ("GAF")
Operational specifications and performance parameters of existing and potential thermal resources, hydro units, and transactions (including owned wind and power purchase agreements) were entered in the Strategist database. Capacity accreditation was based on the 2013-2014 planning year ratings by the Midcontinent ISO and any known or anticipated adjustments to accreditations in future years. The data for the thermal resources included heat rates, emissions, maintenance schedules, and maximum and minimum capability. Fuel price forecasts for oil, coal, and natural gas were also represented in the GAF. A tie line to the Midcontinent ISO energy market was represented along with a corresponding energy market price forecast. Wind generation resources were provided a profile for generation output based on historical performance. The GAF also includes cost data for fixed and variable operation and maintenance expenses and contract prices for energy and capacity.

Capital Expenditures – ("CER")
Planned capital projects unique to each resource were represented in the model. Non-project specific annual capital expenses were projected over the long-term. Capital projects associated with potential resources were also entered in the CER module along with an expenditure profile and specified tax life and book life.

Proview Capacity Expansion – ("PRV")
The Proview Module in Strategist was set up to evaluate a variety of potential resource alternatives subject to the objective function to minimize total societal costs, or revenue requirements. As part of a robust planning process, the Company uses Proview to evaluate a variety of sensitivities to meet the requirements of the resource plan filing and any known or expected regulatory or economic conditions. Otter Tail ran the model from 2014 through 2028 to capture the full 15 years in the study period. Model results from the Proview runs were compared and evaluated for reasonability and compliance with all constraints.

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

5 Preferred Resource Plan

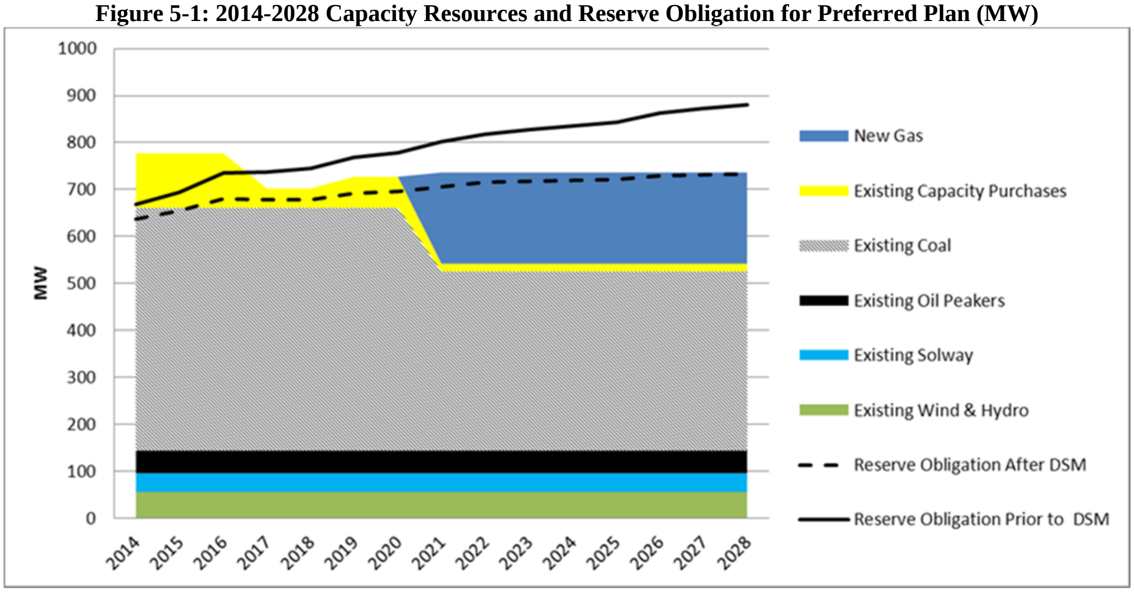
The preferred resource plan identifies possible resources that could be used to serve customer loads over the entire 2014 – 2028 resource planning period. It also details Otter Tail's expected activities during the first five years of the planning period. This section first discusses details associated with the preferred resource plan. Then it presents the results for the scenarios required by the Minnesota Rules for resource plan filings, including high and low load growth scenarios, externality scenarios, and renewable and conservation scenarios. The Company's preferred resource plan, presented in Table 5-1, shows the resource additions anticipated for the planning period.

Table 5-1: Preferred Plan Resource Additions

Resource Plan (MW) - Based on Nameplate ratings		
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021	211 MW frame NG CT	Commercial Operation of frame, natural gas-fired, simple cycle combustion turbine.
2022		
2023		
2024		
2025		
2026		
2027		
2028		

As Figure 5-1 shows, a new natural gas 211 MW combustion unit resource is added in 2021.

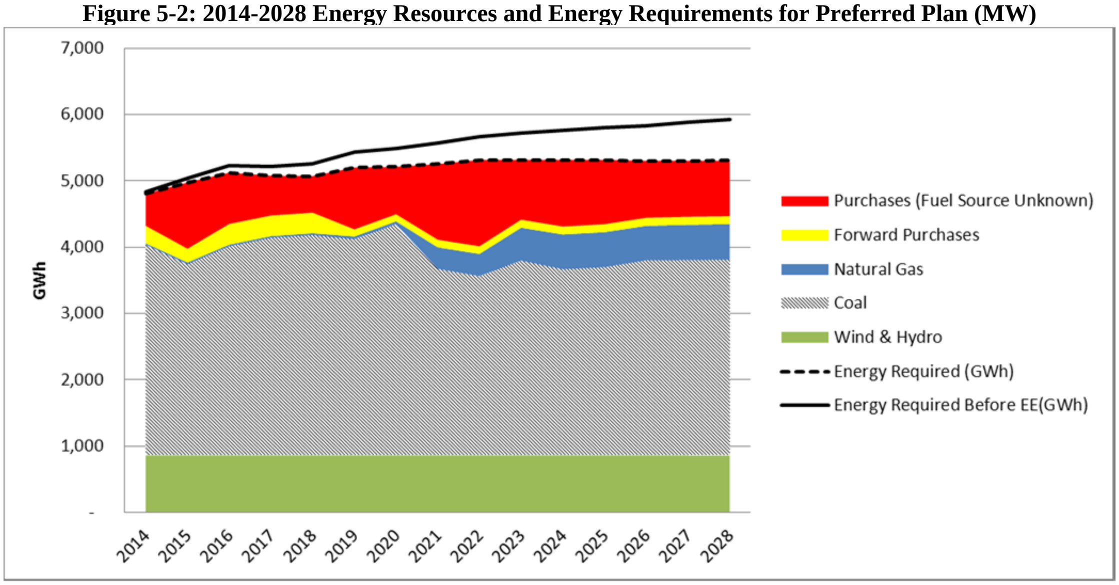
Figure 5-1: 2014-2028 Capacity Resources and Reserve Obligation for Preferred Plan (MW)



5-2 Preferred Resource Plan

Figure 5-2 shows the energy sources in the preferred plan by fuel type. Conservation contributes a significant portion to the Company's future energy needs, as do wind generation, continued market opportunity purchases, and natural gas generation.

Figure 5-2: 2014-2028 Energy Resources and Energy Requirements for Preferred Plan (MW)



5.1 Preferred Resource Plan Description

The Otter Tail preferred resource plan is the least cost plan selected by the Strategist model under the Company's base case assumptions, totaling $3.376B in NPVRR in 2014$. The Company's preferred plan is Energy Market On sensitivity No. 22 from Appendix I. Following is a description and comment on each of the new demand response and energy efficiency resources used in the preferred plan.

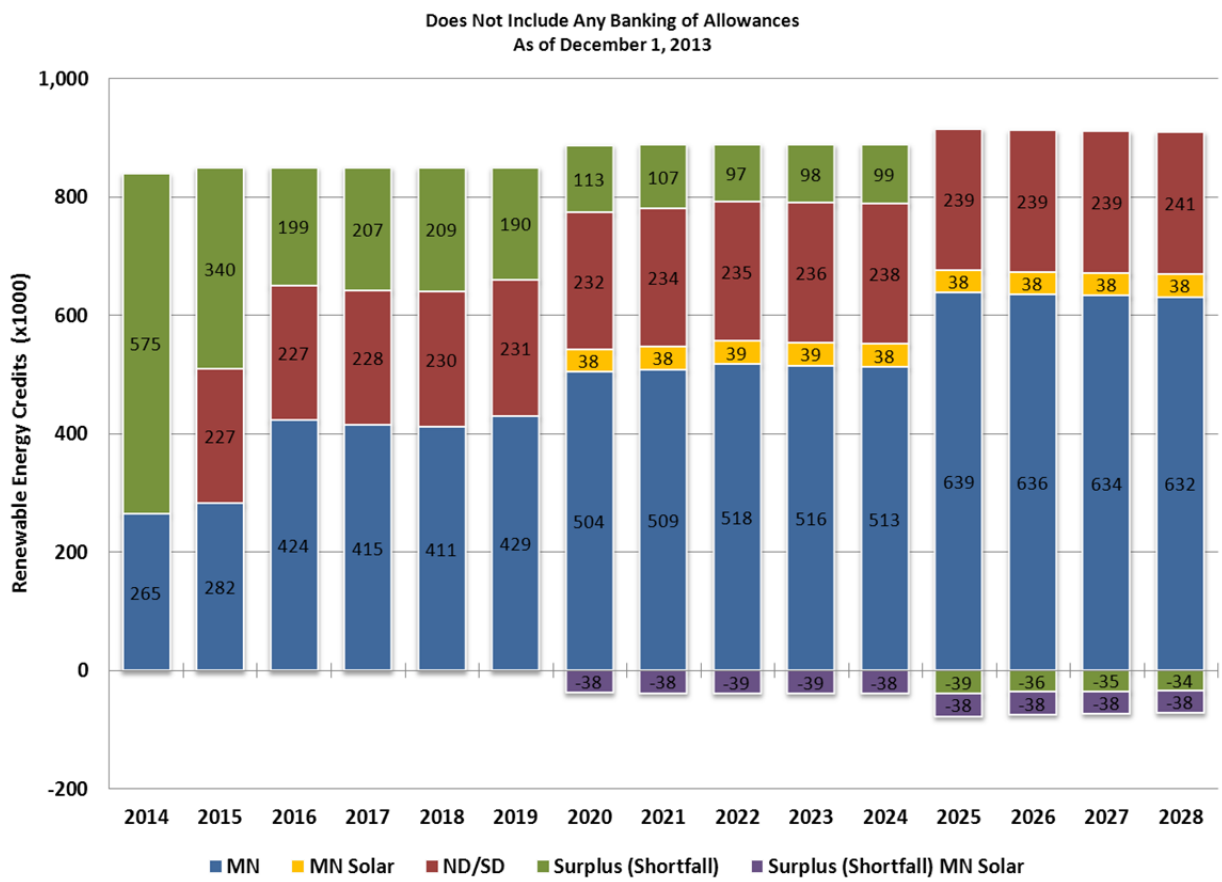
- **1.5 % CIP** – The model uses an annual energy efficiency and conservation alternative for Minnesota load that is 1.5 percent of average retail sales for the prior three years. By 2028, summer peak demand impacts from energy efficiency and conservation are expected to be 91 MW, not including the reserve margin savings.

- **Demand Response –** Demand response includes both load management capability and customer contracts that allow load shedding to a firm service level. In the preferred plan, demand response capability was selected to increase annually and reach 15 MW of additional summer season capability by 2028. To allow the Company time to confirm measurement and verification capability of incrementally new demand response, the new demand response was stair-stepped in every five years in 5 MW increments.

5.2 REO/RES Compliance

Figure 5-3 represents the planned compliance with REO/RES regulation in all jurisdictions under the preferred plan.

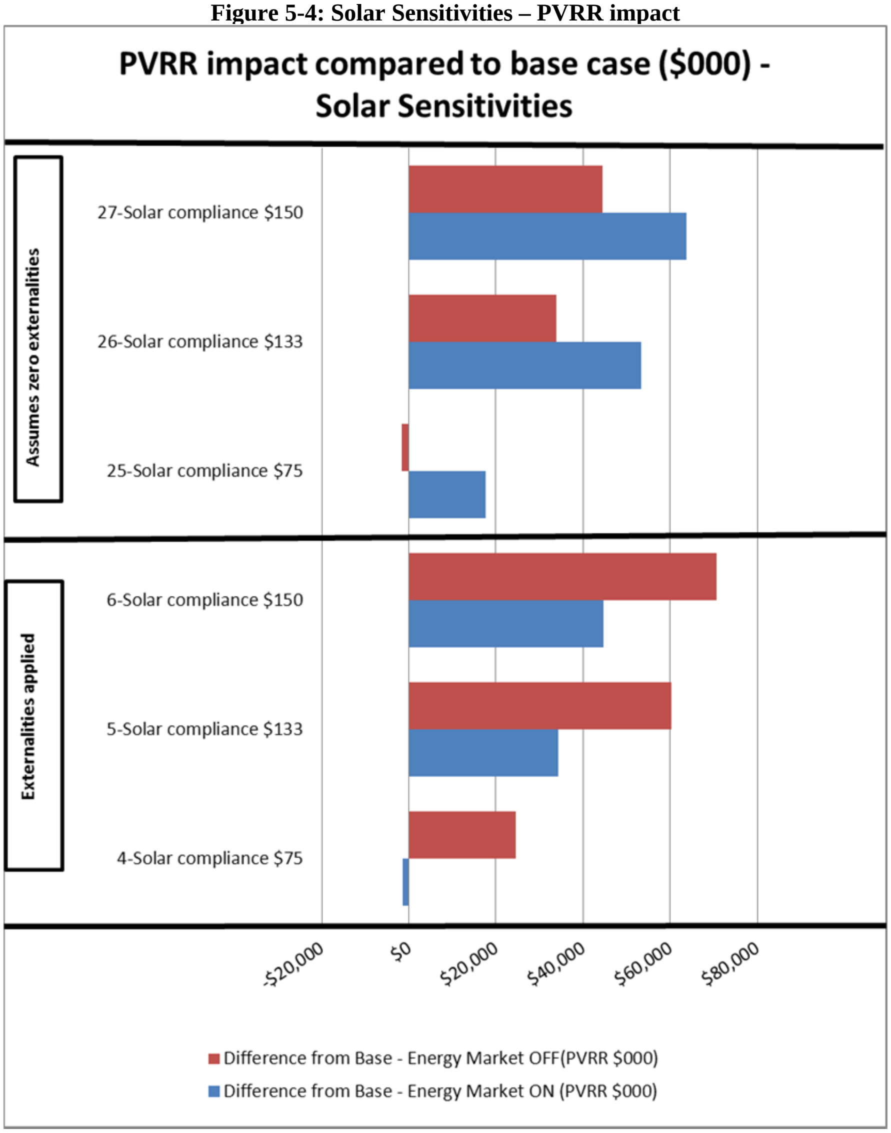
Figure 5-3: Compliance with REO/RES Regulation in All Jurisdictions



5-4 Preferred Resource Plan

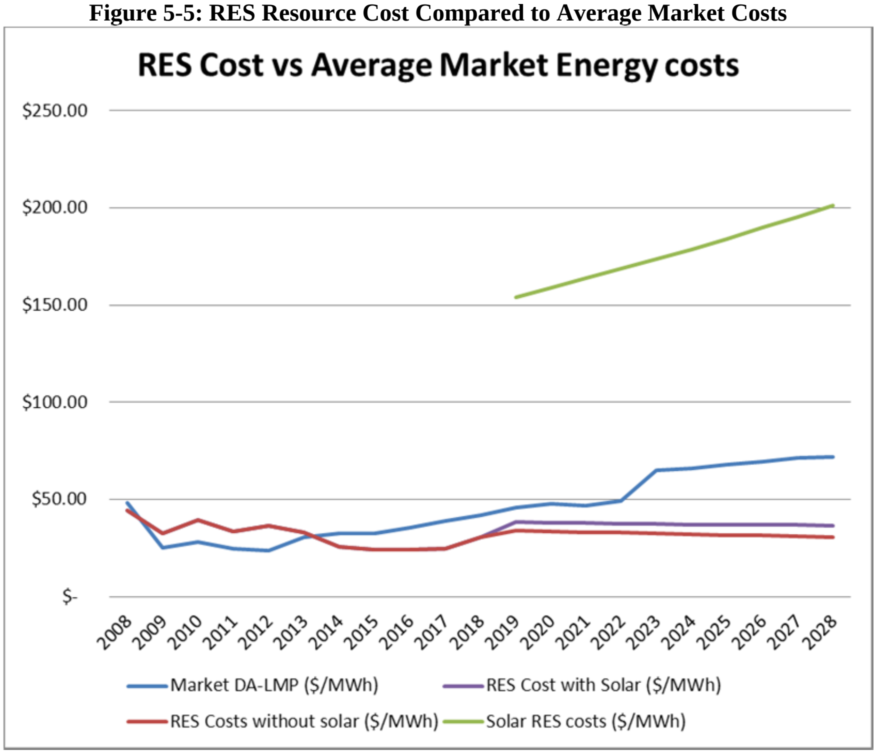
Otter Tail expects to have surplus renewable energy credits until 2020 when the solar portion of the Minnesota RES begins. The solar portion of the RES is a new Minnesota requirement enacted in 2013 to be effective in 2020. The preferred plan does not select solar resources as part of its least cost plan. The Company included 12 solar compliance sensitivities (Energy Market On and Energy Market Off sensitivities numbered 4, 5, 6, 25, 26 and 27 from Appendix I), which included modeling solar purchased power agreements at different price levels to determine the impact of meeting the solar RES. Figure 5-4 shows the impact on the PVRR for the solar compliance sensitivities relative to the base cases. Otter Tail will continue to monitor and evaluate potential solar opportunities on its system.

Figure 5-4: Solar Sensitivities – PVRR impact



To estimate the cost/benefit of RES compliance, Otter Tail compared the cost of Otter Tail's RES eligible resources to the market energy costs. Figure 5-5 shows the comparison. Historical values are used for 2008 through 2012. Forecasted values are used for 2013 through 2028. When the average day-ahead market price is below the RES cost it is a "cost" year (2009-2013). When the average day-ahead market price is above the RES cost, it is a "benefit" year (2008, 2014-2028).

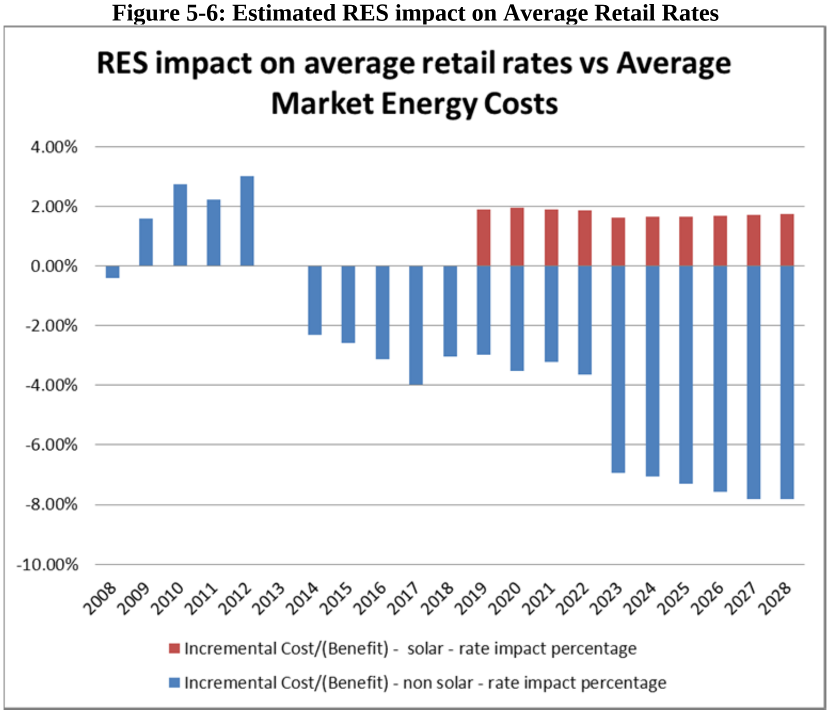
Figure 5-5: RES Resource Cost Compared to Average Market Costs



5-6 Preferred Resource Plan

Figure 5-6 shows the estimated impact of the RES on average retail rates when comparing RES resources to the average energy market price. The solar portion of the RES is estimated to have a 2 percent increase in rates while the remainder of the RES is expected to have a benefit when compared to the average energy market prices (Figure 5-6 does not attempt to compare the cost/benefit of the RES additions to alternative non-market resources). The wind portion of the RES provides 19 percent of the Company's system-wide energy requirement while the solar portion provides 1.5 percent of the Company's Minnesota load (0.75 percent of system-wide energy).

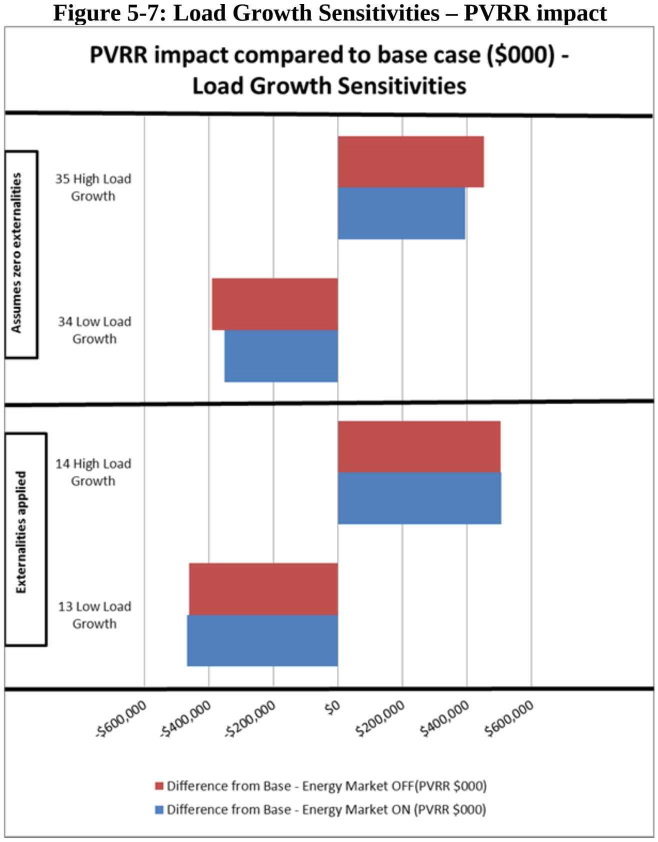
Figure 5-6: Estimated RES impact on Average Retail Rates



5.3 Load Growth Scenarios

The Company included four low load growth sensitivities (Energy Market On and Energy Market Off sensitivities numbered 13 and 34 from Appendix I) and four high load growth sensitivities (Energy Market On and Energy Market Off sensitivities numbered 14 and 35 from Appendix I). As shown in Figure 5-7, the low load growth sensitivities results in lower total revenue requirements and fewer resource additions. The high load growth sensitivities result in higher total revenue requirements and more resource additions.

Figure 5-7: Load Growth Sensitivities – PVRR impact



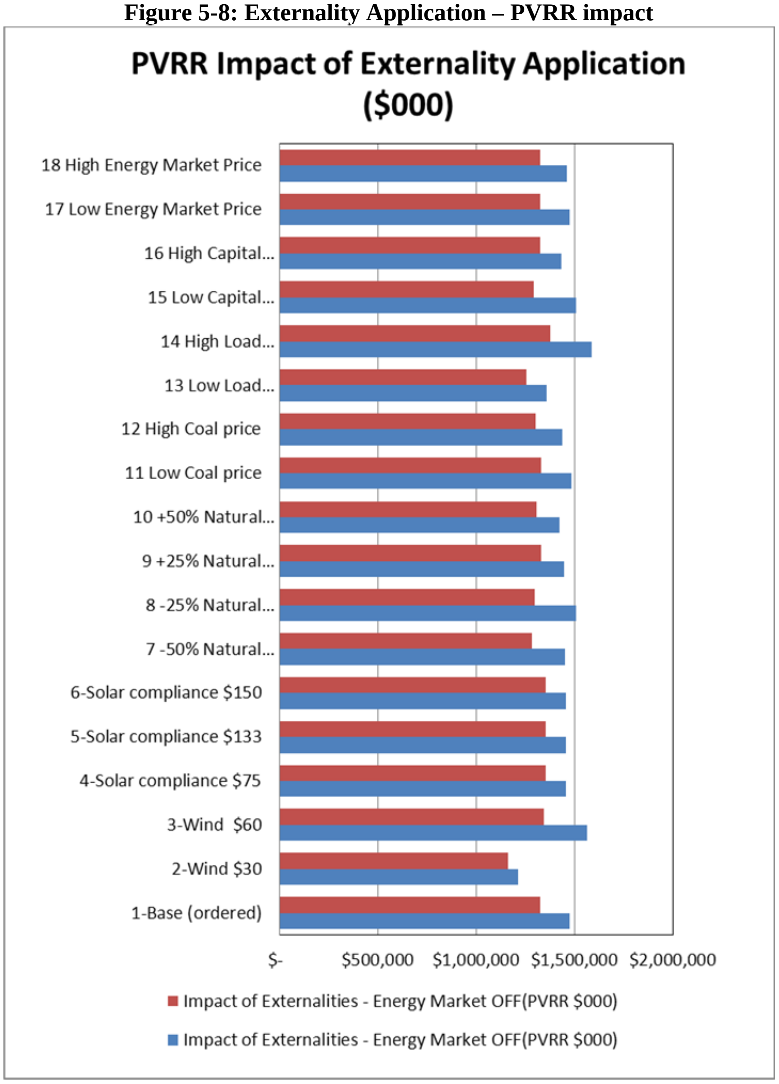
5.4 Environmental Externality Scenarios

The Company evaluated 42 sensitivities where environmental externalities were applied (Energy Market On and Energy Market Off sensitivities 1 thru 21 from Appendix I).

The assumptions for the high (Energy Market On and Energy Market Off sensitivity 20 from Appendix I) and low (Energy Market On and Energy Market Off sensitivity 19 from Appendix I) environmental externality values were taken from the June 5, 2013, *Notice of Revised Updated Environmental Externality Values* as provided by the Commission for rural Minnesota. The high and low CO_2 values were $34 and $9 respectively starting in 2017. For the mid-externality sensitivities, an average of the high and low values was used. In all externality sensitivities, externality values were escalated 3 percent for inflation.

Figure 5-8 shows the impact of externality values on the PVRR. The PVRR for sensitivities 1 through 18 (which use the mid-point externality values) are compared to their zero externality counterpart sensitivities 22 through 39. The average increase to the PVRR is approximately $1.4 billion.

Figure 5-8: Externality Application – PVRR impact



Customers benefit from one uniform plan across the jurisdictions through (1) economy of scale, (2) reduced administrative and ratemaking burden by not having to "jurisdictionalize" the plan, and (3) reduced complexity in operating the system. The Company recognizes that the preferred plan may change as CO_2 regulation becomes defined. The preferred plan provides the greatest flexibility in meeting those changes.

5.5 Emissions and Greenhouse Gas Reduction Goal

The preferred plan shows a reduction in emissions from Otter Tail's historical levels. Figure 5-9 shows the estimated emissions for SO_2 and NO_x. Figure 5-10 shows the estimated emissions for CO_2. Figure 5-11 shows the estimated emissions for mercury. The solid lines indicate historical levels of emissions (2005 to 2012) for Otter Tail-owned units. The dashed lines (2014 to 2028) indicate the estimated emissions of the preferred plan for Otter Tail-owned units.

Figure 5-9: SO_2 and NO_x Emissions

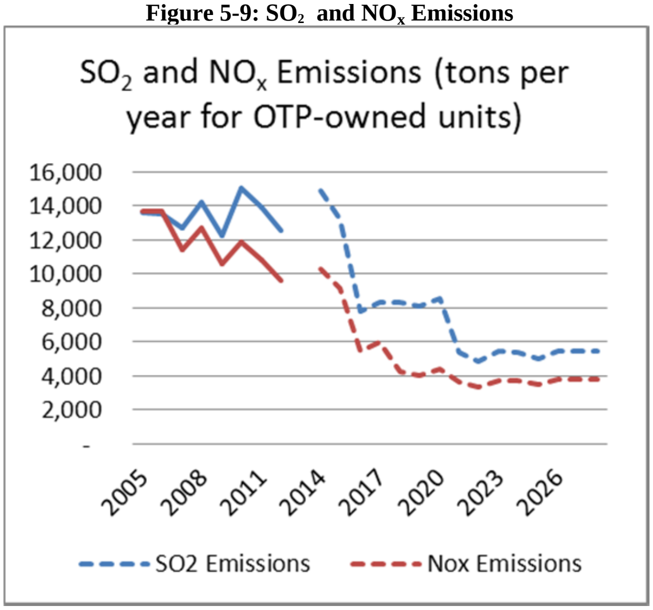
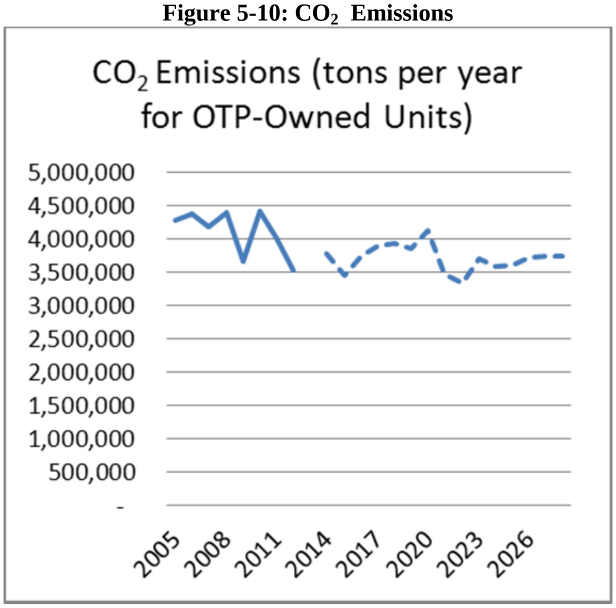
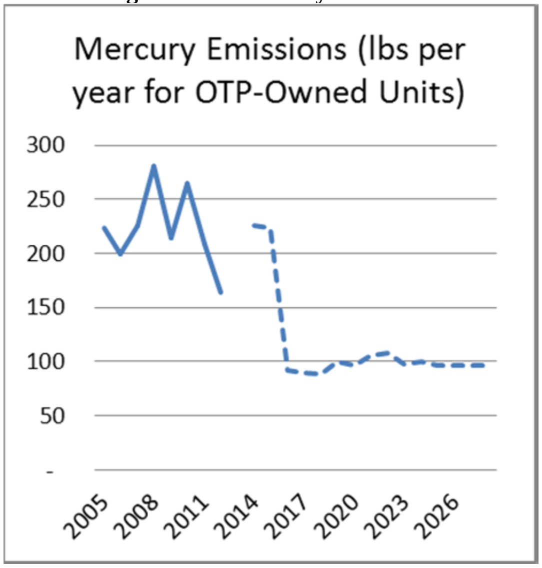


Figure 5-10: CO_2 Emissions



5-10 Preferred Resource Plan

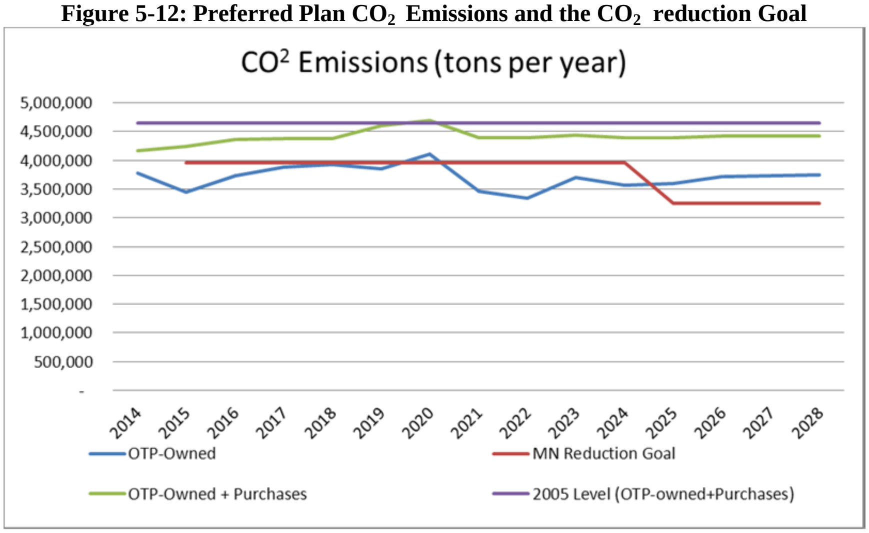
Figure 5-11: Mercury Emissions



Minnesota Statutes §216H.02 states that "It is the goal of the state to reduce greenhouse gas emissions to a level of at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050." Sensitivity No. 21 from Appendix I shows the resource additions to meet the CO_2 reduction goal for Otter Tail's system. Within this sensitivity, the Energy Market Off sensitivity adds 350 MW more wind than the base case and increases the PVRR by more than $87 million. The Energy Market On sensitivity adds 200 MW of wind more than the base case and increases the PVRR by over $39 million.

Figure 5-12 shows the preferred plan CO_2 emissions and how it compares with the CO_2 reduction goal and the 2005 level of CO_2 emissions. The 2005 level is estimated at 4,653,930 tons of CO_2 (3,745,676 tons from Otter Tail-owned units and 908,254 tons assumed for purchased energy based on the 2005 MRO west regional average CO_2 /MWh of 1,821.64 lbs). For market purchases, 1,623.64 lbs of CO_2 are applied to each MWh of energy purchased.

Figure 5-12: Preferred Plan CO_2 Emissions and the CO_2 reduction Goal



5.6 50% and 75% Conservation and Renewable Scenarios

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

Table 5-2 presents the energy calculation for determining whether the conservation and renewable energy target was met. The preferred plan achieves the 50 percent target. The combined additions of CIP and a 50 MW wind resource would meet the 75 percent target of the Company's future energy needs in the Minnesota jurisdiction, assuming only 50 percent of new wind resources are allocated to Minnesota load (Otter Tail notes that the specific jurisdictional allocation of the wind resource might not be proportional among its jurisdictions if the resource addition is not able to be demonstrated to be part of a least cost resource plan).

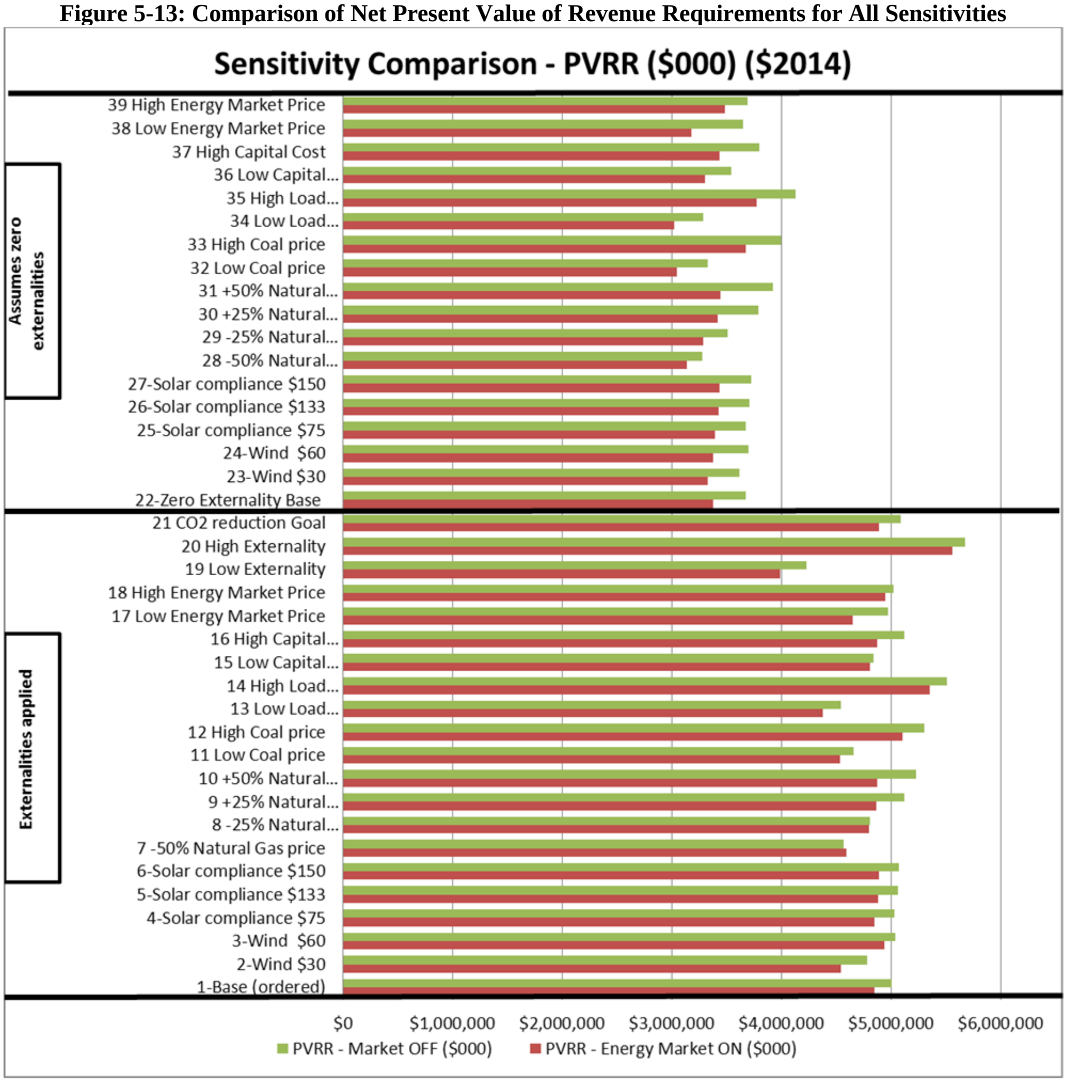
Table 5-2: 50% and 75% Renewable and Conservation as Percent of Total New MN Energy Requirements

	Preferred Plan and the 50% Renewable and Conservation goal			75% Renewable and Conservation goal		
	1.5% Conservation (GWh)	MN 50% Share of 50 MW Wind (GWh)	Total (GWh)	1.5% Conservation (GWh)	MN 50% Share of 50 MW Wind (GWh)	Total (GWh)
New MN CIP	540	-	540	540	-	540
New Wind	-	0	0	-	82	82
Total	540	0	540	540	82	622
Percent of Total New MN Energy Requirements (= 827 GWh)	65%	0%	65%	65%	10%	75%

5.7 Additional Sensitivity Scenarios

Otter Tail evaluated additional sensitivities. They included variations in wind prices, solar prices, natural gas prices, coal prices, capital costs, energy and capacity market prices, and CO_2 reductions. A comparison of the net present value of revenue requirements for all scenarios is provided in Figure 5-13.

Figure 5-13: Comparison of Net Present Value of Revenue Requirements for All Sensitivities



6 Conclusion

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

This resource plan is straightforward in that the resulting generation additions are nearly the same in the majority of the sensitivities: No generation additions during years one through five with the first addition being a natural gas simple-cycle combustion turbine in either 2019 or 2021. The specific size, type and timing of the next resource can be more precisely addressed in the next resource plan.

The preferred plan improves environmental performance through implementation of DSM, renewable resources and environmental upgrades at existing facilities. The resource plan satisfies the regulatory and statutory requirements of all three jurisdictions that it serves.

6.1 Preferred Plan is in the Public Interest

The Company is committed to operating its generation facilities as efficiently as practicable while minimizing adverse effects on the environment. New resources have been selected that will meet the Company's needs while maintaining flexibility and limiting the risk of exposure to changes in financial, social and technological factors beyond its control. With no resource additions during the initial five-year period, 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. By using excess REC's generated in prior years, Otter Tail is compliant with the renewable energy objectives and standards across the entire Otter Tail tri-state system until 2025. 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.

The preferred plan will meet 65 percent of new energy requirements in Minnesota through renewable generation and increased levels of conservation by 2028. The plan satisfies all rules and requirements of the Minnesota statutes and rules, provides a clear concise report to interested parties of what Otter Tail intends to do to satisfy customer needs in the near term, and identifies the resources the Company is considering for viable options for the long term.

6.2 Socio-Economic Impacts of the Preferred Plan

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

6-2 Conclusion

Otter Tail's preferred plan maintains CO_2 emissions below the average level emitted in 2005. This achievement is largely due to greater use of conservation and renewable resources.

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

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

6.3 Five-Year Action Plan

The preferred plan will require considerable activity within the next five years to bring about the resources previously approved and those selected in the plan. Table 6-1 identifies the major activities and the approximate timelines for those activities, beginning with 2013. Some of these activities are already underway. There are many other related activities that will be taking place to support the major items identified in the table that will involve many stakeholders, regulatory agencies, and interested parties.

Table 6-1: Five-Year Action Plan Activities

Year	Activity
2013	June 1 Triennial CIP filing for 2014, 2015, 2016 On-going construction of Big Stone Plant AQCS Project On-going construction of Hoot Lake MATS upgrade
2014	On-going construction of Big Stone Plant AQCS Project On-going construction of Hoot Lake MATS upgrade
2015	On-going construction of Big Stone Plant AQCS Project
2016	June 1 Triennial CIP filing for 2017, 2018, 2019
2017	Preliminary engineering for permit support and interconnection request (Hoot Lake replacement unit)
2018	File interconnection request, Certificate of Need for 2021 combustion turbine (Hoot Lake replacement unit) Environmental permitting for 2021 combustion turbine; initiate detailed design and procurement for 194 MW turbine (Hoot Lake replacement unit) Initiate work on utility-scale solar project to meet the Minnesota Solar Mandate by 2020

CERTIFICATE OF SERVICE

RE: IN THE MATTER OF OTTER TAIL POWER COMPANY'S SUBMITTAL OF ITS 2014-2028 RESOURCE PLAN, DOCKET NO. E017/RP-13-961

I, Wendi A. Olson, hereby certify that I have this day served a copy of the following, or a summary thereof, on Dr. Burl W. Haar and Sharon Ferguson by e-filing and First Class mail, and to all other persons on the attached service list by electronic service or by First Class mail.

Otter Tail Power Company
2014-2028 Resource Plan

Dated this **2nd** day of **December**, **2013**.

/s/ WENDI A. OLSON

Wendi A. Olson
Regulatory Filing Coordinator
Otter Tail Power Company
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Appendix A: Plan Cross Reference

Table 1: *Status of 5-year Action Plan from 2010 IRP Docket No. E017/RP-10-623*

Table 2: *Minnesota Public Utilities Commission Orders since 2010 IRP Docket No. E017/RP-10-623*

Table 3: *Minnesota Statutes and Rules on IRPs*

Table 1: Status of 5-year Action Plan in 2010 IRP Docket No. E017/RP-10-623

Year	Activity	Status
2010	July 1 Triennial CIP filing for 2011, 2012, 2013.	Filed on June 29, 2010 (Docket No. E017/CIP-10-356).
	Implement marketing plan to meet DSM objectives	Included in January 1, 2011 marketing plan.
	Initiate Request for Proposal process for 2012 Wind Farm	62.4 MW Ashtabula III 25-year PPA signed; MN PUC approved August 22, 2013 (Docket No. E017/M-13-386).
	Initiate detailed evaluation of Hoot Lake Plant	Baseload Diversification Study completed and filed on October 3, 2012 (Docket No. E017/RP-10-623). Hoot Lake Plant MATS Project construction in progress.
	File environmental and regulatory permitting for Big Stone Plant AQCS BART project	ADP filed on October 8, 2010; MN PUC granted on January 23, 2012 (Docket No. E017/M-10-1082). Construction in progress.
	Execute Large Generator Interconnection Agreement for <50 MW aeroderivative combustion turbine	No CT needed until at least 2019.
	File environmental and regulatory permitting for 50 MW aeroderivative combustion turbine	No CT needed until at least 2019.
	Initiate detailed design on Big Stone Plant AQCS Project	ADP filed on October 8, 2010; MN PUC granted on January 23, 2012 (Docket No. E017/M-10-1082).
2011	No new action items initiated	
2012	Initiate construction on Big Stone AQCS Project	ADP filed on October 8, 2010; MN PUC granted on January 23, 2012 (Docket No. E017/M-10-1082). Construction in progress.
	Commercial operation of 2012 Wind Farm	62.4 MW Ashtabula III 25-year PPA signed; MN PUC approved on August 22, 2013 (Docket No. E017/M-13-386).
	Initiate detailed design and procurement for <50 MW aeroderivative combustion turbine	No CT needed until at least 2019.
	File Interconnection Request for 2017 combustion turbine	No CT needed until at least 2019.
2013	On-going construction of Big Stone Plant AQCS project	Quarterly reports filed with MN PUC; most recent compliance filing report made on October 11, 2013. (Docket No. E017/M-10-1082). Construction in progress.
	June 1 Triennial CIP filing for 2014, 2015, 2016	Filed on June 1, 2013 (Docket No. E017/CIP-13-277).
	Begin construction of <50 MW aeroderivative combustion turbine	No CT needed until at least 2019.
	File Certificate of Need, environmental permitting for 2017 combustion turbine	No CT needed until at least 2019.
2014	On-going construction of Big Stone Plant AQCS project	
	Commercial operation of <50 MW aeroderivative combustion turbine	No CT needed until at least 2019.
2015	Commercial operation of Big Stone Plant AQCS	Scheduled for October 1, 2015.

Table 2: Minnesota Public Utilities Commission Orders since 2010 IRP

Docket No. E017/RP-10-623 Order Approving Plan Subject to Conditions, Requiring Further filings, and Setting Requirements for Next Resource Plan, dated 2-9-2012		**Section/Reference**
1	Based on the entire record in this case, the Commission approves Otter Tail Power Company's 2011-2025 resource plan, as modified by the Company in response to the parties' comments and as further modified below. This approval does not extend to particular generation projects that are currently under review in other proceedings or will be subject to review in future proceedings, but is a general finding that the plans filed by Otter Tail appear to be reasonable in light of the entire record.	Not Applicable
2	Within nine months of the date of this order, the Company shall file a baseload diversification study, with a specific focus on evaluating retirement and repower options for the Hoot Lake Plant. That study shall include analysis of the transmission implications of all options studied, shall begin with 2011/2012 natural gas costs in analyzing natural gas generation options, and shall set forth the Company's analysis of the costs of all Environmental Protection Agency regulations that affect its operations and its plans for compliance.	Completed
3	The Company's next resource plan filing shall include, as sensitivity scenarios, the full scope of the baseload diversification study required above and shall include a comprehensive section on all Environmental Protection Agency rules that may affect its operations.	Appendix E - Environmental Issues
4	The Company shall add to its five-year action plan at least 50 megawatts of additional wind generation, assuming prices at the time of acquisition are reasonable.	62.4 MW Ashtabula III 25-year PPA signed; MN PUC approved 8-22-2013 (Docket No. E017/M-13-386).
5	In the modeling conducted in its next resource plan, the Company shall adopt a cut-off year to restrict the Strategist model from selecting market purchases. That plan shall include market purchases only in the short term, for fewer than five years, and as a bridge to delay the need for other resources.	2.6 Resource Plan Non-Technical Summary - Preferred Plan is in the Public Interest and Appendix I - IRP Sensitivity Summary (Sensitivity #1)
6	In its next resource plan, the Company shall include in its base case carbon dioxide costs equal to the mid-point of the Commission-approved range. It shall also include a low and a high range in sensitivity options.	5.4 Preferred Resource Plan - Environmental Externality Scenarios and Appendix F - Strategist Assumptions
7	In its next resource plan, the Company shall include in its base case sulfur dioxide costs, using the market cost of sulfur dioxide allowances.	Appendix F - Strategist Assumptions
8	In the modeling conducted in its next resource plan, the Company shall set the wind capacity credit at the most recent long-term wind capacity credit set by the Midcontinent Independent System Operator or at the average of its historical wind capacity credits.	2.2 Resource Plan Non-Technical Summary - Future Resource Needs
9	The Commission encourages the Company to expand its demand response and energy efficiency portfolios.	5.1 Preferred Resource Plan - Preferred Resource Plan Description
10	The Company shall make its next resource plan filing on or before December 1, 2013.	Completed

Docket No. E017/RP-10-623 Order Approving Baseload Diversification Study and Setting Requirements for Next Resource Plan, dated 3-25-2013			Section/Reference
1	The Commission hereby approves Otter Tail's proposal to retrofit Hoot Lake in 2015 and shut the plant down in 2020. Scenario 2020's assumptions will substitute for the Hoot Lake assumptions in Otter Tail's 2011–2025 resource plan and shall have the same effect as if they had been included in the plan approved by the Commission. The specific size, type, and timing of the Hoot Lake replacement units can be revisited as needed in Otter Tail's next resource plan.		Appendix I - IRP Sensitivity Summary
2	The Commission finds that Otter Tail's baseload diversification study meets the requirements of the Commission's February 9, 2012 order and hereby closes this docket with the understanding that Otter Tail will file its next resource plan no later than December 1, 2013.		Not Applicable
3	In its next resource plan, Otter Tail shall do the following:		
	a	Explain how the company has implemented MISO's new "reserve on coincident peak" load and capability calculations in its modeling;	3.4 Current Outlook - Midcontinent ISO Module E Resource Adequacy Obligation
	b	Evaluate greater potential for additional energy efficiency, demand response, renewable distributed generation, and combined heat and power resources;	Appendix D - Potential Resources Appendix K - Distributed Renewable Generation Appendix J - Combined Heat and Power Evaluation
	c	Discuss the company's coordination with MISO regarding its outage scheduling and how the company will manage potential reliability issues as a result of Hoot Lake Plant being offline; and	3.3 Current Outlook - Coordination with MISO with regards to outage scheduling
	d	Include expected timelines for retrofitting Hoot Lake (including installation and outage schedules) and for filing the necessary permitting documents for replacement natural gas facilities.	3.2 Current Outlook - Hoot Lake Plant MATS (Mercury and Air Toxics Standard) Upgrade
4	Otter Tail shall notify the Commission if the company submits a MATS extension request to the MPCA or EPA.		OTP has not sought a MATS extension for the Hoot Lake Plant.

Docket No. E017/RP-10-623 MN PUC letter dated 12-4-2012 to B. Gerhardson	Section/Reference
The Commission requests that utilities seeking SSR status for a facility that has been included in any of its past or pending resource plan filings with the Commission, or if the request may have cost implications in future rate cases or other cost recovery proceedings, to notify the Commission at the time the request is made to MISO. The submission may be designated as trade secret, if appropriate. Also, the filings should be made in the utility's pending or most recent resource plan filing docket.	OTP has not sought SSR status for a facility.

Docket No. E017/RP-10-623 Notice of Information in Future Resource Plan filings, dated 8-5-2013	Section/Reference
Utilities shall include in their resource plans filed after 8-1-2013 an explanation how the resource plan helps the utility achieve the greenhouse gas reduction goals, renewable energy standard, and solar energy standard as listed in the above-referenced legislation. (MN Statute Sec. 216B.2422, subd. 4)	5.2 Preferred Resource Plan - REO/RES Compliance
Utilities should consider adding to their initial resource plan filings, the supplemental information listed at page 4 of the Commission's 5-20-2013 Order regarding its completeness review of MP's resource plan in Docket E015/RP-13-53.	
How the addition of SO2 allowance prices would have impacted its base case and preferred plan;	Appendix F - Strategist Assumptions
How the use of unforced capacity would have impacted its base case and preferred plan;	None; unforced capacity used.
How the use of Commission-approved CO2 values from its November 2, 2012 Order affect its base case and preferred plan;	5.4 Preferred Resource Plan - Environmental Externality Scenarios and Appendix I - IRP Sensitivity Summary
How MP has considered water consumption issues and potential effects on aquatic life from water intake and discharge in its resource plan, both qualitatively and quantitatively.	Appendix E - Environmental Issues
How MP has taken into account possible effects of drought and high water temperature on generating plant availability in its modeling, including the results of modeling the range of these possible effects.	Appendix E - Environmental Issues
How MP has considered demand side management (DSM) programs in its resource plan, and the pros and cons of DSM being considered a reduction in load versus a resource to be chosen, including modeling a range of assumptions.	5.1 Preferred Resource Plan - Preferred Resource Plan Description
Utilities consider convening a stakeholder meeting prior to filing their initial IRPs to answer questions about assumptions used in the filing, for the purpose of responding to questions which could enhance parties' understanding of the filing and reducing the number of information requests parties may need to file.	Stakeholder meeting was held on 9-26-2013.

Docket E-999/CI-07-1199 **Order Establishing 2012 and 2013 Estimate of Future Carbon Dioxide Regulation Costs, dated 11-2-2012**		**Section/Reference**
1	The Commission maintains its estimate of the range of likely costs of CO_2 regulation at between $9 and $34 per ton of CO_2 for 2012 and 2013.	5.4 Preferred Resource Plan - Environmental Externality Scenarios and Appendix I - IRP Sensitivity Summary
2	Utilities shall begin applying the above range of CO_2 values in their resource planning as of 2017.	

Docket E-999/CI-11-852 **Minn. Statutes Sec. 216B.1691, Subd. 2e.**		**Section/Reference**
	Utilities were required to make initial report including clear narrative explanations of the modeling methods and the assumptions used in developing the cost and rate impacts.	OTP filed its Energy Cost Impact Report, on 10-24-2011
	The report must be updated and submitted in subsequent resource plans.	Figure 5-4 - Preferred Resource Plan

Table 3: Minnesota Statutes and Rules - IRPs

Statute	Subsection	Subject	Section/Reference
§216B.1612 Community-Based Energy Development	Subd. 5b - Priority for C-BED projects.	Utility shall include a description of its efforts to purchase energy from C-BED projects, including a list of the projects under contract and the amount of C-BED energy purchased.	Appendix H - C-BED Report
§216B.1691 Renewable Energy Objectives	Subd. 2a - Eligible energy technology standard.	Report on renewable energy objectives and standards.	Appendix G - REO/RES Compliance
	Subd. 2e - Rate impact of standard compliant; report.	Utility must submit a report containing an estimation of the rate impact of RES compliance.	Figure 5-4 - Preferred Resource Plan
	Subd. 2f - Solar energy standard	(a) Utility shall generate or procure sufficient electricity generated by solar energy to serve its retail electricity customers in Minnesota so that by the end of 2020, at least 1.5 percent of the utility's total retail electric sales to retail customers in Minnesota is generated by solar energy. At least ten percent of the 1.5 percent goal must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 20 kilowatts or less.	5.2 Preferred Resource Plan - REO/RES Compliance
		(c) It is an energy goal of the state of Minnesota that by 2030, ten percent of the retail electric sales in Minnesota be generated by solar energy.	Study concludes in 2028; this will be addressed in future resource plans.
§216B.241 Energy Conservation Improvement	Subd. 1c(b) - Energy saving goals.	Utility shall have an annual energy-savings goal equivalent to at least 1.5 percent of annual retail energy sales unless modified by the commissioner. The savings goals must be calculated based on the most recent three-year weather-normalized average.	3.9 Current Outlook - 2007 MN Legislature DSM and Conservation Requirements
§216B.2422 Resource Planning; Renewable Energy	Subd. 2 - Resource plan filing and approval.	Utility shall include the least cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources.	5.5 Preferred Resource Plan - 50% and 75% Conservation and Renewable Scenarios
	Subd. 3 - Environmental costs.	Utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings.	Appendix F - Externality Price Assumptions

	Subd. 4 - Preference for renewable energy facilities.	The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. The public interest determination must include whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f.	6.1 Conclusion - Preferred Plan is in the Public Interest
	Subd. 6 - Consolidation of resource planning and certificate of need.	Utility shall indicate in its resource plan whether it intends to site or construct a large energy facility.	6 Conclusion
§216B.2426 Opportunities for Distributed Generation	Distributed generation.	Report on opportunities for distributed generation.	Appendix K - Distributed Renewable Generation
§216H.02 Greenhouse Gas Emissions Control	Minnesota CO2 Goal	It is the goal of the state to reduce statewide greenhouse gas emissions to a level of at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050.	Study concludes in 2028; 2050 requirement will be addressed in future resource plans.
§216H.03 Failure to adopt greenhouse gas control plan.		Long-term increased emissions from power plants is prohibited and includes new construction, import from source that would contribute to emissions, and long-term PPA of more than 50MW of capacity or more for a term exceeding five years.	None planned.
§216H.06 Emissions consideration in resource planning.	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.	5.4 Preferred Resource Plan - Environmental Externality Scenarios and Appendix I - IRP Sensitivity Summary

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

Appendix B: Minnesota Electric Utility Annual Report

PUBLIC DOCUMENT – TRADE SECRET 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

7610.0120 REGISTRATION

ENTITY ID#	87
REPORT YEAR	2012
Number of Power Plants	14

UTILITY DETAILS

UTILITY NAME	OTTER TAIL POWER COMPANY
STREET ADDRESS	215 SOUTH CASCADE STREET
CITY	FERGUS FALLS
STATE	MN
ZIP CODE	56538-0496
TELEPHONE	218-739-8200
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	Private

CONTACT INFORMATION

CONTACT NAME	STACIE HEBERT
CONTACT TITLE	MANAGER, Supply Services
CONTACT STREET ADDRESS	215 SOUTH CASCADE STREET
CITY	FERGUS FALLS
STATE	MN
ZIP CODE	56538-0496
TELEPHONE	218-739-8635
CONTACT E-MAIL	shebert@otpco.com

UTILITY OFFICERS

NAME	TITLE
CHARLES S. MacFARLANE	PRESIDENT
WARD L. UGGERUD	SENIOR VICE-PRESIDENT, SUPPLY
RODNEY C.H.SCHEEL	VICE-PRESIDENT,ASSET MGMT.
MARK H. HELLAND	VICE-PRESIDENT, CUST. SERVICE
TOM BRAUSE	VICE-PRESIDENT, ADMINISTRATION
PETE WASBERG	DIRECTOR, HR / SAFETY
CRIS KLING	DIRECTOR, PUBLIC RELATIONS
TODD WAHLUND	VICE_PRESIDENT, RNWBL ENERGY,DVL
GEORGE BELL	VICE-PRESIDENT, FINANCE

PREPARER INFORMATION

PERSON PREPARING FORMS	
PREPARER'S TITLE	
DATE	

COMMENTS

ALLOWABLE UTILITY TYPES

Code
Private
Public
Co-op

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0150 FEDERAL OR STATE DATA SUBSTITUTION

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

COMMENTS
MISO submits EIA714 on behalf of Otter Tail Power

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

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

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

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

See "LargestCustomers" worksheet for data entry.

C. MINNESOTA SERVICE AREA MAP

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

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

D. PURCHASES AND SALES FOR RESALE		MWH	RESALE ONLY MWH
UTILITY NAME	INTERCONNECTED UTILITY	PURCHASED	SOLD FOR RESALE
American Electric Power Service	MISO	46,100	55,200
American UE	MISO	26,800	26,800
Ameren Energy Marketing Co	MISO	17,600	17,600
Badger, SD	Badger Municipal Power		149
Basin Electric Power Cooperative		3,818	
Beltrami Electric Cooperative	Minnkota Power Cooperative	55,775	
Cargill Power Markets, LLC	MISO	24,000	19,600
Constellation Energy Commodities Group	MISO	168,800	52,000
Dakota Valley Services		43	
DTE Energy Trading, Inc.	MISO	1,200	2,000
EDF Trading North America	MISO	89,600	242,750
Great River Energy	MISO	1,600	2,400
Horizon Wind Energy LLC	MISO	131,760	131,760
Lake Region Rural Electric Cooperative		11	
MacQuarie Energy LLC	MISO	223,150	18,450
Manitoba Hydro Electric Board	MISO	800	
MidAmerican Energy Company	MISO	1,600	1,600
Minnesota Power	MISO	-3,911	
Minnkota Power Cooperative	MAPP	70,402	8,400
Missouri River Services	MISO		56,000
Montana Dakota Utilities - Mountrail	MISO	-415	
New Folden, MN	New Folden Municipal Power		2,341
Nextra Energy Power Marketing	MISO		1,200
Nielsville, MN	Nielsville Municipal Power		63
Nodak Electric Cooperative	Nodak Electric Cooperative	9,290	
North Central Electric Cooperative		757	
Northern States Power	MISO	438,345	254,945
NorthWestern Energy - NLE	MAPP	14,234	
PKM Electric Cooperative	PKM Electric Cooperative	9,836	
RBC Capital Markets Corporation	MAPP	622,400	587,600
Red Lake Rural Electric Cooperative	MAPP	8,583	
Redwood Electric	MAPP	46	
Shelly, MN	Shelly Municipal Power		663
Sioux Valley Energy		9	
The Energy Authority	MISO	3,200	5,600
Transalta Energy Marketing	MAPP	16,000	14,000
Western Area Power Administration	MISO	30,389	400
Wisconsin Power and Light	MISO		70,400
Midwest ISO		1,247,361	566,438
Non-asset based cost of sales		-70,000	-3,200
OTHER NON UTILTY			
American Crystal Sugar	- - -	23	
Borderline Wind	- - -	1,633	
City of Detroit Lakes	- - -	908	
City of Perham	- - -		
Dakota Magic Casino	- - -		
Energy Maintenance Service-Broadwind Srvcs	- - -	152	
Fleet Farm	- - -		
FPL Energy North Dakota Wind II	- - -	57,212	
Hendricks Wind 1	- - -	2,571	
Kindred School	- - -		
Lac Qui Parle School	- - -	20	
Langdon Wind, LLC	- - -	72,275	
District 45 Methane	- - -	10,096	
Minnesota Small Power (Wind)	- - -	28	
North Dakota Small Power (Wind)	- - -	55	
South Dakota Co Generation	- - -	37	
Pembina Border Station	- - -	172	
State Auto Insurance	- - -		
Stevens Community Medical	- - -	639	
Turtle Mountain Community College	- - -	5,130	
Univ. of MN - Morris	- - -		
Valley Queen Cheese	- - -		

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

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

E. RATE SCHEDULES — **The rate schedule and monthly power cost adjustment information must be submitted in electronic or paper format.**

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

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

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

G. FINANCIAL AND STATISTICAL REPORT — **If applicable, a copy of the Financial and Statistical Report filed with the US Dept. of Agriculture must be submitted in electronic or paper format.**

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

H. GENERATION DATA

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

I. ELECTRIC USE BY MINNESOTA RESIDENTIAL SPACE HEATING USERS

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

COL. 1 NO. OF RESIDENTIAL ELECTRICAL SPACE HEATING CUSTOMERS	COL. 2 NO. OF RESIDENTIAL UNITS SERVED WITH ELECTRICAL SPACE HEATING	COL. 3 TOTAL MWH USED BY THESE CUSTOMERS AND UNITS
7,325	9,689	120,636

Comments

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

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

ENERGY DELIVERED TO ULTIMATE CONSUMERS BY COUNTY

COUNTY CODE	COUNTY NAME	MWH DELIVERED	COUNTY CODE	COUNTY NAME	MWH DELIVERED
1	Aitkin		46	Martin	
2	Anoka		47	Meeker	
3	Becker	41947	48	Mille Lacs	
4	Beltrami	264761	49	Morrison	
5	Benton		50	Mower	
6	Big Stone	20178	51	Murray	
7	Blue Earth		52	Nicollet	
8	Brown		53	Nobles	
9	Carlton		54	Norman	13162
10	Carver		55	Olmstead	
11	Cass	74948	56	Otter Tail	471139
12	Chippewa	4302	57	Pennington	3882
13	Chisago		58	Pine	
14	Clay	13144	59	Pipestone	
15	Clearwater	176820	60	Polk	209263
16	Cook		61	Pope	2439
17	Cottonwood		62	Ramsey	
18	Crow Wing		63	Red Lake	102838
19	Dakota		64	Redwood	2574
20	Dodge		65	Renville	
21	Douglas	46333	66	Rice	
22	Faribault		67	Rock	
23	Fillmore		68	Roseau	14221
24	Freeborn		69	St. Louis	
25	Goodhue		70	Scott	
26	Grant	31713	71	Sherburne	
27	Hennepin		72	Sibley	
28	Houston		73	Stearns	
29	Hubbard		74	Steele	
30	Isanti		75	Stevens	93237
31	Itasca		76	Swift	45597
32	Jackson		77	Todd	764
33	Kanabec		78	Traverse	29274
34	Kandiyohi	7497	79	Wabasha	
35	Kittson	101252	80	Wadena	
36	Koochiching		81	Waseca	
37	Lac Qui Parle	51966	82	Washington	
38	Lake		83	Watonwan	
39	Lake of the Woods		84	Wilkin	21122
40	Le Sueur		85	Winona	
41	Lincoln	21026	86	Wright	
42	Lyon	23388	87	Yellow Medicine	24134
43	McLeod			Unbilled	11532
44	Mahnomen	42280		GRAND TOTAL (Entered)	2084536
45	Marshall	117803			
				GRAND TOTAL (Calculated)	2084536

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

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

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

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

Past Year Entire System		A Non-Farm Residential	B Residential With Space Heat	C Farm	D Small Commercial & Industrial	E Irrigation	F Large Commercial & Industrial	G Street & Highway Lighting	H Other (Include Municipals)	I Total (Columns A through H)
January	No. of Customers	44,480	2,397	1,301	9,451		794	134	222	58,779
	MWH	56,017	6,906	3,598	23,657		106,069	978	1,490	198,714
February	No. of Customers	44,316	2,390	1,272	9,428		782	136	222	58,546
	MWH	53,091	7,011	3,558	27,583		106,495	1,178	1,528	200,444
March	No. of Customers	44,397	2,390	1,278	9,423		782	136	222	58,628
	MWH	44,503	5,526	3,230	23,810		100,777	639	1,550	180,034
April	No. of Customers	44,489	2,390	1,263	9,459		781	136	219	58,737
	MWH	34,413	3,644	2,461	16,435		94,754	921	1,419	154,047
May	No. of Customers	44,615	2,392	1,436	9,573		785	136	219	59,156
	MWH	31,151	2,978	2,277	21,246		99,324	869	1,521	159,367
June	No. of Customers	46,018	2,390	1,441	9,678		778	136	219	60,660
	MWH	30,130	2,299	2,490	13,251		97,914	795	1,394	148,272
July	No. of Customers	46,098	2,384	1,441	9,716		777	136	219	60,771
	MWH	42,280	2,998	3,953	24,910		100,718	845	1,650	177,354
August	No. of Customers	46,152	2,385	1,441	9,740		792	136	219	60,865
	MWH	40,283	2,809	4,683	22,166		102,071	878	1,602	174,493
September	No. of Customers	46,152	2,389	1,429	9,710		773	141	222	60,816
	MWH	32,940	2,429	4,067	15,445		97,935	827	1,357	154,999
October	No. of Customers	45,654	2,382	1,444	9,682		786	141	223	60,312
	MWH	36,603	3,234	3,745	27,697		95,152	922	1,591	168,944
November	No. of Customers	44,708	2,386	1,293	9,522		771	144	224	59,048
	MWH	41,287	4,616	3,419	16,679		96,934	885	1,342	165,161
December	No. of Customers	44,730	2,390	1,277	9,517		783	141	226	59,064
	MWH	54,434	6,647	3,300	31,601		104,067	984	1,651	202,683
	Total MWH	497,132	51,096	40,781	264,479	0	1,202,210	10,721	18,094	2,084,513

Comments

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

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

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

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 (In this column report the number of farms, residences, commercial establishments, etc., and not the number of meters, where different.)	Megawatt-hours (round to nearest MWH) (This column total should equal the grand total in the worksheet labeled "ElectricityByCounty" which provides deliveries by county.)	Revenue ($) (This column total will be used for the Alternative Energy Assessment and should not include revenues from sales for resale (MN Statutes Sec. 216B.62, Subd. 5).)
Farm	1,360	40,781	3,489,149
Nonfarm-residential	47,539	548,228	47,794,238
Commercial	9,575	264,479	20,241,708
Industrial	782	1,202,210	74,985,900
Street and highway lighting	138	10,721	1,615,193
All other	221	18,094	1,290,688
Entered Total	59,615	2,084,513	149,416,876
CALCULATED TOTAL	59,615	2,084,513	149,416,876

Non-farm ($/kWh)	Residential ($/customer)
0.087179	1005.369
CHECK	CHECK

Comments

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

PLEASE PROVIDE THE FOLLOWING INFORMATION FOR THOSE CUSTOMERS USING IN EXCESS OF 10,000 MWH. BE SURE TO INCLUDE YOUR LARGE CUSTOMERS LOCATED IN AND OUTSIDE MINNESOTA.

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

[TRADE SECRET DATA BEGINS

ID#	CUSTOMER NAME	ADDRESS	CITY	STATE	ZIP	MWH
						21,680,544
						29,641,548
						17,372,457
						12,802,764
						67,180,114
						10,580,400
						20,084,368
						62,331,520
						48,478,984
						15,950,382
						37,184,928
						16,384,272
						13,082,142
						33,541,827
						99,670,259
						63,087,593
						99,253,126
						56,563,278
						19,213,200
						17,859,700
						20,450,678
						12,119,400
						64,589,500
						13,132,700
						49,017,616
						54,448,864
						63,294,204
						12,264,000
						17,077,200
						14,581,056
						102,600,200
						13,083,467
						31,276,800
						32,722,144

TRADE SECRET DATA ENDS]

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

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

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

A. PLANT DATA

PLANT NAME		PLANT ID	(leave this cell blank
STREET ADDRESS			
CITY			
STATE		NUMBER OF UNITS	
ZIP CODE			
COUNTY			
CONTACT PERSON			
TELEPHONE			

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
				PLANT TOTAL	0	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
PLANT TOTAL	0.0	0.0				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

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

A. PLANT DATA

PLANT NAME	BIG STONE PLANT	PLANT ID	87004
STREET ADDRESS			
CITY	BIG STONE CITY		
STATE	SD	NUMBER OF UNITS	2
ZIP CODE	57216		
COUNTY	GRANT		
CONTACT PERSON	Stacie Hebert		
TELEPHONE	218-739-8635		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1975	Coal	143839	
2	STB	IC	1975	FO2	0	
				PLANT TOTAL	143839	

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	255.9	255.9	67.20	93.2	7.3	
2	0.6	0.6				
PLANT TOTAL	256.5	256.5				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	SUB	925,120	Tons	8,262	REF	0	Tons	
					FO2	129,826	Gals	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

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

A. PLANT DATA

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

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1981	Coal	782358	
TOTAL						
				PLANT TOTAL	782358	

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	149.4	149.4	61.10	71.7	3.2	
PLANT TOTAL	149.4	149.4				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	LIG	624,094	Tons	7,012	FO2	84,060	Gals	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

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

A. PLANT DATA

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

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	RET	ST	1948	Coal	-282	
2	USE	ST	1959	Coal	276886	
3	USE	ST	1964	Coal	379336	
2A	STB	IC	1959	FO2	0	
3A	STB	IC	1964	FO2	0	
TOTAL						
				PLANT TOTAL	655940	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.0	0.0				
2	52.0	52.0	60.60	97.2	2.9	
3	73.0	73.0	59.20	98.0	2.0	
2A	0.2	0.2				
3A	0.2	0.2				
PLANT TOTAL	125.4	125.4				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	Sub		Tons					
2	Sub	172,582	Tons	9,272	FO2	14,759	Gals	
3	Sub	236,004	Tons	9,267	FO2	27,896	Gals	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

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

A. PLANT DATA

PLANT NAME	POTLATCH COGENERATION	PLANT ID	87030	Retired
STREET ADDRESS				
CITY	BEMIDJI			
STATE	MN	NUMBER OF UNITS	2	
ZIP CODE	56601			
COUNTY	HUBBARD			
CONTACT PERSON	Stacie Hebert			
TELEPHONE	218-739-8635			

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	RET	ST	1992	Wood Waste		
				PLANT TOTAL	0	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1						
PLANT TOTAL	0.0	0.0				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	Wood Waste		Tons					

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

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

A. PLANT DATA

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

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1907	WATER	186	
2	USE	HC	1907	WATER	0	
				PLANT TOTAL	186	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.2	0.2	10.60			
2	0.0	0.0				
PLANT TOTAL	0.2	0.2				

D. UNIT FUEL USED

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

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

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

A. PLANT DATA

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

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1909	Water	3259	
2	USE	HC	1919	Water	2796	
				PLANT TOTAL	6055	

C. UNIT CAPABILITY DATA

Unit ID #	Summer (CAPACITY (MEGAWATTS))	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.5	0.5	74.20			
2	0.5	0.5	63.70			
PLANT TOTAL	1.1	1.1				

D. UNIT FUEL USED

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

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

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

A. PLANT DATA

PLANT NAME	HOOT LAKE HYDRO	PLANT ID	87013
STREET ADDRESS			
CITY	FERGUS FALLS		
STATE	MN	NUMBER OF UNITS	1
ZIP CODE	56537		
COUNTY	OTTER TAIL		
CONTACT PERSON	Stacie Hebert		
TELEPHONE	218-739-8635		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1914	Water	2585	
				PLANT TOTAL	2585	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.8	0.8	36.80			
PLANT TOTAL	0.8	0.8				

D. UNIT FUEL USED

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

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

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

A. PLANT DATA

PLANT NAME	PISGAH HYDRO	PLANT ID	87023
STREET ADDRESS			
CITY	FERGUS FALLS		
STATE	MN	NUMBER OF UNITS	2
ZIP CODE	56537		
COUNTY	OTTER TAIL		
CONTACT PERSON	Stacie Hebert		
TELEPHONE	218-739-8635		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1918	Water	3497	
				PLANT TOTAL	3497	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.7	0.7	56.90			
PLANT TOTAL	0.7	0.7				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

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

A. PLANT DATA

PLANT NAME	TAPLIN GORGE HYDRO	PLANT ID	87026
STREET ADDRESS			
CITY	FERGUS FALLS		
STATE	MN	NUMBER OF UNITS	1
ZIP CODE	56537		
COUNTY	OTTERTAIL		
CONTACT PERSON	Stacie Hebert		
TELEPHONE	218-739-8635		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1925	Water	3122	
				PLANT TOTAL	3122	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.5	0.5	71.10			
PLANT TOTAL	0.5	0.5				

D. UNIT FUEL USED

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

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

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

A. PLANT DATA

PLANT NAME	WRIGHT HYDRO	PLANT ID	87029
STREET ADDRESS			
CITY	FERGUS FALLS		
STATE	MN	NUMBER OF UNITS	1
ZIP CODE	56537		
COUNTY	OTTER TAIL		
CONTACT PERSON	Stacie Hebert		
TELEPHONE	218-739-8635		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1922	Water	1546	
				PLANT TOTAL	1546	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.5	0.5	35.20			
PLANT TOTAL	0.5	0.5				

D. UNIT FUEL USED

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

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

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

A. PLANT DATA

PLANT NAME	FERGUS CONTROL CENTER	PLANT ID	87035
STREET ADDRESS			
CITY	FERGUS FALLS		
STATE	MN	NUMBER OF UNITS	1
ZIP CODE	56537		
COUNTY	OTTER TAIL		
CONTACT PERSON	Stacie Hebert		
TELEPHONE	218-739-8635		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	STB	IC	1995	Oil	23.3	
				PLANT TOTAL	23.3	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	2.0	2.0				
PLANT TOTAL	2.0	2.0				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2	1,915	Gals					

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

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

A. PLANT DATA

PLANT NAME	JAMESTOWN TURBINE PLANT	PLANT ID	87015
STREET ADDRESS			
CITY	JAMESTOWN		
STATE	ND	NUMBER OF UNITS	2
ZIP CODE	58401		
COUNTY	STUTSMAN		
CONTACT PERSON	Stacie Hebert		
TELEPHONE	218-739-8635		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	STB	IC	1976	Oil	750	
2	STB	IC	1978	Oil	415	
				PLANT TOTAL	1165	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	22.0	22.0	120699			
2	22.1	22.1	80740			
PLANT TOTAL	44.1	44.1				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2							
2	FO2							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

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

A. PLANT DATA

PLANT NAME	LAKE PRESTON TURBINE PLANT	PLANT ID	87016
STREET ADDRESS			
CITY	LAKE PRESTON		
STATE	SD	NUMBER OF UNITS	1
ZIP CODE	57249		
COUNTY	KINGSBURY		
CONTACT PERSON	Stacie Hebert		
TELEPHONE	218-739-8635		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	STB	IC	1978	Oil	280	
				PLANT TOTAL	280	

C. UNIT CAPABILITY DATA

Unit ID #	Summer (CAPACITY (MEGAWATTS))	Winter (CAPACITY (MEGAWATTS))	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	22.1	22.1				
PLANT TOTAL	22.1	22.1				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2	47,246						

PUBLIC DOCUMENT - TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

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

A. PLANT DATA

PLANT NAME	SOLWAY	PLANT ID	87036
STREET ADDRESS			
CITY	SOLWAY		
STATE	MN	NUMBER OF UNITS	1
ZIP CODE	57960		
COUNTY	BELTRAMI		
CONTACT PERSON	Stacie Hebert		
TELEPHONE	218-739-8635		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	STB	CT	2003	NG/Oil	53965	
				PLANT TOTAL	53965	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	41.9	41.9				
PLANT TOTAL	41.9	41.9				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	NG	614,320	MMBtu		FO2	39	GAL	

US Department of Energy Energy Information Administration Form EIA-861 (2010)	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 11/30/2013

SCHEDULE 1. IDENTIFICATION

SURVEY CONTACTS: Persons to contact with question about this form

RESPONSE DUE DATE: Please submit by April 30th following the close of calendar year

REPORT FOR: Otter Tail Power Co 14232

REPORTING PERIOD: 2012

Contact Dennis Echelberger
Title: Assistant, Supply Services

Phone: (218) 739-8754 FAX: (218) 739-8629 Email: dechelberger@otpco.com

Logged By / Date: 200001443 04/24/2013

Logged In: [X] Receipt Date (mm/dd/yyyy):

Supervisor Stacie Hebert
Title: Manager, Supply Services

Phone: (218) 739-8635 FAX: (218) 739-8629 Email: shebert@otpco.com

1	Legal Name of Industry Participant	Otter Tail Power Co **Submission Status/Date:** Submitted 04/24/2013
2	Current Address of Principal Business Office	P O Box 496215 South Cascade Street Fergus Falls MN 56538 0496
3	Preparer's Legal Name Operator (if different than line 1)	
4	Current Address of Preparer's Office (if different than line 2)	
5	Respondent Type (Check One)	[ ] Federal [ ] Political Subdivision [ ] Municipal Marketing Authority [ ] Cooperative [ ] Independent Power Producer or Qualifying Facility [ ] State [ ] Municipal [x] Investor-Owned [ ] Retail Power Marketer (or Energy Service Provider) [ ] Wholesale Power Marketer [ ] Transmission

For questions or additional information about the Form EIA-861 contact the Survey Manager: Fax: (202) 287 - 1938 Email: EIA-861@eia.gov
Jorge Luna-Camara Phone: (202) 586-3945 jorge.luna-camara@eia.gov **Stephen Scott** Phone: (202) 586-5140 Email: stephen.scott@eia.gov

US Department of Energy Energy Information Administration Form EIA-861 (2010)	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 11/30/2013

REPORT FOR: Otter Tail Power Co 14232

REPORT PERIOD ENDING: 2012

SCHEDULE 2, PART A. GENERAL INFORMATION

LINE NO.			
1	Regional North American Electric Reliability Council (Not applicable for power marketers)	[ ] TRE (formerly ERCOT) [ ] FRCC [x] MRO [ ] NPCC [ ] RFC (formerly ECAR, MAIN. MAAC) [ ] SERC [ ] SPP [ ] WECC	
1a	Name of RTO or ISO	[ ] California ISO [ ] Electric Reliability Council of Texas [ ] PJM Interconnection [ ] New York ISO [ ] Southwest Power Pool [X] Midwest ISO [ ] ISO New England [ ] None	
2	(For EIA Use Only) Identify the North American Electric Reliability Council where you are physically located	MISO	
3	Enter Control Area Operator(s) Responsible for Your Oversite	Midwest Independent System Ope	56669
4	Did Your Company Operate Generating Plants(s)?	[x] Yes [ ] No	
5	Identify The Activities Your Company Was Engaged In During The Year (Check appropriate activities)	[x] Generation from company owned plant [x] Transmission [x] Buying transmission services on other electrical system [x] Distribution using owned/leased electric wires [ ] Buying distribution on other electrical system [x] Wholesale power marketing [ ] Retail power marketing [x] Bundled Services (electricity plus other services such as gas, water, etc. in addition to electric service))	
6	Highest Hourly Electrical Peak System Demand	Summer (Megawatts) 646.0 Prior Year 643.0 Winter (Megawatts) 787.0 Prior Year 782.0	
	Did Your Company Operate Alternative-Fueled Vehicles During the Year?	[x] Yes [ ] No	
	Does Your Company Plan to Operate Such Vehicles During the Coming Year?	[x] Yes [ ] No	
7	If "Yes", Please Provide Additional Contact Information	Name: Dean Swanson Title: Manager, Transportation Telephone: 218 - 739 - 8590 Fax: 218 - 739 - 8734 Email: dswanson@otpco.com	

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SCHEDULE 2. PART B ENERGY SOURCES AND DISPOSITION

	SOURCE OF ENERGY		MEGAWATTHOURS		DISPOSITION OF ENERGY	MEGAWATTHOURS
1	Net Generation		3,422,671	11	Sales to Ultimate Consumers	4,240,789
2	Purchases from Electricity Suppliers		3,340,134	12	Sales For Resale	2,135,159
3	Exchanged Received (In)			13	Energy Furnished Without Charge	7
4	Exchanged Delivered (Out)			14	Energy Consumed By Respondent Without Charge	11,931
5	Exchanged Net					
6	Wheeled Received (In)		277,001			
7	Wheeled Delivered (Out)		231,819	15	Total Energy Losses (positive number)	420,101
8	Wheeled Net		45,182			
9	Transmission by Others Losses (Negative Number)					
10	Total Sources (sum of lines 1, 2, 5, 8 & 9)		6,807,987	16	Total Disposition (sum of lines 11, 12, 13, 14, & 15)	6,807,987

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SCHEDULE 2, PART C. GREEN PRICING PROGRAMS

Green Pricing programs are voluntary programs that allow customers to pay an extra fee to purchase electricty generated from renewable sources. Renewable Energy Certificates (RECS) are a category of Green Pricing that involves the sale of the renewable attribute created with renewable electricity generation.

STATE/ TERRITORY	TYPE OF CUSTOMER SERVICE PROGRAM (a)	RESIDENTIAL (b)	COMMERCIAL (c)	INDUSTRIAL (d)	TRANSPORTATION (e)	TOTAL (d)
MN	Green Pricing Revenues (thousand $)	10.294	1.737	11.100	.000	23.131
	Green Pricing Sales (MWh)	792.000	136.000	852.000	.000	1,780.000
	Green Pricing Customers	275	17	7		299
	Cents/kWh	1.30	1.28	1.30		1.30
ND	Green Pricing Revenues (thousand $)	6.367	1.369	.000	.000	7.736
	Green Pricing Sales (MWh)	494.006	105.306	.000	.000	599.312
	Green Pricing Customers	194	15			209
	Cents/kWh	1.29	1.30			1.29
SD	Green Pricing Revenues (thousand $)	4.122	2.765	.000	.000	6.887
	Green Pricing Sales (MWh)	107.250	72.000	.000	.000	179.250
	Green Pricing Customers	45	6			51
	Cents/kWh	3.84	3.84			3.84
	Green Pricing Revenues (thousand $)					
	Green Pricing Sales (MWh)					
	Green Pricing Customers					
	Cents/kWh					

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SCHEDULE 2, PART D. NET METERING

Net Metering programs allow customers to sell excess power they generate back to the electrical grid to offset consumption. For net metering applications of 2 MW nameplate capacity and less, provide the information about programs by State and customer class.

State/Territoty (a)			Residential (b)	Commercial (c)	Industrial (d)	Transportation (e)	Total (f)
MN	Photovoltaic	Installed Net Metering Capacity (MW)	0.003	0.004	0.000	0.000	0.007
		Net Metering Customers	1	1	0	0	2
		Electricty Sold back to Utility (MWh)	0.000	0.000	0.000	0.000	0.000
		Capacity/Customer	0.003	0.004			0.004
	Wind	Installed Net Metering Capacity (MW)	0.088	0.253	0.000	0.000	0.341
		Net Metering Customers	4	7	0	0	11
		Electricty Sold back to Utility (MWh)	19.135	39.347	0.000	0.000	58.482
		Capacity/Customer	0.022	0.036			0.031
	Other	Installed Net Metering Capacity (MW)	0.000	0.035	0.000	0.000	0.035
		Net Metering Customers	0	1	0	0	1
		Electricty Sold back to Utility (MWh)	0.000	0.000	0.000	0.000	0.000
		Capacity/Customer		0.035			0.035
	Total	Installed Net Metering Capacity (MW)	0.091	0.292	0.000	0.000	0.383
		Net Metering Customers	5	9	0	0	14
		Electricty Sold back to Utility (MWh)	19.135	39.347	0.000	0.000	58.482
		Capacity/Customer	0.018	0.032			0.027

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SCHEDULE 2, PART D. NET METERING

Net Metering programs allow customers to sell excess power they generate back to the electrical grid to offset consumption. For net metering applications of 2 MW nameplate capacity and less, provide the information about programs by State and customer class.

State/Territoty (a)			Residential (b)	Commercial (c)	Industrial (d)	Transportation (e)	Total (f)
ND	Photovoltaic	Installed Net Metering Capacity (MW)	0.000	0.050	0.000	0.000	0.050
		Net Metering Customers	0	2	0	0	2
		Electricty Sold back to Utility (MWh)	0.000	16.065	0.000	0.000	16.065
		Capacity/Customer		0.025			0.025
	Wind	Installed Net Metering Capacity (MW)	0.052	0.000	0.000	0.000	0.052
		Net Metering Customers	3	0	0	0	3
		Electricty Sold back to Utility (MWh)	0.000	0.000	0.000	0.000	0.000
		Capacity/Customer	0.017				0.017
	Other	Installed Net Metering Capacity (MW)	0.000	0.000	0.000	0.000	0.000
		Net Metering Customers	0	0	0	0	0
		Electricty Sold back to Utility (MWh)	0.000	0.000	0.000	0.000	0.000
		Capacity/Customer					
	Total	Installed Net Metering Capacity (MW)	0.052	0.050	0.000	0.000	0.102
		Net Metering Customers	3	2	0	0	5
		Electricty Sold back to Utility (MWh)	0.000	16.065	0.000	0.000	16.065
		Capacity/Customer	0.017	0.025			0.020

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SCHEDULE 2, PART D. NET METERING

Net Metering programs allow customers to sell excess power they generate back to the electrical grid to offset consumption. For net metering applications of 2 MW nameplate capacity and less, provide the information about programs by State and customer class.

State/Territoty (a)			Residential (b)	Commercial (c)	Industrial (d)	Transportation (e)	Total (f)
SD	Photovoltaic	Installed Net Metering Capacity (MW)	0.000	0.042	0.000	0.000	0.042
		Net Metering Customers	0	2	0	0	2
		Electricty Sold back to Utility (MWh)	0.000	6.140	0.000	0.000	6.140
		Capacity/Customer		0.021			0.021
	Wind	Installed Net Metering Capacity (MW)	0.004	0.000	0.000	0.000	0.004
		Net Metering Customers	2	0	0	0	2
		Electricty Sold back to Utility (MWh)	3.099	0.000	0.000	0.000	3.099
		Capacity/Customer	0.002				0.002
	Other	Installed Net Metering Capacity (MW)	0.000	0.000	0.000	0.000	0.000
		Net Metering Customers	0	0	0	0	0
		Electricty Sold back to Utility (MWh)	0.000	0.000	0.000	0.000	0.000
		Capacity/Customer					
	Total	Installed Net Metering Capacity (MW)	0.004	0.042	0.000	0.000	0.046
		Net Metering Customers	2	2	0	0	4
		Electricty Sold back to Utility (MWh)	3.099	6.140	0.000	0.000	9.239
		Capacity/Customer	0.002	0.021			0.012

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SCHEDULE 3. ELECTRIC OPERATING REVENUE

LINE NO.	TYPE OF OPERATING REVENUE OR COST	THOUSAND DOLLARS		
1	Electric Operating Revenue From Sales To Ultimate Customers (Schedule 4, Parts A, B and D)	305,500.3		
2	Revenue From Unbundled (Delivery) Customers (Schedule 4, Part C)	.0		
3	Electric Operating Revenue from Sale for Resale	30,263.0	Cents/kWh	1.4
4	Electric Credits / Other Adjustments	.0		
5	Revenues from Transmission	.0		
6	Other Electric Operating Revenue	24,280.0		
7	Total Electric Operating Revenue (sum of lines 1, 2, 3, 4, 5 and 6)	360,043.3		

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

STATE / TERRITORY	MN	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
Revenue (thousand dollars)		47,794.2	75,898.5	25,724.2	0.0	149,416.9
Megawatthours		548,227	1,049,345	486,943	0	2,084,515
Number of Customers		47,540	12,066	10	0	59,616
Cents/Kwh		8.718	7.233	5.283		7.168
STATE	ND					
Revenue (thousand dollars)		46,972.5	76,272.2	5,007.9	0.0	128,252.6
Megawatthours		590,455	1,075,948	80,883	0	1,747,286
Number of Customers		44,653	12,714	2	0	57,369
Cents/kWh		7.955	7.089	6.192		7.340
STATE	SD					
Revenue (thousand dollars)		9,383.9	16,586.8	1,860.1	0.0	27,830.8
Megawatthours		114,885	262,826	31,277	0	408,988
Number of Customers		8,652	2,765	1	0	11,418
Cents/kWh		8.168	6.311	5.947		6.805

Total					
Revenue (thousand dollars)	104,150.6	168,757.5	32,592.2	0.0	305,500.3
Megawatthours	1,253,567	2,388,119	599,103	0	4,240,789
Number of Customers	100,845	27,545	13	0	128,403

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

STATE / TERRITORY	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/kWh					
STATE					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/kWh					
STATE					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/kWh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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

STATE / TERRITORY	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/kWh					
STATE					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/kWh					
STATE					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/kWh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

US Department of Energy
Energy Information Administration
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SCHEDULE 4, PART D. BUNDLED SERVICE BY RETAIL ENERGY PROVIDERS, OR ANY POWER MARKETER THAT PROVIDES "BUNDLED SERVICE"

STATE / TERRITORY	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/kWh					
STATE					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/kWh					
STATE					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Censt/kWh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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Schedule 5. Mergers and/or Acquistions

REPORT FOR: Otter Tail Power Co　　Utility Id 14232

REPORTING PERIOD: 2012

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 6A. DEMAND - SIDE MANAGEMENT INFORMATION

LINE NO.		
2	If your Demand-Side Management activities are reported on Schedule 6 of another company's form identify the company	

Note: If you do not have any DSM or another company reports your DSM activities on their Schedule 6, proceed to schedule 6, Part D.

State/Territory	MN	PART A. ACTUAL EFFECTS								
		ANNUAL INCREMENTAL EFFECTS					ACTUAL ANNUAL EFFECTS			
ENERGY EFFICIENCY		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	Total (e)	RESIDENTIAL (f)	COMMERCIAL (g)	INDUSTRIAL (h)	TRANS	Total (e)
3	Energy Effects (megawatthours)	10,012	11,818	8,963		30,793	33,865	55,921	73,460		163,246
4	Actual Peak Reduction (megawatts)	2.0	2.0	2.0	.0	6.0	10.0	11.0	16.0	.0	37.0
LOAD MANAGEMENT											
5	Energy Effects (megawatthours)	35	13			48	3,845	1,234			5,079
6	Potential Peak Reduction (megawatts)	1.0	.0	.0	.0	1.0	73.0	24.0	.0	.0	97.0
7	Actual Peak Reduction (megawatts)	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0

7b	Were these savings verified through an independent evaluation?	N
7c	Are these estimates based on a forecast?	N

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SCHEDULE 6A. DEMAND - SIDE MANAGEMENT INFORMATION

LINE NO.		
2	If your Demand-Side Management activities are reported on Schedule 6 of another company's form identify the company	

Note: If you do not have any DSM or another company reports your DSM activities on their Schedule 6, proceed to schedule 6, Part D.

State/Territory	SD	PART A. ACTUAL EFFECTS									
		ANNUAL INCREMENTAL EFFECTS					ACTUAL ANNUAL EFFECTS				
ENERGY EFFICIENCY		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	Total (e)	RESIDENTIAL (f)	COMMERCIAL (g)	INDUSTRIAL (h)	TRANS	Total (e)
3	Energy Effects (megawatthours)	346	1,168	2,396		3,910	1,171	5,525	19,639		26,335
4	Actual Peak Reduction (megawatts)	.0	1.0	.0	.0	1.0	1.0	3.0	1.0	.0	5.0
LOAD MANAGEMENT											
5	Energy Effects (megawatthours)						27	130			157
6	Potential Peak Reduction (megawatts)	.0	.0	.0	.0	.0	1.0	2.0	.0	.0	3.0
7	Actual Peak Reduction (megawatts)	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0

7b	Were these savings verified through an independent evaluation?	N
7c	Are these estimates based on a forecast?	N

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SCHEDULE 6 PART B. ANNUAL COSTS (THOUSAND DOLLARS)

		(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
	State/Territory	MN				
8	Directs Costs excluding incentive payments-Energy Efficiency	1080	347	0	0	1427
9	Direct Costs excluding incentive payments-Load Management	104	33	0	0	137
10	Incentive Payments-Energy Efficiency	1821	585	0	0	2406
11	Incentive Payments-Load Management	0	0	0	0	0
12	Indirect Costs	3321	1066	0	0	4387
13	Total Cost (sum of all above)	6326	2031	0	0	8357

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SCHEDULE 6 PART B. ANNUAL COSTS (THOUSAND DOLLARS)

	SD				
Directs Costs excluding incentive payments-Energy Efficiency	16	77	0	0	93
Direct Costs excluding incentive payments-Load Management	5	22	0	0	27
Incentive Payments-Energy Efficiency	32	151	0	0	183
Incentive Payments-Load Management	0	0	0	0	0
Indirect Costs	39	186	0	0	225
Total Cost (sum of all above)	92	436	0	0	528

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14	Have there been any major changes to your Demand-Side Management programs (e.g., terminated programs, new information or financing programs, or a shift to programs with dual load building objectives and energy efficiency objectives), program tracking procedures, or reporting methods that affect the comparison of demand-side management data reported on this schedule to data from previous years? (check Yes or No)	[ ] Yes	[x] No
15	Does your company currently operate any incentive-based demand response programs (e.g., direct load control, interruptible programs, demand bidding/buyback, emergency demand response, capacity market programs, and ancillary service market programs)? (check Yes or No) .	[x] Yes	[ ] No

Line		State	Residential	Commercial	Industrial	Transportation
16	If the anser to line 15 is Yes, Please disclose the number of participating customers by state and class	MN	17783	2366	0	0
16	If the anser to line 15 is Yes, Please disclose the number of participating customers by state and class	ND	16308	2464	0	0
16	If the anser to line 15 is Yes, Please disclose the number of participating customers by state and class	SD	3672	439	0	0

[x] [ ]

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17 Does your company currently operate any time-based rate programs (e.g. real-time pricing, critical peak pricing, variable peak pricing and time-of-use rates? Yes No

Line		State	Residential	Commercial	Industrial	Transportation
18	If the anser to line 17 is Yes, Please disclose the number of participating customers by state and class	MN	0	239	0	0
18	If the anser to line 17 is Yes, Please disclose the number of participating customers by state and class	ND	0	35	0	0
18	If the anser to line 17 is Yes, Please disclose the number of participating customers by state and class	SD	0	11	0	0

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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

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State		Residential	Commercial	Industrial	Transportation	Total
MN	Number of AMR Meters	0	1	50	0	51
	Number of AMI Meters	0	0	0	0	0
	Energy Served through AMI Meters (MWh)	0	0	0	0	0
ND	Number of AMR Meters	0	3	18	0	21
	Number of AMI Meters	0	0	0	0	0
	Energy Served through AMI Meters (MWh)	0	0	0	0	0
SD	Number of AMR Meters	0	1	12	0	13
	Number of AMI Meters	0	0	0	0	0
	Energy Served through AMI Meters (MWh)	0	0	0	0	0

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SCHEDULE 7. DISTRIBUTED AND DISPERSED GENERATION

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

PART A. NUMBER AND CAPACITY

State/ Territory: MN

Distributed Generators (Commercial and Industrial Grid Connected/Synchronized Generators) (a)	< 1MW	Dispersed Generators (Commercial and Industrial Generators Not Connected/Synchronized to the Grid) (b)	< 1MW
1. Number of generators	13	1. Number of generators	
2. Total combined capacity (MW)	1.1	2. Total combined capacity (MW)	
3. Capacity that consists of backup-only units	0.7	3. Capacity that consists of backup-only units	
4 Capacity owned by respondent	0.0	4. Capacity owned by respondent	
5. Nature of data reported	A	5. Nature of data reported	

PART B. TYPE OF GENERATORS

1. Internal combustion/reciprocating engines	0.7	1. Internal combustion/reciprocating engines	
2. Combustion turbine(s)		2. Combustion turbine(s)	
3. Steam turbine(s)		3. Steam turbine(s)	
4. Hydroelectric		4. Hydroelectric	
5. Wind turbine(s)	0.3	5. Wind turbine(s)	
6, Photovoltaic	0.0	6. Photovoltaic	
7. Storage		7. Storage	
8. Other	0.1	8. Other	
9. Total	1.1	9. Total	0.0
10. Nature of data reported	A	10. Nature of data reported	

SCHEDULE 7. DISTRIBUTED AND DISPERSED GENERATION

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

PART A. NUMBER AND CAPACITY

US Department of Energy Energy Information Administration Form EIA-861 (2010)	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 11/30/2013

SCHEDULE 7. DISTRIBUTED AND DISPERSED GENERATION

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

PART A. NUMBER AND CAPACITY

State/ Territory: SD

Distributed Generators (Commercial and Industrial Grid Connected/Synchronized Generators) (a)	< 1MW	Dispersed Generators (Commercial and Industrial Generators Not Connected/Synchronized to the Grid) (b)	< 1MW
1. Number of generators	4	1. Number of generators	
2. Total combined capacity (MW)	0.1	2. Total combined capacity (MW)	
3. Capacity that consists of backup-only units	0.0	3. Capacity that consists of backup-only units	
4 Capacity owned by respondent	0.0	4. Capacity owned by respondent	
5. Nature of data reported	A	5. Nature of data reported	

PART B. TYPE OF GENERATORS

1. Internal combustion/reciprocating engines		1. Internal combustion/reciprocating engines	
2. Combustion turbine(s)		2. Combustion turbine(s)	
3. Steam turbine(s)		3. Steam turbine(s)	
4. Hydroelectric		4. Hydroelectric	
5. Wind turbine(s)		5. Wind turbine(s)	
6, Photovoltaic	0.1	6. Photovoltaic	
7. Storage		7. Storage	
8. Other		8. Other	
9. Total	0.1	9. Total	0.0
10. Nature of data reported	A	10. Nature of data reported	

US Department of Energy Energy Information Administration Form EIA-861 (2010)	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 11/30/2013

REPORT FOR: Otter Tail Power Co 14232

REPORT PERIOD ENDING: 2012

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	

US Department of Energy
Energy Information Administration
Form EIA-861 (2010)

ANNUAL ELECTRIC POWER
INDUSTRY REPORT

Form Approved
OMB No. 1905-0129
Approved Expires 11/30/2013

REPORT FOR: Otter Tail Power Co 14232

REPORT PERIOD ENDING: 2012

SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION

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		62	ND - Traill	
42	ND - Griggs		63	ND - Walsh	
43	ND - Kidder		64	ND - Ward	
44	ND - LaMoure		65	ND - Wells	
45	ND - Logan		66	SD - Brookings	
46	ND - McHenry		67	SD - Codington	
47	ND - McLean		68	SD - Day	
48	ND - Mountrail		69	SD - Deuel	
49	ND - Nelson		70	SD - Grant	
50	ND - Pembina		71	SD - Hamlin	
51	ND - Pierce		72	SD - Kingsbury	
52	ND - Ramsey		73	SD - Lake	
53	ND - Ransom		74	SD - Marshall	
54	ND - Renville		75	SD - Moody	
55	ND - Richland		76	SD - Roberts	
56	ND - Rolette				
57	ND - Sargent				
58	ND - Sheridan				
59	ND - Steele				
60	ND - Stutsman				
61	ND - Towner				

US Department of Energy Energy Information Administration Form EIA-861 (2010)	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 11/30/2013

REPORT FOR: Otter Tail Power Co 14232

REPORT PERIOD ENDING: 2012

SCHEDULE 9. COMMENTS

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

US Department of Energy Energy Information Administration Form EIA-861 (2010)	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 11/30/2013

REPORT FOR: Otter Tail Power Co 14232

REPORT PERIOD ENDING: 2012

EIA861 ERROR LOG

Part	State	Error	No.	Error Description/Override Comment	Type	Override
6	B	SD	532	Your indirect costs (line 12) are too large when compared to your energy efficiency costs. They should be less than 40% energy efficiency costs (line 8 + line 10). The higher Indirect Costs are due to Otter Tail exceeding its CIP Incentive Requests. Once this financial incentive request by Otter Tail is approved by the State, the revenue will begin to be collected from the utility's customers.	W	
6	B	MN	532	Your indirect costs (line 12) are too large when compared to your energy efficiency costs. They should be less than 40% energy efficiency costs (line 8 + line 10). The higher Indirect Costs are due to Otter Tail exceeding its CIP Incentive Requests. Once this financial incentive request by Otter Tail is approved by the State, the revenue will begin to be collected fron the utility's customers.	W	

SECTION 2

Electric Utility Information Reporting
<u>Forecast Section</u>

Form EN-0005 – 20

7610.0310 CONTENT OF HISTORICAL AND FORECAST

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

INSTRUCTIONS

The individual worksheets in this spreadsheet file correspond closely to the tables in the paper forms received by the utility.
The instructions provided with the paper forms also pertain to the data to be entered in each of the worksheets in this file.
PLEASE DO NOT CHANGE THE NAME OR ORDER OF ANY OF THE WORKSHEET TABS IN THIS FILE

In general, the following scheme is used on each worksheet:
Cells shown with a light green background correspond to headings for columns, rows or individual fields.
Cells shown with a light yellow background require data to be entered by the utility.
Cells shown with a light brown background generally correspond to fields that are calculated from the data entered, or correspond to fields that are informational and not to be modified by the utility.

Each worksheet contains a section labeled Comments below the main data entry area.
You may enter any comments in that section that may be needed to explain or clarify the data being entered on the worksheet.

Please complete the required worksheets and save the completed spreadsheet file to your local computer.
Then attach the completed spreadsheet file to an e-mail message and send it to the following e-mail address:
rule7610.reports@state.mn.us

If you have any questions please contact:

Steve Loomis
MN Department of Commerce
steve.loomis@state.mn.us
(651) 296-8963

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

7610.0120 REGISTRATION

ENTITY ID#	87
REPORT YEAR	2012

RILS ID#	U10756

UTILITY DETAILS	
UTILITY NAME	Otter Tail Power Co
STREET ADDRESS	215 South Cascade St
CITY	Fergus Falls
STATE	MN
ZIP CODE	56538-0496
TELEPHONE	218/739-8635
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	PRIVATE

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

COMMENTS

PREPARER INFORMATION	
PERSON PREPARING FORMS	
PREPARER'S TITLE	
DATE	

ALLOWABLE UTILITY TYPES

Code

Private

Public

Co-op

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

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

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

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Past Year	2012	No. of Cust.	2,764	101,997	21,860	0	1,896	408	598	129,523	129,523
		MWH	76,016	1,253,567	573,654	0	2,272,951	26,300	38,299	4,240,787	4,240,787
resent Yea	2013	No. of Cust.	2,626	102,050	21,996	0	1,898	390	789	129,749	129,749
		MWH	84,139	1,337,901	604,350	0	2,317,466	26,466	52,649	4,422,972	4,422,972
1st Forecast	2014	No. of Cust.	2,630	102,834	22,095	0	1,909	391	789	130,648	130,648
		MWH	83,197	1,318,912	599,088	0	2,417,795	26,531	51,757	4,497,281	4,497,281
2nd Forecast	2015	No. of Cust.	2,630	103,449	22,189	0	1,923	391	789	131,371	131,371
		MWH	83,782	1,329,919	603,640	0	2,592,423	26,597	51,601	4,687,962	4,687,962
3rd Forecast	2016	No. of Cust.	2,631	104,028	22,273	0	1,939	390	789	132,050	132,050
		MWH	83,875	1,337,346	608,029	0	2,751,726	26,666	51,432	4,859,074	4,859,074
4th Forecast	2017	No. of Cust.	2,632	104,536	22,345	0	1,954	391	789	132,647	132,647
		MWH	84,223	1,346,093	612,170	0	2,734,205	26,737	51,328	4,854,756	4,854,756
5th Forecast	2018	No. of Cust.	2,633	104,985	22,410	0	1,970	391	789	133,178	133,178
		MWH	85,005	1,357,934	616,063	0	2,752,383	26,811	51,243	4,889,438	4,889,438
6th Forecast	2019	No. of Cust.	2,634	105,387	22,468	0	1,988	391	789	133,657	133,657
		MWH	85,802	1,369,502	619,785	0	2,894,784	26,886	51,240	5,047,999	5,047,999
7th Forecast	2020	No. of Cust.	2,633	105,729	22,523	0	2,004	392	789	134,070	134,070
		MWH	86,633	1,380,375	623,398	0	2,929,402	26,963	51,215	5,097,986	5,097,986
8th Forecast	2021	No. of Cust.	2,633	106,005	22,572	0	2,022	392	789	134,413	134,413
		MWH	87,392	1,390,456	626,943	0	2,992,721	27,042	51,269	5,175,824	5,175,824
9th Forecast	2022	No. of Cust.	2,632	106,231	22,613	0	2,042	391	789	134,698	134,698
		MWH	88,085	1,399,624	630,318	0	3,077,886	27,122	51,312	5,274,347	5,274,347
10th Forecast	2023	No. of Cust.	2,631	106,426	22,650	0	2,060	392	789	134,948	134,948
		MWH	88,700	1,407,860	633,558	0	3,107,782	27,203	51,398	5,316,501	5,316,501
11th Forecast	2024	No. of Cust.	2,630	106,595	22,684	0	2,080	392	789	135,170	135,170
		MWH	89,322	1,415,618	636,725	0	3,138,364	27,286	51,514	5,358,829	5,358,829
12th Forecast	2025	No. of Cust.	2,610	106,050	22,714	0	2,100	391	789	134,654	134,654
		MWH	89,792	1,421,056	639,843	0	3,170,109	27,369	51,634	5,399,803	5,399,803
13th Forecast	2026	No. of Cust.	2,580	105,183	22,744	0	2,120	392	789	133,808	133,808
		MWH	89,395	1,412,707	642,941	0	3,202,972	27,454	51,764	5,427,232	5,427,232
14th Forecast	2027	No. of Cust.	2,578	105,224	22,771	0	2,142	392	789	133,896	133,896
		MWH	89,800	1,415,950	646,035	0	3,236,569	27,539	51,873	5,467,766	5,467,766

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

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

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

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

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	MN-ONLY TOTALS	Calculated MN-Only Totals
Past Year	2012	No. of Cust.	1,403	47,668	9,400		769	151	226	59,617	59,617
		MWH	40,781	548,228	264,479		1,202,210	10,722	18,094	2,084,513	2,084,513
Present Year	2013	No. of Cust.	1,300	47,775	9,575	0	790	143	311	59,894	59,894
		MWH	42,558	590,983	273,170	0	1,216,494	10,676	26,030	2,159,911	2,159,911
1st Forecast Year	2014	No. of Cust.	1,298	48,233	9,657	0	795	144	311	60,438	60,438
		MWH	42,217	582,948	271,995	0	1,306,133	10,721	25,397	2,239,411	2,239,411
2nd Forecast Year	2015	No. of Cust.	1,296	48,661	9,734	0	802	144	311	60,948	60,948
		MWH	42,569	589,824	275,182	0	1,468,367	10,762	25,223	2,411,927	2,411,927
3rd Forecast Year	2016	No. of Cust.	1,295	49,038	9,801	0	809	144	311	61,398	61,398
		MWH	42,926	595,265	278,190	0	1,629,167	10,804	25,028	2,581,379	2,581,379
4th Forecast Year	2017	No. of Cust.	1,293	49,354	9,857	0	816	145	311	61,776	61,776
		MWH	43,289	600,856	280,931	0	1,602,369	10,847	24,890	2,563,180	2,563,180
5th Forecast Year	2018	No. of Cust.	1,292	49,618	9,904	0	824	145	311	62,094	62,094
		MWH	43,655	607,294	283,405	0	1,610,960	10,891	24,761	2,580,965	2,580,965
6th Forecast Year	2019	No. of Cust.	1,290	49,847	9,945	0	833	145	311	62,371	62,371
		MWH	44,026	613,406	285,691	0	1,743,720	10,936	24,707	2,722,485	2,722,485
7th Forecast Year	2020	No. of Cust.	1,288	50,051	9,982	0	841	146	311	62,619	62,619
		MWH	44,401	619,188	287,847	0	1,768,733	10,982	24,627	2,755,778	2,755,778
8th Forecast Year	2021	No. of Cust.	1,287	50,225	10,013	0	850	146	311	62,832	62,832
		MWH	44,783	624,778	289,917	0	1,822,089	11,029	24,620	2,817,216	2,817,216
9th Forecast Year	2022	No. of Cust.	1,285	50,357	10,036	0	860	146	311	62,995	62,995
		MWH	45,172	629,838	291,794	0	1,897,093	11,077	24,594	2,899,568	2,899,568
10th Forecast Year	2023	No. of Cust.	1,283	50,461	10,055	0	869	147	311	63,126	63,126
		MWH	45,564	634,349	293,515	0	1,916,548	11,125	24,606	2,925,707	2,925,707
11th Forecast Year	2024	No. of Cust.	1,282	50,545	10,070	0	879	147	311	63,234	63,234
		MWH	45,961	638,566	295,143	0	1,936,812	11,174	24,643	2,952,298	2,952,298
12th Forecast Year	2025	No. of Cust.	1,280	50,613	10,082	0	889	147	311	63,322	63,322
		MWH	46,365	642,790	296,696	0	1,957,888	11,223	24,679	2,979,641	2,979,641
13th Forecast Year	2026	No. of Cust.	1,278	50,671	10,093	0	899	148	311	63,400	63,400
		MWH	46,775	647,075	298,208	0	1,979,742	11,272	24,722	3,007,794	3,007,794
14th Forecast Year	2027	No. of Cust.	1,277	50,718	10,101	0	910	148	311	63,465	63,465
		MWH	47,191	651,400	299,691	0	2,002,359	11,322	24,741	3,036,704	3,036,704

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

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

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

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

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	CALCULATED	
		CONSUMPTION BY ULTIMATE CONSUMERS IN MINNESOTA in MWH [7610.0310 B(1)]	CONSUMPTION BY ULTIMATE CONSUMERS OUTSIDE OF MINNESOTA in MWH [7610.0310 B(2)]	RECEIVED FROM OTHER UTILITIES in MWH [7610.0310 B(3)]	DELIVERED FOR RESALE in MWH [7610.0310 B(4)]	TOTAL ANNUAL NET GENERATION in MWH [7610.0310 B(5)]	TRANSMISSION LINE SUBSTATION AND DISTRIBUTION LOSSES in MWH [7610.0310 B(6)]	TOTAL WINTER CONSUMPTION in MWH [7610.0310 B(7)]	TOTAL SUMMER CONSUMPTION in MWH [7610.0310 B(7)]	(GENERATION + RECEIVED) MINUS (RESALE + LOSSES) MINUS (CONSUMPTION) SHOULD EQUAL ZERO	
Past Year	2012	2,084,513	2,156,274	3,407,958	2,138,359	3,422,671	451,483	2,303,409	1,937,378	0	
Present Year	2013	2,159,911	2,263,061	3,299,351	2,234,467	3,691,000	332,912	2,478,125	1,944,847	0	
1st Forecast Year	2014	2,239,411	2,257,870	3,378,007	2,234,821	3,692,600	338,505	2,485,887	2,011,394	0	314,810
2nd Forecast Year	2015	2,411,927	2,276,035	3,881,089	2,243,869	3,403,600	352,857	2,571,614	2,116,348	0	
3rd Forecast Year	2016	2,581,379	2,277,695	3,762,089	2,209,078	3,671,800	365,737	2,670,628	2,188,447	0	
4th Forecast Year	2017	2,563,180	2,291,576	3,673,061	2,253,493	3,800,600	365,412	2,669,901	2,184,856	0	
5th Forecast Year	2018	2,580,965	2,308,473	3,667,354	2,253,493	3,843,600	368,022	2,688,344	2,201,095	0	
6th Forecast Year	2019	2,722,485	2,325,514	3,885,849	2,253,493	3,795,600	379,957	2,768,315	2,279,684	0	
7th Forecast Year	2020	2,755,778	2,342,208	3,712,399	2,253,493	4,022,800	383,719	2,794,235	2,303,751	0	
8th Forecast Year	2021	2,817,216	2,358,607	4,188,295	2,253,493	3,630,600	389,578	2,833,925	2,341,898	0	
9th Forecast Year	2022	2,899,568	2,374,779	4,392,234	2,253,493	3,532,600	396,994	2,883,837	2,390,510	0	
10th Forecast Year	2023	2,925,707	2,390,794	4,041,560	2,253,493	3,928,600	400,167	2,905,674	2,410,826	0	
11th Forecast Year	2024	2,952,298	2,406,531	4,190,874	2,253,493	3,824,800	403,353	2,927,618	2,431,211	0	
12th Forecast Year	2025	2,979,641	2,420,163	4,199,133	2,253,493	3,860,600	406,437	2,948,231	2,451,573	0	
13th Forecast Year	2026	3,007,794	2,419,438	4,132,626	2,253,493	3,956,600	408,501	2,961,946	2,465,286	0	
14th Forecast Year	2027	3,036,704	2,431,062	4,161,211	2,253,493	3,971,600	411,552	2,981,010	2,486,756	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
Year Peak 2012	14	233	106	0	422	5	7	787	787.0

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 2012	787.0	742.0	635.0	553.0	504.0	563.0	646.0	623.0	565.0	559.0	686.0	724.0

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

NAME OF OTHER UTILITY =>													
Past Year	2012	Summer	0										
		Winter	0										
resent Yea	2013	Summer	0										
		Winter	0										
1st Forecast	2014	Summer	0										
		Winter	0										
2nd Forecast	2015	Summer	0										
		Winter	0										
3rd Forecast	2016	Summer	0										
		Winter	0										
4th Forecast	2017	Summer	0										
		Winter	0										
5th Forecast	2018	Summer	0										
		Winter	0										
6th Forecast	2019	Summer	0										
		Winter	0										
7th Forecast	2020	Summer	0										
		Winter	0										
8th Forecast	2021	Summer	0										
		Winter	0										
9th Forecast	2022	Summer	0										
		Winter	0										
10th Forecast	2023	Summer	0										
		Winter	0										
11th Forecast	2024	Summer	0										
		Winter	0										
12th Forecast	2025	Summer	0										
		Winter	0										
13th Forecast	2026	Summer	0										
		Winter	0										
14th Forecast	2027	Summer	0										
		Winter	0										

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item E. PART 2: FIRM SALES (Express in MW)

NAME OF OTHER UTILITY =>												
Past Year	2012	Summer	0									
		Winter	0									
resent Yea	2013	Summer	0									
		Winter	0									
1st Forecast	2014	Summer	0									
		Winter	0									
2nd Forecast	2015	Summer	0									
		Winter	0									
3rd Forecast	2016	Summer	0									
		Winter	0									
4th Forecast	2017	Summer	0									
		Winter	0									
5th Forecast	2018	Summer	0									
		Winter	0									
6th Forecast	2019	Summer	0									
		Winter	0									
7th Forecast	2020	Summer	0									
		Winter	0									
8th Forecast	2021	Summer	0									
		Winter	0									
9th Forecast	2022	Summer	0									
		Winter	0									
10th Forecast	2023	Summer	0									
		Winter	0									
11th Forecast	2024	Summer	0									
		Winter	0									
12th Forecast	2025	Summer	0									
		Winter	0									
13th Forecast	2026	Summer	0									
		Winter	0									
14th Forecast	2027	Summer	0									
		Winter	0									

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

NAME OF OTHER UTILITY =>			WE	GRE								
Past Year	2012	Summer	50	50								
		Winter	50	50								
Present Year	2013	Summer		100								
		Winter		100								
1st Forecast Year	2014	Summer		100								
		Winter		100								
2nd Forecast Year	2015	Summer		100								
		Winter		100								
3rd Forecast Year	2016	Summer		100								
		Winter		100								
4th Forecast Year	2017	Summer		25								
		Winter		25								
5th Forecast Year	2018	Summer		25								
		Winter		25								
6th Forecast Year	2019	Summer		50								
		Winter		50								
7th Forecast Year	2020	Summer		50								
		Winter		50								
8th Forecast Year	2021	Summer										
		Winter										
9th Forecast Year	2022	Summer										
		Winter										
10th Forecast Year	2023	Summer										
		Winter										
11th Forecast Year	2024	Summer										
		Winter										
12th Forecast Year	2025	Summer										
		Winter										
13th Forecast Year	2026	Summer										
		Winter										
14th Forecast Year	2027	Summer										
		Winter										

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

NAME OF OTHER UTILITY =>												
Past Year	2012	Summer	0									
		Winter	0									
Present Year	2013	Summer	75									
		Winter	75									
1st Forecast Year	2014	Summer	0									
		Winter	0									
2nd Forecast Year	2015	Summer	0									
		Winter	0									
3rd Forecast Year	2016	Summer	0									
		Winter	0									
4th Forecast Year	2017	Summer	0									
		Winter	0									
5th Forecast Year	2018	Summer	0									
		Winter	0									
6th Forecast Year	2019	Summer	0									
		Winter	0									
7th Forecast Year	2020	Summer	0									
		Winter	0									
8th Forecast Year	2021	Summer	0									
		Winter	0									
9th Forecast Year	2022	Summer	0									
		Winter	0									
10th Forecast Year	2023	Summer	0									
		Winter	0									
11th Forecast Year	2024	Summer	0									
		Winter	0									
12th Forecast Year	2025	Summer	0									
		Winter	0									
13th Forecast Year	2026	Summer	0									
		Winter	0									
14th Forecast Year	2027	Summer	0									
		Winter	0									

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	Column 14	Column 15
			SEASONAL MAXIMUM DEMAND	SCHEDULE L. PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND	SEASONAL SYSTEM DEMAND	ANNUAL SYSTEM DEMAND	SEASONAL FIRM PURCHASES (TOTAL)	SEASONAL FIRM SALES (TOTAL)	SEASONAL ADJUSTED NET DEMAND (3 - 5 + 6)	ANNUAL ADJUSTED NET DEMAND (4 - 5 + 6)	NET GENERATING CAPABILITY	PARTICIPATION PURCHASES (TOTAL)	PARTICIPATION SALES (TOTAL)	ADJUSTED NET CAPABILITY (9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (7 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (12 - 14)
Past Year	2012	Summer	648	2	646	646	0	0	646	646	676	100	0	776	26	672	104
		Winter	787	0	787	787	0	0	787	787	690	100	0	790	26	813	-23
Present Year	2013	Summer	668	30	638	787	0	0	638	787	680	100	75	705	0	638	67
		Winter	803	117	686	686	0	0	686	686	679	100	75	704	0	686	18
1st Forecast Year	2014	Summer	685	26	659	686	0	0	659	686	678	100	0	778	0	659	119
		Winter	830	113	717	717	0	0	717	717	678	100	0	778	0	717	61
2nd Forecast Year	2015	Summer	711	30	681	717	0	0	681	717	678	100	0	778	0	681	97
		Winter	860	117	743	743	0	0	743	743	678	100	0	778	0	743	35
3rd Forecast Year	2016	Summer	742	41	701	743	0	0	701	743	678	100	0	778	0	701	77
		Winter	862	123	739	739	0	0	739	739	678	100	0	778	0	739	39
4th Forecast Year	2017	Summer	744	39	705	739	0	0	705	739	678	25	0	703	0	705	-2
		Winter	869	121	748	748	0	0	748	748	678	25	0	703	0	748	-45
5th Forecast Year	2018	Summer	751	39	712	748	0	0	712	748	678	25	0	703	0	712	-9
		Winter	894	121	773	773	0	0	773	773	678	25	0	703	0	773	-70
6th Forecast Year	2019	Summer	775	43	732	773	0	0	732	773	678	50	0	728	0	732	-4
		Winter	903	125	778	778	0	0	778	778	678	50	0	728	0	778	-50
7th Forecast Year	2020	Summer	785	43	742	778	0	0	742	778	678	50	0	728	0	742	-14
		Winter	917	125	792	792	0	0	792	792	678	50	0	728	0	792	-64
8th Forecast Year	2021	Summer	799	50	749	792	0	0	749	792	736	0	0	736	0	749	-13
		Winter	933	137	796	796	0	0	796	796	736	0	0	736	0	796	-60
9th Forecast Year	2022	Summer	815	51	764	796	0	0	764	796	736	0	0	736	0	764	-28
		Winter	942	138	804	804	0	0	804	804	736	0	0	736	0	804	-68
10th Forecast Year	2023	Summer	824	51	773	804	0	0	773	804	736	0	0	736	0	773	-37
		Winter	950	138	812	812	0	0	812	812	736	0	0	736	0	812	-76
11th Forecast Year	2024	Summer	832	51	781	812	0	0	781	812	736	0	0	736	0	781	-45
		Winter	959	138	821	821	0	0	821	821	736	0	0	736	0	821	-85
12th Forecast Year	2025	Summer	841	51	790	821	0	0	790	821	736	0	0	736	0	790	-54
		Winter	968	138	830	830	0	0	830	830	736	0	0	736	0	830	-94
13th Forecast Year	2026	Summer	850	56	794	830	0	0	794	830	736	0	0	736	0	794	-58
		Winter	977	146	831	831	0	0	831	831	736	0	0	736	0	831	-95
14th Forecast Year	2027	Summer	860	56	804	831	0	0	804	831	736	0	0	736	0	804	-68
		Winter	987	146	841	841	0	0	841	841	736	0	0	736	0	841	-105

COMMENTS

The information provided in columns 1 through 8 above reflect Otter Tail Power Company's (OTP) non-coincident peak demand. Starting the summer of 2013 OTP's resource adequacy obligation is no longer based on its non-coincident peak demand forecast. Therefore, the surplus and deficit capacity values in column 15 do not reflect OTP's capacity position. Starting the summer of 2013 OTP's resource adequacy obligation is based on its load at the time of the Midcontinent Indepent System Operator's (MISO) peak, which occurs during the summer months. Since OTP generally does not peak at the same time as the MISO it's resource obligation is approximately 91% of its summer non-coincident net demand shown in column 7. The net reserve capacity obligation in column 13 was valued at zero because OTP's reserve obligation is based on its MISO coincident

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

		ADDITIONS	RETIREMENTS
Past Year	2012	0	0
Present Year	2013	13.1	0
1st Forecast Year	2014	0	0
2nd Forecast Year	2015	0	0
3rd Forecast Year	2016	0	0
4th Forecast Year	2017	0	0
5th Forecast Year	2018	0	0
6th Forecast Year	2019	0	0
7th Forecast Year	2020	0	0
8th Forecast Year	2021	194	136
9th Forecast Year	2022	0	0
10th Forecast Year	2023	0	0
11th Forecast Year	2024	0	0
12th Forecast Year	2025	0	0
13th Forecast Year	2026	0	0
14th Forecast Year	2027	0	0

COMMENTS

Year 2013, Addition of wind generation (62.5 MW nameplate value - accredited capacity expected to be around 20.9% of nameplate)

Year 2021, anticipated addition of (194 MW) Natural Gas Turbine.
Year 2021, proposed retirement date for Hoot Lake Plant, 136 MW.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

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

		FUEL TYPE 1		FUEL TYPE 2		FUEL TYPE 3		FUEL TYPE 4		FUEL TYPE 5		FUEL TYPE 6	
		Name of Fuel	SUB - Sub-bitumin	Name of Fuel	HYD - Hydro (wate	Name of Fuel	NG - Natural Gas	Name of Fuel		Name of Fuel		Name of Fuel	
		Unit of Measure	Tons	Unit of Measure	Gal	Unit of Measure		Unit of Measure	MMBTU	Unit of Measure	Gal	Unit of Measure	
		QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED
Past Year	2012	408586	655939	na	16990	614320	53965						
Present Year	2013	334764	541352	na	22397	270310	26639						
1st Forecast Year	2014	477000	767100	na	22000	225000	22600						
2nd Forecast Year	2015	488000	786000	na	22000	268000	26800						
3rd Forecast Year	2016	484000	780000	na	22000	250000	25100						
4th Forecast Year	2017	484000	779400	na	22000	261000	26200						
5th Forecast Year	2018	488000	786400	na	22000	286000	28800						
6th Forecast Year	2019	507000	819700	na	22000	417000	41900						
7th Forecast Year	2020	506000	817400	na	22000	413000	41500						
8th Forecast Year	2021	0	0	na	22000	908000	92500						
9th Forecast Year	2022	0	0	na	22000	872000	88900						
10th Forecast Year	2023	0	0	na	22000	1184000	121100						
11th Forecast Year	2024	0	0	na	22000	1176000	120400						
12th Forecast Year	2025	0	0	na	22000	1178000	120600						
13th Forecast Year	2026	0	0	na	22000	1215000	124400						
14th Forecast Year	2027	0	0	na	22000	1234000	126400						

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-wc	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)

7610.0500 TRANSMISSION LINES

Subpart 1. **Existing transmission lines**. Each utility shall report the following information in regard to each transmission line of 200 kilovolts now in existence:
- A. a map showing the location of each line;
- B. the design voltage of each line;
- C. the size and type of conductor;
- D. the approximate location of d.c. terminals or a.c. substations; and
- E. the approximate length of each line in Minnesota.

Subpart 2. **Transmission line additions**. Each generating and transmission utility, as defined in part 7610.0100, shall report the information required in subpart 1 for all future transmission lines over 200 kilovolts that the utility plans to build within the next 15 years.

Subpart 3. **Transmission line retirements**. Each generating and transmission utility, as defined in part 7610.0100, shall identify all present transmission lines over 200 kilovolts that the utility plans to retire within the next 15 years.

In Use (enter X for selection)	To Be Built (enter X for selection)	To Be Retired (enter X for selection)	DESIGN VOLTAGE	SIZE OF CONDUCTOR	TYPE OF CONDUCTOR	D.C. OR A.C. (specify)	LOCATION OF D.C. TERMINALS OR A.C. SUBSTATIONS	INDICATE YEAR IF "TO BE BUILT" OR "RETIRED"	LENGTH IN MINNESOTA (miles)
x			230.	954	ACSR	AC	Winger Substation to Wilton Substation		54
x			230.	795	ACSR	AC	Sheyenne Sub to Audubon Substation		42
x			230.	795	ACSR	AC	Audubon Substation to Hubbard Substation		50
x			230.	795	ACSR	AC	Fergus Falls Sub to Wahpeton Substation		28
x			230.	795	ACSR	AC	Fergus Falls Sub to Henning Substation		30
x			230.	954	ACSR	AC	Harvey Substation to Balta Substation		
x			230.	954	ACSR	AC	Balta Substation to Rugby Substation		
x			230.	954	ACSR	AC	Coal Creek Sub to Underwood Substation		
x			230.	954	ACSR	AC	Underwood Sub to Harvey Substation		
x			345.	2-1272	ACSR	AC	Center Sub to Jamestown Substation		
x			230.	954	ACSR	AC	Drayton Substation to Prairie Substation		
x			230.	795	ACSR	AC	Wahpeton Sub to Hankinson Substation		
x			230.	954	ACSR	AC	Browns Valley Sub to Hankinson Sub		
x			230.	1,272	ACSR	AC	Big Stone Substation to Blair Substation		
x			230.	795	ACSR	AC	Hankinson Sub to Forman Substation		
x			230.	795	ACSR	AC	Forman Substation to Oakes Substation		
x			230.	795	ACSR	AC	Oakes Substation to Ellendale Substation		
x			230.	795	ACSR	AC	Pillsbury Substation to Luverne Substation		
x			345.	2-954	ACSS	AC	St. Cloud (Quarry) Sub to Montevideo 345 kV Sub [2]		29
x			230.	795	ACSS	AC	Wilton Sub to Cass Lake Sub [1]		20
x			230.	795	ACSS	AC	Cass Lake Sub to Boswell Sub [1]		50
	x		345.	2-954	ACSS	AC	Bison 345 kV Sub to Alexandria Switch Station [2]	2015	98
	x		345.	2-954	ACSS	AC	Alexandria Switch St. to St. Cloud (Quarry) Sub [2]	2013	77
	x		345.	2-954	ACSS	AC	Cedar Mountain Sub to Helena Switch Sub#1 [3]	2015	72
	x		345.	2-954	ACSS	AC	Cedar Mountain Sub to Helena Switch Sub#2 [3]	2015	72
	x		345.	795	ACSS	AC	Cedar Mountain Sub to Franklin Sub [3]	2015	4
	x		345.	2-954	ACSS	AC	Helena Switch Sub to Chub Lake Sub [3]	2015	20
	x		345.	2-954	ACSS	AC	Chub Lake Sub to Hampton Corners Sub [3]	2015	18
	x		345.	2-954	ACSS	AC	Lyon County Sub to Hazel Creek Sub [3]	2015	24
	x		345.	2-954	ACSS	AC	Hazel Creek Sub to MN Valley Sub [3]	2015	5
	x		345.	2-954	ACSS	AC	Brookings County Sub to Lyon County Sub 3	2015	50
	x		345.	2-954	ACSS	AC	Lyon County Sub to Cedar Mountain Sub#1 [3]	2015	50
	x		345.	2-954	ACSS	AC	Lyon County Sub to Cedar Mountain Sub#2 [3]	2015	50
	x		230.	1,272	ACSR	AC	Big Stone Plant Sub to Big Stone South Sub #1	2017	
	x		230.	1,272	ACSR	AC	Big Stone Plant Sub to Big Stone South Sub #2	2017	
	x		345.	2-954	ACSS	AC	Big Stone South Sub to Ellendale Sub 345 kV [4]	2019	
	x		345.	2-954	ACSS	AC	Big Stone South Sub to Brookings 345 kV [5]	2017	

COMMENTS

ACSR = Aluminum Conductor, Steel Reinforced
ACSS = Aluminum Conductor, Steel Supported

[1] The 230 kV line additions are all part of the CapX 2020 Bemidji-Grand Rapids 230 kV Project. The line is planning to be owned by Minnkota Power Cooperative, Minnesota Power, Otter Tail Power Company, Great River Energy, and Xcel Energy.

[2] The 345 kV line additions are all part of the CapX 2020 Fargo - Monticello 345 kV Project. This project includes line segments between Monticello and a new Quary Substation on the west side of St. Cloud area, a segment between St. Cloud and the Alexandria area and between Alexandria and a new Bison Substation in the Fargo area. It is anticicipated that the line would be owned by Minnesota Power, Otter Tail Power Company, Missouri River Energy Services, Great River Energy and Xcel Energy.

[3] These 345 kV line additions are all part of the CapX 2020 Brookings - Twin Cities 345 kV Project. This project includes line segments between Brookings and Lyon County near Marshall, a segment between Lyon County and Franklin (called Cedar Mountain), a segment between Franklin and the Helena Substation (near New Prague), a segment between Helena Substation and Chub Lake (near Farmington/Lakeville area) and a segment between Chub Lake and Hampton Corners. In addition, there will be a 345 kV line from Lyon County to Hazel Creek (south of Granite Falls) with a tie-in from Hazel Creek to the existing MN Valley Substation. It is anticipated the line would be owned by Xcel Energy, Great River Energy, Otter Tail Power Company, Central Minnesota Municipal Power Agency, and Missouri River Energy Services.

[4] The Big Stone South - Ellendale 345 kV project is a recently approved Multi-Value Project through the MISO transmission planning process. It is anticipated that the line will be owned by Otter Tail Power Company and Montana-Dakota Utilities.

[5] The Big Stone South - Brookings 345 kV project is a recently approved Multi-Value Project through the MISO transmission planning process. It is anticipated that the line will be owned by Otter Tail Power Company and Xcel Energy.

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	DATE	
	7/2/12	1/19/12	<= ENTER DATES
TIME OF DAY	MW USED ON SUMMER PEAK DAY	MW USED ON WINTER PEAK DAY	
0100	442	679	
0200	422	675	
0300	419	688	
0400	408	687	
0500	394	685	
0600	408	694	
0700	457	732	
0800	516	787	
0900	561	776	
1000	588	757	
1100	613	766	
1200	628	762	
1300	625	743	
1400	646	724	
1500	**632**	709	
1600	620	705	
1700	626	711	
1800	623	**637**	
1900	582	633	
2000	542	765	
2100	517	743	
2200	505	733	
2300	484	740	
2400	448	715	

COMMENTS

SECTION 3

Electric Utility Information Reporting
<u>Forecast Section</u>

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 customer and number of customers were developed for each customer class, using historical data on monthly sales, customers, economic activity, and weather conditions. Monthly use per customer and number of customer (Customer) 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 were developed by multiplying use per customer forecasts by customer forecasts for each customer class. 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 at the customer meter of the following: Farm, Large Commercial, Other Public Authority, Residential, Small Commercial, Street Lights, and Unclassified.

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 customer models estimates monthly use per customer 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 customer models is represented by the equation below. In this equation “m2” equals one in February and zero in all other months.

$$\text{Use Per Customer} = a + b_1 * \text{Economic Variable} + b_2 * \text{CDD/day} + b_3 * \text{HDD/day} + b_4 * m2 + \ldots + b_{14} * m12$$

The basic structure for the customer models estimates monthly customers 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 customer model is shown in the equation below.

$$\text{Customers} = a + b_1 * \text{Economic Variable} + b_2 * \text{CDD/day} + b_3 * \text{HDD/day} + b_4 * m2 + \ldots + b_{14} * m12$$

The system peak demand model uses the equation below.

kW = a + b_1 * Winter * HDD Buildup + b_2 * Summer * Temperature Humidity Index Buildup + b_3 * Swing Month * CDD & HDD Buildup + b_4 * Gross Regional Product + b_5 * m2 + … + b_{15} * m12

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
2013 Econometric Forecast
Percent Deviation from Base

	Low Scenario		**High Scenario**	
Year	**Peak**	**Sales**	**Peak**	**Sales**
2014	(6.7%)	(8.8%)	6.7%	9.2%
2018	(6.3%)	(8.3%)	6.3%	8.6%
2023	(6.0%)	(7.9%)	6.0%	8.2%
2028	(5.8%)	(7.8%)	5.8%	8.1%

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 more of 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. Another weakness of the econometric methodology for Otter Tail Power Company is the lack of true economists on staff. While we have staff with “practical” economic training (college and real world), we don’t have any economics PhD’s on staff.

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 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 customer 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

One of the ways to feel confident about the forecast is to do what is called a ‘backcast'. This is where the model is used to predict the historical period. If the model does this 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 error of -0.40% over the 10 years with a -1.85% error for the single year of 2012 (most recent full year backcast). The demand model has an average error of -0.76% over the 10 years with a 0.35% error for the single year of 2012.

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.***

Table 2

Independent Variables Used in the Sales Forecast Models

		State	CDD65	HDD55	Total Personal Income	Number Of Households	Retail Electric Prices	Gross Regional Product	Farm Employment	Retail Sales Per Household	Persons Per Household	Total Population	Manufacturing Employment	Miscellaneous Binaries
Residential	Use Per Customer	MN	X	X	X		X							X
		ND	X	X	X		X							X
		SD	X	X	X		X							X
	Customers	MN				X								X
		ND				X								X
		SD				X								X
Farm	Use Per Customer	MN	X	X				X						X
		ND		X			X	X						X
		SD	X	X				X						X
	Customers	MN							X					X
		ND				X								X
		SD												X
Small Commercial	Use Per Customer	MN	X	X				X						X
		ND	X	X				X						X
		SD	X	X				X						X
	Customers	MN				X								X
		ND						X						X
		SD						X						X
Large Commercial	Use Per Customer	MN	X	X						X				X
		ND	X	X									X	X
		SD	X	X										X
	Customers	MN			X									X
		ND			X									X
		SD			X									X
Other Public Autho	Use Per Customer	MN		X							X			X
		ND		X						X				X
		SD												X
	Customers	MN												X
		ND												X
		SD												X
Streetlighting	Use Per Customer	MN						X						X
		ND						X						X
		SD						X						X
	Customers	MN										X		X
		ND										X		X
		SD										X		X
Unclassified	Use Per Customer	MN	X	X										X
		ND		X										X
		SD		X										X
	Customers	MN												X
		ND												X
		SD												X

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

Variables Used:

Use Per Customer: kwh sales divided by the number of customers
Customers: number of customers

Description/Source:

KWH and number of customers data was 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 8 classes used in the forecast. The variable *Use Per Customer* was calculated by dividing the monthly KWH by the monthly number of customers.

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 checked 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. 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 for cooling and 55 degree base for heating and the rounded average of the twenty-four hourly temperatures. Daily degree days were then averaged and weighted by 2012 sales 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
Retail Sales Per Household
Persons Per Household
Total Population
Manufacturing Employment

Description/Source:

2013 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). The 2013 state profile data contains annual historical data for 1969-2010 and annual forecast data for 2011-2040 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% of the population of the county. County population data was downloaded from 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% 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: ELECTRICITY PRICES

Variables Used: *Retail Electric Prices*

Description/Source: Electricity prices were calculated by dividing revenue by kWh for each class. Monthly Consumer Price Indexes (CPI) were downloaded from the Bureau of Labor Statistics (www.bls.gov/data) and prices were adjusted to 2011 dollars by dividing by the monthly CPI indexes and multiplying by the 2011 annual CPI index. Forecast period prices were developed using the Energy Information Administration (EIA) forecast of Energy Prices by Sector and Source for the West North Central region. The annual growth rate from the EIA forecast was applied to the Company's monthly historical CPI adjusted prices to get monthly price values for the forecast period.

Adjustments Made: None.

Table 3

Independent Variables Used in the Peak Demand Forecast Model	Monthly Binaries	whdd55buildup	sthibuildup	swcdd65hdd55buildup	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: 2013 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). The 2013 state profile data contains annual historical data for 1969-2010 and annual forecast data for 2011-2040 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% of the population of the county. County population data was downloaded from 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% 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**). for Fargo, ND. 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:
whdd55buildup: winter heating degree day buildup
swcdd65hdd55buildup: 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 for cooling and 55 degree base for heating and the rounded average of the twenty-four hourly temperatures. The variables *hddbuildup* and *cddbuildup* 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 *whdd55buildup* has the value of *hddbuildup* 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 3 times *cdd* to1 times *hdd* (3**cdd*+1**hdd*). The variable *swcdd65hdd55buildup* has the value *cddhdd* for the months of May and September and zero for all other months. Forecast period *whdd55buildup* and *swcdd65hdd55builup* 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 IRP process in part to avoid situations that create large price increases.

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 ISO, 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 2013 Planning Year capacity by fuel source for the Company.

Figure 1-1: 2013 Planning Year Accredited Capacity Resources Fuel Source Percent of Total = 779.8 MW

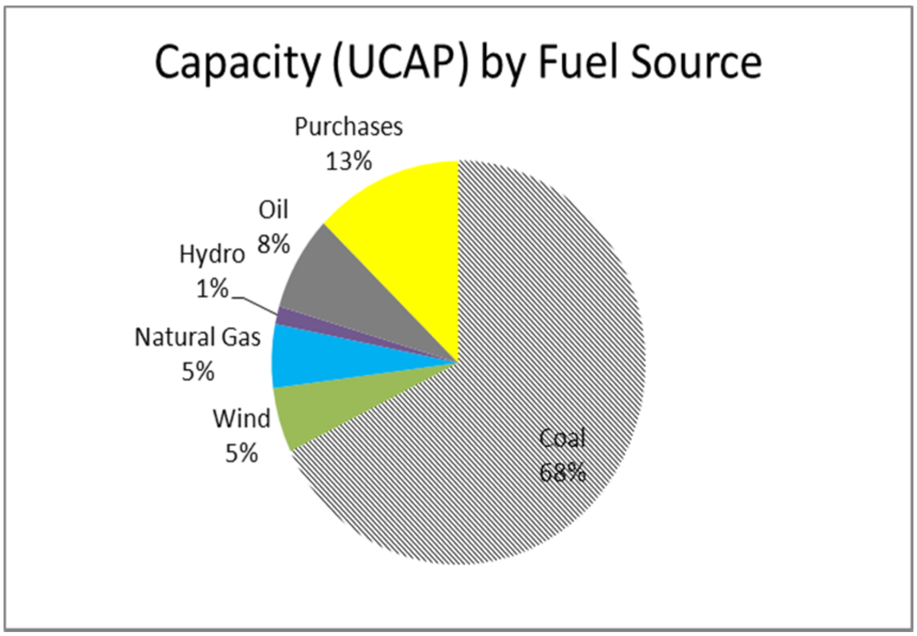


Table 1-1 shows a listing of the Company's resources and their capacity ratings for the 2013 Planning Year. The capacity ratings data provided is based on current Midcontinent ISO ratings under Module E's resource adequacy requirements in effect for the Planning Year June 1, 2013 through May 31, 2014.

Table 1-1: 2013 Company Capacity Resources

Capacity - Owned Resources	Dependable Capacity (MW)	UCAP (MW)
COAL		
Big Stone Plant	256.7	240.5
Coyote	149.0	141.9
Hoot Lake #2	60.9	59.7
Hoot Lake #3	88.0	86.4
GAS CT		
Solway 1	42.4	39.8
WIND		
Astabula	48.0	10.1
Luverne	49.5	13.5
Langdon	40.5	9.3
HYDRO		
Bemidji Hydro	0.1	0.1
Bemidji Hydro 2	-	-
Dayton Hollow Hydro 1	0.5	0.5
Dayton Hollow Hydro 2	0.4	0.4
Hoot Lake Hydro	0.3	0.3
Pisgah Hydro	0.6	0.6
Taplin Gorge Hydro	0.4	0.4
Wright Hydro	0.3	0.3
OIL		
Lake Preston	18.2	14.8
Jamestown 1	20.6	17.9
Jamestown 2	20.4	15.7
Big Stone Diesel	1.1	1.0
Fergus Control Center	1.7	1.6
Hoot Lake Diesel 2A	0.3	0.3
Hoot Lake Diesel 3A	0.2	0.2
Solway IC	-	-
Total Owned:	800.1	655.3

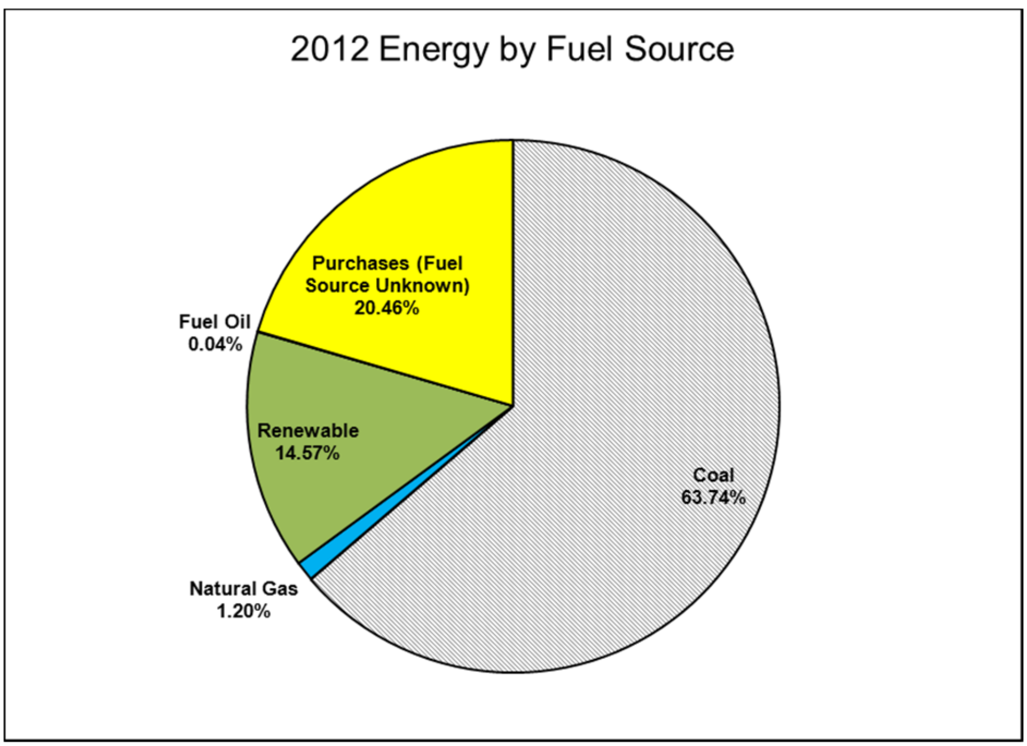
Capacity - Purchased Resources	Dependable Capacity (MW)	UCAP (MW)
WIND		
Edgeley (ND Wind II)	21.0	3.2
Langdon	19.5	4.6
Ashtabula III	0.0	-
Customer Owned Diesel	8.5	8.1
Short Term Capacity contracts	100.0	100.0
Total Purchased:	149.0	115.9

The sources of energy used to serve customer loads in 2012 are shown in Figures 1-2. Historically, between 3 and 5 percent of the Company's identified retail load in Minnesota, on an energy basis, is actually load of other utilities. Otter Tail makes the final delivery of the energy to the customer. Under energy accounting procedures, this energy becomes identified as Otter Tail load. The sources of this energy are not under the control of Otter Tail, but the energy is included in the data shown in the graphs.

The data indicates that about 15 percent of the total energy generated or purchased in 2012 was known to be from renewable resources. About 20 percent of the 2012 energy was purchased from entities where the energy source is unknown. Some may have been renewable. In the data, the energy classified as renewable includes energy from biomass, hydro, wind, solar, and waste.

The following subsections include information and discussions of Otter Tail's existing resources by category as well as discussion of the Midcontinent ISO pool, Midwest Reliability Organization ("MRO"), and transmission resources.

Figure 1-2: 2012 Energy By Fuel Source 4,513,758 MWh for Retail



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. The cost of the licensing process exceeded 1.3 million dollars. 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 units have a FERC classification of low hazard status.

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.

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. Typical annual generation for these two units is about 700 – 1,100 MWh depending on water availability.

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. The arrangement allows the cooling water for the steam plant to be gravity fed, rather than pumped, through the plant and improves the efficiency of the 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. Generally, Otter Tail's peaking units operate on a very limited basis annually, either for emergency or extreme peak times, or for testing purposes.

In the summer of 2001, an inlet fogging system was added to each of the three GE Frame 5 peaking units. The inlet fogging system is to be used during the summer months to increase the output of the turbines during the hotter weather conditions by lowering the temperature of the incoming air. Combustion turbine output is severely impacted by air density, so the denser cooler air allows for higher output capability.

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 operated a very limited number of hours during the year.

Solway Combustion Turbine Plant
Otter Tail brought on-line a new 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 and delay area transmission upgrades for a period of years. The LM6000 is an aeroderivative machine, powered by a Boeing 747 engine.

Hoot Lake Diesels
These diesels were installed as emergency units in case of a blackout, to provide lighting and minimum service to the plants. They are capable of synchronizing with the system and are accredited. Typically these units have only operated for extreme emergency and testing purposes.

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. Most of Otter Tail's engines are considered emergency in nature and therefore exempt from emissions limitations and performance tests. Three requirements of the rule are currently under reconsideration. If the rule remains in its current form only minimal efforts will be needed to comply with the rule.

1.3 Baseload Resources

Otter Tail Power has partial or full ownership of four coal-fired generators located at three plants. 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 1988 at Hoot Lake Plant and 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.

Hoot Lake Plant
The Hoot Lake Plant, consisting of unit #2 and unit #3, is located in Fergus Falls, MN. Hoot Lake #1 generator, built in 1948 with a nameplate rating of 7,500 kW, was retired at the end of 2005. The boiler was retained as a source of emergency heat.

Hoot Lake #2, was built in 1959 with a nameplate rating of 53,500 kW. The unit has experienced improved efficiencies in recent years as a result of efforts to reduce station service requirements. This unit also switched to burning sub bituminous coal in the late 1980’s. Part of the improved efficiencies is associated with burning sub bituminous coal, and part is due to improvements made in reducing station service requirements. Efficiency measures have included replacing the original lighting with new lighting technologies, improved control systems, variable speed drives, and other measures. The switch to sub-bituminous coal has reduced the usage of fuel oil for flame stabilization. The #2 unit is designed as a base load unit, saw intermediate service during the 1980’s and 1990’s, and is now typically operated in base load service again. The unit is equipped with an electrostatic precipitator for particulate removal and over-fire air and low-NO_x burners for NO_x emissions reduction.

Hoot Lake #3 is the largest of the three Hoot Lake units. This 75,000 kW nameplate unit was added in 1964, and is also now burning sub-bituminous coal. Here again, the use of sub-bituminous coal has reduced the need for fuel oil usage for flame stabilization. The unit is also equipped with an electrostatic precipitator for particulate removal and over-fire air and low NO_x burners for NO_x emissions reduction. Hoot Lake #3 was designed for base load duty, but saw mostly intermittent use during the 1980's and 1990’s. The unit now operates most of the time, although market conditions in recent years have resulted in limited cycling if longer periods of lower prices are anticipated.

The following data is provided relative to the Company’s future expectations for the Hoot Lake Plant units.

Both Hoot Lake #2 and #3 are being upgraded to meet the MATS rule scheduled for April 15th, 2015. These upgrades include new electrostatic precipitator components, as well as activated carbon injection and possibly HCL sorbent. As was directed in the Baseload Diversification study completed in 2013, Otter Tail is planning for the retirement of these units in 2020.

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. Station service represented 6.44 percent of gross generation in 1988. In 2009, station service represented 4.43 percent of gross generation.

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 2 percent.

Big Stone Plant, located near Milbank, SD, had been fueled primarily with North Dakota lignite. Following the expiration of the lignite coal contract in 1995, a switch to western sub bituminous was made. The switch to sub-bituminous coal has reduced sulfur dioxide emissions, improved plant heat rate, and resulted in fuel cost savings.

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.

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 Midcontinent ISO due to the transmission limitations.

Coyote completed a high-pressure/intermediate pressure rotor replacement in 2009 that resulted in about a 2 percent increase in efficiency. It also increased the UCAP rating of the plant by about 6,000 kW.

1.4 Demand Resources

Otter Tail Power Company has two demand resources registered under Module E with Midcontinent ISO. Both resources are load modifying resources ("LMR") that are netted from the demand forecast and available to Midcontinent ISO in emergency events. These resources are obligated to provide sustained load reduction for up to 4 hours at a time and be available five times a year to Midcontinent ISO 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 Midcontinent ISO 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 15 MW for Midcontinent ISO planning year 2013/2014 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 41,000 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 25 MW of summer peak load in the months of June through September. These summer loads consists primarily of water heaters, irrigation, the large dual fuel industrials and residential air conditioning. Otter Tail continues to add customers to the newest program that allows cycling control of residential central air conditioning (15 minutes on, 15 minutes off).

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 Midcontinent ISO 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. This resource was certified at 15 MW for Midcontinent ISO planning year 2013/2014. 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 Power Company has the following capacity and energy contracts currently in force. A 50 MW capacity-only contract with Great River Energy from 12/01/2010 – 12/31/2014.
- A capacity-only contract with Great River Energy for 50 MW capacity in 2014 and increases to 100 MW from January 2015 through May 31, 2017.
- A capacity-only contract with Great River Energy that begins with 25 MW on June 1, 2017 through May 31, 2019 and increases to 50 MW for June 2019 through May 31, 2021.
- An energy-only contract with Xcel Energy from November 1, 2013 through August 31, 2016. The amount vary by month and by on-peak and off-peak. This contract was structured to meet Otter Tail's varying monthly need.
- An energy-only contract with Xcel Energy for 50 MW on-peak 5 X 16 energy for calendar years 2016-2018.

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. The amount of energy received by Otter Tail for serving such customers in 2011 and 2012 was 80,080 MWh and 83,479 MWh, respectively.

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 29,870,425 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 Midcontinent ISO. Currently the NDC rating of these units is 10,400 kW in total and the UCAP rating is 9,800 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. Most of Otter Tail's engines are considered emergency in nature and therefore exempt from emissions limitations and performance tests. Three requirements of the rule are currently under reconsideration. If the rule remains in its current form only minimal efforts will be needed to comply with the rule.

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

1.6 Wind Generation Resources

Otter Tail has more than 246 MW of wind generation on the system, including utility owned and contracted wind generation. The Company owns 138 MW of wind generation.

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.

Approximately 108 MW of wind 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.

Table 1-2: Contracted Wind Generation Facilities

Name and Owner	State	kW Rating
FPL Energy ND Wind II - NextEra	ND	21,000
Hendricks Wind I	MN	900
Borderline Wind	MN	900
Dakota Wind Exchange	SD	90
Langdon Wind Energy Center – NextEra	ND	19,500
Ashtabula III – NextEra	ND	62,400
Various Small Wind Producers	ND	1,074
Various Small Wind Producers	MN	2,130
Various Small Wind Producers	SD	3

As shown in Table 1-2, Otter Tail has contracts for roughly 108 MW of wind generation. Often generation from smaller, customer owned units is used to serve the customer and only the surplus generation is sold to Otter Tail.

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-13-277. The Company also operates an energy efficiency program in South Dakota. The Company's MN and SD energy efficiency results have been on target with the energy efficiency goals in historical integrated resource plan filings.

Otter Tail's 2014-2016 CIP triennial, filed on June 1, 2013, supports energy efficiency objectives in the Company's 2011-2015 Integrated Resource Plan, Docket No. E017/RP-10-623 and in the proposed 2014-2028 resource plan. Due to timing and baseline year differences, the annual energy savings resource plan objective of 1.5 percent energy savings will not exactly match the annual energy savings goal in the 2014-2016 CIP triennial plan, which slightly exceeds 1.5 percent annual energy savings. Table 1-3 reflects approved annual energy and demand savings goals for Minnesota's CIP 2014-2016.

Table 1-3: Planned MN Energy Efficiency Goals

Year	Annual MW Savings Goal (Summer)	Annual MWH Savings Goal
2014	8.4	31,405,290
2015	8.4	31,762,333
2016	8.6	32,476,419

The 2014-2016 Plan builds upon lessons learned from more than two decades of offering energy efficiency programs. The entire portfolio can be reviewed in Docket No. E017/CIP-13-277.

1.8 Midcontinent Independent Transmission System Operator ("Midcontinent ISO")

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 Midcontinent ISO and the surrounding non-Midcontinent ISO transmission owners.

Transmission planning occurs at several different levels from individual utility plans, to local joint utility plans to broad regional studies. Regardless of the type of studies, the forum for which these studies are carried out is through a regional transmission planning process. Otter Tail actively participates in several Midcontinent ISO study groups, one of which is the West Subregional Planning Meetings (SPM), which are forums for regional transmission planners to discuss the needs and projects related to the transmission system in the Otter Tail and surrounding area. Additionally, Otter Tail participates in the Western Technical Studies Task Team ("WTSTT"), which is a forum to discuss specific criteria and details from studies related to Western Midcontinent ISO.

Otter Tail closely coordinates its transmission planning efforts with both MAPP and the Midcontinent ISO. For transmission planning purposes, Midcontinent ISO 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.

Midcontinent ISO administers and processes requests to use the transmission system of the Midcontinent ISO transmission owners. Midcontinent ISO has established procedures for processing generation interconnection and delivery service transmission requests of generators and market participants. Through this FERC mandated process, Midcontinent ISO 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, Midcontinent ISO also performs expansion planning studies on an annual basis. These expansion planning studies are referred to as the Midcontinent ISO 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 Midcontinent ISO West region. Through the MTEP process, Midcontinent ISO completes a reliability analysis assessing the transmission system performance against the regional reliability criteria. Otter Tail also participates in the MN TACT (Minnesota Transmission Assessment Compliance Team) group which also performs a reliability assessment of the western transmission system. In the event that standards are not met, additional analysis is completed to find mitigation to a particular system issue. Otter Tail actively participates in the MTEP, MN TACT, generator interconnection, and delivery service efforts by attending meetings, reviewing study results and providing input into the study process.

Midcontinent ISO 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 Northern Area Study (NAS), Market Efficiency Projects ("MEP"), Manitoba Hydro Wind Synergy Study ("MWHSS"), 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 Midcontinent ISO conducts meetings of several stakeholder groups, which include the Planning Subcommittee ("PSC"), the Planning Advisory Committee ("PAC"), the Regional Economic and Criteria Benefits Task Force ("RECB TF"), the Interconnection Process Task Force ("IPTF"), among several others. These meetings are attended by various representatives of the different stakeholder groups at Midcontinent ISO. These meetings act as a forum between Midcontinent ISO staff and the stakeholders to provide input into the processes of the Midcontinent ISO. Otter Tail regularly attends several of these meetings to stay engaged within the Midcontinent ISO transmission planning process as well as provide input and feedback to the Midcontinent ISO.

Otter Tail has been an active participant in the CapX 2020 effort. The CapX 2020 sponsoring companies embarked on a transmission study developing a long-term transmission plan to ensure reliable service to customer loads in the year 2020. The CapX 2020 utilities are currently engaged in construction and operation of what is termed as the "Group 1" projects, which include three 345 kV projects and one 230 kV project within Minnesota. The efforts of the CapX 2020 studies have been closely coordinated with the Midcontinent ISO planning process.

In addition to these previously mentioned planning-related activities, Otter Tail is also monitoring other regional transmission development initiatives, such as the Clean Line HVDC projects, and the Eastern Interconnection Planning Collaborative ("EIPC"). Otter Tail is a regular participant in meetings and conference calls related to these study initiatives.

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 Midcontinent ISO. Since joining Midcontinent ISO and transferring operational control of its high voltage transmission facilities to Midcontinent ISO, Otter Tail has seen positive benefits in this relationship regarding the generator interconnection processes.

Since Otter Tail joined Midcontinent ISO, several generators have successfully interconnected to the Otter Tail electric system under Midcontinent ISO's generator interconnection procedures. Under Midcontinent ISO'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 Midcontinent ISO generator interconnection process if the generator intends on engaging in wholesale transactions. The Midcontinent ISO, 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 Midcontinent ISO process given that Midcontinent ISO 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 Midcontinent ISO 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 Midcontinent ISO, thus freeing up Otter Tail's resources to focus on its key priority of providing clean, efficient, and low cost energy to its customers.

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

The Midcontinent ISO Locational Marginal Pricing ("LMP") energy market was introduced on April 1, 2005. The Midcontinent ISO 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-Midcontinent ISO 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 Midcontinent ISO 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.

Midcontinent ISO Resource Adequacy (Module E)
Otter Tail’s reserve requirements are established by Midcontinent ISO under Module E of the Midcontinent ISO Tariff. For planning year 2013 (June 2013 – May 2014) the Midcontinent ISO reserve margin requirement is 14.3 percent. The reserve margin consists of two components. 6.2 percent of the 14.3 percent is applied to peak demand as a reserve margin. The remaining 8.1 percent consists of the average generator unavailability factor as reported in the Generator Availability Data System (GADS) for the region. Generator equivalent forced outage data and the duration of the outages is used to calculate a factor through which a generator rating is reduced based on its actual availability. This rating is called unforced capacity (“UCAP”). For a utility with exactly average generator availability, the effective reserve margin is then 14.3 percent in total. For a utility with generation performing better than the average, the total effective reserve margin is less than 14.3 percent and for a utility with generation that experiences a higher forced outage rate the total effective reserve margin is higher than 14.3 percent.

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

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

Wind generation is accredited based on unit specific historical capacity factors. Accreditation for the 2013 planning year for the Company’s wind farms varied from 27 percent at the Luverne Wind Farm to 15 percent at the Edgeley Wind Farm.

Otter Tail has successfully registered the load management system and retail firm service level contracts under Module E as Demand Resources. The accredited capability of these resources is subtracted from the Company’s forecast demand prior to calculation of the planning reserve margin. Otter Tail’s accredited Demand Resources for planning year 2013 totaled 30 MW. This accreditation is based on its summer capability which is when Midcontinent ISO experiences its annual peak demand.

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 1-4: Circuit Miles of Transmission by Voltage

Voltage (kilovolts)	Circuit length
345 kV	*51 miles
230 kV	*431 miles
115 kV	862 miles
69 kV	212 miles
41.6 kV	3,765 miles

*Mileage includes CapX facilities with Otter Tail ownership share. Values are listed as Otter Tail miles only and not entire CapX project line length (Values Listed = Total Project Length x Otter Tail Ownership Percentage)

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 2013 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.

As the Strategist model evaluates each year's resource alternatives, it is able to save a finite number of feasible combinations of solutions, called "states." These states are carried forward as starting points to the following year's evaluation of resource alternatives. The model ranks all states by cost and discards those states that rank higher than a prescribed saved states limit. For example, if the saved states limit is 2000, any plan that ranks 2001 or higher based on cost is discarded. It is possible that a feasible state discarded in 2015 could be the least cost solution over the study period. To minimize the potential error of discarding the true least cost plan, it is prudent to minimize the number of alternatives made available to the model. This effort helps to minimize the number of feasible combinations of alternatives and in turn minimizes the likelihood that the model will discard the least-cost plan. Narrowing the number of alternatives for evaluation also shortens the model run-time, allows the model to be more user-friendly for evaluation of various futures, and provides greater opportunity for verification and validation of model performance. The Company aimed to adequately represent every resource type in the mix of alternatives made available to the model while reducing redundancy as much as possible.

Specific cost and performance data used for the computer modeling came from a variety of sources and is provided in detail in Appendix F: Assumptions for Strategist Modeling Scenarios. Much of the specific generator performance information came from a Burns and McDonnell technology assessment study in 2012.

1 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

- Conversion of Hoot Lake Units #2 and #3 from coal to natural gas
- Combined Cycle Gas Turbine ("CCGT")
- Simple Cycle Combustion Turbine
- Wind
- Solar Photovoltaic

Pre-screened Generation Alternatives Not in the Model

- Nuclear
- Pulverized Coal - Subcritical
- Atmospheric Circulating Fluidized Bed Coal ("ACFB")
- Pulverized Coal – Supercritical and Ultra-supercritical (green field site)
- Supercritical Coal, using a brown field site
- Integrated Gasification Combined Cycle ("IGCC")
- Reciprocating Engine Plants
- Phosphoric Acid Fuel Cell ("PAFC")
- Hydro (owned projects)
- Heat Recovery
- Energy Storage
- 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 Strategist 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

Conversion of Hoot Lake Units #2 and #3 from coal to natural gas

The model currently considers the operation of Hoot Lake as a coal fired plant through the year 2020. In the year 2021 a natural gas conversion alternative for units #2 and #3 is made available to the model. This alternative assumes a $54.8 million dollar investment in the facility.

The Hoot Lake site location is advantageous for generation. Some of the advantages of the site are the following:

- A highly trained workforce
- Established transmission interconnection rights
- Water supply
- Existing generation facility infrastructure
- An adequately sized site with buffer area.

No matter what the ultimate fate of the current coal facility is, continued generation from the site will be a consideration into the future.

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 would be 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. The model was given the option of a 311 MW combined cycle alternative during the study period.

Simple Cycle Combustion Turbine
The model was given the option of three simple cycle natural gas-fired combustion turbines to evaluate for installation. The first is a heavy-duty frame unit with an ISO rating of about 211 MW. The heavy-duty frame units are characterized by a lower capital cost per kW and lower maintenance cost, but a higher heat rate than an aeroderivative unit. The second simple cycle combustion turbine option within the model was based on an aeroderivative natural gas-fired combustion turbine with an ISO rating of about 100 MW. The third simple cycle combustion turbine option within the model was based on a aeroderivative natural gas-fired combustion turbine with an ISO rating of about 49 MW.

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 1 MW blocks throughout the study period modeled as a purchased power transaction.

1.2 Technology options not allowed in 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). Efforts made in recent years to repeal the moratorium have failed. 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 currently being conducted on the possibility of developing technologies and regulations around the concept of capturing carbon dioxide from electric generating units using fossil fuels. 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 is not commercially available and will not be considered a likely technology to employ within the current planning period. If regulations or successful demonstration projects develop into full-scale projects which can be offered with commercial and performance guarantees, 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_2 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_2 emissions. This type of operation requires approximately 1.5 times the quantity of limestone to achieve a reduction in SO_2 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 CO2 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_3), 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 nearly 25%-30% higher upfront capital costs, variable O&M about 15%-20% higher, and fixed O&M roughly 50% higher. The Minnesota Next Generation Energy Act of 2007 requires new coal-based generation to offset CO2 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 not currently commercial. 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% – 20% 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 Strategist, largely due to the higher O&M and capital costs. The reciprocating engine plant options investigated are based on 6 x Wärtsilä 20V34DF totaling 49.5 MW.

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 MN Department of Natural Resources 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.

Otter Tail has been working with several non-utility projects within its service territory that are considering small hydroelectric development, but none of these efforts have progressed to any great extent. Each of these potential projects would be measured in kW, rather than MW.

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.

Heat Recovery

Over the past two years Otter Tail has been working with a developer to use binary cycle moderate temperature geothermal technology to recover waste heat for use in generating electricity. The project would be slightly less than ten (10) megawatts in size and would not require the use of any fossil fuel. While technically feasible, the costs associated with the project are thus far too high to be competitive with other resource options. While Otter Tail and the developer will keep this alternative in mind for future development, it was not included in the current analysis due to the high costs.

Energy Storage

Promising new technologies are being developed, tested, and demonstrated in the field of energy storage. These technologies include battery storage, compressed air energy storage, and proven pumped hydro storage. As the overall percentage of intermittent renewable resources connected to the electrical supply system increases, the focus on energy storage technologies will increase. During the mid-1990's the Minnesota Department of Natural Resources promoted the potential development of a pumped storage hydroelectric facility at the Hill Annex State Park at Calumet, MN. Based on preliminary studies jointly conducted by the DNR and Minnesota Power, it was estimated the site had the potential to support a 75 MW facility. The upper and lower reservoirs of the facility would be former taconite mines that are no longer in operation. Otter Tail has not conducted any further studies on the site. Excelsior Energy has filed for a water appropriations permit with the State of Minnesota to use water from the Hill Annex mine site for their proposed Mesaba IGCC project.

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 200,000 kW, microturbines fit into the 25 to 400 kW range. Microturbine efficiencies have not met early manufacturer projections of mid-30 percent and higher. Most available units are in the mid-20's for efficiency in a stand-alone configuration. 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.

The binary cycle technology used for moderate temperature resources would work with any source of waste heat that falls within the moderate temperature range and in sufficient quantity to support a binary cycle unit. Otter Tail has been involved in investigating waste heat generation from combustion turbines used at natural gas compression stations on pipelines. Otter Tail has also searched for other potential waste heat streams that could be used to support a small binary cycle facility. ORMAT is a company that has binary cycle units in the 1.5 – 5 MW range that are designed to be operated remotely. One of the difficulties for developing a small waste heat recovery facility that has been identified is that the State of Minnesota rules require full time staffing of such a facility any time working pressures are in excess of very low pressures. The labor requirements to have staffing 24 hours per day significantly increase the costs and make such facilities uneconomic.

2 Demand Side Resources

Following is a description and comment on each of the demand response and energy efficiency resources used in this resource plan.

- **1.5 percent CIP** – The model uses annual energy efficiency and conservation alternative for Minnesota load that is 1.5 percent of average retail sales for the prior three years. By 2028, summer peak demand impacts from energy efficiency and conservation are expected to be 91 MW, not including the reserve margin savings.

- **Demand Response –** Demand response includes both load management capability and customer contracts that allow load shedding to a firm service level. In the preferred plan, demand response capability was selected to increase annually and reach 15 MW of additional summer season capability by 2028. To allow the Company time to confirm measurement and verification capability of incrementally new demand response, the new demand response was stair-stepped in every 5 years in 5 MW increments.

Appendix E: Assessment of Federal and State Environmental Regulations

Assessment of Federal and State Environmental Regulations

I. CRITERIA AIR POLLUTANTS

The Clean Air Act ("CAA") requires EPA to set standards for six common air pollutants known as "criteria" pollutants. The criteria pollutants are: nitrogen oxides ("NO_X"), sulfur dioxide ("SO_2"), 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_X, for example, is regulated because it is a precursor to fine particle formation, ozone formation, acid deposition and regional haze. Similarly, SO_2 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 Otter Tail Power Company's generating facilities.

A. 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_2 and NO_X from the electric utility industry have been reduced substantially.

1. ARP SO2 Program

The SO_2 program sets a permanent cap on the total amount of SO_2 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_2 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 1 ton of SO_2. 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. Allowance requirements have historically been met by all of Otter Tail's generating facilities by burning low sulfur subbituminous coal at Big Stone and Hoot Lake Plant, and Coyote Station, a lignite-fired unit, is equipped with a spray dryer for SO_2 control. Otter Tail has not sold any of our banked allowances, which we believe positions ourselves to avoid having to purchase allowances in the future for any of our plants.

2. ARP NOx Program

Title IV requires NO_X emission reductions for certain coal-fired EGUs by limiting the NO_X 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_X emission levels from the affected coal-fired 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 has maintained compliance with the Title IV NO_X emission rates by installing low NO_X burners on both Hoot Lake Plant Units 2 and Unit 3 and an over-fire air system at Big Stone Plant. Coyote Station did not require any changes in order to meet the NO_X emission requirements.

B. 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. NO2 and SO2 NAAQS

In 2010, the EPA promulgated new NAAQS for nitrogen dioxide ("NO_2") and SO_2 averaged over one hour.

For the 2010 NO_2 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_2 NAAQS. Therefore, EPA designated all areas of the country as "unclassifiable/attainment". EPA and the states are now in the process of expanding the NO_2 monitoring network, and EPA plans to re-designate areas in 2016 or 2017 based on the new monitoring data.

For $SO_{2,}$ Minnesota, North Dakota, and South Dakota have no monitored violations of the 2010 NAAQS. EPA has undertaken a stakeholder process and requested public comment to discuss how to implement the SO_2 standard, and on July 25, 2013 EPA published a final rule designating 29 areas in 16 states as "nonattainment". None of these areas were in Minnesota, North Dakota, or South Dakota. However, EPA only designated areas as nonattainment based on air quality monitoring data, and EPA made no determinations for all other areas. EPA stated that they were not yet prepared to issue proposed or final designations for other types of areas, and that they expect to issue a new rule to direct states to provide additional modeling or monitoring to inform future rounds of designations. At this time it is uncertain whether Otter Tail's plants will need to take any actions regarding the 2010 SO_2 NAAQS.

2. Ozone and PM NAAQS

In the electric power industry, recent attempts to assist with attainment of the NAAQS for ozone and particulate matter from regional sources have been made through EPA's Clean Air Interstate Rule ("CAIR") and Cross-State Air Pollution Rule ("CSAPR").

a. Clean Air Interstate Rule

On March 10, 2005, the EPA Administrator signed the Clean Air Interstate Rule ("CAIR") to address areas in the eastern half of the United States that were in non-attainment with the 1997 ozone and fine particulate matter NAAQS. The rule required SO_2 and NO_X emissions reductions in 28 states and the District of Columbia, including Minnesota, which was included because the state was deemed to contribute to downwind violations for fine particulate matter.

CAIR created a cap-and-trade program for SO_2 and NO_X allowances similar to the ARP SO_2 program, and in fact, Title IV SO_2 allowances are used for compliance with CAIR. The first phase of CAIR NO_X reductions began in 2009, and the first phase of CAIR SO_2 reductions began in 2010. In anticipation of CAIR, NO_X emissions control equipment was installed on Hoot Lake Plant Unit 2 in 2008, and on Unit 3 in 2006.

A number of petitioners brought legal challenges to various aspects of CAIR in the U.S. Court of Appeals for the D.C. Circuit. Among the challenges was that EPA erred in including the State of Minnesota. On July 11, 2008, after hearing the challenges, the Court vacated CAIR and agreed that EPA had failed to address alleged errors in its analysis for the State of Minnesota.

EPA filed a petition for rehearing on a number of the Court's findings, but did not seek rehearing of the findings regarding Minnesota. On December 23, 2008, the Court granted EPA's petition for rehearing only to the extent it remanded the case without vacatur. This decision allowed CAIR to remain in effect until EPA develops a permanent replacement rule. On May 12, 2009, EPA issued a proposed rule staying the effectiveness of CAIR for Minnesota sources while it conducts notice-and-comment rulemaking addressing whether Minnesota should be included in the CAIR region. Public notice of the final rule staying the implementation of CAIR in

Minnesota appeared in the November 3, 2009 Federal Register. Therefore, Otter Tail has not managed any emissions allowances or had to comply with CAIR.

b. Cross-State Air Pollution Rule

On July 6, 2010, the EPA proposed a rule, termed the Transport Rule, that would require annual SO_2 and NO_X reductions in 23 states, including Minnesota. EPA attempted to design the rule to address the concerns of the Court with respect to CAIR.

As proposed, the rule required that Otter Tail manage a new set of SO_2 and NO_X allowances separate from the Title IV ARP allowances beginning with calendar year 2012. However, the Transport Rule's impact on Hoot Lake Plant would have been minimal and not required any emissions reductions or allowance purchases to be made. The EPA released the final Transport Rule, renamed as the Cross-State Air Pollution Rule ("CSAPR"), on July 8, 2011. The final rule made several changes as compared to the proposed rule, including a substantial change in the allowance allocation methodology, whereby Hoot Lake Plant would need to purchase SO_2 allowances to continue operating at historical levels[1].

A number of states and industry representatives challenged CSAPR, and on December 30, 2011, the D.C. Circuit granted motions to stay CSAPR pending the Court's resolution of the petitions for review. The Court subsequently heard oral argument on April 13, 2012, and issued an order on August 21, 2012 to vacate CSAPR. The order requires EPA to continue administering the Clean Air Interstate Rule pending the promulgation of a valid replacement rule. On March 29, 2013 EPA filed a petition for United States Supreme Court Review of the D.C. Circuit decision, and on June 24, 2013 the Supreme Court granted the petition. Oral argument on the merits of the case is scheduled for December 10, 2013, and it is anticipated that the Court will issue a decision in 2014. The Supreme Court's granting of review does not change the current legal status of CSAPR. Given all of the uncertainty surrounding this rulemaking, at this time it is difficult to determine what compliance measures, if any, may need to be ultimately undertaken.

C. Regional Haze Program

EPA promulgated the Regional Haze Rule ("RHR") in 1999 to address visibility impairment in Class I areas. Class I areas include 156 national parks and wilderness areas, including the Boundary Waters Canoe Area Wilderness and Voyager's National Park in Minnesota. States were required to submit SIPs detailing their strategy to reduce haze, and to set reasonable progress goals that meet the goal of no man-made visibility impairment in Class I areas by 2064. The first regional progress goals must be established for the planning period 2008 to 2018.

Included in the RHR is a provision that sources built between August 7, 1962 and August 7, 1977, and that are found to contribute to visibility impairment in Class I areas, must install best available retrofit technology ("BART"). Hoot Lake Plant Unit 3 and Big Stone Plant were built within the 1962 – 1977 timeframe, and therefore were required to be evaluated whether or not they contribute to visibility impairment in Class I areas.

[1]As detailed in Otter Tail's initial filing for Docket No. E017/M-12-179

In March 2006 the MPCA conducted source-specific dispersion modeling of all BART-eligible Minnesota sources to determine if they contribute to Class I area visibility impairment. The MPCA's dispersion modeling determined that Hoot Lake Plant Unit 3 did not significantly contribute to visibility impairment, and is thus not subject to BART. The MPCA submitted a Regional Haze SIP to EPA for approval on December 30, 2009, which included the findings on Hoot Lake Plant. EPA published final approval of the Minnesota SIP on June 12, 2012[2]; therefore, at this time Hoot Lake Unit 3 does not need to take any further action.

Using air dispersion modeling, Big Stone Plant was found to contribute to visibility impairment at the Badlands National Park in South Dakota, Theodore Roosevelt National Park in North Dakota, Isle Royale National Park in Michigan, and Voyagers National Park and the Boundary Waters Canoe Area in Minnesota. Consequently, Big Stone Plant is required to install and operate BART. The South Dakota Department of Environment and Natural Resources determined that BART constitutes selective catalytic reduction in conjunction with separated over-fire air for control of nitrogen oxides, a scrubber for reducing SO_2, and a baghouse to control particulate matter. EPA's final approval of the SD Regional Haze SIP, including the BART requirements for Big Stone Plant, was published in the Federal Register on April 26, 2012. The equipment must be installed as expeditiously as practicable, but no later than five years from EPA's approval.

For Coyote Station, although the unit is not BART eligible, the North Dakota Regional Haze State Implementation Plan requires that Coyote Station reduce its NOx emissions as part of the State's long term strategy. To satisfy the SIP, separated overfire air equipment must be installed at Coyote by July 1, 2018.

Going forward, states are required by 40 CFR 51.308(g) to submit five-year periodic reports evaluating progress towards the goals established for each mandatory Class I area. Based on the findings of the five-year periodic progress report, a state must make a determination of adequacy of the existing SIP and take action if the strategies are found to be inadequate. In addition, states are required by 40 CFR 51.308(f) to revise their regional haze implementation plan and submit a plan revision to EPA by July 31, 2018, and every 10 years thereafter. The revised plan must address current visibility conditions, effectiveness of the long-term strategy, and affirm or revise reasonable progress goals for Class I areas.

At this time it is highly uncertain how future regional haze SIP revisions could affect Otter Tail's facilities, but post-2020 Otter Tail believes the rule could possibly require NOx and SO_2 reductions at Hoot Lake Plant and possible additional NO_X and SO_2 reductions at Coyote.

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[2] Note that within the June 12, 2012 approval EPA deferred action on the MN Regional Haze SIP for taconite facilities and Xcel Energy's Sherburne County facility until a later time

II. HAZARDOUS AIR POLLUTANTS

A. 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 by electric steam generating plants. The EPA completed required studies and submitted reports to Congress, and determined that it would regulate mercury emissions from electric generating units under the hazardous air pollutant requirements of the CAA.[3] EPA then published final rules that reversed this determination and set forth a cap and trade program for mercury emissions; however, EPA's cap and trade mercury rule was reversed by the United States Court of Appeals for the D.C. Circuit in February 2008.

In response to the D.C. Circuit Court's vacatur, 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, which was subsequently published in the Federal Register on February 16, 2012.

Power plants have three years and sixty days from the date of publication (April 16, 2015) to comply with MATS, although EPA is encouraging state permitting authorities to broadly grant a one-year compliance extension to plants that need additional time to install controls. The EPA is also providing a pathway for reliability critical units to obtain an additional year to achieve compliance; however, the EPA believes there will be few, if any situations, in which this pathway is needed.

Hoot Lake Plant will meet MATS by upgrading the Unit 2 and Unit 3 electrostatic precipitators to reduce particulate, installing activated carbon injection to reduce mercury, and possibly installing a sodium or calcium based dry sorbent injection system to control hydrogen chloride. Coyote Station will meet MATS by installing activated carbon injection. Finally, Big Stone Plant will install activated carbon injection in conjunction with the pollution control equipment required by the Regional Haze Rule. Due to the extensive nature of the Big Stone Plant equipment, on August 27, 2013, the plant was granted a one year extension (until April 16, 2016) by the South Dakota Department of Environment and Natural Resources to comply with MATS. Emissions monitoring equipment and/or stack testing will also be needed to verify compliance with the standards.

B. Minnesota TMDL

The federal Clean Water Act requires each state to evaluate its water bodies and determine whether they meet water-quality standards. For mercury, these standards define how much

[3] 65 Fed. Reg. 79825 (Dec. 20, 2000), Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units.

mercury can be in the water and in fish. Water bodies that do not meet water-quality standards are added to a list of water bodies referred to as the Impaired Waters List. About two-thirds of the water impairments on Minnesota's 2006 Impaired Water List were due to mercury.

To address impaired waters, states are required to evaluate the sources of pollution, the reduction in the pollutant needed to meet water-quality standards, and allowable levels of future pollution. This evaluation, typically done for each water body or watershed, is called a Total Maximum Daily Load, or TMDL. Because the source of essentially all mercury to Minnesota waters is the atmosphere, the Minnesota Pollution Control Agency (MPCA) prepared a statewide mercury TMDL. This TMDL established an annual mercury air emission target of 789 pounds, and was approved by the MPCA Board in December 2006 and by the EPA in March 2007.

To achieve the goals of the TMDL, a stakeholder process was convened to develop specific recommendations. The stakeholders identified sector-specific strategies to meet the TMDL targets by 2025, and one of the sector-specific strategies includes reducing mercury emissions from Minnesota coal-fired generation.

According to the final TMDL stakeholder strategy document, Hoot Lake Plants Units 2 and 3 will be required to file with the MPCA by 2015 a mercury emissions reduction plan that is most likely to result in the removal of at least 70 percent of the mercury emitted from each unit or an equivalent reduction by 2025. Since this timeframe is beyond the timeframe of compliance for the MATS rule, compliance with the TMDL target for Hoot Lake Plant will be demonstrated through compliance with the MATS rule.

III. GREENHOUSE GAS REGULATION

A. Background

In 2009 EPA began addressing greenhouse gas ("GHG") emissions using the 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 CO_2 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. Since the motor vehicle standard regulated GHG emissions for the first time under the CAA, GHG emissions are therefore included in the pollutants subject to the requirements of the New Source Review program of the CAA.

Additionally, on June 25, 2013 President Obama issued a memorandum directing the EPA to implement carbon pollution standards for new power plants, and to implement carbon pollution standards, regulations, or guidelines for modified, reconstructed, and existing power plants.

B. New Source Review

Under the New Source Review Program, the Prevention of Significant Deterioration ("PSD") program applies to areas of the country that attain the NAAQS (or are unclassifiable), 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.

On June 3, 2010, EPA issued a final "tailoring rule" that phases in application of this program to GHG emission sources, including power plants. This program applies to existing sources if there is a physical change or change in the method of operation of the facility that results in a significant net emissions increase. As a result, PSD does not apply on a set timeline as is the case with other regulatory programs, but is triggered depending on what activities take place at a major source.

The EPA decided to phase in the PSD requirements for GHGs in two steps. Beginning on January 2, 2011, GHG control analysis was conducted in PSD permit proceedings only if changes at a facility trigger PSD for criteria pollutants and if the proposed change increases GHGs by over 75,000 tons per year of CO_2e, a measure that converts emissions of each GHG into its carbon dioxide equivalent. Until July of 2011, the threshold applied only to facilities currently subject to PSD or Title V permitting. However, as of July 2011, sources emitting more than 100,000 tons per year of CO_2e are considered major sources subject to PSD requirements if they propose to make modifications resulting in a net GHG emissions increase of 75,000 tons per year or more of CO_2e. Otter Tail's facilities are not contemplating any changes that would result in a significant net GHG emissions increase.

C. New Source Performance Standards

On September 20, 2013, EPA announced proposed New Source Performance Standards ("NSPS") that would additionally regulate GHGs from new electric generating units ("EGUs"). The proposed rulemaking would set the following limits:

- Fossil fuel-fired utility boilers and integrated gasification combined cycle units:
  - 1,100 pounds of CO_2 per megawatt-hour (lb CO_2/MWh-gross) over a 12-operating month period, or
  - 1,000-1,050 lb CO_2/MWh over an 84-operating month (7-year) period

- Natural gas-fired stationary combustion turbines
  - 1,000 lb CO_2/MWh for larger units (>850 mmBtu/hr)
  - 1,100 lb CO_2/MWh for smaller units (≤850 mmBtu/hr)

The rulemaking would not apply to new existing plants of any kind, including reconstruction or modification of existing plants. Additionally, the proposed rule does not apply to low capacity factor EGUs that sell less than 1/3 of their potential power to the grid.

At this time Otter Tail is not actively constructing any new fossil fuel plants, and it is anticipated that EPA will finalize the new source standards in advance of Otter Tail constructing any new generating facilities.

D. Existing Source Guidelines

EPA's existing source GHG guidelines are expected to proceed under Section 111(d) of the CAA. Section 111(d) establishes a federal-state structure, whereby EPA first sets a guideline that prescribes a minimum threshold for each state's development of a performance standard(s). The regulations provide that EPA's guideline to the states must reflect: "the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emissions standard of equivalent stringency can be achieved. The Administrator will specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate." 40 C.F.R. § 60.22(b)(5).

After receiving the guideline, states must submit an implementation plan that is no less stringent than the EPA guideline, and "final compliance shall be required as expeditiously as practicable but no later than the compliance times specified in [the guideline.]" 40 C.F.R. § 60.24(c). However, states do have some leeway to vary from the guidelines to account for the remaining useful life of plants, or provided that the State demonstrates: (1) unreasonable control costs due to plant age, location, or design; (2) physical impossibility of installing control equipment; or (3) other factors that make a less stringent approach significantly more reasonable. 40 C.F.R. § 60.24(f)(3).

The Presidential memorandum directs EPA to issue proposed guidelines for existing plants no later than June 1, 2014, to issue final guidelines by June 1, 2015, and to require States to submit implementation plans to EPA no later than June 30, 2016. Since proposed guidelines have not yet been issued, at this time Otter Tail is not able to assess the potential impact to our generating facilities.

IV. COAL COMBUSTION RESIDUALS REGULATION

On June 21, 2010, EPA published a proposed rule that outlines two possible options to regulate disposal of coal ash generated from the combustion of coal by electric utilities under the

Resource Conservation and Recovery Act ("RCRA"). In one option, EPA would propose to list coal ash destined for disposal in landfills or surface impoundments as "special wastes" subject to regulation under Subtitle C of RCRA. Subtitle C regulations set forth the EPA's hazardous waste regulatory program, which regulates the generation, handling, transport, and disposal of wastes.

The proposal would create a new category of special waste under Subtitle C, so that coal ash would not be classified as hazardous waste, but would be subject to many of the regulatory requirements applicable to hazardous wastes. This option would subject coal ash to technical and permitting requirements from the point of generation to final disposal. EPA is considering whether to impose disposal facility requirements such as liners, groundwater monitoring, fugitive dust controls, financial assurance, corrective action, closure of units, and post-closure care. This option also includes potential requirements for dam safety and stability for surface impoundments, land disposal restrictions, treatment standards for coal ash, and a prohibition on the disposal of treated coal ash below the natural water table. Beneficial re-uses of coal ash would not be subject to these requirements.

Under the second proposed regulatory option EPA would regulate the disposal of coal ash under Subtitle D of RCRA, the regulatory program for non-hazardous solid wastes. In this option, EPA is considering issuing national minimum criteria to ensure the safe disposal of coal ash, which would subject disposal units to location standards, composite liner requirements, groundwater monitoring and corrective action standards for releases, closure and post-closure care requirements, and requirements to address the stability of surface impoundments. Within this option, EPA is also considering not requiring existing surface impoundments to close or install composite liners and allowing them to continue to operate for their useful life.

This option would not regulate the generation, storage, or treatment of coal ash prior to disposal, and no federal permits would be required.[4] EPA's proposal also states that EPA is considering whether to list coal ash as a hazardous substance under the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), and includes proposals for alternative methods to adjust the statutory reportable quantity for coal ash. EPA has not decided which regulatory approach it will take with respect to the management and disposal of coal ash.

The Hoot Lake Plant operates a dry ash disposal site that is regulated, permitted and inspected by the MPCA. The existing operating site is lined with a synthetic liner and it has a leachate collection system. Future portions of the designated disposal areas will be covered with a synthetic cover and an engineered soil cover. The site has a groundwater monitoring system and annual reports have been provided to the MPCA.

[4] 75 Fed. Reg. 35133 (June 21, 2010), Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities, Proposed Rule.

Big Stone Plant operates a dry disposal site that is regulated, permitted and inspected by the South Dakota Department of Environment and Natural Resources ("DENR"). 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 DENR. Big Stone Plant also operates an impoundment to temporarily handle boiler slag that is sluiced to the impoundment. Boiler slag is either dry disposed in the permanent disposal site or beneficially reused, commonly as a blasting media, shingle grit, and in traction control on icy roads.

Coyote Station operates two dry disposal sites that are regulated, permitted and inspected by the North Dakota Department of Health ("DOH"). One site has an engineered clay liner for flue gas desulfurization product, and the other site is permitted to receive inert waste such as boiler slag. The site has a groundwater monitoring system and annual reports have been provided to the DOH. Coyote Station also operates three impoundments to dewater and temporarily handle boiler slag that is sluiced to the impoundments. Similar to Big Stone, the slag at Coyote Station is often beneficially reused.

While additional requirements may or may not be imposed at any or all of these facilities as part of EPA's pending rule, identification of specific costs would be contingent on the requirements of the final rule. EPA has indicated that a final rule may be issued in 2014.

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 April 20, 2011, EPA published proposed national standards for cooling water intake structures at all existing power generating facilities and existing manufacturing and industrial facilities as part of further implementing Section 316(b).

Hoot Lake Plant uses once-through cooling except during periods of low water availability and during periods when the water discharge permit require use of the plant cooling towers. The impact of the Hoot Lake Plant intake structure has been extensively evaluated in two separate studies (conducted in 1976 and 2005), both of which showed minimal impact, and in fact in December 1977 the MPCA, the Minnesota Department of Natural Resources, and EPA concluded that Hoot Lake Plant's intake structure creates a negligible impact in the aquatic ecosystem and was therefore in compliance with Section 316(b).

After issuing the proposed rule, EPA received extensive comments and new data, including the two Hoot Lake Plant studies. Due to the new information EPA received, they published a Notice of Data Availability ("NODA) on June 11, 2012 to provide a further opportunity to comment on the new information and possible revisions to the final rule that the Agency is considering. One of the issues EPA requested further comment on is establishing an alternative compliance limit for facilities that have low impingement rates, which may be applicable to Hoot Lake Plant.

Although a final rule is anticipated in late 2013 or early 2014, OTP will need to wait for publication of the final rule in the Federal Register and likely have discussions with the MPCA before reaching a conclusion on the 316(b) rule impact at Hoot Lake Plant. Both Big Stone Plant and Coyote Station use closed cycle cooling, and it is anticipated that those facilities will not be 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. The proposed rulemaking primarily focuses on discharge restrictions applicable to fly ash transport water, bottom ash transport water, and flue gas desulfurization wastewater.

Effluent limits specific to Hoot Lake Plant and Coyote Station are incorporated into their National Pollutant Discharge Elimination System ("NPDES") permits. Big Stone Plant is a zero discharge facility and therefore does not have a NPDES permit. Hoot Lake Plant's and Coyote Station's permit limits are based on a combination of state water quality standards, the Federal ELG, and best professional judgment. Hoot Lake Plant is permitted for several effluent discharges, including once-through cooling water, coal pile runoff and metal cleaning wastes, and other low-volume waste sources such as floor drains and boiler blowdown. Hoot Lake Plant does not use water to transport either fly ash or bottom ash. Coyote Station's primary effluent discharge is cooling tower blowdown while Big Stone Plant is a zero discharge facility. Although Coyote Station and Big Stone Plant use water to sluice boiler slag, this water is not discharged. Since the ELG rule is not final, at this time Otter Tail is unable to determine how it will affect our facilities, but it appears that the rule could have minimal effect since the facilities do not discharge fly ash transport water, bottom ash transport water, or flue gas desulfurization wastewater. EPA is currently scheduled to issue a final rule in May 2014.

SUMMARY

Environmental Regulatory Assessment Summary

Legend: Air related | Solid Waste related | Water related

Rule	Status	Anticipated Hoot Lake Plant Impact	Anticipated Big Stone Plant Impact	Anticipated Coyote Station Impact	Anticipated Compliance Timeframe
Acid Rain Program	Final	Maintain banked allowances (SO2); Operate existing low NOx burners	Maintain banked allowances (SO2); Operate existing overfire air	Maintain banked allowances (SO2)	Ongoing
2010 NO2 and SO2 NAAQS	Final	Low impact anticipated; MN has no monitored violations	Low impact anticipated; SD has no monitored violations	Low impact anticipated; ND has no monitored violations	2017 - 2022
Clean Air Interstate Rule	Final	None -- Rule stayed for MN	None -- Rule does not apply to SD	None -- Rule does not apply to ND	None
Cross-State Air Pollution Rule	Vacated; being considered by Supreme Court	Rule would have required SO2 allowance purchases	None -- Rule did not apply to SD	None -- Rule did not apply to ND	Unknown
Regional Haze Program – Best Available Retrofit Technology	Final	None – HLP2 not BART eligible and HLP3 deemed not subject to BART	Selective Catalytic Reduction and separated overfire air for NOx, scrubber for SO2, and baghouse for PM	Coyote Station not BART eligible, but Coyote agreed to install separated overfire air for NOx	2016 - 2018
Regional Haze Program – SIP Revisions	Next SIP due by July 31, 2018	Possible reductions of SO2 and NOx	None	Possible NOx and SO2 reductions	Post 2020
Mercury and other Hazardous Air Pollutants (MATS)	Final	Upgrade electrostatic precipitators for PM, install activated carbon injection for Hg, possible dry sorbent injection for HCl	BART equipment plus activated carbon injection	Activated carbon injection	April 2015 (HLP and Coy) April 2016 (BSP)
Minnesota TMDL	Final	70% reduction in mercury air emission; Compliance achieved through MATS	N/A	N/A	2025
Greenhouse Gas Regulation – Tailoring Rule	Final	PSD Review for projects that result in a significant net CO_2 increase – No PSD Projects planned	No PSD projects planned	No PSD projects planned	N/A
Greenhouse Gas Regulation – NSPS	Proposed Sep. 2013	N/A – Applicable to New Plants Only	N/A – Applicable to New Plants Only	N/A – Applicable to New Plants Only	2014 for new plants
Greenhouse Gas Regulation – 111(d)	To Be Proposed June 2014	Unknown	Unknown	Unknown	Unknown

Table Continued on Next Page

Coal Combustion Residuals	Proposed Rule June 2010	Unknown – EPA proposed two significantly different options. Impact to HLP could be low due to managing an active dry ash disposal site with a synthetic liner and leachate collection.	Unknown – EPA proposed two significantly different options. BSP manages an active dry ash disposal site, but the rule could impact design of the current boiler slag impoundment and/or future disposal site sequences.	Unknown – EPA proposed two significantly different options. Coyote manages an active dry ash disposal site, but the rule could impact design of the current boiler slag impoundment and/or future disposal site sequences	Unknown – anticipated 5 years after final rule
Clean Water Act Section 316(b)	Proposed Rule	To Be Determined – potential compliance timeframe coincides closely with planned Hoot Lake Plant retirement	Big Stone uses cooling ponds that qualify as closed cycle cooling	Coyote Station uses a cooling tower that qualifies as closed cycle cooling	Up to 8 years after final rule
Effluent Guidelines	Proposed Rule	Low impact anticipated since HLP does not use any fly ash or bottom ash transport water.	Low impact anticipated due to not discharging boiler slag transport water to waters of the United States.	Low impact anticipated due to not discharging boiler slag transport water to waters of the United States.	2017 - 2022

Appendix F: Strategist Modeling Assumptions

PUBLIC DOCUMENT – TRADE SECRET DATA

HAS BEEN EXCISED

[TRADE SECRET DATA BEGINS…

Appendix F: Strategist Modeling Assumptions

is Trade Secret in its entirety.

…TRADE SECRET DATA ENDS]

Appendix G: Otter Tail's REO/RES Compliance Strategy

Table of Contents

REO/RES Compliance Strategy

This document identifies and discusses the renewable energy requirements of the three states in which Otter Tail Power Company operates. The Company has developed significant wind generation resources, which when included with other 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 load 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 I describes the requirements in each of the state jurisdictions. Additional detail regarding the state rules follows.

Table I
Jurisdictional REO/RES Requirements

	Minnesota	**North Dakota**	**South Dakota**
REO	2007-2009 1% 2010-2011 7% *(as percentage of retail sales after conservation)*	Prior to 2015 0% 2015 and on 10% *(as percentage of retail sales with an adjustment for hydro energy that cannot be counted toward compliance)*	Prior to 2015 0% 2015 and on 10% *(as percentage of retail sales with an adjustment for hydro energy that cannot be counted toward compliance)*
RES[1]	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

[1] 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.

Minnesota

Eligible energy technologies for compliance include solar, wind, hydroelectric with a capacity of less than 100 MW, hydrogen,[2] 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 PUC 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.

North Dakota

The state REO is 10 percent of retail sales by the year 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.[3] Renewable electricity and recycled energy includes electricity generated from solar, wind, biomass,[4] geothermal, hydrogen,[5] 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 PSC has not made a determination of the shelf life of RECs for compliance purposes. The 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 state REO is 10 percent of retail sales by the 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.[6] Renewable electricity and recycled energy include electricity generated from solar, wind, biomass,[7] geothermal, hydrogen,[8] 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.

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[2] After January 1, 2010 the hydrogen must be generated from the other eligible energy technologies listed.

[3] North Dakota Century Code §49-02-30.

[4] Including agricultural crops and wastes and residues, wood and wood wastes and residues, animal wastes, and landfill gas.

[5] Provided that the hydrogen is generated from a source listed in this section of North Dakota Century Code §49-02-25.

[6] South Dakota Codified Laws §49-34A-103.

[7] Includes agricultural crops and wastes and residues, wood and wood wastes and residues, animal and other degradable organic wastes, and landfill gas.

[8] Provided that the hydrogen is generated from a source listed in this section of South Dakota Codified Laws §49-34A-94.

2 Midwest Renewable Energy Tracking System

Otter Tail has registered almost all renewable energy resources within the Midwest Renewable Energy Tracking System ("M-RETS"). There are small customer-owned 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-

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 Tail*Winds*, the Company's green pricing program, are retired into separate state jurisdiction accounts to ensure proper accounting for the green pricing tracker balance.

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.

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 Allowances

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. Jurisdictional ownership of RECs has already become an issue for Otter Tail in the resource recovery rider dockets before the Minnesota and North Dakota Commissions.

The MN Commission, in approving the renewable rider recovery for the Langdon Wind Center, included a requirement that MN retail customers be credited the revenues associated with any sales of Langdon Wind Center RECs. REC ownership has also become an issue raised by interveners in the North Dakota rate case, with interveners claiming that surplus RECs should be sold and the revenue credited back to retail customers.

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 isn't a risk of those RECs exceeding the allowable shelf life for MN compliance. This provides RES compliance through at least 2020, with just MN allocated RECs.

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.
- Sell all surplus Dakotas jurisdiction RECs through 2014, and then re-evaluate the strategy for future banking of any Dakotas surplus RECs for future compliance and transfer to MN.

5 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. This is especially critical after 2015.
- Otter Tail sells the surplus ND and SD RECs before considering banking any allowances to use for REO compliance in those two states.
- 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: Update on C-BED Projects

Update on C-BED Projects

Minnesota Stat. §216B.1612 requires utilities submitting resource plans under Minnesota Stat. §216B.2422 to include a description of its efforts to purchase energy from Community Based Energy Development ("C-BED"), including a list of projects under contract and the amount of C-BED energy purchased.

Otter Tail has one project currently under a C-BED PPA that began in 2011. The PPA is with the University of Minnesota-Morris for the net generation from a 1,650 kw wind facility. The net energy purchased from the project in 2012 was 5,130 MWh.

The Company has numerous C-BED eligible projects that have chosen not to use a C-BED PPA. There are several primary reasons that project developers have chosen not to use the C-BED tariff. Minnesota Stat. §216B.1612, subd. 3 requires a 20-year life of the PPA. Most small developers do not like the risks associated with a long-term firm obligation to supply, as this requirement is viewed as placing them at some future risks should there be significant project difficulties due to mechanical failure. The same subdivision also requires sufficient security to guarantee performance over the life of the project, which increases cost and complexity for the developer. Finally, many project owners choose to use some of the generation to serve their native load on-site and these situations make it more difficult to establish pricing to ensure the higher upfront cost in the C-BED PPA is offset by the lower long-term cost in the PPA.

It is difficult for C-BED projects based in Minnesota to compete economically with other wind generation projects available to the Company. The federal Production Tax Credit ("PTC") currently reduces the cost of wind generation by about 33 percent. Many of the entities eligible for C-BED are tax exempt entities and therefore do not benefit from the federal PTC.

The Company continues to evaluate C-BED projects. However, recent C-BED proposals have had a significant price premium compared to other alternatives. As a result, Otter Tail has not added a C-BED project to its portfolio since 2011.

Appendix I: Integrated Resource Plan

Sensitivity Summary

Appendix I - 2013 Integrated Resource Plan Sensitivity Summary

Externality values applied

Energy Market OFF (after 2018)

Sensitivity:	1-Base (ordered)	2-Wind $30	3-Wind $60	4-Solar compliance $75	5-Solar compliance $133	6-Solar compliance $150	7 -50% Natural Gas price	8 -25% Natural Gas price	9 +25% Natural Gas price	10 +50% Natural Gas price	11 Low Coal price	12 High Coal price	13 Low Load Growth	14 High Load Growth	15 Low Capital Cost	16 High Capital Cost	17 Low Energy Market Price	18 High Energy Market Price	19 Low Externality	20 High Externality	21 CO2 reduction Goal
Mkt Forecast Basis	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013
CO2 Tax/ton(Start Yr)	$21.50 (2017)	$21.50 (2017)	$21.50 (2017)	$21.50 (2017)	$21.50 (2017)	$21.50 (2017)	$21.50 (2017)	$21.50 (2017)	$21.50 (2017)	$21.50 (2017)	$21.50 (2017)	$21.50 (2017)	$21.50 (2017)	$21.50 (2017)	$21.50 (2017)	$21.50 (2017)	$21.50 (2017)	$21.50 (2017)	$9.00 (2017)	$34.00 (2017)	$21.50 (2017)
Assumption Sensitivity	N/A	$30	$60	$75	$133	$150	-50%	-25%	+25%	+50%	-25%	25%			-30%	+30%	-25%	+25%	$9/Ton	$34/Ton	$21.50/Ton
Plan Year																					
2014																					
2015																					Wind(150)
2016																					Wind(50)
2017														Wind(50) CAP(44)							
2018														CAP(44)							
2019	SC-Large(194) Wind(50)	SC-Large(194) Wind(50)	CC(292)	SC-Large(194) SLR(21)	SC-Large(194) SLR(21)	SC-Large(194) SLR(21)	CC(292)	CC(292)	SC-Large(194) Wind(50)	SC-Large(194) Wind(50)	SC-Large(194) Wind(50)	CC(292)	SC-Large(194)	CC(292) SC-Small(44)	CC(292)	SC-Large(194) Wind(50)	SC-Large(194) Wind(50)	SC-Large(194) Wind(50)	SC-Large(194) Wind(50)	CC(292)	SC-Large(194) Wind(100)
2020																					Wind(50)
2021	SC-Med(94)	SC-Small(44) SLR(10) Wind(450)	SC-Small(44) SC-Small(44) SC-Small(44)	SC-Med(94)	SC-Med(94)	SC-Med(94)	SC-Med(94) SC-Small(44)	SC-Med(94) SC-Small(44)	SC-Med(94)	SC-Small(44) SLR(14) Wind(300)	SC-Med(94)	SC-Med(94) Wind(100)	SLR(4) Wind(150)	SC-Small(44) SC-Small(44) SC-Small(44)	SC-Med(94) SC-Small(44)	SC-Med(94)	SC-Med(94)	SC-Med(94)	SC-Med(94)	SC-Med(94) Wind(100)	SC-Med(94)
2022		SC-Small(44)								SC-Small(44)		Wind(100)	SC-Small(44)							Wind(100)	
2023																					
2024	Wind(50)			Wind(50)	Wind(50)	Wind(50)			Wind(50)		Wind(50)					Wind(50)	Wind(50)	Wind(50)	Wind(50)		
2025																					Wind(50)
2026																					Wind(50)
2027																					
2028																					
Planning Period 2014$	$2,713,372	$2,602,688	$2,756,344	$2,728,805	$2,743,993	$2,748,445	$2,532,612	$2,654,644	$2,783,229	$2,807,749	$2,516,143	$2,909,221	$2,455,256	$3,013,168	$2,675,382	$2,759,989	$2,685,025	$2,729,039	$2,324,370	$3,078,856	$2,741,308
Difference from Base	0.00%	-4.08%	1.58%	0.57%	1.13%	1.29%	-6.66%	-2.16%	2.57%	3.48%	-7.27%	7.22%	-9.51%	11.05%	-1.40%	1.72%	-1.04%	0.58%	-14.34%	13.47%	1.03%
End Effects NPV	$2,291,896	$2,176,657	$2,284,546	$2,301,138	$2,321,593	$2,327,591	$2,033,010	$2,151,740	$2,335,163	$2,420,187	$2,144,482	$2,391,253	$2,088,493	$2,496,724	$2,163,069	$2,364,727	$2,291,896	$2,291,896	$1,907,688	$2,597,637	$2,351,286
Total ($000)	$5,005,268	$4,779,345	$5,040,890	$5,029,943	$5,065,586	$5,076,036	$4,565,622	$4,806,384	$5,118,392	$5,227,936	$4,660,625	$5,300,474	$4,543,748	$5,509,892	$4,838,451	$5,124,716	$4,976,921	$5,020,935	$4,232,058	$5,676,493	$5,092,594
Difference from Base	0.00%	-4.51%	0.71%	0.49%	1.21%	1.41%	-8.78%	-3.97%	2.26%	4.45%	-6.89%	5.90%	-9.22%	10.08%	-3.33%	2.39%	-0.57%	0.31%	-15.45%	13.41%	1.74%

Energy Market ON

Sensitivity:	1-Base -Market ON	2-Wind $30	3-Wind $60	4-Solar compliance $75	5-Solar compliance $133	6-Solar compliance $150	7 -50% Natural Gas price	8 -25% Natural Gas price	9 +25% Natural Gas price	10 +50% Natural Gas price	11 Low Coal price	12 High Coal price	13 Low Load Growth	14 High Load Growth	15 Low Capital Cost	16 High Capital Cost	17 Low Energy Market Price	18 High Energy Market Price	19 Low Externality	20 High Externality	21 CO2 reduction Goal
2014																					
2015																					Wind(150)
2016																					Wind(50)
2017														Wind(50)							
2018														CAP(44)							
2019				SLR(21)	SLR(21)	SLR(21)								CAP(35)							Wind(50)
2020														CAP(37)							Wind(50)
2021	SC-Small(44) SC-Small(44) Wind(200) CAP(44)	SC-Small(44) Wind(400) CAP(48)	SC-Large(194)	SC-Small(44) Wind(350) CAP(49)	SC-Small(44) Wind(350) CAP(49)	SC-Small(44) Wind(350) CAP(49)	CC(292)	SC-Med(94) Wind(150) CAP(47)	SC-Small(44) Wind(400) CAP(48)	SC-Small(44) Wind(400) CAP(48)	SC-Med(94) Wind(150) CAP(47)	SC-Small(44) Wind(400) CAP(48)	SC-Small(44) Wind(100) CAP(46)	SC-Small(44) SC-Med(94) Wind(200) CAP(45)	SC-Med(94) Wind(150) CAP(47)	SC-Small(44) Wind(400) CAP(48)	HLtoGas(122) CAP(50)	SC-Small(44) Wind(400) CAP(48)	SC-Large(194)	SC-Small(44) Wind(400) CAP(48)	SC-Small(44) Wind(100) CAP(48)
2022	CAP(43) Wind(50)	CAP(47) Wind(50)		CAP(48) Wind(50)	CAP(48) Wind(50)	CAP(48) Wind(50)		CAP(46) Wind(50)	CAP(47) Wind(50)	CAP(47) Wind(50)	CAP(46) Wind(50)	CAP(47) Wind(50)	CAP(45) Wind(50)	CAP(45) Wind(50)	CAP(46) Wind(50)	CAP(47) Wind(50)	CAP(49) Wind(50)	CAP(13) SC-Small(44)		CAP(47) Wind(50)	CAP(47) Wind(50)
2023	CAP(45)	CAP(49)		CAP(40) Wind(50)	CAP(40) Wind(50)	CAP(40) Wind(50)		CAP(48)	CAP(49)	CAP(49)	CAP(48)	CAP(49)	CAP(47)	CAP(47)	CAP(48)	CAP(49)	CAP(41) Wind(50)	CAP(15)		CAP(49)	CAP(49)
2024	CAP(47)	CAP(41) Wind(50)		CAP(42)	CAP(42)	CAP(42)		CAP(40) Wind(50)	CAP(41) Wind(50)	CAP(41) Wind(50)	CAP(40) Wind(50)	CAP(41) Wind(50)	CAP(48)	CAP(49)	CAP(40) Wind(50)	CAP(41) Wind(50)	CAP(43)	CAP(17)		CAP(41) Wind(50)	CAP(41) Wind(50)
2025	CAP(49)	CAP(43)		CAP(44)	CAP(44)	CAP(44)		CAP(42)	CAP(43)	CAP(43)	CAP(42)	CAP(43)	CAP(40) Wind(50)	CAP(41) Wind(50)	CAP(42)	CAP(43)	CAP(45)	CAP(19)		CAP(43)	CAP(43)
2026	CAP(46)	CAP(40)		CAP(41)	CAP(41)	CAP(41)		CAP(39)	CAP(40)	CAP(40)	CAP(39)	CAP(40)	CAP(37)	CAP(38)	CAP(39)	CAP(40)	CAP(42)	CAP(16)		CAP(40)	CAP(40)
2027	CAP(48)	CAP(42)		CAP(44)	CAP(44)	CAP(44)		CAP(42)	CAP(42)	CAP(42)	CAP(42)	CAP(42)	CAP(39)	CAP(41)	CAP(42)	CAP(42)	CAP(44)	CAP(18)		CAP(42)	CAP(42)
2028	CAP(41) Wind(50)	CAP(45)		CAP(46)	CAP(46)	CAP(46)		CAP(44)	CAP(45)	CAP(45)	CAP(44)	CAP(45)	CAP(42)	CAP(43)	CAP(44)	CAP(45)	CAP(47)	CAP(21)		CAP(45)	CAP(45)
Planning Period 2014$	$2,629,426	$2,517,053	$2,674,114	$2,624,607	$2,639,795	$2,644,247	$2,531,298	$2,613,789	$2,631,633	$2,637,771	$2,439,334	$2,795,093	$2,389,171	$2,894,901	$2,615,091	$2,630,679	$2,555,551	$2,667,318	$2,228,503	$3,006,325	$2,659,394
Difference from Base	0.00%	-4.27%	1.70%	-0.18%	0.39%	0.56%	-3.73%	-0.59%	0.08%	0.32%	-7.23%	6.30%	-9.14%	10.10%	-0.55%	0.05%	-2.81%	1.44%	-15.25%	14.33%	1.14%
End Effects NPV	$2,220,190	$2,024,268	$2,263,458	$2,223,612	$2,244,068	$2,250,065	$2,059,687	$2,184,780	$2,230,473	$2,232,263	$2,097,048	$2,312,208	$1,992,769	$2,461,303	$2,195,835	$2,240,341	$2,097,691	$2,280,068	$1,764,967	$2,556,951	$2,229,228
Total ($000)	$4,849,616	$4,541,321	$4,937,572	$4,848,219	$4,883,863	$4,894,312	$4,590,985	$4,798,569	$4,862,106	$4,870,033	$4,536,381	$5,107,301	$4,381,940	$5,356,204	$4,810,926	$4,871,020	$4,653,242	$4,947,385	$3,993,470	$5,563,275	$4,888,622
Difference from Base	0.00%	-6.36%	1.81%	-0.03%	0.71%	0.92%	-5.33%	-1.05%	0.26%	0.42%	-6.46%	5.31%	-9.64%	10.45%	-0.80%	0.44%	-4.05%	2.02%	-17.65%	14.72%	0.80%

SC-Small (44) - Generic 49 MW nameplate capacity aeroderivitive simple cycle unit	CC (292) - Generic 311 MW nameplate capacity frame type combined cycle unit	HLtoGas(122) - 122 MW nameplate capacity conversion of units 2 and 3 at Hoot Lake Plant from coal to natural ga
SC-Med (94) - Generic 101 MW nameplate capacity aeroderivitive simple cycle unit	Wind (50) - Generic 50 MW nameplate capacity wind resource	CHP(88) - Generic 96 MW nameplate capacity frame type combined heat and power resource
SC-Large (194) - Generic 211 MW nameplate capacity frame type simple cycle unit	SLR (1) - Generic 1 MW nameplate capacity solar photovoltaic resource	

Appendix I - 2013 Integrated Resource Plan Sensitivity Summary

Zero Externalities (current legislation in all jurisdictions)

Energy Market OFF (after 2018)

Sensitivity:	22-Zero Externality Base	23-Wind $30	24-Wind $60	25-Solar compliance $75	26-Solar compliance $133	27-Solar compliance $150	28 -50% Natural Gas price	29 -25% Natural Gas price	30 +25% Natural Gas price	31 +50% Natural Gas price	32 Low Coal price	33 High Coal price	34 Low Load Growth	35 High Load Growth	36 Low Capital Cost	37 High Capital Cost	38 Low Energy Market Price	39 High Energy Market Price
Mkt Forecast Basis	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013	WM May 2013
CO2 Tax/ton(Start Yr	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities	Zero externalities
Assumption Sensitiv	$0/Ton	$30	$60	$75	$133	$150	-50%	-25%	+25%	+50%	-25%	25%			-30%	+30%	-25%	+25%
Plan Year																		
2014																		
2015																		
2016																		
2017														Wind(100) CAP(44)				
2018														CAP(44)				
2019	SC-Large(194) Wind(50)	SC-Large(194) Wind(50)	SC-Large(194) SC-Small(44)	SC-Large(194) SLR(21)	SC-Large(194) SLR(21)	SC-Large(194) SLR(21)	SC-Large(194) CHP(88)	SC-Large(194) SC-Small(44)	SC-Large(194) Wind(50)	SC-Large(194) Wind(50)	SC-Large(194) Wind(50)	SC-Large(194) Wind(50)	SC-Large(194)	SC-Large(194) SC-Med(94)	SC-Large(194) SC-Small(44)	SC-Large(194) Wind(50)	SC-Large(194) Wind(50)	SC-Large(194) Wind(50)
2020																		
2021	SC-Med(94)	SC-Med(94)	SC-Med(94)	SC-Med(94)	SC-Med(94)	SC-Med(94)	SC-Small(44)	CHP(88)	SC-Med(94)	SC-Med(94)	SC-Med(94)	SC-Med(94)	SC-Small(44)	CHP(88)	CHP(88)	SC-Med(94)	SC-Med(94)	SC-Med(94)
2022																		
2023																		
2024	Wind(50)	Wind(50)		Wind(50)	Wind(50)	Wind(50)			Wind(50)	Wind(50)	Wind(50)	Wind(50)	Wind(50)			Wind(50)	Wind(50)	Wind(50)
2025																		
2026																		
2027																		
2028																		
Planning Period 2014$	$2,046,500	$2,024,807	$2,066,736	$2,050,438	$2,065,626	$2,070,078	$1,880,496	$1,978,202	$2,115,950	$2,185,913	$1,848,442	$2,240,940	$1,839,853	$2,300,424	$1,999,769	$2,093,117	$2,021,612	$2,062,508
Difference from Base	0.00%	-1.06%	0.99%	0.19%	0.93%	1.15%	-8.11%	-3.34%	3.39%	6.81%	-9.68%	9.50%	-10.10%	12.41%	-2.28%	2.28%	-1.22%	0.78%
End Effects NPV	$1,631,011	$1,590,019	$1,630,241	$1,625,381	$1,645,837	$1,651,834	$1,400,841	$1,530,840	$1,673,139	$1,733,742	$1,481,955	$1,759,100	$1,446,290	$1,830,302	$1,544,013	$1,703,843	$1,631,011	$1,631,011
Total ($000)	$3,677,512	$3,614,826	$3,696,977	$3,675,819	$3,711,462	$3,721,912	$3,281,337	$3,509,042	$3,789,089	$3,919,655	$3,330,397	$4,000,040	$3,286,144	$4,130,726	$3,543,782	$3,796,960	$3,652,624	$3,693,520
Difference from Base	0.00%	-1.70%	0.53%	-0.05%	0.92%	1.21%	-10.77%	-4.58%	3.03%	6.58%	-9.44%	8.77%	-10.64%	12.32%	-3.64%	3.25%	-0.68%	0.44%

Energy Market ON

Sensitivity:	22-Zero Externality Base (Preferred)	23-Wind $30	24-Wind $60	25-Solar compliance $75	26-Solar compliance $133	27-Solar compliance $150	28 -50% Natural Gas price	29 -25% Natural Gas price	30 +25% Natural Gas price	31 +50% Natural Gas price	32 Low Coal price	33 High Coal price	34 Low Load Growth	35 High Load Growth	36 Low Capital Cost	37 High Capital Cost	38 Low Energy Market Price	39 High Energy Market Price
2014																		
2015																		
2016																		
2017														Wind(50)				
2018														CAP(44)				
2019				SLR(21)	SLR(21)	SLR(21)								CAP(35)				
2020														CAP(37)				
2021	SC-Large(194)	SC-Med(94) Wind(150) CAP(47)	SC-Large(194)	SC-Med(94) SC-Small(44) CAP(25)	SC-Med(94) SC-Small(44) CAP(25)	SC-Med(94) SC-Small(44) CAP(25)	SC-Large(194)	SC-Large(194)	SC-Med(94) SC-Small(44) CAP(33)	SC-Med(94) SC-Small(44) CAP(33)	SC-Large(194)	SC-Large(194)	SC-Med(94) CAP(15)	SC-Large(194) CAP(29)	SC-Large(194)	SC-Med(94) SC-Small(44) CAP(33)	HLtoGas(122) CAP(50)	SC-Large(194)
2022		CAP(46) Wind(50)		CAP(34)	CAP(34)	CAP(34)			CAP(43)	CAP(43)			CAP(24)	CAP(38)		CAP(43)	CAP(15) SC-Small(44)	
2023		CAP(48)		CAP(36)	CAP(36)	CAP(36)			CAP(44)	CAP(44)			CAP(26)	CAP(40)		CAP(44)	CAP(17)	
2024		CAP(40) Wind(50)		CAP(38)	CAP(38)	CAP(38)			CAP(46)	CAP(46)			CAP(28)	CAP(42)		CAP(46)	CAP(19)	
2025		CAP(42)		CAP(40)	CAP(40)	CAP(40)			CAP(49)	CAP(49)			CAP(30)	CAP(45)		CAP(49)	CAP(21)	
2026		CAP(39)		CAP(37)	CAP(37)	CAP(37)			CAP(45)	CAP(45)			CAP(27)	CAP(42)		CAP(45)	CAP(18)	
2027		CAP(42)		CAP(40)	CAP(40)	CAP(40)			CAP(48)	CAP(48)			CAP(29)	CAP(44)		CAP(48)	CAP(21)	
2028		CAP(44)		CAP(42)	CAP(42)	CAP(42)			CAP(50) SLR(2)	CAP(50) SLR(2)			CAP(31)	CAP(47		CAP(50) SLR(2)	CAP(23)	
Planning Period 2014$	$1,931,580	$1,893,365	$1,931,580	$1,935,831	$1,951,020	$1,955,472	$1,829,782	$1,889,325	$1,954,891	$1,972,129	$1,740,477	$2,116,064	$1,734,728	$2,160,578	$1,906,585	$1,951,781	$1,831,677	$1,989,548
Difference from Base	0.00%	-1.98%	0.00%	0.22%	1.01%	1.24%	-5.27%	-2.19%	1.21%	2.10%	-9.89%	9.55%	-10.19%	11.86%	-1.29%	1.05%	-5.17%	3.00%
End Effects NPV	$1,443,938	$1,435,419	$1,443,938	$1,457,318	$1,477,773	$1,483,770	$1,308,592	$1,399,456	$1,460,220	$1,472,731	$1,310,239	$1,555,472	$1,288,192	$1,609,942	$1,396,779	$1,486,452	$1,344,993	$1,494,947
Total ($000)	$3,375,518	$3,328,785	$3,375,518	$3,393,149	$3,428,792	$3,439,242	$3,138,374	$3,288,781	$3,415,110	$3,444,859	$3,050,716	$3,671,536	$3,022,920	$3,770,520	$3,303,365	$3,438,232	$3,176,671	$3,484,495
Difference from Base	0.00%	-1.38%	0.00%	0.52%	1.58%	1.89%	-7.03%	-2.57%	1.17%	2.05%	-9.62%	8.77%	-10.45%	11.70%	-2.14%	1.86%	-5.89%	3.23%

SC-Small (44) - Generic 49 MW nameplate capacity aeroderivitive simple cycle unit	CC (292) - Generic 311 MW nameplate capacity frame type combined cycle unit	HLtoGas(122) - 122 MW nameplate capacity conversion of units 2 and 3 at Hoot Lake Plant from coal to natural ga
SC-Med (94) - Generic 101 MW nameplate capacity aeroderivitive simple cycle unit	Wind (50) - Generic 50 MW nameplate capacity wind resource	CHP(88) - Generic 96 MW nameplate capacity frame type combined heat and power resource
SC-Large (194) - Generic 211 MW nameplate capacity frame type simple cycle unit	SLR (1) - Generic 1 MW nameplate capacity solar photovoltaic resource	

Appendix J: Combined Heat and Power Evaluation

Combined Heat and Power Analysis

Introduction:

A typical Combined Heat and Power ("CHP") facility is a technology arrangement that typically uses a frame combustion turbine ("CT") and a Heat Recovery Steam Generator ("HRSG") to produce both electricity and steam as value products. A CHP facility is similar to a combined cycle plant except that a CHP facility does not have a steam turbine generator for converting steam to electricity. Instead, the steam is used in some type of processing or heating application. A CHP facility can be very attractive from an overall efficiency perspective because, theoretically, it is possible that a greater portion of the exhaust heat coming from the CT can be captured and used. Therefore, from an overall energy perspective, it is possible that a CHP plant could achieve a higher overall efficiency than a modern combined cycle power plant.

Potential of CHP in Rural Minnesota:

Attached in Appendix J is a report of the Minnesota Planning Minnesota Environmental Quality Board dated August 2001 titled "Inventory of Cogeneration Potential in Minnesota." While the report is fairly old (12 years) and much has changed in the energy industry during that time, much of what is included in the report still holds true today. Large commercial and industrial customers with a significant steam need are typically fairly stable in quantity and type of industry.

Section 4.4 of that report list potential cogeneration prospects in Minnesota. The prospects are broken into four categories:

1. Good prospects
2. Potential prospects
3. Already have cogeneration so additional unlikely
4. Poor prospects

The only Otter Tail customers listed, Fergus Falls Regional Treatment Center (now closed) and Ag Processing (Dawson) are both listed in the 4th category – Poor Prospects.

On page 9 of the report, Section 2.8 Summary, the report provides a list of factors that make a cogeneration project feasible. Two of the eight are a high power factor load and high cost electric power resources, neither of which occur in Midcontinent ISO today or are expected in the short- to mid-term future.

While Otter Tail agrees that this study is rather dated, it is likely that the number of potential CHP prospects has not changed drastically over the last 12 years and that the economics that make a CHP project feasible are still relevant.

Our investigations lead to several key questions and analysis points when evaluating these options. First, what is the overall timing of the steam customer and the electric utility? This is a key factor because if the timing of the effort does not match both parties, it will be difficult for the project to be economical for both parties. Second, what is the needed steam load? The maximum steam load will set the overall size of the project. Third, what is the steam need profile? Is the steam needed very stable (typical) or does the steam need vary by day, month, or season? Fourth, can the steam supply be interruptible? The steam customer would generally prefer to have back up boilers available for steam supply if the CHP plant were not available. This fixes the maximum value of the steam at the cost of fuel divided by the efficiency of the steam boiler system (plus the O&M costs).

Otter Tail is in the process of working with an actual agricultural processor with a large steam need and exploring the possibility of a CHP application. While in initial discussions on this potential project, fairly detailed project specifications and operating characteristics were developed. These project specifications and operating characteristics were included in the Company's Strategist modeling and offered as a generation option for the model to choose. Of the 78 Strategist modeling sensitivities analyzed in this resource plan filing, only four of them selected CHP as a part of a least cost plan. The four sensitivities selected all included extreme assumptions where the energy market was off.

The general conclusion of our analysis is as follows. First, the electricity being generated is from a Frame CT which is the least efficient (from a natural gas to electric conversion perspective) and positions the electric energy very poorly in the Midcontinent ISO market. Therefore, supplying base load electric energy from a frame CT is not a cost effective way of supplying customers with energy. The value of the steam produced from the CT/HRSG will offset this high cost somewhat, but it is capped at the cost of converting the energy in the natural gas to steam. Since steam customers value non-interruptible service, it is likely that any steam customer would also make the investment in simple, low-cost natural gas fired package boilers in any case. Therefore, the actual cost of steam from a CHP plant must be lower than the cost of production from a natural gas fired package boiler. This limits the value of steam and puts additional pressure on cost of electricity from the CT.

CHP projects are a highly efficient and effective use of natural resources. The challenges discussed above make it difficult to justify the economics of these projects however. Low Midcontinent ISO market electricity prices (as are seen today), or highly variable Midcontinent ISO electricity costs are not a good fit with high capacity factor, baseload natural gas-fired generation today. If, in the future, the value of natural gas-fired baseload generation facilities were to increase, the interest in pursuing CHP facilities would likely increase. However, even at that, the principal challenge may be synchronizing the timing needs of the steam customer and the generation needs of the utility.

Otter Tail will continue to evaluate CHP as a generation source in the future. The Company will attempt to include smaller increments of CHP in its next resource plan.

Existing Otter Tail CHP:

Otter Tail currently has a large CHP customer located at the site of the Big Stone Power Plant. 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.

Inventory of Cogeneration Potential in Minnesota

Minnesota Planning
Minnesota Environmental Quality Board

August, 2001

Table of Contents

Executive Summary

Background

In June 1999 the Legislative Commission on Minnesota Resources (LCMR) directed the Minnesota Environmental Quality Board and Minnesota Planning to prepare a report on the potential for cogeneration in Minnesota. Cogeneration, or Combined Heat and Power, is the simultaneous production of electrical energy and useful thermal energy from a single energy source. A cogeneration system most commonly utilizes a fuel source to produce steam that can be used to generate electricity and thermal energy that can be used in industrial processes. Interest in cogeneration has grown significantly in recent years due to its energy efficiency benefits and associated reductions in air pollution and greenhouse gas emissions.

The overall goal of this project was to develop a statewide inventory and description of promising cogeneration sites in Minnesota in order to encourage the implementation of cogeneration. The specific objectives of the project were to

1. develop measurable criteria for evaluation of cogeneration viability and an approach for applying these criteria to evaluate the site-specific feasibility of cogeneration for industrial and district energy systems;

2. identify potential cogeneration sites in Minnesota and provide enough information about these sites to allow cogeneration developers to make a preliminary assessment of cogeneration viability;

3. prioritize the potential sites, based on the data gathered, in order to focus development efforts on the opportunities with the best potential;

4. provide a general evaluation of the potential for increased cogeneration in Minnesota and the associated energy efficiency benefits; and

5. provide an overview of various cogeneration technologies.

The Minnesota Environmental Quality Board hired the consulting firm Kattner, FVB, Inc. to identify factors that affect the potential for cogeneration and to conduct a survey of industrial sources in Minnesota regarding the potential for implementation of a cogeneration facility. In May, 2001 Kattner submitted its report to the EQB.

Criteria for Evaluation of Cogeneration Viability

The most important parameters for screening and prioritizing cogeneration opportunities are:

- Size of thermal and power loads, and the relationship between the two;
- Thermal and electric load factors;

- Age of existing thermal facilities and plans for replacement or additional capacity;
- Avoided costs and/or potential revenue for generated power; and
- Fuel supply availability and costs.

Conduct of Study

Kattner's first task was to identify the sources in Minnesota that have facilities burning fuels for thermal energy. For this task, Kattner reviewed the database maintained by the Minnesota Pollution Control Agency on all boilers operated in the State. The MPCA has information on boilers at 552 facilities in the State. Of these facilities, 164 burn more than 100,000 million BTUs (mmBTU) per year and account for over 80% of the fuel burned at such facilities. For purposes of this survey, the smaller facilities burning less than 100,000 mmBTU/year were excluded from the survey, as were the 17 power plants in the State. Although power plants burn 77% of the total fuel consumed in Minnesota, they are designed to achieve maximum electric energy production, not a combination of electric and thermal energy.

Kattner then prepared a survey form containing questions asking for the pertinent information. Kattner selected 142 of the larger sites to include in the survey. Each of these operators was mailed a copy of the survey form with a cover letter explaining the purpose of the survey. Thirty-two of the recipients responded to the survey, and these responses are the basis for the conclusions in this report.

Sites with High Potential for Cogeneration

The study identified four high potential cogeneration sites among survey respondents. An initial site evaluation was performed on three of the sites. These sites are:

- Rahr Malting (Shakopee) – Two options were examined: a 9.3 MW steam turbine cogeneration fueled with biomass; and a 10.4 MW combustion turbine fueled with natural gas.

- Chippewa Valley Ethanol (Benson) – Two options were examined: 3.4 MW and 7.4 MW combustion turbines fueled with natural gas.

- Duluth Steam Cooperative (Duluth) – Two small backpressure steam turbines, totaling 0.9 MW, added to an existing coal-fired boiler facility.

- St. Mary's Duluth Clinic Health Systems (Duluth) – This facility was not evaluated.

Key tasks in each analysis included:

- Analysis of the existing systems for production or purchase of electric and thermal energy and a review of the pertinent costs.
- Identification of potentially feasible cogeneration technologies and fuels, and outline a proposed method of operation for the cogeneration system.

- Analysis of the operating costs of appropriately sized cogeneration systems, and the resulting net operating cost savings.
- Estimation of the capital costs for the cogeneration system.
- Comparison of the capital costs to the net cost savings to estimate a simple payback.

Based on survey responses, ten other sites showed some potential for cogeneration but the data are incomplete to adequately review these sites.

Cogeneration Potential in Minnesota

Based on the results of the survey, there is a technical potential of 1600 to 2100 megawatts (MW) of cogeneration at existing sites in Minnesota. This estimate takes into account the power and thermal demand characteristics of the survey respondents and the relationship of these demands to fuel use, and applies these characteristics to the total fuel use by facilities reporting over 100,000 MMBtu per year fuel consumption to the MPCA. Generally cogeneration facilities at these facilities would have power generation exceeding 1 megawatt. Another study, performed by Kattner/FVB District Energy, Inc. in 1999, focused on small energy users and estimated the technical potential for small cogeneration (under 1 MW) to be 842 MW.

However, economic conditions – specifically the relatively low cost of purchased power, the low utility buy-back rates under the Public Utilities Regulatory Policies Act of 1978 (PURPA), P.L. 95-617., and the volatility of natural gas prices – provide significant economic constraints to cogeneration opportunities that are technically feasible. The 1992 Energy Policy Act, P.L. 102-486, introduced the option for small producers to sell power at wholesale rates. Though lower than retail rates, wholesale rates are still higher than the avoided cost limitations that have been available to small power producers for over 20 years through PURPA. As the market for small power sales continues to develop, the economics for cogeneration will improve.

The economics of cogeneration based on current prices of power (1.0 to 6.5 cents/kilowatt hour) and natural gas ($3 to $6 per thousand cubic feet) are generally not attractive if the facility is sized and operated to offset only purchased power. This design constraint is realistic given the current regulatory and pricing framework for sale of excess power, i.e., there is no reason to design the facility to generate more power than needed on site if the excess power can't be sold at a sufficient price. However, if the excess power can be sold for a significant percentage of the power purchase price, with the cogeneration facility sized and operated consistent with the thermal load, the economics of combustion turbine cogeneration become attractive. It remains to be seen how federal policy will impact the economics of cogeneration.

Cogeneration Technologies

The relative economic and performance attributes of gas turbines, reciprocating engines, steam turbines, combined-cycles and fuel cells are described in an appendix to the report.

1. Introduction

1.1 Background

In June 1999 the Legislative Commission on Minnesota Resources (LCMR) directed the Minnesota Environmental Quality Board to prepare a report on the potential for cogeneration in Minnesota. Cogeneration, or Combined Heat and Power, is the simultaneous production of electrical energy and useful thermal energy from a single energy source. A cogeneration system most commonly utilizes a fuel source to produce steam that can be used to generate electricity and thermal energy that can be used in industrial processes. Interest in cogeneration has grown significantly in recent years due to its energy efficiency benefits and associated reductions in air pollution and greenhouse gas emissions. Evidence of this interest includes:

- The U.S. Department of Energy (DOE) announced in December 1998 a goal to double the use of cogeneration by 2010.
- The U.S. Combined Heat and Power Association was formed during 1999.
- DOE has funded a variety of projects relating to CHP, including development of a guidebook for CHP developers and research on combined heating, cooling and power generation in building-scale systems.
- The International Energy Agency (IEA) has sponsored research on a variety of CHP topics, integrating CHP with district cooling.
- The International Energy Agency is sponsoring research on CHP and district energy as a climate change strategy and use of carbon emissions trading as a key implementation mechanism.

1.2 Purpose of Report

The overall goal of this project was to develop a statewide inventory and description of promising cogeneration sites in Minnesota in order to encourage the implementation of cogeneration.

The specific objectives of the project were to:

1. develop measurable criteria for evaluation of cogeneration viability and an approach for applying these criteria to evaluate the site-specific feasibility of cogeneration for industrial and district energy systems;
2. identify potential cogeneration sites in Minnesota and provide enough information about these sites to allow cogeneration developers to make a preliminary assessment of cogeneration viability;

3. prioritize the potential sites, based on the data gathered, in order to focus development efforts on the opportunities with the best potential;

4. provide a general evaluation of the potential for increased cogeneration in Minnesota and the associated energy efficiency benefits; and

5. provide an overview of various cogeneration technologies.

1.3 Organization of Report

Chapter 1 is an Introduction. Chapter 2 describes the factors affecting the feasibility of cogeneration. Chapter 3 discusses the survey conducted of 142 different industries with more detailed information presented in appendices. Chapter 4 presents the results of the survey. Chapter 5 identifies the facilities in Minnesota that have the greatest potential for cogeneration. Chapter 6 provides an assessment of the cogeneration potential in Minnesota. Appendices present cogeneration terminologies and technologies as well as more detailed information on survey results and analysis.

2. Factors Affecting Cogeneration

2.1 Overview

The most important parameters for screening and prioritizing cogeneration opportunities are:

- Size of thermal and power loads, and the relationship between the two;
- Thermal and electric load factors;
- Age of existing thermal facilities and plans for replacement or additional capacity;
- Avoided costs and/or potential revenue for generated power; and
- Fuel supply availability and costs.

2.2 Size of thermal and power loads

The size of the thermal and electric loads is an important criterion in evaluating cogeneration potential. The size of the loads dictates the types of cogeneration technologies (described in Appendix B) that could be employed. As discussed below, the most economical approach is generally to install cogeneration capacity to supply less than the peak demand in order to keep the cogeneration equipment operating for as many hours as possible.

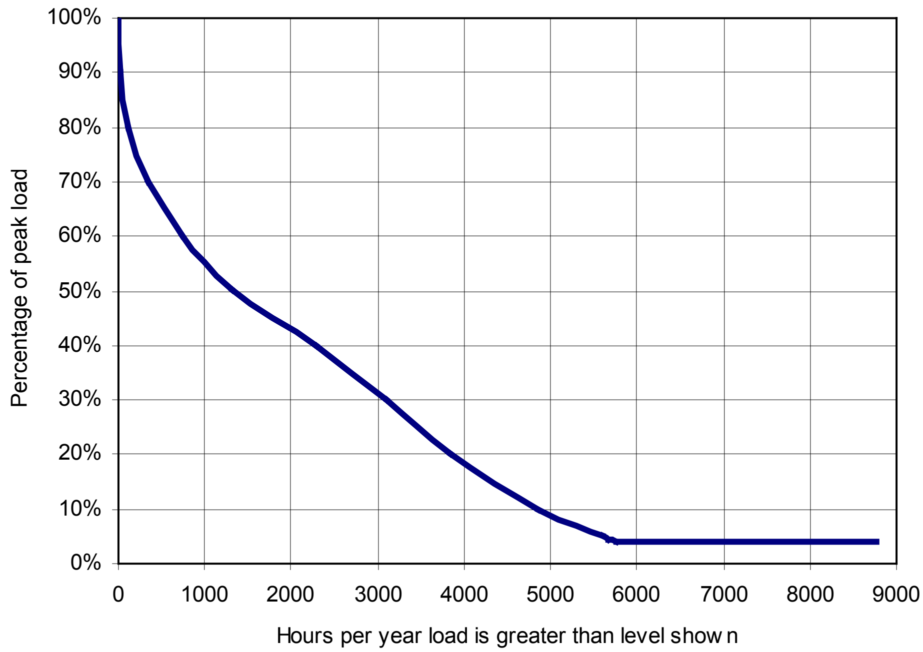
2.3 Thermal and electric load factors

The Equivalent Full Load Hours (EFLH) is an important factor in evaluating cogeneration possibilities. The EFLH is the ratio of the annual energy compared to the peak demand times 8,760 (the number of hours in a year). High electric and thermal EFLH increases the feasibility of cogeneration.

An economically ideal thermal load would be independent of the weather and would be the same year-round. However, loads in the real world are not ideal. A thermal load duration curve of the thermal load is a valuable asset in analyzing cogeneration. Such a curve plots the number of hours per year in which the load is greater than a given percentage of the peak load. Illustrative load duration curves may help to explain how cogeneration units can be sized economically.

Figure 2.1 shows an illustrative load duration curve for space heating and domestic hot water loads. If a cogeneration facility was sized to provide 100% of the peak load, the equipment would be operating at far less than its capacity for most of the year. The load factor for this curve is about 23 percent. The load factor is determined by dividing the actual EFLH (in this case approximately 2,000) by the total number of hours in a year or 8,760.

Figure 2.1
Illustrative Load Duration Curve for Space Heating and Domestic Hot Water



Figures 2.2 and 2.3 show illustrative load curves for hypothetical industrial loads. Figure 2.2 represents a thermal load with 4,000 EFLH, and Figure 2.3 represents a thermal load with 6,500 EFLH. A cogeneration facility sized to provide 50% of the peak thermal demand would have a load factor of about 75% for the load illustrated in Figure 2.2, and about 95% capacity factor for the load illustrated in Figure 2.3.

Figure 2.2
Illustrative Load Duration Curve for Hypothetical Industrial Facility #1

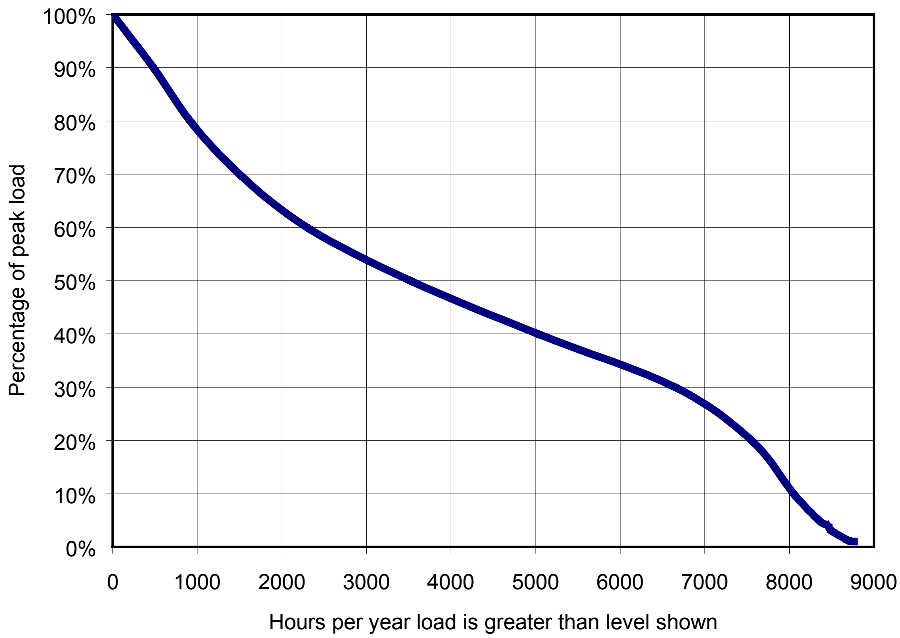
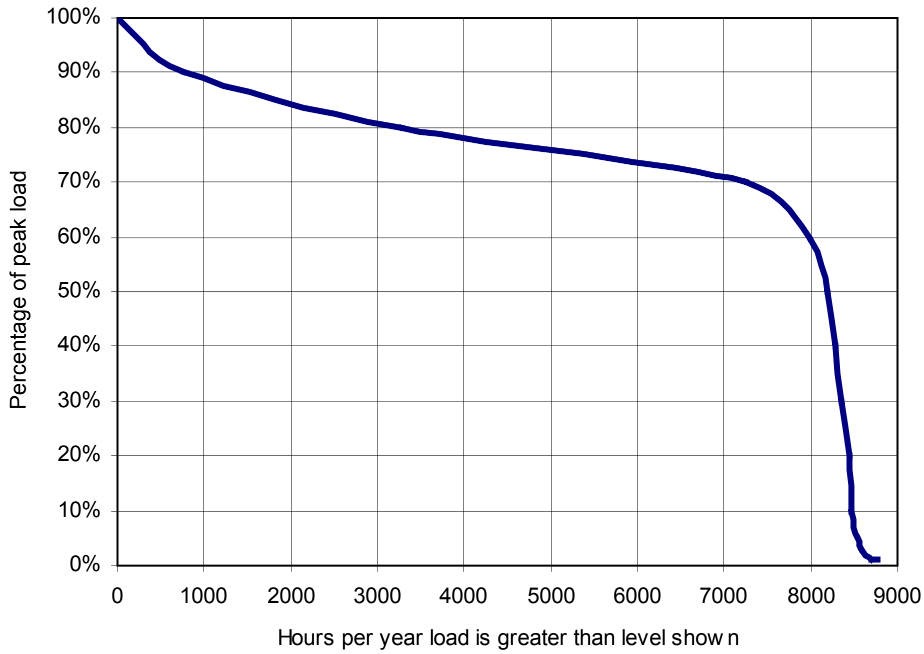


Figure 2.3
Illustrative Load Duration Curve for Hypothetical Industrial Facility #2



If the power generation component of the cogeneration cycle is designed to supply the maximum thermal energy load, the incremental cost of the generator may not be justified by value of the relatively small amount of power cogenerated within the peaking segment of the thermal load duration curve. A smaller cogeneration facility sized to deliver a portion of the thermal energy at a very high load factor could be more economical. The thermal and power loads should be in reasonable synchronization. If they are not, a market for excess power produced or a resource to secure cogenerated power shortfall must be secured. If the cogenerating power resource is to supply a given electric load without an adequate thermal load, a method to dispose of the excess thermal energy must be available. An automatic extraction pressure, condensing steam turbine generator would fulfill this need.

2.4 Age of Existing Thermal Facilities

The age of existing thermal equipment and plans for replacement or additional capacity are important considerations in determining the feasibility of adding cogeneration. Advanced age can mean poor reliability and high maintenance costs, making new equipment a more attractive option to increase reliability and reduce maintenance costs. The ideal times for considering cogeneration are when a new thermal intensive plant is to be constructed, or when existing thermal energy resources are to be replaced. If a potential cogenerator has reliable, reasonably efficient and low cost thermal and power resources that supply the loads, it may be difficult to replace these resources economically given the significant capital investment requirement.

2.5 Avoided Costs and Potential Revenue

The value of the cogenerated electric energy is an important component in evaluating a cogeneration project. This is the value of displaced purchased energy and the revenue from the sale of excess power produced. Low values reduce the economic viability of cogeneration.

The economics of combustion turbine cogeneration based on current prices of power and natural gas are generally not attractive if the facility is sized and operated to offset only purchased power. This design constraint is realistic given the current regulatory and pricing framework for sale of excess power, i.e., there is no incentive to design the facility to generate more power than needed on site if the excess power cannot be sold at a sufficient price. However, if the excess power can be sold for a significant percentage of the power purchase price, with the cogeneration facility sized and operated consistent with the thermal load, the economics of combustion turbine cogeneration become more attractive.

Investment tax credit. Tax credits for investments in cogeneration facilities have been approved by Congress. Generally, the investment tax credit (ITC) proposals would provide a 10% investment tax credit for qualifying facilities. This kind of tax credit would be an incentive to facilities to install cogeneration because it would reduce the payback time by years in some cases.

Production tax credit. Production tax credits (PTC) for production of electricity using biomass materials are currently under consideration in Congress. The proposals would extend the current production tax credit until 2011, with a credit per kWh indexed to inflation. The current credit is 1.7 cents per kWh. If this credit were available, it would drop the payback time on any facility burning biomass.

2.6 Fuel Supply Availability and Cost

The availability and cost of fuel for a cogeneration project are critical factors. As natural gas prices have increased, gas-fired cogeneration becomes less attractive, because the cogenerated power will tend to be relatively more expensive compared to power purchased from a utility using coal and nuclear sources. Although natural gas has tended to be the fuel of choice for many cogeneration projects, other fuels may actually make a project more economical.

2.7 Environmental Benefits

Figure 2.4 compares the efficiency of a representative cogeneration system to current average U.S. power plants and to various new power-only technologies.

The efficiency of cogeneration, and the emission characteristics of gas-fired generation compared to the mix of existing power plants, results in significant environmental benefits. Figure 4.2 compares the emissions of a 7.35 MW gas-fired combustion turbine (from Chippewa Valley Ethanol, Option 2 as described in Chapter 5) to emissions from:

- Purchased power was assumed to be generated by major intermediate load plants operated by Xcel Energy[1] (A.S. King, Black Dog, High Bridge and Riverside plants); and
- Thermal energy was assumed to be generated with Boiler emissions from gas-fired boilers assumed to operate at 82% efficiency.

The data are summarized in Appendix I.

Figure 2.4
Efficiency of Cogeneration Compared to Power-Only Technologies

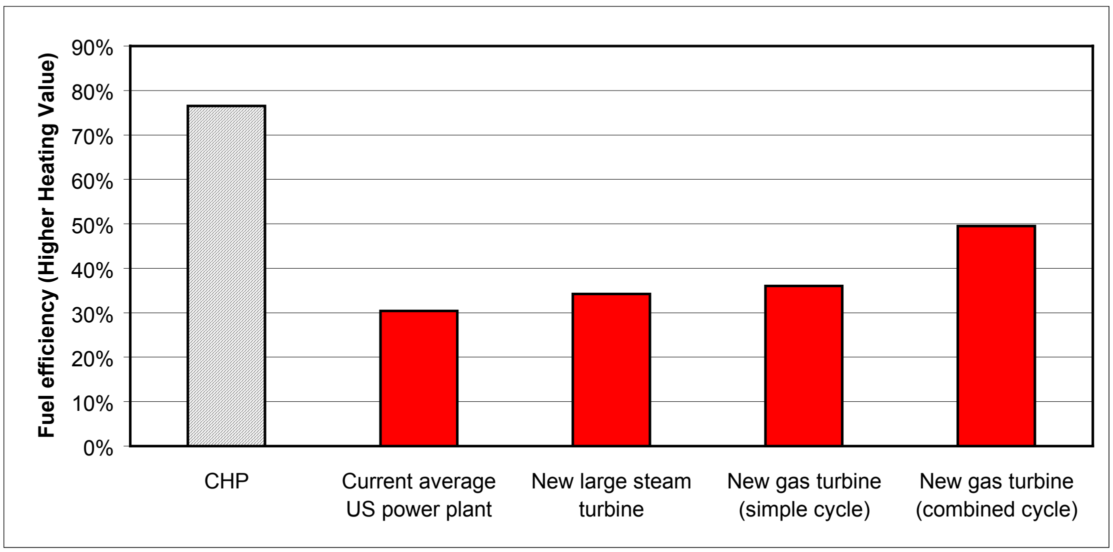
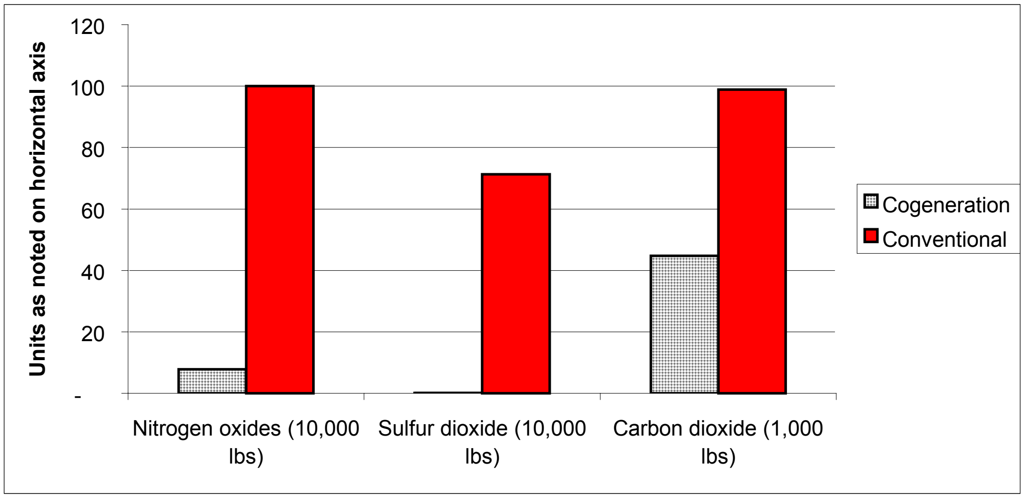


Figure 2.5
Cogeneration Emissions Compared to Local Intermediate Load Power Plants

[1] Per 1990 emissions data provided to the Minnesota Pollution Control Agency.
[13] "The Market and Technical Potential for Combined Heat and power in the Commercial/Institutional Sector" Revision 1, Jan. 2000.



2.8 Summary

In summary, cogeneration is most likely to be cost-effective when the following factors are present:

- A large, high load factor thermal load.
- A large, high load factor power load.
- Relatively high cost electric power resources.
- A cost-effective supply of electricity to back up and augment cogeneration when necessary.
- A relatively high-value market for excess power generation, net of transmission and distribution costs.
- The opportunity to re-dedicate the cost of replacing existing thermal resources to the cost of a new cogeneration project.
- The opportunity to use lower-cost fuels with cogeneration compared to current fuels for thermal production.
- Acceptable environmental impacts of cogeneration, such that the project can be meet all regulatory hurdles in a timely and cost-effective way.

Based on screening analysis of the survey results, this study ranks cogeneration prospects:

3. The Survey

3.1 Chapter Overview

This chapter describes the energy user survey undertaken to identify potential cogeneration sites, including the data and analysis used to identify survey recipients and the process for conducting the survey.

Many large industrial facilities already operate cogeneration systems. For example, in the paper industry, Blandin Paper (Grand Rapids), Boise Cascade (International Falls), Potlatch (Bemidji) and Champion International (Sartell) operate cogeneration systems. In the mining industry, Cyprus Minerals Company in Silver Bay has a cogeneration system. Other industrial cogeneration systems include United Defense (Fridley), Archer Daniels Midland (Mankato), Quadrant Corp. (Perham) and L.S. Power (Cottage Grove). A cogeneration project had been planned for Koch Refinery, using petroleum coke byproduct as a fuel. This would have been a very large project (200-250 MW). Koch was able to negotiate attractive power rates and has, at least temporarily, abandoned the project.[2]

A number of district heating systems have cogeneration facilities, including public utilities in Willmar, Hibbing, Virginia and New Ulm, and the University of Minnesota in Minneapolis. District Energy St. Paul Inc. is a private, non-profit utility that currently operates a 860 kW backpressure cogeneration system and is now designing a 25 MW waste-wood-fired cogeneration facility. Franklin Heating Station in Rochester, which supplies Mayo Clinic and other buildings in Rochester, also uses cogeneration.

3.2 Identification of Survey Recipients

The Minnesota Pollution Control Agency (MPCA) maintains a database on Minnesota facilities that have boiler permits from the MPCA. The MPCA boiler database records the type and quantities of fuel consumed at each site in 1998. Fuel consumption data were converted to show total million Btu (MMBtu) at each site using the conversion factors shown in Appendix C.

Total reported fuel use in 1998 was 556,207,000 MMBtuat 552 sites. Most of this fuel use occurs at the 164 facilities consuming over 100,000 MMBtu per year. These large facilities represented 98% of the total energy use. Seventeen power plants are responsible for 77% of total fuel consumption.

Excluding power plants, total fuel consumption in 1998 was 126,785,000 MMBtu at 536 sites. Non-power-plant fuel users consuming over 100,000 MMBtu were targeted for the survey. These users had a total 1998 fuel use of 118,367,000 MMBTU, or 93 percent of the non-power plant fuel use.

Some of the non-utility sites using more than 100,000 MMBtu were eliminated as survey targets because they were known to already be operating cogeneration facilities. The resulting list of 142 targeted fuel users had a total 1998 fuel use of 109,155,000

[2] "Opportunities to Expand Cogeneration in Minnesota," Center for Energy and Environment.

MMBTU, or 86 percent of non-utility fuel consumption. Information on these users, ranked by fuel consumption, is summarized in Appendix E.

This non-power-utility fuel use is broken down by sector, using Standard Industrial Classification (SIC) codes, in Table 3.1. The number of sites and average fuel use per site is also shown.

Table 3.1
Fuel Consumption by Sector, Excluding Power Plants

SIC	SIC Industry Category	Total Energy (MMBTU)	Number of Sites	Average energy per site (MMBTU)
10	Metal mining	10,738,566	4	2,684,641
20	Food and kindred products	27,926,297	30	930,877
24	Lumber and wood products	10,357,125	11	941,557
26	Paper and allied products	25,705,154	7	3,672,165
27	Printing and publishing	253,299	1	253,299
28	Chemicals and allied products	7,687,691	11	698,881
29	Petroleum and coal products	1,946,612	5	389,322
32	Stone, clay, glass, and concrete products	2,558,856	3	852,952
33	Primary metal industries	1,118,715	2	559,358
34	Fabricated metal products	661,871	4	165,468
35	Industrial machinery and equipment	610,536	2	305,268
36	Electrical and electronic equipment	408,981	2	204,491
37	Transportation equipment	611,699	1	611,699
38	Instruments and related products	166,441	1	166,441
39	Miscellaneous manufacturing industries	212,173	1	212,173
45	Transportation by air	409,254	1	409,254
49	Electric, gas, and sanitary services	11,111,121	11	1,010,102
51	Wholesale trade--nondurable goods	112,180	1	112,180
80	Health services	1,195,658	6	199,276
82	Educational services	4,974,586	10	497,459
87	Engineering and management services	1,596,696	1	1,596,696
92	Justice, public order, and safety	627,063	1	627,063
UN	Unassigned SIC Numbers	7,376,210	32	230,507
	Total	118,366,782	148	799,776

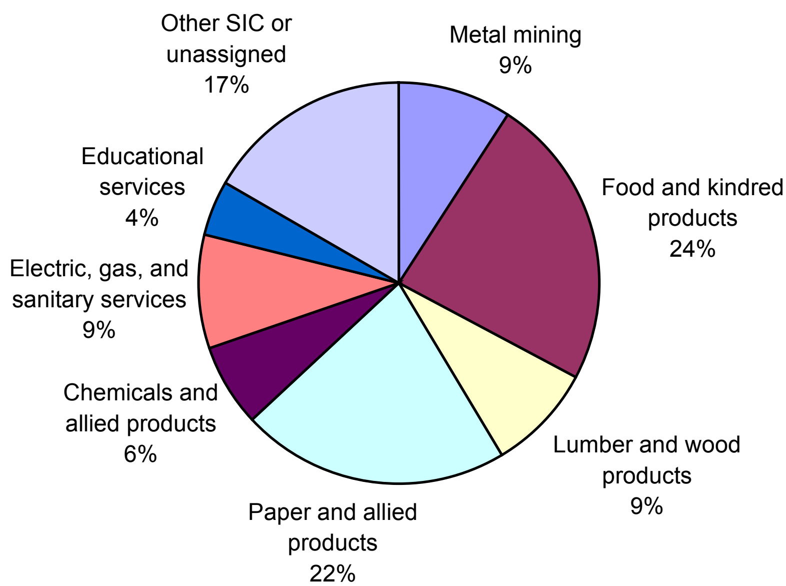
A graphical representation of fuel use by sector is shown in Figure 3.1. Seven sectors are responsible for 83% of the total non-power-utility fuel use:

- Metal mining

- Food and kindred products
- Lumber and wood products
- Paper and allied products
- Chemicals and allied products
- Electric, gas, and sanitary services
- Educational services

Of these, sectors with particularly high fuel use per site include mining, paper and electric, gas and sanitary services. This last category includes district heating facilities and other facilities where in some cases power is generated.

Figure 3.1
Fuel Consumption by Major Sectors Excluding Power Plants (1998)



3.3 Conducting the Survey

A survey form was developed and tested on a sample of ten recipients to determine if potential respondents are able and willing to provide the desired data, and to ensure that survey responses produce the information necessary to evaluate cogeneration potential. A copy of the survey form is included in Appendix F. No changes to the survey form were required based on the test activity, so the survey, with a cover letter, was sent to the 142 targeted fuel users (Appendix E). Telephone follow-up was conducted with 63 recipients.

3.4 Survey Return

Thirty two recipients responded to the survey, for a response rate of 23%. Survey respondents represented a total of 38,713,000 MMBtu of fuel consumption, equal to 31% of the total non-utility fuel use. The survey respondents were fairly evenly distributed relative to facility size.

Data on all fuel users and the relationship of the survey recipients to the total user population is summarized in Table 3.2. Data collected in the survey are summarized in Appendix G. Analysis and discussion of these data are presented in Chapter 4.

Table 3.2
Summary of 1998 Fuel Consumption Data

Fuel Consumption (MMBtu)	**All facilities**	**% of total**
Total	556,206,707	100%
Facilities over 100,000 MMBtu/year	547,788,903	98%
Facilities under 100,000 MMBtu/year	8,417,804	2%
Total non-utility (MMBtu/year)	126,784,586	23%
Number of sites		
Total	552	100%
Facilities over 100,000 MMBtu/year	164	30%
Facilities under 100,000 MMBtu/year	388	70%
Non-utility facilities	536	97%
Survey recipients	142	26%
Survey respondents	32	6%
Average fuel consumption per site (MMBtu)		
Average – All facilities	1,007,621	
Facilities over 100,000 MMBtu/year	3,340,176	
Facilities under 100,000 MMBtu/year	21,695	
Non-utility facilities	236,538	
Survey recipients	763,319	
Survey respondents	1,209,775	

4. Analysis of Survey Information

4.1 Selected Facilities

Of the thirty-two facilities that responded, four sites were judged to have high cogeneration potential and ten sites were judged to have some cogeneration potential based on the data available. The analysis below describes what the survey found with regard to these fourteen sites. The fourteen sites are listed in Table 4.1.

4.2 Survey Results

The size and load factor of the thermal and electric loads are shown in Table 4.1 Two of the sites have very large power demands (70 MW and 90 MW), while seven of the sites have a demand less than 5 MW, and the remaining five sites range from 6 MW to 19 MW. For three of the sites, no information was available for the peak thermal demand.

Table 4.1
Summary of Selected Screening Parameters for 14 Sites

Site #	Site	Peak Power Demand MW	Electric Load Factor EFLH	Peak thermal Demand MMBTU/Hr	Thermal Load Factor EFLH	Average Load Ratio (Elec/Therm)	Total 1998 fuel use (MMBtu)
1	Blandin Energy Center	90.0	8,096	890	4,096	N/A	5,957,718
2	Boise Cascade	70.0	7,571	1,800	6,111	0.16	7,871,515
3	Hormel Foods Corp	19.0	5,789	160	N/A	N/A	540,813
4	Potlatch Corporation	13.0	8,478	N/A	N/A	0.33	1,519,452
5	Rahr Malting Co	12.4	5,242	160	6,666	0.21	1,055,021
6	Seneca Food Corp -- Glencoe	9.7	1,876	90	982	0.70	99,729
7	Marvin Windows and Doors	6.4	3,281	33	5,988	0.36	146,152
8	Seneca Foods Corp -- Rochester	4.6	1,983	182	N/A	N/A	149,557
9	St. Olaf College	3.8	4,474	N/A	N/A	N/A	147,869
10	SMDC Health Systems	3.4	4,118	36	3,889	0.34	159,303
11	Chippewa Valley Ethanol	3.4	6,000	110	5,323	0.12	740,990
12	Ridgewater College	1.7	2,508	N/A	N/A	0.66	278,146
13	Diamond Brands	1.6	5,764	20	7,662	0.21	212,173

14	Duluth Steam Cooperative	0.8	3,196	270	3,147	0.01	991,740

Figure 4.1 illustrates the electricity Equivalent Full Load Hours (EFLH) for the 14 sites. EFLH is the ratio of the annual energy compared to the peak demand times 8,760 hours in a year. Figure 4.2 illustrates the thermal EFLH for the sites (some sites did not provide sufficient data to calculate thermal EFLH). High electric and thermal EFLH increase the feasibility of cogeneration.

Figure 4.1
Electricity Equivalent Full Load Hours

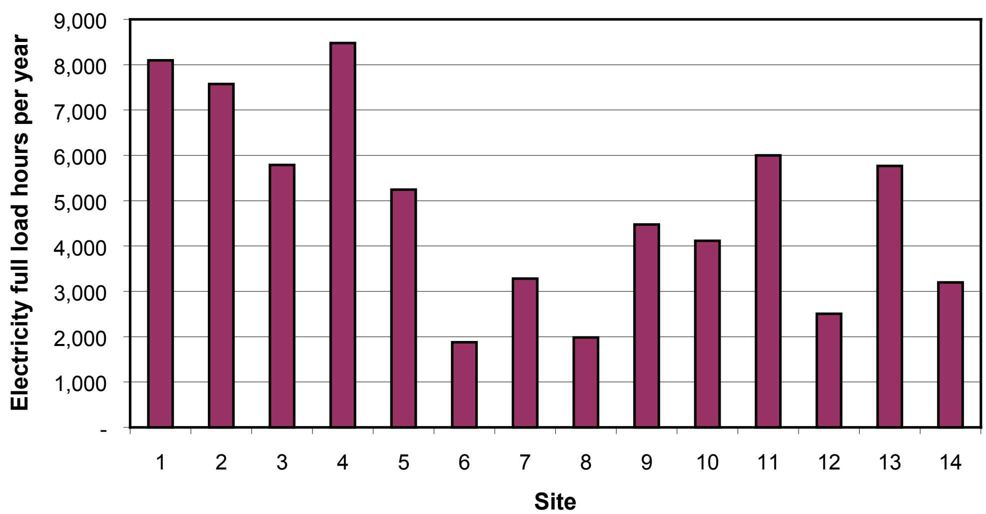
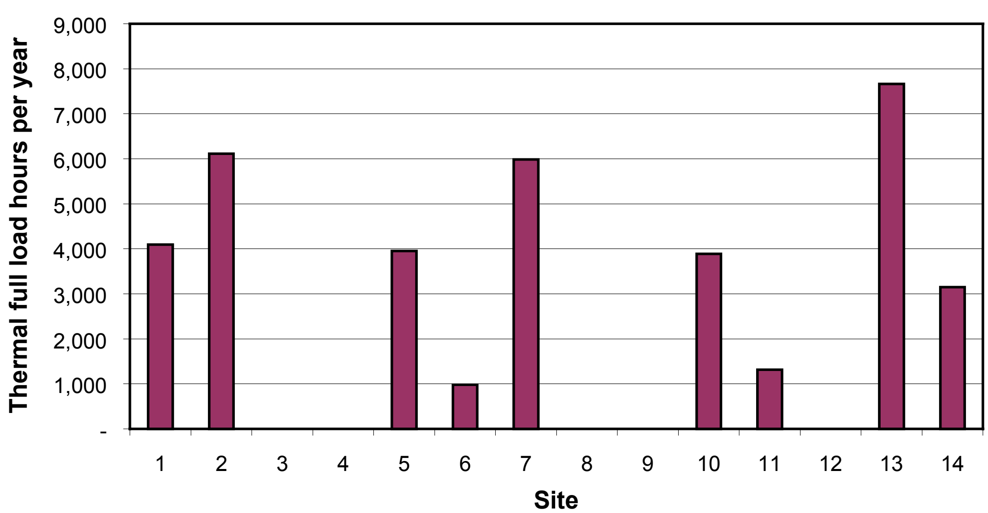


Figure 4.2
Thermal Equivalent Full Load Hours



4.4 Potential for Cogeneration in Minnesota

Based on screening analysis of the survey results, this study ranks cogeneration prospects:

Good prospects, with good data
- Rahr Malting Co (Shakopee)
- Chippewa Valley Ethanol Company (Benson)
- St. Mary's Duluth Clinic (SMDC) Health Systems (Duluth)
- Duluth Steam Cooperative (Duluth)

Potential prospect, but data are inadequate for assessment.
- Seneca Foods Corp. (Rochester)
- Hormel Foods Corp. (Austin)
- St Olaf College (Northfield)
- Crown Cork & Seal (Faribault)
- Froedtert Malt (Winona)
- Dairy Farmers of America (Zumbrota)
- Heartland Corn Products (Winthrop)
- US Steel - Minnesota Ore Operations (Mountain Iron)
- Potlatch Corporation (Brainerd) Already has small cogeneration but thermal and power loads may support more; data are incomplete.
- Boise Cascade (International Falls)– has existing cogeneration but is considering more; key cost data are considered proprietary.

Already have cogeneration, and prospects for additional economical cogeneration is unlikely
- American Crystal Sugar (Crookston)
- American Crystal Sugar (East Grand Forks)
- American Crystal Sugar (Moorhead)
- Order of St Benedict Inc. St Johns University (Collegeville)
- New Ulm Public Utilities (New Ulm)
- Blandin Energy Center (Grand Rapids)

Poor prospects
- Ford Motor Company (St. Paul) Large hydroelectric capacity and poor thermal load factor makes this a poor prospect for cogeneration.
- Louisiana Pacific Corporation (Two Harbors) Wide mix of process requirements and equipment, and access to inexpensive wood fuel and relatively small size for solid fuel cogeneration makes this a difficult prospect for cogeneration.
- Seneca Food Corp (Glencoe) Low load factors make this a poor prospect for cogeneration.
- Ridgewater College (Willmar) Small size makes this a poor prospect, data are incomplete.

- Diamond Brands Inc. (Cloquet) Access to inexpensive wood fuel makes this a poor prospect for cogeneration.
- Interplastic Corp. (Minneapolis) Wide mix of process requirements and poor electric load factor makes this a difficult prospect for cogeneration.
- Fergus Falls Regional Treatment Center (Fergus Falls) Small size and outside purchase of steam makes this a poor prospect, and data are incomplete.
- Northwood Panelboard (Solway) Access to inexpensive wood fuel makes this a difficult prospect for cogeneration.
- North Star Steel (St. Paul) Direct-fired processes eliminates this as a cogeneration prospect.
- Brown Printing Co. (Waseca) Direct-fired processes eliminates this as a cogeneration prospect.
- Marvin Windows and Doors (Warroad) Low cost power makes this a poor prospect for cogeneration.
- Brainerd Regional Human Services (Brainerd) Small size and existing back-up generation makes this a poor prospect; data are incomplete.
- Ag Processing Inc. (Dawson) Small size makes this a poor prospect, data are incomplete.

5. Site Specific Analysis

Of the four sites determined to have good potential for cogeneration, three were analyzed in further detail to get a better idea of the appropriate technology and size and economic viability for each facility.

Preliminary evaluations of the economic feasibility of cogeneration were performed for selected sites. Key tasks in the analysis include:

- Analysis of the present systems for production or purchase of electric and thermal energy and a review of the pertinent costs.
- Identify potentially feasible cogeneration technologies and fuels, and outline a proposed method of operation for the cogeneration system.
- Analyze the operating costs of appropriately sized cogeneration systems, and the resulting net operating cost savings.
- Estimate the capital costs for the cogeneration system.
- Compare the capital costs to the net cost savings to estimate a simple payback.

The following site assessments are very preliminary. Further site analysis would address the following questions:

- What are the detailed provisions of the existing contracts for purchased electric power and fuel, particularly the impact of demand charges?
- What are the costs of standby electric power and electric energy to augment or replace the cogeneration cycle operation during scheduled or forced outages?
- Is the prospect confronted with replacing existing resources due to age, obsolescence, high O&M costs, or unacceptable reliability?
- Are there better data on the efficiency of current fuel use?
- Is the prospect expanding its facility such that it will require increased thermal or electric energy?
- What is the available space within or adjacent to the plant to locate new facilities?
- What are the environmental impacts of cogeneration and what are the related regulatory hurdles?
- What are the costs of implementing cogeneration considering all site-specific factors?
- What is the cogeneration power output considering the impact of ambient temperatures on combustion turbine efficiency?
- What are the opportunities for excess power sales and pricing?

5.1 Rahr Malting Company – Shakopee

This large grain processing plant consumes 1,185,000 thousand cubic feet (mcf) of natural gas and 65,000 Mwh of electric energy annually. The maximum demand for electricity is 12.4 MegaWatts (MW). The current peak demand for thermal energy is 250-300 mmBTU/hour; however, the company is considering process modifications that would reduce the peak demand to 160 mmBTU/hour. Based on the data submitted for the survey, the annual thermal and electric EFLH are 6,666 hours and 5,242 hours, respectively.

The thermal energy produced in this plant is used in the processing and drying of grain. Drying is done in several kilns using hot air produced with indirect gas-fired air heaters or in heat exchangers with a thermal fluid heated to 240°F with gas. If the fluid were to be heated with steam, the steam conditions would be about 15 psig, dry and saturated, assuming a heat exchanger terminal difference of 10°F.

No process steam is currently generated in the plant. The total electric and thermal requirements suggest a good potential for cogeneration. The dispersed use of thermal energy around the plant site in the present plant configuration is not conducive to supply thermal energy from a single cogeneration facility. However, the company is investigating a plan to develop a thermal distribution system around the manufacturing area that could be served from a central cogeneration plant. Scheduling of thermal energy required by the kilns could reduce peak thermal demand, but the annual process thermal energy requirements would not change. The plant operates 24 hours/day and 7 days/week and does not shut down.

The thermal and electric loads with the upgraded thermal system projected by the company and used as the basis for this analysis are as follows:

Peak Loads		
	Thermal	160 MMBtu/hour
	Electric	12.4 MW total, about 10.0 MW without seasonal chiller load
Annual energy		
	Thermal	1,066,500 MMBtu
	Electric	65,000 MWh
Average Loads		
	Thermal	122 MMBtu/hr
	Electric	7.4 MW

Following the plant improvements, the peak power-to-heat ratio will be 0.26 and the average power-to-heat ratio will be 0.21.

Electric power is purchased for $0.045/Kwh including demand and energy charges. . Recent natural gas costs have been $5.00/MMBtu.   There are 2-3 acres available adjacent to the plant for new facilitiesThe facility produces about 58,000 tons per year of biomass by-product that has a fuel value of 7,943 Btu/lb.

Two cogeneration cycles previously outlined were studied for Site 5: a steam boiler with back-pressure steam turbine-generator; and a combustion turbine with a heat recovery steam generator (HRSG).

5.1.1 Option 1 -- Steam Boiler with Back-Pressure Steam Turbine Generator

Of the cogeneration technologies described in Appendix B, a steam turbine generator is of greatest interest because it would provide an opportunity to use biomass fuel produced at the facility site. The company is investigating the availability and use of its plant residue as boiler fuel. This residue consists of grain hulls, chaff and other materials.

Given the size of the required cogeneration, and the ratio of thermal load to electric load, a backpressure steam turbine generator is most appropriate. The turbine-generator would run only to the extent that a thermal load is available. Thus, the electric output of the turbine would be wholly dependent on steam load. The company states that the electric and thermal loads are well synchronized. However, there will be times when these loads are not synchronized, i.e. when the turbine-generator will not produce enough electricity to meet the load. Under the configuration described below, the interconnection with the utility must be retained as a standby electric resource and to augment turbine generator output, or potentially provide an outlet for excess electric energy cogeneration when the respective loads are not synchronized.

A preliminary plant design and a detailed plant heat balance would be necessary for a precise evaluation. However, this preliminary investigation can suggest the economic feasibility of the project. Appropriate design conditions are 600 psig, 750°F steam to the turbine throttle, exhausting to a backpressure of 50 pounds per square inch gage (psig). To supply the 160 MMBtu/hour peak thermal demand would require an estimated 167,000 lbs/hour of steam. Supplying this peak thermal load plus steam for the feedwater heating cycle requires an estimated boiler output of 187,000 lbs/hr. The turbine generator would cogenerate a gross electric output of 9308 kW or 8377 kW net assuming 10% station power (power required within the power plant itself).

The economic analysis assumes operation for 6,300 equivilent full-load hours (EFLH). Total fuel requirements would be 1,537,500 MMBtu per year, of which about 60% could be provided from in-house biomass by-products. The remaining fuel requirement would have to be obtained from the surrounding agricultural area.

The biomass-fired cogeneration facility would generate 81% of power requirements and almost all thermal requirements. No excess power is assumed to be generated and sold to the grid. Purchased power needed to meet the facilities full power requirements was assumed to be 20% more costly per kWh than current power purchases. This rough assumption was made because a relatively few kWh of electricity would be purchased compared with the peak electricity capacity required. In other words, the demand charges per kWh would be higher than under current purchase conditions.

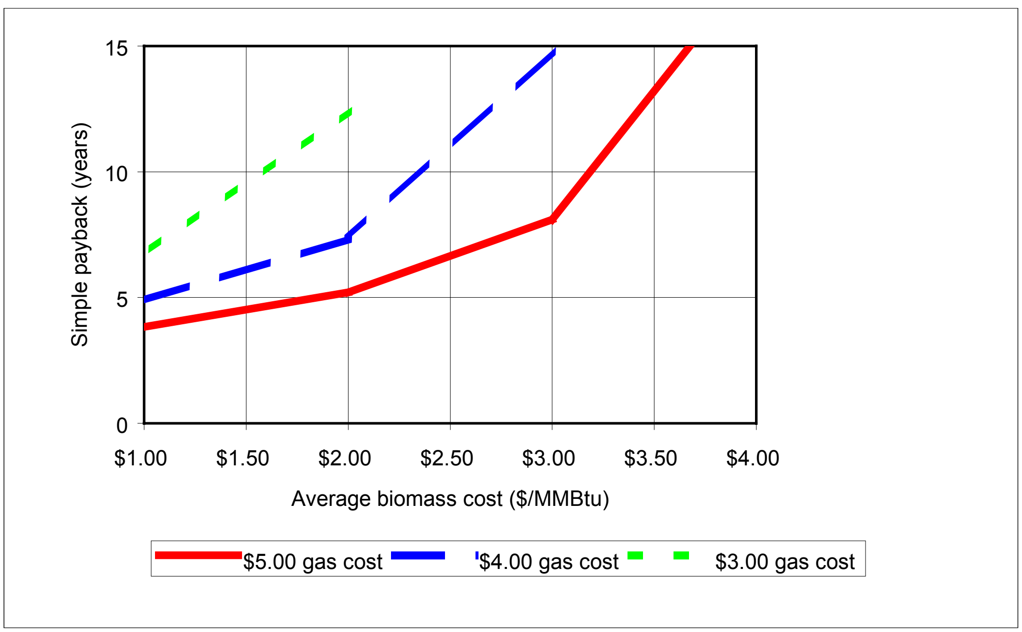
The economic analysis is presented in Appendix H-1. The capital and operating cost estimates were prepared without a detailed plant design and should be viewed as preliminary estimates only. A capital cost of $2,400/kWh of gross power generation capacity is assumed, including boiler, turbine-generator, biomass fuel handling, electrical equipment and a small peaking/back-up boiler. Operating costs include fuel, labor (8

Full-Time-Equivalents or FTE) and $0.014/kWh for maintenance and other non-fuel, non-labor operating costs such as water and chemicals.

With avoided power costs of $0.045/kWh and avoided fuel costs of $5.00/MMBtu, simple payback ranges from 18.3 years to 6.7 years for a range of assumed average biomass costs of $4.00 to $1.00 per MMBtu, as illustrated in Figure 5.1. Payback times increase as shown if the avoided natural gas is assumed to be purchased at $4.00 and $3.00 per MMBtu. The impact is stronger as the assumption of the biomass fuel cost increases. There is no payback at $4.00/MMBtu biomass costs for the $4.00 gas price scenario, and no payback at $3.00/MMBtu biomass costs for the $3.00 and $4.00 gas price scenarios.

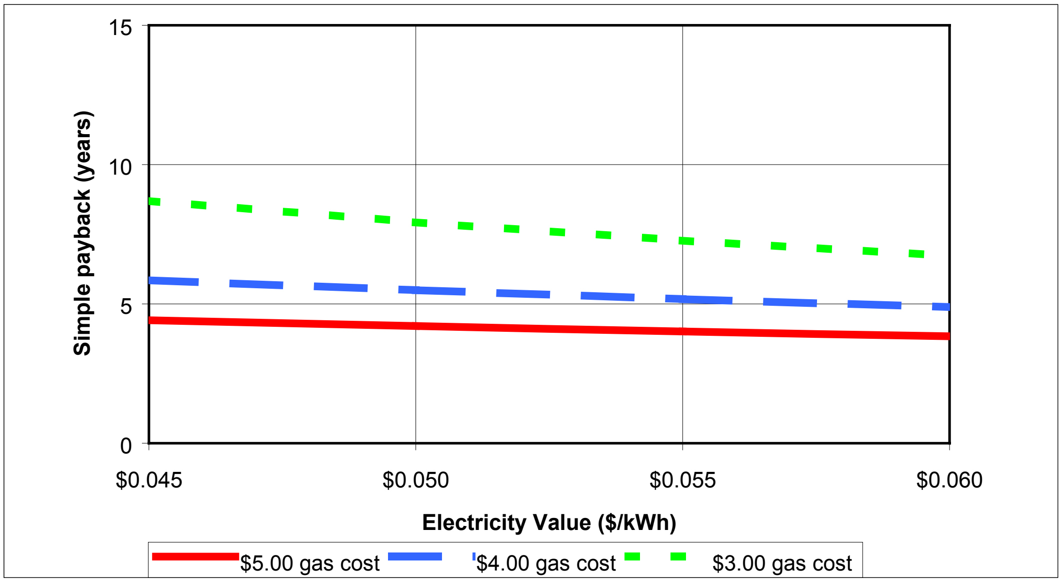
The results are very sensitive to the cost of biomass fuel. If a relatively low fuel cost can be achieved (less than $1.50/MMBtu), a simple payback of less than five years appears possible, assuming an offset natural gas price of $5.00/MMBtu.

Figure 5.1
Steam Turbine Sensitivity to Biomass Fuel Costs at Current Avoided Power and Fuel Costs (Base Case)



Because of the enormous impact of the cogeneration fuel cost and thermal energy production avoided costs, the results are relatively insensitive to the value of avoided power purchases. Figure 5.2 shows the simple payback results across a power value range of $0.045-0.060/kWh, assuming a fuel cost of $1.50/MMBtu.

Figure 5.2
Steam Turbine Sensitivity to Avoided Power Costs at Biomass Cost of $1.50/MMBtu (Base Case)



Two policies could improve the economic feasibility: potential investment tax credits and potential production tax credits.

Investment tax credit. Tax credits for investments in cogeneration facilities are currently under consideration in Congress. Generally, the investment tax credit (ITC) proposals would provide a 10% investment tax credit for qualifying facilities. This drops the payback time by 0.4 to 1.2 years compared to the base case, over the range of $5.00 to $3.00/MMBtu in avoided gas costs, assuming relatively inexpensive biomass fuel ($1.00-$2.00/MMBtu).

Production tax credit. Production tax credits (PTC) for production of electricity using biomass materials such as contemplated in this analysis are currently under consideration in Congress. The proposals would extend the current production tax credit until 2011, with a credit per kWh indexed to inflation. The current credit is 1.7 cents per kWh. If this credit was available, it would drop the payback time by 0.5 to 4.1 years compared to the base case, over the range of $5.00 to $3.00/MMBtu in avoided gas costs, assuming relatively inexpensive biomass fuel ($1.00-$2.00/MMBtu).

Combining the investment tax credit and production tax credits brings the simple payback down to 3.0 years assuming $5.00/MMBtu avoided gas costs and $1.00/MMBtu biomass fuel cost. Paybacks are under 5 years for a wider range of circumstances, as illustrated in Figures 5.3 and 5.4.

Figure 5.3
Steam Turbine Sensitivity to Biomass Fuel Costs at Current Avoided Power and Fuel Costs (with Tax Credits)

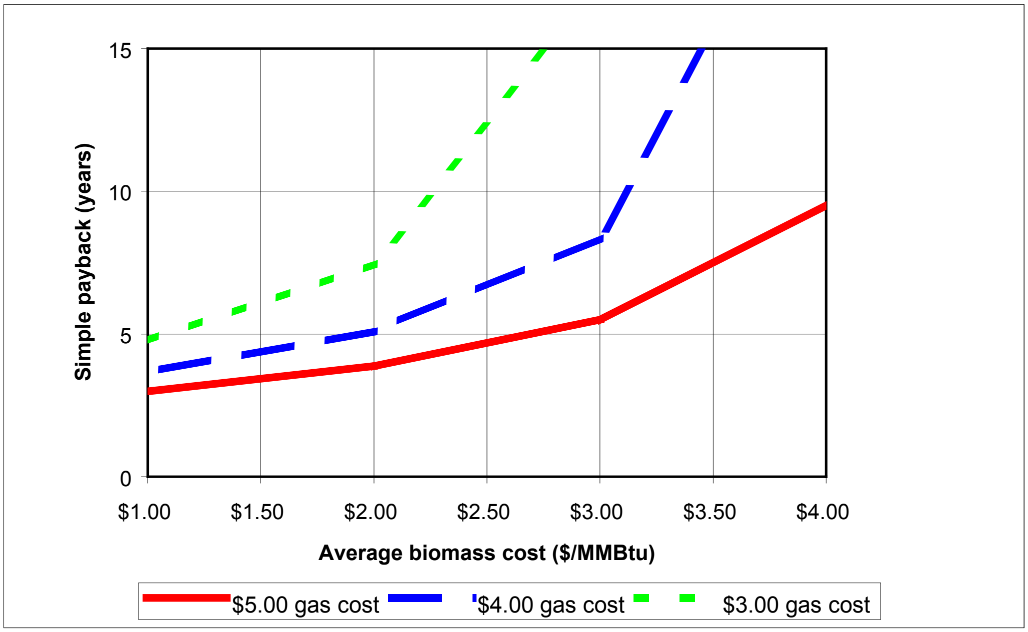
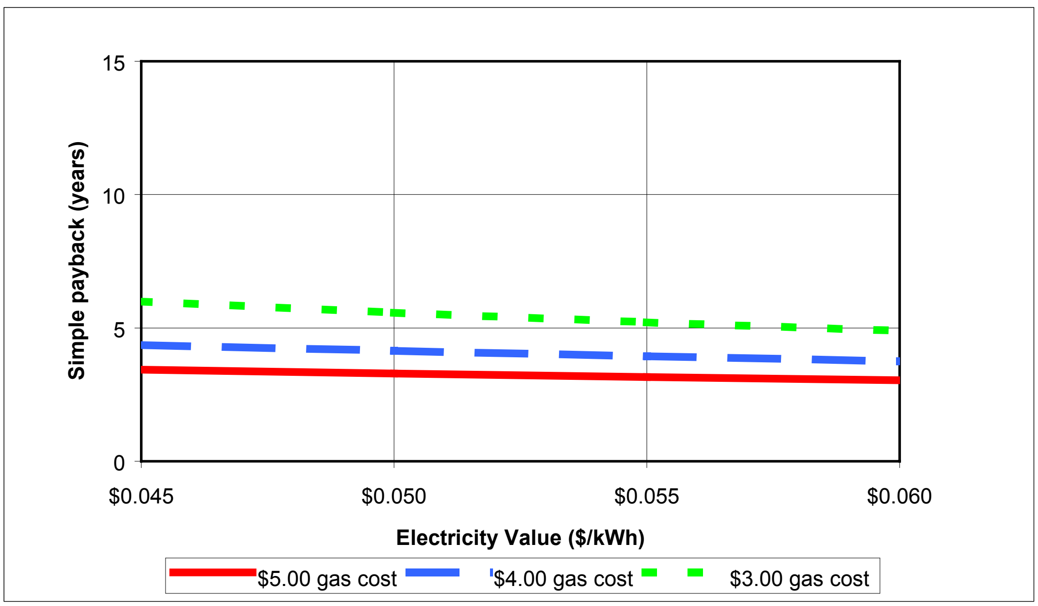


Figure 5.4
Steam Turbine Sensitivity to Avoided Power Costs at Biomass Cost of $1.50/MMBtu (with Tax Credits)



Methods to Increase Electric Output. The electric output of the plant can be increased by raising the turbine throttle steam conditions above 600 psig - 750°F. As an example, raising the conditions to 850 psig - 900°F would increase gross electric output by an estimated 20-25%. With these higher steam conditions, high pressure/temperature parts of the turbine, boiler, piping, etc. require higher cost materials. Additional power could be produced, but the marginal boiler plant cost should be compared with the value of an increase in avoided power purchase costs.

Another method of increasing electric output would be to install a controlled extraction pressure/condensing steam turbine generator. In this configuration, 50 psig process steam is extracted from the turbine at controlled quantity and pressure to supply process needs similar to the exhaust from the back pressure turbine in the previous scenario. Steam also flows to the surface condenser serving the turbine. This allows generation of electric energy on a condensing cycle independently of the process steam requirement. As in the case of the back pressure unit, when the steam extracted from the turbine would generate electric energy greater than plant requirements, some method of marketing the excess or bypassing steam around the turbine would be necessary. When the converse is true and cogenerated electric energy is less than plant load, condensing cycle generation can make up the shortfall by increasing steam flow to the condenser.

The marginal capital costs for this option are greater than for the back pressure turbine option because this option requires:

- higher cost turbine-generator;
- larger boiler and associated auxiliaries;
- added costs for condensing cycle equipment including condenser, cooling tower(s), circulating water pumps and electric service to cooling tower fans and condensate pumps; and
- higher costs for mechanical work including boiler feedwater pumps, feedwater heaters, steam and water piping.

Unless current pricing conditions change it is unlikely to make economic sense to design the facility to generate additional power.

<u>Conclusion</u>

In conclusion, sizing the facility to generate 9.3 MW gross power output is potentially feasible if sufficient biomass fuel can be procured at a low cost. If the cost of biomass fuel averages less than $1.50/MMBtu, and assuming that the cost of offset natural gas consumption is at current high levels ($5.00/MMBtu) and the cost of offset power costs is at current levels ($0.045/kWh), the preliminary economic analysis indicates a simple payback less than 5 years. This payback increases to 5.9 and 8.7 years if the cost of offset gas is assumed to be $4.00 and $3.00, respectively. Investment tax credits and/or production tax credits would make a significant difference in meeting likely financial performance criteria. This would yield simple paybacks less than 5 years even with offset gas assumed to cost up to about $4.50/MMBtu.

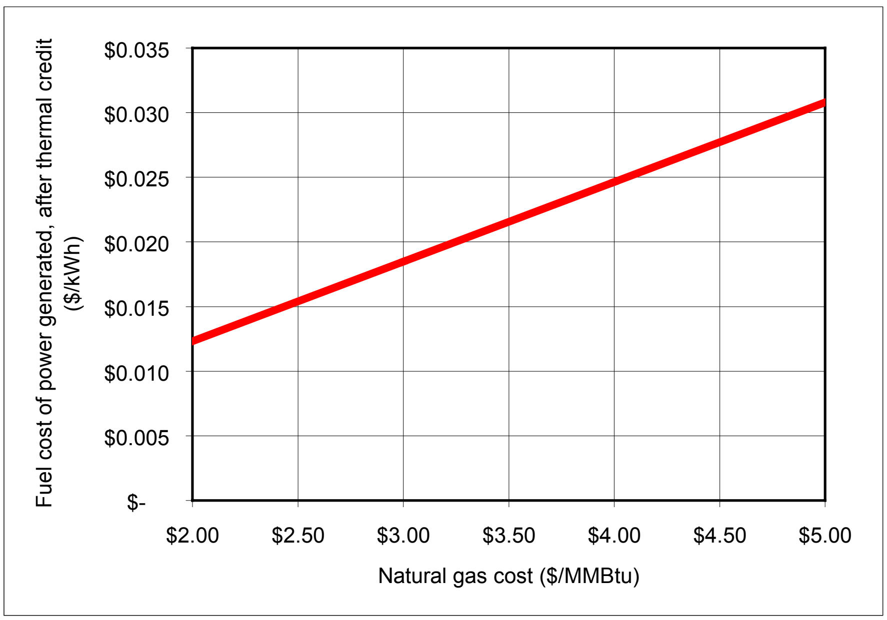
5.1.2 -- Combustion Turbine with Heat Recovery Steam Generator

An alternative to the steam turbine cogeneration would be a combustion gas turbine with a Heat Recovery Steam Generator (HRSG). An appropriately sized gas turbine, rated 10,439 kW at ISO conditions (see glossary) was chosen. Air temperature is most critical as gas turbine output decreases with increases in the compressor inlet air temperature. Output during warm weather can be improved with inlet air cooling.

At ISO conditions this unit would supply exhaust heat to a HRSG to produce 48,600 lbs/hr of 125 psig dry and saturated steam. With maximum supplemental fuel firing of 106 mmBTU/hr, the steam production increases to 150,000 lbs/hr. The turbine-generator would cogenerate a gross electric output of 10.44 MW or 9.92 MW net assuming 5% station power (power required within the power plant itself).

For this site, the thermal load factor of 76% (6,666 EFLH) is greater than the electric load factor of 60% (5,242 EFLH). The operation of the unit will be limited by power load rather than thermal load, unless excess power can be sold at a price greater than the marginal cost of producing the power. It is unlikely that sufficient revenue could be obtained for excess power exported to the grid. Under current conditions, revenue per kWh would probably not exceed $0.015/kWh for electric energy. In order to realize more revenue from power sales, a capacity commitment would have to be made. Figure 5.5 shows the fuel cost of a representative small turbine-generator used for cogeneration.

Figure 5.5
Fuel Cost per kWh in Small Combustion Turbine Cogeneration

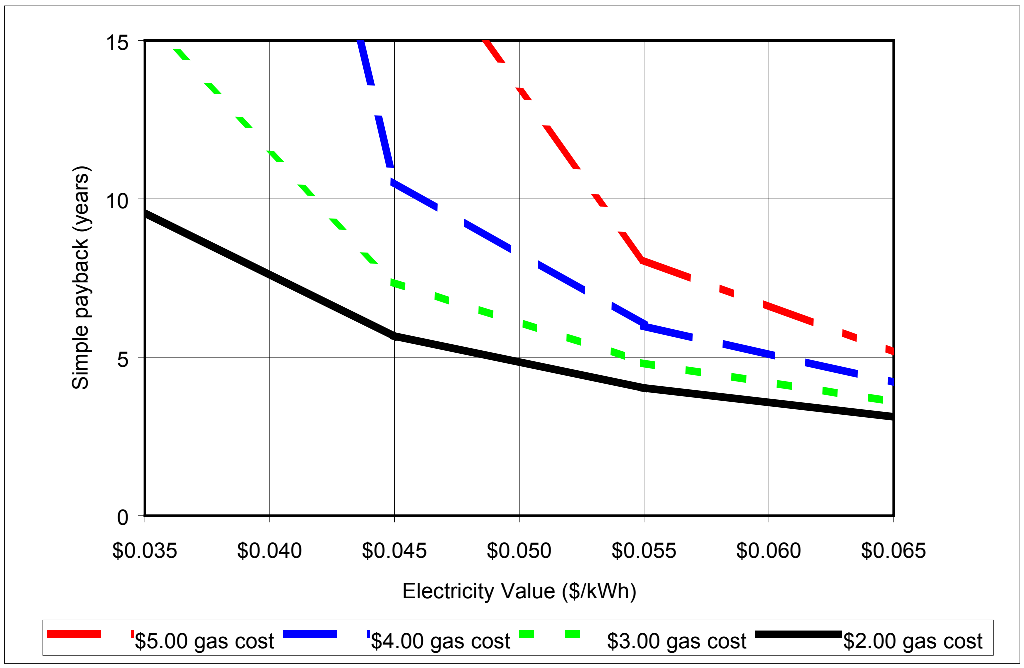


The economic analysis assumes a thermal load factor of 6,350 EFLH. Total fuel requirements would be 1,417,000 MMBtu per year. The cogeneration facility would generate 97% of power requirements and 89% of thermal requirements. No excess power is assumed to be generated and sold to the grid. We assume that the power required to be purchased would be 20% more costly per kWh than current power purchases.

The economic analysis is presented in Appendix H-2. A capital cost of $840/kWh of gross power generation capacity is assumed, including additional boiler capacity to provide thermal capacity not provided with cogeneration (it is unlikely that existing thermal equipment could be re-used with the new central thermal loop). Operating costs include fuel, labor (4 FTE, to provide licensed operators whereas current staff does not include any licensed operators) and $0.0054/kWh for maintenance and other non-fuel, non-labor operating costs such as water and chemicals.

With avoided power costs of $0.045/kWh, simple payback ranges from 19 years to 6 years for a range of natural gas costs of $5.00 to $2.00 per mmBTU. Payback periods drop dramatically if the assumed avoided power cost increases. At $0.065/kWh, payback ranges from 3.1 years (assuming $2.00/MMBtuMMBtugas) to 5.1 years (assuming $5.00/MMBtugas). Sensitivity of payback to the variables is illustrated in Figure 5.6.

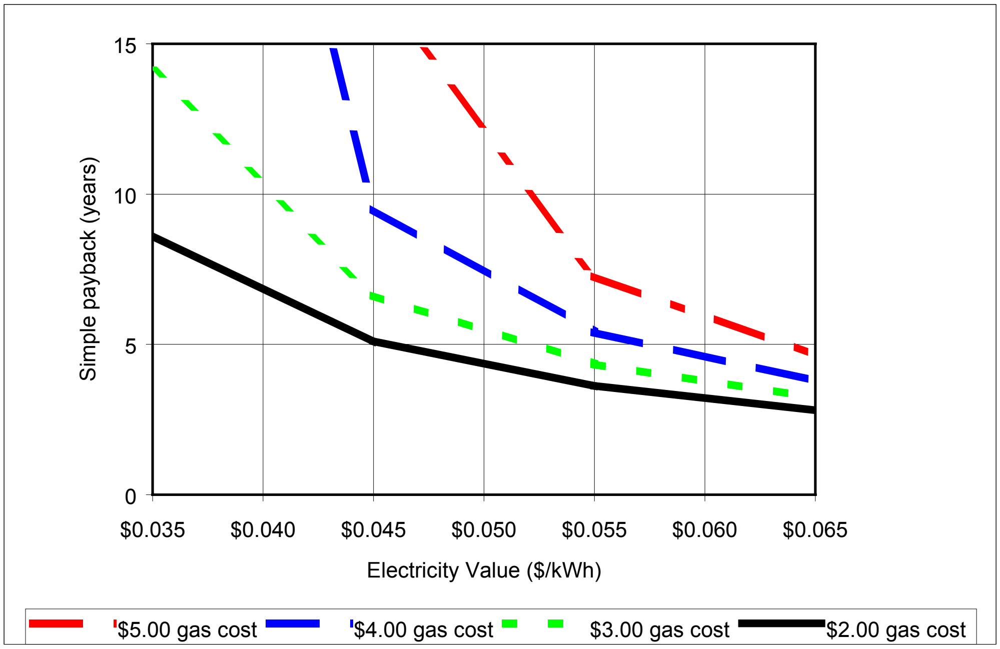
Figure 5.6
Combustion Turbine Sensitivity to Avoided Power Costs at Range of Gas Costs



With a 10% Investment Tax Credit, payback times would decrease by 0.5 to 4.4 years depending on assumed natural gas costs and power values. Resulting payback times are illustrated in Figure 5.7.

This option is not cost-effective under current avoided fuel and power costs. Even assuming natural gas costs $3.00/MMBtu, the simple payback exceeds 5 years unless the avoided power cost is assumed to be about 10% higher than currently ($0.050/kWh rather than $0.045/kWh). Power costs would have to go up considerably, while gas prices would have to remain fairly low, in order for this option to be feasible.

Figure 5.7
Combustion Turbine Sensitivity to Avoided Power Costs at Range of Gas Costs (with Investment Tax Credit)



5.2 Chippewa Valley Ethanol Company – Benson

This ethanol plant consumes 725,000 thousand cubic feet (mcf) of natural gas, 75,000 gallons of propane (about 6,860 mmBTU) and 20,400 Mwh of electric energy annually. The maximum demand for electricity is 3.4 MegaWatts (MW). The current peak demand for thermal energy is 110 mmBTU/hour. Based on the data submitted for the survey, the annual thermal and electric EFLH are 5,600 and 6,000, respectively. About 60% of the fuel is used to generate steam, with the remaining 40% in direct-fired dryers.

The plant has two 1,500 HP boilers, each 60,000 lbs/hour of 65 psig, 315°F steam. One boiler is 1 year old and the other is 4.5 years old. Boiler efficiency ranges from 83-84% (HHV).

The plant also has two 4.5-year-old 1,500 kW diesel engines, with no heat recovery, generating 450 MWH annually. These engines are run during power curtailment periods (about a dozen days per year for 4-6 hours each time) and to ensure power reliability during storms.

The plant operates year-round. The company is currently studying the potential to increase plant production by up to 125%. The plant currently has enough steam generation capacity for a plant production increase of 100%.

The thermal and electric loads used as the basis for this analysis are as follows:

Peak Loads		
	Total Thermal	110 mmBTU/hour
	Steam Thermal	65 mmBTU/hour
	Electric	3.4 MW
Annual energy		
	Total Thermal	611,106 mmBTU
	Steam Thermal	397,219 mmBTU
	Electric	20,400 MWh
Average Loads		
	Total Thermal	70 mmBTU/hr
	Steam Thermal	45 mmBTU/hr
	Electric	2.3 MW

Power costs are \$0.025/kWh energy charge, plus \$6.20/kW/month demand charge up to 2,500 kW. The average power cost about \$0.036/kWh. This power cost is kept low because the facility agrees to be curtailed (using their back-up generation) during high-demand periods.

The ratio of average electric load to average steam thermal load is 0.12, appropriate for a combustion turbine with a heat recovery steam generator (HRSG).

It is important to note that, in addition to the options presented below, an even more attractive alternative would be to obtain cogenerated thermal energy from the biomass-fired power plant that is being planned for implementation near this site. However, not enough is known about this plant to adequately assess the feasibility of this alternative.

5.2.1 Option 1 – Small Combustion Turbine with Heat Recovery Steam Generator

A gas turbine sized for the thermal load (and assuming no power export to the grid) is rated 3.42 MW at ISO conditions was chosen. The turbine-generator would cogenerate a net electric output of 3.25 MW net, assuming 5% station power (power required within the power plant itself).

At ISO conditions this unit would supply exhaust heat to a HRSG to produce 17,900 lbs/hr of 125 psig dry and saturated steam. With maximum supplemental fuel firing of 25.8 mmBTU/hr, the steam production increases to 43,100 lbs/hr. The temperature of the exhaust gas is increased from 915°F to 1400°F, which is the supplemental firing temperature recommended by manufacturers.

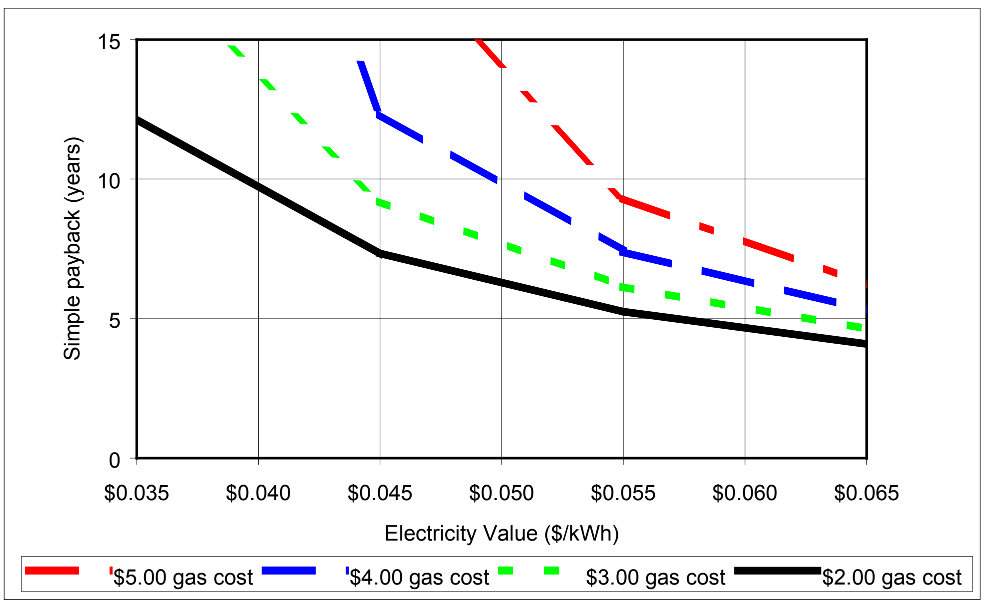
For this site, the steam thermal load factor (6,100 EFLH) is only slightly greater than the electric load factor (6,000 EFLH). For this option it is assumed that the operation of the unit will be limited by power load rather than thermal load, unless excess power can be sold at a price greater than the marginal cost of producing the power, as discussed above under Site 5, Option 2.

The economic analysis assumes operation for 6,250 EFLH. Total fuel requirements would be 522,775 MMBtu per year. The cogeneration facility would generate nearly 100% of power requirements and 88% of thermal requirements. No excess power is assumed to be generated and sold to the grid.

The economic analysis is presented in Appendix H-3. A capital cost of $1,100/kWh of gross power generation capacity is assumed. Operating costs include fuel, labor (1 FTE in addition to licensed engineers already on site) and $0.007/kWh for maintenance and other non-fuel, non-labor operating costs such as water and chemicals.

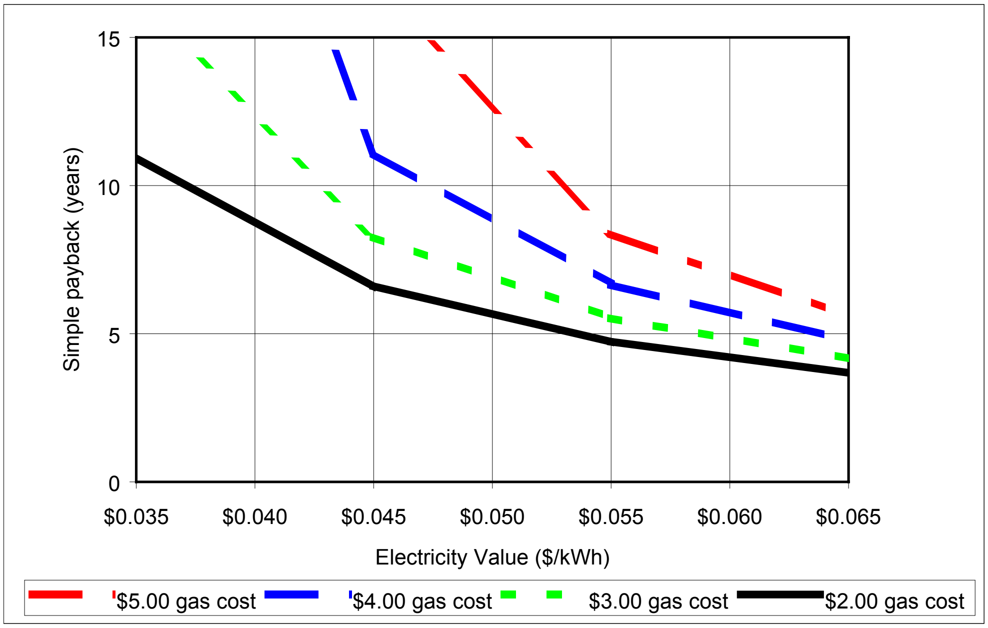
With avoided power costs of $0.036/kWh, simple payback exceeds 12 years, even with natural gas costs as low as $2.00 per MMBtu, as illustrated in Figure 5.8. Payback periods drop dramatically if the assumed avoided power cost increases. At $0.065/kWh, payback ranges from 4.1 years (assuming $2.00/MMBtu gas) to 6.2 years (assuming $5.00/MMBtu gas).

Figure 5.8
Combustion Turbine Sensitivity to Avoided Power Costs at Range of Gas Costs



With a 10% Investment Tax Credit, payback times would decrease by 0.5 to 3.7 years depending on assumed natural gas costs and power values. Resulting payback times are illustrated in Figure 5.9.

Figure 5.9
Combustion Turbine Sensitivity to Avoided Power Costs at Range of Gas Costs (with Investment Tax Credit)



5.2.2 Option 2 – Larger Combustion Turbine with Sale of Excess Power to the Grid

A larger gas turbine was selected to follow the thermal load. The turbine-generator would cogenerate a gross electric output of 7.35MW or 6.98 MW net at ISO conditions, assuming 5% station power (power required within the power plant itself). In this scenario, a significant amount of excess power is generated and is assumed to be sold as discussed below.

At ISO conditions this unit would supply exhaust heat to a HRSG to produce 31,200 lbs/hr of 125 psig dry and saturated steam. With maximum supplemental fuel firing of 31.8 mmBTU/hr, the steam production increases to 62,400 lbs/hr.

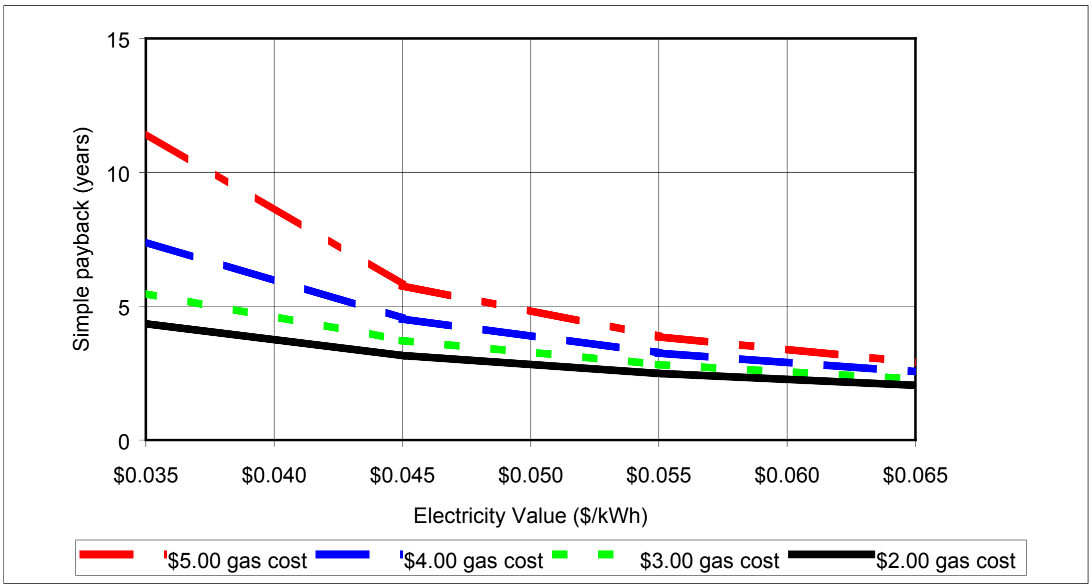
For this option it is assumed that the operation of the unit will be limited by thermal load and that power can be sold at a price greater than or equal to the marginal cost of producing the power. Two power sale price scenarios are examined. In the base case scenario it is assumed that power is sold for $15/MWH. Later, we assume net metering, i.e., power sold to the grid is priced at the same cost as power purchased.

The economic analysis assumes operation for 8,059 EFLH (electric), with supplemental firing according to thermal demand. Total fuel requirements would be 783,884 MMBtuper year. The cogeneration facility would generate nearly 100% of power requirements plus nearly 36,000 MWH for sale and 64% of thermal requirements.

The economic analysis is presented in Appendix H-4. A capital cost of $890/kWh of gross power generation capacity is assumed. Operating costs include fuel, labor (1 FTE in addition to licensed engineers already on site) and $0.0058/kWh for maintenance and other non-fuel, non-labor operating costs such as water and chemicals.

With avoided power costs of $0.035/kWh and assuming excess power is sold for $15/MWH, simple payback ranges from 11.5 years to 4.3 years for a range of natural gas costs of $5.00 to $2.00 per mmBTU, as illustrated in Figure 5.10. Payback periods drop dramatically if the assumed avoided power cost increases. At $0.065/kWh, payback ranges from 2.0 years (assuming $2.00/MMBtugas) to 2.9 years (assuming $5.00/MMBtugas).

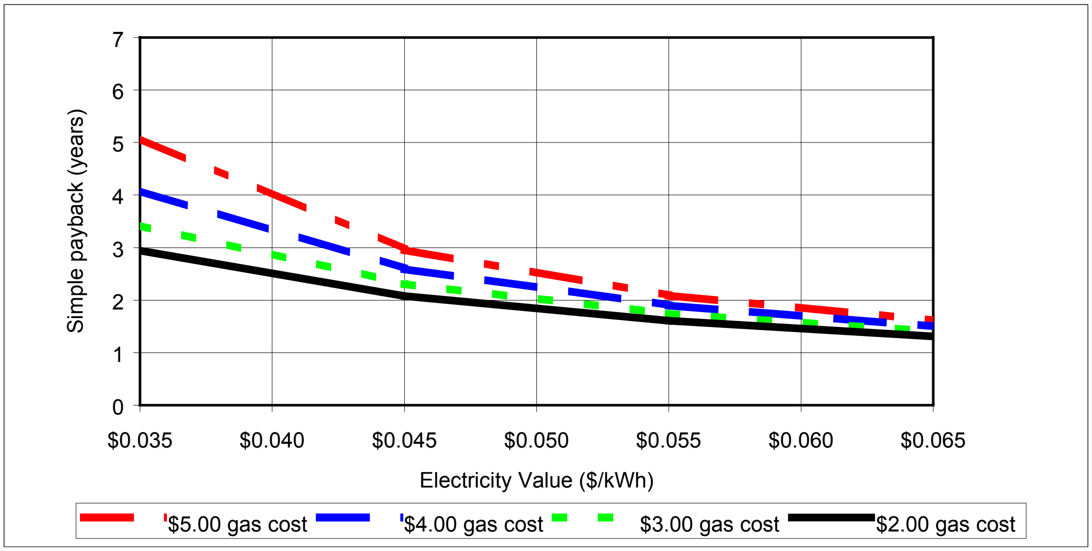
Figure 5.10
Combustion Turbine Sensitivity to Avoided Power Costs at Range of Gas Costs



With a 10% Investment Tax Credit, payback times would decrease by 0.2 to 1.1 years depending on assumed natural gas costs and power values.

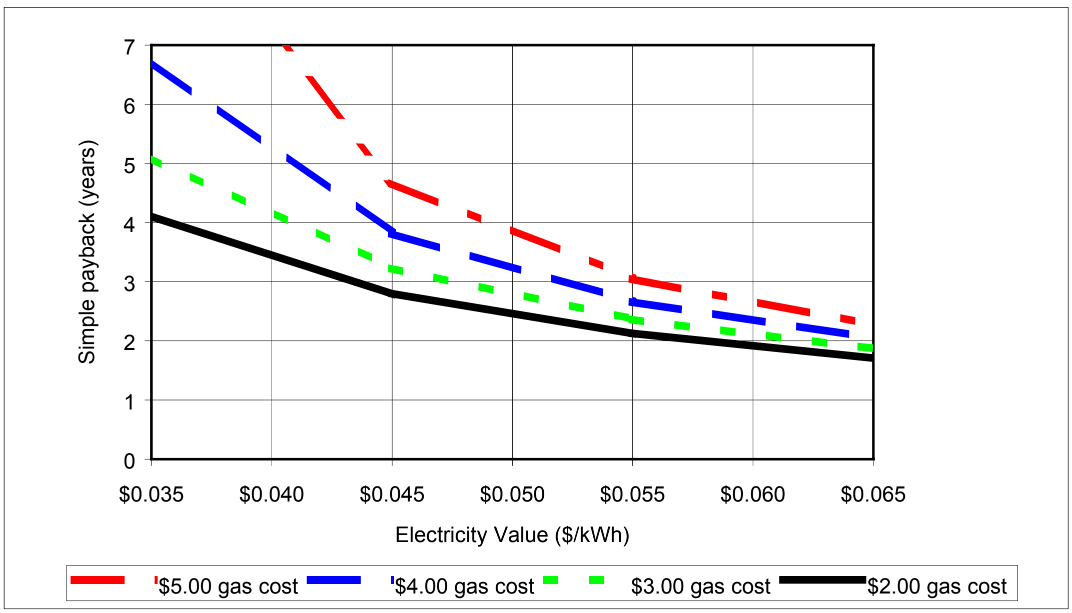
If net metering is assumed, i.e., utility purchase of excess power generation at the same price as the average cost for the facility to purchase power, the economics become very attractive, as illustrated in Figure 5.11.

Figure 5.11
Combustion Turbine Sensitivity to Avoided Power Costs at Range of Gas Costs (assumes Net Metering at 100% of average purchase price)



If it is assumed that the utility purchases power at only 50% of the facility's average purchase costs, the paybacks increase but are still very attractive (Figure 5.12).

Figure 5.12
Combustion Turbine Sensitivity to Avoided Power Costs at Range of Gas Costs (assumes Net Metering at 50% of average purchase price)



5.3 Duluth Steam Cooperative

This plant supplies 160 psig steam to a district heating system serving 225 buildings in the core area of the city. The system has no condensate return lines. The plant has four coal-fired boilers each rated 100,000 lbs/hr which generate steam at 225 psig, dry and saturated. Export steam is reduced to 160 psig with pressure reducing facilities. The boilers are 68 years old, but have been well maintained. In anticipation of adapting the plant for cogeneration, the boilers were successfully pressure tested at the original design pressure of 400 psig and would operate at the pressure in the cogeneration cycle. The current plant fuel is western coal costing $1.30 per MMBtu.

The peak steam generation is 225,000 lbs/hr and steam sales are in the range of 301,000 to 317,000 Mlbs/year. A current study is analyzing the economic and technical feasibility of installing a district cooling system to serve a group of government buildings, using steam-driven absorption chillers. This would increase the summer load on the system and increase the thermal load factor and improve the cogeneration potential.

A 950 kW gas-fired internal combustion engine in the plant provides standby power and eliminates the demand charge from the cost of purchased power, resulting in a cost of $0.038/kWh for purchased power.

The cogeneration system envisioned would require installation of two back-pressure steam turbine-generators rated 295 kW and 627 kW, with throttle steam flows of 33,000 and 64,000 lbs/hr, respectively. The turbines would be supplied with 400 psig, dry and saturated, steam and exhaust at 160 psig. These turbines would be operated singly or in tandem to serve the high load factor segments of the load pattern during the minimum, shoulder and peak heating periods.

The turbine generators would exhaust to the high load factor segment of the steam load pattern and generate approximately 4,408 MWH/year. This output would supplant the 2,122 MWH of plant electric service now purchased, plus 2,285 MWH for sale. The value of this energy plus additional revenue from the sale of reserve power capacity as estimated by the local utility would increase revenues by an estimated $170,000. The estimated marginal operating expenses attributable to cogeneration would be $54,000 (largely due to increasing steam pressure to 400 psig), resulting in $116,000 in operating income available for debt service with no margin for profit or return on investment. The estimated capital cost of the project is $1,217,000. With a preliminary simple payback estimate of 10.5 years, pursuing this project at this time is subject to the investment policies of the owner.

An important advantage of this plant is that it is coal-fired at a low cost per MMBtu. The increasing cost of retail natural gas could result in incremental steam sales for the district heating system, which could enhance the economics of cogeneration.

In addition to the steam district heating system, the owners recently established a district hot water distribution system to supply the thermal requirements of large hotels near the steam plant. These requirements include heat for room and hallway heating, domestic water heating, pools and spas. The hot water is generated with steam/water heat exchangers in the plant and is used in plate heat exchangers at the customer premises to produce the on-site thermal requirements. These customers have 147 and 102 rooms respectively with the latter soon to be expanded to 170 rooms. The domestic hot water needs are large especially during the summer months, which will improve the load factor on the district heating plant and enhance the cogeneration potential.

6 Potential for New Cogeneration

It is not possible to provide a solid quantification of technical or economic potential of new cogeneration in Minnesota based on the data obtained in the survey. However, a rough estimate of the technical potential, based on extrapolation from the survey data, indicates a technical potential of 1,600 to 2,100 MW of new cogeneration. This estimate takes into account the power and thermal demand characteristics of the survey respondents and the relationship of these demands to fuel use, and applies these to the total fuel use by facilities reporting over 100,000 MMBtu per year fuel consumption to the MPCA. Generally cogeneration facilities serving these users would have a power generation capacity exceeding 1 MW. Another study by Kattner/FVB District Energy, focusing on small energy users, estimated technical potential for small cogeneration (under 1 MW) in commercial buildings[13]. In that study, the technical potential in Minnesota for under 1 MW was estimated to be 842 MW.

Quantification of the economic potential for cogeneration is an even more challenging task – one that is beyond the scope of this report. However, some qualitative conclusions can be drawn based on the case study analyses described in Chapter 5.

Preliminary economic analyses of cogeneration were prepared at three sites:

- Rahr Malting, Site 5 – Two options were examined: 9.3 MW steam turbine cogeneration fueled with biomass; and a 10.4 MW combustion turbine fueled with natural gas.

- Chippewa Valley Ethanol, Site 11 – Two options were examined: 3.4 MW and 7.4 MW combustion turbines fueled with natural gas.

- Duluth Steam Cooperative, Site 14 – Two small backpressure steam turbines, totaling 0.9 MW, added to an existing coal-fired boiler facility.

Generally, combustion turbines were determined to be the appropriate cogeneration technology based on the power-to-heat ratios, level of the electric and thermal output requirements and in some cases the temperature requirements of the thermal end-uses.

The preliminary evaluation of the biomass cogeneration option at Rahr Malting indicates that this approach can be feasible if biomass fuel is available at an average cost below $1.50/MMBtu. In cases where the facility is generating a significant portion of the required biomass material, this may be achievable.

The economics of combustion turbine cogeneration based on current prices of power and natural gas are generally not attractive if the facility is sized and operated to offset only purchased power. This design constraint is realistic given the current regulatory and pricing framework for sale of excess power, i.e., there is no incentive to design the facility to generate more power than needed on site if the excess power can't be sold at a sufficient price. However, if the excess power can be sold for a significant percentage of the power purchase price, with the cogeneration facility sized and operated consistent with the thermal load, the economics of combustion turbine cogeneration become more attractive.

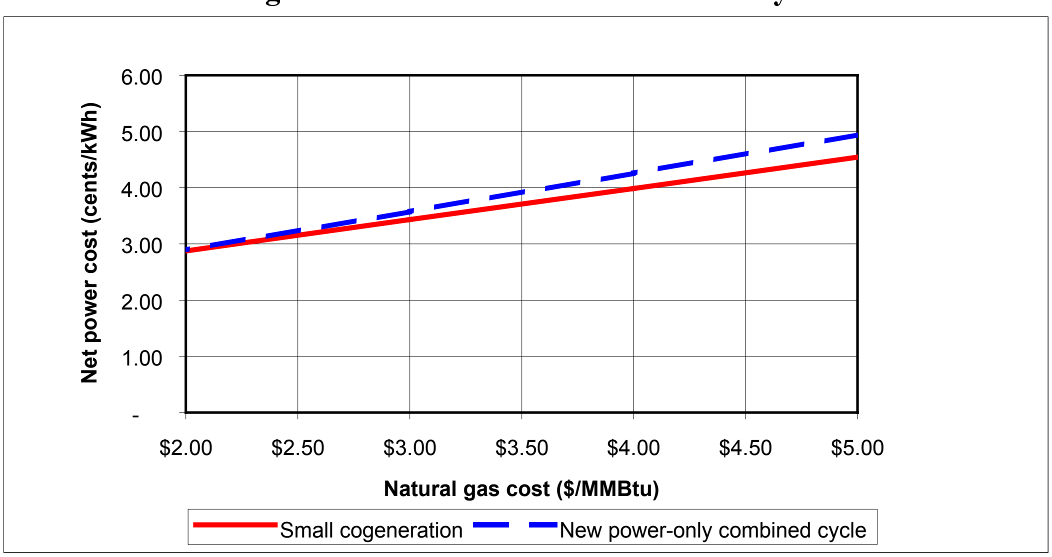
From a public policy standpoint, it is appropriate to ask how the total net economics of power generation with cogeneration compare to the total net economics of non-cogeneration power plants. Although this was not within the scope of this study, one indicative analysis was undertaken as described below.

Small power generation facilities generally require higher capital costs per unit of power output than the large combustion turbine combined cycle facilities likely to be built to provide new power generation capacity. On the other hand, cogeneration provides economies by recovering the waste heat. How do the economics of a small cogeneration facility compare with a large combined cycle non-cogeneration power plant, including debt service, fuel and operating costs? Appendix H-4 presents the total economics, including debt service, of the 7.35 MW facility analyzed for one of the sites evaluated in Chapter 5. Appendix J presents the total economics for a new 260 MW power-only combined cycle power plant.

The analysis indicates that at $2.00/MMBtunatural gas, the net costs of power from a small combustion turbine cogeneration facility are about the same as that from a large new non-cogeneration combined cycle facility. As gas costs increase, cogeneration gains an increasing economic advantage.

This simplified comparative analysis suggests that in addition to providing significant efficiency and environmental benefits, the overall cost of cogeneration compares favorably with new non-cogeneration power plants.

Figure 4.3
Net Power Costs for 7.35 MW Cogeneration Compared to 260 MW Non-Cogeneration Gas Turbine Combined Cycle



Appendix A: Definitions

Term	Abbreviation	Definition
Acid dew point		The temperature in an exhaust stack where the exhaust gases will start to condense into an acidic liquid.
Aero-derivative		This refers to a combustion turbine that was originally designed for aircraft propulsion and has been adapted for use as a stationary power generation source.
Combined Heat and Power	CHP	Combined Heat and Power (CHP), also known as cogeneration, is the simultaneous production of electrical energy and useful thermal energy from a single energy source. A CHP system most commonly utilizes a combustion turbine, steam turbine or reciprocating engine that converts chemical energy into electrical power and useful thermal energy such as steam, hot water, or high temperature gases used in direct-drying industrial processes.
Combined cycle		A thermodynamic cycle that utilizes a combustion turbine to produce steam that in turn is used to drive a steam turbine.
Condensing power plant		An electrical generation facility where the exhaust steam from a steam turbine generator is routed through a condenser where it is condensed and reused in the thermal cycle.
Cyclones		A separator that uses centrigugal forces to remove particulate from combustion gasses.
Diesel engine		A type of reciprocating engine where the fuel is ignited by compression and heat.
District heating		A heating system utilizing either steam or hot water produced in a central plant and distributed to individual buildings via a networked piping system.
Equivalent full load hours	EFLH	The total amount of energy consumed annually divided by the peak hour energy consumption
Fuel cell		A device that utilizes fuel in a chemical reaction to produce electricity similar in nature to a battery.

Gas turbine		A turbine that uses combustion of either gas or liquid fuel as the motive force in rotating an electric generator
Generator		An electro-mechanical device that converts mechanical energy into electrical energy.
Heat Recovery Steam Generator	HRSG	A heat transfer device that transfers heat from a combustion turbine exhaust and produces either hot water or steam.
Higher Heating Value	HHV	This is the heating value of a fuel assuming that water vapor is condensed in the combustion gas mixture.
Intercooler		A heat exchanger located between compressor stages to lower the temperature of the air for improving the output of an engine.
ISO Conditions	ISO	Standard atmospheric conditions of 59 °F (15°C), 60% relative humidity and 14.7 psia (1013 mbar) atmospheric pressure. Established by the International Standards Organization
Lbs/ sq. in absolute	psia	This is a unit of pressure based on an absolute scale where 0 is a perfect vacuum.
Lbs/ sq. in gauge	psig	This is a unit of pressure based on a gauge scale where 0 is atmospheric pressure.
Load factor		This is the EFLH divided by the total number of hours in a year (8,760).
Millibar	mbar	This unit of pressure is equal to 0.01450377 psi
Otto engine		A type of reciprocating engine where the fuel is ignited by a spark.
Reciprocating engine		An internal combustion engine that utilizes either gas or liquid fuel. When the fuel is combusted in the combustion chamber a piston is forced to drive a crank shaft.
Simple cycle		A combustion turbine operating without heat recovery typically used for peaking service.
Steam turbine		A turbine that uses high pressure and high temperature steam as the motive force in rotating an electric generator
Textile baghouse		A type of combustion gas cleaning process where the gasses are routed through textile filter bags to remove particulate.

Appendix B: Cogeneration Technologies

B.1 Introduction

This chapter describes cogeneration technologies. This section has been adapted with permission from a report prepared for International Energy Association,[3] with updating from additional sources. Key terms are defined in Appendix A.

All efficiency calculations are based on the Lower Heating Value (LHV) of fuels. In the discussions of simple cycle and combined cycle gas turbine technologies, performance is based on International Standards Organization (ISO) conditions. ISO conditions are listed in appendix A. In addition, the pressure drop at the intake and at the outlet were each assumed to be 4 inches of water.

B.2 Gas Turbines

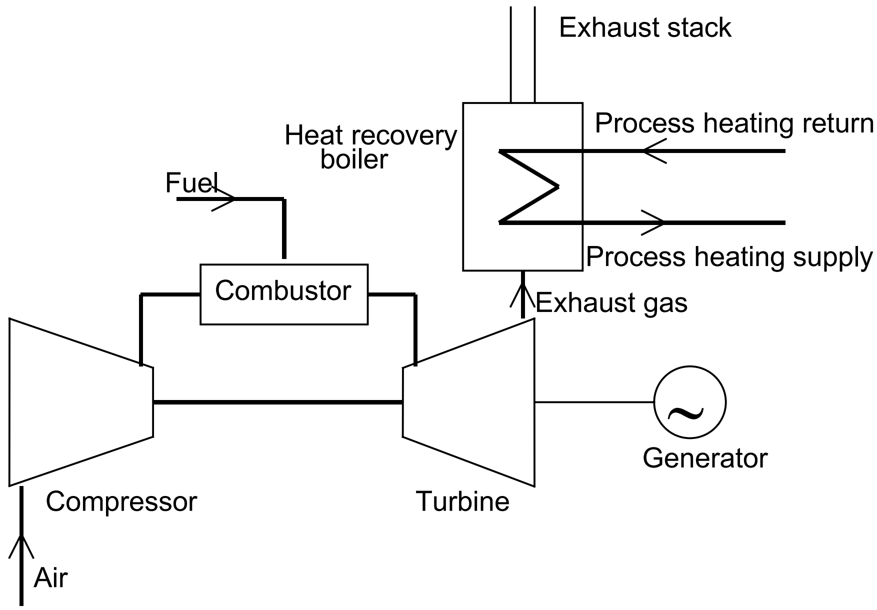
Description of Technology

Combustion turbines, often called gas turbines, generate electricity and heat by combusting fuel in a combustion chamber and using the hot gas to rotate a turbine and generator. Combustion turbines can utilize different fuels such a natural gas or diesel fuel. The combustion cycle is described as follows:

- The conventional gas turbine is an open process, with the intake air and exhaust gas respectively being taken from and released to the surroundings at atmospheric pressure.
- Air is compressed in a compressor, thereby increasing both the pressure and temperature.
- The compressed air is delivered to a combustion chamber where it is mixed with gaseous or liquid fuel and burned. The combustion takes place at a constant pressure and occurs with large quantities of excess air. The turbine exhaust contains oxygen (about 15% O_2) and is therefore capable of supporting additional combustion.
- The high-temperature, high-pressure gaseous combustion products enter the turbine, where the expanding gases perform mechanical work by rotating the turbine shaft. A portion of the produced work is used to drive the compressor and overcome friction, and the remainder is available for power production.
- In cogeneration applications the heat in the hot exhaust gas is recovered in a heat recovery steam generator (HRSG) or directly used in an industrial process.
- The heat in the exhaust gas can be augmented with supplemental firing of additional fuel ahead of the HRSG. The fuel is converted to usable thermal energy at an efficiency exceeding 90 percent.

[3] "Integrating District Cooling with Combined Heat and Power," Resource Efficiency, Inc. for the International Energy Agency, ISBN 90-72130-87-1, 1996.

Figure B.1
Schematic for gas turbine cogeneration



Gas turbines are commercially available in a range of sizes, from 500 kW to over 300 MW. In addition, a new generation of small systems generally called “microturbines” are being developed in sizes down to 30 kW.

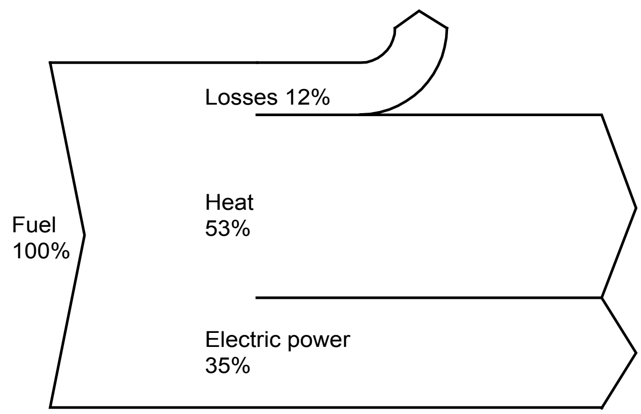
Natural gas and light to heavy fuel oil can be used as fuel for combustion turbines. While natural gas is a "clean" fuel and is relatively problem-free to use in a gas turbine, heavier fuel oils must usually be cleaned to reduce the level of substances that can cause high temperature corrosion or surface deposits in the hot gas path of the turbine. One potentially problematic aspect of using natural gas is the pressure level of the natural gas. With the high pressure ratio (pressure in the combustor after the compressor, divided by intake air pressure) of modern gas turbines, the pressure of the natural gas from low pressure pipelines must be boosted by the use of a separate gas compressor to be able to use the gas in the gas turbine. This adds additional capital and operating costs to the project, increases the amount of parasitic electrical load to drive the compressor and reduces the amount of net electrical energy available for the end user.

Research and development for gas turbines is intensive due to the large and expanding market. R&D efforts are primarily focused on increasing efficiency and/or reducing emissions (primarily NO_X). All major manufacturers of gas turbines 20 MW and larger now have combustors available or on the drawing board for NO_X emissions below 0.1 lb/MMBTU for natural gas without external cleaning or steam/water injection. Increased turbine inlet temperature is the main alternative for increasing the efficiency. R&D is therefore focused on advanced cooling of turbine blades and materials that can sustain turbine inlet temperatures of 2200 to 2550°F (1200 to 1400°C). Electric efficiencies above 40% are now attained by commercial aeroderivative gas turbines, with the latest industrial gas turbines having typical efficiencies of 35-38%.

Performance

Figure B.2 summarizes the electric and thermal efficiency of a representative gas turbine under ISO conditions.

Figure B.2
Sankey diagram (LHV) for cogeneration with gas turbine (size range 20 MW)



Electric efficiency is generally higher in the larger turbines, ranging from 25% for very small turbines (1-2 MW) to 35-40% for larger turbines (20 MW and up). Efficiencies in the 20-40 MW interval are relatively high because many aeroderivative gas turbines, which generally have higher efficiencies, are available in that size range.

The temperature effect of intake air on the *power output* of a combustion turbine is significant. Although there are variations between units, for most turbines, power output increases by about 10% for every 59°F (15°C) drop in outdoor temperature, and conversely output decreases by about 10% for every 59°F (15°C) increase in outdoor temperature.

In an economic evaluation of a cogeneration plant it is important to consider performance at different ambient temperatures depending on the climate conditions during which electric power is most valuable. Power output can be boosted by chilling inlet air to the compressor, either cooling directly on a baseload basis or indirectly through a thermal storage system.

The electric conversion efficiency of gas turbines can be increased by increasing the turbine inlet temperature and/or by increasing the pressure ratio. The compressor section heats the air and raises the pressure to the turbine. By adding or removing stages to the compressor the turbine inlet temperature and pressure ratio can be changed. Generally, a higher pressure ratio results in a lower exhaust temperature. However, lower exhaust temperatures also reduce the potential for thermal recovery, thereby decreasing total energy efficiency. Higher electric conversion efficiencies in gas turbine combined cycles can be obtained for turbines which have higher exhaust temperatures in simple cycle mode.

Emissions

Emissions can vary based on the particular gas turbine equipment, fuels used, and flue gas cleaning equipment. Actual emissions for a facility can only be determined based on facility specific factors.

The main environmental concern regarding gas turbines is the nitrogen oxides (NO_X) emission. Gas turbine plants can reach NO_X emissions below 0.1 lb/MMBTU without any external flue gas cleaning. Low NO_X emissions were previously achieved by injecting steam or water into the combustion chamber, which decreases the efficiency and increases the operating cost. Most manufacturers of medium to large size (> 5 MW) gas turbines can now meet emission limits with dry low-NO_X combustors. Dry low-NO_X combustors typically utilize a staged lean-burn combustion process to reduce the temperature of combustion and resulting in less production of nitrogen oxide emissions.

Carbon dioxide emissions, also a concern for fuel combustion facilities, are related directly to the amount of fuel burned. Natural gas combustion results in CO_2 emissions of about 0.11 lb/MMBTU of gas burned, although this can vary somewhat depending on the chemical properties of the natural gas.

Economics

Gas turbine capital, operating and maintenance (O&M) costs are extremely sensitive to size. A comparison of capital costs and O & M costs is presented in the following table. Capital costs range from up to $1600/kW for a 1 MW combustion turbine cogeneration system to less than $700/kW for large systems (over 100 MW).

Table B.1
Summary of Generalized Capital and Operating Costs of Gas Turbine Cogeneration [4 5 6 7 8]

Size (MW)	Capital Cost ($/kw)	O&M Cost ($/kWh)
1-2	1200-1600	0.008-0.010
5-25	800-1050	0.005-0.006
25-100	650-780	.004-.005
>100	<650	<.003

[4] "The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector," OnSite Sycom Energy Corp. for the U.S. Department of Energy, January 2000 (Revision 1).
[5] Gas Turbine World 1999-2000 Handbook, Gas Turbine World magazine, Vol. 20.
[6] "Electricity: Efficient End-Use and New Generation Technologies and Their Planning Implications," Lund University Press, 1989.
[7] "Existing District Heating System Based Economical Power Production," Parson Brinckerhoff Energy Systems Group, International District Energy Association Annual Conference, 1994.
[8] "Technical Assessment Guide, TRI02276," Electric Power Research Institute, Sept. 1993.

Gas turbine operation and maintenance (O&M) costs include: 1) monthly maintenance that can be accomplished without equipment shutdown; 2) periodic maintenance (approximately every 4,000 hours of operation) including borescope inspection for blade erosion and checkout of fuel systems, sensors and controls, burner cleaning; and 3) major overhaul at intervals of 30,000 to 40,000 hours.

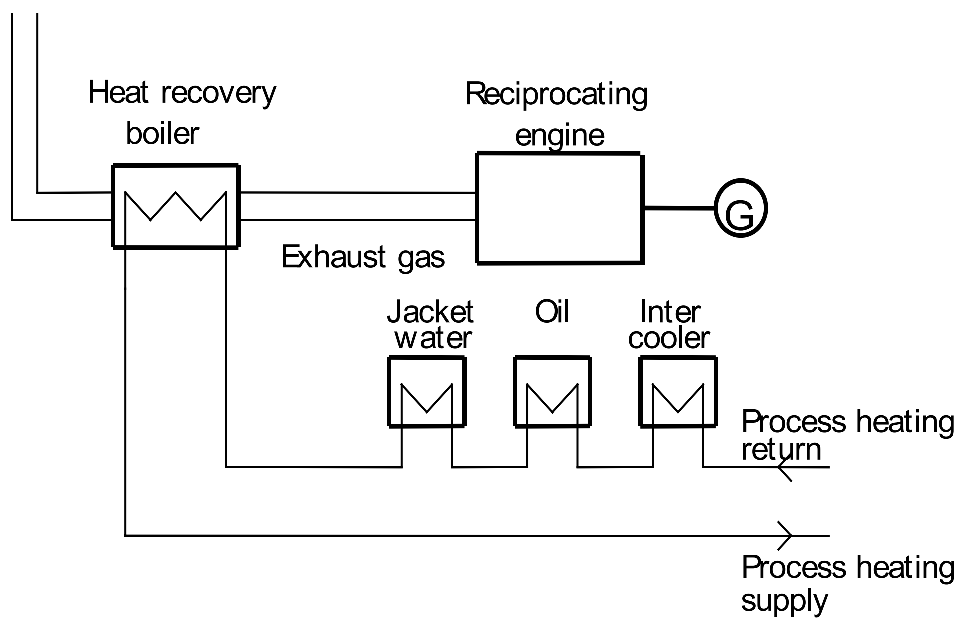
B.3 Reciprocating Engines

Description of Technology

Reciprocating engine cogeneration is illustrated in Figure B.3 and can be briefly described as follows:

- Fuel and air enter a combustion chamber where it is ignited either by compression (diesel cycle) or a spark (Otto cycle) and drives a piston attached to a crank shaft.
- A generator attached to the engine shaft generates electricity.
- Heat is recovered when the hot exhaust gas is cooled in a heat recovery boiler.
- Heat can also be recovered from the engine cooling water and oil lubrication system.
- In addition, heat can be recovered from the turbocharger and intercooler.

Figure B.3
Schematic for reciprocating engine cogeneration



The diesel engine is dominant over Otto engines in sizes above 1-2 MW. Both the diesel engine and the Otto engine can be found in a number of different applications and designs, including 4 and 2 stroke, with 1 to 20 cylinders. Turbochargers are common on both Otto engines and diesel engines to increase the efficiency and power output. Diesel engines are available in sizes up to 50 MW. Otto engines are usually limited to below 2 MW, although some manufacturers are developing larger (5-10 MW) Otto engines because it is increasingly difficult to meet nitrogen oxide emission limits with diesel engines without expensive catalytic converters. These engines are sometimes called "spark-ignited diesel engines" or "gas engines."

Multiple-stage intercoolers that cool the compressed combustion air before it enters the combustion chamber as well as exhaust gas turbines producing additional electricity can be used for larger engines if economical. A multi-stage intercooler allows some of the heat rejected from the cooling of compressed air to be available at a higher and more usable temperature. An exhaust gas turbine converts some of the high temperature "waste" heat to electricity. Many variations are possible for the design of specific equipment for cogeneration, depending on site-specific conditions.

Both gaseous and liquid fuels can be used in reciprocating engines. However, fuel ignition in diesel engines presents a challenge when using natural gas (with an ignition temperature of about 1200°F (650°C) as opposed to about 480°F (250°C) for fuel oil). Conversion of reciprocating engines to use gaseous fuels is achieved in two ways:

- *Injection of oil as a "pilot fuel," using about 5% oil at full load and up to about 10% at part loads.* This can be achieved by mixing air with gas fuel outside the engine. However, in modern larger diesel engines converted to gas combustion the gas fuel is compressed in an external compressor up to a pressure of about 3650 psig (250 bar). The compressed gas is then injected into the engine, where air already has been compressed, just before the ignition point. With this method, the power output is usually not affected by conversion to gaseous fuels, and the engine can be switched between gaseous and liquid fuels.

- *Conversion to spark ignition (Otto engine) in combination with "lean burn" (high air/fuel ratio) designs.* This is generally the approach taken with smaller (under 6 MW) engines, although R&D is continuing to increase the size of engines employing this approach due to its environmental benefits. One disadvantage is the lack of ability to switch fuels. This modified engine has a higher compression ratio than a normal Otto engine but low enough not to self-ignite. The electric efficiency of this modified engine is higher than a conventional Otto engine.

Since the beginning of 1970s, intensive diesel engine R&D has been performed, especially regarding diesel engines for ships due to rapidly increasing oil prices during that time. During the 1970s and 1980s the efficiency was increased from 40% to over 50% for the most efficient two-stroke engines. Substantial increases in efficiency are not expected in the near future. Instead, R&D is concentrated on reducing emissions and maintenance requirements and, to a lesser extent, use of alternative fuels.

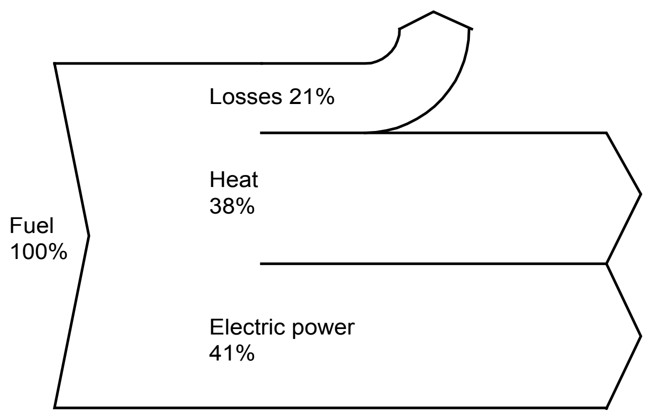
Performance

<u>Electric and Thermal Efficiency:</u>

Electric conversion efficiencies for diesel engines are usually in the range of 40-45% (Figure B.4). Efficiencies over 50% can be achieved with slow-speed two-stroke engines. However, these engines are larger in size (about 15 MW and above), are expensive and have higher emissions relative to gas turbines, with which they will be competing in this size range. The higher efficiency slow-speed two-stroke engines are not addressed in this report because gas turbines (simple cycle or combined cycle) are usually a better choice from the standpoints of both economy and emissions.

For a diesel cogeneration plant the ratio of electric output to thermal output will be slightly above 1.0, and the total efficiency will be about 80%, assuming recovery of thermal energy for a process heating hot water system with 212/167°F(100/75°C) supply/return temperatures.

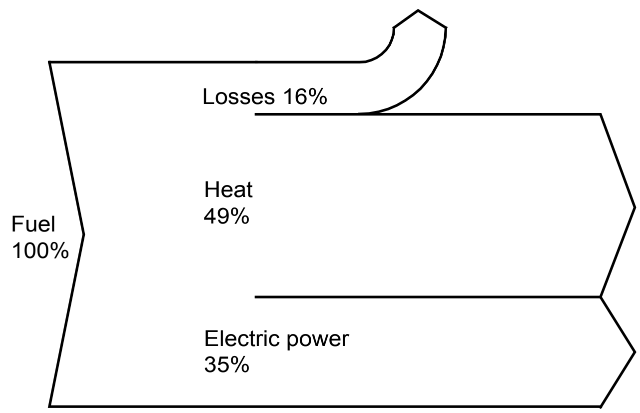
Figure B.4
Sankey diagram (LHV) for cogeneration with diesel engine
(4 stroke, size range 5-15 MW)



The electric efficiency is unchanged regardless of heat supply temperature as long as the intercooler or jacket water temperatures are not raised to accommodate higher heat supply temperatures. Heat recovery up to 212°F (100°C) heat supply temperature is based on hot water with a 77°F (25°C) temperature increase from the engine. Above 248°F (120°C), saturated steam with a condensate return temperature of 100°C is assumed. The total efficiency decreases with increasing heat supply temperatures. However, it is important to note that if there is a use for lower temperature hot water, an additional hot water heat recovery boiler can be installed to raise the total efficiency up to the same level as for hot water heat recovery only.

For Otto engines the electric conversion efficiency ranges from 30-40%, with 35% as a representative value for engines up to 2 MW, as shown in Figure B.5. A total efficiency of around 85%, with an electric/thermal output ratio in the range of 0.55-0.90, can be reached for a cogeneration Otto engine assuming 100/75°C thermal energy recovery. For larger Otto engines or lean-burn gas engines the performance is similar to the performance for a diesel engine. While the gross electric efficiency can be higher for the diesel engine, this can be offset by the electric consumption for compressing gas to the required high pressure in situations where a low pressure gas pipeline supplies the fuel.

Figure B.5
Sankey diagram (LHV) for cogeneration with Otto engine
(size range 1-2 MW)



Emissions

Emissions can vary based on the particular engine, fuels used and flue gas cleaning equipment. Actual emissions for a facility can only be determined based on facility-specific factors.

NO_X emissions from reciprocating engines are relatively high compared to other energy conversion equipment. For a diesel engine the NO_X emissions are around 2-3 lb/MMBTU fuel input without cleaning equipment. Selective catalytic reduction (SCR) is usually used, with a possible emission reduction around 90-95 percent. SCR is normally not used for Otto engines. Instead, two other methods can be used: 1) three-way catalytic converters (non-selective catalytic reduction); and 2) lean-burn which provide reductions comparable to SCR systems.

Economics

Capital Costs

Capital costs for cogeneration plants based on reciprocating engines are generally in the range of \$1000 - \$1400/kW for small units to \$800 - \$900/kW for large units.[2] These values represent the total investment for equipment and installation.

Operation and Maintenance Cost

The operation and maintenance cost for reciprocating engines includes oil consumption, oil changes, replacement of components such as filters, gaskets and spark plugs, and major overhauls at an interval of approximately 50,000 hours. For small Otto engines, below 1 MW, the operation and maintenance cost is in the range of 1.0-2.0 cents/kWh, and for larger Otto and diesel engines 0.5-1.0 cent/kWh. With SCR, 0.25-0.5 cent/kWh should be added. [2 9 10]

[9] Manufacturers data from Wartsila and Caterpillar.

B.4 Steam Turbines

Description of Technology

A steam turbine uses steam to generate electricity. The basic elements of steam turbine cogeneration are illustrated in Figure B.6, and can be briefly described as follows:

- Fuel and air are combusted in a boiler, generating steam. To increase the efficiency of the steam turbine cycle the steam is normally superheated.
- The steam exits the boiler and is directed to the steam turbine, where the steam expands through the turbine, turning the turbine blades that are connected to the electric generator shaft.
- In a backpressure turbine, the steam is exhausted above atmospheric pressure to a heat exchanger where thermal energy is transferred at a relatively low pressure to the thermal loop or steam-driven chiller.
- If higher pressure steam is required, some steam is extracted through ports in the turbine prior to exhaust or the exhaust pressure is increased.
- In a condensing turbine, the steam is condensed using a cooling tower, ground water or surface water, exiting at less than atmospheric pressure. Since turbine efficiency is directly related to the difference between inlet and exhaust steam pressures, condensing (non-cogeneration) turbine plants provide the highest electric efficiency.
- As illustrated in Figure B.6, some cogeneration steam turbine plants include a condensing tail turbine (the low pressure turbine in the figure) to increase the electric output regardless of thermal demand.
- In some steam turbine plants a reheat cycle is used, in which steam is extracted from the turbine and reheated in the boiler during the expansion process. Reheat cycles, with one or two reheat points, improve the overall thermal efficiency because the average temperature of the heat supply is increased.
- Steam turbine plants usually also include a regenerative cycle in which steam is extracted from the turbine and used to preheat boiler feed water. This increases overall efficiency because the steam's latent heat of condensation is returned to the process, thereby increasing the average temperature of the heat supply.

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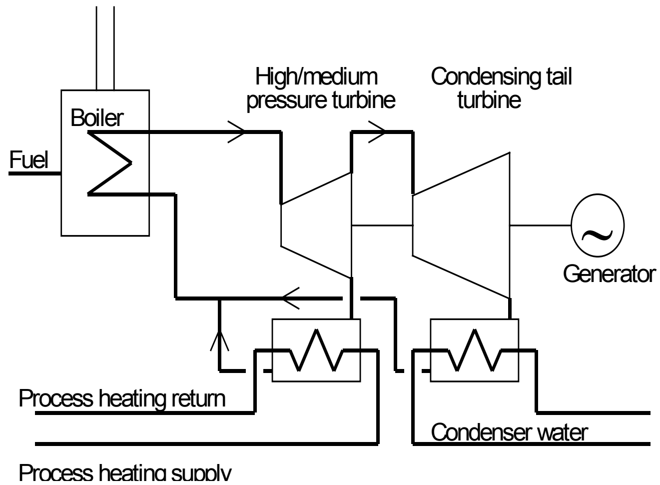
[10] "Small Scale Combined Heat and Power," Energy Technology Series #4, Energy Efficiency Office, United Kingdom.

Figure B.6
Schematic for cogeneration with steam turbine, including condensing tail turbine



Independent steam turbine power plants (i.e., steam turbines which are not just a component of a larger plant) are available in sizes ranging from 5 MW to over 1000 MW, and are the most common type of power plant in use worldwide. (As a component in a larger plant, steam turbines are available in sizes of under 1 MW.) One of the strengths of this technology is the ability to use a wide variety of fuels, including solid fuels and waste materials.

As is the case for all power generation equipment, the steam turbine cycle efficiency would benefit from raised temperature of the heat supplied to the process. While the temperature of the supplied heat to gas turbine cycle has increased rapidly during the last 10 years, the temperature to the steam turbine cycle has been stable at around 1000°F (540°C).

The main difference in the evolution of combustion turbines and steam turbines can be traced in part to the amount of material that must withstand the higher temperatures. For a gas turbine, only the combustor, inlet guide vanes and turbine blades must withstand the higher temperatures, thereby limiting the amount of expensive material needed. For a steam turbine cycle, a large part of the boiler surfaces must withstand the higher temperatures as well as the intake stages of the turbine.

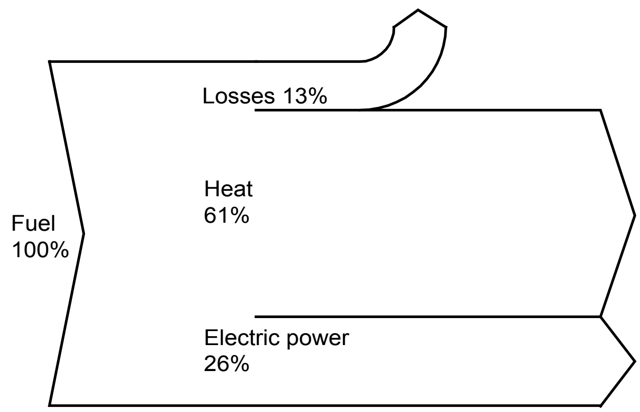
Technology and material for withstanding temperatures above 1000°F (540°C) steam temperatures (such as high-alloy ferritic/martensitic steel, austenitic steel and/or superalloy steels instead of low-alloy ferritic steels used up to 1000°F (540°C) steam temperature) are available but thus far the cost/benefit ratio has been too high. However, R&D for increasing the steam temperature above 1100°F (600°C) is ongoing, raising the possibility of increasing the condensing steam cycle plant efficiency to 45-46% (LHV).

Performance

Electric and Thermal Output

Figure B.7 shows a generalized Sankey diagram for steam turbine cogeneration in the 25 to 50 MW range based on 100/75°C heat extraction. For larger cogeneration plants employing reheat, higher steam pressures and additional feed water preheaters, the electric efficiency can be increased to above 30%.

Figure B.7
Sankey diagram (LHV) for typical steam turbine cogeneration
(size range 25-50 MW)



For a cogeneration plant with a process heating hot water temperature of 212/167°F (100/75°C), the electric efficiency is about 10% lower than a comparable condensing cycle without cogeneration. The part-load performance of steam turbines is in between those of reciprocating engines and gas turbines.

For a cogeneration plant the overall efficiency can be as high as 90% with an electric efficiency of slightly over 30%, compared with the overall efficiency of 40% for a condensing cycle without cogeneration The electricity lost due to heat extraction will generally be about 0.15 units of electricity per unit of heat at 212°F (100°C) extraction. The overall efficiency of a steam cogeneration plant is greatly affected by how low a stack temperature can be allowed relative to acid dew point and flue gas dispersion, and the extent to which excess air can be limited without increasing carbon monoxide (CO) and uncombusted carbon.

Electric usage for auxiliary fuel handling equipment is higher for solid fuel-fired plants than for oil- or gas-fired plants, but compared to the stack losses the electric usage for auxiliaries has a relatively small effect on the overall efficiency. Boiler efficiencies range from about 80% for a boiler with high excess air and high flue gas temperature to above 90% for a larger boiler with good air supply controls and an air preheater.

The electric efficiency for a steam turbine decreases with increasing heat supply temperature while the total efficiency is unchanged (as long as the return temperature of the thermal or condenser loop is constant). This contrasts with reciprocating engines and gas turbines, where the electric efficiency is unchanged for different heat supply temperatures while the total efficiency decreases with increased heat supply temperature.

Emissions

Emissions are related to the boiler technology, fuels used, and flue gas cleaning equipment, and can vary within a wide range. Actual emissions for a facility can only be determined based on facility-specific. Major emissions may consist of nitrogen oxides, sulfur dioxides, carbon monoxide, carbon dioxide and particulates It may be difficult to permit these type of facilities in areas designated as non-attainment areas for these emissions.

Economics

Capital Costs

Gas-fired plants range in cost from less than $1000/kW for large plants to nearly $2000/kW for a 5 MW plant. Solid-fuel-fired plants range in cost from $1500/kW for large plants (over 500 MW) to $2000-2400/kW for smaller plants (10-25 MW).[1] In cogeneration mode the electric output is reduced although the same size boiler and auxiliaries are employed.

Operation and Maintenance Costs

Operation and maintenance (O&M) costs vary between 1.25 cents per kWh for smaller steam turbines (25 MW) to 1.00 cents/kWh for larger steam turbines (100 MW). O&M costs are highly dependent on the type of fuel being burned in the boiler. Higher O&M costs are associated with solid fuel fired boilers versus liquid/gaseous fuel fired boilers. [1]
[11]

B.5 Combined Cycles

Gas Turbine Combined Cycle

<u>Description of Technology</u>

The gas turbine combined cycle is an increasingly common configuration. A combined cycle uses the waste heat from a combustion turbine to generate steam and drive a steam turbine. Figure B.8 illustrates an example of a combined cycle, showing components for both condensing and cogeneration options. Temperatures and pressures vary depending on the particular combined cycle configuration; this figure shows one example for illustrative purposes.

- Natural gas or liquid fuel is combusted in the gas turbine, producing electricity and hot flue gases as described previously in B.2.
- The hot flue gases enter the Heat Recovery Steam Generator (HRSG), where heat is recovered to produce steam (and, in some cogeneration operations, hot water). Output can be increased through supplemental firing, in which additional fuel is combusted using the high oxygen content in the exhaust gas. Supplementary firing can improve the overall efficiency and can improve electric efficiency at part-load conditions.

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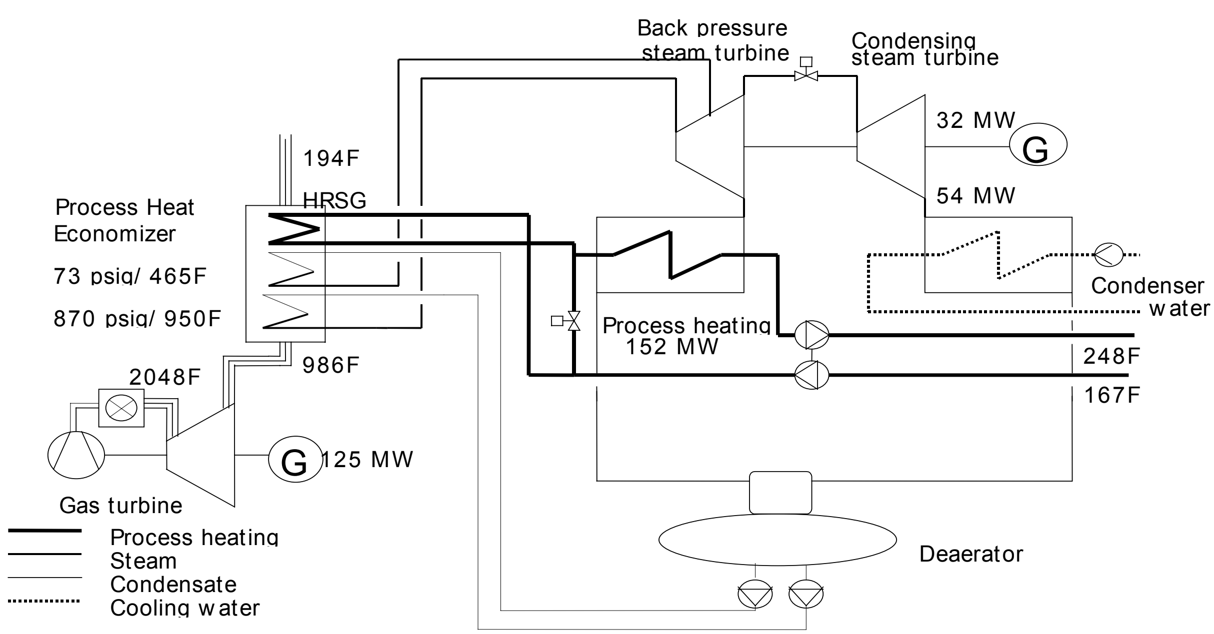
[11] "Technical Assessment Guide, TRI02276," Electric Power Research Institute, Sept. 1993.

- Steam is used to produce additional electricity in a steam turbine (in the example shown, 32 MW in cogeneration mode and 54 MW in condensing mode).
- The steam cycle usually has 2-3 pressure levels; the higher steam pressure to enhance the electric efficiency and the lower pressure to enhance the heat recovery efficiency.
- To increase the overall efficiency a process heating economizer also can be installed in the HRSG.

Figure B.8
Example schematic of a gas-fired combined cycle cogeneration plant

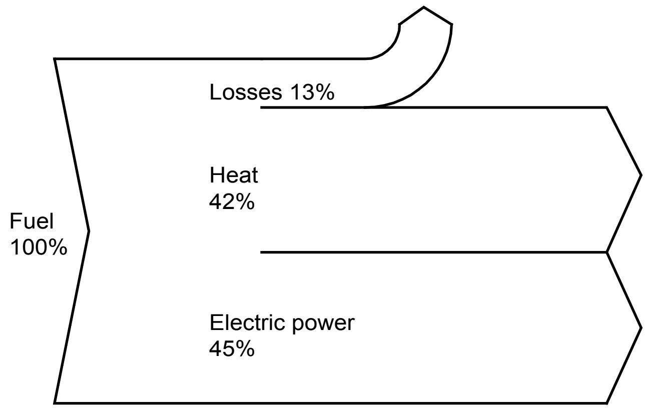


Performance

Electric and Thermal Output

Electric efficiency above 50% can now be reached with many gas turbine combined cycle in condensing mode, with some systems reporting an efficiency of 60%.[2] In cogeneration mode with an extraction temperature of 212/167°F (100/75°C), an electric efficiency of about 45% can be expected, with a total efficiency of about 87% as shown in Figure B.9.

Figure B.9
Sankey diagram (LHV) for gas turbine combined cycle cogeneration



Industrial types of gas turbines tend to have a somewhat lower simple cycle efficiency, but a longer service life, compared to aero-derivative gas turbines. Selection of an aero-derivative versus industrial grade turbine in normally based on the lowest overall life cycle cost. With a combined cycle with one pressure level, the electric efficiency in industrial-type gas turbines is 13-17% higher than the comparable simple cycle. Adding one to two pressure levels can boost electric efficiency by another 1-2%. The efficiency improvement achievable through a combined cycle is generally lower with aero-derivative gas turbines because these types of turbines tend to have a lower exhaust temperature.

The gas turbine combined cycle in condensing mode can reach an electric efficiency around 50%, with an efficiency above 55% possible in larger facilities with multiple steam pressure levels. The design of particular facility is based on performing a life – cycle cost analysis to determine the lowest overall system cost, taking into account first costs as well as operating costs.

Supplementary firing in the heat recovery boiler can be used to increase the overall efficiency. Supplementary firing will normally decrease the electric efficiency because the fuel is not utilized at the highest possible temperature, i.e. in the gas turbine. However, with low exhaust temperatures at part-load conditions, supplementary firing can increase the electric output.

Emissions

Emissions will vary based on the particular gas turbine equipment, fuels used and flue gas cleaning equipment.   Actual emissions for a facility can only be determined based on facility-specific.

The emissions per unit of fuel input are comparable for a gas turbine simple cycle and a gas turbine combined cycle.   However, the combined cycle will have lower emissions per unit of electricity due to the higher electric efficiency.

Economics

Capital and operating costs for condensing combined cycle plants have higher capital costs due to the costs associated with the steam turbine and associated generator.

Solid Fuel Combined Cycle

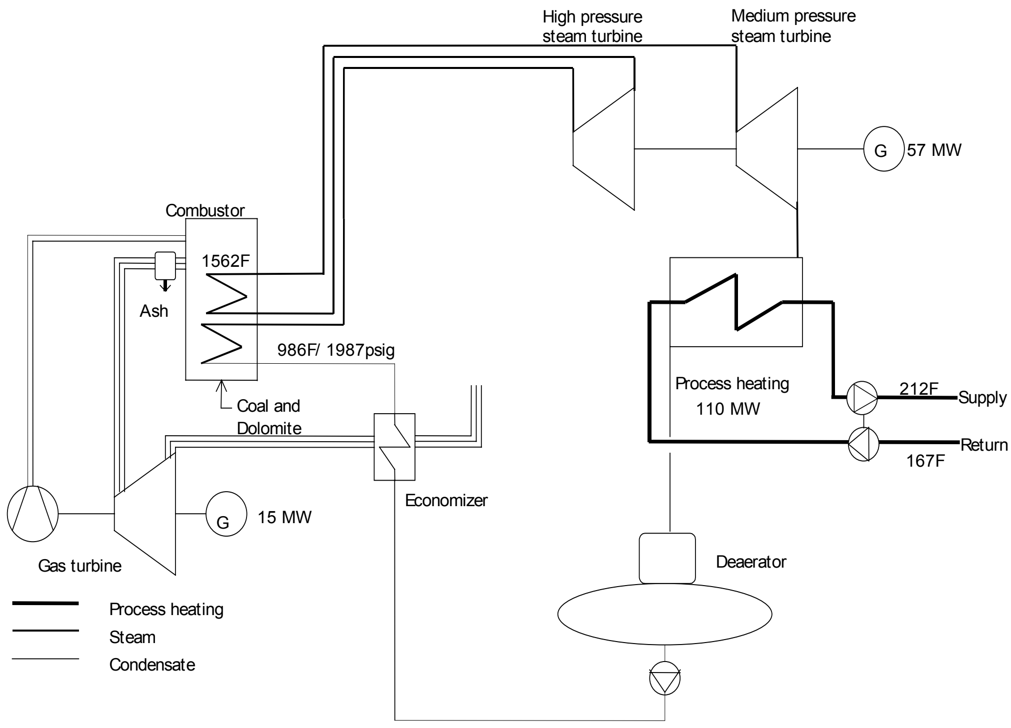
Description of Technology

Pressurized Fluidized Bed Combustion (PFBC) and Integrated Gasification Combined Cycle (IGCC) technologies have been implemented to increase the efficiency of power production from solid fuels primarily consisting of coal or wood.

The basic layout of a PFBC is close to a natural gas combined cycle (see Figure B.10). The main difference is the combustor, which in a PFBC plant is substantially larger and is a fluidized bed boiler. The gas turbine provides compressed air to the boiler and, because of the pressurization of the boiler 175-232 psig (12-16 bar), the size can be considerably smaller compared to what would be required for a normal solid fuel boiler with the same (electric or thermal?) output.

Solid fuel, typically coal or wood waste, is injected into the combustor. Combustion takes place in a bed of limestone that is suspended in the combustion chamber utilizing large combustion air fans. The bed acts like a “fluid”. Combustion takes place in the fluidized bed at a low temperature, 1560°F (850°C). The low combustion temperature reduces the formation of NO_X but is also essential to avoiding ash agglomeration. Steam is generated from water circulated through the fluidized bed to cool the bed and distributed to the steam turbine. Limestone or dolomite is injected into the bed to capture sulfur during combustion. Particulates from the hot flue gas are cleaned with cyclones before entering the gas turbine. In addition to supplying the boiler with compressed air, the gas turbine also provides about 20% of the electric output with the steam turbine producing about 80% of the electric output

Figure B.10
Schematic for a solid fuel-fired combined cycle cogeneration plant (PFBC)



PFBC plants are competing with coal gasification for high technical and environmental performance utilizing coal. Because of the limited market, the price for a PFBC plant under commercial conditions is uncertain. However, the technical and environmental performance should make PFBC an important future option for use of coal for cogeneration.

Performance

Electric and Thermal Output

A higher electric efficiency as well as improved emissions can be reached with a PFBC compared to conventional solid fuel power plants. An electric efficiency of 44-46% LHV can be reached in condensing mode. In cogeneration mode, electric efficiency can reach 34%, with an overall efficiency of 89% LHV. [12]

Emissions

The environmental performance from existing PFBC plants is almost equivalent to gas-fired plants. The absorption of sulfur in the bed can reduce the SO_2 emissions by over 95%. NO_x emissions around 0.02 lb/MMBTU have been obtained with ammonia injection and a small catalytic aid in the flue gas duct. Measured levels of CO and N_2O

[12] "Electric Power Technologies: Environmental Challenges and Opportunities," Report to the Committee on Energy Research and Technology, International Energy Agency, 1993.

are less than 200 parts per million by weight (ppm) and 10 ppm, respectively. With a textile baghouse, the particulate emissions are around 0.004 lb/MMBTU.

B.6 Fuel Cells

A number of new technologies are under development for advanced cogeneration, including supercritical steam cycles, various technologies for gasification of coal and/or biomass, and fuel cells. Of these, the fuel cell is perhaps of greatest interest due to its environmental advantages. For this reason, fuel cells will be briefly addressed here, although not in the depth of the cogeneration technologies presented earlier in this chapter.

Description of Technology

Fuel cells generate electricity and heat through an electrochemical conversion process similar to that long been applied in automobile batteries. Chemical energy is converted to electricity when hydrogen is combined with oxygen to make water. Hydrogen gas can be provided directly to the fuel cell. The hydrogen can be extracted from anything that contains hydrocarbons, including natural gas, biomass, landfill gas, methanol, ethanol, methane and coal-based gas. In the past, units are available in 200 kW modules that can be combined to provide larger installations, although larger units are now becoming available.

Different types of fuel cells are named according to the type of medium used to combine the hydrogen and oxygen. Three types of fuel cells are usually considered for cogeneration applications:

- Phosphorous acid cells, now operating in various sites providing cogeneration. Applications include schools, high rise office buildings and credit card processing centers.
- Molten carbonate systems, now in the demonstration phase for baseload power.
- Solid oxide cells, with a small-scale unit now in the demonstration phase.

Several other types of fuel cells are in use or being developed for various other applications:
- Alkaline -- used in space applications since the 1960s.
- Proton exchange membrane -- for transportation and small-power applications.

Performance

Fuel cells are highly efficient because they convert chemical energy directly into electricity without going through an intermediate combustion step. Total efficiencies exceeding 80% can be achieved when both heat and electricity are used. Efficiency is maintained over a wide range of unit operation.

Emissions

Virtually no emissions are produced in this process (zero emissions if pure hydrogen is used).

Economics

Currently, fuel cell cogeneration systems have a capital cost of approximately $3,000/kW.

Appendix C
Fuel Conversion Factors

Fuel	MMBtu/unit
Natural Gas	1028.00/mmcf
Fuel oil	138.69/1000 gallon
Residual (#5,6)	149.69/1000 gallon
Propane	91.33/1000 gallon
Gasoline	125.07/1000 gallon
Jet fuel	135.00/1000 gallon
Coal - Industrial	20.69/ton
Coal - Utility	17.45/ton
Wood - Industrial	12.80/ton
Ethanol	84.40/1000 gallon
Anthracite	25.00//ton
Bituminous	22.00/ton
Distillate (#1-3)	138.69/1000 gallon
Pet Coke	30.12/ton

Appendix D – References

1. "Integrating District Cooling with Combined Heat and Power," Resource Efficiency, Inc. for the International Energy Agency, ISBN 90-72130-87-1, 1996.

2. "The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector," OnSite Sycom Energy Corp. for the U.S. Department of Energy, January 2000 (Revision 1).

3. Gas Turbine World 1999-2000 Handbook, Gas Turbine World magazine, Vol. 20.

4. "Electricity: Efficient End-Use and New Generation Technologies and Their Planning Implications," Lund University Press, 1989.

5. "Existing District Heating System Based Economical Power Production," Parson Brinckerhoff Energy Systems Group, International District Energy Association Annual Conference, 1994.

6. "Technical Assessment Guide, TRI02276," Electric Power Research Institute, Sept. 1993.

7. Manufacturers data from Wartsila and Caterpillar.

8. "Small Scale Combined Heat and Power," Energy Technology Series #4, Energy Efficiency Office, United Kingdom.

9. "Technical Assessment Guide, TRI02276," Electric Power Research Institute, Sept. 1993.

10. "Electric Power Technologies: Environmental Challenges and Opportunities," Report to the Committee on Energy Research and Technology, International Energy Agency, 1993.

11. "Opportunities to Expand Cogeneration in Minnesota," Center for Energy and Environment.

12. Per 1990 emissions data provided to the Minnesota Pollution Control Agency.

13 "The Market and Technical Potential for Combined Heat and power in the Commercial/Institutional Sector" Revision 1, Jan. 2000.

Appendix E – Survey Recipients Ranked by Total Fuel Use

PCA ID#	facility	MM Btu/year	firstname	lastname	phone	city_b	state	zip_b
7100002	Boise Cascade Corp - International Falls	7,871,515	Brent	Walchuk	2182855522	International Falls	MN	56649
7500003	Northshore Mining Co - Silver Bay	7,646,420	Nancy	Smith	2182266083	Silver Bay	MN	55614
1700002	Potlatch - Cloquet	5,972,705	Kevin	Kangas	2188790638	Cloquet	MN	55720
6100001	Blandin Paper Co	5,957,718	Curt	Firman	2183276306	Grand Rapids	MN	55744
11900002	American Crystal Sugar - E Grand Forks	5,421,375	Annette	Cederberg	2182364304	Moorhead	MN	56560
5700005	Potlatch - Bemidji (MN Wood Products)	5,297,152	Steve	Bailey	2187511708	Bemidji	MN	56601
12900014	Southern Minnesota Beet Sugar COOP	4,655,669	Glenn	Augustine	3203294149	Renville	MN	56284
8300038	Minnesota Corn Processors	2,920,295	Michael	Rutledge	5075372676	Marshall	MN	56258
2700001	American Crystal Sugar - Moorhead	2,905,179	Annette	Cederberg	2182364304	Moorhead	MN	56560
11900001	American Crystal Sugar - Crookston	2,828,745	Annette	Cederberg	2182364304	Moorhead	MN	56560
900011	Champion International Corp - Sartell	2,679,806	Keith	Sowada	3202407340	Sartell	MN	56377
5300011	NRG Energy - Mpls Energy Ctr (Main)	2,011,678	Henry	Hanson	6123496087	Minneapolis	MN	55404
1700006	USG Interiors - Cloquet	1,824,137	Stephen	Povroznik	2188792800	Cloquet	MN	55720-1592
1300006	ADM - Mankato	1,676,848	Chris	Janick	2184244810	Decatur	IL	62525
12300694	3M - Maplewood - Administrative Offices	1,595,266	Linda	Tanner	6127785213	St Paul	MN	55133-3331
3500002	Potlatch - Brainerd (NW Paper Division)	1,519,452	Julie	Hendricks	2188286522	Brainerd	MN	56401-2198
13700005	US Steel Minn Ore Operations - Minntac	1,458,259	Stephani	Campbell	2187497468	Mountain Iron	MN	55768-0417
13700113	EVTAC Mining - Plant	1,404,181	Bradley	Anderson	2187447849	Eveleth	MN	55734
1300007	Cenex Harvest States Coop - Mankato	1,375,240	Jeff	Bergeland	5073452213	Mankato	MN	56002-3247
16300023	3M - Cottage Grove Specialty Matls-Film	1,292,993						
700019	Northwood Panelboard	1,253,301	John	Oschwald	2187512023	Solway	MN	56678-9731
13900013	CertainTeed Corp	1,147,033	Gary	Swenson	6124456450	Shakopee	MN	55379
13900003	Rahr Malting - Shakopee	1,055,021	Paul	Kramer	6124967002	Shakopee	MN	55379
8500049	3M - Hutchinson Tape Manufacturing Plant	1,048,516	Mike	Ossanna	6127784036	St Paul	MN	55133-3331
12300063	District Energy St Paul Inc-Hans O Nyman	1,015,315	Michael	Burns	6512978955	St Paul	MN	55102-1611
13700022	Duluth Steam COOP Assn	991,594	Gerald	Pelofske	2187233601	Duluth	MN	55802
12300055	North Star Steel MN	987,827	Judd	Ebersviller	6517315697	St Paul	MN	55164

PCA ID#	facility	MM Btu/year	firstname	lastname	phone	city_b	state	zip_b
6100010	Potlatch - Grand Rapids	976,570	Bruce	Trebnick	2183273650	Grand Rapids	MN	55744
13700083	Potlatch - Cook	971,683	Todd	Smrekar	2186666902	Cook	MN	55723
5700006	Lamb Weston - RDO Frozen Foods	884,752	Brian	Flynn	2187327252	Park Rapids	MN	56470
3500031	Trus Joist MacMillan - Deerwood	848,578						
15100026	CVEC - Benson Ethanol Plant	740,273	Jon	Buyck	3208434813	Benson	MN	56215
4300041	Corn Plus	712,861	Sheila	Helland	5078934747	Winnebago	MN	56098
1900001	Bongards' Creameries	654,366	Tom	Otto	6124665521	Norwood	MN	55368-9743
12300016	3M - St Paul Tape Manufacturing Division	645,268	Ade	Babatunde	6517787674	St Paul	MN	55133-3331
3300025	Ethanol 2000 LLP	629,674	Terry	Kulesa	5078310063	Bingham Lake	MN	56118
300073	Minnesota Correctional - Lino Lakes	626,459	Jim	Aleckson	6127806100	Lino Lakes	MN	55014
3700066	Spectro Alloys Corp	621,633						
12300039	Ford Motor Co - Twin Cities Assembly Plt	611,107	Marc	Daniels	6516960584	St Paul	MN	55116-1888
13100022	Malt-O-Meal Co - Plant 2 - Northfield	595,229	Robert	Johnston	5076456681	Northfield	MN	55057
13700031	Georgia-Pacific - Duluth Hardboard	592,044	Thomas	Lochner	2187208248	Duluth	MN	55802
1500010	New Ulm Public Utilities Commission	586,314	Gary	Dolmeier	5073598264	New Ulm	MN	56073
3900028	Al-Corn Clean Fuel	576,712	Randall	Doyal	5075282494	Claremont	MN	55924
4900007	USG Interiors - Red Wing	572,388	James	Wilson	6123883513	Red Wing	MN	55066
14300014	Heartland Corn Products	550,801	Ben	Brown	5076475000	Winthrop	MN	55396
9900002	Hormel Foods Corp - Austin	540,813	Lee	Johnson	5074375221	Austin	MN	55912
12900036	Minnesota Energy	538,983	Eileen	Koeberl	3208335939	Buffalo Lake	MN	55314
10500001	Swift & Company	536,625	Chuck	Tennessen	5073722121	Worthington	MN	56187
7300002	Ag Processing - Dawson	536,159	Lee	Gunderson	3207694386	Dawson	MN	56232
5300002	Hennepin County Energy Center	526,428	Patrick	Rainville	6123368531	Minneapolis	MN	55415
14500003	Kraft Foods Inc - Melrose	524,097	Larry	O'Donnell	3202567461	Melrose	MN	56352
14900013	Diversified Energy Co LLC	519,374	Gerald	Bachmeier	3205892931	Morris	MN	56267
10900006	IBM - Rochester	507,241	Cory	Landgren	5072532472	Rochester	MN	55901
2700022	Busch Agricultural Resources - Moorhead	454,231	Gregory	Ballentine	2182338531	Moorhead	MN	56560
10900008	St Mary's Hospital	452,035	Thomas	McNallan	5072556814	Rochester	MN	55902-1970
16900013	Froedtert Malt - Winona	410,498	David	Brunette	4146490284	Milwaukee	WI	53201
5300010	Northwest Airlines Inc\Mpls\St Paul Airp	408,878	Marvin	Dietrich	6127274842	St Paul	MN	55111-3034

PCA ID#	facility	MM Btu/year	firstname	lastname	phone	city_b	state	zip_b
7500019	Louisiana-Pacific Corp - Two Harbors	359,272	Barbara	Hamilton	2188345652	Two Harbors	MN	55616
12300022	University of St Thomas	321,739	Robert	Jacobs Jr	6129626530	St Paul	MN	55105
4900001	ADM - Red Wing	312,127	Chris	Janick	2174244810	Decatur	IL	62525
7300016	Associated Milk Producers Inc - Dawson	305,052	Joe	Vaske	6127692994	Dawson	MN	56232
5700002	Potlatch - Lumbermill - Bemidji	302,656	Peter	Aube	2187516144	Bemidji	MN	56601
14	Metropolitan Medical Center	300,000	Dwayn	Tapani	6123474531	Redwood Falls	MN	56283
15300006	Central Bi-Products - Long Prairie	294,338	Don	McCallum	5076372938			
12300053	MCES Metropolitan WWTP - St Paul	294,254	Keith	Buttleman	6516021015	St Paul	MN	55101
12700013	Central Bi-Products - North Redwood	289,830	Don	McCallum	5076372938	Redwood Falls	MN	56283
300020	Armament Systems Division United Defense	289,485	Douglas	Hildre	6125726938	Minneapolis	MN	55421-1498
6700054	Ridgewater College	278,146	Thomas	Wilts	3202315133	Willmar	MN	56201
16300003	Marathon Ashland Petroleum - St Paul Pk	258,164	Mike	Lukes	6514582726	St Paul Park	MN	55071
16100013	Brown Printing Co - Waseca Division	253,053	J	Schumacher Jr	5078350314	Waseca	MN	56093
5300790	NRG Energy - Mpls Energy Ctr (Riverside)	251,474	Henry	Hanson	6123496087	Minneapolis	MN	55404
3700016	Gopher Resource Corp	250,737						
5300813	Guest Credit Center	239,775	Keith	Kostial	6123045993	Minneapolis	MN	55416
14500008	St Johns University Order of St Benedict	229,569	Dan	Weber	3203632541	Collegeville	MN	56321
13700009	LTV Steel Mining - Hoyt Lakes	228,719	James	Stanhope	2182254373	Hoyt Lakes	MN	55750
13700039	University of MN - Duluth Upper	227,405	Craig	Moody	6126264399	Minneapolis	MN	55455
300019	Onan	226,149	David	Jacobsen	6125745000	Fridley	MN	55432
5300061	Abbott Northwestern Hospital	225,196	Bob	Hallman	6128634161	Minneapolis	MN	55407
13900009	Richards Asphalt Co	213,771	Byron	Richards	6128948000	Savage	MN	55378
1700003	Diamond Brands	212,173	Patrick	Wippler	2188782744	Cloquet	MN	55720-9990
10900010	Associated Milk Producers Inc -Rochester	212,077	Greg	McCutcheon	5072827401	Rochester	MN	55904
3700070	Van Hoven Co Inc	207,761	Melanie	Mornard	6514516858	South St Paul	MN	55075
14500026	St Cloud State University	204,054	Chuck	Lindgren	6122553166	St Cloud	MN	56301
4500049	Pro-Corn LLC	200,968	Richard	Eichstadt	5077654548	Preston	MN	55965
10900032	Quest International	187,986	George	Mathey	5072853400	Rochester	MN	55901
13700073	ME International - Duluth	187,592				Duluth	MN	
16300001	Andersen - Main	185,202	Kirk	Hogberg	6124307437	Bayport	MN	55003

PCA ID#	facility	MM Btu/year	firstname	lastname	phone	city_b	state	zip_b
12300036	Globe Bldg Materials	184,652	Oliver	Du Frene	6127762793	St Paul	MN	55106
12	Mankato State University	184,400	Robert	Isdahl	5073892222	Mankato	MN	
2700008	Moorhead State University	183,679	Alan	Breuer	2182362998	Moorhead	MN	56563
13300023	Agri-Energy LLC	183,587	Gordon	Heber	5072839297	Luverne	MN	56156
300155	Hoffman Enclosures Inc	182,448	Alan	Olson	6124222583	Anoka	MN	55303
4900062	Dairy Farmers of American Inc - Zumbrota	179,715	Steve	Ejnik	5077325124	Zumbrota	MN	55992
13100059	Minn Correctional Facility - Faribault	177,494	Richard	Schaefer	5073324506	Faribault	MN	55021
14500001	Kraft Food Ingredients - Albany	176,099	Daniel	Schneider	6128452131	Albany	MN	56307
14500032	Associated Milk Producers - Paynesville	173,183	Matt	Quade	3202433794	Paynesville	MN	56362
7900019	Unimin Minnesota Corp - Le Sueur	171,111				Le Sueur	MN	
13100007	Crown Cork & Seal - Faribault	170,847				Faribault	MN	
5300146	Honeywell - Golden Valley Home & Bldg	166,283	Greg	Weisjahn	6129544732	Golden Valley	MN	55422
14500067	Cold Spring Granite - Main Plant	160,360	Brian	Sjaaheim	6126853621	Cold Spring	MN	56368
13700166	St Mary's Medical Center	159,303	John	Rice	2187264693	Duluth	MN	55804
7900017	Le Sueur Incorporated	158,610						
9	Fairbault State Hospital	156,700	Brian	Youngberg	5073323304	Faribault	MN	
16300002	3M - Cottage Grove Indust Specialty	149,634						
10900036	Seneca Foods Corp - Rochester	149,557	Brian	Thiel	5072804531	Rochester	MN	55904
13100006	St Olaf College	147,869	Perry	Kruse	5076463280	Northfield	MN	55057-1098
13500002	Marvin Windows & Doors	146,152	Bradley	Baumann	2183861430	Warroad	MN	56763-0100
16300017	3M - Cottage Grove Abrasive Systems Div	143,739						
300156	Federal Cartridge Co - Anoka	142,997	Luke	Davich	6123232569	Anoka	MN	55303
700004	Georgia Pacific - Bemidji Hardboard	142,127	Gary	Wilson	2187515140	Bemidji	MN	56601
5300127	Owens-Corning - Mpls Plant	141,229	Joe	Orvik	6125223395	Minneapolis	MN	55430
1500007	OCHS Brick Co	137,462						
20	Stillwater State Prison	137,200	Bill	Mordick	6517792700			
3500008	State of Minnesota Dept of Human Service	137,006	Bernard	Baloun	2188282459	Brainerd	MN	56401
13100018	Carleton College	136,569	Kirk	Campbell	5076464133	Northfield	MN	55057
7100015	Intl Bildrite	135,759						

PCA ID#	facility	MM Btu/year	firstname	lastname	phone	city_b	state	zip_b
10	Fergus Falls Reg. Treatment Center	135,700	Les	Baird	2187397300	Fergus Falls	MN	
15700024	Lakeside Foods Inc - Plainview	131,985	William	Arendt	5075343141	Plainview	MN	55964
15700015	Federal-Mogul Corp Powertrain Systems	129,810	Ron	Koller	6513454541	Lake City	MN	55041
3100002	Hedstrom Lumber Co Inc - Grand Marais	129,792	Howard	Hedstrom	2183872995	Grand Marais	MN	55604
12300019	Minnesota Brewing Co	129,753	Michael	Hime	6512289173	St Paul	MN	55102
10900022	Crenlo Inc - Plant 3	129,068						
7900022	Seneca Foods Corp - Montgomery	127,026	Tim	Nelson	5073648641	Montgomery	MN	56069
5300312	Superior Plating	124,632	Jayne	Lecy	6123792121	Minneapolis	MN	55413
2700043	Concordia College - Moorhead Campus	121,144	Ansel	Hakanson	2182993362	Moorhead	MN	56562
4900065	Bergquist Co - Cannon Falls	120,200				Cannon Falls	MN	
5300293	Fairview Southdale Hospital	118,372	David	Fashant	6129241394	Edina	MN	55435
13500008	Polaris Industries LP	116,801						
16300025	3M - Cottage Grove Corp Incinerator	114,236						
1500009	Kraft Foods - New Ulm	113,348	Denise	Manderfeld	5073544131	New Ulm	MN	56073
5300048	ADM Milling Co - A Mill	112,071	Cyrus	Irani	6126278000	Minneapolis	MN	55414
3700011	Koch Petroleum Group LP - Pine Bend	110,916				Pine Bend		
5300384	Banta Catalog - Minneapolis	109,981				Minneapolis		
13900005	Anchor Glass Container Corp - Shakopee	107,835				Shakopee		
5300251	Interplastic Corp - Minneapolis Plant	106,763	Sheri	Peterson	6514816860	Minneapolis	MN	55413-1775
14700012	Crown Cork & Seal Co Inc - Owatonna	104,148	Graham	Foulkes	5074551344	Owatonna	MN	55060
8500032	Hutchinson Technology	102,762	Richard	Higgins	3205871950	Hutchinson	MN	55350
10300001	St Peter Regional Treatment Center	102,700	Dave	Woelpern	5079317280	St Peter	MN	56082
12300108	Hamline University	101,102	Mike	Waterbury	6515232227	St Paul	MN	55104
12300386	3M - Abrasives Systems Division	100,954						
8500035	Seneca Foods Corp - Glencoe	99,729	Arlen	Aas	3208642253	Glencoe	MN	55336
12300054	American National Can - St Paul (Eva)	99,691				St. Paul	MN	55107

Appendix F – Survey and Cover Letter

August 31, 2000

<salut> <firstname> <lastname>
<title>
<address_a>
<address_b>
<address_c>
<city>, <state> <zip>

Dear <salut> <lastname>:

The Minnesota Environmental Quality Board (MEQB) is currently assessing the potential for combined heat and power (CHP), also known as cogeneration, in Minnesota. While many industrial and institutional facilities already have CHP systems in place, the MEQB is interested in identifying untapped CHP potential. Further developing Minnesota's CHP potential could have significant economic and environmental benefits for individual firms and for Minnesota as a whole. We have retained Kattner/FVB District Energy Inc. to assist us with this project.

As part of this project, the MEQB is developing an inventory of high-potential CHP sites. This inventory will be used to assess the potential for CHP at individual facilities, and will be available to policy makers and CHP developers. As part of our initial screening we have identified more than one hundred facilities that, based on facility type and fuel use, appear to have some CHP potential. The attached survey will gather additional information necessary to assess CHP potential. In order to minimize the burden on survey respondents, we have made every attempt to keep the survey as brief as possible. Please take a few minutes to fill out the attached survey and return to me by fax at 651/296-3698 or my mail. The completed survey can be returned to me by fax or mail. If it is more convenient for you, you can also fill out a copy at our agency's website, www.mnplan.state.mn.us/eqb/powersurvey.htm .

If we have not received your response by September 15, you will receive a follow-up call. If you have any questions or concerns about either the survey or the project please do not hesitate to contact me by phone at 651/296-2878, or by e-mail at suzanne.steinhauer@state.mn.us.

Thank you for your assistance in this effort to enhance Minnesota's environmental and economic vitality.

Sincerely,

Suzanne Steinhauer
Energy Facilities Planner

Minnesota Cogeneration Survey

Name:____.
Address:____.
Company:____________________________Title: ____________.
Telephone Number:_____________________ Fax Number:_________.
Date:_________Email address:__________________________.

1. Electric Generation:

1.1 Existing electric generation

Type	Capacity	Fuel	Age	Cogen

1.2. Plans for additional electric generation:__________________________
____.

1.3. Annual electricity generation (MWH):__________________________.

1.4. Peak electricity demand (MW):_____________________________.

1.5. Annual electric consumption (MWH):__________________________.

1.6. Sources and costs of electric power:___________________________
____.

2. Thermal Energy Generation:

2.1. Existing thermal generation equipment

Type	Capacity (mmbtu/hr)	Fuel	Age

2.2. Plans for additional thermal generation:____
____.

2.3. Peak thermal energy demand (mmbtu/hr):________________________________.

2.4. Potential nearby additional thermal loads:_______________________________.

2.5. Annual thermal energy consumption (mmbtu):___________________________.

2.6. Breakdown of thermal requirements

Use of Heat					
Temperature (F)					
Pressure (psig)					
Peak demand (mmbtu/hr)					

3. General:

3.1. Fuel costs:____.

3.2. Natural Gas availability:____.

3.3. Access to electric transmission grid:_____________________________________.

3.4. How much space is available for cogeneration facilities inside the plant:___________
____.
Outside the plant:____.

3.5. Annual fuel consumption by fuel type:

Fuel	Unit	Annual consumption
Natural gas	MCF	
Coal	Mmbtu	
Light fuel oil	Gallons	
Residual oil	Gallons	
Other		
Other		
Other		

Appencix G: Survey Data

Appendix G: Survey Data – Contact Information

Company	Name	Telephone	Fax	E-mail
SMDC Health Systems	John Rice	218-786-4693	218-786-2475	
Crown Cork & Seal	Mark Fink	507-455-8167	507-455-1344	
Ford Motor Company	Brad Bystrom	651-696-0660	651-696-0523	BBystrom@Ford.com
ACS - Crookston	Annette Cederberg	218-236-4304	218-236-4365	
ACS - East Grand Forks	Annette Cederberg	218-236-4304	218-236-4365	
Duluth Steam Cooperative	Gerald W Pelofske	218-923-3601	218-723-3600	
Ridgewater College	Tom Wilts	320-231-5133	320-231-5498	twilts@ridgewatermnscu.edu
Froedtert Malt	David L Brunette	414-649-0284	414-649-0295	dbrunette@froedtermalt.com
American Crystal Sugar Co - Moorhead	Annette Cederberg	218-236-4304	218-236-4365	acederbe@crystalsugar.com
Louisiana Pacific Corporation	Barbara Hamilton	218-834-5652	218-834-2363	Barbara.Hamilton@LPCorp.com
Order of St Benedict Inc. St Johns University	Attn: Power Plant	320-363-2541	320-363-3999	
Seneca Food Corp (Glencoe)	Daniel Roe	320-864-2251	320-864-5779	droe@senecafoods.com
Dairy Farmers of America	Radu Rasidescu	507-732-8642	507-732-8669	
Interplastic Corp	Gary Severson	651-481-6861	612-331-4235	Gseverson@Interplastic.com
Fergus Falls Regional Treatment Center	John H Wright	218-739-7322	218-739-7570	john.h.wright@state.mn.us
Hormel Foods Corp	Chad Sayles	507-437-5415	507-437-5524	cbsayles@hormel.com
Chippewa Valley Ethanol Company	Mitch T Miller	320-843-1235	320-843-1239	MJMILLER@cvec.com
Seneca Foods Corp	Jim HauKom	507-280-4500	507-280-4579	JHauKom@senecafood.com
St Olaf College	Perry Kruse	507-646-3280		kruse@stolaf.edu
Northwood Panelboard	Jack Wallingford	218-751-2023	218-751-2075	
North Star Steel	Todd Ebersviller	651-731-5697	651-731-5699	
New Ulm Public Utilities	Robert Stevenson	507-359-8264	507-354-7318	nupuc@newulmtel.net
Brown Printing Co	Dean Veldboom	507-835-0289	507-835-0180	dean.veldboom@bpc.com
Diamond Brands Inc	Patrick Wippler	218-878-2744	218-879-6369	pwippler@diamondbrands.com
Boise Cascade	Jay Lofgren	218-285-5218	218-285-5691	Jay_LoFgren@BC.com
Potlatch Corporation	Julie Hendricks	218-828-6522	218-828-5118	
Heartland Corn Products	Ben Brown	507-647-5000	507-647-5010	ben@mean.net
Marvin Windows and Doors	Bradley J Baumann	218-386-1430	218-3864046	bradbau@marvin.com
US Steel - Minnesota Ore Operations	Raymond Potts	218-749-7598	218-749-7360	rpotts@uss.com
Blandin Energy Center	Tim St. Cyr	218-326-1622	218-326-1161	tstcyr@mnpower.com
Brainerd Regional Human Services	Ron Ledin	218-828-2627	218-828-6096	
Rahr Malting Co	Paul Kramer	952-496-7002	952-496-7055	pkramer@rahr.com
Ag Processing Inc	Lee Gunderson	320-769-4386	320-169-2668	

Appendix G: Survey Data – Summary Assessment

Site	Summary Assessment
St. Mary's Duluth Clinic (SMDC) Health Systems	Good prospect for cogeneration, with good data.
Crown Cork & Seal	Potential prospect, but data are inadequate for assessment.
Ford Motor Company	Large hydroelectric capacity and poor thermal load factor makes this a poor prospect for cogeneration.
ACS - Crookston	Already has cogeneration; prospects for additional economical cogeneration is unlikely.
ACS - East Grand Forks	Already has cogeneration; prospects for additional economical cogeneration is unlikely.
Duluth Steam Cooperative	Good prospect for cogeneration, with good data.
Ridgewater College	Small size makes this a poor prospect, data are incomplete.
Froedtert Malt	Potential prospect, but data are inadequate for assessment.
American Crystal Sugar Co - Moorhead	Already has cogeneration; prospects for additional economical cogeneration is unlikely.
Louisiana Pacific Corporation	Wide mix of process requirements and equipment, and access to inexpensive wood fuel and relatively small size for solid fuel cogeneration makes this a difficult prospect for cogeneration.
Order of St Benedict Inc. St Johns University	Already has cogeneration; prospects for additional economical cogeneration is unlikely.
Seneca Food Corp -- Glencoe	Good prospect for cogeneration, with good data.
Dairy Farmers of America	Potential prospect, but data are inadequate for assessment.
Interplastic Corp	Wide mix of process requirements and poor electric load factor makes this a difficult prospect for cogeneration.
Fergus Falls Regional Treatment Center	Small size and outside purchase of steam makes this a poor prospect, and data are incomplete.
Hormel Foods Corp	Good prospect for cogeneration, with good data.
Chippewa Valley Ethanol Company	Poor thermal load factor makes this a poor prospect for cogeneration.
Seneca Foods Corp -- Rochester	Potential prospect, but data are inadequate for assessment.
St Olaf College	Potential prospect, but data are inadequate for assessment.
Northwood Panelboard	Access to inexpensive wood fuel makes this a difficult prospect for cogeneration.
North Star Steel	Direct-fired processes eliminates this as a cogeneration prospect.
New Ulm Public Utilities	Already has cogeneration; prospects for additional economical cogeneration is unlikely.
Brown Printing Co	Direct-fired processes eliminates this as a cogeneration prospect.
Diamond Brands Inc	Good prospect for cogeneration, with good data.
Boise Cascade	Already has cogeneration but considering adding more, with good data.
Potlatch Corporation -- Brainerd	Already small cogeneration but thermal and power loads may support more; data are incomplete.
Heartland Corn Products	Potential prospect, but data are inadequate for assessment.
Marvin Windows and Doors	Low cost power makes this a poor prospect for cogeneration.
US Steel - Minnesota Ore Operations	Potential prospect, but data are inadequate for assessment.
Blandin Energy Center	Already cogeneration but thermal and power loads may support more; data are incomplete.
Brainerd Regional Human Services	Small size and existing back-up generation makes this a poor prospect; data are incomplete.
Rahr Malting Co	Good prospect for cogeneration, with good data.
Ag Processing Inc	Small size makes this a poor prospect, data are incomplete.

Appendix G: Survey Data – Electric & Thermal Summary

Company	Existing Elec. Generation Total capacity-kW	Peak Power Demand MW	Electric Load Factor EFLH	Peak thermal Demand MMBTU/Hr	Thermal Load Factor EFLH	Ratio Peak Electric to Peak Thermal Demand	Ratio Avg Electric to Avg Thermal Demand
SMDC Health Systems	4,340	3.4	4,118	36	3,889	0.322	0.341
Crown Cork & Seal		7.8	236				
Ford Motor Company	18,000	15.6	6,077	88	1,870	0.605	1.966
ACS - Crookston	6,900	11.3	1,327	242		0.159	
ACS - East Grand Forks	8,200	17.4	5,724	388		0.153	
Duluth Steam Cooperative	950	0.75	3,196	270	3,147	0.009	0.010
Ridgewater College		1.7	2,508				0.662
Froedtert Malt							
American Crystal Sugar Co - Moorhead	6,200	11.7	4,957	242		0.165	
Louisiana Pacific Corporation		3.1	7,235	80	1,370	0.132	0.698
Order of St Benedict Inc. St Johns University	1,900	2.5		73		0.117	
Seneca Food Corp (Glencoe)		9.7	1,876	90	982	0.368	0.702
Dairy Farmers of America							0.000
Interplastic Corp	40	0.005	1,060	35	3,714	0.000	0.000
Fergus Falls Regional Treatment Center	1,000	0.85	4,235	20	3,673	0.148	0.171
Hormel Foods Corp		19	5,789	160		0.405	
Chippewa Valley Ethanol Company	3,000	3.4	6,000	110	5,602	0.105	0.113
Seneca Foods Corp		4.6	1,983	182		0.086	
St Olaf College	4,000	3.8	4,474				
Northwood Panelboard		5.6	7,679	150	282	0.127	3.463
North Star Steel							
New Ulm Public Utilities	47,000	48.1	6,682	39	2,564	4.208	10.966
Brown Printing Co		9.2	6,576	36	6,425	0.877	0.897
Diamond Brands Inc		1.63	5,764	20	7,662	0.278	0.209
Boise Cascade	43,640	70	7,571	1,800	6,111	0.133	0.164
Potlatch Corporation	3,500	13	8,478				0.330
Heartland Corn Products							
Marvin Windows and Doors	7,400	6.4	3,281	33	5,988	0.654	0.358
US Steel - Minnesota Ore Operations							
Blandin Energy Center	34,000	90	8,096	890	4,096	0.345	
Brainerd Regional Human Services	900	1.39	4,861				
Rahr Malting Co	400	12.4	5,242	160	6,666	0.264	0.208
Ag Processing Inc		3.2					

Appendix G: Survey Data – Electric Generation

Company	Electric Generation							Capacity to Demand Percentage
	Type	Quantity	Total Cap. (kW)	Fuel Type	Min age - yrs	Max age -yrs	Co-gen	
SMDC Health Systems	Diesel engine	4	4,340	Diesel	10	36	no	128%
Crown Cork & Seal								
Ford Motor Company	Hydroelectric	1	18,000	Water	75	75	no	115%
ACS - Crookston	Steam Turbines		6,900	Coal	45	45	yes	61%
ACS - East Grand Forks	Steam Turbines		8,200	Coal	80	80	yes	47%
Duluth Steam Cooperative	Cummings Generation	1	950	Diesel	5	5	no	127%
Ridgewater College								
Froedtert Malt								
American Crystal Sugar Co - Moorhead	Steam Turbines		6,200	Coal	50	50	yes	53%
Louisiana Pacific Corporation								
Order of St Benedict Inc. St Johns University	Steam Turbines & (1) Diesel	5	1,900	#2 Fuel	47	53	yes	76%
Seneca Food Corp (Glencoe)								
Dairy Farmers of America								
Interplastic Corp	Ford Engine	1	40	Natural Gas	10	10	no	800%
Fergus Falls Regional Treatment Center	Emergency Generator	1	1,000	#2 Diesel	5	5	no	118%
Hormel Foods Corp								
Chippewa Valley Ethanol Company	Cummings Diesel	2	3,000	Diesel	4.5	4.5	no	88%
Seneca Foods Corp								
St Olaf College		1	4,000	Diesel	3	3	no	105%
Northwood Panelboard								
North Star Steel								
New Ulm Public Utilities	Steam	4	47,000	Coal, Gas, Oil	3	43	yes	98%
Brown Printing Co								
Diamond Brands Inc								
Boise Cascade	Turbines & Waterwheel	12	43,640	Gas, Water	43	73	yes	62%
Potlatch Corporation	Hydro & Steam Turbine	2	3,500	Water, Gas, Coal	42	84	yes	27%
Heartland Corn Products								
Marvin Windows and Doors	Diesel Generators	12	7,400	Diesel			no	116%
US Steel - Minnesota Ore Operations								
Blandin Energy Center	Steam Turbine	2	34,000	Wood, Coal, Gas	20	31	yes	38%
Brainerd Regional Human Services	Diesel engine	3	900	Diesel	10	42	no	65%
Rahr Malting Co		1	400	Fuel Oil	1	1	no	3%
Ag Processing Inc								

Appendix G: Survey Data – Electric Summary

Company	Plans for additional electric generation	Annual electric generation MWH	Peak demand MW	Annual Consumption MWH	Electric Load Factor EFLH	Average Electric Demand KW/hr
SMDC Health Systems	no	Standby	3.4	14,000	4,118	1,598
Crown Cork & Seal	no	None	7.8	1,840	236	210
Ford Motor Company	no	117.3	15.6	94,800	6,077	10,822
ACS - Crookston	no	39,000	11.3	15,000	1,327	1,712
ACS - East Grand Forks	no	50,600	17.4	99,600	5,724	11,370
Duluth Steam Cooperative	yes 2004	None	0.75	2,397	3,196	274
Ridgewater College	yes	None	1.7	4,264	2,508	487
Froedtert Malt				23,931		2,732
American Crystal Sugar Co - Moorhead	no	35,000	11.7	58,000	4,957	6,621
Louisiana Pacific Corporation	no		3.1	22,428	7,235	2,560
Order of St Benedict Inc. St Johns University	yes	300	2.5		0	
Seneca Food Corp (Glencoe)	Possible		9.7	18,198	1,876	2,077
Dairy Farmers of America						
Interplastic Corp	no	Emergency	0.005	5.3	1,060	1
Fergus Falls Regional Treatment Center	no	Emergency	0.85	3,600	4,235	411
Hormel Foods Corp	no		19	110,000	5,789	12,557
Chippewa Valley Ethanol Company	Future	450	3.4	20,400	6,000	2,329
Seneca Foods Corp			4.6	9,124	1,983	1,042
St Olaf College	no	70	3.8	17,000	4,474	1,941
Northwood Panelboard	no		5.6	43,000	7,679	4,909
North Star Steel						
New Ulm Public Utilities	yes 5/2001	16,916	48.1	321,404	6,682	36,690
Brown Printing Co	Reviewing	None	9.2	60,500	6,576	6,906
Diamond Brands Inc	no		1.63	9,396	5,764	1,073
Boise Cascade	Considering	230,000	70	530,000	7,571	60,502
Potlatch Corporation	no	20,431	13	110,219	8,478	12,582
Heartland Corn Products				30,000		3,425
Marvin Windows and Doors	Possibly	1,200	6.4	21,000	3,281	2,397
US Steel - Minnesota Ore Operations	no					
Blandin Energy Center	no	155,520	90	728,640	8,096	83,178
Brainerd Regional Human Services	yes		1.39	6,757	4,861	771
Rahr Malting Co	yes	0	12.4	65,000	5,242	7,420
Ag Processing Inc	no		3.2			

Appendix G: Survey Data – Electric Supplies & Costs

Company	Electric Power Sources	Cost Demand ($/KW)	Energy Costs ($/Kwh)	Average Cost ($/kWh)
SMDC Health Systems	Minnesota Power			0.048
Crown Cork & Seal	Owatonna Public Utilities			
Ford Motor Company	NSP			0.041
ACS - Crookston	Ottertail Power			0.038
ACS - East Grand Forks	City Power			0.049
Duluth Steam Cooperative	Minnesota Power			0.05
Ridgewater College	Willmar Municipal Utilities			0.0383
Froedtert Malt				
American Crystal Sugar Co - Moorhead				0.037
Louisiana Pacific Corporation	Cooperative Light & Power			0.01
Order of St Benedict Inc. St Johns University	NSP			
Seneca Food Corp (Glencoe)	Glencoe Municipal Electric & Mclead Coop Power			0.052 & 0.065
Dairy Farmers of America				
Interplastic Corp	NSP	Sum-9.26 Win-6.61	0.031	
Fergus Falls Regional Treatment Center	Western Area Power Administration			
Hormel Foods Corp	Austin Utilities			
Chippewa Valley Ethanol Company	Agralite Rural Electric Coop/Great River Energy	6.2		0.025
Seneca Foods Corp		11.213		0.0358
St Olaf College	NSP	2.54	0.0305	
Northwood Panelboard	Ottertail Power			0.037
North Star Steel				
New Ulm Public Utilities				
Brown Printing Co	NSP			
Diamond Brands Inc	Minnesota Power			0.045
Boise Cascade	Minnesota Power			
Potlatch Corporation	Minnesota Power			
Heartland Corn Products				
Marvin Windows and Doors	City of Warroad Minnkota Power			0.026
US Steel - Minnesota Ore Operations				
Blandin Energy Center	Minnesota Power & Blandin Energy Center			
Brainerd Regional Human Services	City Power & Light			0.041
Rahr Malting Co	NSP			0.043
Ag Processing Inc	Ottertail power company			

Appendix G: Survey Data – Thermal Generation

Company	Thermal Generation Type	Quantity	Capacity total MMBTUH	Fuel	Min Age - Years	Max Age - Years
SMDC Health Systems	Boilers	3	66	Natural gas	32	36
Crown Cork & Seal						
Ford Motor Company	Boilers	2	160	Gas, Propane, #6 Fuel	44	76
ACS - Crookston	Steam Turbine		334.3	Coal		
ACS - East Grand Forks	Steam Turbine		644.4	Coal		
Duluth Steam Cooperative	Boilers	1	38.8	Coal or Gas	68	68
Ridgewater College	Bolier	6	46	Natural gas, Oil	10	32
Froedtert Malt						
American Crystal Sugar Co - Moorhead	Steam Turbine		300.4	Coal		
Louisiana Pacific Corporation	Oil Heater, Woodburner, Ovens	7	107	Wood, Natural Gas	3	15
Order of St Benedict Inc. St Johns University	Boilers	6	165	Natural Gas, #2 Fuel, Coal	2	53
Seneca Food Corp (Glencoe)	Boilers	3	118	Natural Gas or #2 Fuel	23	52
Dairy Farmers of America		2	83	Natural Gas & Fuel Oil #6	20	20
Interplastic Corp	Boilers, Oxidizer, Process Reactor	8	66	Natural Gas & Propane	1	35
Fergus Falls Regional Treatment Center	Boiler (not in use)	2	92	Coal, Oil-Gas	30	45
Hormel Foods Corp	Boilers	3		Natural Gas, #6 Fuel Oil	2	20
Chippewa Valley Ethanol Company	Boiler, Dryer	3	160	Natural Gas, Propane	1	4.5
Seneca Foods Corp	Boiler	4	147	Natural Gas, Fuel Oil	21	44
St Olaf College	Boilers			Natural Gas, Oil	30	30
Northwood Panelboard	Konus, Lamb, Wellons	5	200	Hog Fuel	4	19
North Star Steel						
New Ulm Public Utilities	Boiler	3	290	Natural Gas, Coal	35	52
Brown Printing Co						
Diamond Brands Inc	Boiler	4	32	Waste Wood & Bark	66	66
Boise Cascade	Boiler	3	2221	Gas, Bark, Sludge, Black Liquor	24	50
Potlatch Corporation	Steam Turbine	1	49.5	Coal, Gas	42	42
Heartland Corn Products						
Marvin Windows and Doors	Boiler	4	104.3	Wood, Natural Gas		
US Steel - Minnesota Ore Operations	Boilers	5	496	Natural Gas, Fuel Oil	22	33
Blandin Energy Center	Boiler	4	1100	Wood, Coal, Gas	0	20
Brainerd Regional Human Services						
Rahr Malting Co	Air to Air Heaters, Boilers	26	308	Natural Gas, Propane	5	20
Ag Processing Inc						

Appendix G: Survey Data – Thermal Summary

Company	Plans for additional thermal generation	Peak thermal demand MMBTU/Hr	Nearby potential loads	Annual thermal consumption MMBTU	Thermal Load Factor EFLH	Average Thermal Demand MMBtu/hr
SMDC Health Systems	no	36	office buildings	140,000	3,889	16
Crown Cork & Seal	no					
Ford Motor Company	no	88		164,520	1,870	19
ACS - Crookston	no	242	None		0	0
ACS - East Grand Forks	no	388	None		0	0
Duluth Steam Cooperative		270		849,731	3,147	97
Ridgewater College	no			21,973		3
Froedtert Malt						
American Crystal Sugar Co - Moorhead	no	242	None		0	0
Louisiana Pacific Corporation	no	80	None	109,599	1,370	13
Order of St Benedict Inc. St Johns University	no	73	None		0	
Seneca Food Corp (Glencoe)	no	90	Unknown	88,400	982	10
Dairy Farmers of America	no			152,726		17
Interplastic Corp	no	35	None	130,000	3,714	15
Fergus Falls Regional Treatment Center	no	20	Unknown	72,000	3,673	8
Hormel Foods Corp	no	160	None		0	
Chippewa Valley Ethanol Company	Possible	110	None	616,250	5,602	70
Seneca Foods Corp	no	182	None		0	
St Olaf College	no					
Northwood Panelboard	no	150	None	42,360	282	5
North Star Steel						
New Ulm Public Utilities	no	39	39 MMBTU/Hr	100,000	2,564	11

Brown Printing Co	no	36	None	230,000	6,425	26
Diamond Brands Inc	no	20	None	153,230	7,662	17
Boise Cascade	no	1,800	None	11,000,000	6,111	1,256
Potlatch Corporation	no			1,139,588		130
Heartland Corn Products						
Marvin Windows and Doors	no	33		200,000	5,988	23
US Steel - Minnesota Ore Operations	no					
Blandin Energy Center	no	890	None	3,645,565	4,096	416
Brainerd Regional Human Services						
Rahr Malting Co	no	160	None	1,066,500	6,666	122
Ag Processing Inc	no					

Appendix G: Survey Data – Thermal Requirements (p. 1 of 2)

Company	Breakdown of Thermal Requirements								
	Space Heating			Dryer			Hot Water		
	Pres - Psig	Temp - F	Demand - PPH	Pres - Psig	Temp - F	Demand - PPH	Pres - Psig	Temp - F	Demand - PPH
SMDC Health Systems	10		30				10		5
Crown Cork & Seal									
Ford Motor Company	175	375	88						
ACS - Crookston									
ACS - East Grand Forks									
Duluth Steam Cooperative	225	397	270						
Ridgewater College									
Froedtert Malt									
American Crystal Sugar Co - Moorhead									
Louisiana Pacific Corporation		70	31		260	40			
Order of St Benedict Inc. St Johns University									
Seneca Food Corp (Glencoe)	15	250	15						
Dairy Farmers of America									
Interplastic Corp									
Fergus Falls Regional Treatment Center									
Hormel Foods Corp									
Chippewa Valley Ethanol Company	65	315							
Seneca Foods Corp									
St Olaf College									
Northwood Panelboard		400	10		380	100			
North Star Steel									
New Ulm Public Utilities	15	250	23						
Brown Printing Co		75			400				
Diamond Brands Inc	12	213	10						
Boise Cascade	40	260	200	165	410	600			
Potlatch Corporation									
Heartland Corn Products									
Marvin Windows and Doors									
US Steel - Minnesota Ore Operations									
Blandin Energy Center									
Brainerd Regional Human Services									
Rahr Malting Co		75	125						
Ag Processing Inc									

Appendix G: Survey Data – Thermal Requirements (p. 2 of 2)

Company	Breakdown of Thermal Requirements								
	Electric Generation			Processing			Sterilizes/Steam		
	Pres - Psig	Temp - F	Demand - PPH	Pres - Psig	Temp - F	Demand - PPH	Pres - Psig	Temp - F	Demand - PPH
SMDC Health Systems							60		1
Crown Cork & Seal									
Ford Motor Company									
ACS - Crookston							400	560	242
ACS - East Grand Forks							400	560	388
Duluth Steam Cooperative									
Ridgewater College									
Froedtert Malt									
American Crystal Sugar Co - Moorhead							400	560	242
Louisiana Pacific Corporation					240	35			
Order of St Benedict Inc. St Johns University									
Seneca Food Corp (Glencoe)				28	265	95			
Dairy Farmers of America				150	352				
Interplastic Corp					430	10	100	350	0.27
Fergus Falls Regional Treatment Center									
Hormel Foods Corp							125 & 15	Saturated	120 & 80
Chippewa Valley Ethanol Company									
Seneca Foods Corp					200				
St Olaf College									
Northwood Panelboard					400	30			
North Star Steel									
New Ulm Public Utilities				140	350	16			
Brown Printing Co									
Diamond Brands Inc				149	334	10			
Boise Cascade				40	260	200			
Potlatch Corporation				100	750	49.5			
Heartland Corn Products							125		
Marvin Windows and Doors							12	244	33.4
US Steel - Minnesota Ore Operations									
Blandin Energy Center	1250	900	270	50, 150, 400	320, 500, 700	540, 90, 270			
Brainerd Regional Human Services									
Rahr Malting Co				<15 psig	175-240	150			
Ag Processing Inc									

Appendix G: Survey Data – Fuel Costs

Company	Natural Gas per MCF	No. 2 Oil per Gal.	No.6 Oil per Gal	Diesel per Gal	Propane per Gal	Wood per ton	Coal per ton
SMDC Health Systems	$3.00	$0.40					
Crown Cork & Seal							
Ford Motor Company	$3.00						
ACS - Crookston							$9.34
ACS - East Grand Forks							$9.34
Duluth Steam Cooperative							$21.97
Ridgewater College	$4.30	$0.90					
Froedtert Malt							
American Crystal Sugar Co - Moorhead							$9.34
Louisiana Pacific Corporation	$3.63					$5.64	
Order of St Benedict Inc. St Johns University	High	$0.90					$40.00
Seneca Food Corp (Glencoe)	Varies						
Dairy Farmers of America	$4.56		$0.50				
Interplastic Corp	$4.78				$0.45		
Fergus Falls Regional Treatment Center							
Hormel Foods Corp	$3.00		$0.45				
Chippewa Valley Ethanol Company	$3.63			$1.05	$0.95		
Seneca Foods Corp	$3.07						
St Olaf College	$4.46		$0.43	$1.00			
Northwood Panelboard	$2.60				$0.30		
North Star Steel							
New Ulm Public Utilities	$4.20						$49.50
Brown Printing Co							
Diamond Brands Inc						$20.00	
Boise Cascade							
Potlatch Corporation	$4.75						$59.00
Heartland Corn Products							
Marvin Windows and Doors	$5.90					$10.00	
US Steel - Minnesota Ore Operations							
Blandin Energy Center							
Brainerd Regional Human Services	$4.00		$0.50				
Rahr Malting Co	$5.00						
Ag Processing Inc							

Appendix G: Survey Data – Fuel Consumption

Company	Natural Gas MCF	No. 2 Fuel Oil Gallons	No. 6 Fuel Oil Gallons	Propane Gal	Refuse tons	Wood tons	Diesel Gal	Coal tons
SMDC Health Systems	135,000	36,000						
Crown Cork & Seal	1							
Ford Motor Company	970							
ACS - Crookston								98,000
ACS - East Grand Forks								180,000
Duluth Steam Cooperative								79,141
Ridgewater College	20,440	5,000						
Froedtert Malt	336,032							
American Crystal Sugar Co - Moorhead								104,000
Louisiana Pacific Corporation	147					27,363		
Order of St Benedict Inc. St Johns University	90	3,000						9,800
Seneca Food Corp (Glencoe)	125,000	>5,000						
Dairy Farmers of America	218,904		12,191					
Interplastic Corp	130,000			45,000				
Fergus Falls Regional Treatment Center					30,000			
Hormel Foods Corp	550,000		1,200,000					
Chippewa Valley Ethanol Company	725,000			75,000				
Seneca Foods Corp	136,144							
St Olaf College	163,000		20,515					
Northwood Panelboard	70,000			155,000				
North Star Steel								
New Ulm Public Utilities	518,000	195,603						
Brown Printing Co	225,000							
Diamond Brands Inc						15,323		
Boise Cascade	4,800,000							
Potlatch Corporation	1,460,000							170
Heartland Corn Products	1,200,000							
Marvin Windows and Doors	12,500					15,000	35,000	
US Steel - Minnesota Ore Operations	7,338,000	144,828				86,355		
Blandin Energy Center	1,400,000					350,000		32,000
Brainerd Regional Human Services	114,373		80,011					
Rahr Malting Co		1,185,000						
Ag Processing Inc								

Appendix G: Survey Data – Expandability

Company	Natural gas utility pressure available	Space Available for Cogeneration Facilities	
		Inside Plant	Outside Plant
SMDC Health Systems		None	Parking lots
Crown Cork & Seal		None	
Ford Motor Company	60	None	Adequate
ACS - Crookston	160	None	Limited
ACS - East Grand Forks	160	Limited	Limited
Duluth Steam Cooperative	15	Some	Adequate
Ridgewater College		Limited	Adequate
Froedtert Malt			
American Crystal Sugar Co - Moorhead	160	Limited	Some
Louisiana Pacific Corporation	50	Unknown	Unknown
Order of St Benedict Inc. St Johns University	30	Some	
Seneca Food Corp (Glencoe)	25	None	5 Acres
Dairy Farmers of America		None	Adequate
Interplastic Corp	3	None	None
Fergus Falls Regional Treatment Center		Limited	Adequate
Hormel Foods Corp		None	10000 sq ft
Chippewa Valley Ethanol Company	94	Limited	125+ Acres
Seneca Foods Corp	10	Limited	
St Olaf College	60	None	None
Northwood Panelboard	100	None	Some
North Star Steel		None	None
New Ulm Public Utilities	300	No need	None
Brown Printing Co	300-400	None	Some
Diamond Brands Inc		None	Adequate
Boise Cascade	400	Limited	
Potlatch Corporation	43	None	None
Heartland Corn Products			100 Acres
Marvin Windows and Doors			
US Steel - Minnesota Ore Operations			
Blandin Energy Center	100 & 200	Limited	None
Brainerd Regional Human Services	10	None	None
Rahr Malting Co	800		2-3 acres
Ag Processing Inc		None	None

Appendix H: Site Assessments

Appendix H-1: Rahr Malting, Option 1 Steam Turbine CHP –Biomass

Operating Parameters

Throttle steam pressure (psig)	600	In-house biomass available (tons)	58,000
Throttle steam temperature (F)	750	Heating value (Btu/lb)	7,943
Backpressure steam pressure (psig)	50	Available MMBtu/year in-house	921,388
Btu per pound required in boiler	1,058	Additional biomass required	616,117
Boiler efficiency	85%		
Throttle steam quantity (pounds/hour)			
Peak	196,192		
At average thermal load	145,500		
Peak power output (MW)			
Gross	9.308		
Net	8.377		
Net as % of peak demand	68%		
Average power output (MW)			
Gross	6.903		
Net	6.213		

Hourly thermal and electric production

	Average thermal	Peak
Fuel use (MMBtu)	181	244
Thermal energy produced (MMBtu)	125	168
Thermal energy produced (% of peak demand)	78%	105%
Fuel displaced (MMBtu)	147	198
Displaced electricity (kWh)	6,213	8,377
Displaced electricity (% of peak demand)	50%	68%
Total efficiency (%)	81%	81%

Annual operations

Target full load hours of operation	7,000	7,000	7,000	7,000
Percent availability	90%	90%	90%	90%
Adjusted full load hours	6,300	6,300	6,300	6,300
Electric output (MWh)	52,776	52,776	52,776	52,776
Thermal output (MMBtu)	1,061,388	1,061,388	1,061,388	1,061,388
Fuel consumption (MMBtu)	1,537,505	1,537,505	1,537,505	1,537,505
Total electricity consumed (MWh)	65,000	65,000	65,000	65,000
Electricity generated (MWh)	52,776	52,776	52,776	52,776
Electricity purchased (MWh)	12,224	12,224	12,224	12,224
Electricity sold (MWh)	-	-	-	-
Assumed value of electricity sold ($/MWh)	$ 15.0	$ 15.0	$ 15.0	$ 15.0

Total thermal energy consumed (MMBtu)	1,066,500	1,066,500	1,066,500	1,066,500
Thermal energy generated with CHP (MMBtu)	1,061,388	1,061,388	1,061,388	1,061,388
Thermal energy generated with non-cogen boiler	5,112	5,112	5,112	5,112

Appendix H-1: Rahr Malting, Option 1 Steam Turbine CHP –Biomass

Steam Turbine CHP -- Biomass **8.38 MW net power output after station load**

Credit for boiler capacity?	**no**
Investment tax credit?	**no**
Renewable production credit?	**no**
Avoided natural gas cost ($/MMBtu)	**$ 5.00**

Economic Analysis with Sensitivity to Biomass Costs

Capital costs	
Capital cost ($/kW)	$ 2,400
Gross capital cost ($)	$ 22,339,200
Boiler capacity credited (MMBtu/hour)	-
Boiler capacity type	gas/oil
Boiler capacity credit ($ per MMBtu/hour)	$ 20,000
Boiler capacity credit ($)	$ -
Investment tax credit (%)	0%
Investment tax credit ($)	$ -
Net capital cost ($)	$ 22,339,200

Operating costs				
Biomass fuel cost ($/MMBtu)	$4.00	$3.00	$2.00	$1.00
Avoided natural gas fuel cost ($/MMBtu)	$ 5.00	$5.00	$5.00	$5.00
Labor cost per FTE	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Number of FTEs	8.0	8.0	8.0	8.0
Non-fuel, non-labor O&M costs ($/kWh)	$ 0.0140	$ 0.0140	$ 0.0140	$ 0.0140
Avoided electricity cost ($/kWh)	$ 0.045	$ 0.045	$ 0.045	$ 0.045
Estimated increase in $/kWh purchased	20%	20%	20%	20%
Annual operating costs				
Fuel	$ 6,150,022	$ 4,612,516	$ 3,075,011	$ 1,537,505
Labor	$ 400,000	$ 400,000	$ 400,000	$ 400,000
Non-fuel, non-labor O&M costs ($/kWh)	$ 738,869	$ 738,869	$ 738,869	$ 738,869
Additional cost for power purchased	$ 110,013	$ 110,013	$ 110,013	$ 110,013
Renewable energy production tax credit	$ -	$ -	$ -	$ -
Total	$ 7,398,903	$ 5,861,398	$ 4,323,893	$ 2,786,387
Annual savings				
Avoided fuel for thermal generation	$ 6,243,461	$ 6,243,461	$ 6,243,461	$ 6,243,461
Avoided electricity costs	$ 2,374,936	$ 2,374,936	$ 2,374,936	$ 2,374,936
Revenue from electricity sales	$ -	$ -	$ -	$ -
Total annual savings	$ 8,618,397	$ 8,618,397	$ 8,618,397	$ 8,618,397

Net operating savings	$ 1,219,494	$ 2,756,999	$ 4,294,505	$ 5,832,010
Simple payback (years)	18.3	8.1	5.2	3.8

Appendix H-1: Rahr Malting, Option 1 Steam Turbine CHP –Biomass

Steam Turbine CHP -- Biomass **8.38 MW net power output after station load**

Economic Analysis with Sensitivity to Power Value at Biomass Cost of **$ 1.50 per MMBtu**
and Avoided Natural Gas Cost of **$ 5.00 per MMBtu**

Cost factors				
Avoided electricity cost ($/kWh)	$ 0.045	$ 0.050	$ 0.055	$ 0.060
Estimated increase in $/kWh purchased	20%	20%	20%	20%
Annual operating costs				
Fuel	$ 2,306,258	$ 2,306,258	$ 2,306,258	$ 2,306,258
Labor	$ 400,000	$ 400,000	$ 400,000	$ 400,000
Non-fuel, non-labor O&M costs ($/kWh)	$ 738,869	$ 738,869	$ 738,869	$ 738,869
Additional cost for power purchased	$ 110,013	$ 122,236	$ 134,460	$ 146,684
Renewable energy production tax credit	$ -	$ -	$ -	$ -
Total	$ 3,555,140	$ 3,567,364	$ 3,579,587	$ 3,591,811
Annual savings				
Avoided fuel for thermal generation	$ 6,243,461	$ 6,243,461	$ 6,243,461	$ 6,243,461
Avoided electricity costs	$ 2,374,936	$ 2,638,818	$ 2,902,700	$ 3,166,582
Revenue from electricity sales	$ -	$ -	$ -	$ -
Total annual savings	$ 8,618,397	$ 8,882,279	$ 9,146,161	$ 9,410,043
Net operating savings	$ 5,063,257	$ 5,314,916	$ 5,566,574	$ 5,818,232
Simple payback (years)	4.4	4.2	4.0	3.8

Appendix H-2: Rahr Malting
Option 2, Combustion Turbine CHP

Operating Parameters	
Peak power output (MW)	
Gross	10.44
Net	9.92
Fuel input (MMBtu/hour) (HHV)	
Turbine	123.2
Full supplemental firing	106.0
Total	229.2
Thermal output (MMBtu/hour)	
Base	48.6
Full supplemental firing	150.0
Input/output calculation (MMBtu/hour)	
Without supplemental firing	
Fuel in	123.2
Electricity out	33.8
Thermal out	48.6
Total out	82.4
Efficiency (HHV %)	66.9%
With supplemental firing	
Fuel in	229.2
Electricity out	33.8
Thermal out	150.0
Total out	183.8
Efficiency (HHV %)	80.2%
Equivalent Full Load Hours of operation	
Electric	6,350
Thermal including supplemental firing	5,953
Peak displaced electricity (% of peak demand)	80%
Thermal energy produced (% of peak demand)	
Without supplemental firing	30%
With supplemental firing	94%
Annual operations	
Electric output (MWh)	62,973
Thermal output (MMBtu)	
Power generation only	308,610
Supplemental firing	643,890
Total	952,500

Fuel consumption (MMBtu)	
Power generation only	743,502
Supplemental firing	673,525
Total	1,417,027
Total electricity consumed (MWh)	65,000
Electricity generated (MWh)	62,973
Electricity purchased (MWh)	2,027
% of electricity requirements generated	97%
Electricity sold (MWh)	-
% of electricity output sold	0%
Assumed value of electricity sold ($/MWh)	$ 15.0
Total thermal energy consumed (MMBtu)	1,066,500
Steam thermal energy consumed (MMBtu)	1,066,500
Thermal energy generated with cogen (MMBtu)	952,500
% of steam thermal produced with cogen	89%
Steam energy generated with non-cogen plant	114,000

Appendix H-2: Rahr Malting
Option 2, Combustion Turbine CHP

Combustion Turbine CHP **9.92 MW net power output**

Economic Analysis with Sensitivity to Gas Prices

Credit for boiler capacity?	**no**			
Investment tax credit?	**no**			
Net metering?	**no**			
Capital costs				
Capital cost ($/kW)	$ 840			
Gross capital cost ($)	$ 8,768,760			
Boiler capacity credited (MMBtu/hour)	-			
Boiler capacity type	gas/oil			
Boiler capacity credit ($ per MMBtu/hour)	$ 20,000			
Boiler capacity credit ($)	$ -			
Investment tax credit (%)	0%			
Investment tax credit ($)	$ -			
Net capital cost ($)	$8,768,760			
Operating costs				
Natural gas cost ($/MMBtu)	**$5.00**	**$4.00**	**$3.00**	**$2.00**
Labor cost per FTE	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Number of FTEs	4.0	4.0	4.0	4.0
Non-fuel, non-labor O&M costs ($/kWh)	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054
Avoided electricity cost ($/kWh)	$ 0.045	$ 0.045	$ 0.045	$ 0.045
Estimated increase in $/kWh purchased	40%	40%	40%	40%
Annual operating costs				
Fuel	$ 7,085,137	$ 5,668,110	$ 4,251,082	$ 2,834,055
Labor	$ 200,000	$ 200,000	$ 200,000	$ 200,000
Non-fuel, non-labor O&M costs ($/kWh)	$ 340,056	$ 340,056	$ 340,056	$ 340,056
Additional cost for power purchased	$ 36,481	$ 36,481	$ 36,481	$ 36,481
Total	$7,661,674	$ 6,244,647	$ 4,827,619	$ 3,410,592
Annual savings				
Avoided fuel for thermal generation	$5,291,667	$ 4,233,333	$ 3,175,000	$ 2,116,667
Avoided electricity costs	$2,833,797	$ 2,833,797	$ 2,833,797	$ 2,833,797
Revenue from electricity sales	$ -	$ -	$ -	$ -
Total annual savings	$8,125,464	$ 7,067,130	$ 6,008,797	$ 4,950,464
Net operating savings	$ 463,789	$ 822,484	$ 1,181,178	$ 1,539,872
Simple payback (years)	18.9	10.7	7.4	5.7

Appendix H-2: Rahr Malting
Option 2, Combustion Turbine CHP

Combustion Turbine CHP **9.92 MW net power output**

Economic Analysis with Sensitivity to Avoided Power Costs

Assumes Natural Gas Cost of $ 5.00 per MMBtu

Cost factors				
Avoided electricity cost ($/kWh)	**$ 0.035**	**$ 0.045**	**$ 0.055**	**$ 0.065**
Revenue for electricity sold ($/kWh)	$ 0.015	$ 0.015	$ 0.015	$ 0.015
Estimated increase in $/kWh purchased	40%	40%	40%	40%
Annual operating costs				
Fuel	$ 7,085,137	$ 7,085,137	$ 7,085,137	$ 7,085,137
Labor	$ 200,000	$ 200,000	$ 200,000	$ 200,000
Non-fuel, non-labor O&M costs ($/kWh)	$ 340,056	$ 340,056	$ 340,056	$ 340,056
Additional cost for power purchased	$ 28,374	$ 36,481	$ 44,588	$ 52,695
Total	$ 7,653,567	$ 7,661,674	$ 7,669,781	$ 7,677,888
Annual savings				
Avoided fuel for thermal generation	$ 5,291,667	$ 5,291,667	$ 5,291,667	$ 5,291,667
Avoided electricity costs	$ 2,204,064	$ 2,833,797	$ 3,463,530	$ 4,093,262
Revenue from electricity sales	$ -	$ -	$ -	$ -
Total annual savings	$ 7,495,731	$ 8,125,464	$ 8,755,196	$ 9,384,929
Net operating savings	$ (157,836)	$ 463,789	$ 1,085,415	$ 1,707,041
Simple payback (years)	(55.6)	18.9	8.1	5.1

Appendix H-3: Chippewa Valley Ethanol Option 1, Combustion Turbine CHP

Operating Parameters	
Peak power output (MW)	
Gross	3.42
Net	3.25
Fuel input (MMBtu/hour) (HHV)	
Turbine	47.2
Full supplemental firing	25.8
Total	73.0
Thermal output (MMBtu/hour)	
Base	17.9
Full supplemental firing	43.1
Input/output calculation (MMBtu/hour)	
Without supplemental firing	
Fuel in	47.2
Electricity out	11.1
Thermal out	17.9
Total out	29.0
Efficiency (HHV %)	61.4%
With supplemental firing	
Fuel in	73.0
Electricity out	11.1
Thermal out	43.1
Total out	54.2
Efficiency (HHV %)	74.3%
Equivalent Full Load Hours of operation	
Electric	6,250
Thermal including supplemental firing	5,378
Peak displaced electricity (% of peak demand)	96%
Thermal energy produced (% of peak demand)	
Without supplemental firing	28%
With supplemental firing	66%
Annual operations	
Electric output (MWh)	20,300
Thermal output (MMBtu)	
Power generation only	111,875
Supplemental firing	237,677

Total		349,552
Fuel consumption (MMBtu)		
Power generation only		280,247
Supplemental firing		242,528
Total		522,775
Total electricity consumed (MWh)		20,400
Electricity generated (MWh)		20,300
Electricity purchased (MWh)		100
% of electricity requirements generated		100%
Electricity sold (MWh)		-
% of electricity output sold		0%
Assumed value of electricity sold ($/MWh)	$	15.0
Total thermal energy consumed (MMBtu)		611,106
Steam thermal energy consumed (MMBtu)		397,219
Thermal energy generated with cogen (MMBtu)		349,552
% of steam thermal produced with cogen		88%
Steam energy generated with non-cogen plant		47,666

Appendix H-3: Chippewa Valley Ethanol Option 1, Combustion Turbine CHP

Combustion Turbine CHP **3.25 MW net power output**

Economic Analysis with Sensitivity to Gas Prices

Credit for boiler capacity?	**no**			
Investment tax credit?	**no**			
Net metering?	**no**			
Capital costs				
Capital cost ($/kW)	$ 1,100			
Gross capital cost ($)	$ 3,760,900			
Boiler capacity credited (MMBtu/hour)	-			
Boiler capacity type	gas/oil			
Boiler capacity credit ($ per MMBtu/hour)	$ 20,000			
Boiler capacity credit ($)	$ -			
Investment tax credit (%)	0%			
Investment tax credit ($)	$ -			
Net capital cost ($)	$ 3,760,900			
Operating costs				
Natural gas cost ($/MMBtu)	$5.00	$4.00	$3.00	$2.00
Labor cost per FTE	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Number of FTEs	1.0	1.0	1.0	1.0
Non-fuel, non-labor O&M costs ($/kWh)	$ 0.0070	$ 0.0070	$ 0.0070	$ 0.0070
Avoided electricity cost ($/kWh)	$ 0.036	$ 0.036	$ 0.036	$ 0.036
Estimated increase in $/kWh purchased	0%	0%	0%	0%
Annual operating costs				
Fuel	$ 2,613,877	$ 2,091,102	$ 1,568,326	$ 1,045,551
Labor	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Non-fuel, non-labor O&M costs ($/kWh)	$ 142,102	$ 142,102	$ 142,102	$ 142,102
Additional cost for power purchased	$ -	$ -	$ -	$ -
Total	$ 2,805,979	$ 2,283,204	$ 1,760,428	$ 1,237,653
Annual savings				
Avoided fuel for thermal generation	$ 2,093,128	$ 1,674,503	$ 1,255,877	$ 837,251
Avoided electricity costs	$ 734,155	$ 734,155	$ 734,155	$ 734,155
Revenue from electricity sales	$ -	$ -	$ -	$ -
Total annual savings	$ 2,827,283	$ 2,408,657	$ 1,990,032	$ 1,571,406
Net operating savings	$ 21,304	$ 125,454	$ 229,603	$ 333,753
Simple payback (years)	176.5	30.0	16.4	11.3

Appendix H-4: Chippewa Valley Ethanol Option 2, Combustion Turbine CHP

Operating Parameters

Peak power output (MW)	
Gross	7.35
Net	6.98
Fuel input (MMBtu/hour) (HHV)	
Turbine	83.3
Full supplemental firing	31.8
Total	115.2
Thermal output (MMBtu/hour)	
Base	31.2
Full supplemental firing	62.4
Input/output calculation (MMBtu/hour)	
Without supplemental firing	
Fuel in	83.3
Electricity out	23.8
Thermal out	31.2
Total out	55.0
Efficiency (HHV %)	66.0%
With supplemental firing	
Fuel in	115.2
Electricity out	23.8
Thermal out	62.4
Total out	86.2
Efficiency (HHV %)	74.9%
Equivalent Full Load Hours of operation	
Electric	8,059
Thermal including supplemental firing	5,989
Peak displaced electricity (% of peak demand)	205%
Thermal energy produced (% of peak demand)	
Without supplemental firing	48%
With supplemental firing	96%

Annual operations

Electric output (MWh)	56,289
Thermal output (MMBtu)	
Power generation only	251,447
Supplemental firing	137,827
Total	389,274

Fuel consumption (MMBtu)		
Power generation only		638,112
Supplemental firing		140,640
Total		778,752
Total electricity consumed (MWh)		20,400
Electricity generated (MWh)		56,289
Electricity purchased (MWh)		-
% of electricity requirements generated		276%
Electricity sold (MWh)		35,889
% of electricity output sold		64%
Assumed value of electricity sold ($/MWh)	$	15.0
Total thermal energy consumed (MMBtu)		611,106
Steam thermal energy consumed (MMBtu)		397,219
Thermal energy generated with cogen (MMBtu)		389,274
% of steam thermal produced with cogen		98%
Steam energy generated with non-cogen plant		7,944

Appendix H-4: Chippewa Valley Ethanol
Option 2, Combustion Turbine CHP

Combustion Turbine CHP **6.98 MW net power output**

Economic Analysis with Sensitivity to Gas Prices

Credit for boiler capacity?	**no**			
Investment tax credit?	**no**			
Net metering?	**no**			
Capital costs				
Capital cost ($/kW)	$ 890			
Gross capital cost ($)	$ 6,543,280			
Boiler capacity credited (MMBtu/hour)	-			
Boiler capacity type	gas/oil			
Boiler capacity credit ($ per MMBtu/hour)	$ 20,000			
Boiler capacity credit ($)	$ -			
Investment tax credit (%)	0%			
Investment tax credit ($)	$ -			
Net capital cost ($)	$ 6,543,280			
Operating costs				
Natural gas cost ($/MMBtu)	$5.00	$4.00	$3.00	$2.00
Labor cost per FTE	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Number of FTEs	1.0	1.0	1.0	1.0
Non-fuel, non-labor O&M costs ($/kWh)	$ 0.0058	$ 0.0058	$ 0.0058	$ 0.0058
Avoided electricity cost ($/kWh)	$ 0.036	$ 0.036	$ 0.036	$ 0.036
Estimated increase in $/kWh purchased	0%	0%	0%	0%
Annual operating costs				
Fuel	$ 3,893,761	$ 3,115,009	$ 2,336,257	$ 1,557,504
Labor	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Non-fuel, non-labor O&M costs ($/kWh)	$ 326,474	$ 326,474	$ 326,474	$ 326,474
Additional cost for power purchased	$ -	$ -	$ -	$ -
Total	$ 4,270,235	$ 3,491,483	$ 2,712,731	$ 1,933,979
Annual savings				
Avoided fuel for thermal generation	$ 2,330,984	$ 1,864,787	$ 1,398,590	$ 932,393
Avoided electricity costs	$ 737,760	$ 737,760	$ 737,760	$ 737,760
Revenue from electricity sales	$ 538,330	$ 538,330	$ 538,330	$ 538,330
Total annual savings	$ 3,607,074	$ 3,140,877	$ 2,674,680	$ 2,208,484
Net operating savings	$ (663,162)	$ (350,606)	$ (38,051)	$ 274,505
Simple payback (years)	(9.9)	(18.7)	(172.0)	23.8

Appendix H-4: Chippewa Valley Ethanol
Option 2, Combustion Turbine CHP

Combustion Turbine CHP **6.98 MW net power output**
Economic Analysis with Sensitivity to Avoided Power Costs

Assumes Natural Gas Cost of $ 5.00 per MMBtu

Cost factors				
Avoided electricity cost ($/kWh)	$ 0.035	$ 0.045	$ 0.055	$ 0.065
Revenue for electricity sold ($/kWh)	$ 0.015	$ 0.015	$ 0.015	$ 0.015
Estimated increase in $/kWh purchased	0%	0%	0%	0%
Annual operating costs				
Fuel	$ 3,893,761	$ 3,893,761	$ 3,893,761	$ 3,893,761
Labor	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Non-fuel, non-labor O&M costs ($/kWh)	$ 326,474	$ 326,474	$ 326,474	$ 326,474
Additional cost for power purchased	$ -	$ -	$ -	$ -
Total	$ 4,270,235	$ 4,270,235	$ 4,270,235	$ 4,270,235
Annual savings				
Avoided fuel for thermal generation	$ 2,330,984	$ 2,330,984	$ 2,330,984	$ 2,330,984
Avoided electricity costs	$ 1,970,104	$ 2,532,990	$ 3,095,877	$ 3,658,764
Revenue from electricity sales	$ 538,330	$ 538,330	$ 538,330	$ 538,330
Total annual savings	$ 4,839,417	$ 5,402,304	$ 5,965,191	$ 6,528,078
Net operating savings	$ 569,182	$ 1,132,069	$ 1,694,956	$ 2,257,842
Simple payback (years)	11.5	5.8	3.9	2.9

Appendix I – Emissions Comparison

Cogeneration

Cogeneration system	
Power generated (MWH)	56,289
Thermal energy produced (MMBtu)	389,274
Fuel consumed (MMBtu)	778,752
Emissions (lbs/MMBtu fuel)	
Nitrogen oxides	0.1000
Sulfur dioxide	0.0007
Particulates	0.0047
Carbon dioxide	115

NO x emission control technology: Low NOx burner with water injection

Emissions	
Nitrogen oxides (lbs)	77,875
Sulfur dioxide (lbs)	543
Particulates (lbs)	3,622
Carbon dioxide (tons)	44,778

Conventional Approach

Major Xcel Intermediate load plants

Emissions (lbs/MWH)	
Nitrogen oxides	16.920
Sulfur dioxide	12.667
Particulates	0.109
Carbon dioxide	1.272
Emissions	
Nitrogen oxides (lbs)	952,418
Sulfur dioxide (lbs)	712,993
Particulates (lbs)	6,160
Carbon dioxide (tons)	71,623

Gas-fired boilers

Thermal energy produced (MMBtu)	389,274
Boiler efficiency (HHV)	82%
Fuel consumption (MMBtu)	474,725

Unit emissions	(lbs/MWh)	(lbs.)
Nitrogen oxides (lbs/MWH)	0.1000	47,472

Sulfur dioxide (lbs/MWH)	0.0007	331
Particulates (lbs/MWH)	0.0047	2,208
Carbon dioxide (tons/MWH)	115	27,297

Total emissions for conventional approach

Nitrogen oxides (lbs)	999,891
Sulfur dioxide (lbs)	713,324
Particulates (lbs)	8,368
Carbon dioxide (tons)	98,920

Comparison of emissions

	Cogeneration	Conventional
Nitrogen oxides (10,000 lbs)	8	100
Sulfur dioxide (10,000 lbs)	0	71
Carbon dioxide (1,000 lbs)	45	99

Appendix J: New Condensing Power Plant

NEW CONDENSING POWER PLANT

Technology type	Large gas turbine combined cycle
Number of units	1
Capacity per unit (Mwe)	259.3
Fuel mix	All natural gas

Power plant capacity and efficiency

		MW	MMBtu/hr	Efficiency
Fuel input				
Heat rate (Btu/KWHe)	6,315			
Fuel input (LHV) per hour			1637.48	
Energy outputs				
Electric output		259.3	884.99	54.0%
Thermal output		-	0.00	0.0%
Total efficiency				54.0%

Transmission losses (% of input fuel) 7.4%

Fuel consumption

	% of total	MMBtu/hr
Natural gas	100%	1,637.48
Fuel oil (# 2)		
Coal		
Biomass		
Total		1,637.48

Million Btu of fuel per MWH of delivered electricity 6.82

Capital cost

Cost per KWHe	$	600
Cost	$	155,580,000

Operation and maintenance costs

Fixed cost		0.0%	of capital cost
Variable cost	$	5.00	per MWHe

Manufacturer and model assumed for technical performance

General Electric S-109EC, with 3 pressure levels, reheat, heat recovery feedwater heating.

ANNUAL COST FACTORS

Financing cost factors

Costs for financing, capitalized interest, reserves (% of construction cost)	***15%***
Interest rate	***7%***
Term (years)	***20***
Capital recovery factor	0.09439

Operating cost factors

Natural gas cost ($ per MMBtu)	***$***	***3.00***
Coal cost ($ per MMBtu)		
Oil cost ($ per MMBtu)		
Biomass cost ($ per MMBtu)		
Operating staff (Full-Time-Equivalents)		***16***
Average $ per FTE	***$***	***50,000***
Administrative staff (Full-Time-Equivalents)		***20***
Average $ per FTE	***$***	***50,000***
Non-personnel general/administrative cost (% of admininistrative staff cost)		***15%***
Capacity factor		***80%***

Annual electricity generated (MWH)	1,817,174
Annual electricity delivered after transmission losses (MWH)	1,682,703

ANNUAL COSTS (million $)

Debt service			$ 14.69
Fuel			$ 34.43
Labor			$ 0.80
General and administrative			
Personnel	$	1.00	
Other G&A	$	0.15	
Subtotal			$ 1.15
Maintenance			$ 9.09
Total			$ 60.15

Summary of annual and unit costs

	Million $	cents per kWh generated	cents per kWh delivered
Fuel	$ 34.43	1.89	2.05
Maintenance and supplies	$ 9.09	0.50	0.54
Labor	$ 0.80	0.04	0.05
G&A	$ 1.15	0.06	0.07
Subtotal operating costs	$ 45.46	2.50	2.70

Debt service	$	14.69	0.81	0.87
Total costs	$	60.15	3.31	3.57

Appendix K: Distributed Renewable Generation

Distributed Renewable Generation

In Docket E017/RP-10-623, the order for the Baseload Diversification Study instructed Otter Tail Power Company to "Evaluate greater potential for additional…renewable distributed generation…" In Appendix K, the Company will address the following with regard to renewable distributed generation:

1. Discussion on why Otter Tail has not included small renewable distributed generation projects as options in its model.
2. A study prepared by a renewable energy project developer on the feasibility of a proposed renewable distributed generation project

New Distributed Renewable Generation Projects

There are two major issues that govern Otter Tail's willingness to purchase capacity and energy from any renewable distributed generation project: First, is it cost competitive with the cost of capacity and energy in the Midcontinent Independent Transmission System Operator ("Midcontinent ISO") market? That is a difficult hurdle in today's energy market. The second is Otter Tail's need for renewable energy to satisfy its renewable energy standard and objectives in the three states it serves.

Wholesale energy prices remain low following the economic recession, 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:

2010: $28.00/MWh
2011: $24.80/MWh
2012: $23.84/MWh
2013 (YTD September 30): $27.33/MWh

As of October 29, 2013, round-the-clock energy in MISO at the Indianapolis hub was trading was trading in the low $30's for 2017.

As you can see in the report issued by R3 Verdant later in Appendix K, their proposal for energy from a new manure methane digestion project is $.08 per kWh. This is more than double the cost of the MISO market well into the future.

Otter Tail has been in negotiation with a large dairy in west central Minnesota to purchase additional energy from manure methane digestion at dairies they operate. Otter Tail currently has a PPA to purchase energy from one of the dairies at a price slightly over $.04/ kWh. The dairy was unwilling to sign a PPA for energy from the existing methane digesters at two other dairies at the same price because at that price it would not be profitable.

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.

During 2013, Otter Tail entered into an agreement to purchase an additional 62.4 MW of wind energy from an existing wind farm located in North Dakota. The price for that energy was significantly below even the 2017 Indianapolis hub round-the-clock energy price quoted above.

With the 2013 additional wind PPA of 62.4 MW, the Company will meet the Renewable Energy Standard in Minnesota and the Renewable Energy Objective in North Dakota and South Dakota through 2025. At its current level, Otter Tail has about 19 percent of its energy coming from renewable sources.

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.

R3 VERDANT
Technologies

The purpose of this document is to access the feasibility of establishing a new renewable energy venture for dairy farms in Minnesota.

Hypothesis

Farmers install commercially-proven, modular, complete mix anaerobic digester technology to convert a mixture of on-farm animal manure and off-farm food waste into distributed renewable electricity and marketable co-products in an environmentally-friendly manner.

Develop a bankable business plan road map to obtain a power purchase agreement from OTPCO.

Why has R3 Verdant Technologies moved away from MSW?

Dairy manure is a leading feedstock for renewable energy generation through newly improved and commercially proven technology. Dairy waste and energy+green attributes potentially become two new cash crops:

- Marketable co-products (liquid fertilizers, soil amendments,etc.) can become potentially new revenue sources.
- Using of food waste significantly improves biogas production.
- Tipping fees – remains another source of new revenue.
- A Dissolution platform for environmental enhancements (nutrient balance, farm odor reduction*, GHG reductions, and local water quality improvements).

Why was Anaerobic Digester Examined

Incentives are needed for renewable energy and rural development:

The State of Minnesota and numerous Federal programs provide funding opportunities that can be harnessed to create thriving renewable programs. Several of these programs are underutilized.

On-Farm Biogas Recovery Facilities: must be located at the site of an agricultural operation. Payments may be made for electricity generated from on-farm biogas recovery facilities that are operational between July 1, 2001 and December 31, 2017, though no payments may be made on electricity generated after December 31, 2015.

Dairies can become the model for public private partnership to address renewable energy needs, improve the environment, and build sustainable dairies.

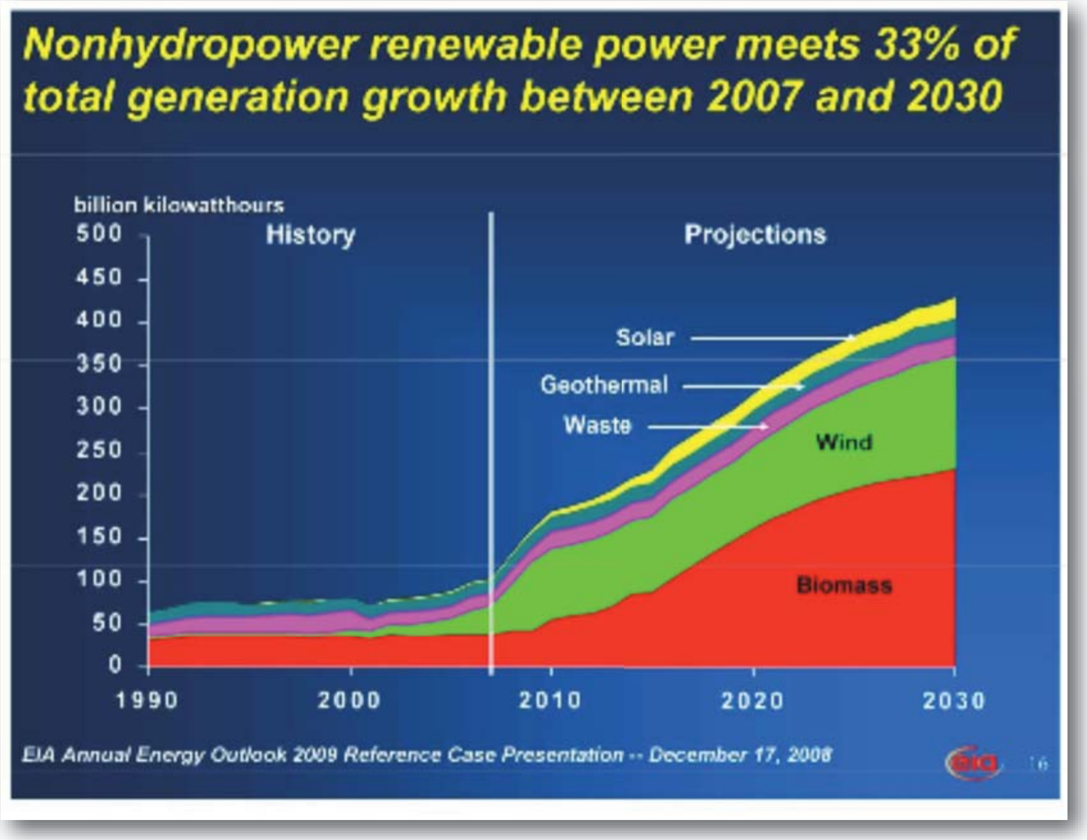
Market Challenge

R3 Verdant Technologies (R3VT) has endeavored to develop a financially-feasible business model that creates scale for Minnesota, North and South Dakota dairies with herd sizes large enough to participate in renewable energy through AD. The parameters are fairly well set; land cost for AD site (farmland prices have been rising steadily in Minnesota since 1990, and have peaked at a state average of over $3,500 per acre in 2011*), market appropriate price points for energy, tipping fees and other farm related services, projecting trends in herd size against the duration of the PPA, while remaining profitable.

** University of Minnesota Farm Land 2012 Economic Report*

Benefits of AD – Renewable Power Markets

Waste and biomass feedstocks will be a key source for future renewable energy generation.



Increased environmental concerns can be addressed by AD. Incentives are an imperative to financial success – Minnesota and globally. The opportunity of making renewable energy from waste is proven. Members of the R3VT team worked on the largest working installation in Idaho.

There are many benefits to this system in addition to the energy it generates. The most important is that it prevents methane gas, a greenhouse gas that is 23 times more detrimental than carbon dioxide, from entering the atmosphere. In addition, it greatly eliminates odors on the farm and significantly reduces flies. As well as the management of two byproducts, separated solids and leftover liquids, that are used as organic fertilizer on pastures. The system allows the dairy to run electrical meters in reverse and to offset electrical usage from other meters at the farm.

Proposed Business Model

Individual farmers each install a modular and scaled complete mix CHP AD, and establish an LLC to aggregate the marketing of power, co-products, and to have R3VT run day-to-day business operations, including maintenance.

- Environmental issues are dealt with jointly.
- Professionally build, run, and manage the AD unit with performance guarantee.
- Have ownership of the modular units to spread operating risks and meet contractual obligations.
- Handle all contracts (aggregates power, REC's, carbon credits, organic waste sourcing, and co-product sales at bulk prices) - scale leads to better pricing. Ensure organic waste deliveries enhancing production of gas / revenue from centralized facility.
- Scale to maximize process design performance.
- Full-time repair person with spare parts in region.
- Allow each farmer better access to public and private funding / financing.
- Jointly market co-products and access add-on technologies for soil amendments.
- Added income, sustainability, and access to constant improvements.
- Add more cows with environmentally approved removal of effluent streams.

Projected Benefits for R3VT Site

- The market for electricity is more favorable than milk
- Generator capacity: 80 kW
- Average performance per month: 28,800 kWh
- Average performance per day : 960 kWh
- Implementation cost: $334,680 – initial conversion to anaerobic digester plus refurbishment
- Initial funding: $155,261 – DPPP and EPA through CA Water Quality Board
- Annual cost savings: $40,000 - $50,000
- Return on investment: 4-5 years

R3 Verdant Technologies Project Report

Methane Digestion Technology

July 29th, 2013

General Overview

R3 Verdant Technologies has assembled a team of technical professionals to design a specific process for animal waste materials in a manner that converts the waste to valuable products.

b) The system involves utilizing anaerobic digestion, which is a process where bacteria break down organic matter for feedstock to be used. Subsequent steps include:

Up front solid waste processing in preparation for digestion

ii) Anaerobic digestion of the prepared solid waste and biodiesel production byproducts to convert the waste into bio-gases (methane and carbon dioxide) and solids digestate

iii) The methane bio-gas produced in the anaerobic digestion process is treated and used as a fuel to produce electricity in a combustion turbine.

iv) The solids digestate from the anaerobic digesters is dewatered. The water is treated and re-circulated for use in the photo-bioreactor as well as boiler water, which is then converted to steam to drive a steam turbine as part of electricity generation.

Anaerobic digester will require regular maintenance in the downstream equipment as the abrasive inorganic materials will cause wear and tear on the equipment.

Critical in the design of the proposed process is the calculations of the regional herd sizes to ensure consistent feedstock stream into the digesters.

Anaerobic Digestion Process

i) Prior to entering the digesters, the prepared manure feedstock will be mixed with recycled wastewater.

ii) The mixed feedstock will then be sent to the heated two-stage anaerobic digesters where the organic materials in the feedstock will decompose and produce both a solids digestate as well as bio-gases.

iii) The anaerobic digestion equipment will be a multi-tank design such that the primary biogases produced will be carbon dioxide from the acidogenic state and methane from the methanogenic state.

iv) Since the carbon dioxide gas will have other constituents in it, it will be treated to remove contaminants and used as feedstock to the Photo Bioreactor.

v) Likewise the methane gas will also be treated and will be used as fuel to power a combustion turbine.The solid materials exiting the anaerobic digesters will be processed as described later

c)Power Generation Process

i) The process for generating electric power is a combined cycle process as follows:

Treated methane gas from the anaerobic digesters supplemented with pipeline natural gas will be used to fire a combustion turbine that will feed electricity to the grid and/or on-site to power process equipment.

ii) The exhaust gas from the combustion turbine will be ducted to a heat recovery steam generating unit (boiler) that will provide steam to a steam turbine, which in turn will provide additional electricity. The flue gas exhaust from the boiler will have the heat removed and recovered and the gas will be treated and used as feedstock to the Photo Bioreactor since it will be high in carbon dioxide content

iii) Exhaust steam from the turbine will be condensed, treated and recycled through the electric generation process

iv) R3 Verdant Technologies projects $.08 /kWh price for methane digestion

Appendix L: Construction Progress Photos

Big Stone AQCS Project and Hoot Lake MATS Project

Big Stone AQCS Project

Figure 1: 11-02-2013 Center SCR Tower

Figure 2: 10-28-2013 Ammonia Unloading/Storage Area/Foundation Work

Figure 3: 10-16-2013 WA-PL Siding

Hoot Lake MATS Project

Figure 4: 10-07-2013 Silo Unloading

Figure 5: 10-07-2013 Erecting Silo