APPENDIX A: MINNESOTA POWER'S 2020 ANNUAL ELECTRIC UTILITY FORECAST REPORT

Minnesota laws and reporting rules governing electric utilities require that electric utilities with Minnesota service area submit to the Minnesota Department of Commerce an annual report containing historical and forecast customer sales and demand values, including forecast methodology and discussion. This report is due by July 1 of each year. Minnesota Power's 2020 Annual Electric Utility Forecast Report ("AFR2020") contains all of the forms and information necessary to meet this annual requirement.

Minnesota Power's AFR2020 contains historical sales and demand data, as well as the customer energy sales and demand forecasts that serve as the starting point for the 2021 Integrated Resource Plan ("2021 IRP"). The forecast report includes two scenarios that reflect the uncertainty in sales and demand facing Minnesota Power over the next few years. This uncertainty is largely due to the COVID-19 pandemic-induced recession, as well as the potential for an industrial customer being added in Minnesota Power's service territory during the 15-year planning horizon. The scenarios were developed to reflect potential for customer changes and the projected timing of those changes.

While the document contains two scenarios,[1] the scenario that forms the basis for the 2021 IRP projects 93 MW of load loss by 2025 when compared to current levels.[2] In the AFR2020, this is referred to as the "Expected" scenario. Much of the load loss can be attributed to two different customers whose facilities are indefinitely idled in the "Expected" scenario.[3] Other discrete load assumptions are included to reflect demand changes by both large industrial and resale customers served by Minnesota Power.

The 2021 IRP also considers a "High" scenario as an expanded load sensitivity in the analysis process. The AFR2020 "High" scenario is identical to the "Expected" scenario, except two large power customers' facilities resume operations following the U.S. recovery from the COVID-19 pandemic induced recession – rather than being indefinitely idled. The "High" scenario does not include all potential for new projects or new load growth, and is focused only on the recovery of the two idled customers. The "High" scenario also provides an additional look for the 2021 IRP to consider with only 30 MW of load loss from current levels.

[1] Descriptions and results of the scenarios begin on page 70 of the AFR2020 document.
[2] July 2019 demand was 1,674.5 MW.
[3] United States Steel's Keetac facility in Keewatin, Minnesota, was one of the facilities assumed to indefinitely idled. Pellet production at the Keetac facility has since resumed in December 2020.

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July 20, 2020

VIA E-FILING
Ms. Anne Sell
Department of Commerce – Division of Energy Resources
85 7th Place East, Suite 280
St. Paul, MN 55101-2198

Re: Minnesota Power's 2020 Annual Electric Utility Forecast Report
Docket No.: E-999/PR-20-11

Dear Ms. Sell:

Enclosed please find Minnesota Power's 2020 Annual Electric Utility Forecast Report pursuant to Minn. Stat. § 216C.17, subd. 2 and Minn. Rules Chapter 7610. As an electric utility with Minnesota service areas, Minnesota Power (or the "Company") is required to submit to the Minnesota Department of Commerce – Division of Energy Resources ("Department") by July 1 of each year an annual report specifying its short- and long-term energy demand forecasts and the facilities necessary to meet the demand. Minn. Rule 7610.0130 provides the Department authority to grant, for good cause, an extension to a requesting utility. At the Company's request, the Department granted an extension for filing its 2020 Annual Electric Utility Forecast Report to August 1, 2020.

Information included in the "**ELEC_68_2019 Largest Customer List.xlsx**" and "**ELEC_68_2019 Forecast Report.xlsx**" Excel workbooks, as well as the **Methodology** document has been designated as **TRADE SECRET**.

Minnesota Power has excised material from the public version of the attached report documents as they identify and contain confidential, competitive information regarding Minnesota Power's methods, techniques and process for supplying electric service to its customers. The energy usage by specific customers and generation by fuel type has been consistently treated as Trade Secret in individual filings before the Minnesota Public Utilities Commission. Minnesota Power follows strict internal procedures to maintain the privacy of this information. The public disclosure of this information would have severe competitive implications for customers and Minnesota Power.

Minnesota Power is providing this justification for the information excised from the attached report and why the information should remain trade secret under Minn. Stat. 13.37. Minnesota Power respectfully requests the opportunity to provide additional justification in the event of a challenge to the Trade Secret designation provided herein.

The following documents have been uploaded to the Department and Minnesota Public Utilities Commission eDockets/eFiling system using Docket Number 20-11:

- Methodology.pdf (**TRADE SECRET** & Public versions)
- ELEC_68_2019 Annual Report.xlsx
- ELEC_68_2019 Forecast Report.xlsx (**TRADE SECRET** & Public versions)
- ELEC_68_2019 Largest Customer List.xlsx (**TRADE SECRET**)
- ELEC_68_2019 Monthly Power Cost Adjustments.xlsx
- ELEC_68_2019 MN Service Area Map.pdf
- ELEC_68_2019 USDOE EIA-861.pdf
- ELEC_68_2019 Rate Schedules.pdf

Please don’t hesitate to contact either one of us if you need additional paper copies or have any questions.

Sincerely,

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Introduction

The utility customer load forecast is the initial step in electric utility planning. Capacity and energy resource commitments are based on forecasts of energy consumption, and seasonal peak demand requirements. Minnesota Power's forecast process combines sound econometric methodology and data from reputable sources to produce a reasonable long-term outlook suitable for planning.

Minnesota Power (or the Company) is committed to continuous forecast process improvement, process transparency, forecast accuracy, and gaining customer insight. This 2020 forecast methodology document demonstrates Minnesota Power's continued efforts to meet these goals through comprehensive documentation, implementation of more systematic and replicable processes, and thorough analysis of results.

A history of increasing accuracy in load forecasting also speaks to the Company's commitment to innovate and enhance its forecast processes. Since 2000, year-ahead forecast error has held fairly steady; current-year forecast error has decreased at an average rate of 0.05 percent per-year.[1] Minnesota Power owes its record of forecast accuracy to a combination of close contact with customers, continuous validation of forecast model inputs, and steady improvements in statistical analytic capabilities.

Similar to last year's Annual Forecast Report (AFR), AFR 2019 that addressed the potential for local additions or losses to the Resale and Industrial customer classes, AFR 2020 will also include estimated impacts of energy efficiency, distributed generation (solar), and electric vehicles in the Expected scenario outlook. This expanded approach to forecasting can then be integrated into the Company's proactive and flexible planning to better inform the critical electric resource decisions ahead. Minnesota Power's forecasting approach helps keep the potential demand and energy outcomes transparent and robust.

2020 Forecast Results Overview

Minnesota Power is submitting two scenarios in its 2020 Annual Electric Utility Report filing that differ only in their assumption for two specific customers' facilities; the Company's Expected case assumes these facilities are indefinitely idled, and the alternative (High) case assumes they resume operations following the U.S. recovery from the COVID-19-induced recession. For further details regarding both scenarios, please see Section 2 beginning on page 70.

Table 1 below shows the Expected case forecast for annual energy sales and seasonal peak demand. Annual energy sales are projected to decline at a -0.4 percent per year rate (on average) from 2019 through 2034. Summer and Winter peak demands are projected to

[1] Both error figures are Mean Absolute Percent Error (MAPE) of the energy sales forecast, and were calculated excluding the recessionary years of 2009 and 2010, in which there are significant and unpredictable fluctuations in large industrial loads. The year-ahead error also excludes 2015 and 2016 due to mining industry downturn.

decline at average annual rates of -0.5 percent and -0.3 percent, respectively. The AFR 2020 load forecast reflects 103 megawatts (MW)[2] of system load loss by 2030.

Table 1: Expected Case Energy Sales and Seasonal System Peak Demand Outlook

Total Energy Sales			System Peak Demand					
	MWh	Y/Y Growth		Summer (MW)	Y/Y Growth		Winter (MW)	Y/Y Growth
2009	8,062,253		2009	1,350		2009	1,545	
2010	10,417,422	29.2%	2010	1,732	28.3%	2010	1,789	15.7%
2011	10,988,200	5.5%	2011	1,746	0.8%	2011	1,780	-0.5%
2012	11,107,357	1.1%	2012	1,790	2.5%	2012	1,774	-0.3%
2013	10,985,809	-1.1%	2013	1,782	-0.5%	2013	1,751	-1.3%
2014	11,038,979	0.5%	2014	1,805	1.3%	2014	1,821	4.0%
2015	10,059,466	-8.9%	2015	1,597	-11.5%	2015	1,554	-14.6%
2016	9,830,787	-2.3%	2016	1,609	0.8%	2016	1,692	8.9%
2017	10,654,217	8.4%	2017	1,689	4.9%	2017	1,794	6.0%
2018	10,638,691	-0.1%	2018	1,728	2.3%	2018	1,714	-4.5%
2019	10,482,913	-1.5%	2019	1,675	-3.1%	2019	1,677	-2.2%
2020	7,782,702	**-25.8%**	2020	1,223	**-26.9%**	2020	1,527	**-8.9%**
2021	9,486,395	**21.9%**	2021	1,546	**26.4%**	2021	1,564	**2.4%**
2022	9,571,810	**0.9%**	2022	1,554	**0.5%**	2022	1,561	**-0.2%**
2023	9,569,929	**0.0%**	2023	1,551	**-0.2%**	2023	1,561	**0.0%**
2024	9,604,425	**0.4%**	2024	1,549	**-0.1%**	2024	1,565	**0.3%**
2025	9,795,945	**2.0%**	2025	1,582	**2.1%**	2025	1,609	**2.8%**
2026	9,963,924	**1.7%**	2026	1,592	**0.7%**	2026	1,609	**0.0%**
2027	9,983,789	**0.2%**	2027	1,591	**-0.1%**	2027	1,609	**0.0%**
2028	10,024,896	**0.4%**	2028	1,590	**-0.1%**	2028	1,610	**0.1%**
2029	10,010,241	**-0.1%**	2029	1,588	**-0.1%**	2029	1,611	**0.0%**
2030	10,019,331	**0.1%**	2030	1,585	**-0.2%**	2030	1,611	**0.0%**
2031	10,021,305	**0.0%**	2031	1,582	**-0.2%**	2031	1,607	**-0.2%**
2032	10,022,602	**0.0%**	2032	1,574	**-0.5%**	2032	1,603	**-0.3%**
2033	9,960,928	**-0.6%**	2033	1,566	**-0.5%**	2033	1,600	**-0.2%**
2034	9,922,651	**-0.4%**	2034	1,557	**-0.6%**	2034	1,596	**-0.2%**

Minnesota Power remains a Winter peaking utility and will continue to expect an approximate 25 MW difference in this seasonal profile. Figures 1 and 2 below show the projected energy sales and system peak demand, respectively for AFR 2020 compared to AFR 2019.

[2] 103 MW = 2030 Annual/Winter Peak (1,611 MW) – 2019 Annual Peak (1,714 MW).

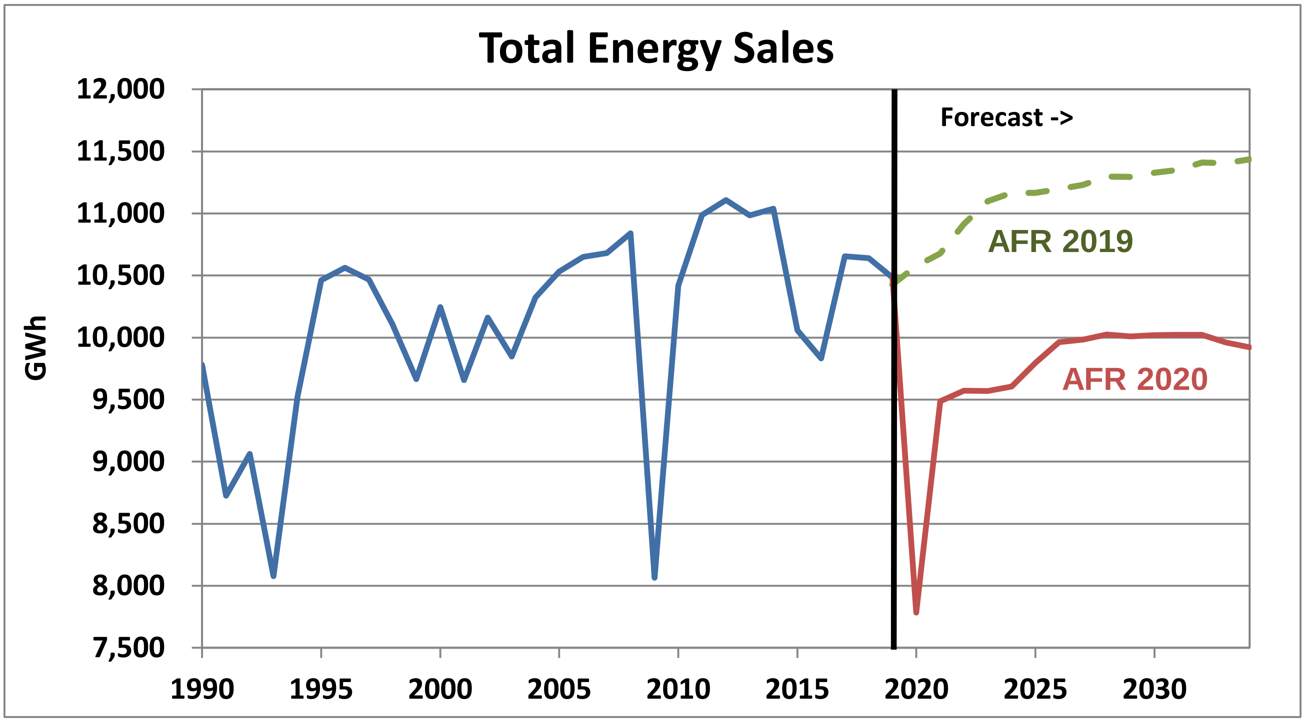

Figure 1: Expected Case Energy Sales Outlook

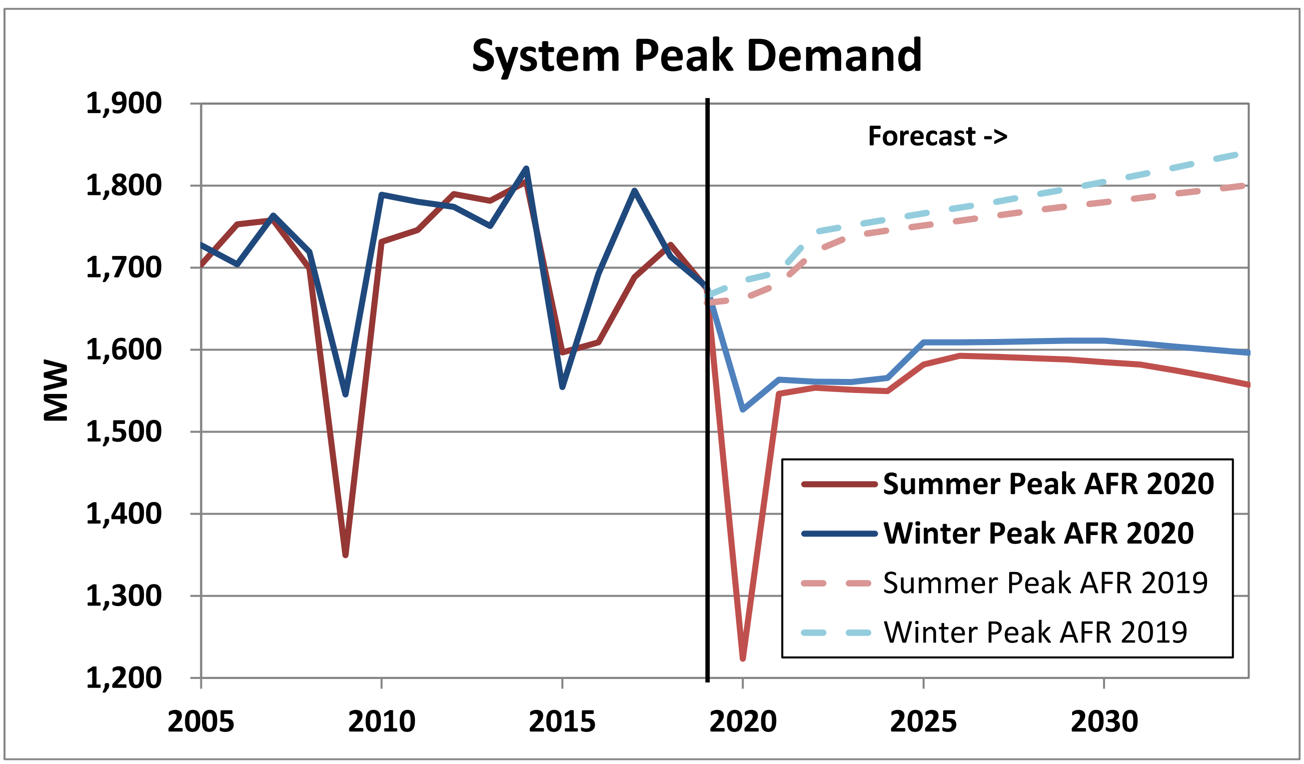

Figure 2: Expected Case Peak Demand Outlook

Document Structure

This report details the construction of the energy sales and demand forecast for Minnesota Power for the 2020-2034 timeframe. Each section is designed to convey the report requirements per Minn. Rules Chapter 7610, and give insight into the Company's forecasting process and results.

Section 1: *Forecast Methodology, Data Inputs, and Assumptions* details the development of customer count, peak demand, and energy sales forecasts. This section contains a step-by-step description of Minnesota Power's forecasting process and details the development of databases and models.

Other information included in Section 1:

- Descriptions of all forecast models used in the development of this year's forecasts, including:
    - Model specifications
    - Model statistics
    - Resulting forecast's growth rates
    - A discussion of each model's econometric merits and potential issues, as well as an explanation/justification of each variable
- Additional steps taken in 2020 to improve the forecast process and product
- Strengths and weaknesses of Minnesota Power's methodology
- All data inputs and sources, including an overview of key economic assumptions
- A description of all changes made to the forecast database since last year's forecast
- A discussion of Minnesota Power's sensitivity to Large Industrial customer contracts
- Minnesota Power's confidence in the forecast

Section 2: *Forecast Results* presents the Expected scenario forecast Minnesota Power developed for the AFR 2020 forecast. This forecast is the product of a robust econometric modeling process and careful consideration of potential industrial and resale customer load developments.

Section 3: *Other Information* presents other report information required by Minnesota law and cross-references the specific requirements to specific sections in this document.

1. Forecast Methodology, Inputs, and Assumptions

A. Overall Framework

Minnesota Power's forecast models are the result of an analytical econometric methodology, extensive database organization, and quality economic indicators. Forecast models are structural, defined by the mathematical relationship between the forecast quantities and explanatory factors. The forecast models assume a normal distribution and are "50/50"; given the inputs, there is a 50 percent probability that a realized actual will be less than forecast and a 50 percent probability that the realized actual will be more than forecast.

The Minnesota Power forecast process involves several interrelated steps: 1) data gathering, 2) data preparation and development, 3) specification search, 4) forecast determination, 5) initial review and verification, and 6) internal company review and approval. The steps of the forecast process are sequential; although, because of the research dimension, the process involves feedback loops between steps 2 and 3. The process is diagrammed in Figure 3 below and discussed in more detail in Section B.

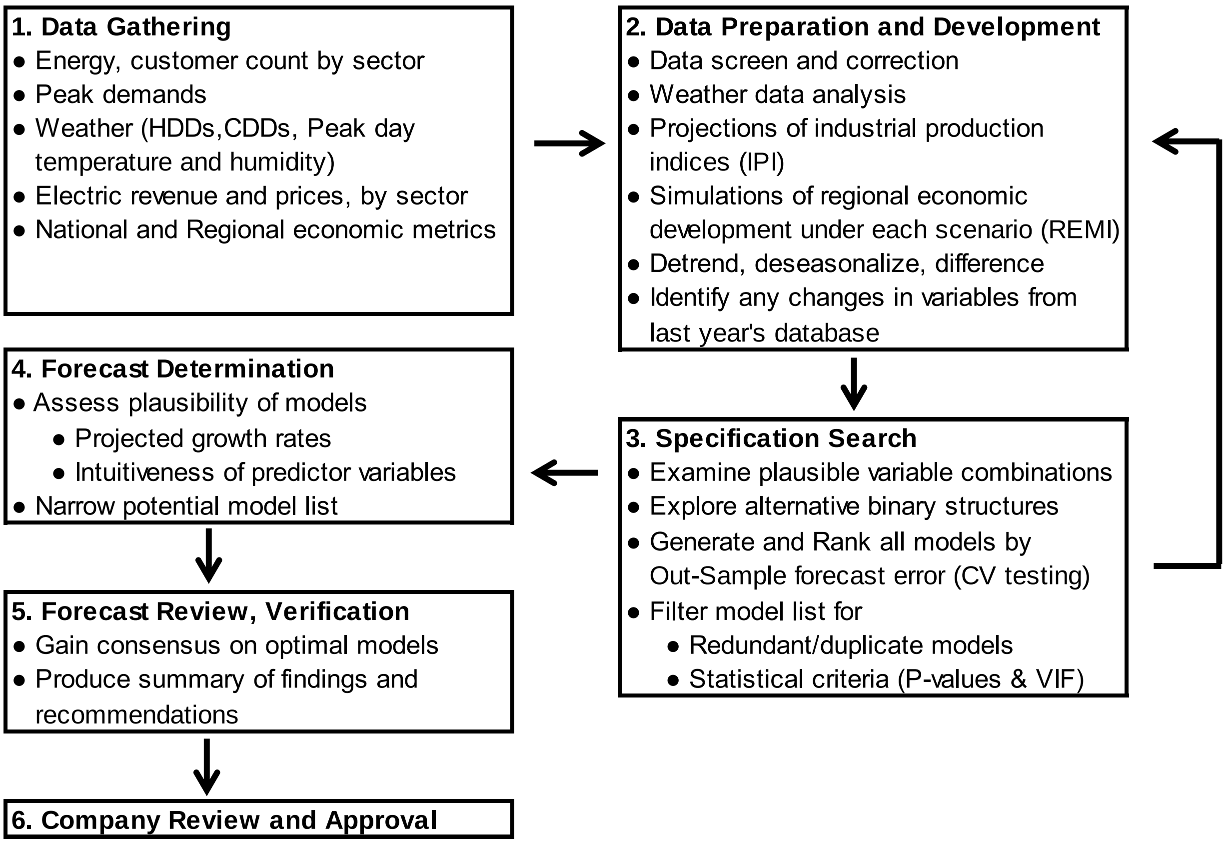

Figure 3: Minnesota Power's Forecast Process

B. Minnesota Power's Forecast Process

i. Process Description

1. *Data Gathering* involves updating or adding to the forecast database. The data used in estimation can be broadly categorized as follows:
   - *Historical quantities of the variables to be forecast,* which consists of energy sales and customer counts for Minnesota Power's defined customer classes, energy sales, and peak demand.
   - *Regional Demographic and Economic data:*

  - *Duluth Metropolitan Statistical Area (MSA)* consists of population, households, sector-specific employment, income metrics, regional product, and other local indicators.
  - *Aggregate 13-County Minnesota Power service territory (13-Co)* consists of population, Gross Regional Product (a Regional Gross Domestic Product (GDP) metric), sector-specific employment, and income metrics.
  - *Individual 13-County Minnesota Power service territory (13-Co)* consists of sector-specific employment and income metrics for each individual County.

- *Indicators of National economic activity* such as the Industrial Production Indexes (IPI) or Macroeconomic indicators such as U.S. GDP or Unemployment.
- *Weather and related data* including heating degree days (HDD), cooling degree days (CDD), temperature, humidity, dew point, and wind speed.
- *Electricity and Alternative Fuel prices*, which includes the price of electricity, natural gas, and heating oil by sector for the Minnesota Power service territory.

After gathering these data, Minnesota Power compares all series to the previous year's database to identify any changes. The cause of any change to the historical data should be explained and justified. This is explained further in Section C: *Inputs and Sources*.

2. *Data Preparation and Development* involves adjusting raw data inputs and then reviewing the data through diagnostic testing. The purpose of this step is to develop consistently defined and formatted data series for use in regression analysis. Adjustments made to specific raw data inputs are described in the "Inputs and Source" section of this document. General data preparation techniques such as *Data Transformation* and *Interpolation* are described in the *Specific Analytical Techniques* section of this document.

3. *Specification Search* involves selecting an appropriate set of variables that serve as explanatory factors for the customer count, energy sales, and peak demand series being modeled.[3] Minnesota Power does this through a formalized modeling and documentation process involving the following steps:

   - *Parameter and Criteria Definition* – During this step the forecaster manually enters the parameters for model generation and the criteria for filtering unacceptable models. This includes identifying the trend and binary variable structure to be used, number of explanatory variables for testing (typically 2) and the maximum values for acceptable variance inflation factors (VIF) and P-values.[4]

   - *Exhaustive Search* – Identifies all possible combinations of economic variables. There are generally between 20,000 and 200,000 possible combinations of predictor variables for each *Search* run. For each of the five customer count models and twenty-three energy models, there were up to twenty-eight different binary variable

[3] Specific analytical techniques applied during this step are detailed in Section D.

[4] To state simply, Variance Inflation Factors identify the presence of multicollinearity and P-values measure the significance of a variable. The definitions of these metrics are explained in greater detail in the *Specific Analytical Techniques* section.

structures tested – and each required a separate *Search* run. In total, there were about 300 *Search* runs producing roughly three million models.

- *Model Generation* – Constructs an ordinary least squares (OLS) regression model for each of the combinations identified in the *Exhaustive Search* step.

- *Ranking* – Conducts Cross-Validation (CV) on all generated models and ranks them according to the models' Out-Sample Forecast Error (Root Mean Square Error). Cross-Validation/Out-Sample testing identifies how well the forecast model can be expected to actually perform, and avoids the bias associated with model assessment based on "In-Sample" forecast error (traditional Mean Absolute Percent Error, Mean Percent Error) or goodness-of-fit (Adjusted-R^2).

- *Filter for Redundant Models* – removes a model from the ranked list if it contains the same economic variable combination[5] as another, statistically superior model.

- *Filtering for Statistical Criteria* – removes a model from the ranked list if it does not meet predefined statistical criteria (HAC-adjusted P-Values,[6] VIF)

After filtering for redundancies and statistical criteria, each of the five customer count models and twenty-three energy models produced between 450 and 97,500 plausible models (about 322,000 in total). Minnesota Power then reviews the top 50-200 models for each dependent variable.[7]

All models generated as part of the *Specification Search* step of AFR 2020 are archived for later review.

4. <u>*Forecast Determination*</u> narrows the list of potential models via a thorough review. Minnesota Power evaluates and compares model statistics, plausibility of the models' outputs (i.e. the forecast), and model structure (binary or time-trend variables). This step involves the utilization of objective metrics as far as is possible to inform judgment on the part of the forecaster.

   The forecast determination process begins by identifying the apparent statistically-superior model. If this model's forecast growth rate is implausible or predictor variables are unintuitive, Minnesota Power moves on to the second most statistically-superior model. This process continues until the Company identifies a plausible and statistically-sound model. This model is then selected as a preferred or preliminary AFR model for the specified dependent variable (class customer count, class energy sales, or system peak demand).

   However, the difference in statistical quality among top models is usually negligible and there are reasons to dismiss the top-ranked model in favor of a lower ranking model. For

[5] Although the model contains the same combination of economic variables, it may vary in that it is a differenced or de-trended form of the variable.

[6] More on Heteroskedasticity and Autocorrelation Consistent (HAC) adjustment in the *Specific analytical Techniques* section.

[7] Models are ranked by a two-year Out-sample Root-Mean-Squared Error (RMSE).

example, a second place model that has a weather variable structure that allows for accurate after-the-fact weather normalization is ideal, and worth a negligible loss in apparent statistical quality.

This step narrows the model list further; from 50-200 to just two or three select models for each dependent variable.

5. *Forecast Review and Verification* produces a list containing a single, preliminary model for each of the dependent series. During this step, analysts compare and debate the quality of models to reach a consensus around a final set of optimal models. Where a consensus cannot be immediately reached because two models may be highly comparable in statistical quality and plausibility of outputs, out-sample forecast accuracy determines the model put forward for *Company Review and Approval.*

6. *Company Review and Approval* involves internally vetting all forecasts to ensure that consistent use of forecast information was employed and that the forecasts are reasonable.

ii. Specific Analytical Techniques

Data Transformation Schema for Economic Variables: Transformations are used to maintain consistency of definition in a variable series and identify different potential relationships between predictor variables and the dependent variable. Minnesota Power uses several data transformations in data development: constant-dollar deflating/inflating, per-day conversion, de-trending/de-seasonalizing, first difference, and exponential.

- *Constant-dollar Deflating/Inflating* - is the process of deflating/inflating all dollar-denominated series to the same base year to maintain consistency of definition. Minnesota Power utilized 2012 as its base year in the 2020 forecast. The 2012 base year is the current standard among public and private data providers such as IHS Global Insight and the Bureau of Economic Analysis (BEA).

- *Per-day Conversion* – divides monthly billed energy use or monthly Heating/Cooling Degree Days by the number of days in the specified month. This transformation normalizes for the effect of varying days-per-month on a monthly aggregate like energy use or Heating/Cooling Degree Days. This results in consistently defined series that are more appropriate for linear regression modeling.

- *De-trend and De-seasonalize* – is the process of removing the historical trend/seasonality from a data series. This reduces the potential for the spurious, or *false,* correlation that often results from mistaking similarity of *trends* with similarity of *variation* between a predictor and the dependent variable.

- *First Difference* – changes the definition of the series from *level* (e.g. the number of customers in a month) to *change* (e.g. the customers gained or lost from one month to the next) by subtracting the previous value from the current. The *first difference* transformation reduces the series to only *variation* (change) so there is no potential to mistake similarity of *trend* with similarity of *variation*.

- *Exponential* – is the application of an exponent to the series; either squaring or cubing the series. This transformation of raw data was only applied to the temperature variables in the Peak Demand model, so the non-linear relationship of load to temperature could be more accurately quantified.

The Company has discontinued use of natural log and first difference of natural log transformations as well as lead/lag transformations for transparency and ease of model interpretation. The addition of these transformations to past reports was exploratory. Minnesota Power forecasters have found these transformations add minimal predictive value, but make resulting model specifications difficult to interpret and difficult to compare year-to-year changes in model inputs.

Interpolation Technique – Minnesota Power collects and utilizes raw monthly-frequency data whenever possible. However, some data series are not available at a monthly-frequency (e.g. U.S. GDP is only available in quarterly and annual frequencies). Interpolation allows annual or quarterly data to be used in monthly-frequency regression modeling by converting it to a monthly variable.

The specific interpolation function utilized in Minnesota Power's forecast process is known as a "Cubic Spline" interpolation. This technique is widely used because it produces a smooth monthly series by constraining the first and second derivatives of the variable to be continuous on the entire time interval.

The spline interpolation procedure was conducted in Statistical Analysis System (SAS) using the "Proc Expand" command with the method specified as "Spline" and the observed as "Middle." The "Middle" specification denotes that an annual-to-monthly interpolation should assume the annual value as June, and July through May should be interpolated points. Quarterly-to-monthly interpolation should assume Quarter 1 as February, Quarter 2 as May, Quarter 3 as August, and Quarter 4 as November; all other months are interpolated points. The cubic spline interpolation function is in piecewise cubic polynomial form:[8]

$$Y_i(t) = a_i + b_i t + c_i t^2 + d_i t^3$$

Where: $0 \le t \le 1$

$i = 1, 2, \ldots, n - 1$

$Y_i = i^{th}$ piece of the spline

a_i, b_i, c_i, and d_i are estimated polynomial coefficients

The cubic spline method of interpolation has been in use since the Company's 2014 AFR and was an improvement over previously-utilized interpolation methods.

Modeling Techniques – Most of the 28 dependent count and energy variables are modeled using a trend variable to explain general, underlying growth and one or two de-trended or differenced economic/demographic variables to explain any economically-driven divergence

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[8] http://mathworld.wolfram.com/CubicSpline.html.

from this trend. This approach to regression modeling reduces the potential for an independent variable to be erroneously identified as significant due to spurious, or *false,* correlation.

As a rule, all models are OLS, which are simple, transparent, explainable, and produce optimal estimates of the coefficients. All input variables' coefficients must be significant at a 90 percent confidence level (as indicated by a HAC-adjusted P-value less than 10 percent) and the VIF of each variable's coefficient must be less than five (indicating minimal multicollinearity). A constant, trend, or binary variable with a P-value greater than 10 percent or VIF greater than five may be retained if it is critical to the model structure.

- Test for multicollinearity using VIFs (Variance Inflation Factors) - multicollinearity is generally unacceptable in the final models but is assessed in the context of other variables and model statistics. The VIF of a variable is a measurement of its correlation with every other variable in the model whereas a correlation matrix would only identify the correlation of two variables to each other at each point in the matrix. Thus, VIFs are superior to a correlation matrix as a method of identifying multicollinearity. VIFs are assessed according to these criteria:

  - VIF less than 3 is optimal - correlation with the remaining variables is less than 82 percent.
  - VIF of 3-5 is acceptable, but is assessed in context with other diagnostics.
  - VIF of 5-10 is generally unacceptable, but is assessed in context with other diagnostics. A VIF greater than 5 implies correlation with remaining variables is greater than 90 percent.
  - VIF greater than 10 is unacceptable correlation for any economic variable. In this case the correlation with the remaining variables is greater than 95 percent.

  VIFs on all economic and demographic variables in all models are well within acceptable limits. Minnesota Power considers high VIFs on certain binaries variables inconsequential since the cause of this correlation is clear; it's interacting with the intercept, weather variables, or other binaries. Because these binaries are important to the structure of the model, they are not excluded in the same way an economic variable would be if found to have high multicollinearity with other variables.

- Heteroscedasticity and Autocorrelation Consistent (HAC) - adjusts the standard errors of regression coefficients to correct t-statistics and P-values for biases resulting from autocorrelation and/or heteroscedasticity. Minnesota Power computes the HAC-adjusted P-values using a common HAC specification.[9] These HAC-adjusted P-values are used to determine inclusion/exclusion in the model. Coefficients themselves are not affected by this adjustment.

  The AFR 2020 HAC-adjustment procedure simultaneously corrects P-values for both autocorrelation and heteroscedasticity. This automated adjustment streamlines model testing and selection, and produces a more robust final forecast.

[9] Developed using Andrews (1991).

Models that meet the above criteria, have plausible outputs (forecasts), and have intuitive econometric interpretations are put forward as potential final models for review during the *Forecast Determination* and *Forecast Review and Verification* steps (AFR 2020 Forecast Process pgs. 7-8).

Once forecast models are verified and finalized, they form the basis of the "econometrically-determined" outlook for energy sales, peak demand, and customer count. Assumptions for future load additions/losses and/or adjustments to account for recent customer expansions are applied to the econometric outlook to produce Minnesota Power's final energy sales, peak demand, and customer count outlook.

Leveraging Binary Variables to Account for Recent Trends – Several of Minnesota Power's largest industrial and resale customers are in a time of significant change, and an accurate load forecast depends on properly identifying and accounting for these changes.

In AFR 2014, Minnesota Power began adjusting historical sales series to "back-out" recent large customer load additions to avoid double-counting customer usage in the forecast timeframe; once (partially) embedded in the econometric projection, and again through a post-regression load adjustment.

This approach is appropriate when the load addition/loss is quantifiable (e.g. a new customer, or a new customer-owned generator), but shouldn't be used when the load addition/loss cannot be accurately quantified (an existing customer's recent expansion); adjusting raw historical sales data with an estimate would just introduce additional uncertainty to the estimate.

Minnesota Power continues to adjust historical series for known/measurable recent load additions, and has supplemented this approach with the use of binaries and trend variables that account for large changes in load that cannot be precisely quantified (such as a customer expansion that's not metered separately).

The variables denote and account for a structural shift in a dependent variable (historical sales), and are then terminated at the start of the forecast timeframe to effectively "back out" this recent change so it can be accurately quantified and explicitly applied through a post-regression adjustment to the econometric series.

Polynomial temperature specification for peak demand – The AFR 2020 peak demand model uses a third-degree (cubed) temperature series alongside an un-adjusted temperature series to capture the non-linear relationship of load to temperature. The two variables (cubed and un-adjusted) create a polynomial temperature specification.

This approach was first used in AFR 2016 and was a change from prior AFRs that leveraged either a monthly interaction specification or a spline-type (temperature range) specification. These previous approaches model the effect of temperature on demand, and identify the non-continuous or non-linear relationship of load to temperature, but neither approach is the simplest solution.

A polynomial temperature specification is continuous/not segmented, so it can always be leveraged for weather-normalization. This specification is much simpler and commonly used in demand modeling. The Company has avoided using this specification in the past, believing that the coefficients associated with the spline-segments efficiently and clearly conveyed information about load's response to weather in a specific temperature range. However, the testing of after-the-fact weather-normalization has convinced Minnesota Power Load Forecasting that a Polynomial specification is superior.

Modeled Peak Demand using hour-specific weather observations – Prior to AFR 2017, the Company modeled peak demand using monthly HDD/CDD or daily high/low temperatures. Since AFR 2017, Minnesota Power has modeled peak demand as a function of the weather observations specific to the hour in which the peak occurred. The Company identified the historical peak date/times and queried an hourly weather observation dataset to identify the hourly temperature, humidity, and wind-chill coincident with the system peak. In theory, the temperature at the time of the peak should be more closely related with the load than a daily high or low temperature (for example). The Company has witnessed improved model statistics using this approach.

Objective pre-specification of seasonal binary variables – This approach allowed Minnesota Power to avoid redundant or unusable specifications in its model *Search* runs, and more efficiently review viable forecast models. Since this does not affect model selection or final AFR model results, and is really just a process efficiency measure, the Company does not consider this new approach to modeling a "methodological adjustment."

As described in Section 1Bi *("Specification Search")*, Minnesota Power's model production process involves *Parameter and Criteria Definition.* During this step the forecaster identifies what structural variables (trend and binary variables) should be included in a particular R *Specification Search* program run. In past AFRs, Minnesota Power determined the binary variable combinations largely through intuition and a guess-and-check approach (e.g. if the January binary was insignificant in several early model runs, this structural variable would be excluded from future runs).

In AFR 2019, the Company leveraged SAS ("Statistical Analysis System") software's "Backward elimination" technique[10] to identify the most plausible seasonally binary variable combination prior to conducting *Specification Search.* This approach is more efficient and objective. The Company leveraged these results for AFR 2020, but did not re-perform the "Backward elimination" process.

[10] Backward elimination works through iteration by first modeling with a full set of seasonal binaries, then removing the insignificant binary that contributes the least to the model, then re-modeling with this subset of seasonal binaries, remove insignificant…etc. until all seasonal binary variables in the subset are significant.
http://support.sas.com/documentation/cdl/en/stathpug/66410/HTML/default/viewer.htm#stathpug_introcom_stat_sect029.htm

iii. Treatment of Demand Side Management, Conservation Improvement Programs, Distributed Generation, and Electric Vehicles in the Forecast

Demand Side Management (DSM) programs represent activities that a utility undertakes to change the configuration or magnitude of the load shape of individual customers or a class of customers.

Minnesota Power has engaged in several different types of DSM:

- *Conservation* - Conservation results in a reduction in total electric energy consumed by a customer and the potential to reduce both on-peak and off-peak demand. Conservation generally results in a reduction in the overall rate of growth of electric energy demand. Conservation, in the context of Minnesota Power conservation programs,[11] may also include process efficiency, which results in the potential to reduce the total electric energy consumed by a customer as well as to decrease on-peak and/or off-peak demand. Process efficiency reduces the overall growth rate of electric demand because it results in greater production, through more efficient equipment or processes, from a facility for the same energy inputs. If the facility failed to implement process efficiency projects, more electric energy would be required to meet production requirements. Process efficiency generally results in avoided energy production and capacity additions over the long-term.

- *Peak Shaving* - Peak shaving reduces peak demand without affecting off-peak demand. Minnesota Power's dual-fuel load control and Large Power (LP) interruptible programs are peak shaving programs for economic and emergency conditions.

- *Load Shifting* - Electric demand is shifted from on-peak to off-peak hours. In 2014, Minnesota Power initiated a Time-of-Day (TOD) Rate Pilot and in 2015 extended the program.[12] Under this rate, customers pay more for usage during on-peak hours and critical peak pricing events, and receive a discount for usage during off-peak hours. The goal of this pilot is to gauge customer interest in new rate offerings that incentivize load shifting and to further inform decisions about broader program implementation and infrastructure investment.

Accounting for Conservation in the Forecast:

Prior to AFR 2019, the effect of conservation programs were assumed implicit in the energy sales forecasts. This approach was favored since it's highly objective, involves no manipulation of the historical energy sales data prior to regression modeling, and required no exogenous adjustment for energy efficiency to be applied to the raw econometric model results. Whether this method can fully capture the recent, escalating effects of conservation on energy sales has come into question.

[11] Minnesota Power's Power of One program is made available to home and business customers. Refer to on-line conservation resources at http://www.mnpower.com/EnergyConservation for more information.
[12] Details of the program extension can be found under Docket Number E015/M-12-233 filed on March 25, 2018.

After thorough research, testing, review by colleagues at other Midwest utilities, and discussions with Minnesota Department of Commerce (DOC) Staff, the Company has identified a preferred approach to forecasting energy efficiency: use energy efficiency as an input variable to the regression models, referred to as "EE as RHS var" or "Energy Efficiency as a Right Hand Side Variable." The "EE as RHS var" methodology has several advantages over other common energy efficiency forecasting methodologies:

- Avoids double-counting energy efficiency impacts in the forecast timeframe.[13]
- Accounts for historical and projected conservation resulting from both Company programs and organic, customer-driven efforts.[14]
- Leverages raw sales data in regression modeling: sales data are not adjusted for conservation impacts prior to modeling.[15]
- Doesn't require after-the-fact adjustments to econometric outputs: the energy sales forecasts already contain the effects of energy efficiency.

An "Energy Efficiency" variable explains recent trends in customer consumption that cannot be explained by economic, demographic, or weather effects. Further, this method allows the Company to quantify the volume of Conservation Improvement Programs (CIP) energy efficiency embedded in the load forecast, which will be useful in a number of applications including resource plan modeling.

Discussion of the interpretation, role/function, and justification for use of a particular energy efficiency variable within a model is documented in Section 1E "Econometric Model Documentation."

Development of the "Energy Efficiency" variable began by gathering savings data for each retail customer class, Superior Water Light and Power, and the Company's 15 municipal customers. Incremental (i.e. first year) savings data for the historical and forecast timeframe was assembled from a number of sources. Table 2 documents the derivation of energy savings assumptions for each historical and forecast period.

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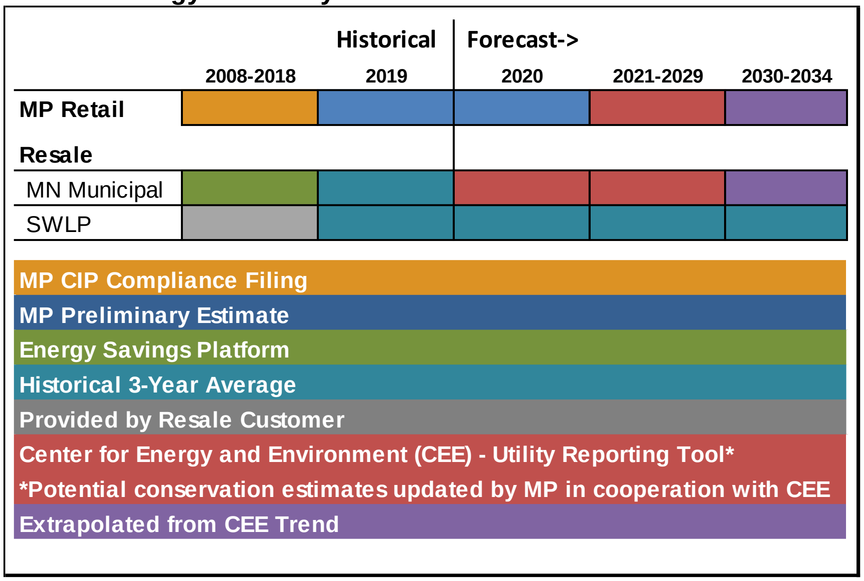
[13] The historical impact of conservation is effectively captured by the βx (coefficient x variable) series for the energy efficiency variable that spans the historical and forecast timeframes. There are no exogenous assumptions or adjustments for energy efficiency, and, in theory, no double counting.

[14] Company-driven energy efficiency is used as an *indicator* of energy sales, and the regression model will assign this variable more or less weight depending on the variable's observed correlation with sales. If the observed decrease in sales is greater than the increase in the energy efficiency variable (i.e. Company-driven energy efficiency), the model is inferring some organically-driven conservation.

[15] Another common method entails "adding-back" historical conservation to actual sales to reconstruct a history in which conservation effects have been removed. This series is modeled, projected, and then modified for future savings. This approach to forecasting sales with conservation impacts seems intuitive, but it involves modifying the historical series using an estimated series (historical CIP savings), which can create uncertainty in the resulting model and forecast.

Table 2: Energy Efficiency Variable Data Source



Historical incremental savings data for Minnesota Power was obtained from the Company's past CIP compliance filings, Minnesota Municipal customers' historical savings information was obtained from the Minnesota "Energy Savings Platform."[16] Superior Water Light and Power provided its own historical savings information to Minnesota Power.

Forecast assumptions for Minnesota Power's residential and commercial savings in 2019 and 2020 were derived from the Company's most recent preliminary estimates of achieved 2019 savings/plan for 2020, and energy savings assumptions[17] beyond 2020, were derived primarily from the Center for Energy and Environment's (CEE) new Utility Reporting Tool.[18] In cooperation and close coordination with CEE, the Company modified CEE's estimates of "Program" potential[19] savings at the generator in two ways:

1. The Program potential savings were re-estimated using CEE's methodology and working papers, but updated using the Company's most recent outlook (AFR 2019) for energy consumption by CIP-participating customers. The outlooks for energy usage growth have decreased considerably since CEE conducted its analysis; therefore the potential for energy efficiency savings have decreased.

[16] http://mncipdata.cloudapp.net/Default.aspx

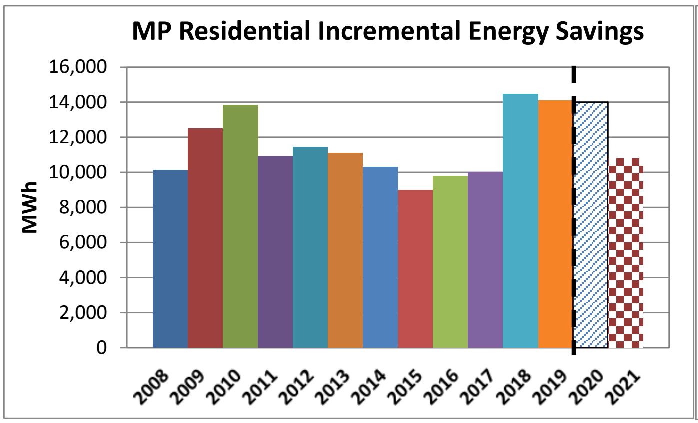
[17] Resale customer assumptions for near-term (2019) incremental savings were not available in CEE's tool, so the Company assumed a five-year historical average. Superior Water Light and Power's incremental savings outlook was assumed as a five-year historical average normalized for large customer conservation projects that are unlikely to occur with any frequency and should not bias the forecast.

[18] https://www.mncee.org/cmsctx/pv/emmaappleman/culture/en-US/wg/bc32b2f9-415e-43fc-885f-a6b77d7329a9/h/7c8c2cd92b01eaff3e98ba1b2941fc39e8cad43c23c520dbe32102e613a9ee03/-/cms/getdoc/5b0746d4-4ad0-49b9-9a85-7d4212b56a03/pv.aspx

[19] CEE projected three levels of potential savings: Program, Economic, and Max Potential. Minnesota Power leveraged the "Program" potential savings figures in its data development since the Program metric aligned most closely with the Company's 2017 Triennial filing and past achieved savings.

2. Projections of municipal customer cumulative savings (starting in 2020) were scaled to align with recent historical savings (a five-year average).[20]

For each of the retail classes and resale customers, the Company cumulated the historical and projected incremental savings[21] to produce a "cumulative energy savings" series.[22] This cumulative series is the optimal variable format/definition for modeling energy sales; Figures 4 and 5 below demonstrate why this is the case by plotting incremental and cumulative residential energy savings (at meter) since the passage of the U.S. "Energy Independence and Security Act" of 2007 and the MN "Next Generation Energy Act" of 2007.



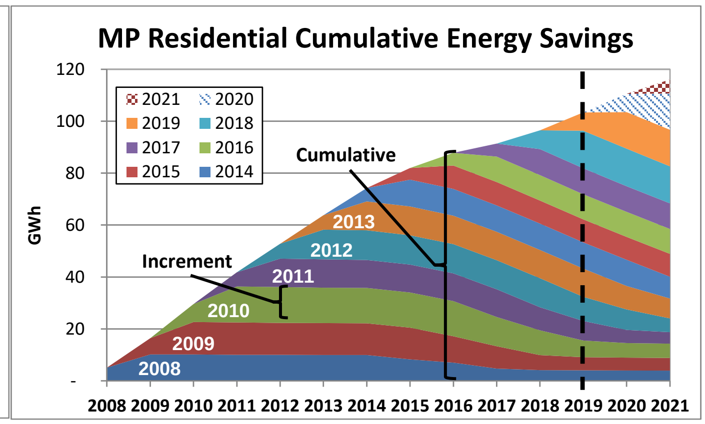


Figure 4: Residential Incremental Energy Savings

Figure 5: Residential Cumulative Energy Savings

Incremental energy savings are the "first year" or single year savings achieved via a portfolio of efficiency measures implemented in a single year. Incremental residential savings at meter are fairly constant from year-to-year, around 11,000 megawatt hours (MWh); from an econometric modeling perspective, this variable might indicate a constant shift in the level of annual sales, but it would not indicate a change in growth rate or trajectory of annual sales.

A cumulative savings metric represents the lasting impacts of conservation programs[23] by aggregating or *cumulating* the savings from all past conservation measures. This cumulative

[20] The CEE forecast of municipal customer incremental savings for 2020 (first forecast year) were, in total, about 50% greater than the five-year historical average of incremental savings for these same municipals. The Company inferred from this that CEE's projections of Cumulative savings were inflated by a similar amount. Scaling the CEE cumulative savings estimates prevented a large step change in the final "energy efficiency" variables for each municipal customer.

[21] For municipal customer savings, the cumulative savings series was calculated by 1) cumulating all incremental savings pre-2020, and adding this to 2) CEE's projection of cumulative savings post-2020. This was computationally easier, and required fewer assumptions on the part of the Company. A similar process for retail classes that leveraged CEE's cumulative savings was not possible since the customer class-level savings needed to be scaled per the composition of past achieved savings.

[22] Using internal estimates of Minnesota Power's past programs' life of measures. A Life of Measure (LoM) is the approximate time a conservation measure will reduce energy consumption. Most conservation measures have a 10-20 year life. A portfolio from any particular program year will contain measures that end earlier than others, so the overall impact of measures implemented in a program year will fade over time.

[23] Figure 5 above also shows how these conservation measure impacts fade over time as, for example, households replace the aging appliances.

series grows substantially from 2008-to-present; a timeframe in which Minnesota Power's residential energy sales growth has largely stalled. From an econometric modeling perspective, a cumulative savings format/definition is indicative of a change in growth rate/trajectory of annual sales. This is precisely the phenomenon that requires explanation and quantification, and why the "cumulative" series is the optimal variable format/definition for modeling energy sales.

Note that accumulating the *annual* incremental series only produces *annual* cumulative savings series, whereas Minnesota Power's energy models are *monthly*-frequency. The Company used the same annual cumulative savings value for all 12 monthly observations of a particular year,[24] and did not attempt to estimate monthly energy savings by distributing or interpolating the annual values. Estimation of monthly savings values would have 1) involved additional assumptions on the part of Minnesota Power forecasters, and 2) potentially imparted bias to the final model through the weather coefficients. A key strength of the "Energy Efficiency as a Right Hand Side Variable" methodology is that it involves making relatively few assumptions, leveraging raw data as much as possible, and relying on the regression modeling process to objectively "solve for" unknown variables such as the seasonality of energy efficiency impacts.

The Company used a cumulative savings, annual "Energy Efficiency" variable in regression models for sales to the residential, commercial, and public authorities classes, as well as four of the Company's 16 resale customers modeled in AFR 2020. The cumulative energy sales assumptions used in regression modeling (i.e. the "Energy Efficiency" variables) and corresponding incremental savings assumptions are shown in the tables below by year. [Note: The commercial-sector "Energy Efficiency" variable was utilized in the public authorities model since: 1) both customer groups are served by the same CIP program (Power Grant/Power of One Business), and 2) the overall trend of conservation in public authorities is likely very similar to commercial customers.]

[24] Note that the Company did not divide the annual values by 12. Dividing or multiplying a variable by a constant (e.g. 12) prior to regression modeling has no effect on the resulting forecast; the regression model would adjust the parameter estimates (i.e. coefficient) to maintain a least squared error function. Dividing a variable by 12 would result in a coefficient that's 12 times larger.

Table 3: Cumulative Energy Sales Assumptions **Table 4: Incremental Energy Savings Assumptions**

[Trade Secret Data Begins

Trade secret data excised.

Trade Secret Data Ends]

Accounting for Distributed Generation (DG):

Prior to AFR 2019, the Company did not make explicit, exogenous assumptions for Distributed Generation: Solar ("DG Solar"), but noted that "it may become possible/necessary to account for this transition in the load forecast."[25] Minnesota Power has identified a viable methodology for this transition, has projected DG Solar adoption, and has adjusted the energy sales and peak demand forecasts per this DG Solar outlook.

New DG Solar installations were projected using the exponential growth observed in recent years where the number of new residential solar installations has grown by about 27% per year and new commercial installations has expanded on average by about 48% per year. This outlook for the number of new installs is combined with assumptions for the sizing (kilowatt (kW) capacity) of those new installations, an expected capacity factor, and seasonal production characteristics to produce estimates of monthly energy production and peak reduction. The energy sales and peak demand forecasts are only adjusted for *new* installations (i.e. installations expected to come online in the forecast timeframe). The effects of currently installed arrays are presumed to be embedded in the forecast.

[25] In Section 1.B.iv. "Treatment of Demand-Side Management (DSM), Conservation Improvement Programs (CIP), and Distributed Generation (DG)" of AFR's 2017 and 2018.

The Company projects that about 2,800 new DG Solar installations will connect to the Minnesota Power grid by 2030 (i.e. installed in years 2020-2030), generating about 15,000 MWh per year and reducing sales by an equivalent amount. The Company adjusted the energy sales and peak demand outlook per all DG Solar adoption in the forecast timeframe (2020-2034); current DG Solar is assumed inherent in the econometric forecast.

Currently, there are nearly 400 small-scale (<40KW)[26] Distributed Generation (DG) Solar installations with a combined nameplate capacity of about 3.3 MW, reducing sales by an estimated 3,300 MWh/year (0.15% of combined residential and commercial sales in 2018). The Company projects that its customers will have installed about 27 MW of new small-scale solar,[27] displacing about 27,000 MWh in energy sales by 2030.

The process of forecasting DG solar generation involves two separate assumptions: 1) the rate of adoption (i.e. number of new installations each year), and 2) the average size of those new installations. When calculating both assumptions, the Company opted to segment the DG solar customer population into Residential and Commercial customers; the two classes show separate rates of historical adoption and have tended to install different sized arrays.

The adoption rate was forecasted by extrapolating the exponential trend observed in recent years; these forecasts are shown as the dotted lines in Figure 6 below. The exponential growth functions were identified by regressing each of the historical installations series against a “time-trend” variable and a square of the time-trend series.

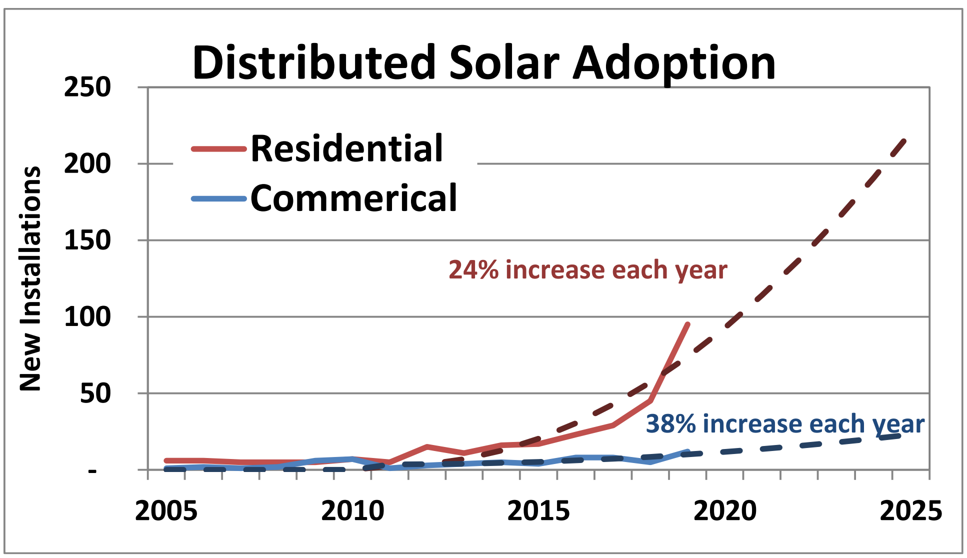


Figure 6: Residential and Commercial Distributed Solar Adoption

[26] AFR 2019 considered “Small-scale” to be <60KW. Using the <40KW more closely aligns with other major filings and current policy.

[27] This is Customer installations only, and does not include Minnesota Power developments like Community Solar.

The average size (capacity) of new installations in the forecast timeframe is assumed as a simple historical average of installation size by class: residential customer DG solar installations have averaged a capacity of about 9 kW and commercial customer DG solar installations have averaged about 19 kW.[28]

The adoption rate series is combined with the average installation size assumption to arrive at an estimate of total kW installed per year in the forecast timeframe for both the residential and commercial classes. The “kW installed per year” series (for both commercial and residential) are transformed into cumulative series that represent the total kW installed as of a point in time, inclusive of all installations from the current and prior years.

Finally, the Company calculated the estimated impact of new DG solar on energy sales by converting the capacity series (kW) to an energy series (kWh) using an 11% capacity factor[29] assumption for new distributed installations. Table 5 below shows the core assumptions of the Company’s annual DG solar outlook.

Table 5: Minnesota Power Outlook for New (post-2019) Distributed Solar

	Installation Count	Capacity (kW)	Energy Production (MWh)
2020	105	1,034	1,020
2021	128	2,289	2,257
2022	153	3,787	3,735
2023	181	5,551	5,474
2024	211	7,604	7,499
2025	244	9,970	9,832
2026	279	12,671	12,496
2027	316	15,730	15,514
2028	356	19,171	18,908
2029	398	23,017	22,700
2030	443	27,290	26,915
2031	490	32,014	31,574
2032	540	37,211	36,700
2033	592	42,906	42,316
2034	646	49,120	48,445

Identifying the impact of DG solar on the monthly peak demand outlook involves calculating the amount of solar generation that’s likely during a specific month’s likely peak time (i.e. historical median peak hour) using a simulated hourly solar production curve.[30] Minnesota

[28] Extremely large outliers were omitted. The Company recognizes that installations are often sized per the energy requirements of the customer, and if per-customer usage declines due to conservation it’s likely that installation size will similarly decrease. The Company also recognizes the potential, past and present, for rouge installations (i.e. installations that are not reported to Minnesota Power); this forecast does not account for this potential.

[29] This is the observed average capacity factor of metered solar installations on Minnesota Power’s System.

[30] The Company used PVSYST software to simulate eight different 10 kW systems per a Typical Meteorological Year. The eight systems varied by location within Minnesota Power’s service territory, and by tilt, azimuth, and tracking ability.

Power typically peaks at 6 or 7 PM (well after sun-set) in winter months, so DG solar at the time of the peak is 0% and projected winter peaks are not reduced. In summer months, Minnesota Power has historically peaked at 3 or 4 PM when DG solar is on average 55% of installed capacity (the effective load carrying capacity or "ELCC" is 0.55).[31] Summer peak forecasts are reduced by 55% of the projected new installed solar capacity; this equates to a 0.6 MW reduction in the 2020 summer peak, growing to an approximate 15 MW reduction in summer peak by 2030.

Accounting for Adoption of Electric Vehicles (EV):

Minnesota Power recognizes the potential load growth that could result from this new electric end-use and has incorporated an outlook for Electric Vehicle (EV) adoption into the residential energy sales and peak demand forecasts.

Fleet vehicles and commercial charging are not addressed in AFR 2020. Fleet EV adoption in Minnesota Power's territory is too limited to gauge the pace of organic adoption or draw meaningful parallels between local and national adoption rates. Projecting public EV charging usage will also require further study. For the sake of simplicity in this inaugural attempt at modeling EV impacts on the Minnesota Power system, the Company attributes all new electric vehicle usage to the residential class. Minnesota Power will continue to gather data and refine its methods to model and incorporate new electric end-uses like EVs into the annual forecast.

The EV adoption rate forecast for the Minnesota Power service territory follows a projected national adoption rate, but lagged by 6 years. To-date, EV adoption/penetration among Minnesota Power customers trails the nation by about 6 years: in 2019 Minnesota Power customers had an approximate EV saturation of 0.12% whereas the national saturation rate[32] was about 1.15%. The National EV saturation rate was last at 0.12% in 2013, so – for the purposes of forecasting – the Company assumed its customers' EV adoption would continue to lag the nation by about 6 years and would follow the national trend forecast from

Each simulated profile was then weighted per the installed kW by location and array specification, and all profiles were totaled. This totalized curve was used to determine the capacity factor of DG solar for each month. Note that this curve was based on 2011 weather information and installations as this was readily available. Simulating with more current information or aggregating actual metered production data would have been time-intensive and likely would have yielded similar results with regards to the capacity factor, which was the only assumption derived from this simulated production curve.

[31] DG solar output is less than 100% during the peak for several reasons, including: 1) diversity in installation arrangement and geography (every solar installation will not experience max output at the same time), 2) the likely Minnesota Power system peak timing is well after noon (12-to-1 PM would be the highest solar output hour), and 3) probabilistic variance in weather is taken into account (although its likely to be sunny and hot on the day of the system peak, that does not guarantee perfect conditions at the precise hour of the peak).

[32] Inside EVs (https://insideevs.com) was used to gather actual EV sales data, and the U.S. household count was derived from the U.S. Census (https://www.census.gov/data/tables/time-series/demo/families/households.html). There are approximately 1.4 million EVs on U.S. roads and about 125 million households in the U.S., so - on average - roughly 1.15% of US households own an EV.

Bloomberg.[33] Figure 7 below shows the adoption rates of Minnesota Power customers and the U.S.

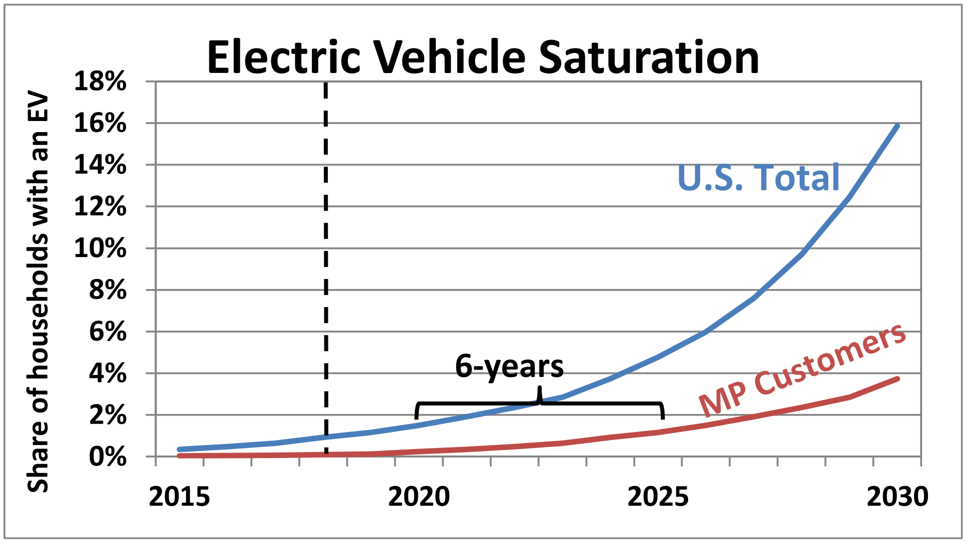


Figure 7: Minnesota Power vs. U.S. Electric Vehicle Saturation

The annual saturation rate outlook (shown in Figure 7) is then multiplied by Minnesota Power's residential customer count[34] to estimate the total number of EVs in Minnesota Power's service territory. The annual EV energy requirements forecast was calculated by multiplying the EV count and an estimate of per-unit energy requirements, which the Company assumes is about 2,520 kWh per year.[35] Table 6 shows the outlook for EVs in the Minnesota Power's service territory.

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[33] Bloomberg's 2019 Electric Vehicle Outlook (EVO). The 2020 Electric Vehicle Outlook (EVO) was released too late in the forecast's development to be included in the 2020 AFR, but the overall adoption rate does not differ significantly from the 2019 adoption outlook.

[34] Count of Standard Residential and All Electric accounts – excludes Dual Fuel and Controlled Access to avoid double counting and inflating the estimate of households served.

[35] General Motors estimates the annual energy use of a Chevy Volt is 2,520 kWh – https://www.energy.gov/eere/electricvehicles/charging-home – Rough estimates of energy requirements based on regional commuting distances and 33 kWh per 100 miles (Nissan Leaf rated efficiency) produced 2,580 kWh, so the Chevy Volt estimate is likely an accurate enough assumption for long-term forecasting.

Table 6: Minnesota Power Residential Electric Vehicle Outlook

	Vehicle Count	Saturation	Energy Requirements (MWh)
2020	272	0.2%	349
2021	379	0.3%	618
2022	525	0.5%	986
2023	705	0.6%	1,438
2024	1,027	0.9%	2,250
2025	1,281	1.2%	2,891
2026	1,672	1.5%	3,875
2027	2,132	1.9%	5,035
2028	2,628	2.4%	6,284
2029	3,188	2.8%	7,695
2030	4,182	3.7%	10,201
2031	5,353	4.8%	13,151
2032	6,737	6.0%	16,639
2033	8,572	7.6%	21,264
2034	10,965	9.7%	27,295

The Company did not attempt to modify this annual energy requirement estimate (2,520 kWh) per regional commute distances or regional climate and related efficiency; both estimates would involve comparisons of national and regional characteristics that are difficult to make at this early stage of adoption. However, the Company did leverage regional temperature information to impart a seasonal (i.e. monthly) distribution to the overall annual EV energy requirements estimates.

EV energy requirements/efficiency will vary with temperature; consequently, EV efficiency will also vary by month. The Company combined regional weather information[36] with observations of the Nissan Leaf's seasonal efficiency[37] to identify this seasonal variance in energy requirements. The results suggest that EV efficiency is optimal between 60 and 70 degrees Fahrenheit which is the average daily temperature during the summer months in northeastern Minnesota.[38] During winter months, when the average daily temperature is just 15 degrees Fahrenheit, EVs will require about 40% more energy than during optimal conditions.

Identifying the impact of EV charging on monthly peak demand requires information on charging patterns/characteristics – i.e. how/when customers will tend to charge their vehicles. A National Renewable Energy Laboratory (NREL) value assessment study of

[36] The Company used a twenty-year historical average temperature by month at Duluth International Airport. This is consistent with weather assumptions used in energy and peak demand forecasting.

[37] https://pubs.acs.org/doi/suppl/10.1021/es505621s/suppl_file/es505621s_si_001.pdf

[38] The Company recognizes that temperature during a summer day may vary considerably, and that overall efficiency in summer months should be lower than optimal. More accurate assumptions for seasonal/temperature-related efficiency would involve more complicated assumptions for driving times and coincident temperatures. This is something the Company will investigate in the future. The Company opted for simplicity of assumption in this regard for this inaugural EV forecast.

electric vehicles[39] contained modeled EV charging patterns for several customer types. For the purposes of determining EV charging load coincident with the system peak demand, Minnesota Power assumed the charging profile representative of: level 1 charging, at a single family dwelling, with *no* Time of Use (TOU) restriction or rate.

Per these profiles, approximately 12% of daily residential EV energy requirements are met at the most typical winter peak hour (6 PM) and about 6% of daily EV energy requirements are met during the likely summer peak hour (3 PM).[40]

The Company projects that by the late 2030, about 4% of Minnesota Power customers will own an EV, and Minnesota Power will be the primary service provider to about 4,200 EVs. This outlook assumes Minnesota Power customers' EV penetration and adoption continues to lag the U.S. by about 6 years. The Company attributes this lag in adoption to issues of income, population density/cost-efficiency of commercial charging station locations, and reduced efficiency in cold-weather. These factors may be overcome with technological advancement or a rapid escalation in gasoline costs, or Minnesota Power customers may "catch-up" to the rest of the country in EV adoption regardless of these limiting factors. The Company will refresh its EV forecast and methodology each year, and will publish the results along with any substantive methodological changes or key findings in the AFR.

iv. Methodological Strengths and Weaknesses

The Company's forecast process combines econometric modeling with a sensible approach to modifying model outputs for assumed changes in large customer loads or new technology adoption. An econometric approach, utilizing regression modeling, is optimal for estimating a baseline projection with a given economic outlook and capturing the historical and projected effects of energy efficiency. However, a fully econometric process would not imply any of the substantial industrial expansions that are likely in the Minnesota Power service territory. A combined "econometric/large customer load addition" approach produces the most reasonable forecast.

The Company's econometric modeling process has two key strengths: it is both highly replicable, and adept at narrowing the list of potential models to only those that are most likely to produce quality results which allows more time for in-depth statistical testing and critical review of each model.

That said, there are some weaknesses to a combined "econometric/large customer load addition" approach. For instance, there is some subjectivity in the perceived likelihood of individual large customer load additions/losses since their magnitude or timing is difficult to estimate in a probabilistic way. To minimize subjectivity on the part of Minnesota Power, the

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[39] https://www.nrel.gov/docs/fy17osti/66980.pdf

[40] The Company recognizes that these assumptions do not capture the mid-day load potential for commercial or "at work" charging, and only accounts for home charging patterns. This is not an oversight. The Company does not currently have sufficient information to project commercial charging, but will re-evaluate in future iterations of the AFR.

Company utilizes information that has been publicly communicated by prospective customers in its scenario planning.

Minnesota Power is highly sensitive to large industrial customer decisions as large taconite, paper, and pipeline customers represent more than half of Minnesota Power's system demand and energy sales at any given point in time. The Company addresses this potential for error by maintaining close contact with existing and potential customers to keep current on their plans.

C. Inputs and Sources

Minnesota Power draws on a number of external data sources and vendors for its indicator variables. Each year, the forecast database is updated with the most current economic and demographic data available. This involves an update of the entire historical timeframe since these data are frequently revised. Special attention is given to identifying any changes from previous years' data and data sources. Changes from last year's database are clarified later in this section.

i. AFR 2020 Forecast Database Inputs

Weather

Weather data for Duluth, Minnesota was collected for historical periods from the National Oceanic and Atmospheric Administration (NOAA) and from Weather Underground (WU).[41] Minnesota Power utilizes Monthly HDDs and CDDs in energy sales forecasting and peak-day weather conditions in peak demand forecasting.

Monthly total HDD and CDD are sourced from NOAA. The monthly total HDD and CDD values are normalized for the number of days in a month by dividing the monthly HDD or CDD count by the number of days in the month. This results in the "per-day" series HDDpd and CDDpd. For example:

The "per-day" value of 46.1 HDDpd in January 1990 was calculated as follows:

> Duluth Minnesota's HDD count for January 1990 (1428) is divided by the number of days in January (31) to produce an HDDpd value of 46.1.

Normalizing the series by transforming to a per-day unit allows for a more accurate estimate of the weather's impact on energy sales. The forecast assumes a twenty-year historical average for each month (Jan 2000 – Dec 2019). For example, January's forecast assumption is an average of Jan-00, Jan-01,…, Jan-19.

[41] http://www.wunderground.com/.

Temperature, humidity, and wind-chill data used to model peak demand are derived from Schneider Electric. In previous forecasts, the Company has leveraged either NOAA or WU for daily or monthly-frequency values. The 2020 AFR forecast database features weather observations that are specific to the historical peak hour (i.e. the temperature, humidity, and wind-chill at the time of the peak). This closer alignment between the peak demands and the weather that induced them should produce a more accurate estimate of weather-sensitivity and a more accurate forecast of future peak demand.

Development of the historical weather series begins by establishing the date and time of historical monthly peaks. Weather observations for these date/times is then gathered and organized into a monthly-frequency weather series.

Calculating a twenty-year historical average of peak-time weather for use as a forecast assumption requires recorded peak dates for the timeframe prior to the establishment of the current electronic database (1998-1999). Minnesota Power uses the Federal Energy Regulatory Commission (FERC) Form 1 to identify the dates for peaks prior to 1999 and then gathers the corresponding weather data. Forecast assumptions for peak-day weather can be calculated from the completed twenty-year history.

A Temperature-Humidity Index (THI)[42] is utilized to take into account the effect of heat and, when applicable, humidity on summer peaks. The THI is only applicable when temperatures exceed 75 degrees. A Wind-chill (WC) index[43] was also utilized to capture the cold temperatures and, when applicable, the cooling effects of wind speed. The WC index is only applicable when temperatures drop below 40 degrees and wind speeds are greater than 3 miles per hour.

<u>IHS Global Insight</u>

IHS Global Insight is the singular source for all economic and demographic outlooks used in Minnesota Power's load forecast.[44] A single source for National, Metropolitan Statistical Area (MSA), and County-level outlooks ensures internal consistency of forecast assumptions.

IHS Global Insights data development process begins with producing a national-level forecast. County-level and MSA data for Northeast Minnesota is then calculated through a "Top-down/Bottom-up" approach; the Minnesota Power area economy is modeled independently, considering unique local conditions, and is then linked to the national economy to ensure consistency across the national, regional, state, and MSA levels.

Since 2009, Minnesota Power has utilized IHS Global Insight estimates of historical and forecast economic activity in Northeast Minnesota as key inputs to energy and customer count models. Recent years' forecast processes have featured an expansion of IHS Global

[42] http://www.wpc.ncep.noaa.gov/html/heatindex_equation.shtml.
[43] http://www.nws.noaa.gov/os/windchill/index.shtml.
[44] With the exception of two series that are derived from REMI: Population and GRP for the 13-County Planning Region.

Insight data use, and AFR 2020 continues this trend towards greater granularity and constancy.

AFR 2014 featured the adoption of IHS Global Insight's national-level economic indicators as inputs to Industrial Production Index (IPI) modeling process. IHS Global Insight provided access to more national-level variables than the previous source[45] and allowed Minnesota Power to expand its IPI forecast database. The data source change also maintained consistency of assumption in all areas of Minnesota Power's forecast process and among all levels of geographic granularity.

In both AFR 2015 and AFR 2016, the Company expanded the forecast database to include more geographically-granular indicators to add predictive power by more-closely aligning with the area containing Minnesota Power's customer base. AFR 2015 featured the addition of Duluth Metropolitan Statistical Area (Duluth MSA)[46] economic indicators, and the AFR 2016 database was expanded to include economic indicators for all *individual* counties in the 13-County Planning Area in addition to the 13-County Planning Area Aggregate.[47] This expanded the number of economic/demographic predictor variables from 78 (in AFR 2015 database) to 454 (in the AFR 2016 and subsequent databases).

IHS Global Insight utilizes the most current historical data available from public data sources, which is updated frequently. These updates flow through IHS Global Insight's process to ultimately effect the historical series used in Minnesota Power's forecast database. Thus, the historical regional employment and income data has changed from last year's database.

The frequency of the raw Duluth MSA and National-level economic data is quarterly, and interpolation to a monthly frequency is necessary for use in Minnesota Power's monthly forecasting process. The interpolation method used is described in the *Specific Analytical Techniques* section.

<u>Regional Economic Models, Inc. (REMI)</u>

Minnesota Power subscribes to the latest REMI Policy Insight version (PI+) for northeastern Minnesota. This input/output econometric simulation software combines a national economic outlook[48] with specified regional economic conditions to produce a forecast for a 13-County Planning Area such as employment by sector, population, economic output by sector, and Gross Regional Product (GRP).

For AFR 2020, REMI was used to quantify the indirect economic effects of known and expected changes in regional employment (i.e. expansions and layoffs/closures) to produce an expected economic outlook for the region.

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[45] Blue Chip Economic Indicators.
[46] The Duluth MSA is defined as St. Louis and Carlton counties in Minnesota, and Douglas County in Wisconsin.
[47] Minnesota Power's 13 County Planning Area is defined as: Carlton, Cass, Crow Wing, Hubbard, Itasca, Koochiching, Lake, Morrison, Pine, Saint Louis, Todd, and Wadena counties in Minnesota, and Douglas County Wisconsin.
[48] Prior to simulation, REMI is calibrated to the IHS Global Insight National Economic Outlook.

IHS Global Insight economic indicators for both 13-County Planning Area and the Duluth MSA are calibrated using the results of REMI's economic simulations. As the REMI outlook is adjusted for alternative planning scenarios, the monthly employment and income outlooks are changed accordingly.

Some indicators such as population and GRP are not provided by IHS Global Insight for the 13-County Planning area. These series are derived directly from REMI outputs, and are of annual frequency. Interpolation to a monthly frequency is necessary for use in Minnesota Power's monthly forecasting process. The interpolation method used is described in the *Specific Analytical Techniques* section.

Like IHS Global Insight, REMI relies on data from public sources that are subject to revision. These revised data inputs result in revised historical values for the economic and demographic indicators used in Minnesota Power's database.

<u>Indexes of Industrial Production (IPI series)</u>

The indexes of industrial production are measures of sector-specific production in a given month relative to a base year, 2012 in this case (that is, 2012 = 100). The indexes exhibit a high degree of correlation with Minnesota Power's historical industrial energy sales and are, therefore, ideal for forecasting future energy sales to the class.

The historical national-level IPI data were obtained from the Board of Governors of the Federal Reserve. The historical data is regularly revised to incorporate better data, better methods, and to update the base year. To capture these revisions, Minnesota Power updates the entire historical data series each year. These revisions are explained on the Federal Reserve's website.[49]

Forecasts for each national-level IPI were developed from the projections of national-level economic indicators from IHS Global Insight, and are, therefore, consistent with all other AFR 2020 forecast assumptions. These macroeconomic drivers are used to model and forecast the national-level IPI series.

The historical Minnesota iron IPI was developed using actual iron ore production data from the U.S. Geological Survey website (USGS).[50] The projected Minnesota iron IPI was developed by scaling the national-level Iron IPI forecast using an assumption of the industry's composition going forward. Minnesota now comprises about 83% of U.S. product, so the Minnesota iron IPI equals the national-level IPI x 0.83. The entire historical and forecast Minnesota iron IPI was then indexed to 2012 for consistency with past AFRs, the other IPI series used in AFR 2020, and the U.S. Federal Reserve's current standard index year.

[49] http://www.federalreserve.gov/releases/g17/revisions/Current/g17rev.pdf.
[50] https://minerals.usgs.gov/minerals/pubs/commodity/iron_ore/

Note that Minnesota Power de-trends all input variables prior to modeling and opted to utilize an already de-seasonalized series from the external source rather than applying its own de-seasonalizing function. Both the seasonally-adjusted and unadjusted series are available from the Board of Governors of the Federal Reserve. The 2020 forecast database utilizes the seasonally adjusted historical indexes.

Energy Prices

Estimates of future Minnesota Power rate changes are incorporated into the average electric price forecasts as generally indicative of the intention and anticipation of changes in the Company's rate structure and prices.

Average energy prices, history and forecast data, are from the Department of Energy (DOE) and Energy Information Administration (EIA). The fuel types considered are electricity and natural gas. End-use class energy price data is categorized by DOE/EIA into residential, commercial, and industrial. DOE's Annual Energy Outlook (AEO) is used for the forecast period. DOE provides historical energy price data for Minnesota, forecast energy price data for the West North Central (WNC) region, and the national total. Minnesota Power's historical average electric price data are from the Company's FERC Form 1 and represent annual class revenue divided by annual class energy. All energy prices are deflated by the 2012 base year GDP implicit price deflator (IPD).

Energy Efficiency, Distributed Solar, and Electric Vehicles

Refer to section 1B iv. "Treatment of DSM, CIP, DG, and EV in the Forecast" for all data and assumption sources concerning Energy Efficiency, Distributed Solar, and Electric Vehicles.

ii. Adjustments to Raw Energy Use and Customer Count Data

Minnesota Power made a limited number of adjustments to internally developed data for AFR 2020, which fall into three general categories:

1. Adjustments to raw customer count data for billing anomalies
2. Adjustments to raw sales and peak demand data for large load additions and losses
3. Adjustments to convert sales data into overall energy requirements data

Adjustments to raw customer count and energy sales data for billing anomalies – Minnesota Power's historical customer count and energy sales data contain a number of anomalous or missing observations that can affect modeling and resulting forecasts.

Employing a binary variable during modeling or adjusting the raw data prior to modeling are two common techniques used to avoid biasing models with anomalous observations. Prior to the AFR 2014 process, Minnesota Power used both techniques, but their application was not entirely consistent. The Company's current database and modeling policy is as follows:

Where there is a systemic shift (e.g. seasonal billing in residential customers count), Minnesota Power does not adjust the raw data and instead utilizes a binary variable in modeling. When there are less than 3 consecutive anomalous observations, Minnesota Power adjusts the raw data prior to regression using straight-line interpolation. In general, an observation was considered anomalous if it varied by more than 0.5 percent from a straight-line-interpolated value.

The 2020 customer count and energy sales database contains 251 monthly points (about 2.7 percent of all monthly points) that have been adjusted in this way.

Adjustments to raw sales and peak demand data to account for large load additions and losses – All adjustments to the historical database are described below in detail and organized by sector. The impact of this methodological change on the forecast for each customer class is discussed in the *Model Documentation* section.

[TRADE SECRET DATA BEGINS

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Trade secret data excised.

TRADE SECRET DATA ENDS]

Notes on Adjustments to historical series:

- When assessing the ability of economic variables to reflect the above mentioned structural breaks, Minnesota Power identified those instances when the raw energy sales series could be modeled more accurately than the adjusted series; in these cases when the economic data explains the change, the use of the raw sales series is appropriate. When the adjusted series can be modeled more accurately than the raw series, then it's evident that the economic data cannot adequately explain the shift and the adjusted historical sales series should be utilized. However, it should be noted that it is the Company's preference to use binary variables in these instances when the relationship between variables has changed by some measurable constant. This technique utilizes the raw data series (unadjusted) as a result.

- When recent load additions or losses can be accurately quantified, they are removed from the historical sales and peak series prior to modeling and a post-regression adjustment is used to account for the load addition or loss in the forecast timeframe. When it is not possible to accurately quantify this recent change (e.g. if a customer is served by a municipal customer and their usage data is not accessible by Minnesota Power), then no adjustment is made to the historical data. In this case, a post-regression adjustment is still applied to account for the load addition in the forecast timeframe. When it's evident that this load addition or loss is reflected in the econometric forecast or the change can be modeled with a binary variable, Minnesota Power will cease the application of a specific post-regression adjustment.

iii. Changes to Forecast Database

Regarding externally derived data, Minnesota Power noted several changes between the AFR 2020 forecast database and the AFR 2019 database. Several changes involve adjustments to the historical dependent series (energy use, customer count, peak) and are explained in the previous section on "***Adjustments to raw sales and peak demand data to account for large load additions and losses.***"

Regarding, regional economic indicators, all changes were fairly minor and are explainable and plausible. Minnesota Power is confident in moving forward with the database updates.

Table 7 shows the series that were utilized in both the AFR 2019 and the AFR 2020 forecasts. The table shows the percent difference of the last full historical year common to both databases (2018), and identifies the percent difference in a forecast year (2025) for comparison.

Table 7: Changes to Forecast Database

Economic and Demographic Variables	Changes to Database 2019 to 2020	Percent difference in variable in 2018	Percent difference in variable by 2025
MP Area Total Non-Farm Employment	Change #1	-0.2%	-0.9%
MP Area Employment in Education & Health	Change #1	-0.1%	1.9%
MP Area Employment in Government	Change #1	0.0%	-1.2%
MP Area Employment in Professional Business Services	Change #1	-1.1%	-2.4%
MP Area Employment in Construction, Natural Resources, & Mining	Change #1	-0.7%	-13.1%
MP Area Gross Regional Product	Change #1	4.2%	3.5%
MP Area Non-Wage Personal Income	Change #1	5.4%	4.7%
MP Area Wage Distribution	Change #1	1.8%	4.2%
MP Area Population	Change #1	-0.1%	-0.7%
MP Area Product per Capita	Change #1	4.3%	4.3%
MP Area Employment to Population Ratio	Change #1	-0.2%	-0.1%
Duluth MSA Total Non-Farm Employment	Change #2	0.0%	-0.7%
Duluth MSA Employment in Education & Health	Change #2	0.0%	2.0%
Duluth MSA Employment in Government	Change #2	0.0%	-0.8%
Duluth MSA Employment in Services	Change #2	0.0%	0.5%
Duluth MSA Housing Starts	Change #2	242.1%	-10.2%
Duluth MSA Population	Change #2	-0.1%	-0.6%
Duluth MSA Employment to Population Ratio	Change #2	0.1%	-0.1%
St. Louis County Employment in Government	Change #3	-0.1%	-1.0%
St. Louis County Employment in Education and Health	Change #3	0.0%	2.4%
St. Louis County Employment in Information Services	Change #3	0.0%	-10.5%
St. Louis County Employment in Leisure & Hopsitality	Change #3	0.1%	-0.3%
St. Louis County Total Personal Income	Change #3	3.2%	3.5%
St. Louis County Non-Wage Personal Income	Change #3	3.6%	3.2%
Itasca County Total Personal Income	Change #3	5.3%	5.9%
Itasca County Wage Distribution	Change #3	1.3%	4.9%
Morrison County Employment in Leisure & Hopsitality	Change #3	-0.6%	-1.0%
Morrison County Employment in Government	Change #3	-0.2%	0.1%
Morrison County Non-Wage Personal Income	Change #3	5.9%	1.1%
Douglas County Employment in Education and Health	Change #3	0.1%	1.2%
Industrial Production Index: Iron Ore Mining	Change #4	-7.2%	-6.9%
Industrial Production Index: Paper	Change #4	0.0%	-11.1%

Change #1 (Minnesota Power Area Employment, Regional Product, & Population Metrics) – When aggregated to annual values, total non-farm employment and population series for the Minnesota Power 13-County area show overall downward movement from the AFR 2019 historical data. The outlooks for each series have been updated to reflect the most current outlook by IHS Global Insight.

Change #2 (Duluth MSA Employment, Metro Product, Population, and Housing Metrics) – Most Duluth MSA variables are lower than in the AFR 2019 database. AFR 2019's Housing Starts preliminary value for 2018 has since been revised by IHS Global Insight to reflect a much higher (659 vs. 193) actual number. Similar to the 13-County metrics above, the outlooks for each series have been updated to reflect the most current outlook by IHS Global Insight.

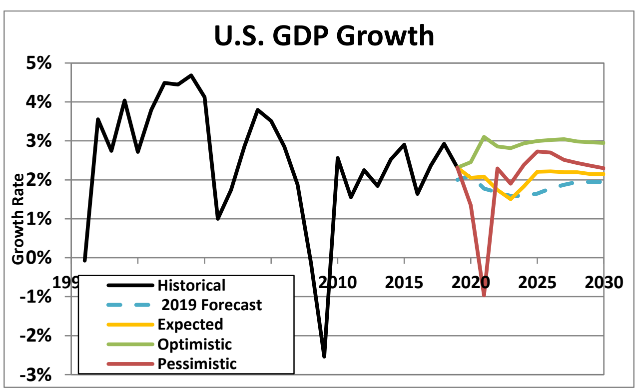
<u>Change #3 (Individual County Employment/Personal Income Metrics)</u> – Most employment and income variables for St. Louis/Itasca/Morrison/Douglas Counties have increased relative to the AFR 2019 historical data. The historical data and projections for each series have been updated to reflect the most current data available from IHS Global Insight.

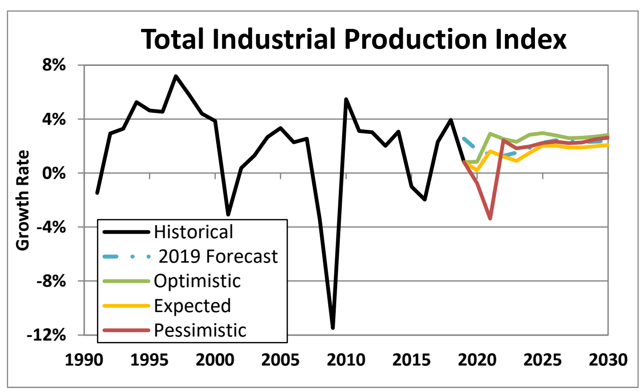
<u>Change #4 (Industrial Production Indexes)</u> – As noted in the *Inputs and Sources* section, historical IPI series were downloaded from the Federal Reserve Board's Data Download Program. The iron IPI in both the 2020 and 2019 databases is a Minnesota-only definition using the methodology described in the "AFR 2020 Inputs and Sources" section. It should be noted that the base year (2012 = 100) for all IPI is the same as last year's projection.

D. Overview of Key Inputs/Assumptions

i. National Economic Assumptions

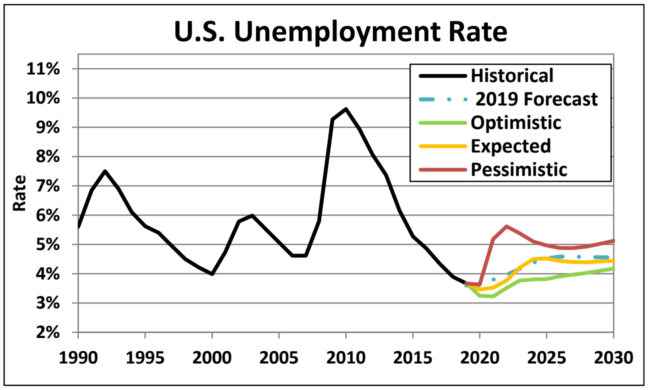
The national economic outlook is derived from IHS Global Insight and serves as the basis for Minnesota Power's regional economic model simulations. Some of the key outputs of the national economic forecast are GDP, IPI, unemployment rates, and auto sales. These variables are shown in Figures 8-11 below, for the Expected, Optimistic, and Pessimistic cases.

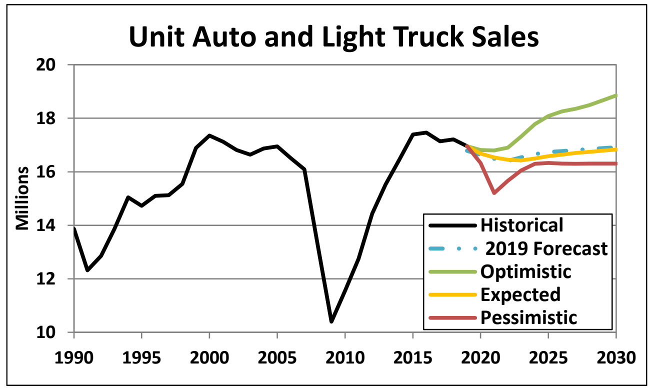




Figures 8 and 9: National Economic Outlook (GDP and Industrial Production)

The Expected case (yellow) macroeconomic outlook serves as the underlying assumption for AFR 2020. In the Expected case, U.S. GDP and IPI growth average 2.1 and 1.8 percent per year from 2020-2034, respectively.



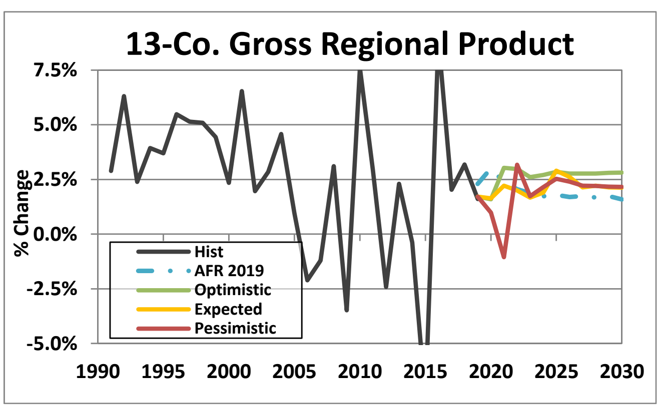


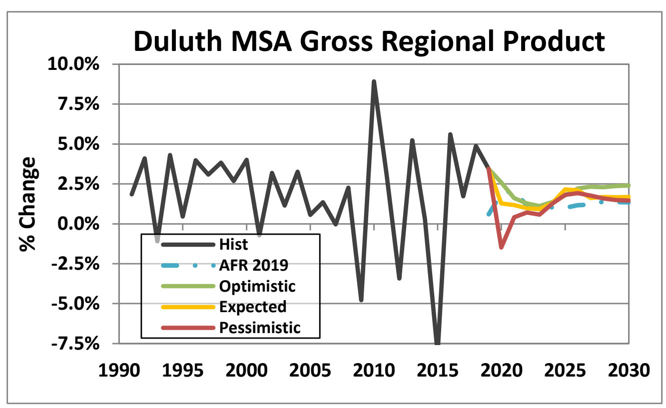
Figures 10 and 11: National Economic Outlook (Unemployment Rate and Auto Sales)

Figure 10 shows the unemployment rates in the three national outlooks all fluctuate slightly in the first few years of the forecast timeframe before reaching long term labor market stability consistent with the assumed rate of GDP growth. Assumptions of unit auto and light truck sales in Figure 11 show a similar pattern in the forecast timeframe with moderate decreases in the short-term and stabilization in the long-term.

ii. Regional Economic Assumptions

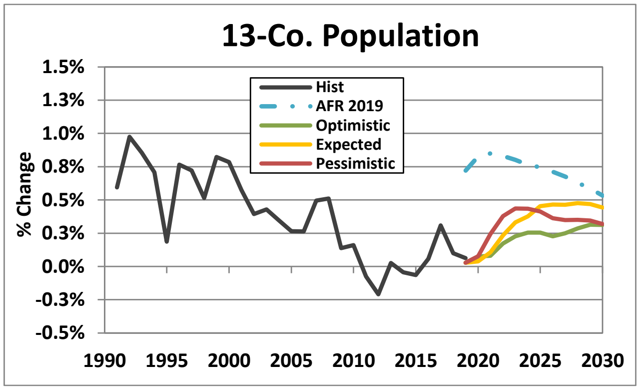
The Regional Economic Model provided by REMI is calibrated to the geographic area additively defined as 13 counties, 12 counties in Minnesota (Carlton, Cass, Crow Wing, Hubbard, Itasca, Koochiching, Lake, Morrison, Pine, Saint Louis, Todd, and Wadena) and one county in Wisconsin (Douglas). This is referred to as the “13-County Planning Area.” Minnesota Power expanded its database to include economic and demographic indicators at the Metropolitan Statistical Area level (this includes St. Louis and Carlton counties in Minnesota and Douglas County Wisconsin). The graphs below show alternative economic outlooks for both regions based on the high and low outlooks for the nation. The regional economic outlooks are further specified by incorporating scenario-specific inputs into REMI, as described in Section 1.C. Figures 12 and 13 compare the historical and projected growth rate of both regions’ product.

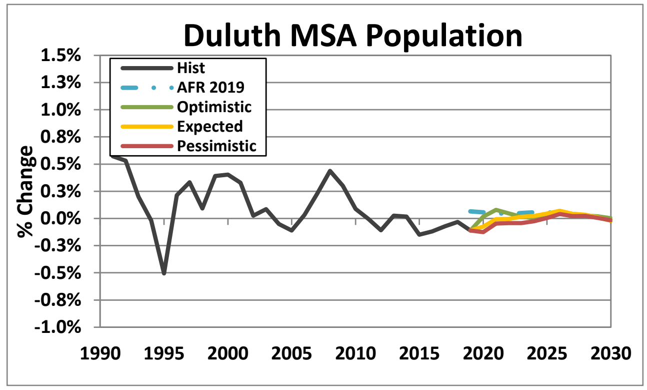




Figures 12 and 13: Regional Economic Outlooks (13-County Product and Duluth MSA Product)

The 13-County Planning Area's Gross Regional Product averages 2.1 percent per-year growth in the forecast timeframe whereas the Duluth MSA product averages just 1.5 percent per-year in the forecast timeframe. Population growth rates show a similar trend: the 13-County Planning Area grows at about 0.4 percent in the forecast timeframe and the Duluth MSA area population declines at -0.01 percent per-year. The difference in the two regions' historical and projected growth, shown below in Figures 14 and 15, demonstrates why Minnesota Power expanded its database to include both Duluth MSA and the 13-County regional data.





Figures 14 and 15: Regional Economic Outlooks (13-County Population and Duluth MSA Population)

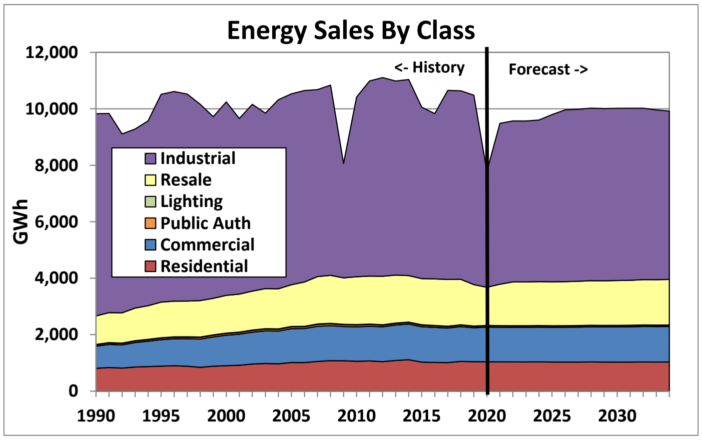
A. Econometric Model Documentation

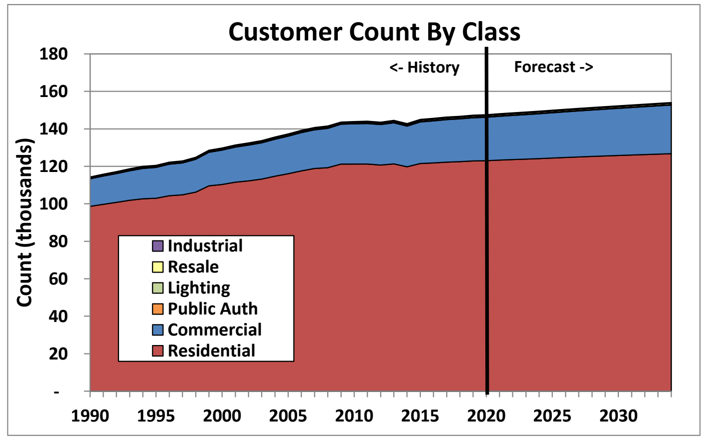
This section presents the statistical detail of all models utilized in the development of the AFR 2020 forecast. The model's structure, key diagnostic statistics, forecast results, and a discussion of the model are provided for added transparency.

Models are shown with each variable's coefficient, t-statistic, P-value, and VIF. A graph displays the historical series, growth rates for timeframes of interest, and compares this year's forecast to last year's forecast. A table shows a more focused view of the forecast with a shorter historical timeframe to examine year-over-year growth rates. Key diagnostic statistics for the OLS model are shown in a table in the bottom left corner of each page. Specific diagnostic criteria and modeling techniques discussed in this section are described in detail in Section B. Minnesota Power's Forecast Process under the heading *Specific Analytical Techniques.*

Minnesota Power offers a discussion of the modeling approach, econometric interpretations of key variables, and potential model issues for each model. This portion of the model documentation also compares this year's model with last year's model and notes any interesting findings or insights gained.

The forecast values shown in the chart and tables for each model combine the econometric output with specific load, energy, and customers count additions. The total energy sales outlook is shown below (left) with the total customer count outlook (right).





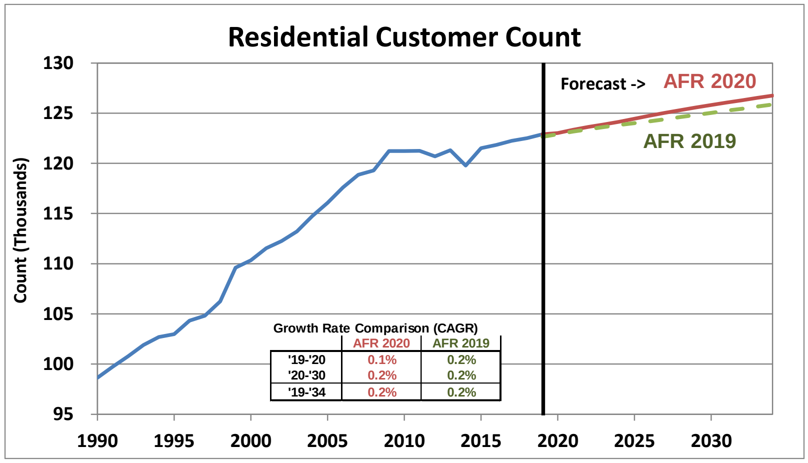
Figures 16 and 17: Projection of Energy Sales and Customer Count by Class

Minnesota Power did not develop a model to forecast Sales for Resale customer count. Minnesota Power currently has 16 resale customers, each of which has signed a service agreement. The loss or gain of a resale customer is therefore better accounted for by reviewing these agreements and communicating with customers. Econometric models are not appropriate for estimating future resale customer counts.

Residential Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2019
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications			
Variable	Coefficient	P-Value	HAC-P-Value	VIF
CONST	95,425.11	0.00%	0.00%	
Time_Trend	94.57	0.00%	0.00%	
Bill_Res_1	(1,983.41)	0.00%	0.00%	
Bill_Res_2	(3,554.99)	0.00%	0.00%	
Bi_2012_2034	16,897.34	0.00%	0.00%	
Trend_2012_2034	(72.51)	0.00%	0.00%	
PBS_13_t	0.24	0.00%	9.00%	2.30



Residential Customer Count

	Count	Y/Y Growth
2009	121,217	
2010	121,235	0.0%
2011	121,251	0.0%
2012	120,697	-0.5%
2013	121,314	0.5%
2014	119,789	-1.3%
2015	121,515	1.4%
2016	121,836	0.3%
2017	122,253	0.3%
2018	122,506	0.2%
2019	122,895	0.3%
2020	123,012	**0.1%**
2021	123,356	**0.3%**
2022	123,626	**0.2%**
2023	123,870	**0.2%**
2024	124,141	**0.2%**
2025	124,450	**0.2%**
2026	124,749	**0.2%**
2027	125,030	**0.2%**
2028	125,303	**0.2%**
2029	125,561	**0.2%**
2030	125,811	**0.2%**
2031	126,052	**0.2%**
2032	126,290	**0.2%**
2033	126,531	**0.2%**
2034	126,759	**0.2%**

Model Statistics	Magnitude
Adjusted R^2	99.7%
AIC	12.37
SIC	12.44
Degrees of Freedom	353
Durban-Watson	0.6
MAPE	0.31%
In-Sample RMSE	480
Out-of-Sample RMSE	659

Model Discussion

The AFR 2020 forecast of residential customer count is very similar to the AFR 2019 outlook. The forecast annual growth rate remained the same at 0.2%. The AFR 2020 projected customer count is about 775 customers (0.6%) higher than the AFR 2019 outlook by 2030.

The key economic driver of customer growth this year is Employment in the Professional Business Services sector (13-County). This differs from last year's model which utilized both Professional Business Services (13-County) and Education & Health employment (Duluth MSA).

Minnesota Power's econometric interpretation of the key drivers is as follows: For each new Professional & Business Services employee, the customer count should increase by about 0.24. This is in addition to a general upward trend over time.

The combination of a binary and a trend variable for the 2012-2034 timeframe marks a shift in the level and trend of the estimate to align with recent customer growth. These variables effectively shift the first forecast year (2020) to align with the last historical year (2019). Without these corrective variables, a small but growing divergence between actual and predicted customer growth in the late historical timeframe suggests the economic indicators alone would overstate customer count. Without these binary and trend variables, the model would project an increase of about 3,400 customers from 2019 to 2020 (a 2.7% increase).

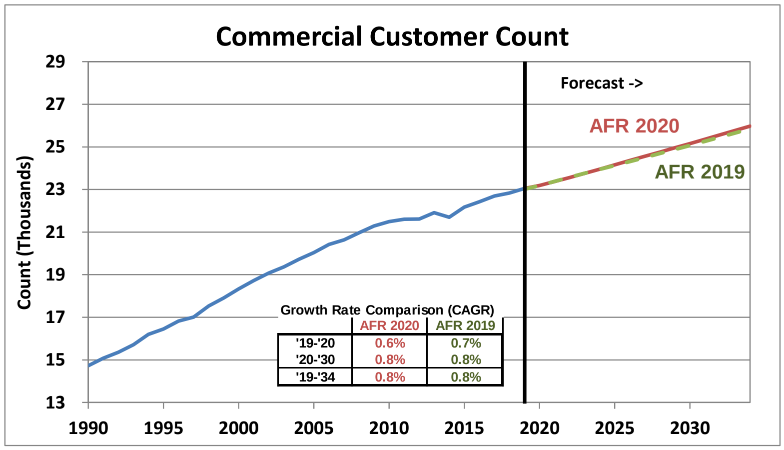
Two binary variables (Bill_Res) account for seasonal billing between 1994 and 2001. Due to accounting practices, during this timeframe the recorded customer counts from November to May are 2,000-6,000 lower than from June to October. Previous years' residential customer count models also utilized these variables.

This year's model is highly comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a high goodness-of-fit, and the low Schwarz information criterion (SIC) indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample and Out-sample error metrics are nearly identical to last year: In-sample MAPE is 0.31% vs. 0.31% in the 2019 model, and Out-sample RMSE is 659 vs. 658 in the 2019 model. The low Variance Inflation Factors (VIF) of each economic variable proves there is no significant multicollinearity among non-binary, non-trend variables.

Commercial Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2019
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications			
Variable	Coefficient	P-Value	HAC-P-Value	VIF
CONST	13,401.80	0.00%	0.00%	
Time_Trend	28.29	0.00%	0.00%	
Bi_2010_2034	3,197.26	0.00%	0.00%	
Trend_2010_2034	(13.50)	0.00%	0.00%	
Info_StLou_t	0.25	0.00%	0.00%	3.50
GRP_13_t	38.91	0.00%	0.01%	1.90



Commercial Customer Count

	Count	Y/Y Growth
2009	21,287	
2010	21,491	1.0%
2011	21,603	0.5%
2012	21,614	0.1%
2013	21,915	1.4%
2014	21,697	-1.0%
2015	22,170	2.2%
2016	22,420	1.1%
2017	22,695	1.2%
2018	22,834	0.6%
2019	23,047	0.9%
2020	23,186	**0.6%**
2021	23,371	**0.8%**
2022	23,560	**0.8%**
2023	23,754	**0.8%**
2024	23,951	**0.8%**
2025	24,156	**0.9%**
2026	24,360	**0.8%**
2027	24,559	**0.8%**
2028	24,757	**0.8%**
2029	24,955	**0.8%**
2030	25,154	**0.8%**
2031	25,357	**0.8%**
2032	25,561	**0.8%**
2033	25,766	**0.8%**
2034	25,969	**0.8%**

Model Statistics	Magnitude
Adjusted R^2	99.9%
AIC	9.15
SIC	9.22
Degrees of Freedom	354
Durban-Watson	1.4
MAPE	0.34%
In-Sample RMSE	96
Out-of-Sample RMSE	99

Model Discussion

The AFR 2020 forecast of commercial customer count is very similar to the AFR 2019 outlook. The forecast annual growth rate remained unchanged from last year at 0.8%. The AFR 2020 projected customer count is about 85 customers (0.3%) higher than the AFR 2019 outlook by 2030.

Key economic drivers of customer growth include Employment in the Information sector (St. Louis County), as well as 13-County Gross Regional Product – the same drivers as AFR 2019. 13-County Gross Regional Product has been used in past AFR commercial models, so this is not new or unintuitive. Employment in the Information sector has been leveraged as an indicator of commercial customer account growth for several years now.

Minnesota Power's econometric interpretation of the key drivers is as follows: For each job added in the Information sector, the commercial customer count should increase by about 0.25. As Gross Regional Product increases by $1 Billion, commercial customer count should increase by about 39. These impacts are in addition to a general upward trend over time.

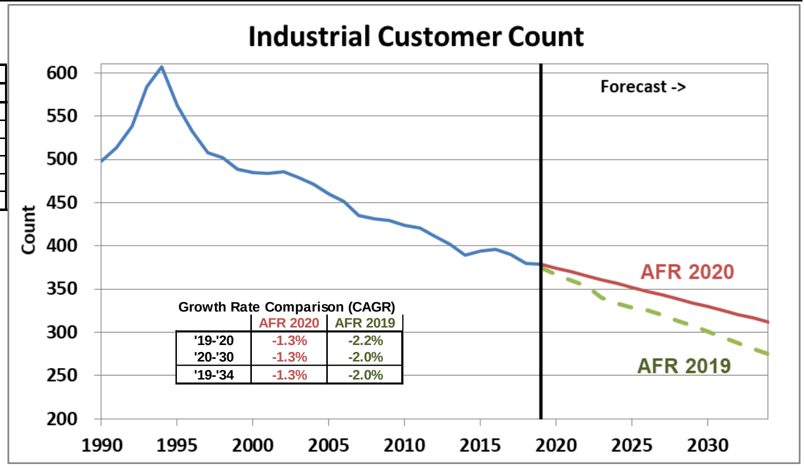
The combination of a binary and a trend variable for the 2010-2034 timeframe mark a shift in the level and trend of the estimate to align with recent customer growth. These variables effectively shift the first forecast year (2020) to align with the last historical year (2019). Without these corrective variables, a small but growing divergence between actual and predicted customer growth suggests the economic indicators alone would overstate customer count, and the 2020 forecast value confirms this. Without these binary and trend variables, the model would project an increase of about 820 customers from 2019 to 2020 (a 3.6% increase).

This year's model is highly comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a high goodness-of-fit, and the low SIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample and Out-sample error metrics are nearly identical: In-sample MAPE is 0.34% vs. 0.34% in the 2019 model, and Out-sample RMSE is 99 vs. 99 in the 2019 model. The low Variance Inflation Factors (VIF) of each economic variable proves there is no significant multicollinearity among non-binary, non-trend variables.

Industrial Customer Count - Expected Scenario

Estimation Start/End: 2/1990 - 12/2019
Unit Modeled/Forecast: Monthly Customer Count

	Model Specifications			
Variable	Coefficient	P-Value	HAC-P-Value	VIF
CONST	564.77	0.00%	0.00%	
Time_Trend	(0.57)	0.00%	0.00%	
Bi_2014_2034	(54.52)	19.62%	3.54%	
Trend_2014_2034	0.19	14.70%	8.87%	
Gov_13_diff	0.001	70.80%	6.04%	1.00
ProductPerCap_13_diff	22,272.83	4.75%	8.36%	1.10



Industrial Customer Count		
	Count	Y/Y Growth
2009	429	
2010	424	-1.2%
2011	421	-0.7%
2012	411	-2.4%
2013	402	-2.2%
2014	390	-3.1%
2015	394	1.0%
2016	396	0.6%
2017	390	-1.6%
2018	380	-2.5%
2019	379	-0.3%
2020	374	**-1.3%**
2021	370	**-1.1%**
2022	365	**-1.3%**
2023	360	**-1.3%**
2024	356	**-1.1%**
2025	352	**-1.1%**
2026	348	**-1.4%**
2027	343	**-1.3%**
2028	339	**-1.3%**
2029	334	**-1.3%**
2030	330	**-1.3%**
2031	325	**-1.3%**
2032	321	**-1.4%**
2033	317	**-1.4%**
2034	312	**-1.4%**

Model Statistics	Magnitude
Adjusted R^2	87.1%
AIC	6.19
SIC	6.25
Degrees of Freedom	353
Durban-Watson	0.0
MAPE	2.39%
In-Sample RMSE	22
Out-of-Sample RMSE	27

Model Discussion

The AFR 2020 forecast of industrial customer count growth is similar to the AFR 2019 outlook. The key economic drivers of customer count are Public sector employment (13-County) and 13-County Product per-capita. The AFR 2019 model for industrial customer count was driven by Total Non-Farm Employment (13-County) and Product per-capita (13-County).

Minnesota Power's econometric interpretation of the key drivers are as follows: As the month-to-month change in 13-County Public sector employment increases by 1,000 the customer count should increase by 1. As the month-to-month change in 13-County Product per-capita increases by 0.0001 the customer count should increase by 2.2. These impacts are in addition to a general downward trend over time, as indicated by the negatively signed trend variable.

The combination of a binary and a trend variable for the 2014-2034 timeframe mark a shift in the level and trend of the estimate to align with recent customer growth. These variables effectively shift the first forecast year (2020) to align with the last historical year (2019). Without these corrective variables, a small but growing divergence between actual and predicted customer growth suggests the economic indicators alone would understate customer count, and the 2020 forecast value confirms this. Without these binary and trend variables, the model would project a decrease of about 15 customers from 2019 to 2020 (a -4.0% decrease).

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's moderate goodness-of-fit, and the low SIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample and Out-sample error metrics are very similar: In-sample MAPE is 2.39% vs. 2.59% in the AFR 2019 model, and Out-sample RMSE is 27.2 vs. 26.2 in the 2019 model. The low Variance Inflation Factor (VIF) of the economic variable proves there is no significant multicollinearity among non-binary, non-trend variables.

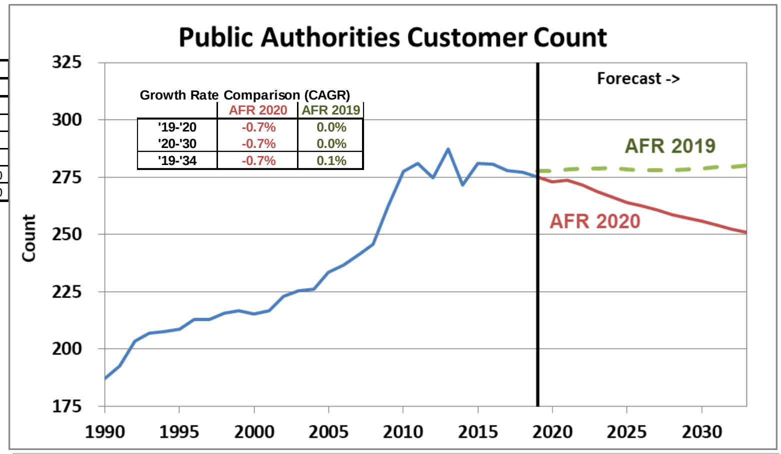
Public Authorities Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2019
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications			
Variable	Coefficient	P-Value	HAC-P-Value	VIF
CONST	(250.16)	0.00%	0.00%	
Bi_7_2009	57.31	0.00%	0.00%	
Bi_2013_2034	(61.82)	0.00%	0.26%	
Trend_2013_2034	0.26	0.00%	0.18%	
TotNonF_13_t	0.00	0.00%	0.00%	1.20
MSA_Edu_Health_t	9.779	0.00%	0.00%	2.00

Public Auth. Customer Count		
	Count	Y/Y Growth
2009	262	
2010	278	5.8%
2011	281	1.2%
2012	275	-2.3%
2013	287	4.6%
2014	272	-5.5%
2015	281	3.4%
2016	281	-0.1%
2017	278	-1.0%
2018	277	-0.3%
2019	275	-0.7%
2020	273	**-0.7%**
2021	274	**0.2%**
2022	272	**-0.7%**
2023	269	**-1.1%**
2024	266	**-0.9%**
2025	264	**-0.9%**
2026	263	**-0.5%**
2027	261	**-0.8%**
2028	259	**-0.7%**
2029	257	**-0.6%**
2030	256	**-0.5%**
2031	254	**-0.6%**
2032	252	**-0.7%**
2033	251	**-0.6%**
2034	249	**-0.7%**

Model Statistics	Magnitude
Adjusted R^2	95.1%
AIC	3.97
SIC	4.03
Degrees of Freedom	354
Durban-Watson	0.4
MAPE	2.19%
In-Sample RMSE	7.2
Out-of-Sample RMSE	10.1



Model Discussion

The AFR 2020 forecast of public authorities customer count growth is lower than the AFR 2019 forecast. Key economic drivers of customer growth include 13-County Total Non-Farm employment and Employment in the Education & Health sector (Duluth MSA). Last year's model was driven by Employment in the Education & Health sector (Duluth MSA) and Public sector employment (13-County).

Minnesota Power's econometric interpretation of the key drivers is as follows: For every 1,000 jobs added to Total Non-Farm employment, the customer should increase by about 1. For every 1,000 jobs added in the Education & Health sector at the Duluth MSA level, the customer count should increase by about 9.8.

A binary variable starting in July-2009 accounts for a step-change or "systematic shift" in the historical accounting data. The corrective binary variables shift the forecast up slightly to avoid improbable decreases in customer counts, but do not impact the forecast trajectory; this is determined by the economic variables.

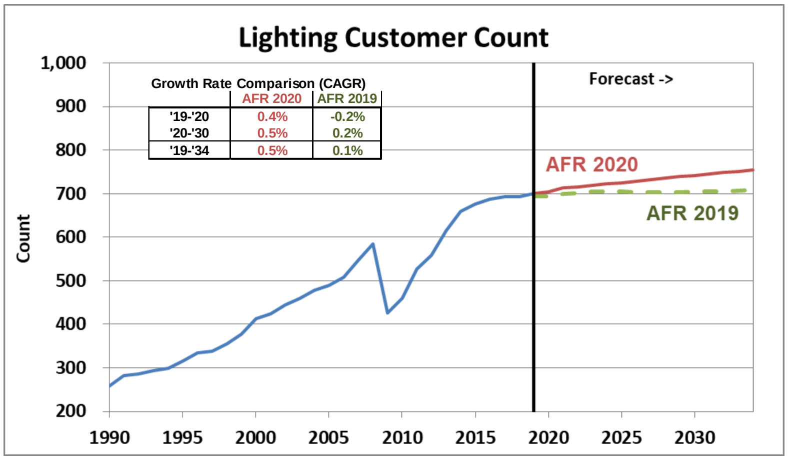
The combination of a binary and a trend variable for the 2013-2034 timeframe mark a shift in the level and trend of the estimate to align with recent customer growth. These variables effectively shift the first forecast year (2020) to align with the last historical year (2019). Without these corrective variables, a small but growing divergence between actual and predicted customer growth suggests the economic indicators alone would understate customer count, and the 2020 forecast value confirms this. Without these binary and trend variables, the model would project a decrease of about 11 customers from 2019 to 2020 (a -4.0% decrease).

This year's model is highly comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a high goodness-of-fit, and the low SIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample and Out-sample error metrics are similar: In-sample MAPE is 2.19% vs. 1.49% in the 2019 model, and Out-sample RMSE is 10.1 vs. 6.0 in the 2019 model. The low Variance Inflation Factors (VIF) of each economic variable proves there is no significant multicollinearity among non-binary, non-trend variables.

Street Lighting Customer Count - Expected Scenario

Estimation Start/End:	2/1990 - 12/2019
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications			
Variable	Coefficient	P-Value	HAC-P-Value	VIF
CONST	(197.09)	0.00%	1.54%	
Time_Trend	1.32	0.00%	0.00%	
Bi_7_2009	(1,001.22)	0.00%	0.00%	
Trend_7_2009	3.56	0.00%	0.00%	
Bi_2014_2034	1,182.66	0.00%	0.00%	
Trend_2014_2034	(4.01)	0.00%	0.00%	
EduH_13_t	0.01	0.00%	0.00%	3.70
MSA_Pop_diff	53.621	0.00%	3.88%	1.30



Lighting Customer Count

	Count	Y/Y Growth
2009	426	
2010	460	7.9%
2011	527	14.5%
2012	559	6.1%
2013	615	10.0%
2014	660	7.4%
2015	677	2.6%
2016	688	1.7%
2017	693	0.8%
2018	693	-0.1%
2019	701	1.1%
2020	704	**0.4%**
2021	713	**1.2%**
2022	715	**0.3%**
2023	718	**0.5%**
2024	722	**0.5%**
2025	725	**0.4%**
2026	729	**0.5%**
2027	732	**0.5%**
2028	735	**0.4%**
2029	739	**0.5%**
2030	742	**0.4%**
2031	746	**0.4%**
2032	748	**0.3%**
2033	751	**0.4%**
2034	755	**0.5%**

Model Statistics	Magnitude
Adjusted R^2	99.4%
AIC	4.79
SIC	4.88
Degrees of Freedom	350
Durban-Watson	0.3
MAPE	1.90%
In-Sample RMSE	11
Out-of-Sample RMSE	14

Model Discussion

The AFR 2020 forecast of street lighting customer count growth is higher than the AFR 2019 outlook. The key drivers of customer growth include Employment in the Education & Health sector (13-County) and Duluth MSA Population – the same variables as last year's model.

Minnesota Power's econometric interpretation of the key drivers is as follows: As 13-County employment in Education & Health increases by 1,000, street lighting customer count should increase by about 12 customers. As the month-to-month change in Duluth MSA population increases by 1,000, street lighting customer count should increase by about 54 customers. These impacts are in addition to a general upward trend over time.

A combination of a binary and trend variable starting in July-2009 account for a step-change or "systematic shift" in the historical accounting data.

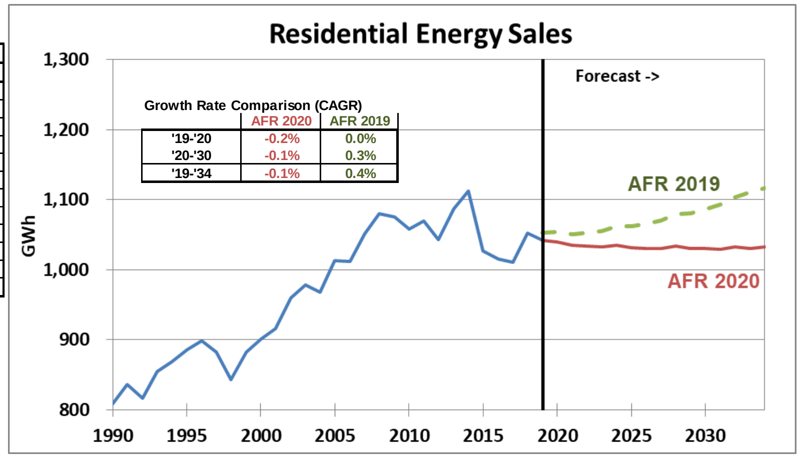
A combination of a binary variable for 2014-2034 and trend variable denoting the 2014-2034 timeframe shift the level and trend of the estimate to align with recent customer growth. These variables effectively shift the first forecast year (2020) to align with the last historical year (2019). Without these corrective variables, a small but growing divergence between actual and predicted customer growth suggests the economic indicators alone would overstate customer count, and the 2020 forecast value confirms this. Without these binary and trend variables, the model would project an increase of about 75 customers from 2019 to 2020 (a 10.6% increase).

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a quality goodness-of-fit, and the low SIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample and Out-sample error metrics are very similar: In-sample MAPE is 1.90% vs. 1.95% in the 2019 model, and Out-sample RMSE is 14 vs. 14 in the 2019 model. The low Variance Inflation Factor (VIF) of the economic variable proves there is no significant multicollinearity among non-binary, non-trend variables.

Residential Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2019
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (kWh)

	Model Specifications			
Variable	Coefficient	P-Value	HAC-P-Value	VIF
CONST	17.21	0.00%	0.00%	
Bi_Feb	(1.45)	0.04%	0.95%	
Bi_Mar	(2.14)	0.00%	0.00%	
Bi_Apr	(1.74)	0.00%	0.00%	
Bi_May	(1.64)	0.01%	0.00%	
Bi_Jun	(1.43)	0.04%	0.00%	
Bi_Oct	(2.76)	0.00%	0.00%	
Bi_Nov	(2.40)	0.00%	0.00%	
Bi_2008_2034	1.65	0.00%	0.00%	
EE_Res	(0.00001)	0.51%	0.39%	
Dul_HDDpd	0.25	0.00%	0.00%	2.70
Dul_CDDpd	0.93	0.00%	0.00%	2.30



Residential Energy Sales		
	MWh	Y/Y Growth
2009	1,075,117	
2010	1,057,476	-1.6%
2011	1,069,856	1.2%
2012	1,043,281	-2.5%
2013	1,086,481	4.1%
2014	1,112,579	2.4%
2015	1,026,454	-7.7%
2016	1,015,465	-1.1%
2017	1,010,955	-0.4%
2018	1,052,800	4.1%
2019	1,042,353	-1.0%
2020	1,039,776	**-0.2%**
2021	1,034,896	**-0.5%**
2022	1,033,882	**-0.1%**
2023	1,033,118	**-0.1%**
2024	1,035,475	**0.2%**
2025	1,030,922	**-0.4%**
2026	1,029,984	**-0.1%**
2027	1,029,924	**0.0%**
2028	1,033,730	**0.4%**
2029	1,029,932	**-0.4%**
2030	1,029,812	**0.0%**
2031	1,029,421	**0.0%**
2032	1,032,937	**0.3%**
2033	1,030,569	**-0.2%**
2034	1,032,547	**0.2%**

Model Statistics	Magnitude
Adjusted R^2	84.4%
AIC	1.24
SIC	1.37
Degrees of Freedom	348
Durban-Watson	2.0
MAPE	5.69%
In-Sample RMSE	1.8
Out-of-Sample RMSE	1.9

Model Discussion

The AFR 2020 forecast of residential energy use is lower than the AFR 2019 outlook. The graph shown above shows the final residential energy sales outlook, which combines the econometric forecast (i.e. the product of the use-per-customer per day model and the customer count model) and the projected impacts of electric vehicle and distributed solar adoption.

The AFR 2020 residential per-customer use model does not use an employment or demographic indicator variable as these variables rarely correlate well with per-customer usage and often are not intuitive or explainable. Instead, the Company uses weather and seasonal binary variables to indicate month-to-month variation in sales, a time-trend to indicate long-term underlying growth, and Energy Efficiency variables to explain recent changes in seasonality and long-term underlying growth.

The “EE_Res” variable represents the cumulative effects of all past conservation measures on each year’s sales, and the annual energy savings value is leveraged for all 12 monthly observations of a given year. The Energy Efficiency variable suggests residential energy consumption to be about 30,000 MWh (2.8%) lower in 2020 than it would have been in the absence of all past Minnesota Power CIP and organic, customer-driven conservation.

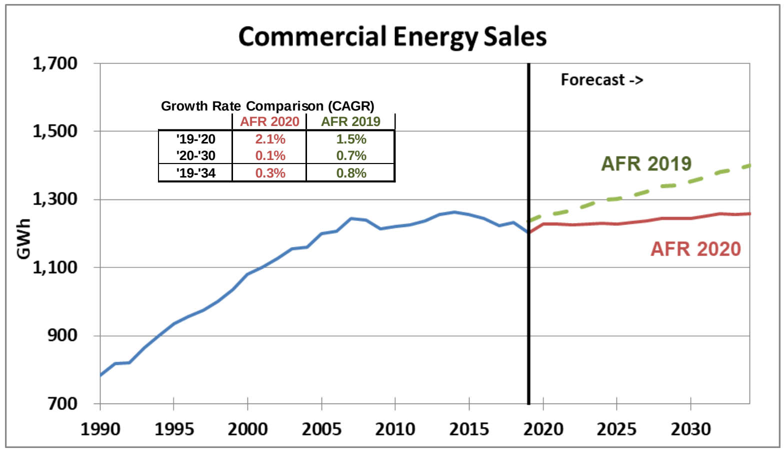
The AFR 2020 and AFR 2019 models both use simple monthly HDD and CDD (per-day) specification. Simplifying the weather variable definition in both respects did not seem to negatively affect model statistics or output. This approach guarantees accurate after-the-fact weather-normalization and was applied in all other weather-sensitive models as well.

This year’s model is comparable to last year’s in terms of statistical quality. The Adjusted R-Squared indicates there’s a quality goodness-of-fit, and the low SIC indicates a highly parsimonious model. The HAC-Adjusted P-values (“HAC-P-Value”) suggests all variables’ coefficients’ are significant. In-sample and Out-sample error metrics are similar: In-sample MAPE is 5.69% vs. 5.44% in the 2019 model, and Out-sample RMSE is 1.9 vs. 1.8 in the 2019 model. The low Variance Inflation Factors (VIF) of each economic variable proves there is no significant multicollinearity among non-binary, non-trend variables.

Commercial Energy Use - Expected Scenario

Estimation Start/End:	2/1990 - 12/2019
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (kWh)

	Model Specifications			
Variable	Coefficient	P-Value	HAC-P-Value	VIF
CONST	31.25	23.23%	4.39%	
Time_Trend	0.03	1.21%	0.00%	
Bi_Jan	(7.97)	0.01%	0.03%	
Bi_Apr	(13.71)	0.00%	0.00%	
Bi_May	(10.96)	0.00%	0.00%	
Bi_Aug	10.44	0.00%	0.00%	
Bi_Sep	9.93	0.00%	0.00%	
Bi_Oct	(12.64)	0.00%	0.00%	
Bi_Nov	(12.34)	0.00%	0.00%	
EE_Com	(0.00004)	0.29%	0.00%	
Dul_HDDpd_Seas	0.4240	0.00%	0.00%	3.10
Dul_CDDpd	3.48	0.00%	0.00%	2.30
EmpltoPop_13_diff	799.91	0.48%	1.23%	1.00
MSA_Service_t	1.34	0.00%	0.00%	3.20



Commercial Energy Sales

	MWh	Y/Y Growth
2009	1,212,778	
2010	1,221,753	0.7%
2011	1,226,174	0.4%
2012	1,237,386	0.9%
2013	1,256,540	1.5%
2014	1,262,464	0.5%
2015	1,254,681	-0.6%
2016	1,243,045	-0.9%
2017	1,223,786	-1.5%
2018	1,233,117	0.8%
2019	1,202,403	-2.5%
2020	1,227,755	**2.1%**
2021	1,227,491	**0.0%**
2022	1,226,346	**-0.1%**
2023	1,226,790	**0.0%**
2024	1,230,816	**0.3%**
2025	1,228,137	**-0.2%**
2026	1,232,659	**0.4%**
2027	1,237,501	**0.4%**
2028	1,244,424	**0.6%**
2029	1,243,374	**-0.1%**
2030	1,245,153	**0.1%**
2031	1,250,433	**0.4%**
2032	1,257,801	**0.6%**
2033	1,256,776	**-0.1%**
2034	1,257,757	**0.1%**

Model Statistics	Magnitude
Adjusted R^2	61.0%
AIC	4.41
SIC	4.57
Degrees of Freedom	345
Durban-Watson	2.7
MAPE	4.47%
In-Sample RMSE	8.9
Out-of-Sample RMSE	9.2

Model Discussion

The AFR 2020 forecast of commercial energy use is lower than the AFR 2019 estimate. The graph above shows the final residential energy sales outlook, which combines the econometric forecast (i.e. the product of the use-per-customer per day model and the customer count model) and the projected impacts of distributed solar adoption.

Key drivers of this year's commercial energy use model are the 13-County Employment-to-Population ratio and Services sector (Duluth MSA) employment. Last year's model was driven by Total Non-Farm Employment (MSA) and Public Sector Employment (13-County).

Minnesota Power's econometric interpretation of the key drivers is as follows: As the month-to-month change in the Employment-to-Population ratio increases by .1, monthly commercial use-per customer should increase by about 2,430 kWh. For every 1,000 Services sector jobs added in the Duluth MSA, monthly commercial use-per-customer should increase by about 41 kWh.

The AFR 2020 model uses an Energy Efficiency variable as a predictor of commercial per-customer sales: the "EE_Com" variable represents the cumulative effects of all past conservation measures on each year's sales, and the annual energy savings value is leveraged for all 12 monthly observations of a given year. The Energy Efficiency variable suggests commercial energy consumption to be about 10,000 MWh (0.8%) lower in 2020 than it would have been in the absence of all past Minnesota Power CIP and organic, customer-driven conservation.

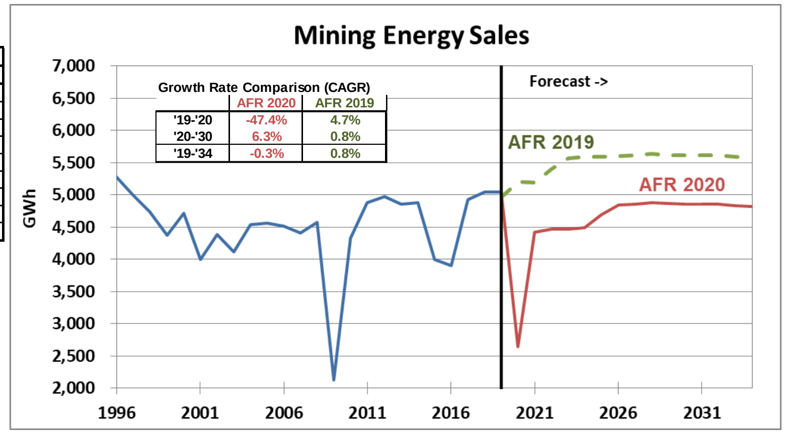
This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared of 61% indicates there's just a moderate traditional "goodness-of-fit", but this was the case in last year's model as well (Adjusted R-Squared was also 61%) and the Company does not consider the R-Squared an indicator of predictive quality. Minnesota Power's objective metric is the Out-Sample Root Mean Square Error.

The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample and Out-sample error metrics are similar: In-sample MAPE is 4.47% vs. 4.41% in the 2019 model, and Out-sample RMSE is 9.19 vs. 9.13 in the 2019 model. The low Variance Inflation Factors (VIF) of each economic variable proves there is no significant multicollinearity among non-binary, non-trend variables.

Mining and Metals Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2019
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications			
Variable	Coefficient	P-Value	HAC-P-Value	VIF
CONST	(47,167.07)	0.00%	0.02%	
Bi_Mine1	(1,464.92)	0.00%	0.00%	
Bi_Mine2	1,200.15	0.00%	0.00%	
Trend_Mine2	(46.14)	0.00%	0.00%	
Bi_Mine3	(409.85)	1.04%	3.01%	
Bi_Mine4	(2,619.38)	0.00%	0.00%	
Bi_Mine5	(427.93)	0.95%	0.42%	
MSA_Pop_t	185.81	0.00%	0.00%	1.70
MN_Iron_IPI_t	79.33	0.00%	0.00%	2.70



Mining and Metals Energy Sales

	MWh	Y/Y Growth
2009	2,124,675	
2010	4,324,450	103.5%
2011	4,874,331	12.7%
2012	4,968,517	1.9%
2013	4,851,094	-2.4%
2014	4,879,520	0.6%
2015	4,000,557	-18.0%
2016	3,906,570	-2.3%
2017	4,930,188	26.2%
2018	5,039,138	2.2%
2019	5,038,704	0.0%
2020	2,648,800	**-47.4%**
2021	4,426,719	**67.1%**
2022	4,466,021	**0.9%**
2023	4,468,010	**0.0%**
2024	4,491,561	**0.5%**
2025	4,688,812	**4.4%**
2026	4,848,086	**3.4%**
2027	4,854,432	**0.1%**
2028	4,874,239	**0.4%**
2029	4,863,482	**-0.2%**
2030	4,860,282	**-0.1%**
2031	4,854,562	**-0.1%**
2032	4,857,486	**0.1%**
2033	4,830,777	**-0.5%**
2034	4,815,253	**-0.3%**

Model Statistics	Magnitude
Adjusted R^2	89.3%
AIC	12.79
SIC	12.91
Degrees of Freedom	279
Durban-Watson	1.4
MAPE	4.63%
In-Sample RMSE	590
Out-of-Sample RMSE	713

Model Discussion

The AFR 2020 outlook for mining and metals energy use is significantly lower than the AFR 2019 projection. The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load additions.

All econometric models use the "expected" rate of national economic growth per IHS Global Insight's January 2020 release. However, the Mining class for AFR 2020 has been adjusted per the May 2020 release that includes recessionary impacts of Covid19. The Company elected to go this route – a single, post-econometric modeling class adjustment vs. performing an entire re-model of all variables – as the Mining class represents a substantial share of total energy sales. Without an adjustment, forecast error would be large, and a complete re-model of all variables was deemed unnecessary.

Key drivers of this year's mining energy use model are Duluth MSA Population and the Minnesota (MN) Iron IPI. The econometric interpretation of economic variables are as follows: As Population (Duluth MSA) increases by 1,000, Minnesota Power's mining and metals customers' should increase monthly use by about 5,650 MWh. For each 1-unit increase in the MN IPI for Iron, Minnesota Power's mining and metals customers' should increase monthly use by about 2,415 MWh.

This year's model incorporates some of the same binary variables as AFR 2019 to control for known or suspected definitional changes in the historical mining energy sales series. These variables have been added with the goal of avoiding bias in the IPI's coefficient for these past definitional changes in the mining and metals sales series.

The "Bi_Mine1" binary variable denotes a timeframe from May-2015 to Feb-2017, when significant mining load was idled. The variable accounts for a change in relationship between Minnesota Power mining customer energy use and the MN IPI, and allow for a more exact estimation of the relationship

"Bi_Mine2" and "Trend_Mine2" are binary and trend variables (respectively) that denote the timeframe from 1996-2001, when a large mining customer ended operations. The two variables account for a change in relationship between Minnesota Power mining customer energy and the MN IPI, and allow for a more exact estimation of the relationship during the current paradigm.

The "Bi_Mine3" binary variable denotes certain months between Sep-2013 and Apr-2015 where the model would systematically over-forecast monthly energy use by about 3.3%. This variable accounts for a possible change in the regular relationship between mining customer usage and the MN IPI.

The "Bi_Mine4" binary variable denotes the recession period from early 2009 to early 2010 where the model would systematically over-forecast monthly energy use by about 60%. This variable accounts for a possible change in the regular relationship between mining customer usage and the MN IPI.

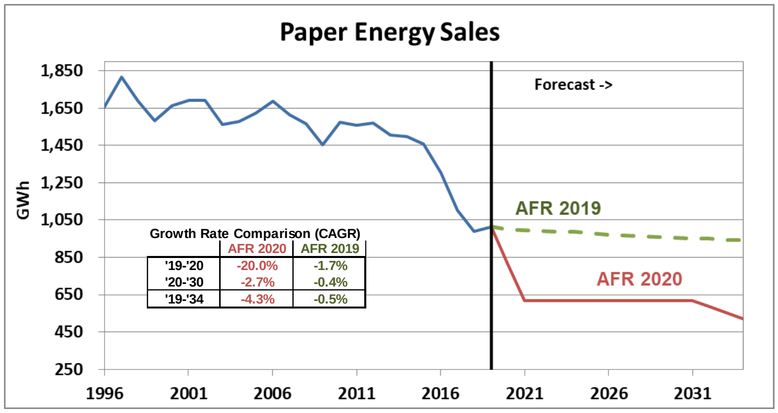
The "Bi_Mine5" binary variable denotes known seasonal operations specific to Minnesota Power's mining customers.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a quality goodness-of-fit, and the low SIC indicates a highly parsimonious model. The P-values suggests all variables' coefficients' are significant. In-sample and Out-sample error metrics are similar: In-sample MAPE is 4.63% vs. 4.84% in the 2019 model, and Out-sample RMSE is 713 vs. 724 in the 2019 model. The low Variance Inflation Factor (VIF) of the economic variable proves there is no significant multicollinearity among non-binary, non-trend variables.

Paper and Wood Products Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2019
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications			
Variable	Coefficient	P-Value	HAC-P-Value	VIF
CONST	4,228.90	0.00%	0.00%	
Time_Trend	(1.05)	0.00%	1.99%	
Bi_Mar	158.12	0.28%	0.00%	
Bi_Jun	214.53	0.01%	0.00%	
Bi_Jul	109.47	3.78%	3.42%	
Bi_Aug	327.08	0.00%	0.00%	
Bi_Sep	324.37	0.00%	0.00%	
Bi_Oct	310.91	0.00%	0.00%	
Bi_Nov	126.41	1.76%	0.70%	
Bi_Paper1	(412.16)	0.34%	0.00%	
Bi_Paper2	(562.40)	0.01%	0.00%	
Bi_Paper3	(318.27)	6.27%	0.01%	
Bi_2017	(164.83)	12.41%	0.56%	
Bi_2016_2034	2,193.07	23.34%	2.04%	
Trend_2016_2034	(6.15)	28.90%	3.82%	
Paper_IPI_diff	25.46	2.06%	0.58%	1.00



Paper/Wood Energy Sales

	MWh	Y/Y Growth
2009	1,453,928	
2010	1,572,565	8.2%
2011	1,559,519	-0.8%
2012	1,570,852	0.7%
2013	1,505,113	-4.2%
2014	1,498,810	-0.4%
2015	1,456,091	-2.9%
2016	1,302,920	-10.5%
2017	1,104,160	-15.3%
2018	987,208	-10.6%
2019	1,013,971	2.7%
2020	811,601	**-20.0%**
2021	617,701	**-23.9%**
2022	617,701	**0.0%**
2023	617,701	**0.0%**
2024	616,628	**-0.2%**
2025	617,701	**0.2%**
2026	617,701	**0.0%**
2027	617,701	**0.0%**
2028	616,628	**-0.2%**
2029	617,701	**0.2%**
2030	617,701	**0.0%**
2031	616,721	**-0.2%**
2032	586,697	**-4.9%**
2033	553,663	**-5.6%**
2034	522,134	**-5.7%**

Model Statistics	Magnitude
Adjusted R^2	80.4%
AIC	10.96
SIC	11.16
Degrees of Freedom	272
Durban-Watson	1.0
MAPE	4.68%
In-Sample RMSE	233
Out-of-Sample RMSE	353

Model Discussion

The AFR 2020 outlook for paper and wood Products energy requirements is lower than the AFR 2019 projection. The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load additions.

The AFR 2020 model is driven by the Industrial Production Index (IPI) for Paper. Last year's model used both Total Non-Farm Employment (Duluth MSA) and the IPI for Paper as economic drivers.

Minnesota Power's econometric interpretation of the key driver is as follows: As the month-to-month change in the Paper IPI increases by 1, monthly paper and wood customer use increases by about 775 MWh.

The three "Bi_Paper" binary variables denote decreases in sales to paper customers due to transition of customer generation assets or closure of paper production capacity. Binary variables are used as this is not a situation in which pre-regression adjustments to the historical series would be appropriate. These variables terminate at the beginning of the forecast timeframe, producing an econometric forecast that's at a pre-change-in-operations level. Post-regression load adjustments are then applied to reduce the outlook in the amount of the operational changes likely demands.

A combination of a binary variable for 2016-2034 and trend variable denoting the 2016-2034 timeframe shift the level and trend of the estimate to align with recent energy use. These variables effectively shift the first forecast year (2020) to align with the last historical year (2019). Without these corrective variables, a small but growing divergence between actual and predicted customer growth suggests the economic indicators alone would overstate energy use, and the 2020 forecast value confirms this. Without these binary and trend variables, the model would project an increase of about 440,000 MWh from 2019 to 2020 (a 43.3% increase).

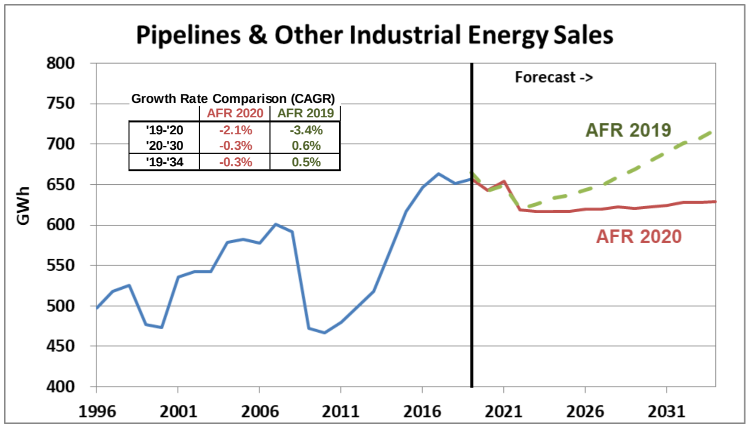
This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's reasonable goodness-of-fit, and error metrics show this is a fairly accurate model: In-sample MAPE is 4.68% vs. 4.62% in the 2019 model, and Out-sample RMSE is 353 vs. 263 in the 2019 model.

A low SIC indicates a highly parsimonious model. The low Variance Inflation Factors (VIF) of each economic variable proves there is no significant multicollinearity among non-binary, non-trend variables. HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' (except the intercept) are significant.

Pipelines and Other Industrial Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2019
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications			
Variable	Coefficient	P-Value	HAC-P-Value	VIF
CONST	(2,332.25)	0.00%	0.01%	
Time_Trend	1.16	0.00%	0.00%	
Bi_Pipe_Other1	(3,565.64)	0.00%	0.00%	
Trend_Pipe_Other1	12.63	0.00%	0.00%	
TotNonF_13_t	0.02	0.00%	0.00%	2.80



Other Industrial Energy Sales

	MWh	Y/Y Growth
2009	472,751	
2010	467,062	-1.2%
2011	479,799	2.7%
2012	498,474	3.9%
2013	517,786	3.9%
2014	568,206	9.7%
2015	616,625	8.5%
2016	646,339	4.8%
2017	663,444	2.6%
2018	651,545	-1.8%
2019	656,590	0.8%
2020	642,976	**-2.1%**
2021	653,666	**1.7%**
2022	618,844	**-5.3%**
2023	616,665	**-0.4%**
2024	616,901	**0.0%**
2025	616,885	**0.0%**
2026	619,776	**0.5%**
2027	620,018	**0.0%**
2028	621,964	**0.3%**
2029	620,800	**-0.2%**
2030	622,745	**0.3%**
2031	624,023	**0.2%**
2032	627,933	**0.6%**
2033	627,957	**0.0%**
2034	628,637	**0.1%**

Model Statistics	Magnitude
Adjusted R^2	64.6%
AIC	9.56
SIC	9.62
Degrees of Freedom	283
Durban-Watson	1.3
MAPE	6.35%
In-Sample RMSE	118
Out-of-Sample RMSE	136

Model Discussion

The outlook for pipelines and other industrial energy sales is lower than the AFR 2019 projection. The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load additions/losses.

The AFR 2020 econometric driver for the pipelines and other industrial model is 13-County Total Non-Farm Employment. The AFR 2019 model included Construction, Natural Resources, & Mining Employment (13-County) and Population (13-County).

Minnesota Power's econometric interpretation of the key driver is as follows: As the Total Non-Farm Employment increases by 1,000, other industrial monthly energy usage increases by about 460 MWh. This is in addition to a general upward trend over time.

Both AFR 2020 and AFR 2019 models feature two key structural variables: a binary ("Bi_Pipe_Other1") and a trend variable ("Trend_Pipe_Other1") denoting the period in which a large pipeline customer began adding substantial load, and drove the majority of the energy use increase in the customer class. The binary and trend variables effectively "back-out" this recent load addition, so this customer's expected energy use can be addressed in isolation through a post-regression load addition to avoid double-counting.

The ability to address this pipeline customer's expected usage directly and exactly in the forecast timeframe is especially important in the AFR 2020 forecast; there is a high likelihood that this recently-added pumping load will be short-lived due to pumping capacity additions elsewhere on the system. This shift is evident in the graph above; usage by pipeline and other industrial customers drops sharply from 2021 to 2022 as added pumping capacity outside Minnesota Power's territory relieves the pumps served by a specific retail pumping customer.

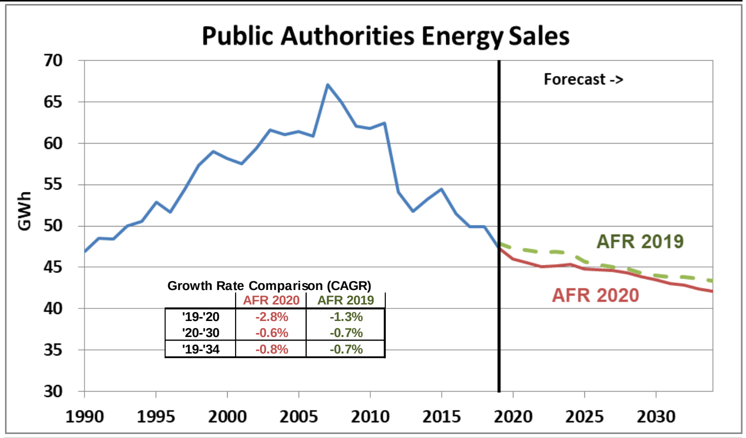
This year's model is similar to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a reasonable goodness-of-fit, and the low SIC indicates a highly parsimonious model. In-sample and Out-sample error metrics are similar to last year's: In-sample MAPE is 6.35% vs. 6.69% in the 2019 model, and Out-sample RMSE is 136 from 139 in the 2019 model. The low Variance Inflation Factors (VIF) of each economic variable proves there is no significant multicollinearity among non-binary, non-trend variables.

The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Public Authorities Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2019
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications			
Variable	Coefficient	P-Value	HAC-P-Value	VIF
CONST	(112.14)	15.64%	28.41%	
Time_Trend	0.15	0.00%	0.02%	
Bi_Jan	(7.26)	8.90%	4.04%	
Bi_May	(10.85)	0.58%	2.78%	
Bi_Nov	(9.78)	1.06%	0.59%	
EE_Com	(0.0002)	0.00%	0.00%	
Dul_HDDpd	0.18	2.54%	2.25%	2.20
Dul_CDDpd	3.51	0.12%	0.54%	1.80
EduH_13_t	0.004	1.11%	3.52%	4.30
Gov_StLou_t	0.01	0.29%	2.18%	1.90



Public Auth. Energy Sales

	MWh	Y/Y Growth
2009	62,036	
2010	61,766	-0.4%
2011	62,457	1.1%
2012	54,074	-13.4%
2013	51,736	-4.3%
2014	53,236	2.9%
2015	54,470	2.3%
2016	51,455	-5.5%
2017	49,945	-2.9%
2018	49,884	-0.1%
2019	47,302	-5.2%
2020	45,985	**-2.8%**
2021	45,550	**-0.9%**
2022	45,113	**-1.0%**
2023	45,202	**0.2%**
2024	45,365	**0.4%**
2025	44,819	**-1.2%**
2026	44,745	**-0.2%**
2027	44,647	**-0.2%**
2028	44,363	**-0.6%**
2029	43,838	**-1.2%**
2030	43,498	**-0.8%**
2031	43,086	**-0.9%**
2032	42,898	**-0.4%**
2033	42,442	**-1.1%**
2034	42,156	**-0.7%**

Model Statistics	Magnitude
Adjusted R^2	41.1%
AIC	5.94
SIC	6.05
Degrees of Freedom	350
Durban-Watson	2.2
MAPE	10.05%
In-Sample RMSE	19
Out-of-Sample RMSE	20

Model Discussion

The AFR 2020 outlook for public authorities energy use is similar to the AFR 2019 forecast. Key drivers of this year's energy use model are Education & Health sector employment (13-County) and St. Louis County Public sector employment AFR 2019 also used area Education & Health employment, along with Product per-capita (13-County).

Minnesota Power's econometric interpretation of the key driver is as follows: For every 1,000 job increase in the Education & Health sector, monthly public authority usage should increase by about 122 MWh. As St. Louis County Public sector employment increases by 1,000 jobs, monthly public authority usage should increase by about 183 MWh.

The AFR 2020 model uses an Energy Efficiency variable as a predictor of public authorities' energy sales: the "EE_Com" variable represents the cumulative effects of all past conservation measures on each year's sales, and the annual energy savings value is leveraged for all 12 monthly observations of a given year. The commercial-sector energy efficiency variable was used for the public authorities model since 1) both customer groups are served by the same CIP program (Power Grant/Power of One Business), and 2) the overall trend of conservation in public authorities is likely very similar to commercial customers.

The Energy Efficiency variable suggests public authorities energy consumption to be about 540 MWh (0.1%) lower in 2020 than it would have been in the absence of all past Minnesota Power CIP and organic, customer-driven conservation.

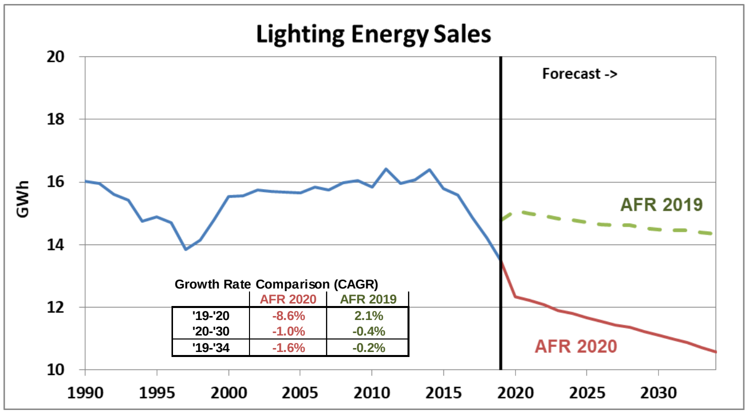
This year's model is similar to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's moderate goodness-of-fit, and the low SIC indicates a highly parsimonious model. In-sample and Out-sample error metrics are similar to last year's: In-sample MAPE is 10.05% vs. 10.36% in the 2019 model, and Out-sample RMSE is 19.7 vs. 20.1 in the 2019 model. The low Variance Inflation Factors (VIF) of each economic variable proves there is no significant multicollinearity among non-binary, non-trend variables.

The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' (except the intercept) are significant.

Street Lighting Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2019
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

Variable	Model Specifications: Coefficient	P-Value	HAC-P-Value	VIF
CONST	29.03	0.05%	0.00%	
Time_Trend	(0.01)	16.97%	9.73%	
Bi_Jan	2.58	1.33%	0.45%	
Bi_Feb	(2.53)	1.53%	0.11%	
Bi_Mar	(9.73)	0.00%	0.00%	
Bi_Apr	(14.81)	0.00%	0.00%	
Bi_May	(20.79)	0.00%	0.00%	
Bi_Jun	(24.15)	0.00%	0.00%	
Bi_Jul	(23.54)	0.00%	0.00%	
Bi_Aug	(19.82)	0.00%	0.00%	
Bi_Sep	(12.02)	0.00%	0.00%	
Bi_Oct	(8.63)	0.00%	0.00%	
Bi_Nov	(2.97)	0.45%	0.00%	
Bi_Light1	(2.11)	2.55%	1.37%	
Trend_Light2	(0.55)	0.20%	0.00%	
NonWPI_StLou_t	0.00	3.76%	0.06%	1.00
EduH_13_t	0.00	1.06%	0.08%	1.60



Lighting Energy Sales

	MWh	Y/Y Growth
2009	16,050	
2010	15,834	-1.3%
2011	16,420	3.7%
2012	15,954	-2.8%
2013	16,066	0.7%
2014	16,400	2.1%
2015	15,801	-3.7%
2016	15,588	-1.4%
2017	14,873	-4.6%
2018	14,206	-4.5%
2019	13,482	-5.1%
2020	12,321	**-8.6%**
2021	12,205	**-0.9%**
2022	12,077	**-1.0%**
2023	11,901	**-1.5%**
2024	11,800	**-0.8%**
2025	11,652	**-1.3%**
2026	11,545	**-0.9%**
2027	11,435	**-1.0%**
2028	11,365	**-0.6%**
2029	11,212	**-1.3%**
2030	11,099	**-1.0%**
2031	10,974	**-1.1%**
2032	10,874	**-0.9%**
2033	10,704	**-1.6%**
2034	10,555	**-1.4%**

Model Statistics	Magnitude
Adjusted R^2	83.7%
AIC	2.83
SIC	3.01
Degrees of Freedom	343
Durban-Watson	1.7
MAPE	4.78%
In-Sample RMSE	4.0
Out-of-Sample RMSE	4.2

Model Discussion

The outlook for energy use by street lighting customer is lower than the AFR 2019 forecast, but the model utilizes similar economic variables as drivers. Both the AFR 2020 and the AFR 2019 lighting per-day use models use St. Louis County Non-Wage Personal Income as a key economic/demographic indicator, but AFR 2020 also includes Education & Health sector employment (13-County).

Minnesota Power's econometric interpretation of the key driver is as follows: As area Non-Wage Personal Income increases by $1 Billion, monthly lighting usage should increase by about 91 MWh. For every 1,000 jobs added in the Education & Health sector, monthly lighting usage should increase by about 14 MWh.

"Bi_Light1" is a binary variable denoting the 1990-1999 timeframe and effectively shifts the level of the estimate to account for changes to the Company's accounting practices, which affected historical energy use data. The corrective binary shifts the forecast to avoid improbably changes in energy use, but does not impact the forecast trajectory; this is determined by the economic variables.

"Trend_Light2" is a trend variable denoting the 2019-2034 timeframe and effectively creates a new forecast trajectory influenced by levels starting in 2019 (this level is then held constant in the forecast timeframe). This trend variable shifts the forecast to avoid improbably changes in energy use, and unlike "Bi_Light1", it does impact the forecast trajectory; in addition to the economic variables.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's high goodness-of-fit, and the low SIC indicates a highly parsimonious model. In-sample and Out-sample error metrics are similar to last year's: In-sample MAPE is 4.78% vs. 4.99% in the 2019 model, and Out-sample RMSE is 4.17 vs. 4.25 in the 2019 model. The low Variance Inflation Factors (VIF) of each economic variable proves there is no significant multicollinearity among non-binary, non-trend variables.

The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

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System Peak Demand - Expected Scenario

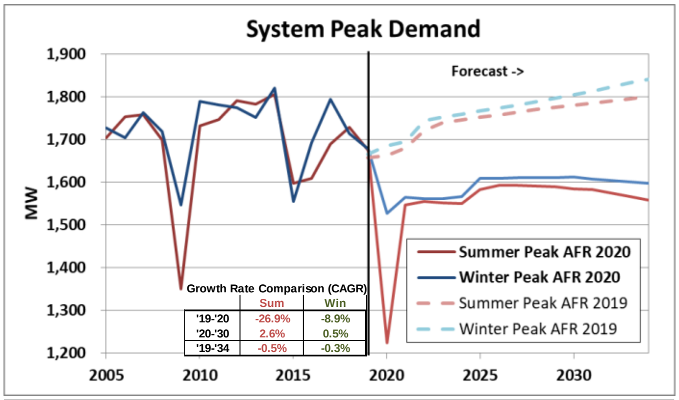
Estimation Start/End:	6/1999 - 12/2019
Unit Modeled/Forecast:	Monthly Peak Demand

	Model Specifications			
Variable	Coefficient	P-Value	HAC-P-Value	VIF
CONST	323.27	0.00%	0.00%	
Weather-Normalized_Energy-per-day	0.04	0.00%	0.00%	1.25
Summer-Peak Binary	42.62	0.00%	0.03%	1.31
Winter-Peak Binary	17.96	7.38%	2.18%	1.55
Wind-Chill_Temp-Humid_Index	(1.11)	0.00%	0.00%	11.69
Wind-Chill_Temp-Humid_Index_3	0.0002	0.00%	0.00%	8.43
Bi_1999_2001	(37.69)	0.00%	0.00%	1.03
Bi_2008	107.50	0.00%	0.00%	1.04
Bi_2017_2034	55.54	0.00%	0.00%	1.04
Jan_W-N_Energy-per-day	(0.001)	5.69%	0.58%	1.72
Feb_W-N_Energy-per-day	(0.001)	2.17%	0.22%	1.64
Mar_W-N_Energy-per-day	(0.001)	0.29%	0.05%	1.27

System Peak Demand

	Summer (MW)	Y/Y Growth		Winter (MW)	Y/Y Growth
2009	1,350		2009	1,545	
2010	1,732	28.3%	2010	1,789	15.7%
2011	1,746	0.8%	2011	1,780	-0.5%
2012	1,790	2.5%	2012	1,774	-0.3%
2013	1,782	-0.5%	2013	1,751	-1.3%
2014	1,805	1.3%	2014	1,821	4.0%
2015	1,597	-11.5%	2015	1,554	-14.6%
2016	1,609	0.8%	2016	1,692	8.9%
2017	1,689	4.9%	2017	1,794	6.0%
2018	1,728	2.3%	2018	1,714	-4.5%
2019	1,675	-3.1%	2019	1,677	-2.2%
2020	1,223	**-26.9%**	2020	1,527	**-8.9%**
2021	1,546	**26.4%**	2021	1,564	**2.4%**
2022	1,554	**0.5%**	2022	1,561	**-0.2%**
2023	1,551	**-0.2%**	2023	1,561	**0.0%**
2024	1,549	**-0.1%**	2024	1,565	**0.3%**
2025	1,582	**2.1%**	2025	1,609	**2.8%**
2026	1,592	**0.7%**	2026	1,609	**0.0%**
2027	1,591	**-0.1%**	2027	1,609	**0.0%**
2028	1,590	**-0.1%**	2028	1,610	**0.1%**
2029	1,588	**-0.1%**	2029	1,611	**0.0%**
2030	1,585	**-0.2%**	2030	1,611	**0.0%**
2031	1,582	**-0.2%**	2031	1,607	**-0.2%**
2032	1,574	**-0.5%**	2032	1,603	**-0.3%**
2033	1,566	**-0.5%**	2033	1,600	**-0.2%**
2034	1,557	**-0.6%**	2034	1,596	**-0.2%**

Model Statistics	Magnitude
Adjusted R^2	88.0%
AIC	7.17
SIC	7.34
Degrees of Freedom	235
Durban-Watson	1.4
MAPE	1.98%
In-Sample RMSE	35
Out-of-Sample RMSE	39



Model Discussion

The long-run outlook for Minnesota Power's system peak (delivered load) is lower than the 2019 outlook due to reduced sales in all classes.

Minnesota Power continued the modeling methodology established in AFR 2014 that more accurately accounts for recent changes in the customer class composition. Historical demand is adjusted to remove recent large customer load additions, so they can be more accurately and directly accounted for in the forecast time frame. This avoids the potential for double-counting customer load. Adjustments to the historical peak demand data are detailed in the Adjustments to Raw Data section.

Temperature variables play a critical role in peak demand modeling, and both the definition and structure of these variables are important for interpreting the results. Both the 2020 and 2019 AFR use a third-degree polynomial specification on a Wind-Chill & Temperature Humidity Index (WCTHI). Similar to last year, the AFR 2020 peak demand is modeled as a function of the weather observations specific to the hour in which the peak occurred.

A polynomial temperature specification has been selected since AFR 2016 because using a spline specification in after-the fact weather-normalization can be problematic. It's sometimes impossible to calculate the weather impact in months like May or September that may lack extreme enough weather to fit into a specific spline-segment definition (THI/High-temp or Wind-Chill/Low-temp). A polynomial temperature specification is continuous, not segmented, so it can always be leveraged for weather-normalization. This methodological/variable specification change is discussed further in the Specific Analytical Techniques section.

The 2020 AFR peak demand model utilized two binaries to indicate the month of the system's historical summer and winter peaks, and assumed this peak in July/January (respectively) throughout the forecast timeframe. Summer peaks typically occur in either July or August, historical winter peaks have occurred in November, December, February, but are most likely in January. This broad distribution of peak occurrence dilutes the model's measured seasonality, and as a result, the peak forecast will understate both the summer and winter peak demand figures. The utilization of these peak binaries focuses the seasonal peaks – which may have occurred in August or July, or December or January - into the months of July and January. This ensures seasonal peaks are not under forecast as a result of historical diversity in the timing of those seasonal peaks.

The model also includes two binaries ("Bi_1999_2001" and "Bi_2008") denoting periods of economic downturn for Minnesota Power's large industrial customers, resulting in abnormally low usage. During (or immediately following) these periods the normal relationship of Peak-to-Energy was affected by the idling of large, high load factor customers. These binaries effectively remove these downturn periods from consideration in the regression model and allow for more accurate estimation of model coefficients under more normal economic conditions.

The "Bi_2017_2034" variable begins Dec-2017 and continues through the end of the forecast timeframe. It represents a step-change due to load reductions by two large industrial customers that cannot be accurately quantified or "backed-out" from the historical series. This binary is necessary to align the immediate forecast years with recent, "backed-out" historical levels.

There is no energy efficiency variable in the peak demand model. All conservation impacts are inherent in the econometric energy sales forecast, which is used as an input to the peak demand regression model.

This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's high goodness-of-fit, and the low SIC indicates a highly parsimonious model. In-sample and Out-sample error metrics are similar to the 2019 model: In-sample MAPE is 1.98% vs. 1.76% in the 2019 model, and Out-sample RMSE is 39 vs. 35 in the 2019 model. The Variance Inflation Factors (VIF) on the two weather terms suggests they are highly correlated with each other. This is expected; the two variables are related by a power of 3 (one is the cubed-root of the other). This is not indicative of any negative underlying issues concerning multicollinearity.

The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

B. Confidence in Forecast & Historical Accuracy

Minnesota Power has a strong record of accurate forecasting and consistent improvements in forecast accuracy over time. Excluding the mining downturn years (2009/2010 and 2015/2016), each successive AFR has reduced its current-year energy sales forecast error, on average, by about 0.05 percent over the prior year.

Tables 8-10 show Minnesota Power's past AFR forecast accuracy for aggregate energy use, Summer Peak, and Winter Peak demand. The bottom values in each column (**Bold**) represent the forecast accuracy in the current year, or the year it was produced. For example, the lower right value of -1.8 percent is the difference between the forecast produced in 2019 (AFR 2019) and the 2019 year-end actual. Similarly, the cell just above the current year accuracy (***Bold, Italic***) represents the accuracy of the forecast in the year immediately after its formulation. For example, AFR 2015 (formulated in 2015) forecast of 2016 was 5.9 percent (581 GWh) above the actual (due to effects of Mining downturn).

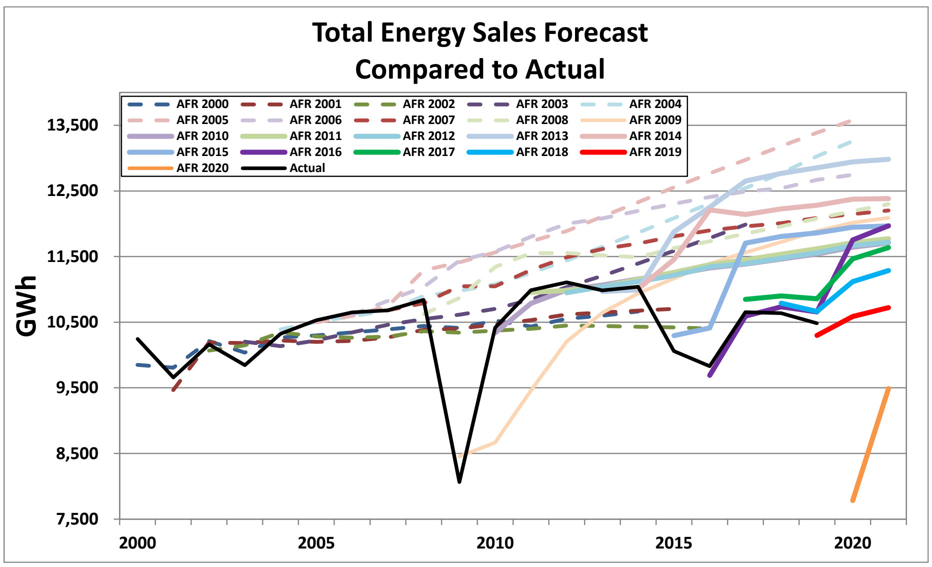


Figure 18: AFR Energy Sales Forecast Accuracy

Table 8: AFR Energy Sales Forecast Accuracy

Total Energy Sales Forecast Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Average Error of AFR	Avg. Error Year-Ahead
AFR 2000	**-3.9%**	***1.5%***	0.5%	1.9%	-0.6%	**-2.2%**	-2.9%	-2.7%	-3.7%	29.1%	1.0%	-5.1%	-5.0%	-3.5%	-3.4%						0.1%	1.5%
AFR 2001		**-2.0%**	***0.3%***	3.4%	-1.0%	-3.1%	**-4.1%**	-3.9%	-4.2%	29.0%	0.5%	-4.2%	-4.4%	-3.1%	-3.3%	6.4%					0.4%	0.3%
AFR 2002			**-0.9%**	***3.1%***	0.2%	-2.4%	-3.6%	**-3.8%**	-4.4%	28.2%	-0.4%	-5.4%	-5.9%	-5.0%	-5.5%	3.6%	5.8%				0.2%	3.1%
AFR 2003				**3.6%**	***-1.8%***	-2.9%	-2.9%	-2.1%	**-2.7%**	31.6%	2.8%	-1.3%	-0.6%	2.0%	3.2%	15.2%	19.8%	12.5%			5.1%	1.8%
AFR 2004					**0.6%**	***-0.3%***	-0.5%	0.0%	0.6%	**36.1%**	6.4%	2.4%	3.0%	6.0%	7.5%	20.1%	25.2%	17.7%	20.0%		9.7%	0.3%
AFR 2005						**-0.3%**	***-0.5%***	0.6%	4.1%	41.5%	**11.0%**	6.8%	7.0%	10.2%	11.7%	24.8%	29.9%	21.8%	23.9%	27.7%	13.8%	0.5%
AFR 2006							**-0.3%**	***1.4%***	1.8%	41.8%	11.1%	**7.4%**	8.0%	10.0%	10.5%	22.3%	26.2%	17.2%	17.9%	20.9%	13.5%	1.4%
AFR 2007								**0.0%**	***-0.5%***	37.0%	6.0%	2.8%	**3.4%**	5.7%	6.0%	17.4%	21.0%	12.3%	12.9%	15.3%	10.3%	0.5%
AFR 2008									**-2.0%**	***34.8%***	8.9%	5.1%	4.0%	**4.8%**	4.1%	15.6%	19.3%	11.2%	12.4%	15.2%	10.7%	34.8%
AFR 2009										**4.8%**	***-16.8%***	-13.9%	-8.1%	-3.1%	**-0.9%**	11.0%	15.9%	8.5%	10.2%	13.4%	0.7%	16.8%
AFR 2010											**-0.8%**	***-1.8%***	-1.0%	0.7%	1.1%	**11.6%**	15.2%	6.9%	7.7%	10.1%	4.4%	1.8%
AFR 2011												**-0.3%**	***-1.1%***	0.5%	1.0%	11.9%	**15.7%**	7.5%	8.4%	10.8%	5.5%	1.1%
AFR 2012													**-1.4%**	***0.5%***	0.7%	11.5%	15.4%	**6.9%**	7.8%	10.2%	5.9%	0.5%
AFR 2013														**-0.2%**	***-0.4%***	18.1%	24.6%	18.7%	**20.0%**	22.6%	13.5%	0.4%
AFR 2014															**-0.3%**	***13.9%***	24.2%	13.9%	14.9%	**17.2%**	13.3%	13.9%
AFR 2015																**2.4%**	***5.9%***	9.9%	11.0%	13.1%	7.3%	5.9%
AFR 2016																	**-1.4%**	***-0.6%***	0.9%	1.7%	-0.4%	0.6%
AFR 2017																		**1.8%**	***2.5%***	3.6%	2.1%	2.5%
AFR 2018																			**1.4%**	***1.7%***	1.4%	1.7%
AFR 2019																				**-1.8%**	-1.8%	

N.n%	= *Year-Ahead Foreast*	Avg Year-Ahead Error =	2.2%
		Avg Year-Ahead Error (No Downturns) =	-0.5%
N.n%	= Current Year Forecast	Avg Current Year Error =	0.0%
N.n%	= 5 Year-Ahead Forecast	Avg 5 Year Error =	8.0%
		Avg 5 Year Error (No Downturns) =	3.9%

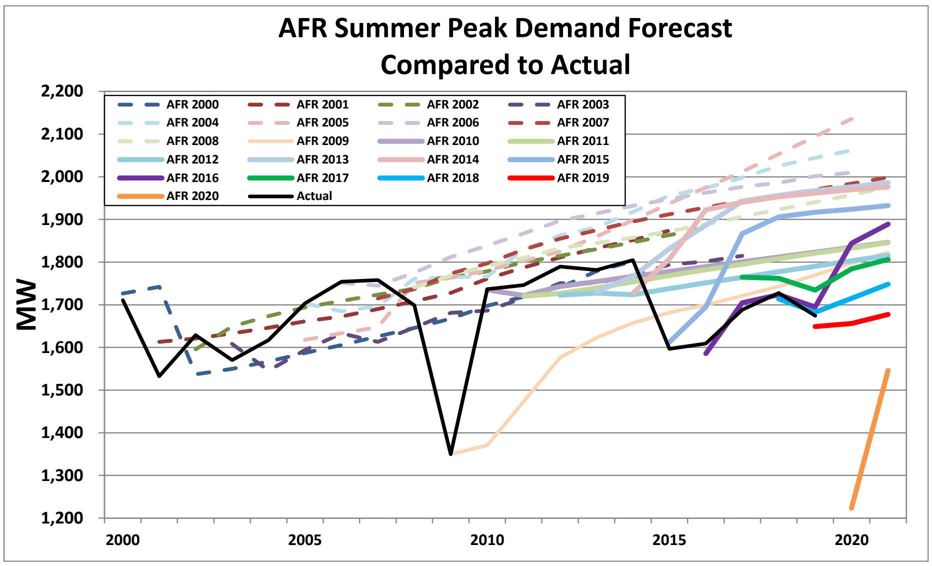


Figure 19: AFR Summer Peak Demand Forecast Accuracy

Table 9: AFR Summer Peak Demand Forecast Accuracy

Summer System Peak Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Average Error of AFR	Avg. Error Year-Ahead
AFR 2000	0.9%	13.7%	-5.6%	-1.3%	-3.1%	-6.8%	-8.5%	-7.5%	-3.1%	23.6%	-2.2%	-1.6%	-2.8%	-0.2%	-0.1%						-0.3%	13.7%
AFR 2001		5.2%	-0.5%	4.0%	1.8%	-2.5%	-4.6%	-3.8%	0.5%	28.0%	1.4%	2.4%	1.2%	2.9%	2.6%	17.4%					3.7%	0.5%
AFR 2002			-2.0%	5.0%	3.5%	-0.6%	-2.6%	-1.9%	2.3%	30.7%	2.4%	3.1%	1.4%	2.7%	2.3%	16.7%	16.9%				5.3%	5.0%
AFR 2003				2.4%	-4.4%	-6.4%	-6.9%	-8.2%	-3.1%	24.6%	-2.9%	-1.7%	-2.2%	-1.7%	-2.0%	12.4%	12.0%	7.5%			1.3%	4.4%
AFR 2004					0.0%	0.0%	-3.9%	-3.5%	3.7%	30.8%	1.7%	4.8%	4.1%	5.6%	6.3%	22.5%	22.7%	18.4%	17.2%		8.7%	0.0%
AFR 2005						-5.0%	-6.9%	-6.3%	3.1%	30.7%	2.5%	3.3%	2.0%	4.4%	5.2%	21.3%	22.8%	19.2%	18.8%	25.1%	9.3%	6.9%
AFR 2006							-0.2%	-0.7%	4.5%	34.3%	5.9%	7.0%	6.0%	7.5%	7.0%	22.0%	22.0%	17.1%	15.0%	19.5%	11.9%	0.7%
AFR 2007								-2.4%	2.2%	31.4%	3.5%	4.8%	3.6%	5.2%	5.0%	19.8%	19.8%	15.1%	13.2%	17.7%	10.7%	2.2%
AFR 2008									2.5%	31.0%	3.2%	3.7%	2.4%	3.6%	2.9%	17.3%	17.4%	12.9%	11.3%	15.9%	10.3%	31.0%
AFR 2009										0.0%	-21.1%	-15.6%	-11.9%	-8.9%	-8.2%	5.3%	5.7%	1.9%	0.9%	5.7%	-4.2%	21.1%
AFR 2010											-0.1%	-1.4%	-2.6%	-1.5%	-2.1%	11.3%	11.2%	6.6%	4.9%	8.9%	3.5%	1.4%
AFR 2011												-1.5%	-3.5%	-2.4%	-2.8%	10.8%	10.8%	6.3%	4.7%	8.7%	3.5%	3.5%
AFR 2012													-3.7%	-3.0%	-4.5%	8.8%	8.9%	4.5%	2.9%	6.9%	2.6%	3.0%
AFR 2013														-2.8%	-2.1%	14.7%	17.3%	15.1%	13.2%	17.5%	10.4%	2.1%
AFR 2014															-4.3%	13.2%	19.5%	14.9%	13.1%	17.2%	12.3%	13.2%
AFR 2015																1.0%	5.4%	10.6%	10.3%	14.5%	8.3%	5.4%
AFR 2016																	-1.4%	0.9%	-0.2%	1.2%	0.1%	0.9%
AFR 2017																		4.5%	2.0%	3.6%	3.4%	2.0%
AFR 2018																			-0.8%	0.5%	-0.2%	0.5%
AFR 2019																				-1.5%	-1.5%	

N.n%	= Year-Ahead Foreast	Avg Year-Ahead Error =	1.6%
		Avg Year-Ahead Error (No Downturns) =	-1.7%
N.n%	= Current Year Forecast	Avg Current Year Error =	-0.5%
N.n%	= 5 Year-Ahead Forecast	Avg 5 Year Error =	5.3%
		Avg 5 Year Error (No Downturns) =	2.9%

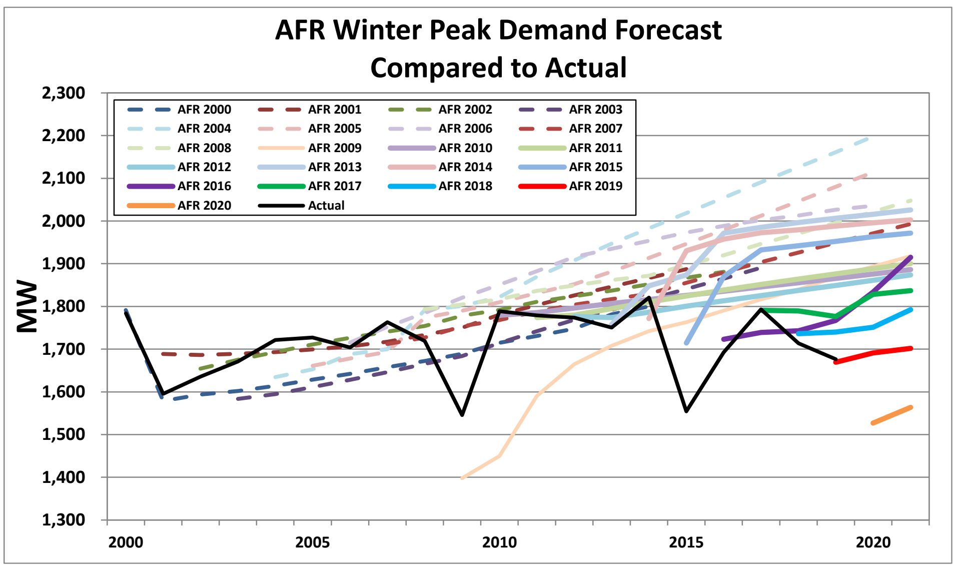


Figure 20: AFR Winter Peak Demand Forecast Accuracy

Table 10: AFR Winter Peak Demand Forecast Accuracy

Winter System Peak Error

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Average Error of AFR	Avg. Error Year-Ahead
AFR 2000	0.4%	-1.0%	-2.6%	-4.1%	-6.2%	-5.7%	-3.6%	-6.0%	-2.7%	9.3%	-4.1%	-2.7%	-1.5%	1.8%	-1.1%						-2.0%	1.0%
AFR 2001		5.8%	3.1%	1.1%	-1.6%	-1.6%	0.2%	-2.6%	0.8%	13.3%	-0.4%	1.4%	2.9%	5.5%	2.5%	21.4%					3.4%	3.1%
AFR 2002			1.1%	0.2%	-1.6%	-0.9%	1.3%	-1.3%	2.0%	15.1%	0.2%	1.8%	2.8%	4.9%	1.7%	20.1%	11.2%				3.9%	0.2%
AFR 2003				-5.2%	-7.4%	-6.7%	-4.4%	-6.6%	-3.1%	9.0%	-4.1%	-2.1%	-0.3%	2.4%	-0.2%	18.4%	10.2%	5.5%			0.3%	7.4%
AFR 2004					-5.0%	-4.3%	-0.9%	-3.6%	4.2%	16.6%	1.9%	5.1%	7.6%	11.2%	8.9%	29.9%	21.4%	16.6%	24.1%		8.9%	4.3%
AFR 2005						-3.8%	-1.5%	-3.9%	3.2%	15.8%	1.2%	2.9%	4.4%	7.5%	5.1%	25.2%	17.0%	12.2%	19.4%	24.1%	8.6%	1.5%
AFR 2006							0.7%	-0.6%	3.8%	17.8%	3.5%	5.8%	8.0%	10.5%	7.3%	27.0%	17.5%	11.7%	17.5%	20.9%	10.8%	0.6%
AFR 2007								-2.9%	0.5%	13.5%	-1.1%	0.5%	1.7%	3.8%	0.5%	19.4%	11.1%	6.2%	12.4%	16.2%	6.3%	0.5%
AFR 2008									4.3%	16.8%	1.6%	3.2%	4.2%	6.3%	2.8%	22.1%	13.5%	8.6%	15.0%	19.1%	9.8%	16.8%
AFR 2009										-9.6%	-18.9%	-10.6%	-6.2%	-2.4%	-4.3%	13.4%	5.8%	1.3%	7.4%	11.5%	-1.2%	18.9%
AFR 2010											-0.5%	0.4%	1.3%	3.2%	-0.2%	17.5%	8.5%	2.9%	8.3%	11.3%	5.2%	0.4%
AFR 2011												-0.3%	0.3%	2.5%	-0.6%	17.4%	8.6%	3.3%	8.8%	11.9%	5.8%	0.3%
AFR 2012													0.1%	1.3%	-1.9%	15.8%	7.1%	1.8%	7.2%	10.3%	5.2%	1.3%
AFR 2013														0.4%	1.5%	20.5%	16.5%	10.7%	16.5%	19.7%	12.3%	1.5%
AFR 2014															-2.7%	24.2%	15.7%	10.0%	15.5%	18.6%	13.6%	24.2%
AFR 2015																10.3%	10.5%	7.8%	13.4%	16.5%	11.7%	10.5%
AFR 2016																	1.8%	-3.0%	1.7%	5.4%	1.5%	3.0%
AFR 2017																		-0.1%	4.4%	6.0%	3.4%	4.4%
AFR 2018																			1.3%	3.8%	2.6%	3.8%
AFR 2019																				-0.4%	-0.4%	

N.n%	= Year-Ahead Foreast	Avg Year-Ahead Error =	1.6%
		Avg Year-Ahead Error (No Downturns) =	-0.6%
N.n%	= Current Year Forecast	Avg Current Year Error =	-0.2%
N.n%	= 5 Year-Ahead Forecast	Avg 5 Year Error =	5.4%
		Avg 5 Year Error (No Downturns) =	3.6%

2. AFR 2020 Scenario Forecast Descriptions

A. Forecast Scenario Descriptions

i. Expected Scenario: The AFR 2020 Expected scenario includes changes in customer operations that are not certain, but have a high likelihood of occurring. This high likelihood is characterized by formal communication from the customer, plus one or more of the following:

- An Electric Service Agreement is either executed or is in negotiation;
- The change in operation is supported by customer actions, such as construction or investment that will result in additional power requirements; and/or
- A timeframe for the operation and resulting power.

The Expected scenario assumes additional load from several new and existing customers. Most notably, this scenario accounts for a new industrial facility on the Iron Range; the facility is expected to reach full demand in mid-2026. This scenario also assumes the indefinite idle of two large power customers' facilities.

The scenario assumes a moderate, or "expected," rate of national economic growth as the basis for the regional economic model.[51]

The Expected scenario results in compound annual energy sales and peak demand decline of -0.4 percent and -0.3 percent, respectively, from 2019 through 2034.

ii. High Scenario: The AFR 2020 High scenario is identical to the Expected scenario, except two large power customers' facilities resume operations following the U.S. recovery from the COVID-19-induced recession – rather than being indefinitely idled. The High scenario does not include all potential for new projects or new load growth, and is focused only on the potential for recovery of two currently idled customers.

For consideration in the Company's High scenario, projects/expansions/re-starts are deemed possible, but include any number of the following:

- Facing significant political headwinds;
- Require highly favorable economic conditions; and/or
- Not fully developed or vetted; in some state of pre-feasibility or engineering study that doesn't yet define timing, load impacts, etc.

[51] All econometric models use the "expected" rate of national economic growth per IHS Global Insight's January 2020 release. However, the Mining class for AFR 2020 has been adjusted per the May 2020 release that includes recessionary impacts of COVID-19. The Company elected to go this route – a single, post-econometric modeling class adjustment vs. performing an entire re-model of all variables – as the Mining class represents a substantial share of total energy sales. Without an adjustment forecast error would be large, and a complete re-model of all variables was deemed unnecessary.

The scenario assumes a moderate, or “expected,” rate of national economic growth as the basis for the regional economic model.

The High scenario results in compound annual growth of 0.1 percent for both energy sales and peak demand from 2019 through 2034.

B. Other Adjustments to Econometric Forecast

Minnesota Power’s forecast scenario is the summation of the econometric model results and arithmetic adjustments for impacts which cannot be accurately modeled. These exogenous impacts are documented as separate seasonal peak and energy adjustments in the Expected scenario tables. These adjustments fall into the following categories:

1. **Net Load/Energy Added**: are exogenous adjustments for load added due to Distributed Solar Generation, Electric Vehicle impacts, new customers or expansion by existing customers, and lost load due to closure or loss of contract. This adjustment includes all load added or lost on the system, regardless of how that load is met; “Net Load/Energy Added” accounts for any change in load at the system level. To preserve customer confidentiality, the seasonal demand and energy impacts are netted to a single value before being applied to the econometric values.

2. **Customer Generation:** is the demand on Minnesota Power system that is met by customer owned generation. Customer generation can fluctuate without clear economic causes so this component of Minnesota Power system peak is removed to more accurately model demand for an econometric forecast. The process for this adjustment can be outlined in 3 steps:

    - Remove Customer Generation from the historical peak series.
    - Econometrically project a less volatile “FERC load coincident w/Monthly Minnesota Power System peak (MW)” monthly peak series.
    - Arithmetically account for Customer Generation after forecasting.

    This procedure has been a methodological staple of Minnesota Power forecasting for over a decade and increases the quality of the econometric processes and resulting forecasts.

    The forecast assumption for customer generation is determined by averaging the historical customer generation coincident with the monthly peak over a twelve-year historical timeframe. The result is a set of 12 distinct monthly values for each month of the year. The MWh adjustment is determined similarly through averaging the most recent twelve-year historical timeframe, but excluding 2009 due to its irregularly low value. These adjustments are credits that increase the estimated peaks and system energy use projection by the estimated amount.

This Customer Generation adjustment to peak and energy forecasts also accounts for expected changes in the operation or ownership of generating assets that would affect deliveries to customers.

3. **Dual Fuel**: Minnesota Power has a robust Dual Fuel program for residential and commercial customers. Dual Fuel impacts are accounted for in the forecast in the same way as conservation. The impacts of historical interruptions are assumed to be inherent in the forecast since curtailments affected historical monthly peak demand. Post-regression adjustments for dual fuel would produce an artificially low peak demand forecast. Minnesota Power will account for dual fuel interruption as a resource and not as an adjustment to the load forecast.

C. Scenario Peak Demand and Energy Outlooks

i. Expected Scenario

Peak Forecast (MW)

	Econometric		+ Net Load Added		= MP Delivered Load		+ Customer Gen.		= MP System Peak			
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Annual	
2000					1,469	1,503	242	281	1,711	1,784	1,784	2000
2001					1,383	1,421	150	175	1,533	1,595	1,595	2001
2002					1,464	1,456	165	180	1,629	1,636	1,636	2002
2003					1,408	1,496	163	175	1,570	1,671	1,671	2003
2004					1,449	1,533	168	189	1,617	1,721	1,721	2004
2005					1,535	1,555	169	172	1,703	1,727	1,727	**2005**
2006					1,584	1,534	169	170	1,753	1,704	1,753	2006
2007					1,582	1,584	176	179	1,758	1,763	1,763	2007
2008					1,552	1,575	147	145	1,699	1,719	1,719	2008
2009					1,200	1,369	150	176	1,350	1,545	1,545	2009
2010					1,591	1,599	140	190	1,732	1,789	1,789	**2010**
2011					1,573	1,630	173	150	1,746	1,780	1,780	2011
2012					1,603	1,605	187	169	1,790	1,774	1,790	2012
2013					1,645	1,589	136	162	1,782	1,751	1,782	2013
2014					1,620	1,637	184	184	1,805	1,821	1,821	2014
2015					1,442	1,461	155	94	1,597	1,554	1,597	**2015**
2016					1,453	1,520	156	173	1,609	1,692	1,692	2016
2017					1,538	1,599	150	195	1,689	1,794	1,794	2017
2018					1,589	1,564	139	150	1,728	1,714	1,728	2018
2019					1,567	1,555	108	122	1,675	1,677	1,677	2019
2020	1,418	1,503	(317)	(92)	**1,101**	**1,411**	122	116	**1,223**	**1,527**	**1,527**	**2020**
2021	1,496	1,497	(66)	(53)	**1,430**	**1,444**	116	119	**1,546**	**1,564**	**1,564**	2021
2022	1,490	1,491	(56)	(49)	**1,434**	**1,442**	119	119	**1,554**	**1,561**	**1,561**	2022
2023	1,484	1,486	(52)	(45)	**1,432**	**1,441**	119	119	**1,551**	**1,561**	**1,561**	2023
2024	1,480	1,484	(50)	(38)	**1,430**	**1,446**	119	119	**1,549**	**1,565**	**1,565**	2024
2025	1,476	1,481	(14)	8	**1,462**	**1,489**	119	119	**1,582**	**1,609**	**1,609**	**2025**
2026	1,472	1,477	0	13	**1,473**	**1,489**	119	119	**1,592**	**1,609**	**1,609**	2026
2027	1,469	1,473	3	17	**1,472**	**1,490**	119	119	**1,591**	**1,609**	**1,609**	2027
2028	1,465	1,469	5	22	**1,470**	**1,491**	119	119	**1,590**	**1,610**	**1,610**	2028
2029	1,461	1,465	7	27	**1,469**	**1,491**	119	119	**1,588**	**1,611**	**1,611**	2029
2030	1,456	1,460	9	32	**1,465**	**1,492**	119	119	**1,585**	**1,611**	**1,611**	**2030**
2031	1,452	1,455	11	33	**1,463**	**1,488**	119	119	**1,582**	**1,607**	**1,607**	2031
2032	1,447	1,449	8	35	**1,455**	**1,484**	119	119	**1,574**	**1,603**	**1,603**	2032
2033	1,441	1,443	6	37	**1,447**	**1,480**	119	119	**1,566**	**1,600**	**1,600**	2033
2034	1,435	1,437	3	40	**1,438**	**1,477**	119	119	**1,557**	**1,596**	**1,596**	2034

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= MP Delivered Energy	- Customer Gen.	= System Energy Use	MP System		
						Peak	Load Factor	
2000			10,029,324					
2001			9,476,860					
2002			9,950,113	1,187,858	11,137,971	1,636	0.78	2002
2003			9,638,417	1,232,635	10,871,052	1,671	0.74	2003
2004			10,117,168	1,267,728	11,384,896	1,721	0.76	2004
2005			10,345,265	1,258,895	11,604,160	1,727	0.77	**2005**
2006			10,443,777	1,195,070	11,638,847	1,753	0.76	2006
2007			10,670,857	1,252,965	11,923,822	1,763	0.77	2007
2008			10,826,034	1,276,158	12,102,192	1,719	0.80	2008
2009			8,062,253	1,108,014	9,170,267	1,545	0.68	2009
2010			10,417,422	1,299,292	11,716,714	1,789	0.75	**2010**
2011			10,988,200	1,422,107	12,410,307	1,780	0.80	2011
2012			11,107,357	1,200,317	12,307,674	1,790	0.79	2012
2013			10,985,809	1,185,139	12,170,948	1,782	0.78	2013
2014			11,038,979	1,287,965	12,326,944	1,821	0.77	2014
2015			10,059,466	1,227,221	11,286,687	1,597	0.81	**2015**
2016			9,830,787	1,074,786	10,905,573	1,692	0.74	2016
2017			10,654,217	1,215,894	11,870,111	1,794	0.76	2017
2018			10,638,691	1,236,276	11,874,967	1,728	0.78	2018
2019			10,482,913	1,064,454	11,547,367	1,677	0.79	2019
2020	10,106,626	(2,323,925)	**7,782,702**	957,125	**8,739,826**	**1,527**	**0.65**	**2020**
2021	10,052,243	(565,848)	**9,486,395**	933,575	**10,419,970**	**1,564**	**0.76**	2021
2022	10,013,647	(441,837)	**9,571,810**	937,977	**10,509,787**	**1,561**	**0.77**	2022
2023	9,981,217	(411,288)	**9,569,929**	937,977	**10,507,906**	**1,561**	**0.77**	2023
2024	9,989,292	(384,867)	**9,604,425**	940,547	**10,544,972**	**1,565**	**0.77**	2024
2025	9,948,302	(152,358)	**9,795,945**	937,977	**10,733,922**	**1,609**	**0.76**	**2025**
2026	9,938,641	25,283	**9,963,924**	937,977	**10,901,901**	**1,609**	**0.77**	2026
2027	9,928,774	55,015	**9,983,789**	937,977	**10,921,766**	**1,609**	**0.77**	2027
2028	9,942,711	82,185	**10,024,896**	940,547	**10,965,442**	**1,610**	**0.78**	2028
2029	9,896,509	113,733	**10,010,241**	937,977	**10,948,218**	**1,611**	**0.78**	2029
2030	9,875,778	143,553	**10,019,331**	937,977	**10,957,308**	**1,611**	**0.78**	**2030**
2031	9,848,912	172,393	**10,021,305**	937,977	**10,959,282**	**1,607**	**0.78**	2031
2032	9,851,325	171,278	**10,022,602**	940,547	**10,963,149**	**1,603**	**0.78**	2032
2033	9,791,164	169,763	**9,960,928**	937,977	**10,898,905**	**1,600**	**0.78**	2033
2034	9,752,985	169,666	**9,922,651**	937,977	**10,860,628**	**1,596**	**0.78**	2034

Customer Count Forecast by Class

Year	Residential	Commercial	Industrial	Street Lighting	Public Authorities	Resale	Total
2005	116,072	20,040	460	490	233	18	137,313
2006	117,596	20,419	451	509	237	18	139,229
2007	118,870	20,630	435	548	241	18	140,742
2008	119,300	20,969	431	585	246	18	141,549
2009	121,217	21,287	429	618	262	18	143,831
2010	121,235	21,491	424	2,209	278	18	145,655
2011	121,251	21,603	421	5,335	281	18	148,909
2012	120,697	21,614	411	6,414	275	18	149,429
2013	121,314	21,915	402	655	287	18	144,591
2014	121,601	22,096	394	660	282	17	145,050
2015	121,515	22,170	394	673	281	17	145,050
2016	121,836	22,420	396	689	281	17	145,639
2017	122,295	22,695	390	695	278	17	146,370
2018	122,557	22,834	380	693	277	17	146,758
2019	122,926	23,059	379	701	275	17	147,356
2020	**123,012**	**23,186**	**374**	**704**	**273**	**16**	**147,565**
2021	**123,356**	**23,371**	**370**	**713**	**274**	**16**	**148,099**
2022	**123,626**	**23,560**	**365**	**715**	**272**	**16**	**148,553**
2023	**123,870**	**23,754**	**360**	**718**	**269**	**16**	**148,987**
2024	**124,141**	**23,951**	**356**	**722**	**266**	**16**	**149,453**
2025	**124,450**	**24,156**	**352**	**725**	**264**	**16**	**149,964**
2026	**124,749**	**24,360**	**348**	**729**	**263**	**16**	**150,465**
2027	**125,030**	**24,559**	**343**	**732**	**261**	**16**	**150,941**
2028	**125,303**	**24,757**	**339**	**735**	**259**	**16**	**151,409**
2029	**125,561**	**24,955**	**334**	**739**	**257**	**16**	**151,863**
2030	**125,811**	**25,154**	**330**	**742**	**256**	**16**	**152,309**
2031	**126,052**	**25,357**	**325**	**746**	**254**	**16**	**152,750**
2032	**126,290**	**25,561**	**321**	**748**	**252**	**16**	**153,189**
2033	**126,531**	**25,766**	**317**	**751**	**251**	**16**	**153,632**
2034	**126,759**	**25,969**	**312**	**755**	**249**	**16**	**154,060**

Energy Sales Forecast (MWh) by Customer Class

Year	Residential	Commercial	Industrial	Street Lighting	Public Authorities	Resale	Total
2005	1,013,156	1,200,075	6,761,669	15,646	61,396	1,293,323	10,345,265
2006	1,011,699	1,206,607	6,782,975	15,831	60,882	1,365,783	10,443,777
2007	1,051,453	1,244,930	6,622,051	15,752	67,056	1,669,615	10,670,857
2008	1,079,837	1,240,324	6,737,333	15,983	64,912	1,687,645	10,826,034
2009	1,075,116	1,212,778	4,051,352	16,049	62,036	1,644,922	8,062,253
2010	1,057,476	1,221,754	6,364,080	15,833	61,768	1,696,511	10,417,422
2011	1,069,856	1,226,174	6,913,648	16,420	62,458	1,699,643	10,988,200
2012	1,043,281	1,237,386	7,037,843	15,954	54,074	1,718,819	11,107,357
2013	1,086,481	1,256,540	6,873,993	16,066	51,736	1,700,993	10,985,809
2014	1,112,579	1,262,464	6,946,536	16,400	53,237	1,647,763	11,038,979
2015	1,026,454	1,254,681	6,073,273	15,801	54,471	1,634,786	10,059,466
2016	1,015,465	1,243,045	5,855,829	15,588	51,455	1,649,405	9,830,787
2017	1,010,955	1,223,786	6,697,793	14,873	49,945	1,656,865	10,654,217
2018	1,052,800	1,233,117	6,677,892	14,206	49,884	1,610,791	10,638,691
2019	1,042,353	1,202,403	6,709,265	13,482	47,302	1,468,108	10,482,913
2020	**1,039,776**	**1,227,755**	**4,103,377**	**12,321**	**45,985**	**1,353,488**	**7,782,702**
2021	**1,034,896**	**1,227,491**	**5,698,086**	**12,205**	**45,550**	**1,468,165**	**9,486,395**
2022	**1,033,882**	**1,226,346**	**5,702,566**	**12,077**	**45,113**	**1,551,827**	**9,571,810**
2023	**1,033,118**	**1,226,790**	**5,702,376**	**11,901**	**45,202**	**1,550,543**	**9,569,929**
2024	**1,035,475**	**1,230,816**	**5,725,089**	**11,800**	**45,365**	**1,555,880**	**9,604,425**
2025	**1,030,922**	**1,228,137**	**5,923,398**	**11,652**	**44,819**	**1,557,016**	**9,795,945**
2026	**1,029,984**	**1,232,659**	**6,085,563**	**11,545**	**44,745**	**1,559,427**	**9,963,924**
2027	**1,029,924**	**1,237,501**	**6,092,151**	**11,435**	**44,647**	**1,568,132**	**9,983,789**
2028	**1,033,730**	**1,244,424**	**6,112,831**	**11,365**	**44,363**	**1,578,184**	**10,024,896**
2029	**1,029,932**	**1,243,374**	**6,101,983**	**11,212**	**43,838**	**1,579,902**	**10,010,241**
2030	**1,029,812**	**1,245,153**	**6,100,728**	**11,099**	**43,498**	**1,589,041**	**10,019,331**
2031	**1,029,421**	**1,250,433**	**6,095,306**	**10,974**	**43,086**	**1,592,085**	**10,021,305**
2032	**1,032,937**	**1,257,801**	**6,072,115**	**10,874**	**42,898**	**1,605,978**	**10,022,602**
2033	**1,030,569**	**1,256,776**	**6,012,398**	**10,704**	**42,442**	**1,608,039**	**9,960,928**
2034	**1,032,547**	**1,257,757**	**5,966,024**	**10,555**	**42,156**	**1,613,612**	**9,922,651**

ii. High Scenario

Peak Forecast (MW)

	Econometric		+ Net Load Added		= **MP Delivered Load**		+ Customer Gen.		= **MP System Peak**			
	Sum	Win	Sum	Win	**Sum**	**Win**	Sum	Win	**Sum**	**Win**	*Annual*	
2000					1,469	1,503	242	281	1,711	1,784	*1,784*	2000
2001					1,383	1,421	150	175	1,533	1,595	*1,595*	2001
2002					1,464	1,456	165	180	1,629	1,636	*1,636*	2002
2003					1,408	1,496	163	175	1,570	1,671	*1,671*	2003
2004					1,449	1,533	168	189	1,617	1,721	*1,721*	2004
2005					1,535	1,555	169	172	1,703	1,727	*1,727*	**2005**
2006					1,584	1,534	169	170	1,753	1,704	*1,753*	2006
2007					1,582	1,584	176	179	1,758	1,763	*1,763*	2007
2008					1,552	1,575	147	145	1,699	1,719	*1,719*	2008
2009					1,200	1,369	150	176	1,350	1,545	*1,545*	2009
2010					1,591	1,599	140	190	1,732	1,789	*1,789*	**2010**
2011					1,573	1,630	173	150	1,746	1,780	*1,780*	2011
2012					1,603	1,605	187	169	1,790	1,774	*1,790*	2012
2013					1,645	1,589	136	162	1,782	1,751	*1,782*	2013
2014					1,620	1,637	184	184	1,805	1,821	*1,821*	2014
2015					1,442	1,461	155	94	1,597	1,554	*1,597*	**2015**
2016					1,453	1,520	156	173	1,609	1,692	*1,692*	2016
2017					1,538	1,599	150	195	1,689	1,794	*1,794*	2017
2018					1,589	1,564	139	150	1,728	1,714	*1,728*	2018
2019					1,567	1,573	108	95	1,675	1,668	*1,675*	2019
2020	1,502	1,503	(409)	(92)	**1,094**	**1,411**	122	122	**1,216**	**1,533**	**1,533**	**2020**
2021	1,496	1,497	(13)	22	**1,483**	**1,519**	122	125	**1,605**	**1,644**	**1,644**	2021
2022	1,490	1,491	52	59	**1,542**	**1,550**	125	125	**1,668**	**1,675**	**1,675**	2022
2023	1,484	1,486	56	63	**1,540**	**1,549**	125	125	**1,665**	**1,675**	**1,675**	2023
2024	1,480	1,484	58	68	**1,538**	**1,552**	125	125	**1,663**	**1,677**	**1,677**	2024
2025	1,476	1,481	92	110	**1,568**	**1,591**	125	125	**1,694**	**1,717**	**1,717**	**2025**
2026	1,472	1,477	102	111	**1,575**	**1,587**	125	125	**1,700**	**1,713**	**1,713**	2026
2027	1,469	1,473	101	111	**1,570**	**1,584**	125	125	**1,695**	**1,710**	**1,710**	2027
2028	1,465	1,469	99	112	**1,564**	**1,581**	125	125	**1,690**	**1,706**	**1,706**	2028
2029	1,461	1,465	97	113	**1,559**	**1,577**	125	125	**1,684**	**1,703**	**1,703**	2029
2030	1,456	1,460	95	114	**1,551**	**1,574**	125	125	**1,676**	**1,699**	**1,699**	**2030**
2031	1,452	1,455	93	115	**1,544**	**1,570**	125	125	**1,670**	**1,695**	**1,695**	2031
2032	1,447	1,449	90	117	**1,537**	**1,566**	125	125	**1,662**	**1,691**	**1,691**	2032
2033	1,441	1,443	88	119	**1,529**	**1,562**	125	125	**1,654**	**1,688**	**1,688**	2033
2034	1,435	1,437	85	122	**1,520**	**1,559**	125	125	**1,645**	**1,684**	**1,684**	2034

Energy Sales Forecast (MWh)

	Econometric	+ Net Energy Added	= **MP Delivered Energy**	- Customer Gen.	= **System Energy Use**	**MP System**		
						Peak	*Load Factor*	
2000			10,029,324					
2001			9,476,860					
2002			9,950,113	1,187,858	11,137,971	1,636	*0.78*	2002
2003			9,638,417	1,232,635	10,871,052	1,671	*0.74*	2003
2004			10,117,168	1,267,728	11,384,896	1,721	*0.76*	2004
2005			10,345,265	1,258,895	11,604,160	1,727	*0.77*	**2005**
2006			10,443,777	1,195,070	11,638,847	1,753	*0.76*	2006
2007			10,670,857	1,252,965	11,923,822	1,763	*0.77*	2007
2008			10,826,034	1,276,158	12,102,192	1,719	*0.80*	2008
2009			8,062,253	1,108,014	9,170,267	1,545	*0.68*	2009
2010			10,417,422	1,299,292	11,716,714	1,789	*0.75*	**2010**
2011			10,988,200	1,422,107	12,410,307	1,780	*0.80*	2011
2012			11,107,357	1,200,317	12,307,674	1,790	*0.79*	2012
2013			10,985,809	1,185,139	12,170,948	1,782	*0.78*	2013
2014			11,038,979	1,287,965	12,326,944	1,821	*0.77*	2014
2015			10,059,466	1,227,221	11,286,687	1,597	*0.81*	**2015**
2016			9,830,787	1,074,786	10,905,573	1,692	*0.74*	2016
2017			10,654,217	1,215,894	11,870,111	1,794	*0.76*	2017
2018			10,638,691	1,236,276	11,874,967	1,728	*0.78*	2018
2019			10,482,913	1,064,454	11,547,367	1,675	*0.79*	2019
2020	10,106,626	(2,323,925)	**7,782,702**	978,117	**8,760,818**	**1,533**	***0.65***	**2020**
2021	10,052,243	(289,378)	**9,762,865**	975,444	**10,738,309**	**1,644**	***0.75***	2021
2022	10,013,647	324,014	**10,337,661**	979,846	**11,317,507**	**1,675**	***0.77***	2022
2023	9,981,217	472,408	**10,453,625**	979,846	**11,433,471**	**1,675**	***0.78***	2023
2024	9,989,292	500,194	**10,489,486**	982,531	**11,472,017**	**1,677**	***0.78***	2024
2025	9,948,302	731,339	**10,679,641**	979,846	**11,659,487**	**1,717**	***0.78***	**2025**
2026	9,938,641	872,891	**10,811,532**	979,846	**11,791,378**	**1,713**	***0.79***	2026
2027	9,928,774	871,034	**10,799,807**	979,846	**11,779,653**	**1,710**	***0.79***	2027
2028	9,942,711	871,304	**10,814,014**	982,531	**11,796,545**	**1,706**	***0.79***	2028
2029	9,896,509	866,507	**10,763,016**	979,846	**11,742,862**	**1,703**	***0.79***	2029
2030	9,875,778	864,798	**10,740,576**	979,846	**11,720,422**	**1,699**	***0.79***	**2030**
2031	9,848,912	863,089	**10,712,001**	979,846	**11,691,847**	**1,695**	***0.79***	2031
2032	9,851,325	863,866	**10,715,191**	982,531	**11,697,722**	**1,691**	***0.79***	2032
2033	9,791,164	860,460	**10,651,624**	979,846	**11,631,470**	**1,688**	***0.79***	2033
2034	9,752,985	860,363	**10,613,348**	979,846	**11,593,194**	**1,684**	***0.79***	2034

3. Other Information

A. Subject of Assumption

Section 7610.0320, Subpart 4, lists specific assumptions to be discussed. The following list contains the discussion of each assumption and Minnesota Power's response.

- Assumptions made regarding the availability of alternative sources of energy.
  - Minnesota Power makes no assumptions regarding the availability of alternative sources of energy.
- Assumptions made regarding expected conversion from other fuels to electricity or vice versa.
  - Minnesota Power's assumptions regarding conversion are explicitly included in the saturation rates for electric heating.
- Assumptions made regarding future prices of electricity for customers and the effect that such prices would have on system demand.
  - See Section 1.C.
- Assumptions made in arriving at the data requested (historical reporting).
  - Minnesota Power makes no such assumptions.
- Assumptions made regarding the effect of existing energy conservations programs under Federal or State legislation on long-term electricity demand
  - See Demand Side Management above.
- Assumptions made regarding the projected effect of new conservations programs the utility deems likely to occur through Federal or State legislation.
  - See Section 1.F.
- Assumptions made regarding current and future saturation levels of appliances and electric space heating.
  - See Section 1.F.

B. Coordination of Forecasts with Other Systems

Minnesota Power is a member of the Midwest Reliability Organization (MRO), Midcontinent Independent System Operator (MISO), Edison Electric Institute (EEI), Upper Midwest Utility Forecasters (UMUF), and other trade associations. While each member of these groups independently determines its power requirements, periodic meetings are held to share information and discuss forecasting techniques and methodologies.

C. Compliance with 7610.0320 Forecast Documentation

Statute or Rule	***Requirement***	***Reference Section***
7610.0320, Subp. 1(A)	The overall methodological framework that is used.	Section 1.A
7610.0320, Subp. 1(B)	The specific analytical techniques that are used, their purpose, and the components of the forecast to which they have been applied.	Sections 1.D, 1.F
7610.0320, Subp. 1(C)	The manner in which these specific techniques are related in producing the forecast.	Section 1.D
7610.0320, Subp. 1(D)	The purpose of the technique, typical computations specifying variables and data, and the results of appropriate statistical tests.	Section 1.F
7610.0320, Subp. 1(E)	Forecast confidence levels or ranges of accuracy for annual peak demand and annual electrical consumption.	Section 1.F
7610.0320, Subp. 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 to the utility.	Sections 1.B, 1.F
7610.0320, Subp. 2(A)	A complete list of data sets used in making the forecast, including a brief description of each data set and an explanation of how each was obtained, or a citation to the source.	Sections 1.C
7610.0320, Subp. 2(B)	A clear identification of any adjustments made to the 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.	Section 1.F
7610.0320, Subp. 3	Discussion of essential assumptions.	Sections 1.E, 1.F
7610.0320, Subp. 4	Subject of assumption.	Section 3
7610.0320, Subp. 5(A)	Description of the extent to which the utility coordinates its load forecasts with those of other systems.	Section 3
7610.0320, Subp. 5(B)	Description of the manner in which such forecasts are coordinated.	Section 3

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0120 REGISTRATION

ENTITY ID#	68
REPORT YEAR	2019

Number of Power Plants	19

UTILITY DETAILS

UTILITY NAME	Minnesota Power Co
STREET ADDRESS	30 W Superior St
CITY	Duluth
STATE	MN
ZIP CODE	55802-2093
TELEPHONE	218-722-5642 x3865
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	PRIVATE

CONTACT INFORMATION

CONTACT NAME	Benjamin Levine
CONTACT TITLE	Senior Utility Load Forecaster
CONTACT STREET ADDRESS	30 West Superior Street
CITY	Duluth
STATE	MN
ZIP CODE	55802-2093
TELEPHONE	218-355-3120
CONTACT EMAIL ADDRESS	blevine@mnpower.com

UTILITY OFFICERS

NAME	TITLE
Bethany Owen	President & Chief Executive Officer
Alan Hodnik	Executive Chairman
Robert Adams	Senior Vice President, Chief Financial Officer
Steve Morris	Vice President, Controller & Chief Accounting Officer
Maggie Thickens	Vice President, Chief Legal Officer & Corporate Secretary
Nicole Johnson	Vice President, Chief Administrative Officer
Franklyn Frederickson	Vice President, Minnesota Power Customer Experience
Julie Pierce	Vice President, Minnesota Power Strategy & Planning
Josh Skelton	Vice President, Minnesota Power Generation Operations & ALLETE Safety
Patrick Cutshall	Vice President, Corporate Treasurer
Daniel Gunderson	Vice President, Minnesota Power Transmission & Distribution
Ken Voss	Chief Technology Officer
Jered Granley	Chief Risk Officer
Bill Carlson	Chief Audit Officer

PREPARER INFORMATION (do not type "Same as Above")

PERSON PREPARING FORMS	Benjamin Levine
PREPARER'S TITLE	Senior Utility Load Forecaster
DATE	7/20/2020
PREPARER'S EMAIL ADDRESS	blevine@mnpower.com

COMMENTS

ALLOWABLE UTILITY TYPES

Code*

Private
Public
Co-op

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0150 FEDERAL OR STATE DATA SUBSTITUTIO

FEDERAL AGENCY (please spell out acronyms	FORM NUMBER	FORM TITLE	FILING CYCLE (enter an "X" in the cell) MONTHLY	YEARLY	OTHER
US Dept of Energy, Federal Energy Regulatory Commission	FERC-1	Annual Report of Major Electric Utility		X	
US Dept of Energy, Federal Energy Regulatory Commission	FERC-5	Statement of Electric Operating Revenue and Income	X		
US Dept of Energy, Federal Energy Regulatory Commission	FERC-45	Part 45 Informational Report			X
US Dept of Energy, Federal Energy Regulatory Commission	FERC-67	Steam Electric Plant, Air and Water Survey		X	
US Dept of Energy, Federal Energy Regulatory Commission	FERC-80	Licensed Projects Recreation Report			X
US Dept of Energy, Federal Energy Regulatory Commission	FERC-82	Retail Rate Level Change			X
US Dept of Energy, Energy Information Administration	EIA-411	Coordinated Bulk Power Supply and Demand Program Report		X	
US Dept of Energy, Energy Information Administration	EIA-412	Annual Electric Industry Financial Report (Terminated)		X	

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

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

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

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

See "LargestCustomers" worksheet for data entry.

C. MINNESOTA SERVICE AREA MAP

The referenced map must be submitted in electronic format.

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

D. PURCHASES AND SALES FOR RESALE

UTILITY NAME (please spell out acronyms)	INTERCONNECTED UTILITY (please spell out acronyms)	MWH PURCHASED	RESALE ONLY MWH SOLD FOR RESALE
Dahlberg Light & Power			0
Superior Water Light & Power			796,348
City of Aitkin			37,420
City of Biwabik			6,498
City of Brainerd			83,041
City of Buhl			6,697
City of Ely			37,602
City of Gilbert			11,167
City of Grand Rapids			158,656
City of Hibbing			123,184
City of Keewatin			5,725
City of Mountain Iron			19,214
City of Nashwauk			11,794
City of Pierz			10,524
City of Proctor			26,902
City of Randall			4,848
City of Two Harbors			28,370
City of Virginia			100,118
Other Non-Required Sales			3,184,844
Non-Associated Other Utilities		293,761	
Municipals		24,937	
Other Cooperatives		510,523	
Square Butte Electric Power		1,435,546	
Non-Utilities		64,841	
Power Marketers		1,331,070	
Other Public Authorities		3,587,080	
Utility		186	
Foreign		333,837	
City of Wadena	Western Area Power Administration (WAPA)	70,560	70,560
City of Staples	Western Area Power Administration (WAPA)	27,928	27,928
Great River Energy	Great River Energy (GRE)	2,487,626	2,408,547
Otter Tail Power	Otter Tail Power (OTP)	629,703	629,703

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

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

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

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

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

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

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

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

H. GENERATION DATA

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

I. ELECTRIC USE BY MINNESOTA RESIDENTIAL SPACE HEATING USERS

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

COLUMN 1 NUMBER OF RESIDENTIAL ELECTRICAL SPACE HEATING CUSTOMERS	COLUMN. 2 NUMBER OF RESIDENTIAL UNITS SERVED WITH ELECTRICAL SPACE HEATING	COLUMN 3 TOTAL MWH USED BY THESE CUSTOMERS AND UNITS
117,399	117,399	185,489

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 IN 2019

COUNTY CODE	COUNTY NAME	MWH DELIVERED	COUNTY CODE	COUNTY NAME	MWH DELIVERED
1	Aitkin		46	Martin	
2	Anoka		47	Meeker	
3	Becker		48	Mille Lacs	
4	Beltrami		49	Morrison	256,679
5	Benton	24,448	50	Mower	
6	Big Stone		51	Murray	
7	Blue Earth		52	Nicollet	
8	Brown		53	Nobles	
9	Carlton	343,537	54	Norman	
10	Carver		55	Olmstead	
11	Cass	120,562	56	Otter Tail	950
12	Chippewa		57	Pennington	
13	Chisago		58	Pine	73,708
14	Clay		59	Pipestone	
15	Clearwater		60	Polk	
16	Cook		61	Pope	
17	Cottonwood		62	Ramsey	
18	Crow Wing	125,418	63	Red Lake	
19	Dakota		64	Redwood	
20	Dodge		65	Renville	
21	Douglas		66	Rice	
22	Faribault		67	Rock	
23	Fillmore		68	Roseau	
24	Freeborn		69	St. Louis	6,100,985
25	Goodhue		70	Scott	
26	Grant		71	Sherburne	
27	Hennepin		72	Sibley	
28	Houston		73	Stearns	6,653
29	Hubbard	96,447	74	Steele	
30	Isanti		75	Stevens	
31	Itasca	766,398	76	Swift	
32	Jackson		77	Todd	205,777
33	Kanabec		78	Traverse	
34	Kandiyohi		79	Wabasha	
35	Kittson		80	Wadena	94,824
36	Koochiching	194,855	81	Waseca	
37	Lac Qui Parle		82	Washington	
38	Lake	603,563	83	Watonwan	
39	Lake of the Woods		84	Wilkin	
40	Le Sueur		85	Winona	
41	Lincoln		86	Wright	
42	Lyon		87	Yellow Medicine	
43	McLeod				
44	Mahnomen			GRAND TOTAL (Entered)	9,014,805
45	Marshall				
				GRAND TOTAL (Calculated)	9,014,805

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 (2019)	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	2,908	117,344	2,259	22,941	9	375	702	277	146,814
	MWH	88,830	25,741	3,549	109,104	439,344	148,594	1,537	4,210	820,908
February	No. of Customers	3,444	116,962	2,087	22,950	9	372	701	276	146,801
	MWH	69,527	32,212	3,341	103,662	368,730	140,009	1,413	3,650	722,544
March	No. of Customers	3,112	117,040	2,422	22,995	9	372	701	277	146,928
	MWH	67,753	27,356	3,554	101,992	428,070	144,488	1,195	4,499	778,907
April	No. of Customers	3,407	117,149	2,122	23,065	9	369	700	276	147,097
	MWH	54,159	19,362	2,641	88,977	399,066	147,674	1,080	3,936	716,895
May	No. of Customers	3,148	117,277	2,382	23,043	9	369	699	276	147,203
	MWH	55,322	13,337	2,571	92,826	418,661	133,285	947	3,127	720,076
June	No. of Customers	3,552	117,645	1,986	23,011	9	371	700	276	147,550
	MWH	54,849	8,520	2,068	93,195	406,274	130,939	834	3,563	700,242
July	No. of Customers	3,027	117,550	2,501	23,100	9	370	699	274	147,530
	MWH	77,998	5,476	2,909	111,454	424,001	129,904	803	4,477	757,022
August	No. of Customers	3,264	117,379	2,259	23,076	9	370	699	274	147,330
	MWH	67,951	5,424	2,833	109,378	406,732	149,911	854	4,212	747,296
September	No. of Customers	3,533	117,580	2,001	23,060	9	367	700	274	147,524
	MWH	58,651	4,988	2,036	93,518	411,226	139,870	995	3,990	715,275
October	No. of Customers	3,047	117,529	2,473	23,008	9	366	702	273	147,407
	MWH	68,011	6,582	2,651	93,836	446,926	140,052	1,122	4,150	763,329
November	No. of Customers	3,527	117,649	1,987	23,103	9	368	702	274	147,619
	MWH	76,892	14,692	2,340	100,367	450,040	139,888	1,301	3,854	789,373
December	No. of Customers	3,031	117,682	2,471	23,218	9	369	705	273	147,758
	MWH	82,755	21,800	3,673	104,093	439,633	125,947	1,401	3,636	782,938
	Total MWH	822,698	185,489	34,166	1,202,403	5,038,704	1,670,560	13,482	47,302	9,014,805

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 consume
Exclude station use, distribution losses, and unaccounted for energy losses from this table altogeth

Classification of Energy Delivered to Ultimate Consumers (include energy used during the year for irrigation and drainage pumping)	This column reports the number of farms, residences, commercial establishments, etc., and not the number of meters, where different. Number of Customers at End of Year	This column total should equal the grand total in the worksheet labeled "ElectricityByCounty" which provides deliveries by county. Megawatt hours (round to nearest MWH)	This column total will be used for the Alternative Energy Assessment and should NOT include revenues from sales for resale (Minnesota Statutes, Section 216B.62, Subd. 5). Revenue ($)
Farm	2,246	34,166	4,516,726
Non-Farm Residentia	120,649	1,008,187	105,216,072
Commercial	23,047	1,202,403	115,480,501
Industrial	379	6,709,265	415,956,121
Street & Highway Lighting	701	13,482	2,288,726
All other	275	47,302	4,228,805
Entered Tota	147,297	9,014,805	647,686,951
		^ should match ElectricityByCounty Tab, cell G55	
CALCULATED TOTAL	147,297	9,014,805	647,686,951
		^ should match ElectricityByCounty Tab, cell G55	

COMMENTS

REMEMBER TO SEND/UPLOAD THE FOLLOWING ATTACHMENTS:	
DO NOT INSERT THE ATTACHMENT INTO THIS WORKBOOK	
1	If applicable, the Largest Customer List (Attachment ELEC-1), if the separate LargestCustomers workbook was not used (pursuant to MN Rules Chapter 7610.0600 B)
2	Minnesota Service Area Map (pursuant to MN Rules Chapter 7610.0600 C)
3	Rate Schedules and Monthly Power Cost Adjustments (pursuant to MN Rules Chapter 7610.0600 E)
4	Report form EIA-861 filed with US Department of Energy (pursuant to MN Rules Chapter 7610.0600 F)
5	If applicable, for rural electric cooperatives, the Financial and Statistical Report filed with US Department of Agriculture (pursuant to MN Rules Chapter 7610.0600 G)

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

ELEC_###_2019 Annual Report (this workbook)
ELEC_###_2019 Largest Customer List
ELEC_###_2019 MN Service Area Map
ELEC_###_2019 Rate Schedules
ELEC_###_2019 Monthly Power Cost Adjustments
ELEC_###_2019 USDOE EIA-861
ELEC_###_2019 USDOA Financial and Statistical Report

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

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	0.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
Plant Total	0.00	0.00				

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide descriptio
***** Energy Source & Fuel Type**	BIT	Bituminous Coa
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood wast
	STM	Steam
	SUB	Sub-Bituminous Coa
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide descriptio

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 10 / Hours Unit Called Upon to Produce

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentag

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,7

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,76

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Boswell Energy Center	**PLANT ID**	68003
STREET ADDRESS	1210 NW 3rd St		
CITY	Cohasset		
STATE	MN	**NUMBER OF UNITS**	4
ZIP CODE	55721		
COUNTY	Itasca		
CONTACT PERSON	Paul Undeland		
TELEPHONE	218-313-4616		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	RET	ST	1958	COAL	0	Retired
2	RET	ST	1960	COAL	0	Retired
3	USE	ST	1973	COAL	1,571,078	
4	USE	ST	1980	COAL	2,588,933	MP share
				Plant Total	4,160,011.16	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0	0	0.0	0.0	0.0	
2	0	0	0.0	0.0	0.0	
3	355	355	51.0	66.0	8.7	
4	468	468	63.8	82.8	13.8	
Plant Total	823.00	823.00				

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	0	TONS	0	NG	0	MCF	N/A
2	SUB	0	TONS	0	NG	0	MCF	N/A
3	SUB	951,882	TONS	8,988	NG	41,079	MCF	N/A
4	SUB	1,939,004	TONS	9,047	NG	42,476	MCF	N/A

ALLOWABLE CODES

Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
***** Energy Source & Fuel Type**	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Laskin Energy Center	**PLANT ID**	68015
STREET ADDRESS	PO Box 166		
CITY	Aurora		
STATE	MN	**NUMBER OF UNITS**	2
ZIP CODE	55705		
COUNTY	Saint Louis		
CONTACT PERSON	Jodi Piekarski		
TELEPHONE	218-313-4416		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1953	GAS	10,287	
2	USE	ST	1953	GAS	9,167	
				Plant Total	19,454.01	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	55	55	2.5	97.7	4.7	
2	55	55	2.1	97.6	12.2	
Plant Total	110.00	110.00				

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	NG	156,220	MCF					
2	NG	139,799	MCF					

ALLOWABLE CODES

Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
***** Energy Source & Fuel Type**	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8,760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	M.L. Hibbard	PLANT ID	68009
STREET ADDRESS	4913 Main St		
CITY	Duluth		
STATE	MN	NUMBER OF UNITS	2
ZIP CODE	55807		
COUNTY	Saint Louis		
CONTACT PERSON	Chris Rousseau		
TELEPHONE	218-725-2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
3	USE	ST	1949	SUB/WOOD	6,059	
4	USE	ST	1951	SUB/WOOD	15,786	
				Plant Total	21,845.84	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
3	30	30	2.2	81.5	12.3	
4	32	32	6.4	84.1	0.0	
Plant Total	62.00	62.00				

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)
3	SUB	8,096	TONS	8,982	NG	5,842	MCF	
3	WOOD	172,819	TONS					
4	SUB	5,195	TONS	8,982	NG	2,731	MCF	
4	WOOD	94,488	TONS					

ALLOWABLE CODES

Cell Heading	Code	Code Definition
* Unit Status	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
*** Energy Source & Fuel Type	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
** Unit Type	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
**** Unit of Measure	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Rapids Energy Center	PLANT ID	68025
STREET ADDRESS	502 NW 3rd St		
CITY	Grand Rapids		
STATE	MN	NUMBER OF UNITS	4
ZIP CODE	55744		
COUNTY	Itasca		
CONTACT PERSON	Jodi Piekarski		
TELEPHONE	218-313-4416		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
4	USE	HC	1917	HYD	1,793	Gross MWs
5	USE	HC	1948	HYD	6,294	Gross MWs
6	USE	ST	1969	GAS	503	Gross MWs **Note** As of Jan. 2, 2020 the Wood/Coal boilers were shut down. Ju
7	USE	ST	1980	GAS	19,019	Gross MWs **Note** As of Jan. 2, 2020 the Wood/Coal boilers were shut down. Ju
				Plant Total	27,609.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
4	0.60	0.60	34.1	65.3	34.7	
5	1.50	1.50	48.0	74.4	25.6	
6	14.13	14.13	0.6	93.6	7.0	
7	9.58	9.58	16.7	46.1	3.2	
Plant Total	25.81	25.81				

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)
6	WOOD	0	TONS		SUB	118	TONS	9,244
7	WOOD	0	TONS		SUB	118	TONS	9,244
7	NG	1,743,609	MCF					

ALLOWABLE CODES

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

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	SAPPI Cloquet Turb Genr 5	**PLANT ID**	68020
STREET ADDRESS	2201 Avenue B		
CITY	Cloquet		
STATE	MN	**NUMBER OF UNITS**	1
ZIP CODE	55720		
COUNTY	Carlton		
CONTACT PERSON	David Chura		
TELEPHONE	218-355-3280		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
5	USE	ST	2001	WOOD/GAS	0	No MP ownership in 2019
				Plant Total	0.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
5	22.60	22.60	0.0	0.0	0.0	
Plant Total	22.60	22.60				

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)
5	WOOD	0	TONS		NG	0	MCF	

ALLOWABLE CODES

Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
***** Energy Source & Fuel Type**	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Taconite Harbor	**PLANT ID**	68026
STREET ADDRESS	PO Box 64		
CITY	Schroeder		
STATE	MN	**NUMBER OF UNITS**	3
ZIP CODE	55705		
COUNTY	Cook		
CONTACT PERSON	Eric Sutherland		
TELEPHONE	218-313-4772		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	STB	ST	1953	COAL	0	Reserve Shutdown 9/26/2016
2	STB	ST	1953	COAL	0	Reserve Shutdown 9/12/2016
3	RET	ST	1954	COAL	0	Retired 5/26/2015
				Plant Total	0.00	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	75.00	75.00	0.0	0.0	0.0	
2	75.00	75.00	0.0	0.0	0.0	
3	0.00	0.00	0.0	0.0	0.0	
Plant Total	150.00	150.00				

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	0.00	TONS	0	FO2	0.00	GAL	
2	SUB	0.00	TONS	0	FO2	0.00	GAL	
3	SUB	0.00	TONS	0	FO2	0.00	GAL	

ALLOWABLE CODES

Cell Heading	Code	Code Definition
* Unit Status	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
*** Energy Source & Fuel Type	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
** Unit Type	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
**** Unit of Measure	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage)
$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage)
$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Thomson Hydroelectric Station	**PLANT ID**	68016
STREET ADDRESS	180 State Hwy 210		
CITY	Carlton		
STATE	MN	**NUMBER OF UNITS**	6
ZIP CODE	55718		
COUNTY	Carlton		
CONTACT PERSON	Chris Rousseau		
TELEPHONE	218-725-2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1907	HYD	59,277.38	
2	USE	HC	1907	HYD	58,771.87	
3	USE	HC	1907	HYD	66,585.12	
4	USE	HC	1914	HYD	57,396.49	
5	USE	HC	1918	HYD	56,373.28	
6	USE	HC	1949	HYD	73,142.86	
				Plant Total	371,547.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	13.00	13.00	52.1%	98.5%	0.0%	
2	13.00	13.00	51.6%	99.4%	0.0%	
3	13.00	13.00	58.5%	99.6%	0.2%	
4	10.80	10.80	60.7%	99.1%	0.7%	
5	10.80	10.80	59.6%	99.5%	0.0%	
6	12.00	12.00	69.6%	99.1%	0.6%	
Plant Total	72.60	72.60				

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
***** Energy Source & Fuel Type**	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available X 100}}{\text{Hours Unit Called Upon to Produce}}$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production X 100}}{\text{Accredited Capacity Rating (MW) of the Unit X 8,760}}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Blanchard Hydroelectric Station	**PLANT ID**	68001
STREET ADDRESS	PO Box 157		
CITY	Little Falls		
STATE	MN	**NUMBER OF UNITS**	3
ZIP CODE	56345		
COUNTY	Morrison		
CONTACT PERSON	Chris Rousseau		
TELEPHONE	218-725-2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1925	HYD	40,874.09	
2	USE	HC	1925	HYD	43,238.33	
3	USE	HC	1988	HYD	26,241.07	
				Plant Total	110,353.49	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	6.00	6.00	77.77%	99.37%	0.07%	
2	6.00	6.00	82.26%	99.36%	0.09%	
3	6.00	6.00	49.93%	94.77%	2.33%	
Plant Total	18.00	18.00				

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition
* Unit Status	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
*** Energy Source & Fuel Type	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
** Unit Type	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
**** Unit of Measure	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) $\dfrac{\text{Hours Unit Failed to be Available X 100}}{\text{Hours Unit Called Upon to Produce}}$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage) $\dfrac{\text{Total Annual MWH of Production X 100}}{\text{Accredited Capacity Rating (MW) of the Unit X 8,760}}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Pillager Hydroelectric Station
STREET ADDRESS	13449 Pillager Dam Rd
CITY	Pillager
STATE	MN
ZIP CODE	56473
COUNTY	Cass
CONTACT PERSON	Chris Rousseau
TELEPHONE	218-725-2100
PLANT ID	68011
NUMBER OF UNITS	2

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1917	HYD	3,102.39	
2	USE	HC	1917	HYD	5,359.43	
				Plant Total	8,461.82	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.76	0.76	47.98%	61.63%	38.36%	
2	0.76	0.76	82.89%	99.28%	0.44%	
Plant Total	1.52	1.52				

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
***** Energy Source & Fuel Type**	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Little Falls Hydroelectric Station	**PLANT ID**	68007
STREET ADDRESS	1 Hydro St		
CITY	Little Falls		
STATE	MN	**NUMBER OF UNITS**	6
ZIP CODE	56345		
COUNTY	Morrison		
CONTACT PERSON	Chris Rousseau		
TELEPHONE	218-725-2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1919	HYD	6,344.07	
2	USE	HC	1919	HYD	6,325.57	
3	USE	HC	1920	HYD	7,001.73	
4	USE	HC	1979	HYD	7,649.92	
5	USE	HC	1906	HYD	1,944.93	
6	USE	HC	1906	HYD	1,925.20	
				Plant Total	31,191.42	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.80	0.80	90.53%	98.18%	1.67%	
2	0.80	0.80	90.26%	97.31%	2.12%	
3	1.10	1.10	72.66%	96.60%	3.31%	
4	1.10	1.10	79.39%	93.02%	6.90%	
5	0.40	0.40	55.51%	69.68%	1.47%	
6	0.40	0.40	54.94%	69.85%	28.95%	
Plant Total	4.60	4.60				

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
***** Energy Source & Fuel Type**	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8,760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Scanlon Hydroelectric Station
STREET ADDRESS	
CITY	Scanlon
STATE	MN
ZIP CODE	55720
COUNTY	Carlton
CONTACT PERSON	Chris Rousseau
TELEPHONE	218-725-2100
PLANT ID	68013
NUMBER OF UNITS	4

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1923	HYD	1,147.47	
2	USE	HC	1923	HYD	1,541.49	
3	USE	HC	1923	HYD	2,084.04	
4	USE	HC	1923	HYD	2,487.12	
				Plant Total	7,260.12	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.40	0.40	32.75%	58.91%	40.91%	
2	0.40	0.40	43.99%	57.24%	0.13%	
3	0.40	0.40	59.48%	73.03%	0.10%	
4	0.40	0.40	70.98%	99.33%	0.32%	
Plant Total	1.60	1.60				

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition
* Unit Status	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
*** Energy Source & Fuel Type	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
** Unit Type	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
**** Unit of Measure	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Sylvan Hydroelectric Station
STREET ADDRESS	13753 Sylvan Dam Rd
CITY	Pillager
STATE	MN
ZIP CODE	56473
COUNTY	Cass
CONTACT PERSON	Chris Rousseau
TELEPHONE	218-725-2100
PLANT ID	68014
NUMBER OF UNITS	3

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1913	HYD	4,255.97	
2	USE	HC	1913	HYD	3,740.59	
3	USE	HC	1915	HYD	3,533.62	
				Plant Total	11,530.18	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.60	0.60	80.97%	98.36%	0.47%	
2	0.60	0.60	71.17%	95.46%	0.64%	
3	0.60	0.60	67.23%	98.20%	0.62%	
Plant Total	1.80	1.80				

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
***** Energy Source & Fuel Type**	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Winton Hydroelectric Station	**PLANT ID**	68019
STREET ADDRESS	PO Box 156		
CITY	Winton		
STATE	MN	**NUMBER OF UNITS**	2
ZIP CODE	55796		
COUNTY	Lake		
CONTACT PERSON	Chris Rousseau		
TELEPHONE	218-725-2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
2	USE	HC	1923	HYD	11,464.56	
3	USE	HC	1923	HYD	13,452.04	
				Plant Total	24,916.60	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
2	2.00	2.00	65.44%	97.17%	0.91%	
3	2.00	2.00	76.78%	96.12%	1.67%	
Plant Total	4.00	4.00				

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
***** Energy Source & Fuel Type**	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Knife Falls Hydroelectric Station	**PLANT ID**	68006
STREET ADDRESS			
CITY	Cloquet		
STATE	MN	**NUMBER OF UNITS**	3
ZIP CODE	55720		
COUNTY	Carlton		
CONTACT PERSON	Chris Rousseau		
TELEPHONE	218-725-2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1922	HYD	3,805.41	
2	USE	HC	1922	HYD	4,756.43	
3	USE	HC	1922	HYD	3,722.49	
				Plant Total	12,284.32	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.80	0.80	54.30%	97.23%	0.54%	
2	0.80	0.80	67.87%	97.77%	0.17%	
3	0.80	0.80	53.12%	97.33%	0.63%	
Plant Total	2.40	2.40				

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
***** Energy Source & Fuel Type**	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available X 100}}{\text{Hours Unit Called Upon to Produce}}$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production X 100}}{\text{Accredited Capacity Rating (MW) of the Unit X 8,760}}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Fond Du Lac Hydroelectric Station	**PLANT ID**	68005
STREET ADDRESS	14302 Oldenberg Pkwy		
CITY	Duluth		
STATE	MN	**NUMBER OF UNITS**	1
ZIP CODE	55808		
COUNTY	Saint Louis		
CONTACT PERSON	Chris Rousseau		
TELEPHONE	218-725-2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1924	HYD	63,002.10	
				Plant Total	63,002.10	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	11.60	11.60	55.30%	89.90%	0.88%	
Plant Total	11.60	11.60				

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
***** Energy Source & Fuel Type**	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage)
$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage)
$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Prairie River Hydroelectric Station	**PLANT ID**	68012
STREET ADDRESS			
CITY	Grand Rapids		
STATE	MN	**NUMBER OF UNITS**	2
ZIP CODE	55734		
COUNTY	Itasca		
CONTACT PERSON	Chris Rousseau		
TELEPHONE	218-725-2100		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1921	HYD	1,869.66	
2	USE	HC	1921	HYD	1,354.47	
				Plant Total	3,224.13	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.70	0.70	30.49%	96.77%	0.45%	
2	0.40	0.40	38.65%	97.12%	0.10%	
Plant Total	1.10	1.10				

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
***** Energy Source & Fuel Type**	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Taconite Ridge 1	**PLANT ID**	68027
STREET ADDRESS	County Road 102		
CITY	Mountain Iron		
STATE	MN	**NUMBER OF UNITS**	1
ZIP CODE	55768		
COUNTY	St. Louis		
CONTACT PERSON	Dan Jones		
TELEPHONE	218-355-2335		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	WI	2008	Wind	46,807.83	
				Plant Total	46,807.83	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	25.00	25.00	22.40%	83.57%	16.43%	
Plant Total	25.00	25.00				

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
***** Energy Source & Fuel Type**	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage)
$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$
Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage)
$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Bison	**PLANT ID**	68028
STREET ADDRESS	5198 30th St		
CITY	New Salem		
STATE	ND	**NUMBER OF UNITS**	4
ZIP CODE	58563		
COUNTY	Morton		
CONTACT PERSON	Ben Reister		
TELEPHONE	701-843-6122		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	WI	2010/2011	Wind	244,356.12	
2	USE	WI	2012	Wind	284,921.66	
3	USE	WI	2012	Wind	290,828.91	
4	USE	WI	2014	Wind	750,938.50	
				Plant Total	1,571,045.19	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	81.80	81.80	34.2%	97.8%	1.8%	
2	105.00	105.00	31.0%	98.1%	1.5%	
3	105.00	105.00	31.6%	97.4%	2.2%	
4	204.80	204.80	41.8%	96.9%	2.7%	
Plant Total	496.60	496.60				

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
***** Energy Source & Fuel Type**	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2019

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	Camp Ripley Solar	**PLANT ID**	68029
STREET ADDRESS	15000 Highway 115		
CITY	Little Falls		
STATE	MN	**NUMBER OF UNITS**	1
ZIP CODE	56345		
COUNTY	Morrison		
CONTACT PERSON	Dan Jones		
TELEPHONE	218-355-2335		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	Solar	2016	SOLAR	14,011.80	
				Plant Total	14,011.80	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	10.00	10.00	16.00%	N/A	N/A	
Plant Total	10.00	10.00				

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)

ALLOWABLE CODES

Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
***** Energy Source & Fuel Type**	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

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

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

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

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

INSTRUCTIONS

These worksheet tabs correspond closely to the tables in the forecast instructions received by the utility.
The forecast instructions pertain to the data to be entered in each of the worksheet tabs.
PLEASE DO NOT CHANGE THE **NAME** OR **ORDER** OF ANY OF THE WORKSHEET TABS OR CHANGE THE NAME OF THIS WORKBOOK.

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

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

Each worksheet tab contains a section labeled "Comments" below the main data entry area.
You may enter any comments in that section to provide an explaination or clarification on the data entered; OR why data IS NOT being entered on the worksheet tab (for example: cells left blank).

Cells with automatic calculations (typically totals) are provided on some worksheets to assist with the accuracy of the data provided by the utility. It is recognized that there may be circumstances in which the data entered by the utility is more appropriate or accurate than the value in the corresponding automatically-calculated cell. If the value in the automatically-calculated cell does not match the value that your utility entered, please provide an explanation in the Comments area at the bottom of the worksheet tab.

Please complete the required worksheet tabs and save the completed workbook to your local computer.
Then attach the completed workbook to an email message, include your contact information, and send it to the following email address:
rule7610.reports@state.mn.us

If you have any questions please contact:

Anne Sell
MN Department of Commerce
rule7610.reports@state.mn.us
(651) 539-1851

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT - FORECAST SECTION

7610.0120 REGISTRATION

ENTITY ID#	68
REPORT YEAR	2019

RILS ID#	U10680

UTILITY DETAILS	
UTILITY NAME	Minnesota Power Company
STREET ADDRESS	30 W Superior St
CITY	Duluth
STATE	MN
ZIP CODE	55802-2093
TELEPHONE	218-722-5642 x3865
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	PRIVATE

CONTACT INFORMATION	
CONTACT NAME	Benjamin Levine
CONTACT TITLE	Senior Utility Load Forecaster
CONTACT STREET ADDRESS	30 W Superior St
CITY	Duluth
STATE	MN
ZIP CODE	55802-2093
TELEPHONE	218-355-3120
CONTACT E-MAIL	blevine@mnpower.com

COMMENTS

PREPARER INFORMATION	(do not type "Same as Above")
PERSON PREPARING FORMS	Benjamin Levine
PREPARER'S TITLE	Senior Utility Load Forecaster
DATE	7/20/2020
PREPARER'S EMAIL ADDRESS	blevine@mnpower.com

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	2019	No. of Customers	2,246	120,649	23,047	9	370	701	275	147,297	147,297
		MWH	34,166	1,008,187	1,202,403	5,038,704	1,670,560	13,482	47,302	9,014,805	9,014,805
Present Year	2020	No. of Customers	2,246	120,766	23,186	9	365	704	273	147,549	147,549
		MWH	34,166	1,005,610	1,227,755	2,648,800	1,454,578	12,321	45,985	6,429,214	6,429,214
1st Forecast Year	2021	No. of Customers	2,246	121,110	23,371	9	361	713	274	148,083	148,083
		MWH	34,166	1,000,730	1,227,491	4,426,719	1,271,367	12,205	45,550	8,018,229	8,018,229
2nd Forecast Year	2022	No. of Customers	2,246	121,380	23,560	9	356	715	272	148,537	148,537
		MWH	34,166	999,715	1,226,346	4,466,021	1,236,545	12,077	45,113	8,019,984	8,019,984
3rd Forecast Year	2023	No. of Customers	2,246	121,624	23,754	9	351	718	269	148,971	148,971
		MWH	34,166	998,951	1,226,790	4,468,010	1,234,366	11,901	45,202	8,019,386	8,019,386
4th Forecast Year	2024	No. of Customers	2,246	121,895	23,951	9	347	722	266	149,437	149,437
		MWH	34,166	1,001,308	1,230,816	4,491,561	1,233,528	11,800	45,365	8,048,545	8,048,545
5th Forecast Year	2025	No. of Customers	2,246	122,204	24,156	9	343	725	264	149,948	149,948
		MWH	34,166	996,756	1,228,137	4,688,812	1,234,586	11,652	44,819	8,238,929	8,238,929
6th Forecast Year	2026	No. of Customers	2,246	122,503	24,360	9	339	729	263	150,449	150,449
		MWH	34,166	995,818	1,232,659	4,848,086	1,237,477	11,545	44,745	8,404,497	8,404,497
7th Forecast Year	2027	No. of Customers	2,246	122,784	24,559	9	334	732	261	150,925	150,925
		MWH	34,166	995,757	1,237,501	4,854,432	1,237,719	11,435	44,647	8,415,657	8,415,657
8th Forecast Year	2028	No. of Customers	2,246	123,057	24,757	9	330	735	259	151,393	151,393
		MWH	34,166	999,564	1,244,424	4,874,239	1,238,591	11,365	44,363	8,446,712	8,446,712
9th Forecast Year	2029	No. of Customers	2,246	123,315	24,955	9	325	739	257	151,847	151,847
		MWH	34,166	995,765	1,243,374	4,863,482	1,238,501	11,212	43,838	8,430,339	8,430,339
10th Forecast Year	2030	No. of Customers	2,246	123,566	25,154	9	321	742	256	152,293	152,293
		MWH	34,166	995,646	1,245,153	4,860,282	1,240,446	11,099	43,498	8,430,290	8,430,290
11th Forecast Year	2031	No. of Customers	2,246	123,806	25,357	9	316	746	254	152,734	152,734
		MWH	34,166	995,254	1,250,433	4,854,562	1,240,744	10,974	43,086	8,429,219	8,429,219
12th Forecast Year	2032	No. of Customers	2,246	124,044	25,561	9	312	748	252	153,173	153,173
		MWH	34,166	998,771	1,257,801	4,857,486	1,214,630	10,874	42,898	8,416,625	8,416,625
13th Forecast Year	2033	No. of Customers	2,246	124,285	25,766	9	308	751	251	153,616	153,616
		MWH	34,166	996,403	1,256,776	4,830,777	1,181,621	10,704	42,442	8,352,889	8,352,889
14th Forecast Year	2034	No. of Customers	2,246	124,513	25,969	9	303	755	249	154,044	154,044
		MWH	34,166	998,381	1,257,757	4,815,253	1,150,771	10,555	42,156	8,309,039	8,309,039

* 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 ***actual number of customers*** the utility has in that category at year's end, ***not the number of meters***.

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	MN-ONLY TOTALS	Calculated MN-Only Totals
Past Year	2019	No. of Customers	2,246	120,649	23,047	9	370	701	275	147,297	147,297
		MWH	34,166	1,008,187	1,202,403	5,038,704	1,670,560	13,482	47,302	9,014,805	9,014,805
Present Year	2020	No. of Customers	2,246	120,766	23,186	9	365	704	273	147,549	147,549
		MWH	34,166	1,005,610	1,227,755	2,648,800	1,454,578	12,321	45,985	6,429,214	6,429,214
1st Forecast Year	2021	No. of Customers	2,246	121,110	23,371	9	361	713	274	148,083	148,083
		MWH	34,166	1,000,730	1,227,491	4,426,719	1,271,367	12,205	45,550	8,018,229	8,018,229
2nd Forecast Year	2022	No. of Customers	2,246	121,380	23,560	9	356	715	272	148,537	148,537
		MWH	34,166	999,715	1,226,346	4,466,021	1,236,545	12,077	45,113	8,019,984	8,019,984
3rd Forecast Year	2023	No. of Customers	2,246	121,624	23,754	9	351	718	269	148,971	148,971
		MWH	34,166	998,951	1,226,790	4,468,010	1,234,366	11,901	45,202	8,019,386	8,019,386
4th Forecast Year	2024	No. of Customers	2,246	121,895	23,951	9	347	722	266	149,437	149,437
		MWH	34,166	1,001,308	1,230,816	4,491,561	1,233,528	11,800	45,365	8,048,545	8,048,545
5th Forecast Year	2025	No. of Customers	2,246	122,204	24,156	9	343	725	264	149,948	149,948
		MWH	34,166	996,756	1,228,137	4,688,812	1,234,586	11,652	44,819	8,238,929	8,238,929
6th Forecast Year	2026	No. of Customers	2,246	122,503	24,360	9	339	729	263	150,449	150,449
		MWH	34,166	995,818	1,232,659	4,848,086	1,237,477	11,545	44,745	8,404,497	8,404,497
7th Forecast Year	2027	No. of Customers	2,246	122,784	24,559	9	334	732	261	150,925	150,925
		MWH	34,166	995,757	1,237,501	4,854,432	1,237,719	11,435	44,647	8,415,657	8,415,657
8th Forecast Year	2028	No. of Customers	2,246	123,057	24,757	9	330	735	259	151,393	151,393
		MWH	34,166	999,564	1,244,424	4,874,239	1,238,591	11,365	44,363	8,446,712	8,446,712
9th Forecast Year	2029	No. of Customers	2,246	123,315	24,955	9	325	739	257	151,847	151,847
		MWH	34,166	995,765	1,243,374	4,863,482	1,238,501	11,212	43,838	8,430,339	8,430,339
10th Forecast Year	2030	No. of Customers	2,246	123,566	25,154	9	321	742	256	152,293	152,293
		MWH	34,166	995,646	1,245,153	4,860,282	1,240,446	11,099	43,498	8,430,290	8,430,290
11th Forecast Year	2031	No. of Customers	2,246	123,806	25,357	9	316	746	254	152,734	152,734
		MWH	34,166	995,254	1,250,433	4,854,562	1,240,744	10,974	43,086	8,429,219	8,429,219
12th Forecast Year	2032	No. of Customers	2,246	124,044	25,561	9	312	748	252	153,173	153,173
		MWH	34,166	998,771	1,257,801	4,857,486	1,214,630	10,874	42,898	8,416,625	8,416,625
13th Forecast Year	2033	No. of Customers	2,246	124,285	25,766	9	308	751	251	153,616	153,616
		MWH	34,166	996,403	1,256,776	4,830,777	1,181,621	10,704	42,442	8,352,889	8,352,889
14th Forecast Year	2034	No. of Customers	2,246	124,513	25,969	9	303	755	249	154,044	154,044
		MWH	34,166	998,381	1,257,757	4,815,253	1,150,771	10,555	42,156	8,309,039	8,309,039

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

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

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

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

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	CALCULATED
		CONSUMPTION BY ULTIMATE CONSUMERS IN MINNESOTA MWH [7610.0310 B(1)]	CONSUMPTION BY ULTIMATE CONSUMERS OUTSIDE OF MINNESOTA MWH [7610.0310 B(2)]	RECEIVED FROM OTHER UTILITIES MWH [7610.0310 B(3)]	DELIVERED FOR RESALE MWH [7610.0310 B(4)]	TOTAL ANNUAL NET GENERATION MWH [7610.0310 B(5)]	TRANSMISSION LINE SUBSTATION AND DISTRIBUTION LOSSES MWH [7610.0310 B(6)]	TOTAL WINTER CONSUMPTION MWH [7610.0310 B(7)]	TOTAL SUMMER CONSUMPTION MWH [7610.0310 B(7)]	(GENERATION + RECEIVED) MINUS (RESALE + LOSSES) MINUS (CONSUMPTION) SHOULD EQUAL ZERO
Past Year	2019	9,014,805	0	7,660,860	4,652,952	6,477,004	470,107	5,096,534	5,093,203	0
Present Year	2020	6,429,214	0	2,842,531	2,765,299	7,100,384	748,402	4,302,985	3,345,647	0
1st Forecast Year	2021	8,018,229	0	2,993,885	2,657,498	8,356,932	675,090	4,842,994	4,708,409	0
2nd Forecast Year	2022	8,019,984	0	2,585,554	2,244,616	8,417,625	738,580	4,842,336	4,726,049	0
3rd Forecast Year	2023	8,019,386	0	2,592,630	2,248,656	8,389,544	714,132	4,873,498	4,725,940	0
4th Forecast Year	2024	8,048,545	0	2,496,685	2,253,262	8,496,953	691,831	4,864,075	4,729,481	0
5th Forecast Year	2025	8,238,929	0	2,160,527	2,387,713	9,163,995	697,880	5,038,757	4,870,396	0
6th Forecast Year	2026	8,404,497	0	2,047,720	2,285,772	9,357,439	714,890	5,046,953	4,922,181	0
7th Forecast Year	2027	8,415,657	0	2,069,645	2,278,414	9,333,387	708,961	5,084,885	4,932,446	0
8th Forecast Year	2028	8,446,712	0	2,037,138	2,267,085	9,398,257	721,598	5,062,601	4,938,211	0
9th Forecast Year	2029	8,430,339	0	2,082,832	2,236,485	9,277,683	693,690	5,071,201	4,945,331	0
10th Forecast Year	2030	8,430,290	0	2,160,184	2,184,347	9,152,462	698,009	5,071,237	4,947,077	0
11th Forecast Year	2031	8,429,219	0	2,089,032	2,261,122	9,324,781	723,472	5,092,378	4,949,302	0
12th Forecast Year	2032	8,416,625	0	2,107,538	2,270,711	9,292,791	712,994	5,048,505	4,934,826	0
13th Forecast Year	2033	8,352,889	0	2,103,649	2,303,827	9,280,751	727,684	5,031,429	4,917,931	0
14th Forecast Year	2034	8,309,039	0	2,117,507	2,278,548	9,191,661	721,581	1,697,152	4,897,279	0

COMMENTS

Minnesota Power's 2020 AFR was developed during a pandemic-induced recession, and the load outlook is highly uncertain. The forms submitted as part of this filing were completed using the best information available at the time.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

		FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Last Year Peak Day	2019	7.4	245.3	226.6	557.1	356.5	3.2	317.4	1713.5	1713.5

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	2019	1713.5	1703.5	1646.2	1566.8	1519.2	1571.2	1674.5	1608.2	1516.2	1562.6	1668.0	1608.3

COMMENTS
Coincident non-Large Power load at peak hour is approximated by scaling by class energy consumption in peak month.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

NAME OF OTHER UTILITY =>			Oliver Cty Wind (ND FPLE 1&2)	Wing River Wind (CBED)	Manitoba Hydro (MHEB)	Great River Energy (GRE)	Nobles 2	Contract Solar	Minnkota
Past Year	2019	Summer	17.4	0.2	100.0	150.0	-	7.5	50.0
		Winter	17.4	0.2	100.0	150.0	-	7.5	50.0
Present Year	2020	Summer	16.0	0.1	250.0	-	-	7.3	
		Winter	16.0	0.1	250.0	-	-	7.3	
1st Forecast Year	2021	Summer	17.3	0.1	250.0	-	37.5	7.4	
		Winter	17.3	0.1	250.0	-	37.5	7.4	
2nd Forecast Year	2022	Summer	17.3	0.1	250.0	-	37.5	17.7	
		Winter	17.3	0.1	250.0	-	37.5	17.7	
3rd Forecast Year	2023	Summer	17.3	0.1	250.0	-	37.5	20.8	
		Winter	17.3	0.1	250.0	-	37.5	20.8	
4th Forecast Year	2024	Summer	17.3	0.1	250.0	-	37.5	20.8	
		Winter	17.3	0.1	250.0	-	37.5	20.8	
5th Forecast Year	2025	Summer	17.3	0.1	250.0	-	37.5	20.8	
		Winter	17.3	0.1	250.0	-	37.5	20.8	
6th Forecast Year	2026	Summer	17.3	0.1	250.0	-	37.5	20.8	
		Winter	17.3	0.1	250.0	-	37.5	20.8	
7th Forecast Year	2027	Summer	17.3	0.1	250.0	-	37.5	20.8	
		Winter	17.3	0.1	250.0	-	37.5	20.8	
8th Forecast Year	2028	Summer	17.3	0.1	250.0	-	37.5	20.8	
		Winter	17.3	0.1	250.0	-	37.5	20.8	
9th Forecast Year	2029	Summer	17.3	0.1	250.0	-	37.5	20.8	
		Winter	17.3	0.1	250.0	-	37.5	20.8	
10th Forecast Year	2030	Summer	17.3	0.1	250.0	-	37.5	20.8	
		Winter	17.3	0.1	250.0	-	37.5	20.8	
11th Forecast Year	2031	Summer	17.3	0.1	250.0	-	37.5	20.8	
		Winter	17.3	0.1	250.0	-	37.5	20.8	
12th Forecast Year	2032	Summer	17.3	0.1	250.0	-	37.5	20.8	
		Winter	17.3	0.1	250.0	-	37.5	20.8	
13th Forecast Year	2033	Summer	17.3	0.1	250.0	-	37.5	20.8	
		Winter	17.3	0.1	250.0	-	37.5	20.8	
14th Forecast Year	2034	Summer	17.3	0.1	250.0	-	37.5	20.8	
		Winter	17.3	0.1	250.0	-	37.5	20.8	

COMMENTS

Minnesota Power long-term resource planning approach utilizes UCAP for unit accreditation. The accredited MW value of purchases in the table above are consistent with the "Load&GenCap" table.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

NAME OF OTHER UTILITY =>			Basin Electric Power Cooperative (BEPC)	NextEra	PY20-21 PRA			
Past Year	2019	Summer	100.0	30.0				
		Winter	100.0	30.0				
Present Year	2020	Summer		0.9	196.7			
		Winter		0.9	196.7			
1st Forecast Year	2021	Summer						
		Winter						
2nd Forecast Year	2022	Summer						
		Winter						
3rd Forecast Year	2023	Summer						
		Winter						
4th Forecast Year	2024	Summer						
		Winter						
5th Forecast Year	2025	Summer						
		Winter						
6th Forecast Year	2026	Summer						
		Winter						
7th Forecast Year	2027	Summer						
		Winter						
8th Forecast Year	2028	Summer						
		Winter						
9th Forecast Year	2029	Summer						
		Winter						
10th Forecast Year	2030	Summer						
		Winter						
11th Forecast Year	2031	Summer						
		Winter						
12th Forecast Year	2032	Summer						
		Winter						
13th Forecast Year	2033	Summer						
		Winter						
14th Forecast Year	2034	Summer						
		Winter						

COMMENTS
Minnesota Power long-term resource planning approach utilizes UCAP for unit accreditation. The accredited MW value of purchases in the table above are consistent with the "Load&GenCap" table.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

NAME OF OTHER UTILITY =>			Manitoba Hydro (MHEB)	TransAlta (TA)	Shell Energy North America (SENA)	NextEra (NEPM)
Past Year	2019	Summer	150	100	50	
		Winter	175		25	40
Present Year	2020	Summer	348			
		Winter	283			
1st Forecast Year	2021	Summer	283			
		Winter	283			
2nd Forecast Year	2022	Summer	133			
		Winter	133			
3rd Forecast Year	2023	Summer	133			
		Winter	133			
4th Forecast Year	2024	Summer	133			
		Winter	133			
5th Forecast Year	2025	Summer	133			
		Winter	133			
6th Forecast Year	2026	Summer	133			
		Winter	133			
7th Forecast Year	2027	Summer	133			
		Winter	133			
8th Forecast Year	2028	Summer	133			
		Winter	133			
9th Forecast Year	2029	Summer	133			
		Winter	133			
10th Forecast Year	2030	Summer	133			
		Winter	133			
11th Forecast Year	2031	Summer	133			
		Winter	133			
12th Forecast Year	2032	Summer	133			
		Winter	133			
13th Forecast Year	2033	Summer	133			
		Winter	133			
14th Forecast Year	2034	Summer	133			
		Winter	133			

COMMENTS
The participation purchases listed in the table above are energy-only transactions and do not affect the Company's Load/Capacity position.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

NAME OF OTHER UTILITY =>			NextEra (NEPM)	Shell Energy North America (SENA)	American Electric Power (AEPEP)	TransAlta	Macquarie
Past Year	2019	Summer	75			85	
		Winter	85		50		
Present Year	2020	Summer	50		50		
		Winter	50	50			50
1st Forecast Year	2021	Summer	50	50			50
		Winter					
2nd Forecast Year	2022	Summer					
		Winter					
3rd Forecast Year	2023	Summer					
		Winter					
4th Forecast Year	2024	Summer					
		Winter					
5th Forecast Year	2025	Summer					
		Winter					
6th Forecast Year	2026	Summer					
		Winter					
7th Forecast Year	2027	Summer					
		Winter					
8th Forecast Year	2028	Summer					
		Winter					
9th Forecast Year	2029	Summer					
		Winter					
10th Forecast Year	2030	Summer					
		Winter					
11th Forecast Year	2031	Summer					
		Winter					
12th Forecast Year	2032	Summer					
		Winter					
13th Forecast Year	2033	Summer					
		Winter					
14th Forecast Year	2034	Summer					
		Winter					

COMMENTS
The participation purchases listed in the table above are energy-only transactions and do not affect the Company's Load/Capacity position. The Nextera sale for winter 2019 is two separate contracts: the first is 50 MW on-peak and the second is 85 MW off-peak.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	Column 14	Column 15
			SEASONAL MAXIMUM DEMAND	SCHEDULE L. PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND	SEASONAL SYSTEM DEMAND	ANNUAL SYSTEM DEMAND	SEASONAL FIRM PURCHASES (TOTAL)	SEASONAL FIRM SALES (TOTAL)	SEASONAL ADJUSTED NET DEMAND (Column 3 - 5 + 6)	ANNUAL ADJUSTED NET DEMAND (Column 4 - 5 + 6)	NET GENERATING CAPABILITY	PARTICIPATION PURCHASES (TOTAL)	PARTICIPATION SALES (TOTAL)	ADJUSTED NET CAPABILITY (Column 9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (Column 7 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (Column 12 - 14)
Past Year	2019	Summer	1,533		1,533	1,692	325	130	1,338	1,496	1,733	-	-	1,733	121	1,459	274
		Winter	1,692		1,692	1,692	325	130	1,496	1,496	1,733	-	-	1,733	134	1,630	103
Present Year	2020	Summer	1,175		1,175	1,470	273	198	1,099	1,395	1,662	-	-	1,662	105	1,203	458
		Winter	1,470		1,470	1,470	273	198	1,395	1,395	1,662	-	-	1,662	131	1,526	136
1st Forecast Year	2021	Summer	1,484		1,484	1,506	312	-	1,172	1,194	1,428	-	-	1,428	132	1,304	124
		Winter	1,506		1,506	1,506	312	-	1,194	1,194	1,410	-	-	1,410	134	1,328	83
2nd Forecast Year	2022	Summer	1,492		1,492	1,503	323	-	1,169	1,181	1,403	-	-	1,403	133	1,302	102
		Winter	1,503		1,503	1,503	323	-	1,181	1,181	1,385	-	-	1,385	134	1,315	71
3rd Forecast Year	2023	Summer	1,489		1,489	1,503	326	-	1,164	1,177	1,405	-	-	1,405	133	1,296	109
		Winter	1,503		1,503	1,503	326	-	1,177	1,177	1,387	-	-	1,387	134	1,311	76
4th Forecast Year	2024	Summer	1,488		1,488	1,508	326	-	1,162	1,182	1,387	-	-	1,387	132	1,294	92
		Winter	1,508		1,508	1,508	326	-	1,182	1,182	1,368	-	-	1,368	134	1,316	52
5th Forecast Year	2025	Summer	1,519		1,519	1,549	326	-	1,193	1,224	1,622	-	-	1,622	135	1,328	294
		Winter	1,549		1,549	1,549	326	-	1,224	1,224	1,604	-	-	1,604	138	1,362	242
6th Forecast Year	2026	Summer	1,529		1,529	1,549	326	-	1,203	1,224	1,604	-	-	1,604	136	1,339	265
		Winter	1,549		1,549	1,549	326	-	1,224	1,224	1,604	-	-	1,604	138	1,362	242
7th Forecast Year	2027	Summer	1,528		1,528	1,550	326	-	1,202	1,224	1,604	-	-	1,604	136	1,338	266
		Winter	1,550		1,550	1,550	326	-	1,224	1,224	1,604	-	-	1,604	138	1,362	242
8th Forecast Year	2028	Summer	1,526		1,526	1,551	326	-	1,201	1,225	1,604	-	-	1,604	136	1,336	268
		Winter	1,551		1,551	1,551	326	-	1,225	1,225	1,604	-	-	1,604	138	1,363	241
9th Forecast Year	2029	Summer	1,525		1,525	1,551	326	-	1,199	1,226	1,604	-	-	1,604	136	1,335	269
		Winter	1,551		1,551	1,551	326	-	1,226	1,226	1,560	-	-	1,560	138	1,364	196
10th Forecast Year	2030	Summer	1,521		1,521	1,552	326	-	1,196	1,226	1,560	-	-	1,560	135	1,331	229
		Winter	1,552		1,552	1,552	326	-	1,226	1,226	1,474	-	-	1,474	138	1,364	110
11th Forecast Year	2031	Summer	1,519		1,519	1,548	326	-	1,193	1,222	1,474	-	-	1,474	135	1,328	146
		Winter	1,548		1,548	1,548	326	-	1,222	1,222	1,474	-	-	1,474	138	1,360	114
12th Forecast Year	2032	Summer	1,512		1,512	1,544	326	-	1,186	1,219	1,474	-	-	1,474	135	1,320	154
		Winter	1,544		1,544	1,544	326	-	1,219	1,219	1,474	-	-	1,474	137	1,356	118
13th Forecast Year	2033	Summer	1,504		1,504	1,541	326	-	1,178	1,215	1,474	-	-	1,474	134	1,312	162
		Winter	1,541		1,541	1,541	326	-	1,215	1,215	1,474	-	-	1,474	137	1,352	122
14th Forecast Year	2034	Summer	1,495		1,495	1,537	326	-	1,169	1,212	1,474	-	-	1,474	133	1,302	172
		Winter	1,537		1,537	1,537	326	-	1,212	1,212	1,474	-	-	1,474	137	1,349	126

COMMENTS

Minnesota Power's 2020 AFR was developed during a pandemic-induced recession, and the load outlook is highly uncertain. The forms submitted as part of this filing were completed using the best information available at the time. Also, Minnesota Power long-term resource planning approach reflected in the "Load&GenCap" table (above) utilizes UCAP for unit accreditation, and a MISO-Coincident peak demand forecast instead of the MP System peak (Non-Coincident Peak). The Net Reserve Capacity Obligation of 8.9% is assumed for both summer and winter.

Note: the "Past Year 2019" is reported using UCAP and actual MISO-Coincident loads for summer and winter peak. Inclusion of actual (as opposed to forecast) loads in 2019 will result in a surplus/deficit position that varies from was entered in MISO Module E for PY 19-20.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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

		ADDITIONS	RETIREMENTS
Past Year	2019		
Present Year	2020		
1st Forecast Year	2021		
2nd Forecast Year	2022		
3rd Forecast Year	2023		
4th Forecast Year	2024		
5th Forecast Year	2025	254	
6th Forecast Year	2026		
7th Forecast Year	2027		
8th Forecast Year	2028		
9th Forecast Year	2029		
10th Forecast Year	2030		
11th Forecast Year	2031		
12th Forecast Year	2032		
13th Forecast Year	2033		
14th Forecast Year	2034		

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued) **PUBLIC DOCUMENT – TRADE SECRET DATA EXCISED**

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

[TRADE SECRET DATA BEGINS

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

		FUEL TYPE 1		FUEL TYPE 2		FUEL TYPE 3		FUEL TYPE 4		FUEL TYPE 5		FUEL TYPE 6		FUEL TYPE 7	
		Name of Fuel	SUB	Name of Fuel	FO2	Name of Fuel	WOOD	Name of Fuel	NG	Name of Fuel	HYD	Name of Fuel	WIND	Name of Fuel	SOLAR
		Unit of Measure	TONS	Unit of Measure	GALLONS	Unit of Measure	TONS	Unit of Measure	MCF	Unit of Measure		Unit of Measure		Unit of Measure	
		QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED
Past Year	2019														
Present Year	2020														
1st Forecast Year	2021														
2nd Forecast Year	2022														
3rd Forecast Year	2023														
4th Forecast Year	2024														
5th Forecast Year	2025														
6th Forecast Year	2026														
7th Forecast Year	2027														
8th Forecast Year	2028														
9th Forecast Year	2029														
10th Forecast Year	2030														
11th Forecast Year	2031														
12th Forecast Year	2032														
13th Forecast Year	2033														
14th Forecast Year	2034														

TRADE SECRET DATA ENDS]

LIST OF FUEL TYPES

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

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0500 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	Forbes - Minntac		25.5
x			230.	795	ACSR	AC	Arrowhead - Bear Creek		55.24
x			230.	1431/1590	ACSR	AC	Boswell - Blackberry Ckt 1		18.19
x			230.	954	ACSR	AC	Arrowhead - Forbes		47.49
x			230.	795	ACSR	AC	Riverton - Badoura		46.4
x			230.	795	ACSR	AC	Riverton - Blackberry		67.2
x			230.	954	ACSR	AC	Iron Range - Forbes		33.84
x			230.	1,590	ACSR	AC	Shannon - McCarthy Lake		16.4
x			230.	1431/1590	ACSR	AC	Boswell - Blackberry Ckt 2		18.81
x			230.	954	ACSR	AC	Shannon - Minntac		23.12
x			230.	795	ACSR	AC	Riverton - Wing River (Staples)1		35.97
x			230.	954	ACSR	AC	Iron Range - 98 Line Tap		64.25
x			230.	954	ACSR	AC	Arrowhead - 98 Line Tap		0.74
x			230.	954	ACSR	AC	Hilltop - 98 Line Tap		7.02
x			230.	795	ACSR	AC	Badoura - Hubbard		14.98
x			230.	1,590	ACSR	AC	Calumet - McCarthy Lake		3.32
x			230.	1,590	ACSR	AC	Boswell - Calumet		25.84
x			230.	954	ACSR	AC	Iron Range - Blackberry Ckt 1		0.58
x			230.	954	ACSR	AC	Iron Range - Blackberry Ckt 2		0.76
x			230.	795	ACSR	AC	Bear Creek - Rock Creek (Kettle River)1		11.8
x			230.	795	ACSS	AC	Boswell - Zemple3		0.68
x			230.	795	ACSS	AC	Zemple - Cass Lake3		4.11
x			230.	954	ACSR	AC	Shannon - Littlefork		81.61
x			230.	795	ACSR	AC	Hubbard - Audubon (Shell River)1		4.53
x			230.	954	ACSR	AC	Littlefork - Moranville (Little Fork River)1		7.5
x			230.	795	ACSS	AC	Cass Lake - Wilton3		1.77
x			250.	2,839	ACSR	DC	Arrowhead - Square Butte (ND Border)2		231.56
x			345.	2-954	ACSS/TW	AC	Monticello - Quarry4		4.23
x			345.	2-954	ACSS/TW	AC	Quarry - Riverview Road4		4.55
x			345.	2-954	ACSS/TW	AC	Riverview Road - Alexandria Switching Station4		4.93
x			345.	2-954	ACSS/TW	AC	Alexandria Switching Station - Bison (ND Border)2,4		19.85
x			500.	3-1192	ACSR	AC	Chisago (Kettle River)1 - Forbes (Denham)1		7.79
x			500.	3-1192	ACSR	AC	Iron Range - Dorsey (MB Border)2		224.17

COMMENTS
1 Point of interconnection in parenthesis for partially-owned tie lines
2 Only mileage in Minnesota shown for lines that cross state or provincial boundaries
3 MP-owned miles represent 9.3% of total circuit mileage under a "tenants in common" model
4 MP-owned miles represent 14.7% of total circuit mileage under a "tenants in common" model

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0600, item A. 24 - HOUR PEAK DAY DEMAND

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

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

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

	DATE OF PEAK DAY DEMAND	DATE OF PEAK DAY DEMAND	
	7/26/19	1/29/19	**<= ENTER DATES**
TIME OF DAY	MW USED ON **SUMMER** PEAK DAY	MW USED ON **WINTER** PEAK DAY	
0100	1382	1521	
0200	1365	1524	
0300	1377	1541	
0400	1384	1544	
0500	1380	1571	
0600	1421	1584	
0700	1445	1632	
0800	1498	1660	
0900	1535	1681	
1000	1550	1690	
1100	1574	1664	
1200	1604	1662	
1300	1627	1655	
1400	1635	1650	
1500	1660	1663	
1600	1661	1684	
1700	**1675**	1690	
1800	1665	**1714**	
1900	1639	1675	
2000	1620	1660	
2100	1605	1636	
2200	1588	1594	
2300	1542	1565	
2400	1502	1551	

COMMENTS

REMEMBER TO SEND/UPLOAD THE FOLLOWING ATTACHMENTS:

DO NOT INSERT THE ATTACHMENT INTO THIS WORKBOOK

1 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.
(pursuant to MN Rules Chapter 7610.0500 Subpart 1, Existing transmission lines)

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

ELEC_###_2019 Forecast Report (this workbook)
ELEC_###_2019 TL Map

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