Appendix P

July 2023 Annual Electric Utility Forecast Reports

Appendix P

Forecast Information from Minnesota Power's and Great River Energy's July 2023 Annual Electric Utility Forecast Reports

Pursuant to Minn. R. 7849.0270, subp. 1 and Minn. R. 7849.0270, subp. 2(A)-2(D), a Certificate of Need application must provide information related to peak demand and annual consumption data for an applicant's entire service territory and system. Minnesota Power and Great River Energy requested and were granted an exemption from this rule requirement by the Minnesota Public Utilities Commission.[1] In lieu of the information required by Minn. R. 7849.0270, Minnesota Power and Great River Energy agreed to provide substitute data in the form of forecast information from Minnesota Power's and Great River Energy's most recent Annual Electric Utility Forecast Reports ("AFRs") and any forecast information used by the Applicants or MISO in analyzing the need for the Project.[2]

Minnesota Power and Great River Energy filed their 2023 AFR filings with the Commission on June 30, 2023 and July 7, 2023, respectively, in Docket No. E-999/PR-23-11. A copy of Minnesota Power's 2023 AFR filing and the forecast information from Great River Energy's most recent AFR are provided in this appendix. Other forecast information used by the Applicants or MISO in analyzing the need for the Project is discussed in Chapter 3 of the Application.

[1] *In re Application of Minnesota Power and Great River Energy for a Certificate of Need for the Northland Reliability Project 345 kV Transmission Line*, Docket No. E015, ET2/CN-22-416, ORDER (June 21, 2023).
[2] *In re Application of Minnesota Power and Great River Energy for a Certificate of Need for the Northland Reliability Project 345 kV Transmission Line*, Docket No. E015, ET2/CN-22-416, Request for Exemption from Certain Certificate of Need Application Content Requirements (Apr. 19, 2023).

Appendix P: Great River Energy 2023 Annual Electric Utility Forecast Report Demand and Energy Forecast[1]

Forecast Year	Annual Peak Demand (MW)	Annual Energy (MWH)
2022 Actual	1,857	10,527,769
2023	1,766	10,535,597
2024	1,816	10,657,527
2025	1,825	10,767,309
2026	1,831	10,976,289
2027	1,836	11,052,951
2028	1,842	11,107,915
2029	1,848	11,163,155
2030	1,853	11,218,670
2031	1,858	11,274,463
2032	1,864	11,330,535
2033	1,870	11,386,887
2034	1,877	11,443,521
2035	1,884	11,500,438
2036	1,892	11,557,640
2037	1,900	11,615,128

[1] MPUC Docket No. E999/PR-23-11

minnesota power
AN ALLETE COMPANY

30 West Superior Street
Duluth, MN 55802-2093
www.mnpower.com

June 30, 2023

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 2023 Annual Electric Utility Forecast Report
Docket No. E-999/PR-23-11

Dear Ms. Sell:

Enclosed please find Minnesota Power's 2023 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.

Information included in the "**ELEC_68_2022 Largest Customer List.xlsx**" and "**ELEC_68_2022 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 23-11:

- ELEC_68_2022 Annual Report.xlsx
- ELEC_68_2022 Forecast Report.xlsx (**TRADE SECRET** & Public versions)
- ELEC_68_2022 Largest Customer List.xlsx (**TRADE SECRET**)
- ELEC_68_2022 Monthly Power Cost Adjustments.xlsx
- ELEC_68_2022 MN Service Area Map.pdf
- ELEC_68_2022 USDOE EIA-861.pdf
- ELEC_68_2022 Rate Schedules.pdf
- METHOD23.pdf (**TRADE SECRET** & Public versions)

Please don't hesitate to contact me if you need additional paper copies or have any questions.

Sincerely,

Timothy Beddow
Customer Insights and Forecasting Analyst Senior
Minnesota Power
218-355-3391
tbeddow@mnpower.com

TB:th
Attach.

cc: Leah Peterson
David Moeller
Jennifer Cady
Marcia Podratz

**STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION**

In the Matter of Minnesota Power's 2023 Annual Electric Utility Forecast Report	Docket No. E-999/PR-23-11

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 a 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 2023 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. 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.

Minnesota Power has observed increased variability and lower industry operating levels in recent years. This variability and lower operating levels are expected to continue over the forecast period and are taken into account as a normalized adjustment to a representative level in the forecast.

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Table of Figures

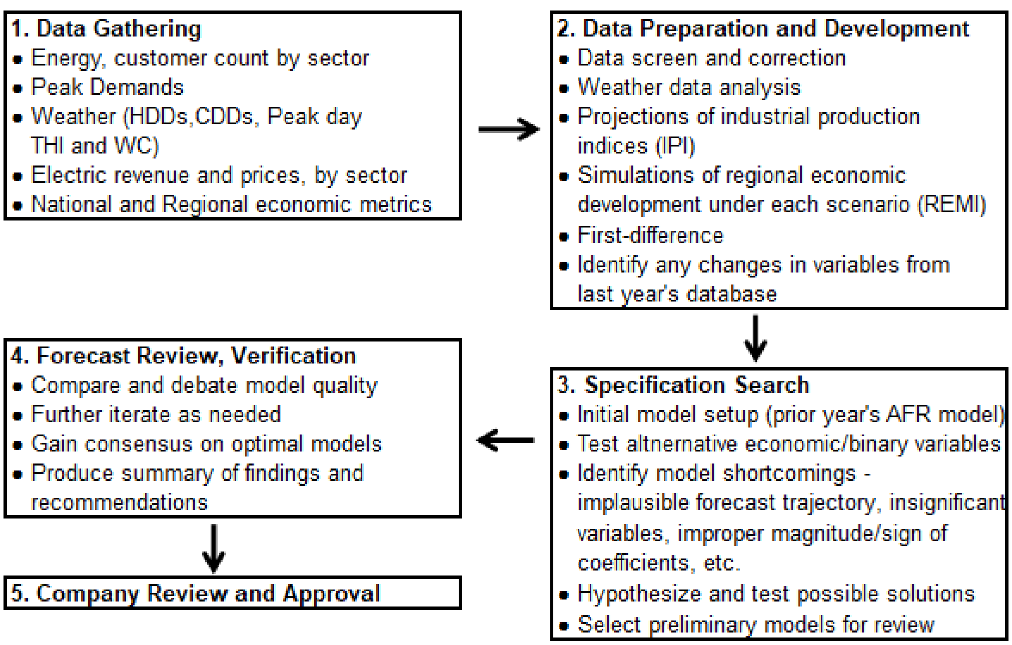
I. Forecast Methodology

A. Overall Framework (7610.0320, Subp. 1.A)

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) initial review and verification, and 5) internal company review and approval. The steps of the forecast process are sequential, and the process is diagrammed in Figure 1 below.

Figure 1: Minnesota Power's Forecast Process



B. Specific Analytical Techniques (7610.0320, Subp. 1.B) and Relation to Forecast (7610.0320, Subp. 1.C)

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 the following data transformations in data development:

- *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 AFR 2023. 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 (peak demand).
- *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.

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. Gross Domestic Product (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.

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

- *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. Minnesota Power adjusts 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).

  This approach is supplemented 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 is 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 2023 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.

- *Modeled Peak Demand using hour-specific weather observations* – 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. The Company has seen improved model statistics using this approach.

As a rule, all models are ordinary least squares (OLS), which are simple, transparent, explainable, and produce optimal estimates of the coefficients. Once input variables' coefficients are determined to be statistically significant and models are 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.

C. Statistical Techniques, Typical Computations Specifying Variables and Data, and the Results of Appropriate Statistical Tests (7610.0320, Subp. 1.D)

This section presents the statistical detail of all models utilized in the development of the AFR 2023 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, P-value and Heteroscedasticity and Autocorrelation Consistent (HAC) P-value. Minnesota Power includes the HAC P-value as it adjusts for biases resulting from autocorrelation and/or heteroscedasticity. These HAC-adjusted P-values are used to determine inclusion/exclusion in the model. Coefficients themselves are not affected by this adjustment. For each model, 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.

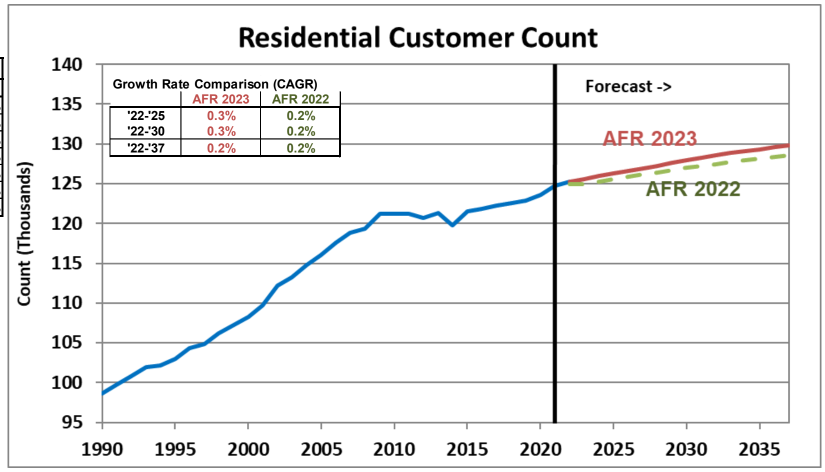
Below, Minnesota Power offers a discussion of the modeling approach, econometric interpretations of key variables, and potential model issues for each model. This portion of the model documentation also compares this year's model with last year's model and discusses findings or insights gained.

Figure 2: Residential Customer Count – Expected Scenario

Residential Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2022
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	98,163.07	0.00%	0.00%
Bill_Res_1	(2,152.37)	0.00%	0.00%
Bill_Res_2	(2,790.00)	0.00%	0.00%
Dum_2009_2037	8,168.46	0.00%	0.00%
T_2009_2037	(33.15)	0.00%	0.00%
Res_C_2021_2037	1,577.56	0.00%	0.00%
MSA_HousStart_Cumulative	1.07	0.00%	0.00%



Residential Customer Count		
	Count	**Y/Y Growth**
2011	121,251	
2012	120,697	-0.5%
2013	121,314	0.5%
2014	121,601	0.2%
2015	121,515	-0.1%
2016	121,836	0.3%
2017	122,295	0.4%
2018	122,557	0.2%
2019	122,926	0.3%
2020	123,617	0.6%
2021	124,691	0.9%
2022	125,243	0.4%
2023	125,613	**0.3%**
2024	125,939	**0.3%**
2025	126,257	**0.3%**
2026	126,601	**0.3%**
2027	126,940	**0.3%**
2028	127,269	**0.3%**
2029	127,596	**0.3%**
2030	127,920	**0.3%**
2031	128,238	**0.2%**
2032	128,553	**0.2%**
2033	128,849	**0.2%**
2034	129,112	**0.2%**
2035	129,348	**0.2%**
2036	129,576	**0.2%**
2037	129,801	**0.2%**

Model Statistics	Magnitude
Adjusted R^2	99.8%
AIC	5902
Durban-Watson	0.7
MAPE	0.27
In-Sample RMSE	413

Model Discussion

Both AFR 2023 and AFR 2022 had growth rates of approximately 0.2%, but AFR 2023 starts from a slightly higher level, resulting in a slightly higher residential cutomer count.

The key economic variable driving the residential customer count projection was Duluth MSA Cumulative Housing Starts, which is a rolling accumulation of annual housing starts beginning in 1990. This transformation converts a rate variable into a level variable, which better describes the underlying long-term trend of customer growth.

A combination of binary and trend variables ("Dum_2009_2037"" and "T_2009_2037") denote post-recession shifts in the relationship of MSA housing starts and residential customer count; housing starts continued, but customer counts stalled. This may be due in part to a shift towards suburban construction, where home construction continued but just outside Minnesota Power service territory. Without these corrective binary and a trend variables, the model would overestimate customer counts in recent historical years and, presumably, in the forecast timeframe.

The "Res_C_2021_2037" binary variable begins in mid-2021 and denotes a realignment of the MSA housing starts metric and customer counts; the mid-pandemic increase in demand for housing appears to be driving residential development in Minnesota Power's service territory, leading to customer growth. Two binary variables (Bill_Res) account for divergence from long-term trends due to "seasonal billing" between 1994 and 2001. This accounting practice recorded customer counts from November to May as 2,000-6,000 lower than from June to October.

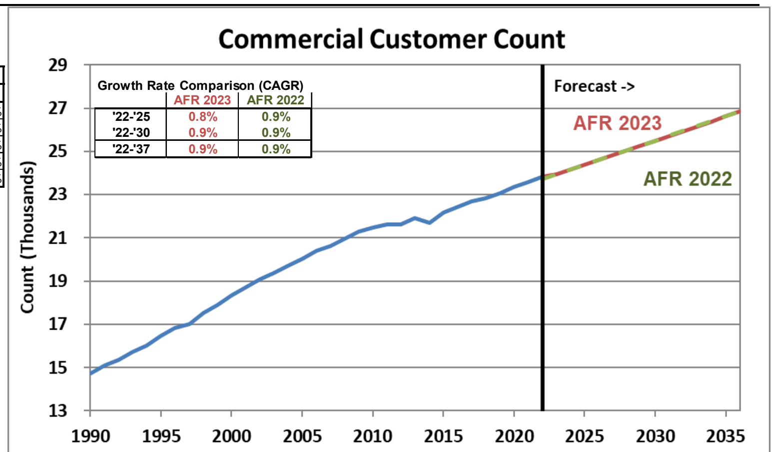
This year's model is highly comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a high goodness-of-fit, and the AIC indicates a highly parsimonious model that's not over fit. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics such as the MAPE indicate model accuracy is comparable to AFR 2022 (0.27%).

Figure 3: Commercial Customer Count – Expected Scenario

Commercial Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2022
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	13,500.23	0.00%	0.00%
T	27.26	0.00%	0.00%
Bi_2010_2037	2,250.37	0.00%	0.00%
T_2010_2037	(10.68)	0.00%	0.00%
MSA_Real_GMP	0.12	0.00%	0.00%



Commercial Customer Count		
	Count	Y/Y Growth
2011	21,603	
2012	21,614	0.1%
2013	21,915	1.4%
2014	22,096	0.8%
2015	22,170	0.3%
2016	22,420	1.1%
2017	22,695	1.2%
2018	22,834	0.6%
2019	23,059	1.0%
2020	23,346	1.2%
2021	23,580	1.0%
2022	23,816	1.0%
2023	23,936	**0.5%**
2024	24,159	**0.9%**
2025	24,397	**1.0%**
2026	24,617	**0.9%**
2027	24,835	**0.9%**
2028	25,055	**0.9%**
2029	25,272	**0.9%**
2030	25,493	**0.9%**
2031	25,716	**0.9%**
2032	25,941	**0.9%**
2033	26,165	**0.9%**
2034	26,390	**0.9%**
2035	26,614	**0.8%**
2036	26,840	**0.8%**
2037	27,066	**0.8%**

Model Statistics	Magnitude
Adjusted R^2	99.8%
AIC	4829
Durban-Watson	1.1
MAPE	0.39
In-Sample RMSE	107

Model Discussion

The AFR 2023 forecast of commercial customer count is similar to the AFR 2022. The forecast's long-term annual growth is very similar to the AFR 2022 growth rate with both averaging approximately 0.9%

The key economic driver of customer growth was Duluth MSA Real Gross Metro Product (GMP). Local GMP has historically tracked well with commercial customer counts, but COVID-19 caused the two series (GMP and commercial counts) to diverge, likely due to government supports like the Paycheck Protection Program (PPP) and Minnesota Power suspending disconnections for small business (general service) customers. A Trend variable accounts for some of this underlying customer count growth that appears unrelated to immediate economic conditions.

A combination of binary and trend variables ("Bi_2010_2037" and "T_2010_2037") denote a post-Great Recession, abrupt shift in customer count growth – customer counts grew at an average rate of 2.0% prior to 2010, and only 0.8% since. Without these corrective binary and trend variables, the model would overestimate customer counts in recent historical years and, presumably, in the forecast timeframe.

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 AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are very similar: MAPE is the nearly the same as the 2022 model (0.4%), and RMSE is 107 vs. 109 in the 2022 model.

Figure 4: Industrial Customer Count – Expected Scenario

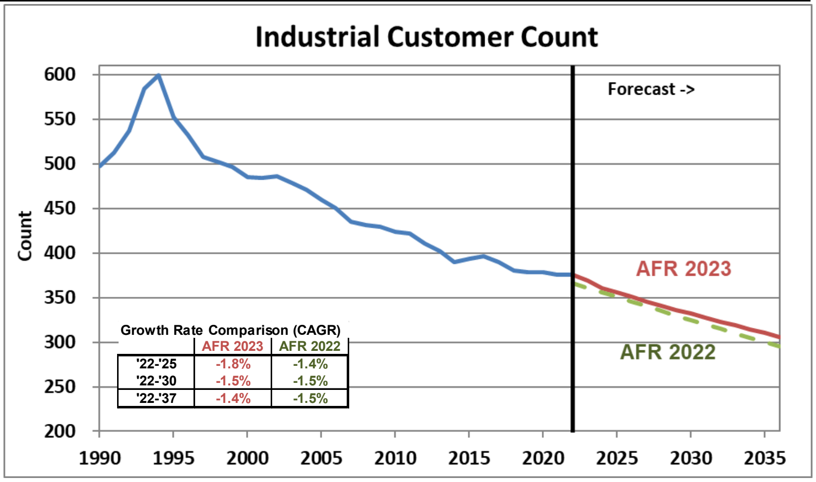
Industrial Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2022
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	427.45	0.00%	0.00%
T	(0.36)	0.00%	0.00%
Ind_1991_1997	42.14	0.00%	0.00%
MFG_13	0.005	0.00%	0.00%

Industrial Customer Count	Count	Y/Y Growth
2011	421	
2012	411	-2.4%
2013	402	-2.2%
2014	394	-2.0%
2015	394	-0.1%
2016	396	0.6%
2017	390	-1.6%
2018	380	-2.5%
2019	379	-0.3%
2020	378	-0.2%
2021	375	-0.7%
2022	375	0.0%
2023	369	**-1.7%**
2024	361	**-2.2%**
2025	356	**-1.5%**
2026	351	**-1.3%**
2027	346	**-1.5%**
2028	341	**-1.5%**
2029	336	**-1.2%**
2030	332	**-1.3%**
2031	328	**-1.3%**
2032	323	**-1.4%**
2033	319	**-1.3%**
2034	314	**-1.3%**
2035	310	**-1.4%**
2036	306	**-1.3%**
2037	302	**-1.3%**

Model Statistics	Magnitude
Adjusted R^2	93.1%
AIC	3358
Durban-Watson	0.1
MAPE	2.20
In-Sample RMSE	17



Model Discussion

The AFR 2023 forecast annual growth rate for industrial customer count increased from -1.6% to -1.4%, but the customer count projection is similar; AFR 2023 is just 11 customers higher than the AFR 2022 outlook by 2037.

The key economic driver of industrial customer count was Manufacturing sector employment (13-County). This sector was a good representation of Minnesota Power's industrial customers as it encompasses the range of business sectors in this class, including: wood products, pulp/paper/paperboard mills, food products, foundries, and petroleum refining.

"Ind_1991_1997" is a binary variable that denotes the January-1991 through December-1997 timeframe where Industrial customer counts increased and then decreased very rapidly: a 23.7% increase from January-1991 to June-1994, followed by a 36.2% decrease from June-1994 to December-1997. These dramatic swings in customer counts were most likely due to accounting classifications of customers at the time and this binary variable effectively "backs-out" these points from consideration to avoid biasing the model.

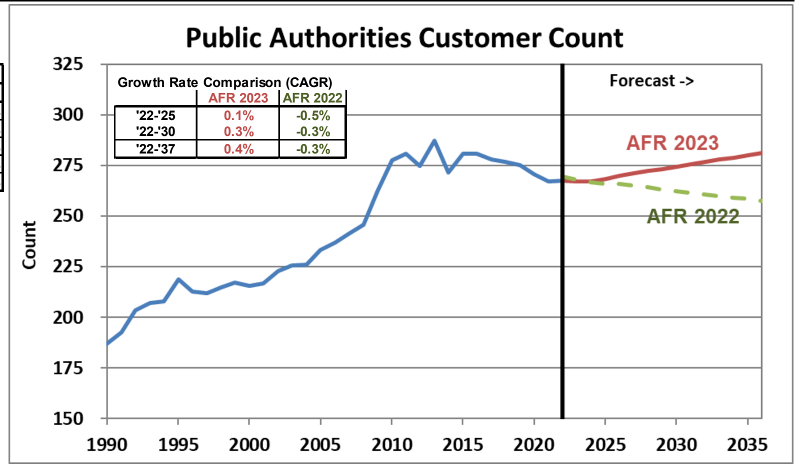
This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's moderate goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. The MAPE has declined 0.05 from 2.25 in AFR 2022 to 2.20 in the AFR 2023 model, and RMSE is unchanged at 17 from last year's model.

Figure 5: Public Authorities Customer Count – Expected Scenario

Public Authorities Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2022
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	126.61	0.00%	0.00%
Bi_Gov_Light_2009_2037	42.31	0.00%	0.00%
Bi_2015_2037	46.50	0.00%	0.00%
T_2015_2037	(0.15)	0.00%	0.00%
GRP_13	4.65	0.00%	0.00%



Public Auth. Customer Count		
	Count	Y/Y Growth
2011	281	
2012	275	-2.3%
2013	287	4.6%
2014	282	-1.9%
2015	281	-0.4%
2016	281	-0.1%
2017	278	-1.0%
2018	277	-0.3%
2019	275	-0.7%
2020	271	-1.5%
2021	267	-1.4%
2022	268	0.1%
2023	267	**-0.1%**
2024	267	**0.0%**
2025	268	**0.3%**
2026	270	**0.7%**
2027	271	**0.5%**
2028	273	**0.5%**
2029	273	**0.3%**
2030	274	**0.4%**
2031	276	**0.4%**
2032	277	**0.4%**
2033	278	**0.4%**
2034	279	**0.4%**
2035	280	**0.4%**
2036	281	**0.4%**
2037	282	**0.4%**

Model Statistics	Magnitude
Adjusted R^2	96.4%
AIC	2557
Durban-Watson	0.3
MAPE	1.89
In-Sample RMSE	6.1

Model Discussion

The AFR 2023 forecast annual growth rate for public authorities customer count has increased from AFR 2022's -0.2% to now reflect a 0.4% average increase.

The key economic driver of customer growth was 13-County Gross Regional Product (GRP). GRP is a measure of general economic health that correlates with local government revenues, and presumably local government accounts with Minnesota Power. 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 2015-2037 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 (2023) to align with the last historical year (2022). 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 2023 forecast value confirms this. Without these binary and trend variables, the model would project an abrupt and unreasonably large increase in customers in 2023.

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 AIC indicates a highly parsimonious model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are comparable to the AFR 2022 model: MAPE increased slightly to 1.89 from AFR 2022's 1.7, and RMSE also increased to 6.1 in AFR 2023 compared to 2022's 5.4.

Figure 6: Street Lighting Customer Count – Expected Scenario

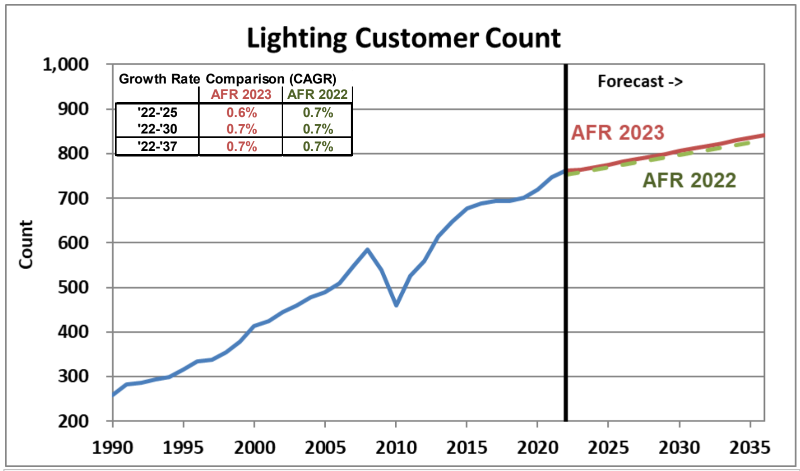
Street Lighting Customer Count - Expected Scenario

Estimation Start/End:	1/1990 - 12/2022
Unit Modeled/Forecast:	Monthly Customer Count

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	227.20	0.00%	0.00%
T	1.47	0.00%	0.00%
Bi_2009_2014	(723.40)	0.00%	0.00%
Trend_2009_2014	2.46	0.00%	0.00%
Bi_2015_2037	298.49	0.00%	0.00%
Trend_2015_2037	(0.97)	0.00%	0.00%
Bi_2020_2037	1.92	81.46%	61.14%
Trend_2020_2037	2.71	0.01%	0.00%

Lighting Customer Count		
	Count	**Y/Y Growth**
2011	5,335	
2012	6,414	20.2%
2013	655	-89.8%
2014	660	0.8%
2015	673	2.0%
2016	689	2.4%
2017	695	0.9%
2018	693	-0.3%
2019	701	1.1%
2020	720	2.7%
2021	746	3.7%
2022	762	2.1%
2023	764	**0.2%**
2024	770	**0.8%**
2025	776	**0.8%**
2026	782	**0.8%**
2027	788	**0.8%**
2028	794	**0.8%**
2029	800	**0.8%**
2030	805	**0.7%**
2031	811	**0.7%**
2032	817	**0.7%**
2033	823	**0.7%**
2034	829	**0.7%**
2035	835	**0.7%**
2036	841	**0.7%**
2037	847	**0.7%**

Model Statistics	Magnitude
Adjusted R^2	99.2%
AIC	3246
Durban-Watson	0.1
MAPE	2.61
In-Sample RMSE	14



Model Discussion

The AFR 2023 forecast annual growth rate for street lighting customer count is nearly identical to AFR 2022.

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 and extends through December-2014.

A combination of a binary variable and trend variable denoting the 2015-2037 timeframe pick up where the 2009-2014 variable left off, shifting the level and trend of the estimate to align with the updated accounting data going forward.

The combination of a binary and a trend variable for the 2020-2037 timeframe (beginning early-2020) mark a shift in the level and trend of the estimate to align with recent customer growth (this was in addition to the 2015-2037 change in forecast trajectory captured by the variables above). These variables effectively shift the first forecast year (2023) to align with the last historical year (2022). Without these corrective variables, 2023 monthly forecasted values would be understated.

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 AIC indicates a highly parsimonious model. The HAC-Adjusted P-values (“HAC-P-Value”) suggests all variables’ coefficients’ are significant with the exception of "Bi_2020_2037." It was determined this variable was needed because this variable wasused in last year's model, i.e. for year-to-year consistency, and this is an important factor shaping consumption in the forecast timeframe.

In-sample error metrics such as MAPE and RMSE are nearly identical.

Figure 7: Residential Energy Use – Expected Scenario

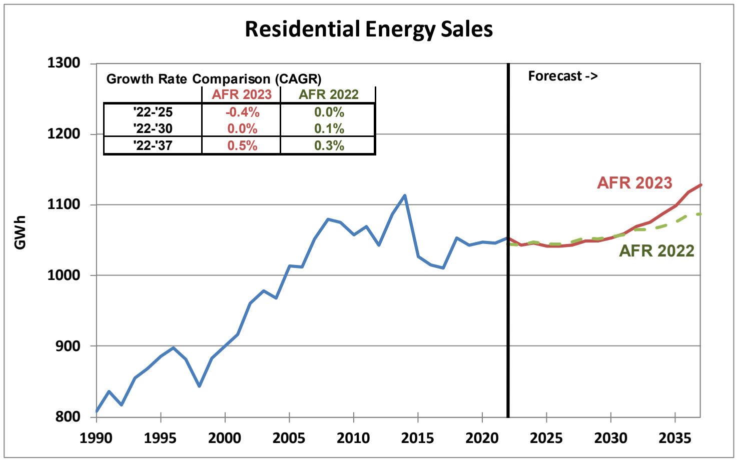
Residential Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2022
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (kWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	17.05	0.00%	0.00%
EE_Res	(0.0000141)	0.01%	0.00%
Dul_HDDpd	0.2508370	0.00%	0.00%
Dul_CDDpd	1.03	0.00%	0.00%

Residential Energy Sales		
	MWh	Y/Y Growth
2011	1,069,856	
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	1,046,910	0.4%
2021	1,046,341	-0.1%
2022	1,053,657	0.7%
2023	1,043,223	**-1.0%**
2024	1,046,133	**0.3%**
2025	1,042,073	**-0.4%**
2026	1,041,945	**0.0%**
2027	1,043,291	**0.1%**
2028	1,049,118	**0.6%**
2029	1,048,761	**0.0%**
2030	1,052,818	**0.4%**
2031	1,058,568	**0.5%**
2032	1,069,641	**1.0%**
2033	1,075,636	**0.6%**
2034	1,086,657	**1.0%**
2035	1,099,105	**1.1%**
2036	1,117,017	**1.6%**
2037	1,128,485	**1.0%**

Model Statistics	Magnitude
Adjusted R^2	85.7%
AIC	1582
Durban-Watson	2.0
MAPE	5.50
In-Sample RMSE	1.8



Model Discussion

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 electric vehicle and distributed solar adoption.

The AFR 2023 residential per-customer use model did 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 an Energy Efficiency variable to explain recent changes (since 2007) in the underlying trend of per-customer usage 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 AFR 2023 model uses simple monthly HDD and CDD (per-day) specifications. 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.

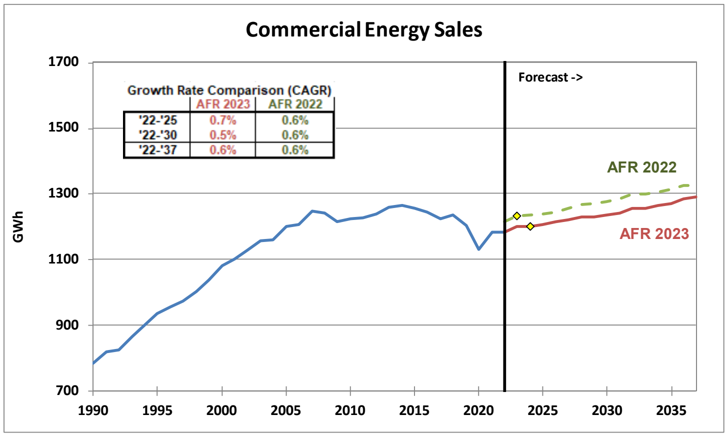
This year’s model is comparable to last year’s in terms of statistical quality. The Adjusted R-Squared indicates there’s a quality goodness-of-fit, and the AIC indicates a highly parsimonious model. The HAC-Adjusted P-values (“HAC-P-Value”) suggests all variables’ coefficients’ are significant. In-sample error metrics are similar: MAPE is 5.5% vs 6.2% in the 2022 model, and RMSE is 1.8 vs. 2 in the 2022 model.

Figure 8: Commercial Energy Use – Expected Scenario

Commercial Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2022
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (kWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	68.45	0.00%	0.00%
Jan	(7.20)	0.02%	0.06%
Apr	(12.30)	0.00%	0.00%
May	(9.38)	0.00%	0.00%
Aug	10.91	0.00%	0.00%
Sep	7.33	0.02%	0.01%
Oct	(10.61)	0.00%	0.00%
Nov	(11.89)	0.00%	0.00%
Bi_2007_2037	1.34	36.62%	14.79%
EE_Com	(0.00)	0.00%	0.00%
Dul_HDDpd	0.4723	0.00%	0.00%
Dul_CDDpd	3.99	0.00%	0.00%
EmpltoPop_13	197.08	0.00%	0.00%



Commercial Energy Sales		
	MWh	Y/Y Growth
2011	1,226,174	
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	1,131,101	-5.9%
2021	1,181,246	4.4%
2022	1,181,683	0.0%
2023	1,200,000	1.6%
2024	1,199,709	0.0%
2025	1,205,513	0.5%
2026	1,212,974	0.6%
2027	1,221,442	0.7%
2028	1,229,732	0.7%
2029	1,229,768	0.0%
2030	1,233,373	0.3%
2031	1,240,904	0.6%
2032	1,253,717	1.0%
2033	1,256,058	0.2%
2034	1,263,362	0.6%
2035	1,270,393	0.6%
2036	1,282,781	1.0%
2037	1,288,318	0.4%

Model Statistics	Magnitude
Adjusted R^2	67.2%
AIC	2867
Durban-Watson	2.7
MAPE	4.54
In-Sample RMSE	9

Model Discussion

The AFR 2023 forecast of commercial energy use is lower than AFR 2022 due to forecasted lower use-per-customer. The commercial energy use forecast grows at a 0.6% per year (average) pace, compared to the AFR 2022 forecast (0.8%).

The graph above shows the final commercial energy sales outlook, which combines the econometric forecasts of use-per-customer per day and customer count, along with arithmetic adjustments for: 1) the planned installation of new generation at a specific customer's facility, and 2) the projected impacts of distributed solar adoption.

The key driver of this year's commercial energy use model was the 13-County Employment-to-Population ratio. COVID-19 resulted in a substantial loss of energy sales without any corresponding decrease in customer counts, which is unprecedented and difficult to model with the typical economic indicators. The Employment-to-Population ratio indicates the rate of employment utilization, and both correlates and explains commercial property/account energy utilization during the initial economic contraction and recovery from COVID-19.

"Bi_2007_2037" is a binary variable starting in 2007 that accounts for a step-change, or "systematic shift," in energy use for this class around the time of the 2007 Energy Act. Sales to this class have remained essentially flat since this time (aside from the COVID-19 recession of 2020).

The AFR 2023 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. This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared of 67.2% 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 only 65%) and the Company does not consider the R-Squared an indicator of predictive quality. Minnesota Power leverages other objective metrics for determining model selection such as Mean Absolute Percent Error and Root Mean Square Error.

The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant. In-sample error metrics are similar: MAPE is 4.5% vs. 4.7% in the 2022 model, and RMSE is 9 vs. 9 in the 2022 model.

Figure 9: Mining and Metals Energy Use – Expected Scenario

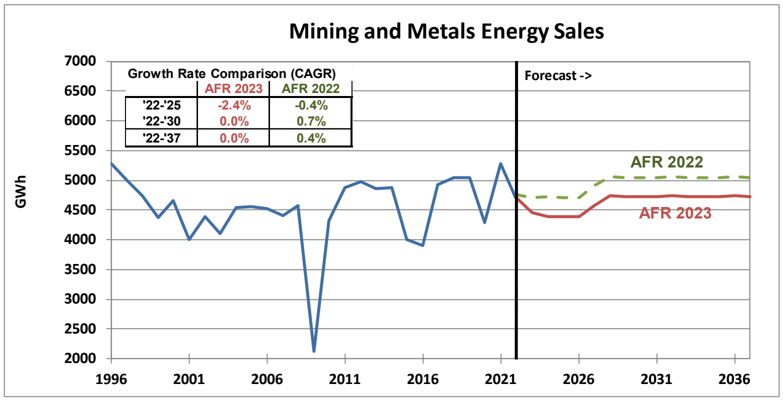
Mining and Metals Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2022
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	5,136.88	0.00%	0.00%
Trend_Mine1	(26.99)	0.00%	0.00%
Bi_Mine2	(299.15)	22.43%	5.38%
Bi_Mine3	(2,563.44)	0.00%	0.00%
Bi_Mine4	(1,432.36)	0.00%	0.00%
Bi_Mine5	(980.57)	1.15%	0.18%
Bi_Mine6	235.61	8.30%	5.26%
MN_Iron_IPI	72.34	0.00%	0.00%

Mining and Metals Energy Sales		
	MWh	Y/Y Growth
2011	4,874,331	
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	4,295,593	-14.7%
2021	5,280,743	22.9%
2022	4,712,773	-10.8%
2023	4,455,711	**-5.5%**
2024	4,393,621	**-1.4%**
2025	4,381,832	**-0.3%**
2026	4,381,101	**0.0%**
2027	4,581,333	**4.6%**
2028	4,737,834	**3.4%**
2029	4,724,202	**-0.3%**
2030	4,724,957	**0.0%**
2031	4,725,716	**0.0%**
2032	4,739,447	**0.3%**
2033	4,727,231	**-0.3%**
2034	4,727,989	**0.0%**
2035	4,728,748	**0.0%**
2036	4,742,488	**0.3%**
2037	4,730,263	**-0.3%**

Model Statistics	Magnitude
Adjusted R^2	74.5%
AIC	5405
Durban-Watson	1.1
MAPE	4.98
In-Sample RMSE	975



Model Discussion

The AFR 2023 outlook for mining and metals energy use is lower than the AFR 2022 projection due to reduced customer operations (post-regression adjustments). The graph and table show the total sales forecast for this class, which combines the output of the econometric forecast with load adjustments.

The key economic driver of this year's mining energy use model was the Minnesota (MN) Iron IPI, which measures the real production output nationwide in the industry and is scaled to MN-only.

This year's model incorporates several binary variables 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.

"Trend_Mine1" is a trend variable that denotes the timeframe from 1996-2001, when a large mining customer ended operations. The variable accounts for a possible change in relationship between Minnesota Power mining customer energy and the MN IPI, and allows for a more exact estimation of the relationship during the current paradigm.

The "Bi_Mine2" binary variable denotes and normalizes for some of the observable seasonality in mining operations.

The "Bi_Mine3" binary variable denotes the recession period from early 2009 to early 2010, when significant mining load was idled. This variable accounts for a possible change in the relationship between mining customer usage and the MN IPI.

The "Bi_Mine4" binary variable denotes a timeframe from May-2015 to February-2017, when significant mining load was idled. This variable accounts for a possible change in the relationship between mining customer usage and the MN IPI.

The "Bi_Mine5" binary variable denotes months between April-2020 and November-2020, when significant mining load was idled. This variable accounts for a possible change in the relationship between mining customer usage and the MN IPI.

The "Bi_Mine6" binary variable denotes operations of four smaller metals customers in the January-2010 to September-2016 timeframe. These customers' are backed out of the historical series prior to regression modeling, but their historical production contributed to national iron IPI. This binary variable ("Bi_Mine6") explains the temporary distortion in the energy-sales-to-National-IPI relationship.

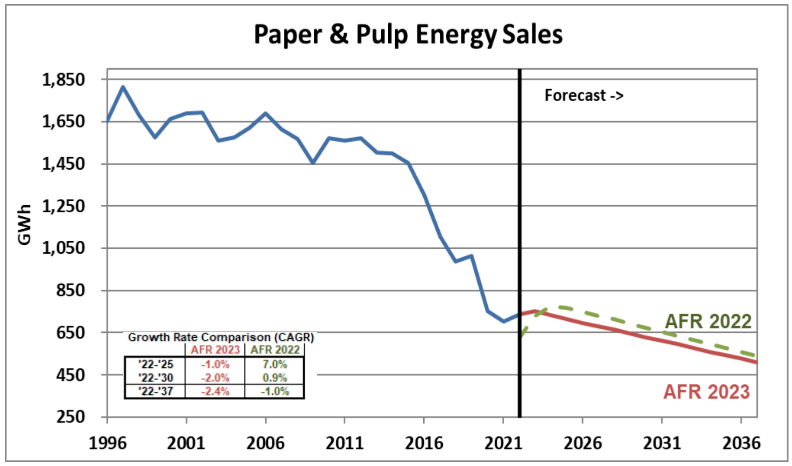
This year's model is comparable to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's a quality goodness-of-fit, and the AIC indicates a highly parsimonious model. The P-values suggests all variables' coefficients' are significant. In-sample error metrics are similar: the MAPE is 4.98 compared to 2022 model at 4.8%, but RMSE is higher at 975 vs. 622 in the 2022 model.

Figure 10: Paper and Pulp Products Energy Use – Expected Scenario

Paper and Pulp Products Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2022
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	4,692.43	0.00%	0.00%
T	(3.93)	0.00%	0.00%
Mar	135.01	16.84%	2.05%
Jun	163.15	9.63%	1.99%
Aug	314.71	0.14%	0.00%
Sep	315.37	0.15%	0.01%
Oct	259.61	0.89%	0.14%
Dec	(149.62)	12.72%	4.00%
Term_Paper_20_37	(1,467.89)	0.00%	0.00%
Paper_IPI_diff	30.41	11.50%	6.28%
Paper_22_Gen	930.42	0.84%	0.00%



Paper & Pulp Energy Sales		
	MWh	**Y/Y Growth**
2011	1,559,519	
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	752,072	-25.8%
2021	701,549	-6.7%
2022	735,506	4.8%
2023	752,956	**2.4%**
2024	733,150	**-2.6%**
2025	713,980	**-2.6%**
2026	696,854	**-2.4%**
2027	679,876	**-2.4%**
2028	664,404	**-2.3%**
2029	645,438	**-2.9%**
2030	628,254	**-2.7%**
2031	611,070	**-2.7%**
2032	595,442	**-2.6%**
2033	576,700	**-3.1%**
2034	559,515	**-3.0%**
2035	542,330	**-3.1%**
2036	526,513	**-2.9%**
2037	507,958	**-3.5%**

Model Statistics	Magnitude
Adjusted R^2	69.2%
AIC	4933
Durban-Watson	0.5
MAPE	9.10
In-Sample RMSE	470

Model Discussion

The AFR 2023 outlook for paper and wood products energy requirements is a bit lower than the AFR 2022 projection by 2037 due to the removal a prospective customer's load following project cancellation. 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 2023 model was driven by the Industrial Production Index (IPI) for Paper, which measures the real production output nationwide in the industry, and indicates an underlying secular decline of the North American Paper industry (and demand for paper products).

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 In-sample error metrics are a bit different: MAPE is the same as the 2022 model at 9.1, and RMSE increased to 470 vs. 392 in the 2022 model.

The AIC indicates a highly parsimonious model. HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' (except the intercept) are significant.

Figure 11: Other Industrial Energy Use – Expected Scenario

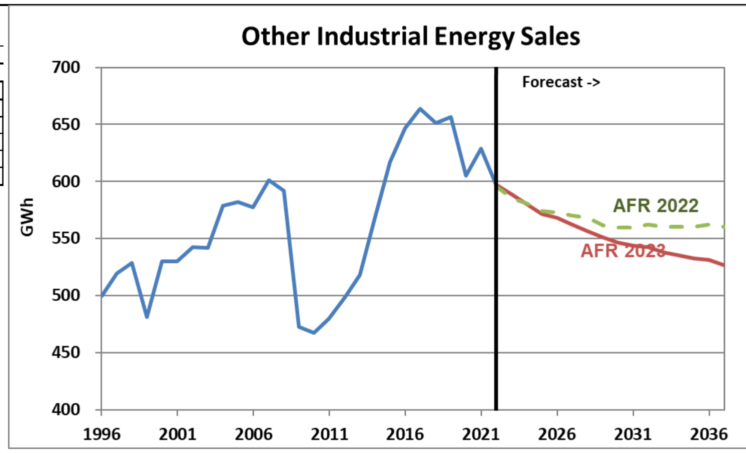
Other Industrial Energy Use - Expected Scenario

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

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value

Other Industrial Energy Sales

	MWh	Y/Y Growth
2012	498,474	
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	651,546	-1.8%
2019	656,590	0.8%
2020	605,277	-7.8%
2021	629,017	3.9%
2022	597,430	-5.0%
2023	588,462	**-1.5%**
2024	580,200	**-1.4%**
2025	571,522	**-1.5%**
2026	568,226	**-0.6%**
2027	562,059	**-1.1%**
2028	556,089	**-1.1%**
2029	550,823	**-0.9%**
2030	546,132	**-0.9%**
2031	543,565	**-0.5%**
2032	542,472	**-0.2%**
2033	537,935	**-0.8%**
2034	535,333	**-0.5%**
2035	532,892	**-0.5%**
2036	531,532	**-0.3%**
2037	526,758	**-0.9%**



Model Discussion

Minnesota Power has broken out Other Industrial into four sectors: 1) Pipelines, 2) Foundries, 3) Food Products, and 4) Remaining.

Due to several Other Industrial sub-sectors containing just two or three customers, these sector-level forecasts could imply trade secret information. Minnesota Power will only show the aggregate of all sectors ("Other Industrial") in the graph above and table to the left. The sector-specific models of projected energy and the model discussions are discussed on the following pages, and are marked "TRADE SECRET" due to the limited number of customers in each sector.

Figure 12: Pipelines Energy Use – Expected Scenario

Pipelines Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2022
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	(973.21)	0.00%	0.04%
Bi_Pipelines1	(5,257.81)	0.00%	0.00%
Trend_Pipelines1	18.30	0.00%	0.00%
TTU_13	0.03	0.00%	0.00%

Model Statistics	Magnitude
Adjusted R^2	77.5%
AIC	3907
Durban-Watson	0.6
MAPE	12.31
In-Sample RMSE	98

Model Discussion

Minnesota Power modeled and projected energy sales to pipeline customers individually, independent of total Other Industrial sales.

The AFR 2023 econometric driver for the pipelines model was 13-County Trade, Transportation, & Utilities (TTU) Employment. The TTU employment variable was selected as it directly encompasses the pipeline sector being modeled and highlights a major advantage of more granular forecasting for Other Industrial sub-sectors – economic variable specificity (last year's total Other Industrial model had 13-County Total Non-Farm Employment as the economic variable).

A binary ("Bi_Pipelines1") and a trend variable ("Trend_Pipelines1") denote 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 Adjusted R-Squared indicates there's a reasonable goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are notably comparable to last year's model: MAPE decreased to 12.31% compared to 2022 models MAPE of 12.4%. RMSE increased to 98 from 96 from 2022's model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 13: Foundries Energy Use – Expected Scenario

Foundries Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2022
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

Variable	Model Specifications		
	Coefficient	P-Value	HAC-P-Value
CONST	(440.82)	0.00%	0.00%
Bi_1999_2000	(65.02)	0.00%	0.00%
Bi_2011_2014	54.55	0.00%	0.00%
TotNonF_StLou	0.01	0.00%	0.00%
Foundry_IPI	1.55	0.00%	0.00%

Model Statistics	Magnitude
Adjusted R^2	55.1%
AIC	3151
Durban-Watson	1.0
MAPE	8.57
In-Sample RMSE	31

Model Discussion

Minnesota Power modeled and projected energy sales to foundry customers individually, independent of total Other Industrial sales.

The Foundries energy use model leveraged two economic variables: Total St. Louis County Non-Farm Employment, and IPI for Primary Metals. The IPI for Primary Metals measures the national level real output in the industry, and is the model's indicator of national demand of primary metals products. St. Louis County non-farm employment is a more granular indicator of local business operations, and explains local foundry operations that may deviate from the national trend. All of Minnesota Power's foundry customers are located in St. Louis County.

"Bi_Foundries1" is a binary variable denoting the 1999-2000 timeframe when energy sales began decreasing ahead of the national-level Primary Metals IPI-recognized-downturn due to a local mining customer winding down operations. This variable accounts for a possible change in the relationship between foundry customer usage and the Primary Metals IPI.

"Bi_Foundries2" is a binary variable denoting the 2011-2014 timeframe and represents a customer that expanded operations temporarily, diverging from the national-level Primary Petals IPI. This variable accounts for a possible change in the relationship between foundry customer usage and the Primary Metals IPI.

The Adjusted R-Squared indicates there's a reasonable goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are comparable to last year's model: MAPE is 8.57% vs 8.4% in the AFR 2022 model, and RMSE is 31 vs. 29 in the AFR 2022 model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 14: Food Products Energy Use – Expected Scenario

Food Products Energy Use - Expected Scenario

Estimation Start/End:	1/1996 - 12/2022
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

Variable	Model Specifications		
	Coefficient	P-Value	HAC-P-Value
CONST	(291.99)	0.00%	0.21%
Bi_Food_Products1	27.10	0.00%	0.01%
Food_Products_IPI	4.52	0.00%	0.00%

Model Statistics	Magnitude
Adjusted R^2	71.7%
AIC	2789
Durban-Watson	1.2
MAPE	7.67
In-Sample RMSE	18

Model Discussion

Minnesota Power modeled and projected energy sales to food product customers individually, independent of total Other Industrial sales.

Energy sales to the food products sector was modeled using the IPI for Food Products (Food, Beverage, and Tobacco). The IPI for Food Products measures the real production output nationwide in the industry, and indicates an underlying growth trend in this class.

"Bi_Food_Products1" is a binary variable denoting the 2015-2037 timeframe. This variable represents a new level of sales following period of expansion for one of the customers in this class (beginning in 2015) and continues throughout the forecast timeframe. A binary variable approach is utilized as Minnesota Power is not adjusting the econometric model in the forecast timeframe to account for increased sales.

The Adjusted R-Squared indicates there's a reasonable goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are also comparable to last year's model: MAPE is 7.67 vs. 7.65% in AFR 2022, and RMSE is 18 vs. 16 in AFR 2022 model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 15: Other Industrial Remaining Energy Use – Expected Scenario

Other Industrial Remaining Energy Use - Expected Scenario

Estimation Start/End:	1/2001 - 12/2022
Unit Modeled/Forecast:	Monthly Per-Customer, Per-Day Use (kWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	0.66	0.00%	0.00%
Bi_Remaining1	0.34	0.00%	0.00%
MFG_StLou	0.00002	13.16%	5.12%

Model Statistics	Magnitude
Adjusted R^2	21.3%
AIC	-249
Durban-Watson	2.5
MAPE	12.88
In-Sample RMSE	0.2

Model Discussion

Minnesota Power modeled and projected energy sales to other industrial: remaining customers individually, independent of total Other Industrial sales. The other industrial: remaining sub-sector includes all industrial customer usage not accounted for in: Mining, Paper, Pipelines, Foundries, and Food Product Manufacturing.

The sole econometric variable used in the other industrial remaining model was St. Louis County Manufacturing Employment. Many of the customers in this class are either directly involved in manufacturing, or supply manufacturers with the goods/inputs they need to create a finished product to sell. Several of the larger customers in this class are located in St. Louis County; because of this, Minnesota Power selected the more granular variable to inform the model, instead of a more general/broader Manufacturing employment series.

"Bi_Remainder1" is a binary that indicates months in the 2001-2002 timeframe where energy sales have erroneous values. This binary essentially removes the erroneous data points from consideration in the model as they would have a negative influence on the model's integrity.

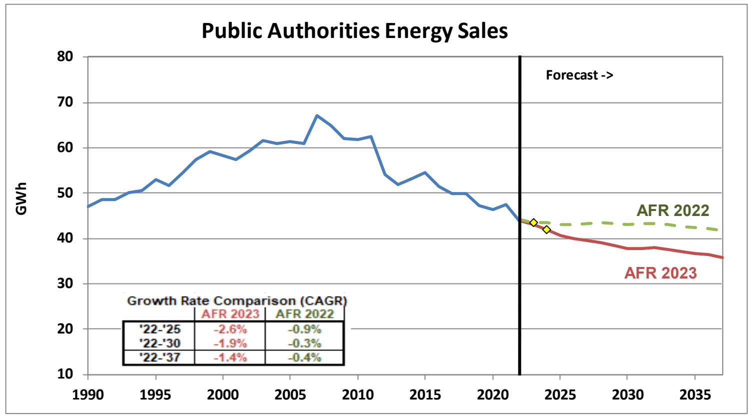
The Adjusted R-Squared indicates there's a moderate goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are also reasonable and comparable to AFR 2022 models: MAPE is comparable AFR 2022 at 12.88 vs. 13%, and RMSE is similar to AFR 2022 models at just 0.2 vs. .01 in AFR 2022. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 16: Public Authorities Energy Use – Expected Scenario

Public Authorities Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2022
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
Intercept	(1,319.05)	0.00%	0.00%
Bi_2021_2037	14.68	0.47%	0.04%
EE_Com	(0.00)	0.00%	0.00%
Dul_HDDpd	0.16	1.39%	1.30%
Dul_CDDpd	4.19	0.00%	0.01%
MSA_Pop	5.34	0.00%	0.00%



Public Auth. Energy Sales		
	MWh	**Y/Y Growth**
2011	62,458	
2012	54,074	-13.4%
2013	51,736	-4.3%
2014	53,237	2.9%
2015	54,471	2.3%
2016	51,455	-5.5%
2017	49,945	-2.9%
2018	49,884	-0.1%
2019	47,302	-5.2%
2020	46,375	-2.0%
2021	47,497	2.4%
2022	43,943	-7.5%
2023	42,974	**-2.2%**
2024	41,939	**-2.4%**
2025	40,577	**-3.2%**
2026	39,960	**-1.5%**
2027	39,568	**-1.0%**
2028	38,942	**-1.6%**
2029	38,270	**-1.7%**
2030	37,775	**-1.3%**
2031	37,774	**0.0%**
2032	37,916	**0.4%**
2033	37,405	**-1.3%**
2034	37,054	**-0.9%**
2035	36,641	**-1.1%**
2036	36,369	**-0.7%**
2037	35,812	**-1.5%**

Model Statistics	Magnitude
Adjusted R^2	39.7%
AIC	3495
Durban-Watson	2.1
MAPE	10.51
In-Sample RMSE	20

Model Discussion

The key economic driver of this year's Public Authorities energy use model was Duluth MSA Population. This variable indicates the underlying growth trend, which impacts government entities' operations (affecting energy use).

The AFR 2023 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, and 2) the overall trend of conservation in public authorities is likely very similar to commercial customers.

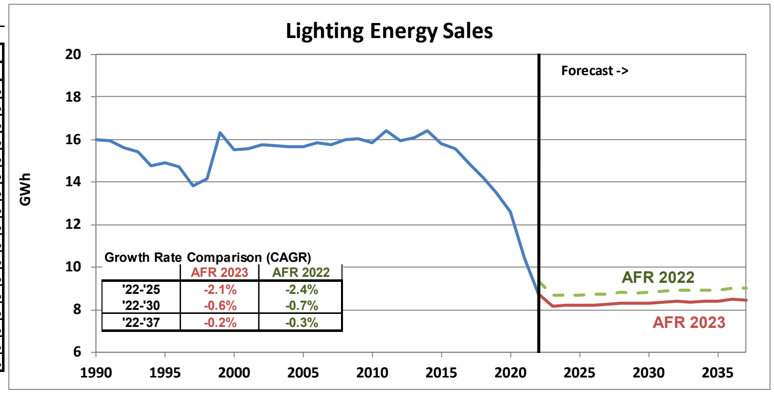
This year's model is similar to last year's in terms of statistical quality. The Adjusted R-Squared indicates there's moderate goodness-of-fit, and the AIC indicates a highly parsimonious model. In-sample error metrics are similar to last year's: MAPE is 10.51% vs. 10.7% in the 2022 model, and RMSE is 20 vs. 20.1 in the 2022 model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

Figure 17: Street Lighting Energy Use – Expected Scenario

Street Lighting Energy Use - Expected Scenario

Estimation Start/End:	1/1990 - 12/2022
Unit Modeled/Forecast:	Monthly Per-Day Use (MWh)

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	49.96	0.00%	0.00%
T	(0.01)	3.23%	4.79%
Jan	2.77	0.49%	0.11%
Feb	(1.93)	4.86%	0.83%
Mar	(9.32)	0.00%	0.00%
Apr	(14.12)	0.00%	0.00%
May	(20.02)	0.00%	0.00%
Jun	(23.20)	0.00%	0.00%
Jul	(22.74)	0.00%	0.00%
Aug	(19.22)	0.00%	0.00%
Sep	(11.70)	0.00%	0.00%
Oct	(8.39)	0.00%	0.00%
Nov	(2.91)	0.30%	0.00%
Bi_Light_1	(2.49)	0.28%	1.88%
Bi_Light_2	99.90	0.00%	0.00%
Trend_Light_2	(0.30)	0.00%	0.00%
NonWPI_StLou	0.002	1.32%	1.80%



Lighting Energy Sales	MWh	Y/Y Growth
2011	16,420	
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	12,617	-6.4%
2021	10,445	-17.2%
2022	8,744	-16.3%
2023	8,171	**-6.6%**
2024	8,227	**0.7%**
2025	8,217	**-0.1%**
2026	8,221	**0.0%**
2027	8,239	**0.2%**
2028	8,294	**0.7%**
2029	8,285	**-0.1%**
2030	8,310	**0.3%**
2031	8,334	**0.3%**
2032	8,389	**0.7%**
2033	8,377	**-0.1%**
2034	8,395	**0.2%**
2035	8,412	**0.2%**
2036	8,475	**0.7%**
2037	8,468	**-0.1%**

Model Statistics	Magnitude
Adjusted R^2	86.4%
AIC	2231
Durban-Watson	1.6
MAPE	5.46
In-Sample RMSE	4

Model Discussion

The AFR 2023 lighting per-day use model utilized St. Louis County Non-Wage Personal Income as a key economic/demographic indicator.

"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.

"Bi_Light2" and "Trend_Light2" are binary and trend variables denoting the 2017-2037 timeframe and effectively creates a new forecast trajectory influenced by levels starting in 2017 (this level is then held constant in the forecast timeframe after January-2023). This binary and trend combination shifts the forecast to account for Minnesota Power's LED lighting program's impact on 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 AIC indicates a highly parsimonious model. In-sample error metrics are similar to last year's: MAPE is 5.46% vs. 5.1% in the 2022 model, and RMSE is 4.0, the same as AFR 2022. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

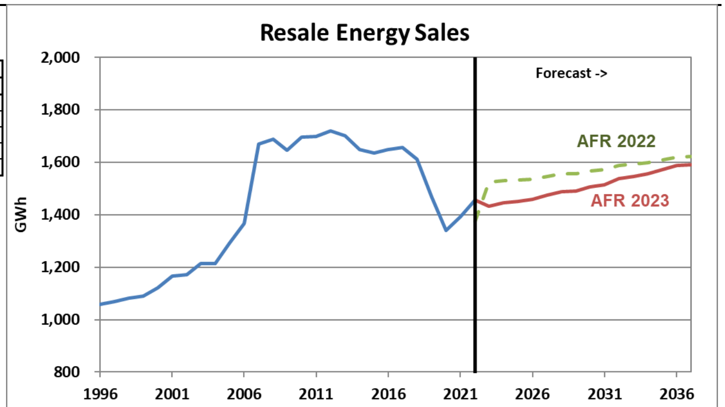
Figure 18: Resale Energy Use – Expected Scenario

Resale Energy Use - Expected Scenario

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

	Model Specifications			
Variable	Coefficient	P-Value	HAC-P-Value	VIF

Resale Energy Sales		
	MWh	Y/Y Growth
2012	1,718,819	
2013	1,700,993	7.2%
2014	1,585,993	3.3%
2015	1,634,786	3.1%
2016	1,649,405	0.9%
2017	1,656,865	0.5%
2018	1,610,792	-2.8%
2019	1,468,108	-8.9%
2020	1,340,290	-8.7%
2021	1,393,315	4.0%
2022	1,456,237	4.5%
2023	1,431,230	-1.7%
2024	1,445,326	**1.0%**
2025	1,451,569	**1.6%**
2026	1,458,255	**0.5%**
2027	1,473,983	**0.2%**
2028	1,486,851	**0.9%**
2029	1,491,614	**0.6%**
2030	1,507,032	**1.0%**
2031	1,514,931	**0.5%**
2032	1,537,945	**0.9%**
2033	1,545,762	**0.5%**
2034	1,556,741	**0.7%**
2035	1,571,770	**1.0%**
2036	1,586,685	**0.9%**
2037	1,590,314	**0.2%**



Model Discussion

AFR 2023 is continuing the practice of forecasting each resale customer separately. Minnesota Power will not be providing graphs or tables that include forecast values for individual resale customers (similar to the approach mentioned above for Other Industrial).

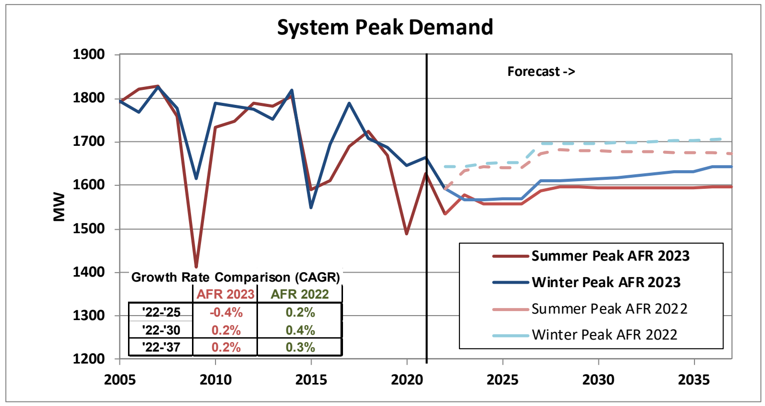
Due to the trade secret nature of individual resale customers' forecasts, Minnesota Power will only be showing the aggregate forecast summary for total Resale energy sales in the graph above and table to the left.

Figure 19: System Peak Demand – Expected Scenario

System Peak Demand - Expected Scenario

Estimation Start/End:	6/1999 - 12/2022
Unit Modeled/Forecast:	Monthly Peak Demand

	Model Specifications		
Variable	Coefficient	P-Value	HAC-P-Value
CONST	378.52	0.00%	<.0001
WN_MWhpd	0.04	0.00%	<.0001
S	36.22	0.00%	0.05%
W	18.59	3.96%	1.17%
Bi_1999_2001	(26.74)	0.05%	0.01%
Bi_2008	108.57	0.00%	<.0001
WC_THI	(1.25)	0.00%	<.0001
WC_THI_3	0.0002	0.00%	4.35%
Jan_WN_MWhpd	(0.001)	0.94%	0.05%
Feb_WN_MWhpd	(0.001)	0.65%	<.0001
Mar_WN_MWhpd	(0.001)	0.17%	0.37%



System Peak Demand					
	Summer (MW)	Y/Y Growth		Winter (MW)	Y/Y Growth
2011	1,746		2011	1,789	
2012	1,789	2%	2012	1,780	0%
2013	1,781	0%	2013	1,773	0%
2014	1,805	1%	2014	1,751	-1%
2015	1,589	-12%	2015	1,818	4%
2016	1,610	1%	2016	1,547	-15%
2017	1,688	5%	2017	1,693	9%
2018	1,724	2%	2018	1,789	6%
2019	1,668	-3%	2019	1,707	-5%
2020	1,487	-11%	2020	1,687	-1%
2021	1,625	9%	2021	1,646	-2%
2022	1,533	-6%	2022	1,663	1%
2023	1,579	3%	2023	1,591	-4%
2024	1,557	-1%	2024	1,566	-2%
2025	1,556	0%	2025	1,565	0%
2026	1,556	0%	2026	1,569	0%
2027	1,587	2%	2027	1,569	0%
2028	1,597	1%	2028	1,611	3%
2029	1,595	0%	2029	1,611	0%
2030	1,595	0%	2030	1,612	0%
2031	1,594	0%	2031	1,614	0%
2032	1,594	0%	2032	1,618	0%
2033	1,595	0%	2033	1,622	0%
2034	1,595	0%	2034	1,626	0%
2035	1,595	0%	2035	1,631	0%
2036	1,596	0%	2036	1,631	0%
2037	1,596	0%	2037	1,643	1%

Model Statistics	Magnitude
Adjusted R^2	88.8%
AIC	2822
Durban-Watson	1.5
MAPE	1.92
In-Sample RMSE	35

Model Discussion

The long-run outlook for Minnesota Power's system peak is lower than the 2022 outlook primarily due to a projected decrease in industrial energy consumption relative to AFR 2022.

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. 2023 AFR used a third-degree polynomial specification on a Wind-Chill & Temperature Humidity Index. Peak demand is modeled as a function of the weather observations specific to the hour in which the peak occurred.

The 2023 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.

There is no energy efficiency variable in the peak demand model and no explicit assumption for peak demand savings. Conservation impacts are accounted for by leveraging the energy sales forecast, which includes the effects of conservations, as the key 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 AIC indicates a highly parsimonious model. In-sample error metrics are very similar to the 2022 model: MAPE is 1.9% vs. 1.9% in the 2021 model, and RMSE is 34 vs. 34 in the 2021 model. The HAC-Adjusted P-values ("HAC-P-Value") suggests all variables' coefficients' are significant.

D. Forecast Confidence and Historical Accuracy (7610.0320, Subp. 1.E and Subp. 1.F)

Minnesota Power has a strong record of both accurate forecasting and consistent improvements in forecast accuracy over time. Excluding the mining downturn years (2009/2010 and 2015/2016), as well as the 2020 COVID-19 recession (including 2021), each successive AFR has reduced its current-year energy sales forecast error, on average, by about 0.04 percent over the prior year.

Figures 20 through 22 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, in Figure 20 the bottom value of -15.7 percent in the 2020 column is the difference between the forecast produced in 2020 (AFR 2020) and the 2020 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 the Mining downturn).

Figure 20: AFR Forecast Accuracy – Aggregate System Energy

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	2020	2021	2022
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%								
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%							
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%						
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%					
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%				
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%			
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%	38.1%		
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%	31.6%	18.6%	
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%	32.1%	19.5%	26.9%
AFR 2009										**4.8%**	***-16.8%***	-13.9%	-8.1%	-3.1%	**-0.9%**	11.0%	15.9%	8.5%	10.2%	13.4%	30.2%	17.5%	24.3%
AFR 2010											**-0.8%**	***-1.8%***	-1.0%	0.7%	1.1%	**11.6%**	15.2%	6.9%	7.7%	10.1%	26.1%	13.8%	20.5%
AFR 2011												**-0.3%**	***-1.1%***	0.5%	1.0%	11.9%	**15.7%**	7.5%	8.4%	10.8%	26.9%	14.4%	21.0%
AFR 2012													**-1.4%**	***0.5%***	0.7%	11.5%	15.4%	**6.9%**	7.8%	10.2%	26.4%	13.9%	20.5%
AFR 2013														**-0.2%**	***-0.4%***	18.1%	24.6%	18.7%	**20.0%**	22.6%	40.2%	26.2%	33.4%
AFR 2014															**-0.3%**	***13.9%***	24.2%	13.9%	14.9%	**17.2%**	34.0%	20.3%	27.0%
AFR 2015																**2.4%**	***5.9%***	9.9%	11.0%	13.1%	**29.4%**	16.3%	22.6%
AFR 2016																	**-1.4%**	***-4.3%***	-2.9%	-2.2%	20.4%	**10.1%**	19.3%
AFR 2017																		**1.8%**	***2.5%***	3.6%	24.2%	13.1%	**19.3%**
AFR 2018																			**1.4%**	***1.7%***	20.4%	9.7%	16.7%
AFR 2019																				**-1.8%**	***14.7%***	4.2%	12.1%
AFR 2020																					**-15.7%**	***-7.8%***	-2.2%
AFR 2021																						**-8.7%**	***-2.7%***
AFR 2022																							**-1.2%**

Figure 21: AFR Forecast Accuracy – Summer Peak

Forecast	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
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%								
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%							
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%						
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%					
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%	17.5%				
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%	19.1%	25.6%			
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%	15.2%	20.0%	35.2%		
AFR 2007								-2.4%	2.2%	31.4%	3.5%	4.8%	3.6%	5.2%	5.0%	19.8%	19.8%	15.1%	13.4%	18.1%	33.4%	23.0%	
AFR 2008									2.5%	31.0%	3.2%	3.7%	2.4%	3.6%	2.9%	17.3%	17.4%	12.9%	11.6%	16.3%	31.6%	21.6%	30.2%
AFR 2009										0.0%	-21.1%	-15.6%	-11.9%	-8.9%	-8.2%	5.3%	5.7%	2.0%	1.1%	6.1%	20.9%	12.2%	20.5%
AFR 2010											-0.1%	-1.4%	-2.6%	-1.5%	-2.1%	11.3%	11.2%	6.7%	5.1%	9.3%	23.4%	13.6%	21.2%
AFR 2011												-1.5%	-3.5%	-2.4%	-2.8%	10.8%	10.8%	6.3%	4.9%	9.2%	23.3%	13.6%	21.2%
AFR 2012													-3.7%	-3.0%	-4.5%	8.8%	8.9%	4.5%	3.1%	7.3%	21.2%	11.7%	19.3%
AFR 2013														-2.8%	-2.1%	14.7%	17.3%	15.1%	13.5%	18.0%	32.9%	22.2%	30.2%
AFR 2014															-4.3%	13.2%	19.5%	14.9%	13.3%	17.6%	32.5%	21.6%	29.3%
AFR 2015																1.0%	5.4%	10.6%	10.6%	14.9%	29.4%	18.9%	26.4%
AFR 2016																	-1.4%	1.0%	0.0%	1.6%	24.0%	16.2%	23.9%
AFR 2017																		4.5%	2.2%	4.0%	20.0%	11.1%	18.1%
AFR 2018																			-0.6%	0.9%	15.4%	7.6%	14.8%
AFR 2019																				-1.1%	11.4%	3.2%	12.1%
AFR 2020																					-17.7%	-4.9%	1.3%
AFR 2021																						-6.3%	0.8%
AFR 2022																							3.9%

Figure 22: AFR Forecast Accuracy – Winter Peak

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	2020	2021	2022
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%								
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%							
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%						
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%	5.7%					
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%	16.9%	24.5%				
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%	12.5%	19.9%	23.3%			
AFR 2006							0.7%	-0.6%	3.8%	17.8%	3.5%	5.8%	8.0%	10.5%	7.3%	27.0%	17.5%	11.9%	17.9%	20.1%	23.7%		
AFR 2007								-2.9%	0.5%	13.5%	-1.1%	0.5%	1.7%	3.8%	0.5%	19.4%	11.1%	6.5%	12.8%	15.5%	19.8%	19.8%	
AFR 2008									4.3%	16.8%	1.6%	3.2%	4.2%	6.3%	2.8%	22.1%	13.5%	8.8%	15.4%	18.3%	22.8%	23.1%	35.4%
AFR 2009										-9.6%	-18.9%	-10.6%	-6.2%	-2.4%	-4.3%	13.4%	5.8%	1.5%	7.8%	10.8%	15.1%	15.3%	26.6%
AFR 2010											-0.5%	0.4%	1.3%	3.2%	-0.2%	17.5%	8.5%	3.2%	8.7%	10.6%	14.0%	13.4%	23.7%
AFR 2011												-0.3%	0.3%	2.5%	-0.6%	17.4%	8.6%	3.5%	9.2%	11.2%	14.7%	14.3%	24.7%
AFR 2012													0.1%	1.3%	-1.9%	15.8%	7.1%	2.0%	7.6%	9.6%	13.1%	12.6%	23.0%
AFR 2013														0.4%	1.5%	20.5%	16.5%	11.0%	16.9%	19.0%	22.5%	21.8%	32.8%
AFR 2014															-2.7%	24.2%	15.7%	10.3%	15.9%	17.9%	21.3%	20.4%	31.1%
AFR 2015																10.3%	10.5%	8.1%	13.8%	15.8%	19.3%	18.6%	29.1%
AFR 2016																	1.8%	-2.8%	2.1%	4.8%	11.4%	15.1%	25.7%
AFR 2017																		0.1%	4.8%	5.3%	11.1%	10.4%	20.4%
AFR 2018																			1.7%	3.2%	6.4%	7.8%	17.3%
AFR 2019																				-1.0%	2.8%	2.3%	14.3%
AFR 2020																					-7.2%	-6.0%	1.8%
AFR 2021																						-7.0%	0.9%
AFR 2022																							7.1%

E. Methodology Strengths and Weaknesses and Suitability to the System (7610.0320, Subp. 1.F)

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 reflect 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 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.

F. Data Requirements (7610.0320, Subp. 1.F)

Data used in Minnesota Power's forecast 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 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.

II. Forecast Data Inputs & Adjustments

A. Forecast Database Inputs (7610.0320, Subp. 2.A)

Weather

Weather data for Duluth, Minnesota was collected for historical periods from the National Oceanic and Atmospheric Administration (NOAA) and from Weather Underground (WU).[1] 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.

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 2001 – Dec 2020).

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 AFR 2023 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.

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

A Temperature-Humidity Index (THI)[2] 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[3] 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.

IHS Global Insight

IHS Global Insight is the singular source for all economic and demographic outlooks used in Minnesota Power's load forecast.[4] 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.

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.

Regional Economic Models, Inc. (REMI)

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[5] with specified regional economic conditions to produce a forecast for a 13-County

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2 http://www.wpc.ncep.noaa.gov/html/heatindex_equation.shtml.
3 http://www.nws.noaa.gov/os/windchill/index.shtml.
4 With the exception of two series that are derived from REMI: Population and GRP for the 13-County Planning Region.
5 Prior to simulation, REMI is calibrated to the IHS Global Insight National Economic Outlook.

Planning Area such as employment by sector, population, economic output by sector, and Gross Regional Product (GRP).

For AFR 2023, 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.

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.[6]

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

[6] http://www.federalreserve.gov/releases/g17/revisions/Current/g17rev.pdf.

2023 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).[7] 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 percent 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 2023, and the U.S. Federal Reserve's current standard index year.

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).

B. Forecast Adjustments (7610.0320, Subp. 2.B)

1. Adjustments to Raw Energy Use and Customer Count Data

Minnesota Power made a limited number of adjustments to internally developed data for AFR 2023, which fall into three general categories:

a. **Adjustments to raw customer count 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. Where there is a systemic shift (e.g., seasonal billing in residential customers count),

[7] https://minerals.usgs.gov/minerals/pubs/commodity/iron_ore/.

Minnesota Power does not adjust the raw data and instead utilizes a binary variable in modeling. When there are fewer than three 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.

b. **Adjustments to raw sales and peak demand data for large load additions and losses**: All adjustments to the historical database are described below in detail and organized by sector:

[TRADE SECRET DATA BEGINS

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] **TRADE SECRET DATA ENDS]**

2. 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 adjustments fall into the following categories:

a. **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, loss of contract, or reduced industry operating levels. Minnesota Power has observed increased variability and lower industry operating levels in recent years. This variability and lower operating levels are expected over the forecast period and are taken into account as a normalized adjustment to a representative level in the forecast. 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.

b. **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 three 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.

c. **Dual Fuel**: Minnesota Power has a demand response program for residential and commercial customers. 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 interruptions as a resource and not as an adjustment to the load forecast.

d. **Electric Vehicles**: There are two components of the Electric Vehicle (EV) energy forecast: 1) The EV saturation rate per household and 2) the energy requirements per vehicle.

First, Minnesota Power estimated its current EV saturation rate per household in its service territory. Currently, there are 501 known electric vehicles in Minnesota Power's service territory,[8] and the Company estimates there are about 600 light duty (i.e. passenger vehicles) EVs in Minnesota Power's retail service territory. This equates to a 0.5 percent saturation rate for household vehicle ownership. To-date, this saturation rate trails the nation by about six years. The Company then identified an updated publicly available forecast that considers recent industry trends and legislative action that incentivizes EVs. The EV adoption rate forecast for the Minnesota Power service territory follows Goldman Sachs's projected national adoption rate,[9] but lagged by about six years. The Company attributes this lag in adoption to issues of income, population density/cost-efficiency of commercial charging station locations, and

[8] https://mn.gov/puc/activities/economic-analysis/electric-vehicles/.
[9] https://www.goldmansachs.com/intelligence/pages/electric-vehicles-are-forecast-to-be-half-of-global-car-sales-by-2035.html#:~:

reduced efficiency in cold-weather. The annual saturation rate outlook is then multiplied by Minnesota Power's residential customer count[10] 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.[11] The Company did not attempt to modify this annual energy requirement estimate 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.

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 electric vehicles[12] 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.

Under the AFR 2023 expected scenario, Minnesota Power customers about 35,300 EVs (approximately 30% saturation rate) and the added energy requirements from post-2021 EV adoption increases to about 88,100 MWh. This level of EV ownership would increase summer peak coincident demand by about 11 MW and winter peak demand by 32 MW.

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10 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.

11 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.

e. **Distributed Generation** (DG): 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. Minnesota Power modified its methodology for the rate of adoption to use the publicly available US Energy Information Administrations distributed residential solar generation forecast for AFR 2023. The average size (capacity) of new installations in the forecast timeframe is assumed as a simple historical average of installation size by class. Minnesota Power than calculated estimated impact of new DG solar on energy sales by converting the capacity series (kW) to an energy series (kWh) using an 11 percent capacity factor assumption for new distributed installations.

Identifying the impact of DG solar on the monthly peak demand outlook involves calculating the amount of solar generation that is likely during a specific month's likely peak time (i.e., historical median peak hour) using a simulated hourly solar production curve. Minnesota Power typically peaks at 6:00 or 7:00 PM (well after sunset) in winter months, so DG solar at the time of the peak is zero percent and projected winter peaks are not reduced. In summer months, Minnesota Power has historically peaked at 3:00 or 4:00 PM when DG solar is on average 55 percent of installed capacity (the effective load carrying capacity or ELCC is 0.55).

III. Overview of Key Assumptions (7610.0320, Subp. 3)

A. 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. IHS Global Insight forecasts U.S. GDP and IPI growth to average 1.6 and 1.0 percent per year from 2023-2023, respectively.

B. 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 in Wisconsin).

The 13-County Planning Area's Gross Regional Product is forecasted to average 0.2 percent per-year growth in the forecast timeframe whereas the Duluth MSA product averages 1.4 percent per-year in the forecast timeframe. Population for the 13-County Planning Area grows at about 2.1 percent in the forecast timeframe and the Duluth MSA area population remains consistent with current levels.

IV. Subject of Assumption (7610.0320, Subp. 4)

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 makes no assumptions regarding the expected conversion from one fuel source to another*.
- Assumptions made regarding future prices of electricity for customers and the effect that such prices would have on system demand.
  - *See Section II.A.*
- 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 and assumptions made regarding the projected effect of new conservations programs the utility deems likely to occur through Federal or State legislation.

  Minnesota Power uses 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.*
- *Accounts for historical and projected conservation resulting from both Company programs and organic, customer-driven efforts.*
- *Leverages raw sales data in regression modeling: sales data are not adjusted for conservation impacts prior to modeling.*
- *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 energy efficiency embedded in the load forecast.

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 14 Minnesota municipal customers. Incremental (i.e., first year) savings data for the historical and forecast timeframe was assembled from a number of sources. Historical incremental savings data for Minnesota Power was obtained from the Company's past annual energy efficiency compliance filings, Minnesota Municipal customers' historical savings information was obtained from CIP results filed with the Department of Commerce.[13] Superior Water Light and Power provided its own historical savings information to Minnesota Power.

Forecast assumptions for Minnesota Power's residential and commercial savings were derived from the Company's most recent preliminary estimates of achieved and energy savings assumptions beyond 2022, were derived primarily from the Center for Energy and Environment's (CEE) Utility Reporting Tool.

For each of the retail classes and resale customers, the Company cumulated the historical and projected incremental savings to produce a "cumulative energy savings"

[13] 2021 results filed in Docket No. E-999/PR-22-24

series.[14] *This cumulative series is the optimal variable format/definition for modeling energy sales. A cumulative savings metric represents the lasting impacts of conservation programs by aggregating or cumulating the savings from all past conservation measures. Minnesota used an annual "Energy Efficiency" variable in regression models for sales to the residential, commercial, and public authority classes, as well as three of the Company's 15 resale customers modeled in AFR 2023.*

- Assumptions made regarding current and future saturation levels of appliances and electric space heating.
    - *Minnesota Power makes no assumptions regarding current and future saturation levels of appliances and electric space heating*.

V. Coordination of Forecasts with Other Systems (7610.0320, Subp.5)

Minnesota Power is a member of the Midwest Reliability Organization (MRO), Midcontinent Independent System Operator (MISO), Edison Electric Institute (EEI), 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.

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[14] 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- to 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.

STATE OF MINNESOTA	)	AFFIDAVIT OF SERVICE VIA
	) ss	ELECTRONIC FILING
COUNTY OF ST. LOUIS	)	

Tiana Heger of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 30th day of June, 2023, she served Minnesota Power's 2023 Annual Electric Utility Forecast Report in **Docket No. E-999/PR-23-11** on the Minnesota Public Utilities Commission and the Energy Resources Division of the Minnesota Department of Commerce via electronic filing. The persons on E-Docket's Official Service List for this Docket were served as requested.

Tiana Heger