From: Brady Ryall
To: Dan Peaco; Kathy Kelly; Doug A. Smith
Cc: Bob Peters; Steinfeld, Dayna; Bill Haight; Will Gardner; Christle, Darren (CCA); Wilde, Angela (PUB)
Subject: Documents to assist Daymark with Load Forecast and Export Revenue Forecast Reviews
Date: Friday, September 15, 2017 12:38:39 AM
Attachments: NFAT PUB-MH I-058b - Changes in forecast unit export prices.pdf
MMF-31 Whitfield Russell Associates Presentation - May 13 2014 - Redacted.pdf
CAC-25 - CAC Consolidated Load Forecast Simpson Gotham.PDF
CAC-26 - CAC Export Price Analysis Gotham.PDF
CAC-65 - Gotham_Simpson_Load Forecasting Presentation.pdf
CAC-66 - Gotham_Review of Export Price Forecast for NFAT.pdf
NFAT Rebuttal-final redacted.pdf

Dan, Kathy, and Team,

Here is a list of additional documents that may be of assistance in your reviews.

Export Revenues
PUB Minimum Filing Requirement (MFR) 24 through 31 and 79 through 84. Some of these have redactions; you may request the unredacted ones from MH.

MFR 80 is the chart that Bob Peters showed. It is the continuation of a NFAT chart which Bob called the "Whitfield Russell exhibit" because he used it in his evidence for the intervener MMF, but the source data were from NFAT IR PUB/MH I-58. Both are public documents and are attached to this email.

MFR 83 and 84 are the related to the NFAT exhibits that we discussed that gave rise to La Capra undertaking the review of the promised export revenues. At the NFAT, we asked MH to provide support for their $9B of export revenues. Through several iterations of undertakings, we ended up with NFAT CSI Exhibits MH-37 and -38 [note: MH-37 was initially mis-identified as MH-36].

We asked La Capra to verify the numbers from MH-37 and MH-38 since La Capra had access to the export contracts and volumes from various SPLASH modeling runs. La Capra filed its response to CSI Undertaking U-34 and I believe it was Exhibit LCA-5. La Capra's response is a few pages of text and a number of spreadsheet tables. There was a spreadsheet provided to MH on CD as well; MH should have a copy of it. You may in fact wish to request all of the LCA exhibits from MH. They should be happy to know that you no longer have these in your possession.

Because of La Capra's work at verifying the firm capacity and firm energy revenues in these contracts, this work is not replicated in the current GRA scope of work and these firm revenues are to be taken as a given, per scope of work item 3. Please note that the exhibits have a third table of surplus or unfirm energy sales and revenues. These would fall under scope of work item 2.

There is no redacted version of MFR 84 so the request is repeated here:

MFR 84: Provide NFAT CSI Exhibits MH-37 and MH-38 and updates of each of these schedules of export revenues, volumes (energy and capacity), and unit price by export contract for each year of the contracts and broken down by capacity, firm energy, and contracted surplus energy. [NFAT CSI Exhibits MH-37 and MH-38]

Consumer Association of Canada's witness Dr. Gotham of Purdue State University also provided evidence on MH's export revenue forecasting, attached to this email.

<u>Load Forecast</u>
You mentioned that you have the Elenchus report from the NFAT. Dr. Gotham also provided evidence on MH's load forecasting, including some criticisms, attached to this email.

MH responded to the evidence of Elenchus and Dr. Gotham in its rebuttal, attached.

As always, please contact me if you have any questions.

Regards,

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From:	Brady Ryall
To:	Dan Peaco; Doug A. Smith; Bill Haight
Subject:	Re: NFAT - Potomac material
Date:	Monday, October 23, 2017 4:06:42 PM
Attachments:	Transcript 04-01-2014 Potomac.pdf

Transcript

Regards,

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On Mon, Oct 23, 2017 at 3:04 PM, Brady Ryall <brady@ryalleng.com> wrote:

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From:	Brady Ryall
To:	Dan Peaco; Doug A. Smith; Bill Haight
Subject:	NFAT - Potomac material
Date:	Monday, October 23, 2017 4:04:39 PM
Attachments:	miso_potomac_redacted_mar_25_2014.pdf

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Standard Approaches to Load Forecasting and Review of Manitoba Hydro Load Forecast for Needs For and Alternatives To (NFAT)

Wayne Simpson

University of Manitoba

Douglas Gotham

Purdue University

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INTRODUCTION

The Manitoba Hydro report on Needs for and Alternatives to Business Case (NFAT, August, 2013) provides load forecasts to 2032 that constitute the starting point for their assessment of alternative development plans. Elenchus Research Associates have now provided a review of Manitoba Hydro's load forecast for the Public Utilities Board (Elenchus, January, 2014) that describes the forecasting process in detail and provides an assessment of its accuracy and reliability. In summary, Elenchus (iv) finds that the NFAT load forecast is reasonable but deficient in terms of the alternative economic and population scenarios considered and the methodology used to assess its reliability. This report attempts to avoid duplication with the work done by Elenchus to provide additional discussion of the accuracy and reliability of Hydro's load forecasts in the NFAT. It is meant to be read as a companion to the Elenchus report. In particular, this is not an attempt to repeat the detailed description of Hydro's load forecast methodology already provided by Elenchus.

This report is structured in two parts. Part 1 provides a general overview of load forecasting techniques and the significance of forecast accuracy for resource planning purposes. Part 2 looks specifically at Manitoba Hydro's load forecasting in the NFAT.

PART 1 - Standard Approaches to Load Forecasting

A number of different approaches to load forecasting exist, each with its own advantages and disadvantages. In general, load forecasting methods can be classified as bottom-up, top-down, or a hybrid of those two. Bottom-up forecasting involves producing projections at the individual customer or device level and summing across the various customers and/or devices. Top-down forecasts are produced by aggregating the customers into larger groups and projecting usage at the group level. Hybrid approaches use features of both bottom-up and top-down methods.

In general, forecasting models use what is known about the past to predict what will happen in the future. The level of detail and sophistication of the model may vary considerably, as can the model's ability to capture fundamental changes in the future. In many cases, different forms of forecasting models will be used in conjunction. For example, an estimate for one of the drivers of an econometric model may be derived using a regression model for that driver.

While there are a number of approaches to load forecasting, they are not all equally appropriate. In its whitepaper on forecasting methodologies, the Mid-continent Independent System Operator (MISO) identifies the qualities of a good forecasting system as understandability, credibility, accuracy, reasonable cost, maintainability, and adaptability. MISO also provides lists of acceptable and unacceptable forecasting methods MISO, ("Peak Forecasting Methodology Review," 2013-12-06, https://www.misoenergy.org/_layouts/miso/ecm/redirect.aspx?id=98923). The inclusion of different methods on those lists is provided with the description of the approaches.

Top-down forecasting

Trend analysis

Load forecasting using trend analysis (also referred to as time series or regression analysis) relies solely on the historical load with no consideration of the factors that affected the amount of energy used. In essence, regression models determine a mathematical equation that explains historical usage and extrapolated to future usage using that equation. Perhaps the simplest form of this model is to assume the future value will stay at the historical average. The most common form of a trend model is a linear trend. In a linear trend, the historical data is fit to a straight line (as best as possible). The slope of the line then provides the change in value from one period to the next in the future. The line fit is usually determined using the ordinary least squares method.[1] It is also possible to use non-linear regressions (such as polynomial[2] or exponential[3]) in a trend model.

The major advantage of trend analysis is simplicity. It requires no data beyond the historical observations of the value that is being forecasted and the regression can be calculated using the statistical functions of commercial spreadsheet software.

The major disadvantage of trend analysis is inaccuracy. Trend models do not account for changes in the economic, climatic, and demographic factors that may change energy use. It may not be possible to obtain a regression with a good fit to the historical data, particularly if there is a lot of variability in the data. Furthermore, the choice of historical data can influence the results. For instance, a load forecast based on the past five years, which saw a significant economic recession, would produce a very different result than one based on the last twenty years.

Load forecasts based on regression models have been largely discredited. In its forecasting review whitepaper, MISO states that "any statistical extrapolation of historical trend using only data from the series to be forecast is unacceptable as the primary forecasting technique."

Econometric models

Econometric models attempt to quantify the relationship between the parameter that is being forecast (the output variable) and a number of factors that affect the output variable. These factors are commonly referred to as explanatory variables or drivers. Each explanatory variable affects the output variable in a different way. For instance, manufacturing output may be positively correlated with energy use in that they tend to go up and down together, while electricity price may be negatively correlated with energy use. The mathematical relationships (aka sensitivities) are determined

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[1] The ordinary least squares method is used for estimating a line that is as close as possible to the historical data. For each time period for which the data is collected (for annual data this would be for each year), the difference between the historical value and the corresponding value on the line is determined. These differences are then squared and summed across all points. The line with the best fit is the one that has the lowest value for that sum.

[2] A polynomial function is a mathematical expression where the variables are raised to an integer power. The simplest form is when the variable is squared ($y=x^2$). An extension of the square function is the quadratic ($y=ax^2+bx+c$). Higher order polynomials include cube functions and beyond.

[3] An exponential function is one where the variable is an exponent of some constant ($y=a^x$). An exponential function will increase or decrease by a fixed percentage as opposed to a fixed value in a linear function.

simultaneously and can be calculated via any of the methods used in time series forecasting, such as linear, polynomial, and exponential. Thus, an equation is derived that includes the relationship of each driver to the output. Projections of the values for the drivers are then used to determine the output variable for each forecast period.

The appropriate explanatory variables may differ from one utility or region to another. They may also change over time as factors change. Common explanatory variables include population and demographics, employment, economic output, personal income, weather, and the price of electricity and competing energy sources.

Econometric forecasting is more time and resource intensive than trend analysis. In addition to the development of the model, it requires the acquisition or development of projections of the drivers. These projections may be produced in house, using another econometric model or a regression model, or they may be produced by commercial vendors or by government entities.

The major advantages of econometric forecasting are the potential for improved accuracy, the ability to analyze the impact of scenarios that are more optimistic or pessimistic, and a greater understanding of the factors that affect the forecast uncertainty.

The major disadvantage of econometric forecasts is that it is difficult to account for factors that will change the future relationship between the drivers and the output variable. A common example of this is changes in energy efficiency, either through utility demand-side management programs or through government codes and standards.

MISO includes econometric forecasting on its “Acceptable List” of forecasting methodologies.

Bottom-up forecasting

Survey-based forecasts

Survey-based (aka informed opinion) forecasts use information from a select group of customers regarding their future plans as the basis for the forecast. This is most commonly done with the largest consumers of energy, since those customers have the greatest impact on the forecast and are often a source of considerable uncertainty. Information is collected regarding the customers’ future production and expansion plans. Sources for this information can be from direct contact with the customer, public announcements, or discussions with an industry expert. The forecast then reflects the information regarding future plans. Thus, if a facility is expected to maintain current production levels, the forecast will indicate a constant load. Similarly, an increase in production or an addition of new facilities will result in a forecast load increase. Conversely, if a customer is expected to scale back production or close facilities, forecast load will drop.

The major advantage of survey-based forecasts is the ability to account for expected fundamental changes in customer demand for large users, especially in the near-term when customer plans are relatively firm. It may be difficult to capture these changes in an econometric model.

The major disadvantage of survey-based forecasting is the lack of information regarding customers' plans in the long-term. Most industrial facilities do not know what their production levels will be five or ten years into the future. Similarly, while some customers will cease operations in the long-term, very few are currently expecting to do so in the future. New facilities will likely be added in the long-term, but the forecaster will have no knowledge of them. Thus, survey-based forecasts are inherently inaccurate in the long-term. A second disadvantage of survey-based forecasts is the lack of transparency. Conversations between large customers and utility representatives are typically held in confidence.

Entities that rely on this type of forecasts will sometimes rely on it only for the early period of the forecast and use another method, such as econometrics, for the later period.

MISO includes informed opinion forecasting on its "Unacceptable List" of forecasting methodologies.

End-use models

End-use forecasts look at energy use at the individual device level. The consumption of energy is categorized into a number of different activities which provide a desired service or end use. Examples of these include lighting, refrigeration, space heating, and cooling. End use models start with a catalogue of the existing stock of devices for each end use. This includes the vintage, or age, fuel source, and efficiency of the devices. For each forecast period, the model assumes that some of the existing stock will fail, with failure rates being a function of the vintage of the device. When failure occurs, the device can either be repaired or replaced. Additionally, new devices will be added to the stock as the number of homes and businesses increase. In some cases, old (but still functioning) devices may be replaced by new ones as well. New devices, along with replacement of existing devices, are chosen from the available options. This provides a new "existing" stock to be used for the next forecast period. The forecast is then derived from the energy used by all of the devices in each forecast period.

The repair/replace and new purchase decisions are based on the purchase and operating costs of the available options for the end use, along with the customer payback period. Alternatively, a model may have a distribution of payback periods to reflect differences in consumer behavior. Thus, the model will choose between options with low purchase costs and those that are more efficient but cost more to buy. Also, end-use models can reflect the competition between different energy sources, such as electricity vs. natural gas.

The major advantage of end-use models is the ability to directly capture changes in efficiency, through both government codes and standards and incentive programs. In the case of a changing standard, such as the phase out of incandescent lamps, the model simply does not include the less efficient option as a possibility for new stock once the standard is in place. For incentive programs, the purchase price of the efficient option can be adjusted to reflect the rebate or tax exemption.

Disadvantages of end-use models include being very data-intensive, the potential to miss energy consumption from devices that have yet to be invented or adopted, and the inability to capture changes in customer behavior. It is not feasible to know the exact number of devices that are in use. Populating the initial stock of devices is usually done via customer surveys and care must be taken to ensure that the surveys are representative of the overall mix of customers. While most end-use models include a miscellaneous category for devices that either do not use much energy or are not widely used, over time new end uses evolve that are often not adequately captured. Early end use models did not include personal computers and other such devices. Most current end use models do not include electric vehicles, which could be a significant user of electricity in the long-term. Finally, end use models generally do not account for changes in customer behavior that may affect the amount that a device is used. Once they have installed a higher efficiency device, some customers may use the device in a different fashion than they used the old one. A customer may adjust the thermostat to a more comfortable setting with a high efficiency air conditioning or space heating system.

MISO includes end-use forecasting on its "Acceptable List" of forecasting methodologies.

Hybrid forecasting

Hybrid forecasting models employ facets of both top-down and bottom-up models. The most common of these is the statistically-adjusted end-use (SAE) model, which embeds econometric formulations within an overall end-use model. In reality, most end-use models are hybrid to some degree in that they rely on top-down approaches to determine the growth in new devices. Other types of hybrid models are possible, such as using a survey-based model for the short-term which feeds into a longer-term econometric or regression model.

In general, hybrid approaches attempt to combine the relative advantages of both model types. This usually comes at the cost of increased model complexity.

MISO includes hybrid forecasting on its "Acceptable List" of forecasting methodologies.

Forecast accuracy for resource planning

Regardless of the methodology used to develop the load forecast, having an accurate forecast is an important factor in resource planning. An inaccurate forecast can have significant reliability and cost implications. For instance, if the forecast is too low (load ends up being much higher than was predicted), the utility could end up having insufficient resources in the future. This may force the utility to rely on options that can be implemented with a short lead time (such as a market purchase) that could be more expensive than the options that could have been used if the forecast had been more accurate. Similarly, if the forecast is too low, the utility will acquire too many resources (and earlier than necessary). This also results in expenses that are higher than they would have been with an accurate forecast. While a perfectly accurate forecast is unattainable, it is important to avoid a forecasting methodology and assumptions that are likely to introduce a bias in either direction.

PART 2 - Report on Manitoba Hydro Load Forecasting in the NFAT

Context

Elenchus provides an extensive discussion of a variety of possible scenarios that could impact electricity demand, both domestic and imported, including the development of competitive alternative energy sources.   The report, however, spends less time assessing the load forecast on its own terms in the absence of the arrival of alternative energy competition. Although it identifies Hydro's lack of analysis of alternative population and economic growth scenarios, it does not deal with other important limitations of the Hydro load forecasting methodology. In particular, it does not consider the important effects of rising Hydro rates projected in the NFAT apart from a limited discussion in section 2.1.3 and on page 46.

Forecast Methodology

Manitoba Hydro's load forecasting methodology can be described as one that is evolving but that remains a blend of existing approaches that is at times difficult to understand. It uses a variety of approaches to forecast load that preclude any assessment of within-sample reliability, an important component of any evaluation of prospective forecast error.[4] It also provides limited discussion of its methodology that makes it difficult to assess how Hydro has constructed its models and evaluated them against alternative approaches.

Residential Basic Forecast

The residential load forecast uses an "end use" methodology common in the industry that divides the customer base by dwelling type, area and heating type. The process forecasts residential customers via a consensus (simple average of forecasters) forecast of residential population divided by some past average of people per household (about 2.8 since 1997) and then forecasts the proportion using electric heating for each customer group. This latter forecast of electric heating share used a variety of regression[5] techniques until 2013, when the regression approach was abandoned completely in favour of an ad hoc approach involving an adjusted five-year moving average. This "bottom up" ad hoc approach is not compared to any sort of "top down" econometric approach, such as a set of regression models for the customer groups that would include population, income (GDP or household income measures), prices, weather, and other factors. [Elenchus, (16) also notes the "lack of consideration of alternative models and methods, such as top-down econometric approaches, to test the reference case scenario."] Thus, we have no idea whether the Hydro approach provides superior forecasts to such alternatives, as is implied in the NFAT. There is also no natural assessment of the within-sample reliability of the forecasting technique that would follow from the use of regression methods (e.g. R^2 as a measure of within-sample forecast error). In short, there is no rationale for the forecasting method that is chosen and its obvious deficiencies in providing estimates of prospective forecast reliability.

Manitoba Hydro assumes the number of customers will change proportionately with population. This relies on the assumption that the number of people per household will not change. This has not been true in the past and is unlikely to hold true in the future. The number of occupants per household will be affected by not only the number of people, but the relative ages of the population. For instance, if the fastest growing segment of the population is over 50, there will usually be fewer people per household in the future. Another factor affecting the number of occupants per household is personal income. As income increases, the number of occupants per household generally decreases. In the housing model used by the State Utility Forecasting Group (SUFG) for the state of Indiana, headship

[4] Within-sample forecasting error refers to a measure of the differences between the forecast and actual outcomes in the data available to the forecaster, such as the coefficient of determination (R^2) in econometric forecasting models. The measure provides an indication of the extent to which the forecasting methodology can predict known outcomes and, as such, is an indicator of the expected accuracy of the forecast in the short term.

[5] See the section on trend analysis in Part 1 for an explanation of regression-based forecasting.

rates (the inverse of occupants per household) are projected using a logit model that is a function of age, income, marital status, and the prior year's headship rate.

Manitoba Hydro projects the number of dwellings that use electricity for heating from a five-year average and then uses that as an exogenous assumption to the end use model. This nullifies one of the major benefits of end-use modeling, which is the ability to simulate the economic trade-off of different technologies and fuel sources based on the capital and fuel costs of the different options. Ideally the number of new dwellings would be an exogenous input and the fuel choice decision would be handled endogenously by the model.

General Service Mass Market

The forecast of growth of the General Service Mass Market has employed regression models, but the model specification has changed from year to year without any explanation of the rationale (Elenchus, 18). In the current version, only GDP growth and residential customer growth are components of the model, but the regression methodology does permit an assessment of within-sample forecast reliability and a consistent method to choose the appropriate forecasting model going forward. Whether that model selection methodology has been used in the past is unclear, since the basis for the choice of the current forecasting elements (GDP and residential customer growth) rather than alternative specifications is unclear.

This sector is forecast with an econometric formulation to determine the number of customers, using GDP and population as the drivers. The electricity utilization per customer is then assumed to stay constant at the most recent 5-year average. In reality, utilization per customer will not stay constant, especially when real electricity prices are changing.

The SUFG forecasting methodology for Indiana is a little different in that customers are separated into commercial and industrial classifications (as opposed to combining them and separating out the largest customers), but the experience is still informative. Indiana experienced a period of declining (in real terms) rates from 1985 to 2005 and has experienced increasing real rates from then on. During the period of declining rates, the commercial sector saw intensity (in utilization per unit of floor space) increase at 2.4% annually. With the start of rate increases, we start to see declines in intensity of 0.4%. In the industrial sector, intensity (in utilization per real manufacturing GSP) has been dropping since the mid-1980s. During the earlier period of declining rates, intensity fell by an average of 1.2% annually. More recently, the decline has been 1.9% per year.

General Service Top Customers

The forecast of Top Customers is based on assessments from Hydro's own economic experts and account representatives. While Hydro argues that regression techniques are inappropriate for this customer segment, its own methodology has had a consistent upward bias on the order of 5% (Elenchus, 23). Also, there is no justification that this approach is superior to appropriately crafted regression modelling in terms of forecast accuracy, nor is there any assessment in the NFAT of the limitations of the forecasting methodology used. Furthermore, this approach relies on two forecasting methods (informed opinion and trend analysis) from MISO's list of unacceptable methods.

Missing Elements

Electricity is a standard product whose demand should be understood as part of customer demand (the residential customer component) and as an input to production (the General Service Mass Market and Top Customer components). The principle factors in a conventional analysis of demand for a product of this nature would be: the price of the product (electricity), the prices of related products (especially alternative energy products available to residential and commercial customers), income (household incomes and the value of production (GDP)), population, and factors such as weather.

While Hydro spends a great deal of time examining the variation in demand related to weather (cooling and heating days), this is largely a short-term phenomenon unless there are dramatic changes in weather patterns (climate change) that are relevant to the forecasting horizon. Weather variation may account for some of the fluctuation in load demand within each year and, to a lesser extent, across years, while the other factors (and weather trends related to climate change) will account for movement in the trend or average load over time. This trend constitutes the expected long-term forecast about which weather will cause minor variations. In short, there should be less concern about adjustments for weather (which are, in any case, of dubious value in the NFAT according to Elenchus (27-29)) and more concern about the limitations of the trend forecasting methodology.

Elenchus (ii-iii, 30-31, 42-43) makes a similar point in referring repeatedly to the need for a wider range of population and GDP scenarios, since potential variation arising from population and economic growth is ignored in the risk analysis in the NFAT. What is missing in the Elenchus report is some indication of how much alternative population and economic growth scenarios might matter to the comparison of alternative plans, something that will not be resolved directly by the alternative DSM scenarios Hydro is now running. These DSM scenarios may, however, provide some indication of the implications of reduced load projections for the comparison of alternative development plans.

It is also a puzzle why the load growth forecast for Manitoba (1.6%; NFAT, ch.4, p.12) exceeds the load growth forecast for the U.S. (0.9%) despite similar population growth forecasts in Manitoba and the U.S. and higher GDP growth forecasts for the U.S. compared to Manitoba. This was not resolved in the interrogatories. This is an issue about their forecast trend, however, rather than potential variability about the trend arising from population and economic growth uncertainty.

The major missing factor in the load forecast is prices. The NFAT (Exec Summary, 9) admits that energy prices matter but makes no attempt to incorporate what amount to fairly substantial projected rate increases into its load forecast. Moreover, Hydro indicates that it does not pay attention to what is a fairly robust literature on the impact of prices on electricity demand from other jurisdictions. In response to the interrogatories GAC_CAC/MH II-001a and b, Manitoba Hydro did produce some correlations of prices with customer usage, but the results are based on a small number of points and a simple regression analysis that ignores the other important factors in the determination of customer demand. A more detailed analysis, or the application of results from better analyses elsewhere, is needed.

Manitoba Hydro indicates that prices would increase by about 4% per year in nominal terms, or about 2% per year in real terms (NFAT, Appendix D, 55). This should result in a reduction in utilization per customer for a number of reasons: it results in reduced disposable income for customers so they purchase fewer energy using devices, those purchases that customers make are more likely to be made with energy efficiency in mind, customers may opt to use energy sources other than electricity where possible (conversion from natural gas to electricity for space heating is less likely to occur), and customers may change their behavior (adjusting temperature settings, turning off lighting when not in use, etc.). If electric rates have been stable for some time, it is possible that the forecasting model estimation would not capture the impact of price elasticity.

Some illustrative "back of the envelope" calculations might indicate the potential size of the price effects on load forecasting in NFAT. Take the U.S. estimates that a 10% increase in the price of electricity can be expected to reduce household load by around 5% in the long run (http://www.e3network.org/ElasticitySurvey2_matt.pdf). Compounded annually, the projected 2% (real) increase in electricity prices over 30 years amounts to a whopping 80% increase in rates over and above general price inflation. Apply this increase only to the residential sector, which accounts for about 1/3 of load. Hydro projects a load increase of 1.6% per annum for this sector, of which 1.2% is attributed to population growth and 0.4% to increased energy usage (NFAT, ch.4, 12). Over 30 years, this implies load growth of about 60%, with about 45% attributable to population growth and 15% attributable to increased usage per household, ignoring the impact of price increases. Applying the U.S. price elasticity estimates, however, implies that the 80% increase in prices would reduce load by 40% (since a 10% price increase would reduce load by 5%), implying that load per household would actually decline by about 25% over the 30 years due to rising electricity rates.[6] Combined with the load growth due to rising population of 45%, this implies only a 20% increase in residential load or about one-third of the 60% projected by Hydro.

Hydro projects total load growth of about 7,899 Gwh, from 24,367 Gwh in 2011/12 to 32,266 Gwh in 2031/32 (NFAT, ch.12, 2-3). It appears that residential load growth is more rapid than other growth, but assume that only one-third of this growth is residential, or 2,633 Gwh. If actual growth is only one-third of that figure because of reduced household usage due to rising electricity prices, as suggested above, then load growth would be reduced by more than 1,755 Gwh. The NFAT (ch.12, p.2) suggests that one year of load growth constitutes 420 Gwh, so this amounts to a reduction in load growth of 4.2 years. By comparision, the revisions to the load forecast for 2013 amount to a reduction in load growth of 3 years by 2031/32, which defers the need for new resources by one year. This suggests that electricity conservation in the residential customer base alone, arising from the rate increases projected by Hydro, would defer the need for new resources by at least another year. Since the commercial sector would also be sensitive to increases in the price of electricity, reductions in load growth in the General Service Mass Market and Top Customer sectors might be expected to defer load growth correspondingly by as much as three years. While this is only illustrative, these are quite significant numbers that would substantially affect planning.

Indiana has seen an increase in prices in real terms since 2005. The SUFG forecasting models indicate real price elasticities of -0.4 for the residential sector, -0.26 for the commercial sector, and -0.48 for the industrial sector. Thus a 2% real price increase in the residential sector would result in 0.8% less electricity use. While one would expect the actual price elasticities to be different in Manitoba than

[6] These are estimates of the average effect of electricity price increases on consumers. There may be differences across households. Lower income households, for example, may be less able to reduce electricity consumption than higher income households, since their electricity use is already devoted primarily to necessities. Harvey Stevens and Wayne Simpson explore this issue in a separate submission to this hearing.

they are in Indiana, there still should be a dampening of electricity demand as real prices rise. Yet Manitoba Hydro is projecting electricity usage to grow at the same rate as it has historically, with an average annual increase of 0.4% in utilization per customer.

It should be noted that The Brattle Group uses a price elasticity of -0.4 in the export price forecast model that was used as an input to Manitoba Hydro's export price forecast. Furthermore, they label that value as conservative and low (NFAT, Appendix 3.1, slide 51).

Assessment of Forecast Reliability

The reliability of the forecast depends on two components: (i) the within-sample reliability of the forecast instrument and (ii) the beyond-sample accuracy of projections of the inputs (e.g., economic or demographic projections) to the forecasting model. In a 30 year forecast based on annual data, it is safe to say that (ii) likely matters far more than (i) because the variability arising from (i) will lead to short-run forecast errors (over a few years) that will largely cancel over the longer run (30 years) while the projection errors from (ii) are far more likely to accumulate over time, e.g. a prolonged economic or population/immigration slowdown.

Hydro's forecasting methodology makes it difficult to assess within-sample forecasting reliability. The extensive discussion of the impact of weather on forecast reliability does not make up for the absence of reliability estimates based on other forecast inputs such as population and economic growth. A consistent econometric approach to forecasting would solve this problem, but other statistical solutions to assess the within-sample reliability of the present forecasting method (Monte Carlo or bootstrapping approaches, for example) are likely feasible as well.[7]

It is also very difficult to assess the reliability of the beyond-sample accuracy of projections to the inputs to the forecasting model. Elenchus emphasizes the need for alternative population and economic growth projections to assess the sensitivity of the load forecasts, and subsequent plan evaluations to these two components of their forecasting model. In addition, there are important inputs to the load forecast, such as prices, that are not considered at all by Hydro or extensively by Elenchus.

The most disturbing omission from the Hydro forecasting methodology must be the impact of rising electricity prices because all the evidence implies that the bias introduced by this omission is upward; that is, the omission of price effects leads to inflated load forecasts and requirements for new system capacity. Indeed, our illustrative results with fairly conservative estimates of the responsiveness of U.S. consumers to electricity price increases imply requirements for new system capacity may be overestimated by several years.

[7] For any forecasting methodology where the data can be measured and characterized in terms of one or a series of empirical probability distributions, repeated draws from the distribution(s) can be used to measure the difference between the forecast and actual outcomes to assess forecasting error.

Review of Manitoba Hydro Export Price Forecast for Needs For and Alternatives To (NFAT)

Douglas J. Gotham

Purdue University

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Introduction

Based on the market valuation, export sales revenue represents a very significant part of the plan to meet expenditures (over $9.3 billion in present value from exports). Thus, if export prices are even slightly lower than the projected price, there will be significantly reduced revenue. Alternative plans have reduced (but still significant) revenue from export sales.

Manitoba Hydro uses an export price forecast that is an average of six forecasts provided by various consultants. With the exception of one of these forecasts, prepared by The Brattle Group, these forecasts are not available due to the proprietary nature of the models and the competitively sensitive nature of the information. Furthermore, the assumptions behind these forecasts are not available. Thus, it is not possible to speak definitively about the reasonability of the export price forecast and assumptions. Manitoba Hydro did include supporting information in its Business Case that raises concerns about the assumptions behind its export price forecast and thus, about the export price forecast itself.

This document looks at three general areas: the applicability of the supporting information provided by Manitoba Hydro, the implication of the inclusion of carbon costs in the export price forecast, and the reasonability of the export price forecast from The Brattle Group.

Manitoba Hydro's Supporting Information

This section examines two potential issues: the existence of transmission congestion between the export region, the area into which Manitoba Hydro will be selling electricity, and the rest of the MISO market; and the future load growth in the export region.

Transmission Congestion

Manitoba Hydro indicates that there are no significant transmission congestion issues between the Minnesota/Wisconsin region and the rest of the Mid-continent Independent System Operator (MISO). This contradicts determinations by the MISO Independent Market Monitor and the U.S. Federal Energy Regulatory Commission (FERC), as well as evidence based on wholesale electricity prices. The existence of congestion is significant because it means that the additional transactions between Manitoba Hydro and the Minnesota/Wisconsin region of MISO will have a larger impact on market prices than would occur without congestion. In essence, congestion shrinks the size of the market since it excludes participants from outside the congested area. Thus, one would expect lower market prices when Manitoba Hydro is selling into the market (and lower revenues for Manitoba Hydro) and higher market prices when Manitoba Hydro is purchasing from the market (and higher costs for Manitoba Hydro).

To examine the impact of transmission congestion on market prices, an analysis of published day-ahead market price indices for the period of March through December 2013 was performed. The specifics of that analysis are included as an appendix and the pertinent results are provided here. The analysis uses on-peak and off-peak price indices published in Megawatt Daily for four hubs in the MISO market: Illinois Hub (IL), Indiana Hub (IN), Michigan Hub (MI), and Minnesota Hub (MN). A comparison of those price indices (for March-December 2013) was performed to look for consistent variations between the Minnesota Hub and the other three MISO hubs.

If congestion exists between the Minnesota Hub and the rest of MISO, it will show up in one of two ways. If the Minnesota Hub has an excess of supply which cannot get out of the region due to congestion, the hub price will be lower than the prices at the other hubs. If the Minnesota Hub has a shortage of supply and congestion keeps outside suppliers from getting energy to the region, the hub price will be higher than prices at the other hubs. It should be noted that the existence of lower (or higher) prices is not sufficient to show that congestion exists. Losses associated with transmitting the energy will result in a price differential between the exporting and importing regions. Transmission losses are generally low (a few percent), so larger price differences between hubs would be an indicator of congestion.

In order to look for evidence of congestion, the magnitude of the difference between hub price indices was examined. Figure 1 shows the percentage of days that a particular hub's off-peak price exceeded the all other hub prices by more than 10 % (in blue) or was more than 10 % less than any other hub price (in red). Since a difference of that magnitude is unlikely to arise from transmission losses alone, the figure indicates that congestion exists frequently and that the congestion affects market prices in the Minnesota region. In particular, the off-peak prices in the Minnesota Hub are often suppressed relative to the rest of MISO, with indices more than 10 % lower than any of the other three hub occurring 36 % of the time. In some hours, this effect was even larger: in 19 % of the off-peak periods, the Minnesota Hub was more than 20 % lower than any of the other three. It was more than 30 % lower in 9 % of the off-peak periods and more than 40 % lower in 5 % of the periods.

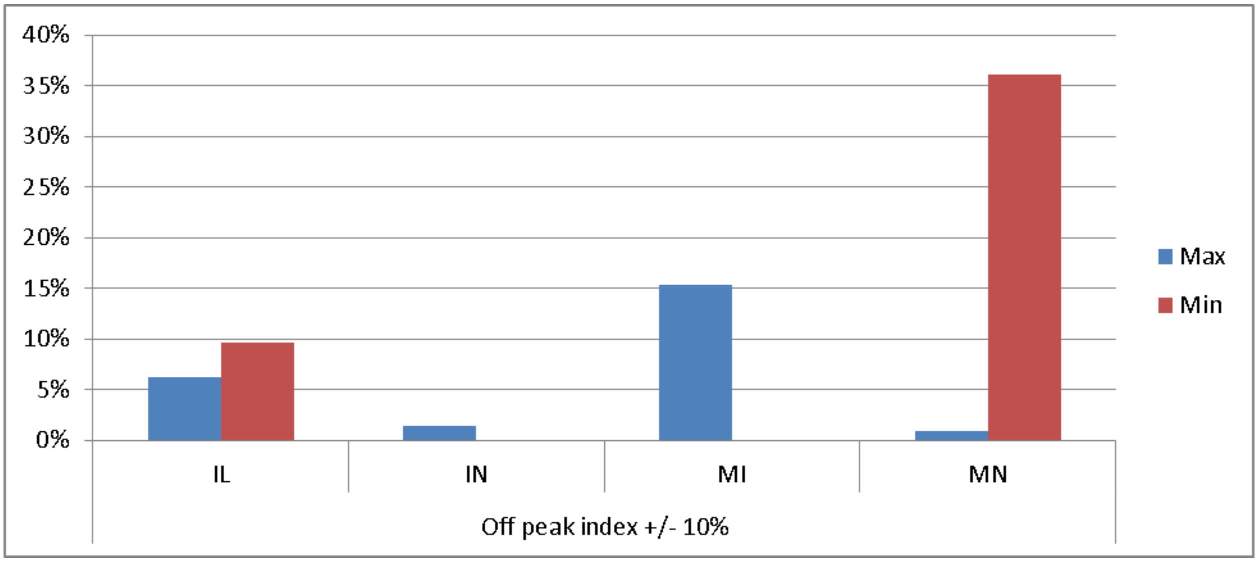

Figure 1. Percentage of days where the off-peak index for a hub was 10 % more (blue) or 10 % less (red) than any other hub

It should be noted that on-peak price indices indicate that congestion also affects Minnesota Hub prices during those periods as well. This happens less frequently than in the off-peak periods and prices can be lower than others on some days (indicating that congestion is limiting the ability to export power) while prices can be higher than others on some days (indicating that congestion is limiting imports). Minnesota Hub on-peak prices are more than 10 % higher than any of the others 13 % of the time and more than 10 % lower than the others 7 % of the time.

The observations of persistent low off-peak prices and on-peak prices that are sometimes high and low at other times are consistent with the high levels of wind generation capacity in the region. The wind generation is generally higher during the off-peak periods when demand is low. This results in a surplus of supply in the region and the excess generation is unable to move to other regions due to the transmission congestion. If the wind is not blowing during on-peak periods, a shortage of supply can occur (with congestion limiting imports). If the wind is blowing and weather is mild during the on-peak hours, the conditions observed during a number of off-peak days can be replicated. That is, excess supply plus congestion results in low prices.

The existence of transmission congestion has also been identified by independent sources. According to the U.S. Federal Energy Regulatory Commission (FERC) website, "*Since the start of the Day-2 market on April 1, 2005, persistent transmission constraints in the Wisconsin and the Upper Peninsula of Michigan (WUMS) and Minnesota areas have caused their prices to* *diverge from other areas of MISO, usually at times of high loads or decreased generation supply.*"[1]

The existence of transmission congestion in the Minnesota and Wisconsin regions is further borne out by the MISO Independent Market Monitor, Potomac Economics. In their most recent State of the Market Report, they identified three Narrow Constrained Areas, all of which are in the Minnesota, Wisconsin, and Upper Michigan areas. Narrow Constrained Areas are defined as "*chronically constrained areas that raise more severe potential local market power concerns (i.e., tighter market power mitigation measures are employed).*"[2] When asked about this in the Information Request process, Manitoba Hydro dismisses the significance of the classification by focusing on the second half of the statement regarding market power mitigation.[3] Unfortunately, transmission constraints that affect market power will also affect market prices. Regardless of the purpose of the analysis, the MISO Independent Market Monitor found evidence that the transmission system is chronically constrained in that region.

Furthermore, Potomac Economics identified transmission congestion as a factor affecting wholesale market prices in the Minnesota region in its IEC report.[4]

Further evidence of transmission congestion impacting market prices in the Minnesota region comes from MISO's modeling for its transmission planning process. MISO published hourly Locational Marginal Prices (LMPs) for 2017, 2022, and 2027 as part of 2012 MISO Transmission Expansion Planning (MTEP12) process.[5] In addition to LMPs, hourly transmission loss and congestion components were provided for four scenarios. For the Business as Usual (BAU) scenario, "*demand, energy and inflation growth rates are based on recent historical data and assume existing standards for resource adequacy and renewable mandates.*" The Combined Policy (COMBO) scenario is intended to capture the effects of a number of federal policies, including a $50/ton carbon cost, a national renewable portfolio standard, the widespread implementation of smart grid technologies, and the deployment of electric vehicles. It also includes 23 GW of coal retirements (compared to 12 GW in the other scenarios). The Historical Growth (HG) scenario is similar to the BAU but assumes that load growth will occur at the rate experienced prior to the recent economic downturn. The Limited Growth (LG) scenario assumes that energy and demand will grow at ½ the rate used in the BAU.

[1] http://www.ferc.gov/market-oversight/mkt-electric/midwest.asp, updated November 26, 2013 and accessed January 27, 2014.

[2] "2012 State of the Market Report for the MISO Electricity Markets," Potomac Economics, June 2013, pg. 61.

[3] Manitoba Hydro response to CAC/MH II-209.

[4] "Report on Export Prices and Revenues relating to the Need For and Alternatives To (NFAT) Manitoba Hydro's Preferred Development Plan," Potomac Economics, January 15, 2014, Section II.C.2.

[5] https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPFutures.aspx

The annual average LMPs, transmission loss components, and transmission congestion components for the Minnesota Hub are provided in Tables 1-3. It should be noted that a negative value for loss or congestion indicates a reduction in the locational price from the system-wide average, while a positive value corresponds to a higher locational price. Congestion reduces Minnesota Hub annual average price by 3 to 12 % depending on the scenario and year. Table 4 shows the average system-wide marginal price for the MISO region.

Table 1. Average LMPs for Minnesota Hub ($/MWh)

	BAU	COMBO	HG	LG
2017	29.65	80.10	33.14	24.94
2022	32.54	107.68	40.76	24.39
2027	37.78	100.13	51.24	26.57

Table 2. Average Loss Component ($/MWh)

	BAU	COMBO	HG	LG
2017	-1.47	-3.39	-1.59	-1.52
2022	-1.85	-5.45	-1.59	-1.37
2027	-2.75	-6.48	-2.82	-2.05

Table 3. Average Congestion Component ($/MWh)

	BAU	COMBO	HG	LG
2017	-0.96	-5.21	-2.22	-1.85
2022	-1.50	-8.30	-3.33	-2.72
2027	-2.40	-10.73	-7.43	-3.24

Table 4. Average MISO System Marginal Price ($/MWh)

	BAU	COMBO	HG	LG
2017	32.08	88.71	36.95	28.32
2022	35.89	121.43	45.67	28.48
2027	42.93	117.35	61.50	31.86

The export price forecast prepared by The Brattle Group provides price projections for the Midwest Reliability Organization (MRO) West region, which includes Minnesota and western

Wisconsin, along with Iowa and much of Nebraska and the Dakotas.[6] It also includes price projections for the entire region modeled, which includes the rest of MISO (excluding the MISO South addition) and portions of the PJM Interconnection and the Southwest Power Pool. A comparison of the price projections for the MRO West region and the aggregate results for the larger area indicates that the MRO West prices are generally $3-4/MWh less than the aggregate area prices. This is consistent with the combined transmission loss and congestion components from the MISO MTEP12 process and to the observed differences in price indices from Megawatt Daily, which indicates that the modeling from The Brattle Group likely captured some congestion impacts. It should be noted that the MISO MTEP12 process indicated that congestion impacts would increase in the future but the price difference between the smaller region and the larger area from The Brattle Group did not change appreciably over time.

Load Growth in the Export Region

The supporting information from Manitoba Hydro includes projected load growth in the export region that may be too robust. Manitoba Hydro includes load growth from the EIA 2013 Annual Outlook that is for the U.S. as a whole. A more appropriate load growth would be for the two census divisions that represent the states comprising the area into which they would be selling energy. The growth rates for these regions are lower than the U.S. average in EIA's analysis.

The EIA growth rates also do not include the impacts of carbon costs. Inclusion of carbon costs would result in higher electricity prices and a corresponding lower growth in electricity demand. This is significant because Manitoba Hydro does include carbon costs in their export prices. This indicates that there may be inconsistency within the export price forecast assumptions. The use of higher load growth plus carbon costs would bias the export price forecast upwards.

Manitoba Hydro provides forecast energy growth at a U.S. national level from the U.S. Energy Information Administration (EIA) of 0.9 % per year in its 2013 Annual Energy Outlook (AEO) as supporting evidence, as well as MISO system-wide forecasts from MTEP12. It should be noted that the 2013 MTEP assumptions for the BAU are 0.81 % energy growth and 0.75 % demand growth.[7] Considering the uncertainty of future electricity usage, these numbers are not unreasonable.

However, load growth varies considerably from one area to another and a smaller region that is more representative of the area into which Manitoba Hydro would be exporting would be more appropriate. EIA forecasts load growth at the census division level in the AEO. For the 2013 AEO, the energy growth in the East North Central census division (Indiana, Illinois, Michigan, Ohio, and Wisconsin) is only 0.3 %. The energy growth for the West North Central census

[6] "NFAT Business Case," Manitoba Hydro, Appendix 3.1
[7] "MISO Transmission Expansion Plan 2013," MISO.

division (Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and South Dakota) is 0.6 %.

Manitoba Hydro also provided load forecasts from Minnesota Power (0.6% for both energy and demand) and Northern States Power (0.5% for energy and 0.7% for demand).[8] Based on these forecasts, load growth of 0.5-0.6 % would be more appropriate than the U.S. projection of 0.9 %.

It is important to note that none of the projections from EIA, MISO, or Northern States Power include the impact of higher prices from imposing a cost on CO2 emissions. Minnesota Power includes a very low price of $2.50/ton in 2013 increasing to $3.50/ton in 2017.[9] The Brattle Group did include the price impact on load growth in the export price forecast. The Brattle Group used a base forecast growth of 0.4% per year and adjusted that using a price elasticity of -0.4. Thus, for every 10 percent increase in customer rates, usage was dropped by 4 %.

CO2 Cost

There is considerably uncertainty surrounding the use of CO2 costs in the export price forecast. The imposition of CO2 restrictions in the Midwestern U.S. is not a foregone conclusion. If such restrictions are imposed, when will they happen, what form will the take, and how stringent will they be? Inclusion of these costs represents a significant risk to Manitoba Hydro's revenue if they should not develop as expected. It should be noted that Potomac Economics assigned a 50% total probability for the scenarios that included CO2 costs in its IEC report.

Based on a comparison of The Brattle Group's Base and Low CO2 cases, inclusion of moderate CO2 costs will result in an increase of $13-14/MWh in the export price. Alternatively, if the CO2 costs do not materialize, the price of (and corresponding revenue from) exports would be about 20-25% lower. With an expected present value revenue of $9.3 billion from exports, this would result in a shortfall of $1.8-2.3 billion, assuming that the export price forecast from The Brattle Group is representative of Manitoba Hydro's forecast.

Comparison of the Brattle Forecast to MISO MTEP12 and Potomac Economics Report

A comparison of the all hours energy price projections (without capacity prices) for the BAU/Base/Reference cases for the MTEP12, Brattle, and Potomac Economics IEC report is provided in Table 5. It should be noted that the MTEP12 BAU did not include a cost of CO2, while the Brattle and Potomac numbers are estimated from figures in the reports. The Potomac is further adjusted from the peak and off-peak numbers on a weighted average basis (using 80 on-peak and 88 off-peak hours per week). It should also be noted that the Brattle projections are for a similar but slightly different geographical region (MRO West vs. Minnesota Hub).

[8] "NFAT Business Case," Manitoba Hydro, Chapter 6
[9] Manitoba Hydro response to IR CAC/MH I-201

Table 5. BAU/Base/Reference Export Region All Hours Energy Price Projections

	MTEP12	Brattle	Potomac
2017	29.65	30	25
2022	32.54	46	39
2027	37.78	51	43

Since the MTEP BAU does not include CO2 costs, a more direct comparison of the outputs of the three models would be to compare the MTEP12 BAU, Brattle Low CO2 (which actually has no CO2 costs), and Potomac No Carbon cases. Table 6 provides that comparison, using the same estimation methods as described earlier.

Table 6. MTEP BAU vs. Brattle Low CO2 vs. Potomac No Carbon All Hours Energy Prices

	MTEP	Brattle	Potomac
2017	29.65	30	25
2022	32.54	33	29
2027	37.78	37	31

The MTEP12 BAU and Brattle Low CO2 energy forecasts are very similar; with the Potomac No Carbon forecast roughly 10-20 % lower. It should be noted that the MTEP12 BAU assumes more robust load growth than is assumed by The Brattle Group.

The Brattle Group energy price forecast for the MRO West Region (which includes Minnesota) is about $3-4/MWh less than the energy price forecast for the entire region (which is larger than MISO), at least in the earlier years. That difference is consistent with what can be observed from the historical price indices from Megawatt Daily and from MISO's MTEP LMPs. In Brattle's case, the difference declines over time while in MISO's it increases, so there is something of a difference in later years.

The load growth Brattle used is more realistic than the numbers that Hydro used for the U.S. to support their business case. They start with a 0.4 % load growth and adjust downward for price elasticity (as we know, Hydro failed to do this in their domestic load forecast).

In comparing the MISO BAU numbers for 2017, 2022, and 2027 (the 3 years provided) to the Brattle Low CO2 case (the closest match in terms of assumptions), the energy prices for both the

Minnesota region and the larger areas modeled were pretty close. The Potomac forecast prices were lower than that, but they have already spoken to that.

The Brattle Base Case includes CO2 prices, which are a huge uncertainty. Potomac used a lower CO2 price in two of their four scenarios and only gave a 50 % probability to a CO2 price occurring at all. MISO had one scenario out of 4 with CO2 prices. It was a combined policy scenario with a national renewable standard and a very high CO2 price (a very low probability, very high cost bookend).

Summary

While Manitoba Hydro does not acknowledge it, there is substantial evidence from multiple sources that significant congestion exists between Minnesota and Wisconsin and the rest of the MISO market. This congestion has the potential to reduce market prices in the region into which Manitoba Hydro would be exporting. In turn, this would reduce the revenue from sales.

The actual export price forecast and the assumptions behind it are not known due to confidentiality concerns. Supplemental evidence provided by Manitoba Hydro was in the range of reasonable expectations, but likely on the high end of the range. The reasons for this include using load forecasts that were not representative of the export region and that did not include the impact of higher prices that would be consistent with the CO2 costs assumed by Manitoba Hydro.

Of the six proprietary forecasts used to develop Manitoba Hydro's export price forecast, information was only available for the forecast from The Brattle Group. The load growth and resultant price projections were reasonable (similar to the MISO MTEP12 and higher than Potomac Economics). The Brattle Group's forecast included a price reduction due to transmission losses and congestion similar to what was seen elsewhere, used a load forecast that was similar to others for that region, and included a reduction in load when prices increase.

If the electricity price projections from The Brattle Group are indicative of Manitoba Hydro's forecast from the average of the vendor forecasts, it is reasonable. If the Manitoba Hydro forecast is higher than the Brattle forecast, there is cause for concern.

The inclusion of CO2 costs in the export price forecast is inherently uncertain and poses a substantial risk. Even if CO2 restrictions are imposed, the level and timing of the costs are critical to the revenue needed by Manitoba Hydro.

Appendix

Beginning on March 4, 2013, Megawatt Daily, an electric industry report published Monday through Friday (excepting holidays) by Platts, a division of McGraw-Hill, has published day-ahead price indices for various U.S. trading hubs. The indices reported are for both on-peak and off-peak periods and include four hubs in the MISO region: Illinois Hub, Indiana Hub, Michigan Hub, and Minnesota Hub. According to Platts, the Minnesota Hub "*comprises approximately 170 nodes in and around the cities of Minneapolis and St. Paul, Minn.*"[10] A comparison of those price indices (for March-December 2013) was performed to look for consistent variations between the Minnesota Hub and the other three MISO hubs.

If congestion exists between the Minnesota Hub and the rest of MISO, it will show up in one of two ways. If the Minnesota Hub has an excess of supply which cannot get out of the region due to congestion, the hub price will be lower than the prices at the other hubs. If the Minnesota Hub has a shortage of supply and congestion keeps outside suppliers from getting energy to the region, the hub price will be higher than prices at the other hubs. It should be noted that the existence of lower (or higher) prices is not sufficient to show that congestion exists. Losses associated with transmitting the energy will result in a price differential between the exporting and importing regions. Transmission losses are generally low (a few percent), so larger price differences between hubs would be an indicator of congestion.

The following figures show the percentage of days when a given hub had the highest (blue) or lowest (red) indices for either the on-peak (Figure 2) or off-peak (Figure 3) periods. During the on-peak periods, the Minnesota Hub had the highest price index 42 % of the time and the lowest price index 27 % of the time. During the off-peak periods, the Minnesota Hub had the highest price 7 % of the time and the lowest price 70 % of the time. This indicates that the Minnesota Hub area was exporting energy during most of the off-peak hours, while it imported during some of the on-peak periods and exported during others.

[10] "Methodology and Specifications Guide: North American Electricity," Platts, updated January 2014.

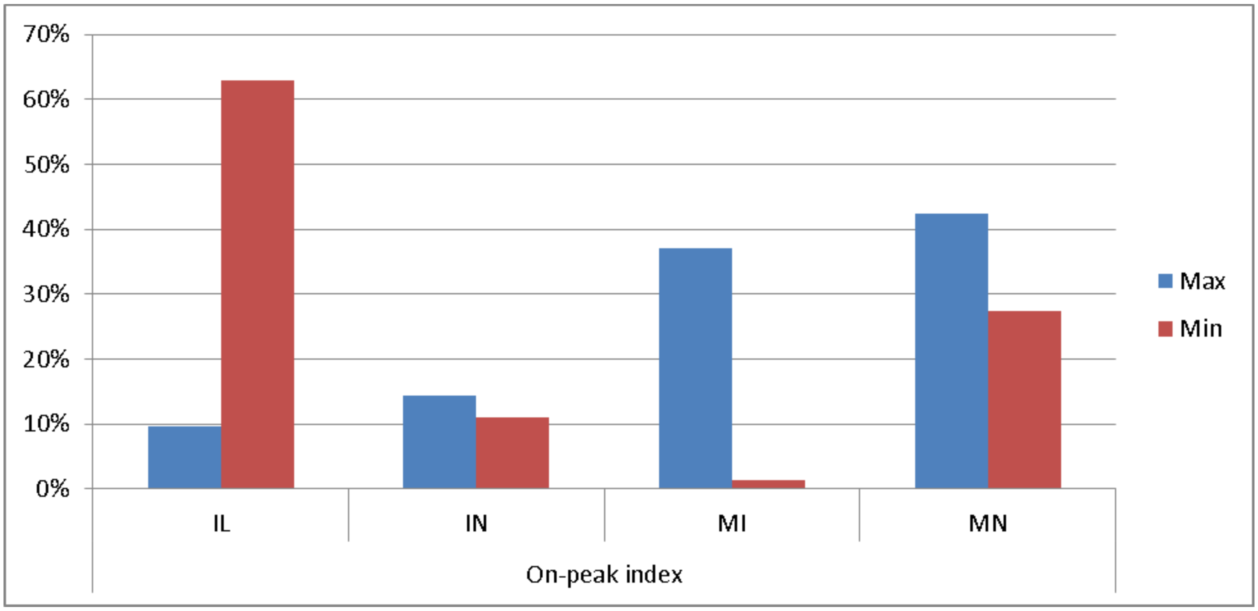

Figure 2. Percentage of days where the on-peak index for a hub was the highest (blue) or lowest (red) of any hub

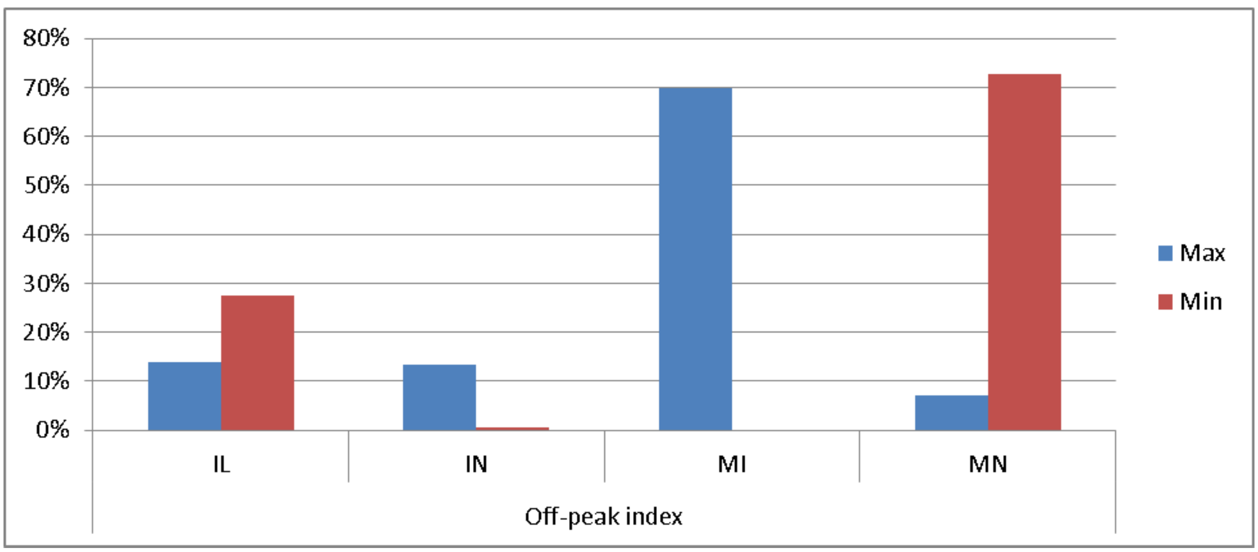

Figure 3. Percentage of days where the off-peak index for a hub was the highest (blue) or lowest (red) of any hub

In order to look for evidence of congestion, the magnitude of the difference between hub price indices was examined. Figures 4 and 5 show the percentage of time that a particular hub's price exceeded the all other hub prices by more than 10% (in blue) or was more than 10% less than any other hub price (in red). Since a difference of that magnitude is unlikely to arise from transmission losses alone, the figures indicate that congestion exists frequently and that the congestion affects market prices in the Minnesota region. In particular, the off-peak prices in the Minnesota Hub are often suppressed relative to the rest of MISO, with indices more than 10% lower than any of the other three hub occurring 36% of the time. In some hours, this effect was even larger: in 19% of the off-peak periods, the Minnesota Hub was more than 20% lower than any of the other three. It was more than 30% lower in 9% of the off-peak periods and more than 40% lower in 5% of the periods.

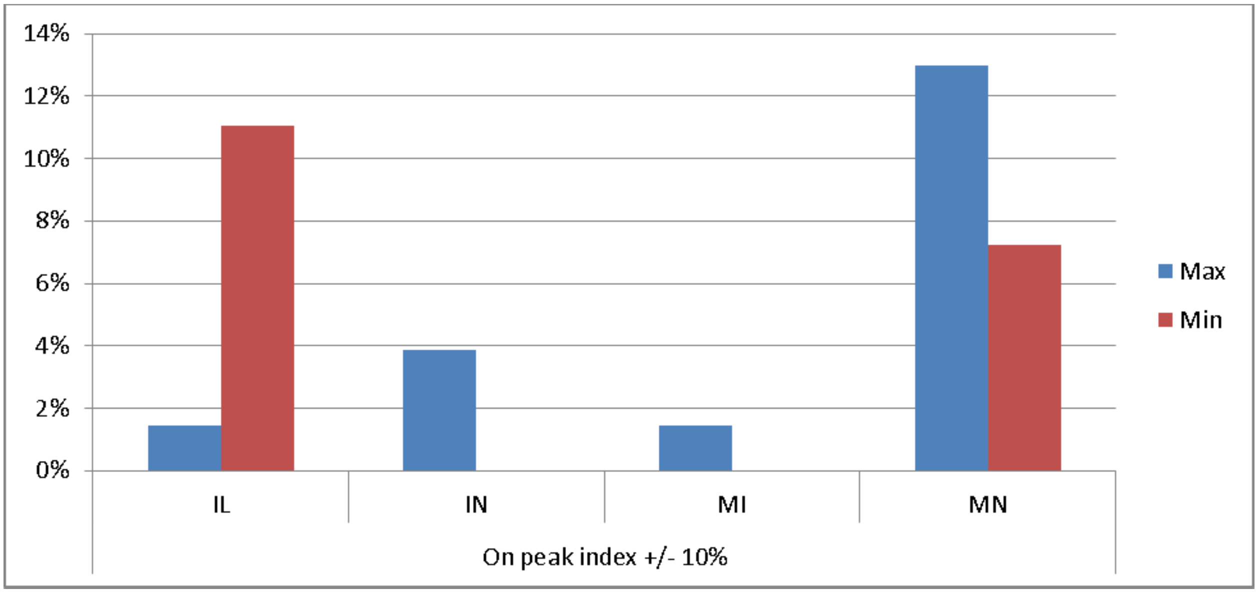

Figure 4. Percentage of days where the on-peak index for a hub was 10 % more (blue) or 10 % less (red) than any other hub

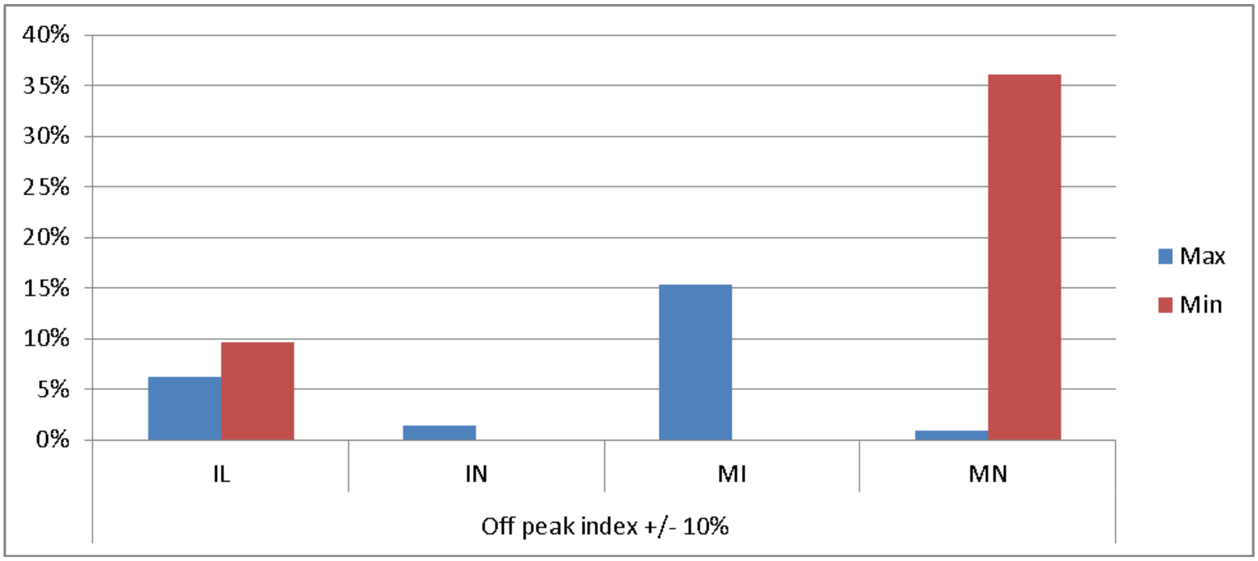

Figure 5. Percentage of days where the off-peak index for a hub was 10 % more (blue) or 10 % less (red) than any other hub

Load Forecasting for the NFAT

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Outline

- Standard Forecasting Approaches
- Review of the MH Load Forecast
- Response to MH Rebuttal and New Developments
- Summary and Conclusion

Standard Forecasting Approaches

- Top-down
  - Trend analysis
  - Econometric
- Bottom-up
  - Survey-based
  - End-use
- Hybrid

Trend Analysis

- AKA trend analysis or regression analysis.
- Relies solely on the historical load to project future load (does not account for causal factors).
- Easy to do but generally inaccurate, especially under changing circumstances.
- MISO considers this to be an unacceptable method.

Econometric

- Estimate the historical relationship between load and various factors.
- Use that relationship with projections of the factors to forecast load.
- Generally improved accuracy but has difficulty accounting for things that change the historical relationship (like efficiency standards).
- MISO considers this to be an acceptable method.

Survey-based

- AKA informed opinion.
- Use information regarding select customers' future plans as basis for the forecast.
- Will account for expected fundamental changes in demand from large users.
- A lack of reliable information tends to result in poor long-term accuracy.
- Lacks transparency.
- MISO considers this to be an unacceptable method.

End-use

- Total load is built up from the individual device level while tracking the number of devices at different ages and efficiencies.
- Addition of new devices and replacement of existing devices is estimated going forward.
- Forecast obtained by summing across all devices.
- Can directly capture changing efficiency standards.
- Data intensive and does not capture changes in customer behavior well.
- MISO considers this to be an acceptable method.

Hybrid

- Employ facets of both top-down and bottom-up approaches.
- Statistically-adjusted end-use (SAE) is most common.
- Attempts to combine the relative advantages of both types.
- Increased model complexity.
- MISO considers this to be an acceptable method.

Review of MH Forecast

NFAT Load Forecast: General Issues

- A unified approach vs. a hybrid model of forecasting methods as in the NFAT
- Blend of approaches in hybrid model makes overall assessment complex, e.g. within-sample reliability (vs., say, a unified econometric approach)
- Is the NFAT load forecasting methodology clear? We found it difficult to understand at some points.
- Are the individual components of the blended forecast justified compared to standard alternatives, including a more unified approach? Unclear from the NFAT.

Residential Load Forecast

Independent population forecasts

Consensus population forecast (avg.)

Size of household

(avg. vs.?)

Household forecast (Pop/2.8?)

% electric heating

(MA vs. ?)

Residential households load forecast

General Service Mass Market Forecast

Growth Forecast (Regression – Specification?

Justification?

Reliability?)

Electricity utilization

(MA vs. ?)

GSMM electricity demand forecast

Top Customer Forecast

MH Expert Assessments

- Not MISO standard (econometric or other)
  - consistent upward bias
- Justification? reliability?

Top Customer electricity demand forecast

Trend vs. Volatility

- MH focus on weather (heating/cooling days) affects short-term volatility but less important than long-term trends e.g climate change …
- … but also population, GDP, energy prices
- Unclear how alternative population, GDP scenarios affect comparison of plans (Elenchus)

Consumer Demand for Electricity

- Economic theory and evidence suggests important factors are:
  - Income (GDP)
  - Population (per capita demand)
  - **Own Price (Real Price of Electricity)**
  - Prices of Close Substitutes and Complements (Other energy prices)
  - Other relevant factors e.g. weather?

Role of Prices in Load Forecasting

- “There are also linkages between electricity prices and demand. Lower power prices tend to spur demand and reduce the incentive for efficiency, which over time puts upward pressure on prices. Higher power prices, on the other hand, tend to do the opposite, spurring new supply and depressing demand, which in turn moderates those high power prices over time” (NFAT, ch.3, p.7)
- But no consideration of prices in MH/NFAT 2012 or 2013 load forecasts

Does Price of Electricity Matter?

- “The real electricity price is forecast to increase by 1.7% in 2013/14, and then increase by 2.0% per year throughout the rest of the forecast period” (NFAT, App.D, p.55)
- Implies an 80% increase in electricity prices above general price inflation over 30 years
- What impact?

Does Price of Electricity Matter?

- MH/NFAT says impact of price increases on customer demand will be zero or small
- No experience/data with price increases of this magnitude in Manitoba
- Evidence elsewhere suggests response is significant
  - Indiana since 2005
  - "Based on a review of these surveys, the numbers that come up most often are 0.2 for the short run elasticity, and 0.7 for the long run" (http://www.e3network.org/ElasticitySurvey2_matt.pdf)

Does Price Matter? Illustrative Calculation

- 0.5 long-run price elasticity for electricity, 80% price increase over 30 years

  → 40% reduction in load

- MH residential forecast: 1.6% load growth (1.2% due to population, 0.4% load growth due to usage)

  → 60% load growth (45% due to pop, 15% due to use) over 30 years (no price effects))

- 40% reduction in load (price effects)

  → 25% load decline (usage), 20% load increase overall (1/3 of forecast)

Does Price Matter? Illustrative Calculation

- NFAT (ch.12, 2-3) projects load growth of 7.9 Gwh to 2031/32 of which ≈1/3 residential or 2.63 Gwh
- Price effect is to reduce load growth by ≈2/3 or 1.76 Gwh or reduce load growth by 4.2 yrs
- 2013 load forecast revisions reduce load growth by 3 years and defer need for new resources 1 year

→ residential price response alone (1/3 of load) would defer resources 1+ years

- General Service Mass Market, Top Customers (2/3 of load)?

Load Forecast Reliability

- Within sample reliability difficult (perhaps not impossible) to assess with blended approach compared to econometric approach
- Beyond sample reliability
  - Likely more important over 30 year horizon
  - Depends on reliability of projections for pop, income and sensitivity of load forecast to these projections (Elenchus)
  - Should also depend on projections for prices (2% p.a.) which could inflate load forecast and new system requirements significantly

MH Rebuttal Evidence and New Developments

Focus of Our Evidence

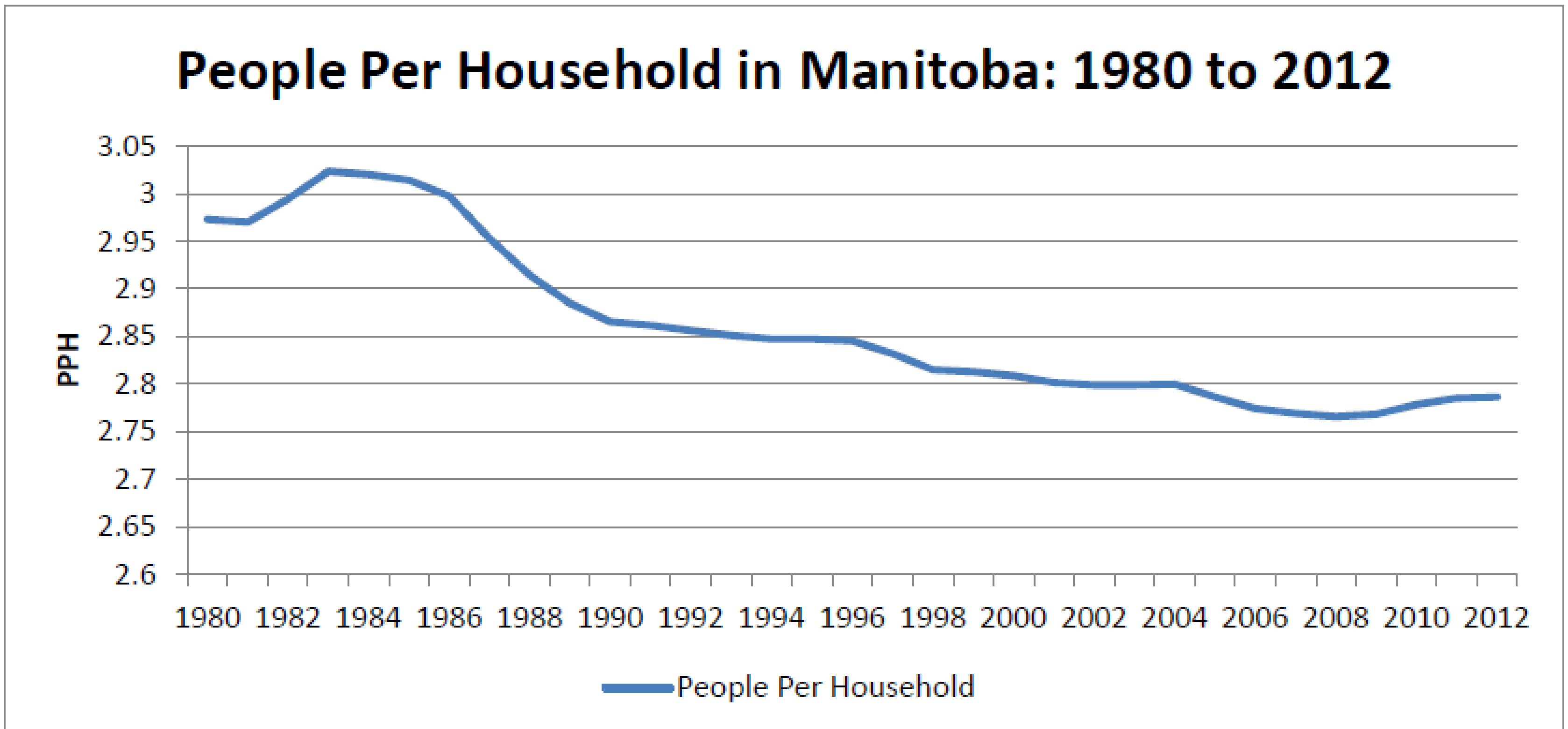
- Page 3, “The evidence of Elenchus and Drs. Simpson & Gotham focus their review on Manitoba load growth over the last ten years.”
  - This is untrue for us. Our evidence focuses on issues associated with the methodology, assumptions, and transparency. At no point in our evidence do we focus on Hydro’s recent load growth.

Manitoba Growth vs. Other Jurisdictions

- On page 5, in response to our concern over the projected load growth in light of other forecasts, Hydro presented an outdated table from the North American Electric Reliability Corporation (NERC) that had generally higher forecasts than the most recent version.
  - MH-94 provided the most recent version.

People per Household

- Page 8 provides the historical number of people per household



People per Household

- Page 9, “This trend has clearly demonstrated an overall decline and levelization of people per household to around 2.79.”
  - The levelization is not clear. What is clear is that it changes over time in response to some phenomena, which is why we state that a more analytically sound approach is appropriate.

People per Household

- Page 13, “Through the econometric model used to create the General Service Mass Market forecast, Manitoba Hydro has found a significant relationship between customer growth in the Residential Basic sector and growth in GDP to customer growth in the General Service Mass Market sector, and forecasts using this relationship.”
  - Since the number of residential customers is also an input to the General Service Mass Market forecast, it is even more important to have a reasonably good, analytically sound method of projecting the number of residential customers.

Average Use Per Dwelling

- Pages 10-11, paragraphs labeled 2 and 3 indicate that the percentage of dwellings using electricity for space and water heating is expected to increase, based on current trends.
  - These expectations are predicated on the Hydro assumption that the current trend (which was built on years of low electricity prices and high natural gas prices) will continue, even after electricity prices increase considerably.
  - MH-87, slide 82 indicates that MH will be considering DSM initiatives involving fuel switching.

Growth in Top Consumers

- Page 13, "Drs. Simpson and Gotham discount Manitoba Hydro's use of "informed opinion" and "time series" in its forecast of Top Consumers on the basis that such approaches are deemed unacceptable under MISO's list of forecasting methods (Simpson and Gotham, page 1).
  - The rebuttal attempts to defend the use of informed opinion forecasts in the short-term but does not address the use of a linear trend for the long-term, which is also unacceptable per MISO. Furthermore, Section 2.3.5.2 on the long term forecast only covers issues associated with the Elenchus report, not to any of our criticism.

Top Consumers

- Page 14, "This assessment is based upon only the most recent five year period and is dominated by the unexpected closure of one Top Consumer and by the recent economic downturn."
  - The fact that the closure of one Top Consumer was unexpected goes to a major flaw in informed opinion forecasting. That is, very few consumers expect to fail.

Price Elasticity

- Page 19, "Manitoba Hydro has among the lowest electricity prices in North America. As outlined in Manitoba Hydro's response to PUB/MH I-256, electricity prices have increased slowly at or close to the rate of inflation. As a result, the effect of price changes on customers' use of electricity would have been largely overwhelmed by the effect of other factors that affect demand for electricity, such as population increases, economic growth, improvements in residential construction, appliance efficiency, and the underlying random year-to-year variation in load."
  - This will no longer be true when the expected rate increases take place.

Price Elasticity

- Page 19, “In 2012, the model incorporating the Price of Gas/Price of Electricity ratio predicted a decline in the percentage of New Electric Heat customers to the total number of new customers while the price of natural gas continued to fall. However, the actual market penetration of electric heat billed homes increased in 2011 and 2012.”
  - Without knowing the specifics of the model used, it is not possible to know whether the model was truly appropriate. For instance, did they use (or consider using) lagged prices to account for the delay in customer perception of prices to catch up with the reality of prices?

Price Elasticity

- Page 20, “As well, price increases on higher starting prices, which result in a greater absolute expense to a consumer, may result in higher price elasticity than in jurisdictions with low and stable electricity prices.”
  - It could also result in lower price elasticity if the starting price is high enough. For areas with very high prices, most of the customer’s ability to adjust behavior has been squeezed out already, with only essential use left. At this point, there would be very little reaction to a price increase.

Price Elasticity

- MH-87, Slide 12 indicates that MH will consider incorporating price elasticity in the next forecast
  - It should be noted that the estimated impact (a reduction of 500-600 GWh) represents a price elasticity of less than -0.05 to -0.056, which is on the low end of what has been seen elsewhere
  - While it is understood that these numbers are not being proposed by MH, it should be noted that if the elasticity is higher, a greater reduction will occur.
  - For instance, a price elasticity of -0.4 (as was used in the export price modeling by The Brattle Group), would indicate a load reduction of about 4,000 GWh.

Forecast Accuracy

- Page 25, "Manitoba Hydro agrees that "a perfectly accurate forecast is unattainable", and as such presents a forecast created to be a midpoint for the potential range of variability. The expectation is that there will be a 50% chance that actual growth will be higher than the forecast, and a 50% chance that it will be lower."
  - In our opinion, they have failed to achieve a 50/50 forecast, especially with respect to the price elasticity issue. In order for this to be true, there would have to be an equal chance that the price elasticity would be either too high or too low, which is not the case here.

Summary

- MH’s forecasting methodology lacks clarity and consistency, making it difficult to evaluate
- MH relies on non-standard methods for some components and overly simplistic assumptions for others
- Lack of price elasticity introduces an upward bias in the forecast

Review of Export Price Forecast for NFAT

Douglas Gotham, PhD
Director, State Utility Forecasting Group
Purdue University

Export Price Analysis

- Due to its competitively sensitive nature, neither the MH export price forecast nor the assumptions behind the forecast are known.
- It is not possible to draw definitive conclusions.
- Thus, I have focused on those aspects that are available
  - Supplemental information included by MH in its NFAT filing
  - The Brattle Group export price forecast

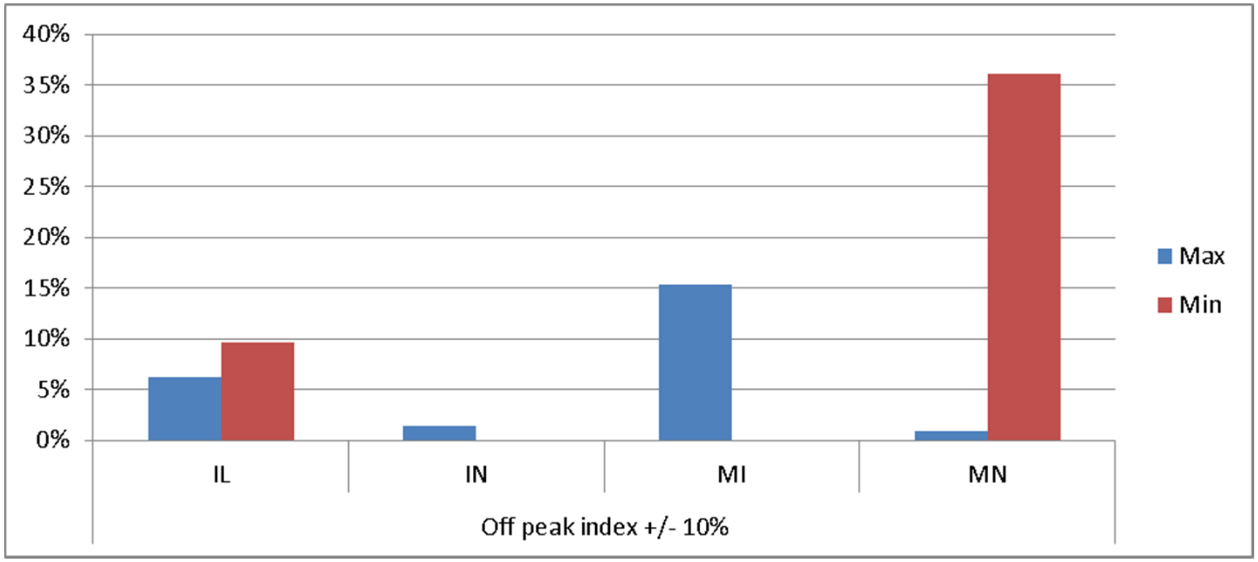
Potential Areas of Concern

- Transmission congestion
- Projected load growth in the export region
- Carbon costs

Transmission Congestion

- Transmission congestion can be significant in that it shrinks the size of the export market and reduces the price that MH receives from the exported energy.
  - A number of different public sources indicate that there is transmission congestion between the Minnesota Hub and the rest of MISO
    - Historical market prices
    - MISO transmission planning process
    - MISO Independent Market Monitor's *State of the Market Report*
    - Federal Energy Regulatory Commission

Market Prices



- Percentage of days where the off-peak index for a hub was 10 % more (blue) or 10 % less (red) than any other hub
- Data from *Megawatt Daily*, April – December 2013

Load Growth

- In its supporting information, MH provides load growth forecasts that may be inappropriate for the export region.
- MH provides a U.S. national load growth projection from the Energy Information Administration (EIA) [0.9%].
- EIA's projection for the East North Central [0.3%] and West North Central [0.6%] regions are lower than the national average.
- A higher load growth projection will result in higher export price projections.

Carbon Costs

- MH supplemental information includes costs associated with restrictions on carbon dioxide emissions in its export price forecast.
- There is considerable uncertainty as to if, when, and what degree some form of carbon restriction will be imposed in the Midwestern U.S.
- Should carbon costs fail to materialize, export prices (and revenue) will be significantly reduced.

Uncertainty of Carbon Costs

- Potomac provided 2 reference prices (one with and one without carbon costs).
- Both Potomac and MNP estimated the likelihood of carbon pricing to be 50/50.
- The inclusion of carbon costs in the individual consultant forecasts are not available due to CSI concerns

Regional Perspective

- Much of the Midwestern US has an industrial-based economy that relies on low electricity prices for their economic competitiveness. They tend to oppose environmental restrictions that threaten those prices.
  - Indiana Gov. Mitch Daniels op-ed in the Wall Street Journal (IR PUB/CAC-Gotham-4) referred to cap-and-trade of CO2 as “imperialism” with “wealthy but faltering powers – California, Massachusetts, and New York – seeking to exploit politically weaker colonies in order to prop up their own decaying economies.”

Federal Action

- US EPA is expected to release proposed performance standards for existing generation this summer.
- The politically divided Congress has not produced any legislation on greenhouse gases.
- The Obama administration has stated on multiple occasions that they will not propose a carbon tax*.

* The White House, Office of the Press Secretary, Press Release – November 25, 2012; and Ben Geman, "A Carbon Tax in Our Future?" thehill.com, February 28, 2013.

Importance of Carbon Costs

- Based on a comparison of The Brattle Group's Base and Low CO_2 cases, inclusion of moderate CO_2 costs will result in an increase of $13-14/MWh in the export price.
- Alternatively, if the CO_2 costs do not materialize, the price of exports would be about 20-25% lower (based on Brattle and Potomac prices).
- La Capra (Appendix 9B, Page 84) indicates that the results of having no costs for carbon "are significant with the Preferred Development Plan benefits versus All Gas over 78 years dropping by about $340 Million."

Export Price Comparisons

BAU/Base/Reference Export Region All Hours Energy Price Projections

	MTEP12	Brattle	Potomac
2017	29.65	30	25
2022	32.54	46	39
2027	37.78	51	43

MTEP BAU vs. Brattle Low CO2 vs. Potomac No Carbon All Hours Energy Prices

	MTEP	Brattle	Potomac
2017	29.65	30	25
2022	32.54	33	29
2027	37.78	37	31

Brattle Price Forecast

- The assumptions in the Brattle forecast regarding congestion and load growth in the export region are appropriate.
- The Brattle forecast includes carbon costs that may or may not happen in the future.
- The Brattle forecast is consistently above the Potomac forecast but similar to the MISO MTEP12 prices, especially when compared under similar carbon assumptions.
- If the Brattle forecast is actually representative of the MH forecast, the MH forecast is reasonable.
- If the MH forecast is higher than the Brattle forecast, there is cause for concern.

MH Rebuttal Evidence and New Developments

Section 8.1.4 Page 97

- "Both the Potomac and Gotham reports contain several mischaracterizations."
  - There is very little in the rebuttal regarding my "mischaracterizations." MH attributes an assumption on my part that is false (regarding load growth) and they consider congestion to not be significant (sections 8.1.17.1-2). Otherwise, they speak specifically to issues with the Potomac report. I fail to see how this qualifies as "several mischaracterizations."

Section 8.1.10 Page 102

- "The Gotham report appears to assume that the indicative macro-level US electric load growth statistics outlined in Chapter 3 of the NFAT filing were provided by Manitoba Hydro to each price forecast consultant as a required input."
  - This is false. The report clearly states that the assumptions are not known and that if they were consistent with the supplemental information, there would be cause for concern. Citing from page 1,

  "*Furthermore, the assumptions behind these forecasts are not available. Thus, it is not possible to speak definitively about the reasonability of the export price forecast and assumptions. Manitoba Hydro did include supporting information in its Business Case that raises concerns about the assumptions behind its export price forecast and thus, about the export price forecast itself.*

  This document looks at three general areas: the applicability of the supporting information provided by Manitoba Hydro, the implication of the inclusion of carbon costs in the export price forecast, and the reasonability of the export price forecast from The Brattle Group."

Section 8.1.11

- This section is entitled “Carbon Price Embedded within the Export Price Forecast is Reasonable”.
- It is too heavily redacted to verify this.

Section 8.1.17.1 Page 107

- MH appears to take issue with my use of “such simple and subjective terms as ‘significant’”, yet they characterize congestion as “minimal” and “relatively minor” in their response to CAC/MH I-032a.
  - Congestion has been neither minimal nor minor thus far in 2014

Average Weekly Indices for 2014

On-peak				Off-peak			
Illinois	Indiana	Michigan	Minnesota	Illinois	Indiana	Michigan	Minnesota
58.88	63.29	71.23	51.77	39.56	44.92	50.67	32.54

Average Minnesota Hub prices are 12-27% lower on-peak than their counterparts.

Average Minnesota Hub prices are 18-36% lower off-peak than their counterparts.

Data source: Megawatt Daily, MISO weekly price indices, Jan. 4 to Apr. 19

Congestion Affects Capacity Prices

- On April 15, MISO released the results of their 2014-15 Planning Resource Auction.
- See Exhibit re: MISO resource auction
- This results in a much lower price in Zone 1 and a higher price in Zones 2-7 due to capacity export limit.

Grid Parity

- As electricity prices increase, the cost of customer-owned generation becomes economically competitive.
- Beyond this point, increasing costs lead to increases in self-generation (and decreases in purchases from the utility).
- Mr. Todd from Elenchus spoke about this in the context of the domestic load forecast (April 2), but the concept is applicable to the export market as well.
- This could reduce load growth in the export region and essentially results in a cap on the electricity price.
  - The level of the cap depends on the future costs of various self-generation options.

Summary

- While the specific inputs to and results of the MH export price forecast are not public, there are some issues of which to be aware.
  - Congestion issues may limit the amount of energy that can be moved through the Minnesota region into the rest of MISO, which would reduce prices.
  - Future load in the export region may be lower than indicated by MH's supplemental information.
  - The existence, timing and magnitude of carbon costs represent a major source of uncertainty.