DESCRIPTION OF FORECASTING

The Commission asked the Applicants to provide a description of how some utilities use forecasts of energy consumption to predict levels of peak power demand (Exemption Order Point 8E). This information is provided below.

Xcel Energy

Xcel Energy creates native energy requirements based on the sales forecasts. The sales forecasts are estimates of MWh levels measured at the customer meter, but do not include line or other losses. The various jurisdictional class sales forecasts are summed to yield the total system sales forecast. A system loss factor for each legal entity, developed based on average historical losses, is then applied to the sales forecast to calculate total system losses. The sum of the system MWh sales and system losses equals native energy requirements. The native energy requirements, along with peak producing weather and binary variables, are then used as independent variables within an econometric model to forecast MW peak demand for the Xcel Energy North System.

Great River Energy

The 2004 Great River Energy Long Range Load Forecast ("2004 LRLF") used the energy forecast and an econometric forecast of seasonal (summer and winter) load factors to forecast demand. The 2004 LRLF was used as the basis for Great River Energy's 2005 Integrated Resource Plan.

The 2007 Benchmark Peak Load Forecast developed by Power System Engineering is an econometric model that uses energy as an independent variable. The variable is essentially a weather adjusted load factor approach. The forecast was used in Great River Energy's application for a certificate of need for the Elk River Peaking Station (Docket No. ET2/CN-07-678).

Central Minnesota Municipal Power Agency

Central Minnesota Municipal Power Agency uses forecast software to predict peak load and energy consumption. The software bases the forecast on historical data that correlates with the date, temperature, humidity, wind, etc.

Minnesota Municipal Power Association

Minnesota Municipal Power Association does not use an energy forecast to directly forecast peak demand. Instead, peak demand is calculated using a regression model of Minnesota Municipal Powr Association's previous peaks.

Minnesota Power

Minnesota Power does not use the forecasts of energy consumption to predict peak levels of power demand. Instead, Minnesota Power utilizes an econometric forecasting technique to develop forecasts of annual customer counts by class, annual energy requirements by class, and summer and winter seasonal peak demands. A detailed description of Minnesota Power's load forecasting techniques, inputs, and results can be found in its most recent Advance Forecast Report on file with the Minnesota Department of Commerce.

Minnkota Power Cooperative

Minnkota Power Cooperative's existing Power Requirements Study ("PRS") forecasts future annual energy consumption for the next 10 years (in the next PRS the forecast will go out 20 years). Future peak demands estimates are derived from the annual energy requirements utilizing a load factor estimate based on historical values.

Southern Minnesota Municipal Power Agency

Southern Minnesota Municipal Power Agency's annual non-coincidental peak demands ("NCPs") are forecasted for each member using a regression technique that establishes a relationship between a member's historical annual peaks and annual inlet to member system ("IMS") energy requirements. The model used is shown below:

$$NCP\ (t) = a*(IMS\ (t) + e\ (t)$$

Where.

NCP (t) = a member's annual maximum peak demand in year (t).
IMS (t) = a member's annual IMS ENERGY IN YEAR (T).
e (t) = the residual or "error" term in year (t).
t = time or year indicator (e.g. 1969 – 2002).
a = coefficient of the explanatory variable.

By running the model on the historical data, the coefficient of the explanatory variable us determined. Load factor ("LF") can be derived from this coefficient because the coefficient equals:

1/ (8760 x LF)

Forecast peak demands are obtained by inserting the forecasted IMS energy into the model. This is the same peak forecasting method used in our previous forecasts.

Coincidence factors are utilized to convert member's maximum NCP forecasts to an annual system peak forecast. These coincident peak demand ("CP") in terms of its non-coincident peak demand.

It is important to note that this methodology does not require that the CP and NCP occur in the same month.

Once a coincidence factor is obtained for any given member, that member's forecasted annual NCP is multiplied by the coincidence factor to yield a forecasted CP. The forecasted CPs for the 18 members were then summed to obtain the forecasted system peak.

It is important to point out that the peak forecasts are based on the assumption of "normal peak weather" conditions. If peak weather conditions are quite abnormal, as was the case in the summers of 1988, 1992, 1995, 1999, and 2001, then actual peal demands could differ substantially from forecast peak demands.

Once the IMS peak demand forecast is complete, it is adjusted to derive the Total Energy Requirement ("TER") peak demand forecast. Adjustments made to the IMS forecast include deductions for; Western Area Power Administration ("WAPA") allocations, deductions for member hydro generation, deductions for the Rochester load above 216 MW, and other member curtailments. TER represents the amount of power and energy Southern Minnesota Municipal Power Agency must actually supply to its members, plus transmission line losses, and is the forecast which is to be met with the least cost combination of future supply-side and demand side resources.

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