Industrial Group Request

Request:

Pira Forecast – Provide the industry assumptions (i.e. timing of pipeline completion, sources of fuel supplies, etc.) that underlie the PIRA Forecasts.

Response:

NS Power has utilised forecasts by PIRA Energy Group (PIRA) for natural gas prices at

(i) Henry Hub in the long term (2015-2030);

(ii) differentials to Henry Hub prices at various pricing points in the North East United States ("NE Basis") in the long term (2015-2030); and

(iii) NE Basis in the short term (2014/5) all as reported in PIRA's Scenario Planning Service: Annual Guidebook 2014 and other on-line sources developed and maintained by PIRA.

The following are highlights from PIRA's key assumptions behind PIRA's Reference case for natural gas prices at Henry Hub in the long term:

- Overall U.S. gas demand will grow at around 2.2%/year between 2014 and 2030. Total North American demand will be slightly higher at 2.4%.

- Modest carbon prices are assumed to be imposed directly or indirectly by 2020. Industrial demand is assumed to grow at 2.2%/year. Direct use of gas in transportation, will reach just over 7 BCF/D by 2030. Canadian growth of 3.4%/year will be led by strong growth in both power generation and oil sands use.

- Mexican growth is assumed at 3.5%/year.

- Non-conventional U.S. production reaches nearly 91 BCF/D in 2020 and over 109 by 2030 reflecting continued productivity improvement and the production potential in the Marcellus/Utica

- Canadian production will rise to 15 BCF/D in 2020 and 24 by 2030. Canada is assumed to begin exporting LNG (from the West Coast) to Asia pre-2020.

The following are highlights from PIRA's key assumptions behind PIRA's forecast for NE Basis:

- By 2017, two projects — AIM and the CT Expansion projects — are anticipated to provide incremental capacity.

- By 2020, a large amount of capacity is added on the Tennessee Gas pipeline and/or Spectra's Alonguin pipeline (Northeast Expansion Project (Wright, NY-Dracut) and the Atlantic Bridge project).

Request:

Industrial load – What is the anticipated effect of Michelin Granton reducing operations on energy, peak load and firm peak load in each case (Base/High/Low)?

Response:

The anticipated reduction in operations at Michelin Granton is not reflected in this initial load forecast. The Michelin announcement was the same week as the IRP technical conference and neither sufficient time nor information was available to update the forecast. The final version of the forecast for the IRP will be updated to be issued on April 11 to reflect an anticipated reduction in load of 30 percent at Michelin Granton in 2015.

Request:

Industrial load – Is Large Industrial included in the "Other Industrial Load" (Slide 88)? If not, where?

Response:

Yes, large industrial load is included in the "Other Industrial Load" line on slide 88.

Request:

Municipal load – Where is Municipal load shown?

Response:

Municipal load is captured within the three sector forecasts.

Request:

Peak load – Provide the calculations of System Peak and Firm Peak load.

Response:

The following steps outline how system peak and firm peak loads are calculated:

1. For each month historical coincident load factors are calculated for each class using load research data.

2. Using these load factors the following formula is used to obtain the class contribution to a monthly peak:

   Forecasted monthly energy / (monthly coincident load factor * days in the month * 24 hours in a day)

3. For PHP it is assumed the on peak demand is 65 MW during the winter months.

4. All classes calculated peak contribution are then added together along with losses to obtain monthly peaks, the highest of which is considered the system peak

5. The firm peak is obtained by only adding the calculated peak contribution for firm energy classes.

The table below shows the peak calculations from the base cases for the year 2014.

Customer Class	Forecasted Energy for Peak Month (MWh)	Coincident Load Factor (%)	System Peak Contribution (MW)	Firm Peak Contribution (MW)
Residential	456,527	64.8	1048	1048
ETS	30,169	139.3	32	32
Small General	24,284	97.7	37	37
General Demand	231,415	84.1	410	410
Large General	31,449	91.7	51	51
Unmetered	8,518	65.6	19	19
Small Industrial	20,773	90.5	34	34
Medium Industrial	38,358	90.0	63	63
Large Industrial	9,385	99.7	14	14

Customer Class	Forecasted Energy for Peak Month (MWh)	Coincident Load Factor (%)	System Peak Contribution (MW)	Firm Peak Contribution (MW)
L.I. Interruptible	46,799	109.5	64	0
GR&LF	95	424.9	0	0
Municipal	19,241	74.3	39	39
Shore Power	0	0.0	0	0
PHP			65	0
Losses			222	215
Peak (MW)			2097	1963

Request:

System energy/PHP – Would not the incremental cost of energy for PHP increase in from Low to Base and Base to High? Might this affect PHP energy usage? What assumptions or calculations has NSPI made regarding incremental energy costs in the different scenarios?

Response:

Potential incremental energy costs could impact PHP's energy usage as could the value of the Canadian dollar, timber cost, local and foreign demand for paper, etc. For simplicity, NS Power used the same method to forecast PHP's energy requirement as it uses to forecast large industrial customers; that is, load is assumed unchanged year over year unless supplemental information is known about a customer's expected operating conditions.

For the purpose of forecasting PHP energy usage, NS Power has not made assumptions or calculations for the incremental cost of energy in the specific scenarios.

Request:

Growth rates – In each case the growth rates for Residential and Commercial fluctuate slightly from year to year but then remain constant for 2030-2040. Industrial remains flat for 2025-2040. Why?

Response:

The Residential and Commercial forecasts were developed using the End Use model which was built to the year 2030. Beyond 2030 a straight line projection was used to forecast energy values. For the Industrial forecast the econometric model was used which had only been extended out to 2025.

Request:

Losses – Show how were losses calculated. What losses were assumed for PHP?

Response:

Transmission losses are assumed to be 3 percent of the transmission requirement. Historical distribution losses are calculated by taking the annual system losses and subtracting the assumed transmission losses. Distribution losses as a percentage of distribution sales are then calculated. Forecasted distribution losses are calculated by multiplying a 3 year average of the distribution loss percentage by the forecasted distribution sales for the forecasted year.

PHP is treated as a transmission customer and their losses are assumed to be 3 percent.

Request:

Interruptible load – In the Base and Low load cases, the Interruptible load (calculated as System Peak minus Firm Peak) drops by 56 MW in 2020. How was this amount calculated?

Response:

The forecast reduction in interruptible load in the base and low cases in 2020 is due to the removal of PHP from the forecast beyond 2019. PHP is assumed to contribute 65 MW to the firm peak. This value is based on the optimized load profile for PHP developed for the Stern Paper Mill Load Study completed in March 2012 and filed in the PWCC Load Retention Tariff proceeding.

Request:

EERAM inputs – What are the bases for the original 6% and revised 2.7% "Avg annual elec rate increase" (Slide 95)?

Response:

The 6 percent figure used by ENSC is a rounded average of the individual electricity price forecasts for the residential, small general, general and medium industrial rate classes as used in the EERAM. NS Power understands that the EERAM price forecast for each rate class was calculated using the year over year increase in the Base Fuel and Non-Fuel components of NS Power's approved rates from 2013 to 2014. This approach excludes the reduction for the Fuel adjustment for 2014. The net revenue increase for customers was 3 percent for 2014.

The 2.7 percent figure is NS Power's average overall rate increase over the 25 year period from 1989-2014, including all rate components and years when there was no rate increase.