Docket No. _______
Exh. TDI-SGP-11

2013 Annual Markets Report

Internal Market Monitor
May 6, 2014

Table 1-1
Key Statistics on Load, Locational Marginal Prices (LMPs), and Input Fuels

Statistic[a]	2012	2013	% Change 2012 to 2013
Real-time Load (GWh)	128,082	129,336	1%
Weather-normalized real-time load (GWh)	128,249	127,754	0%
Peak real-time load (MW)	25,880	27,379	6%
Average day-ahead Hub LMP ($/MWh)	36.08	56.42	56%
Average real-time Hub LMP ($/MWh)	36.09	56.06	55%
Average natural gas price ($/MMBtu)	3.95	6.97	76%

(a) GWh and MWh stand for *gigawatt-hours* and *megawatt-hours*, respectively; MW stands for *megawatts*; and MMBtu stands for *million British thermal units*. The *Hub* is a collection of energy pricing locations that has a price intended to represent an uncongested price for electric energy, facilitate energy trading, and enhance transparency and liquidity in the marketplace. *Weather-normalized* results are those that would have been observed if the weather were the same as the long-term average.

Table 1-2 shows wholesale electricity costs (in dollars and dollars per megawatt-hour; $/MWh) by market in 2013 compared with 2012. Total costs increased by about 45%, while energy costs increased by about 57%.[5] As discussed in the sections that follow, the increase in energy costs was the result of an increase in natural gas prices. Higher ancillary service costs resulted from the implementation of rule changes that increased both the amount of reserves purchased in the Forward Reserve Market (FRM) and the systemwide 30-minute reserve requirements, as well as the inclusion of opportunity costs in the calculation of the regulation clearing price.[6]

Table 1-2
Wholesale Market Cost Summary

Type	Annual Costs ($ Billions)			Average Costs ($/MWh)		
	2012	2013	% Change	2012	2013	% Change
Energy	4.77	7.49	57%	37.42	58.14	55%
Capacity	1.19	1.06	−11%	9.36	8.20	−12%
Ancillary Services	0.13	0.27	107%	1.04	2.12	105%
Total	6.10	8.82	45%	47.81	68.46	43%

[5] The annual total cost of electric energy is approximated as the product of the annual real-time load obligation for the region and the average annual real-time LMP. The real-time load obligation is the requirement that each market participant has for providing electric energy at each location (i.e., pricing node, load zone, or the Hub) equal to the amount of load it is serving, including external and internal bilateral transactions.

[6] Thirty-minute operating-reserve (TMOR) can be provided by an on-line or off-line resource that can increase output within 30 minutes or electrically synchronize to the system and increase output within 30 minutes in response to a contingency. The TMOR requirement is set to equal at least 50% of the second-largest contingency loss. A system's *first contingency* (N-1) is when the power element (facility) with the largest impact on system reliability is lost. A *second contingency* (N-1-1) takes place after a first contingency has occurred and is the loss of the facility that at that time has the largest impact on the system.

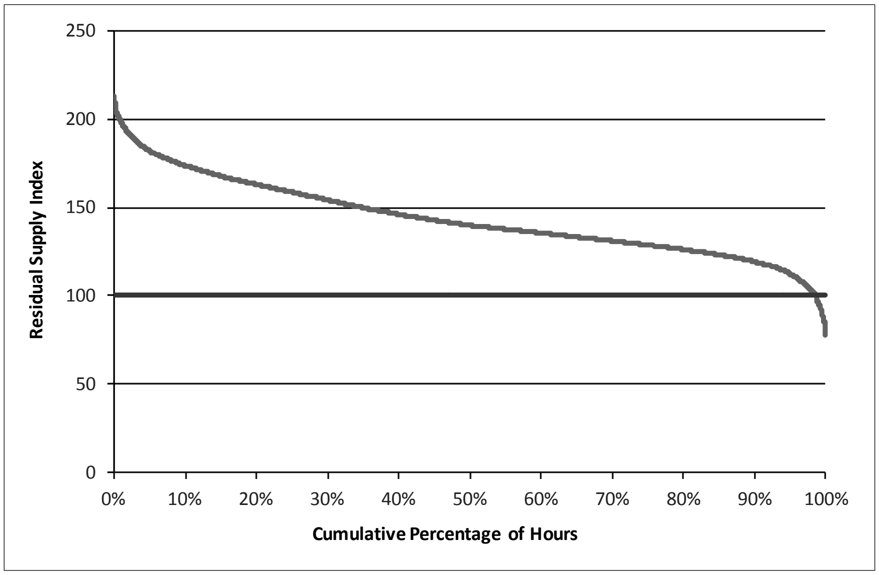

Figure 2-4: Systemwide Residual Supply Index duration curve, all hours, 2013.

2.1.3 Relationship between Real-Time Energy Prices and Other Market Factors

This section examines the relationships between real-time electric energy prices, fuel prices, and other market factors. Day-ahead market outcomes are also referenced where appropriate. Short-lived price spikes typically are explained by unexpected sudden changes in weather, fuel prices, and unplanned generator or transmission outages.

2.1.3.1 Energy Prices and Marginal Units

The LMP is set by the cost of the megawatt dispatched to meet the next increment of load at the pricing location. The resource that sets price is called the marginal unit. Because the price of electricity changes as the price of the marginal unit changes, and the price of the marginal unit is largely determined by its fuel type, examining marginal units by fuel type helps explain changes in electricity prices. The system has at least one marginal unit associated with meeting the energy requirements on the system during each pricing interval. If transmission is not constrained, the marginal unit is classified as the *unconstrained* marginal unit. In intervals with binding transmission constraints, an additional marginal unit exists for each constraint.

In 2013, unconstrained pricing intervals accounted for approximately 93% of all pricing intervals. When considering both unconstrained and constrained intervals, natural gas was the marginal fuel during 69% of all pricing intervals, followed by pumped-storage generation and coal, which were marginal in 8% and 7% of all pricing intervals, respectively. See Figure 2-5.