Polar Vortex Energy Pricing Implications—Commercial Opportunities and System Reliability

By Judah Rose, Shanthi Mathiah, Frank Brock, John Karp, and Trishagni Sakya
ICF International

Executive Summary

For the second time in just over three years, a major weather event (the so-called polar vortex) has generated significant profits for generators, particularly in the eastern and southern United States. Wholesale power price increases were caused by many factors, notably high and fluctuating delivered natural gas pricing, generation supply shortages, and differing market structures. Changing weather patterns will accelerate the number and size of these opportunities for investors who understand the relationships among these factors.

These weather patterns are also revealing potential reliability risks to the current grid. To the outside observer, the grid performed adequately during the polar vortex. But a more detailed look shows that grid reliability is a growing problem in many areas. Resource levels and mix, market structure and seasonal resource participation are creating inadvertent consequences that may undermine grid reliability. The shortages highlight the need for a forensic review of the regulatory structures to ensure reliable power grids and appropriate price signals and the potential need for new reliability-driven investments.

Power Pricing on January 3, 6, and 7

Daily average power prices fluctuated wildly from $40/MWh to nearly $800/MWh over this period. Prices spiked on January 6 in ERCOT and on January 7 in most other markets in the US. Natural gas prices ranged from $4/MMBtu to $40/MMBtu (Figures 1 and 2).

Figure 1. Percent Increase on Day Prior–Day-Ahead, Real-Time, and Gas Pricing; January 6 and 7.
Natural Gas Prices Spike on Demand, Pipeline Constraints

Natural gas prices in New England and eastern New York reached record highs on January 7, with midpoint prices ranging from $35 to $40 per MMBtu and bids as high as $100 per MMBtu. While there are unconfirmed reports of some wellhead freeze-off in the Marcellus area and the Texas Eastern Transmission compressor station in Pennsylvania was out of service for a portion of the day, there appear to have been no major gas supply disruptions during the cold snap; in other words, the high prices at New England and eastern New York hubs were due to high demand and pipeline constraints, not an interruption of upstream gas supplies.

In many markets, the increase in delivered natural gas prices was a key contributor to the increase in power prices. The principal exception to this appears to be ERCOT, where gas prices did not increase while power prices increased dramatically (Figures 1 and 3).
Figure 3. Daily Day-Ahead vs. Daily Real-Time Energy Prices; January 6 and 7.

Source: SNL, ISO data

Generation Supply and Power Demand

The highest prices in the US occurred in the ERCOT region. This market has had low reserve margins relative to other markets and concerns about resource adequacy since 2011.

Generally, many ISOs experienced high levels of forced outages on January 6 and 7 (Figure 4). Additionally, winter peak demand hit records or near-records in all eastern ISOs. Many ISOs were forced to issue emergency alerts and call reserves or reduce voltage. This raises the question as to whether the system operated reasonably well under extreme circumstances, or alternatively, whether changes in the resource mix with coal retirements, increased reliance on natural gas, increased reliance on summer-only resources (notably demand resources, but also increasingly generation), and increased penetration of intermittent supply, combined with market structure changes, may be inadvertently compromising grid reliability and/or resulting in very high prices that might be avoided. We believe this question can be answered only with detailed forensic evaluation and this activity should be undertaken in the near-term.

Figure 4. Shortage Event Causes and Timeline by ISO.

<table>
<thead>
<tr>
<th>ISO</th>
<th>Shortage Event Cause</th>
<th>Timeline</th>
</tr>
</thead>
<tbody>
<tr>
<td>ERCOT</td>
<td>Loss of 3,700 MW due to forced outages</td>
<td>Jan 6 6:52 am: Energy Emergency Alert (EEA) Level 1 (call reserves)</td>
</tr>
<tr>
<td></td>
<td>13,000 MW of planned outages</td>
<td>Jan 6 7:01 am: EEA Level 2 (risk of outages)</td>
</tr>
<tr>
<td></td>
<td>Record winter peak demand</td>
<td>Jan 6 9:23 am: Back to normal conditions</td>
</tr>
<tr>
<td>PJM</td>
<td>Loss of 36,600 MW due to forced outages</td>
<td>Jan 6 6:30 pm: EEA level 1 (call reserves)</td>
</tr>
<tr>
<td></td>
<td>Record winter peak demand</td>
<td>Jan 6 7:50-8:50 pm: EEA level 2 (voltage reduction)</td>
</tr>
<tr>
<td></td>
<td>Beaver Valley 1 Nuke went down Jan 6</td>
<td>Jan 8: EEA level 1 canceled</td>
</tr>
<tr>
<td>MISO</td>
<td>Record winter peak demand</td>
<td>Jan 4 10 pm: Cold weather alert</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Jan 7 7:15 am: Max Gen Alert</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Jan 7 7:30 am: Max Gen Warning (next step EEA Level 1)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Jan 7 11:15 am: Drop from Max Gen Warning to Alert</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Jan 7 10 pm: Back to normal conditions</td>
</tr>
<tr>
<td>NYISO</td>
<td>Possible record winter demand</td>
<td>Jan 4 pm: Activate voluntary demand resources</td>
</tr>
<tr>
<td></td>
<td>Indian Point 3 Nuke went down Jan 6</td>
<td>Jan 7 10 pm: Back to normal conditions</td>
</tr>
<tr>
<td>ISO-NE</td>
<td>High winter demand (not record)</td>
<td>No shortage events recorded</td>
</tr>
</tbody>
</table>

Source: SNL, ISO reports.
Price Spike Levels Dictated by Market Structure

The electricity price caps in the US vary depending on the RTO and the regulator. The highest $/MWh prices occurred in ERCOT, which is regulated by the Texas PUCT and not FERC with respect to price caps (Figure 5). ERCOT has a $5,000/MWh price cap, the highest established thus far in North America. This cap will increase to $9,000/MWh by 2015. In contrast, the price cap in PJM, the nation’s largest RTO, is $1,800/MWh (excluding congestion). Thus, it is not surprising that during shortages of generation capacity—e.g., periods when insufficient operating reserves were available—prices would be higher in ERCOT than PJM. The differences in price caps relate to difference in market structure: ERCOT does not have a capacity market while PJM does.

Figure 5. Daily Day-Ahead, Daily Real-Time, and Max Real-Time Energy Prices; January 6 and 7.

Source: SNL, ISO data

Predictability of the Problems

ICF in its recent report*, and others have identified ISO NE as having insufficient gas delivery capacity to avoid high prices for gas, and hence power, especially during colder than normal weather conditions. Hence, ISO-NE’s price explosion was the most predictable in the country and ICF has worked with commercial clients to anticipate and structure business activities around this opportunity. Indeed, for the winter season, ISO-NE delivered gas prices have been high on many occasions, even before this most recent cold snap.

Substitutability of Demand Response (DR—also referred to as contracted Interruptible Load) and Generation

PJM has a very large reliance on interruptible load—it represents more than half of the expected reserves in some periods, with the remainder being physical generation supply. PJM also contracts resources for the summer season only; this arrangement is especially prevalent for DR (most PJM DR is contracted for summer only), but generation is increasingly attempting to have a comparable arrangement. PJM reported significant problems maintaining system security during the evening of January 6 (in addition to having high prices) and indicated that it interrupted load with interruptible contracts. The performance of this interruptible load in comparison to generation will be an important issue forensic activity. It will also be complex, because it must address not only the performance of the DR that was called, but what would have happened if PJM had contracted with generation instead of DR to begin with. In contrast, ISO NE does not rely heavily on interruptible load. This may be surprising since ISO NE has contracted more demand resources than any other region in its three year-ahead resource procurement auctions. However, only 27% of contracted interruptible load was actually in place compared to the initial results of its capacity auctions.

FERC and NERC Treatment of Reliability

NERC, the Electric Reliability Organization (ERO) of the US, has recently adopted new rules for assessing resource adequacy and required reserve margins. NERC has also worked with FERC and others on issues related to gas delivery and generation reliability. ICF has been active in these areas and has demonstrated the importance of fuel supply reliability in addition to generation supply reliability.

Most reliability activities in the power sector are focused on maintaining grid reliability during the summer peak. This is because summer peak demand in the US has historically been higher than winter peak demand. In addition, there has been a trend to rely on summer-only resources. Reliability during the winter peak is, however, extremely critical in order to maintain home heating and public health and safety. This, combined with the recent cold snap, should lead to a review of the robustness of reliability rules in light of the actual experience of the winter of 2014.

ICF International will continue to monitor the developments of the polar vortex and its effects on energy markets and will provide incremental updates in the future.

For questions, please contact:

Judah Rose  ▪  +1.703.934.3342  ▪  judah.rose@icfi.com
Shanthi Muthiah ▪  +1.703.934.3881 ▪  shanthi.muthiah@icfi.com
About the Authors

Judah L. Rose joined ICF in 1982 and has over 30 years of experience in the energy industry. Mr. Rose’s clients include electric utilities, financial institutions, law firms, government agencies, fuel companies, and Independent Power Producers (IPP). Mr. Rose is one of ICF’s Distinguished Consultants, an honorary title given to three of ICF’s 4,500 employees, and has served on the Board of Directors of ICF International as the Management Shareholder Representative. Mr. Rose has supported the development, acquisition, and financing of tens of billion dollars of new and existing power plants and is a trusted counselor to the utility, IPP, and financial community. Mr. Rose frequently provides expert testimony and litigation support. Mr. Rose has testified as an expert in scores of state and other legal proceedings including in nearly 25 states, federal and international jurisdictions. Mr. Rose has also addressed approximately 100 major energy conferences, authored numerous articles published in Public Utilities Fortnightly, the Electricity Journal, Project Finance International, and written numerous company studies. Mr. Rose received an M.P.P. from the John F. Kennedy School of Government, Harvard University, and an S.B. in Economics from the Massachusetts Institute of Technology.

Shanthi Muthiah joined ICF International in 1995 and directs the Power team within the Energy Advisory Solutions practice. Her power industry experience has spanned regional markets in North America, Europe, Australia, Asia, and the Caribbean. Transactional experience includes acquisition support for potential bidders (largely private equity and IPPs) and sellers of generation assets and portfolios; energy markets advisor for the Dynegy and Calpine Unsecured Creditor Committees and NRG Energy in the bankruptcy and restructuring processes; financing and development due diligence support for various IPP and utilities including for gas, coal, hydro and wind projects and portfolios; litigation and regulatory support to utilities; and advisor to power companies in contracting and asset optimization for new or existing power plants.

Frank Brock has more than 17 years of experience in energy economics and modeling. His areas of expertise include the analysis and modeling of natural gas end-use demand, natural gas use for electric power generation, and renewable energy and energy efficiency technologies. At ICF International, Mr. Brock has participated in dozens of studies for both public and private sector clients on such topics such the valuation of energy infrastructure assets, the impacts of environmental policies on energy markets, and long-term trends in energy demand.

John Karp joined ICF International’s Wholesale Power team in 2007. With over 6 years of experience, John has helped provide power market valuations, cash-flow forecasts and energy market forward price curves for many different types of clients, such as independent power producers, investment firms, utilities and state, federal and local governments and regulators. Mr. Karp has significant experience using ICF’s proprietary energy model, IPM, to deliver long-term energy price forecasts and power portfolio valuations. Mr. Karp received a BS and MS in Systems Engineering and Operations Research from the George Washington University.

Trishagni Saky is a Research Assistant in ICF’s Energy Advisory Solutions practice for the Wholesale Power Markets team. She has expertise in power price forecasting, plant valuations and power market analysis. Trishagni uses ICF’s proprietary energy models, IPM and SRAM for detailed price forecasts and analysis. Prior to working at ICF, Trishagni attended the Smith College and earned a B.A. in Economics and Mathematics.