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Chairman Murkowski, Ranking Member Cantwell, and members of the Committee:

Thank you for the opportunity to appear before you today to discuss the performance of the electric system during recent winter weather events. I appreciate your attention to this important issue.

The recent cold weather event stretching from late December into early January tested the bulk power system and affected different regions in different ways. Although we are still receiving and reviewing data, it appears that, notwithstanding stress in several regions, overall the bulk power system performed relatively well. We have previously taken action to address known and anticipated challenges regarding reliability and resilience, and the recent cold weather event highlights the importance of both continued evaluation of the bulk power system and the need for the Commission to remain vigilant in addressing these issues.

The Polar Vortex of 2014

How the bulk power system performed during the winter event—now commonly referred to as the 2014 Polar Vortex—provides useful context for understanding how the bulk power system performed under the winter weather events of the past month. During the 2014 Polar Vortex, much of the United States experienced sustained and, at times, extreme cold weather. With temperatures 20 to 35 degrees below average in many areas, winter electric peak demand reached record highs in the regions served by several of the country's regional transmission organizations (RTO) and independent system operators (ISO), including the Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection, L.L.C. (PJM), New York Independent System Operator, Inc. (NYISO), and Southwest Power Pool, Inc. (SPP), with ISO New England Inc. (ISO-NE) experiencing a winter peak electric demand just below its record level. The extreme cold weather and corresponding increased demand challenged the electric system. These challenges were compounded by unplanned generator shutdowns, including those caused by mechanical failures related to temperatures falling below plants' design basis, poor winterization, and the stress of extended run times; frozen coal piles; natural gas interruptions; and fuel-oil delivery problems, including propane deliveries. These combined circumstances tested grid reliability and power supplies, and contributed to high electricity prices.

At the same time, record high natural gas demand placed extreme stress on the U.S. natural gas system. In the Northeast, natural gas pipelines serving the region issued capacity constraint warnings and operational flow orders (OFOs), holding pipeline customers to scheduled flows and making it difficult for some natural gas to make it to market demand centers. Many storage facilities also issued restrictions on withdrawals. In the upper Midwest, an explosion on TransCanada's Mainline Line 1 lateral in Manitoba disrupted natural gas supplies to the Canadian and upper Midwest markets. The high natural gas demand and pipeline constraints translated to record high natural gas spot prices, spiking to $123/MMBtu in New York City against an average winter 2013-2014 price of $11.30/MMBtu; $120/MMBtu in Philadelphia against an average winter 2013-2014 price of $9.70/MMBtu; and over $50/MMBtu in the Midwest against an average winter 2013-2014 price of $7.44/MMBtu.

Electricity prices during the 2014 Polar Vortex reached $2,000/MWh for a number of hours in some regions. On-peak average real-time prices ran from $300-$700/MWh in PJM and MISO. High natural gas prices contributed to these electricity prices because natural gas was the marginal fuel for most electricity markets. Even these high prices, however, did not reflect the entire cost of the event. Some of the actions taken by RTOs and ISOs resulted in historically high out-of-market make-whole payments, or uplift payments, to reimburse generators for costs that were not covered through normal energy and ancillary service sales. During the event, the RTOs and ISOs declared emergency conditions on several occasions, and some implemented emergency procedures, including emergency demand response, voltage reduction, and emergency energy purchases. Ultimately, the bulk power system remained stable and generally performed reliably throughout the 2014 Polar Vortex; however, the event underscored the need for the Commission and industry to focus on market design enhancements, as well as improved gas-electric coordination.

Applying Lessons from the 2014 Polar Vortex

The Commission took numerous actions, both nationwide and with a region-specific focus, to address reliability and resource performance issues since the 2014 Polar Vortex.

Among its broader efforts, for example, the Commission examined fuel assurance, grid reliability, and generator performance issues that arose during the 2014 Polar Vortex, and it required RTOs/ISOs to report on their strategies to address market and system performance associated with fuel assurance issues. The Commission also has taken action to respond to the increasing use of natural gas for electric generation, including revising its regulations (Order No. 809) to better coordinate the scheduling of transportation service on interstate natural gas pipelines with the scheduling practices of the wholesale natural gas and electric industries, and to provide additional scheduling flexibility to all shippers on interstate natural gas pipelines. The Commission also issued orders that facilitated improved communications between the RTOs/ISOs and natural gas pipelines. Situational awareness for the RTOs/ISOs is of particular importance during stressed system conditions, caused by, for example, increased demand for natural gas during a cold snap. Among other things, improved communications can provide RTOs/ISOs confidence that natural gas-fired resources will respond when called upon to provide energy. This confidence, in turn, mitigates the need to take costly actions that an RTO/ISO may otherwise feel compelled to take if a natural gas-fired generator does not respond as expected.

Additionally, the Commission initiated proceedings to evaluate price formation in the energy and ancillary services markets operated by RTOs/ISOs, with a focus, in part, on providing correct incentives for market participants to follow commitment and dispatch instructions, to make efficient investments in facilities and equipment, and to maintain reliability. As part of that effort, the Commission issued Order No. 831, requiring RTOs/ISOs to revise their existing offer caps to help ensure that energy prices reflect the cost to serve demand and that resources will not operate at a loss during extreme winter weather conditions when fuel supply can be tight.

As to region-specific efforts, the Commission approved significant capacity market reforms in both ISO-NE and PJM that are intended to provide greater financial incentives for improved resource performance and to impose penalties for non-performance. The Commission also has approved a series of temporary, short-term, out-of-market winter reliability programs in New England, which, among other things, provide financial incentives for resources to secure firm fuel in advance of the coldest months. And, even before issuing Order No. 831, in direct response to unprecedented spikes in fuel costs caused during the 2014 Polar Vortex, the Commission granted PJM, NYISO, and MISO temporary waivers of certain tariff provisions related to the offer price cap to allow qualifying resources to recover their full verified costs of providing energy under such extreme weather conditions. As recently as this month, due to the most recent cold weather event stretching from late December 2017 into January 2018, the Commission again granted NYISO and MISO temporary waivers of tariff provisions related to the offer cap, while noting that the impending implementation of Order No. 831 reforms should render such waivers unnecessary in the future.

The Cold Weather Event of December 2017-January 2018

In reviewing the performance of the electric system during the recent winter weather events, it is useful to consider the impact of the recent weather event on both the provision of service and the associated costs of that service.

We are still receiving information from the ISOs and the RTOs regarding the recent cold weather event. However, the bulk power system appears to have performed relatively well. There were no customer outages resulting from failures of the bulk power system, generators, or transmission lines. Overall peak load in the eastern market regions was slightly below levels during the 2014 Polar Vortex.

During this period, each region managed its system in different ways. In managing their systems, beginning on December 28 and continuing into early January, several regions issued Cold Weather Alerts to prepare for cold weather. In MISO, for example, a Cold Weather Alert directs generators to implement winterization plans for plants, ensure the availability of staff to operate plants if called on, double-check fuel supplies, and defer maintenance on generators and transmission lines, if possible. As the cold weather settled in and the risk to reliability increased, RTOs/ISOs issued Conservative Operations Notices and Watches. These notices suspend maintenance on generators and transmission facilities so that they may be available, if needed. These notices also permit out-of-market actions to relieve system constraints. On January 5, for example, all eastern market regions, the Tennessee Valley Authority, and parts of the Southeast had declared system alerts or conservative operations. As noted, while Commission staff is continuing to gather data regarding the types of actions taken during the recent cold weather event, these alerts and warnings are less severe than, and in fact are aimed at preventing, the kind of emergency actions taken during the 2014 Polar Vortex.

Throughout the cold weather event, the bulk transmission system operated reliably, with no loss of load due to transmission system failures. One notable event was the tripping on January 4 of one of the transmission lines connecting the Pilgrim nuclear station to the New England grid. The loss of this line required the plant operator to manually remove the plant from service. In PJM, gas supply issues caused outages at certain generation facilities, but mechanical problems and other factors caused significantly more outages across all types of generation facilities.

With limited exceptions, the RTOs/ISOs had sufficient reserves to ensure reliable operations. To place that statement in context, RTOs/ISOs hold generation in reserve to address unexpected contingencies like an unplanned generation outage. If an RTO/ISO gets to the point that it does not have enough resources in reserve, a reserve shortage event is declared, and the reserve price is set administratively to reflect the fact that the system has a scarcity of resources needed to reliably serve load. During the recent cold weather event, only MISO and NYISO experienced reserve shortage events. As noted, we are still receiving data. Based on what we know, it appears MISO experienced a limited number of shortages between January 1 and January 5 and NYISO experienced a limited number of reserve shortages on January 5 and 7.

During the 2014 Polar Vortex, there were a large number of forced outages of generating stations due to failures in plant systems (boilers, electrical equipment, pumping equipment, and other components), fuel supply issues, and other factors. Initial data suggest that generator performance during the recent cold weather event improved when compared to the 2014 Polar Vortex. However, a definitive assessment cannot be made at this time.

While there were no significant reliability issues during this recent cold weather event, wholesale energy prices were high. Average energy prices in the eastern RTOs/ISOs were more than four times higher than the average energy price last winter. Looking at the period starting around December 28, 2017 through January 7, 2018, day-ahead energy prices

- at ISO-NE's internal hub prices averaged $177/MWh with a maximum price of $320/MWh,
- at PJM's Eastern Hub prices averaged $165/MWh with a maximum price of $375/MWh,
- in NYISO's Zone J (New York City) prices averaged $167/MWh with a maximum price of $315/MWh, and
- at the MISO Indiana Hub prices averaged $56/MWh with a maximum price of $158/MWh.

These figures compare to prices ranging from the low-$30s/MWh to low-$40s/MWh last winter.

We would expect competitive pressures supplemented by market power mitigation rules to lead to energy market prices that reflect the cost of fuel to generate energy and any shortage conditions. However, the Commission is attentive to the potential for behavior that takes advantage of extreme weather events. As part of its daily surveillance activities, Commission staff is reviewing market data to identify market outcomes during the most recent cold weather event that could be the result of manipulative behavior.

Given the expectation that energy market prices are consistent with fuel market fundamentals, I will provide some details about fuel markets during the cold weather event. The cold weather that affected much of the Northeast and Midwest during the first week of January triggered a number of natural gas pipeline capacity constraints, resulting in record-setting natural gas price spikes. Trading for January 5—the peak day for spot prices—came near the end of a long succession of tight market conditions, during which total U.S. natural gas demand topped 100 Bcfd for 11 straight days in comparison to an average demand of 93.5 Bcfd in January of last year. Total U.S. natural gas demand averaged 127 Bcfd from December 25 to January 4.

In the Northeast, natural gas spot prices in New York peaked at $140/MMBtu on January 4 for flow on January 5, with two trades reported as high as $175/MMBtu. That same day, seven trading points in the Northeast and Mid-Atlantic cleared with volume-weighted average prices of greater than $100/MMBtu, while three others were above $75/MMBtu. New England was, in part, able to compensate for pipeline capacity constraints with cross-border supplies from Eastern Canada and Liquefied Natural Gas (LNG). The Canaport LNG import terminal received a 3.2 Bcf cargo from Trinidad and Tobago on January 3. Additionally, internationally-sourced LNG into the Everett LNG import terminal near Boston aided in serving the New England market. Everett received three cargoes totaling approximately 9 Bcf between December 29 and January 10, also sourced from Trinidad and Tobago. Finally, with regional heating oil prices hovering significantly below natural gas prices, around $13/MMBtu, in the Northeast and New England, it became economical for power plants to run on oil instead of natural gas. Of note, the New England region's reliance on oil-fired units during this period highlights the need to timely replenish oil inventories and carefully manage emission allowances.

In the Midwest, natural gas spot prices were elevated, but generally did not trade above $10/MMBtu. However, Northern Natural Ventura saw record natural gas prices on December 28, when Northern Border pipeline issued an OFO signaling tight conditions that resulted in an average price of $67/MMBtu, with some trades reported as high as $100/MMBtu. Pipelines in the Midwest had fewer capacity constraints than those in the Northeast, allowing greater access to supplies from multiple sources, including the nearby Appalachian Basin.

Finally, in the Southeast and Gulf Coast, prices at Henry Hub rose as high as $6.88/MMBtu from approximately $2.60/MMBtu before the cold snap. Although there were some operating constraints in the region, they were not as widespread as experienced in the Northeast.

Delivery limitations on pipelines traversing the Northeast and parts of the Midwest were prevalent in late December and early January, with several long-haul pipelines issuing system-wide restrictions. OFOs were declared on Algonquin, Dominion, Iroquois, Tennessee, and Texas Eastern pipelines in the Northeast, while other pipelines across the grid warned shippers to remain in balance so as not to trigger restrictions. Most of the OFOs declared during the cold were lifted on or before January 9.

There are several key factors that made this most recent cold weather event less impactful to the U.S. pipeline system as a whole than during the 2014 Polar Vortex. Pipeline disruptions were less systematic and more regional in nature. Additionally, new pipeline connections provided markets near the Marcellus and Utica shale production areas better access to natural gas supplies. Increased storage withdrawals and timely use of LNG supplies also contributed to maintaining system stability.

In addition to the cost of energy generated to serve load, the cost of generation held in reserve can be an important component of the total cost borne by consumers. High prices for generation held in reserve indicates a stressed system because fewer resources are available to respond to unexpected contingencies. The frequency at which reserve prices increased to non-trivial levels during the recent cold weather event varied by region. Some of these differences are due to differences in the specific reserve market design each RTO/ISO uses. ISO-NE experienced reserve prices over $1/MWh for only 13 percent of hours. Reserve prices for resources that can respond within 10 minutes were greater than $1/MWh in 41 percent of hours in PJM, 39 percent of hours in NYISO and 72 percent of hours in the MISO. Commission staff is continuing to review these market outcomes to understand whether they are representative of actual differences in operational experience and to understand the degree to which the actions that RTOs/ISOs appropriately took to maintain reliability were reflected in market outcomes.

While higher wholesale energy prices are ultimately borne by retail customers, they send important signals to drive performance and investment. During moderate system conditions, many resources earn little to no revenue above their short-term variable costs and thus receive little revenue to offset the long-term fixed costs of building and maintaining the resource. In addition to capacity market revenue, the energy revenue earned during stressful conditions provides a means to recover a resource’s fixed costs. Prices that accurately reflect fuel costs and system conditions also send signals that drive operational and investment decisions for both resources and consumers.

Looking Forward

Just as the Commission and the RTOs/ISOs drew lessons from the Polar Vortex of 2014 and applied them in ways that better prepared us for the recent cold weather event, we will examine these recent events carefully and seek to learn from them.

I also would like to emphasize several points that the Commission made in an order we issued on January 8 in response to the Proposed Rule on Grid Reliability and Resilience Pricing submitted to the Commission by the Secretary of Energy, and to initiate a new proceeding in Docket No. AD18-7-000.

First, in that order the Commission made clear that the resilience of the bulk power system will remain a priority of the Commission. The Commission recognizes that we must remain vigilant with respect to challenges to the resilience of the bulk power system, because affordable and reliable electricity is vital to the country's economic and national security. We appreciate the Secretary of Energy reinforcing the resilience of the bulk power system as an important issue that warrants further attention.

Second, in recent years, we have seen a variety of economic, environmental, and policy drivers that are changing the way electricity is procured and used. These changes present new opportunities and challenges regarding the reliability, affordability, environmental profile, and resilience of the electric system. In navigating these changes, the Commission's markets, transmission planning rules, and reliability standards should evolve as needed to address the bulk power system's continued reliability and resilience.

Third, to those ends, the Commission initiated a new proceeding to further explore resilience issues in the RTOs/ISOs. The goals of this new proceeding are: (1) to develop a common understanding among the Commission, industry, and others as to what resilience of the bulk power system means and requires; (2) to understand how each RTO/ISO assesses resilience in its geographic footprint; and (3) to use this information to evaluate whether additional Commission action regarding resilience is appropriate at this time. Therefore, the Commission directed each RTOs/ISOs to submit within 60 days of that order specific information regarding the resilience of the bulk power system in its region. We expect to review the additional material and promptly decide whether additional Commission action is warranted to address grid resilience.

Fourth, in announcing its initiative to further explore grid resilience, the Commission recognized that RTOs/ISOs are well suited to understand the needs of their respective regions and initially assess how to address resilience given the needs of their individual regions. Indeed, the report released last week by ISO-NE illustrates that type of thoughtful, forward-looking attention to resilience challenges. In addition, the concept of resilience necessarily involves issues that extend beyond the Commission's jurisdiction, such as distribution system reliability and modernization. For that reason, the January 8 order encourages RTOs/ ISOs and other interested entities to engage with state regulators and other stakeholders to address resilience at the distribution level.

I look forward to working with the Members of this Committee to promote the resilience of the bulk power system. I appreciate your attention to this important issue.