UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing — Docket No. RM18-1-000

COMMENTS OF AMERICAN PETROLEUM INSTITUTE

I. INTRODUCTION

The American Petroleum Institute ("API") is a national trade association representing over 625 member companies involved in all aspects of the oil and natural gas industry. API's members include producers, refiners, suppliers, pipeline operators, and marine transporters, as well as service and supply companies that support all segments of the industry. API advances its market development priorities by working with industry, government, and customer stakeholders to promote increased demand for and continued availability of our nation's clean abundant natural gas resources for a cleaner and more secure energy future. Electricity generation is a significant market for clean-burning natural gas and our members are both producers and consumers of electricity. Therefore, API has an interest in ensuring wholesale electricity market rules and regulations treat natural gas generation equitably, providing a non-discriminatory level playing field for all resource types.

On September 28, 2017, the Secretary of Energy issued the "Notice of Proposed Rulemaking for the Grid Resiliency Pricing Rule" ("DOE NOPR") for final action by the Federal Energy Regulatory Commission ("FERC" or "Commission"). FERC subsequently opened a new

docket (RM18-1) to examine the proposed rule and setting a short 20-day comment period. API respectfully submits the following comments in protest of the rule.

API has previously elaborated on the many benefits the use of natural gas in power generation has brought to the electric industry, its residential, commercial and industrial customers, and the nation as a whole. Most recently these benefits were set out in testimony before the House of Representatives Committee on Energy and Commerce Subcommittee on Energy, included as an attachment to these comments. Natural gas has a history of reliability across the natural gas system and the industry's ability to ensure delivery of its product to its customers. These benefits are well documented and outlined in detail in the latest Natural Gas Council white paper, also included as an attachment to these comments. API will herein, discuss the policy and legal implications of the DOE NOPR. We will also discuss the rationale put forth in the DOE NOPR and the issues with the recent IHS Markit[1] study that is used to justify this action.

The DOE NOPR seeks to force competitive wholesale energy markets to provide cost-of-service type guaranteed cost recovery to a subset of resources under the guise of maintaining reliability and resilience.[2] Neither the North American Electric Reliability Corporation's ("NERC") nor the affected regional transmission organizations and independent system operators' ("RTOs/ISOs") analyses have indicated that any reliability or resource adequacy

[1] IHS Markit, "Ensuring Resilient and Efficient Electricity Generation, The value of the current diverse US power supply portfolio," September 2017.
[2] We recognize that the DOE NOPR does not specify coal and nuclear plants, however, while possible, it would be difficult and prohibitively expensive for any other type of facility to meet the 90-day on-site fuel requirement.

concerns exist.[3] In fact, the RTO/ISO most affected by this NOPR, PJM, has had, and projects it will continue to have, very healthy reserve margins[4] even in spite of the already substantial numbers of coal retirements (and announced retirements) in that region.[5]

The recent DOE staff report released in August of this year, also did not cite an "emergency" nor find that the grid was currently not reliable, and staff recommended fuel-neutral and market-based reforms.[6] DOE staff specifically noted, "Resource portfolios could be complemented with wholesale market and product designs that recognize and complement resource diversity by compensating providers for the value of ERS [essential reliability services] on a *technology-neutral basis* [emphasis added]. More work is needed to define, quantify, and value resilience."[7] This DOE NOPR would distort the markets and support power generators that cannot compete with the superior economics of natural gas generation, citing a reliability "emergency," even though one has not been shown to exist.

API's submission of these comments should not be construed to accept that the 20-day comment period was sufficient. It was not, particularly for a proposed rule that upsets the very foundations of the competitive wholesale electricity markets.

[3] See NERC reliability assessments, which also contain information on each RTO/ISO: http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx
[4] See PJM's reserve margin forecast: http://pjm.com/-/media/planning/res-adeq/20170705-forecasted-reserve-margin-graph.ashx?la=en
[5] See the PJM study on reliability: http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx
[6] DOE, "Staff Report on Electricity Markets and Reliability," August 2017.
[7] Id, p. 100.

II. FERC QUESTIONS

A. Need for Reform

The Commission proposes several questions regarding whether there is a need for reform, but there are more fundamental questions that need to be asked first. The DOE NOPR purports to address a need to maintain resilience. But what defines resilience and how is it measured? In general terms, while the Federal Power Act ("FPA") does not define the term "resilience," we understand that resilience has been generally characterized as the grid's ability to withstand, or recover from, low probability, high impact events. The specific elements of resilience that are essential to the system need to be studied and analyzed. Then, market mechanisms can be formulated to ensure delivery of the services at the lowest cost or to pay for the value of the services.

Without knowing this fundamental definition, no effective solution can be offered. These are the rudimentary questions that need to be answered *before* proposing solutions. What events qualify and in what time should the recovery occur, remains undefined. Is recovery measured in hours, days, or years? The Commission's questions on these topics cannot and should not be addressed in this docket and on such an expedited timeframe. The question of grid resilience should be examined in detail through a reasoned, thoughtful process. Proposed solutions can then be based on sound analysis and rationale as required by law. This can only be accomplished through a separate, thorough, and dedicated process that is not under an unreasonable time constraint, as parties are under in this proceeding.

The following paragraphs outline just a few examples of how the DOE NOPR does not demonstrate the required nexus between the proposed "solution" and the resilience problem it

asserts.

The DOE NOPR provides no nexus between its claimed concern of resilience and its proposed solution regarding "fuel-secure" generation. As noted above, the DOE NOPR does not define "resilience," nor demonstrate that cost-based recovery for "fuel-secure" generation will achieve greater reliability or resilience on the bulk power system. While NERC has highlighted coal and nuclear generation retirements and the shift toward natural gas as a dominant fuel source, as *possible* long-term reliability concerns, NERC has also suggested a number of solutions to address them, including improved coordination, system planning, and investments in transmission and pipeline infrastructure.[8] The latter options, investments in transmission and build out of pipeline infrastructure, in contrast to the DOE NOPR, are uniquely within the Commission's jurisdiction, support market-based solutions, and would not result in the negative impacts associated with the DOE NOPR that are identified in these comments.

More specifically, the Commission has the authority under Section 219 of the FPA[9] and Order No. 679 to grant incentives to new transmission construction and the authority under Section 216 of the FPA[10] to assist in transmission siting under certain circumstances. It is noteworthy that "hardening" of the electricity grid, as opposed to 90 days of on-site fuel supply, would go much further towards reducing the impact of hurricanes and other weather events cited by the DOE as a basis for the NOPR.

[8] See NERC State of Reliability reports, available at: http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/Forms/AllItems.aspx
[9] 16 U.S.C. § 824s.
[10] *Id*. § 824p.

The Commission also has the authority under Section 7[11] to grant certificates of public convenience and necessity for construction of new interstate natural gas facilities.[12] The Commission is the lead agency for environmental review of such facilities under the National Environmental Policy Act.[13] As such, the Commission has the ability to set the pace for permitting interstate natural gas facilities. In addition, the Commission has authority to approve flexible rate structures for interstate natural gas facilities, including approving market based rate authority where an applicant can demonstrate a lack of market power. In fact, several Commission-regulated natural gas facilities have market-based rate authority.[14]

Similarly, the DOE NOPR asserts that the existence of the 2014 Polar Vortex and other more recent natural disasters reinforce the urgency for the Commission to act now to ensure reliability and resilience. However, the DOE NOPR does not explain how the proposed tariff changes will ensure system reliability and resilience during such events. For example, the DOE NOPR does not address the role that transmission and distribution grid resilience plays in preventing outages or even *whether* the presence of on-site fuel supplies prevents outages. In PJM's comprehensive report analyzing the causes and impacts of the 2014 Polar Vortex, it found, among other things, that "all conventional forms of generation, including coal and nuclear plants were challenged by the extreme weather conditions," and that 42% of the forced outages caused by the Polar Vortex were the result of equipment issues associated with both coal and natural gas units.[15] Thus, from a generator availability perspective, the greatest risk

[11] 15 U.S.C. § 717f.
[12] *Id.* § 717f(h).
[13] *Id*. § 717n.
[14] *See*, *e.g. Stagecoach Pipeline & Storage Company LLC*, Docket No. RP16-287-000 (Letter Order issued Dec. 24, 2015).
[15] "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events," *PJM Interconnection L.L.C.*, May 8, 2014 at p. 24, *available at* http://www.pjm.com/~/media/library/reports-
(Continued...)

during the Polar Vortex was not a lack of available fuel supply, but a failure of generators to perform during extreme conditions.[16] As a result, PJM took the approach of revising its capacity market rules to ensure that generators submitting to capacity performance obligations will be available during extreme conditions.[17]

B. Eligibility

What is eligible to receive compensation for resilience is not an appropriate discussion to have at this time and will not be until the issues in Section A, above, have been resolved.

1. The 90-day On-site Fuel Requirement

The DOE NOPR argues that power plants with 90 days of on-site fuel provide both reliability and resilience benefits. Reliability refers to the power grid's capability to supply power on demand to customers without interruption, while resilience (as noted above) is not as well understood and only generally defined as being able to withstand and/or recover from catastrophic events. However, both the reliability and resilience benefits of maintaining such long-term, on-site fuel storage are questionable.

Maintaining a 90 days on-site fuel supply would only increase reliability in the highly unlikely scenario that the transmission network remained operational, but the catastrophic event disrupted fuel supplies for many large power plants for multiple months. While such a disruption

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notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

[16] *Id.* at 26.

[17] *See PJM Interconnection L.L.C.*, Capacity Performance Initiative, Oct. 23, 2014 *available at:* https://www.pjm.com/~/media/committees-groups/committees/elc/postings/capacity-performance-cost-benefit-analysis.ashx. Of note is the fact that PJM based its Capacity Performance Proposal on an expected 30 *hours* of emergency conditions per year, not 90 *days*.

could theoretically occur, many potentially catastrophic events – including acts of war,[18] massive earthquakes, or extreme weather – could also cause system-wide multi-month outages and also render plants with 90-day fuel supplies inoperable. Thus, simply maintaining a 90-day fuel supply on-site, which is the focus of the DOE NOPR, provides no clear appreciable benefit in any likely scenario. Moreover, the DOE NOPR does not account for the fact that larger power plants create their own unique reliability risks during catastrophic events, because the loss of large plants puts a greater strain on the grid than the loss of smaller plants resulting in less reliability – the exact opposite of the intent of the DOE NOPR.

In reality, failures in the transmission and distribution systems cause the vast majority of long-lasting power outages.[19] For example, the largest blackout in U.S. history occurred in August 2003 when unpruned foliage caused the failure of a high voltage transmission line, which in turn led to a cascading failure of the electrical system. During that blackout, nine nuclear reactors shut down because they lost offsite power – access to a 90 day fuel supply notwithstanding.[20] On September 9, 2011 a large power outage occurred in Southern California and the Tijuana area of Mexico.[21] The outage started with the loss of a single 500 kilovolt transmission line (due to human error), and led to the shutdown of the San Onofre Nuclear Generating station.

As noted earlier, the DOE NOPR specifically cites the Polar Vortex – when interruptible natural gas deliveries were curtailed over a short period of hours – to justify the importance of

[18] It bears noting that some disruptions, such as war, could also impact the flow of uranium to nuclear power plants, as, according to EIA, this fuel is predominantly imported from other countries. See: https://www.eia.gov/uranium/marketing/
[19] See: The Rhodium Group, "The Real Electricity Reliability Crisis," October 3, 2017.
[20] CBS New, "Biggest blackout in U.S. history," August 15, 2003, available at: https://www.cbsnews.com/news/biggest-blackout-in-us-history/
[21] See: https://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf

providing financial support to plants with 90 days of on-site fuel storage. However, maintaining a 90-day on-site fuel supply would have provided no appreciable reliability benefit beyond a fuel supply that lasts a few hours, as during this event, where the generation emergencies in PJM amounted to an aggregate total of only 20 hours.[22] Moreover, interruptible fuel supply did not cause the majority of outages during the Polar Vortex.[23]

In the aftermath of the Polar Vortex, the RTOs/ISOs took steps to improve market designs that will reduce the likelihood of natural gas supply interruptions going forward. In 2015, under similar conditions to the Polar Vortex, the PJM system performed remarkably well because of the reforms that had been instituted by PJM.[24]

Having a large inventory of coal at a plant is unlikely to be helpful except during an interruption of the coal transportation system. An appropriate inventory does indeed provide reliability and resilience by protecting against the frailties of the coal transportation system. The events that have been identified as justification for a 90 day on-site supply of fuel have all been short-term events. Outages have never lasted more than a few days, and major outages have all almost entirely been due to transmission infrastructure issues.[25]

The DOE NOPR also does not reflect that access to off-site fuel – rather than access to on-site fuel – can also improve the reliability benefit a power plant provides to the grid. Fuel delivery issues impact many fuel sources. Most of the Powder River Basin ("PRB") coal is

[22] PJM: http://pjm.com/-/media/committees-groups/committees/elc/postings/performance-assessment-hours-2011-2014-xls.ashx?la=en
[23] Operational Events and Market Impacts January 2014 Cold Weather, Craig Glazer, PJM Vice-President of Federal Government Policy, July 2, 2014.
[24] See: http://www.pjm.com/-/media/library/reports-notices/weather-related/20150513-2015-winter-report.ashx?la=en
[25] See: The Rhodium Group, "The Real Electricity Reliability Crisis," October 3, 2017.

transported over a 120 mile span that is owned by two railroads and is usually referred to as the "joint line." PRB coal is the source for more than half the coal consumed for electric generation. A joint line train derailment in May 2005 curtailed PRB coal production in Wyoming and Montana for several months, with some utilities in the Midwest continuing to experience problems with deliveries through the spring of 2006, almost a whole year.[26, 27]

Another example is when Hurricane Harvey forced NRG to switch two of its coal-fired units to natural gas because of water soaking the coal piles.[28] According to NRG, "The external coal pile at W.A. Parish became so saturated with rainwater that coal was unable to be delivered into the silos from the conveyer system. In response to that situation, we transferred W.A. Parish Unit 5 and Unit 6 to natural gas rather than coal as the fuel source. These units haven't used natural gas for operational purposes since 2009."[29] In this case, having access to the natural gas pipeline network provided a reliability benefit to the power grid, while having access to 90 days of on-site coal fuel supply would not have provided any reliability benefit at all.

For the foregoing reasons, the 90 day requirement is arbitrary and *not* an indicator of resilience.

C. Implementation

As stated before, questions regarding resilience and the services required to maintain resilience still need to be specified, therefore it is premature to discuss implementation. Additionally, the DOE NOPR does not specify a practical way to address resilience.

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[26] See: https://www.oe.netl.doe.gov/docs/Final-Coal-Study_101507.pdf
[27] See: https://www.ferc.gov/CalendarFiles/20060623124512-Statement%20of%20William%20Mohl-Entergy%20for%20EEI-6-15-06.pdf
[28] Platts, "Harvey's rain caused coal-to-gas switching: NRG Energy," September 27, 2017.
[29] Id.

Implementing the DOE NOPR rule could destroy competitive wholesale electricity markets by imposing cost-of-service regulations on certain regions and certain resources, thereby eliminating the market-based solutions that have been so effective in improving grid performance and reliability as the grid has evolved.

D. Rates

With respect to setting rates, it is an open question whether FERC has the authority to do as requested in the DOE NOPR. The DOE NOPR asks the Commission to create rules guaranteeing private merchant generation owners recovery of their operating and maintenance (O&M) expenses and a return on investment, which is outside the scope of FERC's jurisdiction. In regulated states, how utility-owned generators manage O&M and return on investment is under state jurisdiction. These jurisdictional and legal authority issues need to be resolved before discussion begins about how FERC should set rates.

1. Legal Standard

FERC's authority arises from the FPA and the Commission must meet a just and reasonable standard. There are numerous arguments contained in this filing that are offered to show that the DOE NOPR cannot be shown to be just and reasonable. The below discusses some specific issues with respect to rates and FERC authority.

a. The Commission Lacks Authority to Implement the DOE NOPR Under Sections 205 and 206 of the FPA

FERC is a "creature of statute" and has "'*only* those authorities conferred upon it by

Congress.'"[30] The FPA does not give the Commission general authority to regulate the buying and selling of electricity, nor does it allow FERC to control in-state generation, which is an area reserved exclusively to the states.[31] Rather, its jurisdiction is specifically proscribed to the regulation of "the *sale* of electric energy at wholesale in interstate commerce."[32] In the DOE NOPR, DOE proposes that the Commission act under Sections 205[33] and 206[34] of the FPA to order that certain "fuel-secure" generation be compensated fully for the generation costs plus a reasonable return on investment. To achieve the DOE NOPR's goal, the Commission would also have to order each affected RTO/ISO[35] to buy such generation in their organized competitive wholesale markets, even when that generation would otherwise not be purchased. Neither Section 205 nor 206 of the FPA gives the Commission that power.

Section 205 of the FPA authorizes the Commission to play a "passive and reactive role," such that the Commission may accept or reject a rate proposed by an RTO/ISO or utility upon a finding that the proposed rate is just and reasonable.[36] Section 205 of the FPA does not authorize the Commission to establish its own rate.[37] Under Section 206 of the FPA, the Commission may unilaterally establish a rate for the sale of wholesale power, along with any

[30] *Atlantic City Electric Co. v. FERC*, 295 F.3d 1, 8 (D.C. Cir. 2002) (quoting *Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001)).
[31] *Pacific Gas & Elec. Co. v. State Energy Resources Conservation and Development Comm'n*, 461 U.S. 190, 205 (1983) ("Need for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States.").
[32] 16 U.S.C. § 824(b) (emphasis added).
[33] *Id*. § 824d.
[34] *Id*. § 824e.
[35] On October 10, 2017, the DOE published a revised version of the DOE Proposal in the Federal Register. While the original version of the DOE Proposal appears to apply to all electric resources located in RTO markets, the amended DOE Proposal applies only to resources within those RTOs with active energy and capacity markets.
[36] *NRG Power Mktg, LLC v. FERC*, No. 15-1452, at 11-12 (D.C. Cir. 2017).
[37] 16 U.S.C. § 824d(a); *NRG Power Mktg, LLC* at 11 ("Section 205 does not authorize [the Commission] to impose a new rate scheme of its own making without the consent of the utility or Regional Transmission Organization that made the original proposal.").

associated rules or practices directly affecting that rate.[38] However, the Commission's authority extends only to the establishment of the rate and terms and conditions associated with that rate. Section 206 of the FPA does not provide the Commission with the authority to mandate that buyers and sellers enter into specific contracts, nor does it authorize the Commission to require that wholesale markets purchase electricity offered by specific resources. Indeed, when contracts are voluntarily entered into, the Commission must honor them even if they compensate the seller at *less* than a just and reasonable rate.[39]

The DOE NOPR would require each affected RTO/ISO to have in place a just and reasonable rate that ensures that each eligible "fuel-secure" generation resource is fully compensated for its costs and a return on equity. Full compensation, as contemplated in the DOE NOPR, can only be achieved if the eligible resource is dispatched at the rate that the affected RTO/ISO is required to pay, or provided some form of out-of-market payments above and beyond cleared capacity prices to ensure they reach that "full-compensation" level. Thus, to achieve its goal of stopping "the imminent loss of generators with on-site fuel supplies" the Commission must not only establish a just and reasonable cost-of-service rate for specific generation resources, but also require the affected RTOs/ISOs to somehow pay the specified rate as well. In doing so, the DOE NOPR effectively mandates that wholesale markets must buy from a specific type of generation, and significantly oversteps the boundaries of the Commission's jurisdiction. Nothing in Section 206 of the FPA allows the Commission to require wholesale customers to buy power at a specific rate or from a specific type of

[38] *See FERC v. Electric Power Supply Assoc. et al.,* 136 S.Ct. 760 (2016).
[39] *Morgan Stanley Capital Group Inc. v. Pub. Util. District No.1 of Snohomish County, et al.,* 128 S.Ct. 2733 (2008). Even if RTO markets are not considered contracts, but tariffs of general applicability, the Commission does not have the power to mandate anything more than the price and terms and conditions of that tariff. It does not authorize the Commission to require an RTO to favor one generation source over another.

generation.[40] Additionally, Section 206 does not provide the Commission with the authority to determine whether a particular resource is required for reliability or resilience, but the DOE NOPR would require the Commission to make such a determination, wholly untethered from legislative text. Through the DOE NOPR, the Commission would have to make the unsupported determination that certain "fuel-secure" generation is needed for resilience, would establish a rate, and would require that the affected RTO/ISO or utility purchase the output of the "fuel-secure" generation through deregulated wholesale markets. Such an arrangement goes far beyond the limits of the Commission's authority.[41]

b. The DOE NOPR Has Not Met The Required Burden To Establish That The Existing Rate Is Unjust And Unreasonable.

Even if the Commission has the authority to implement the DOE NOPR under Section 206 of the FPA, the Commission cannot act without first demonstrating that the existing rates and associated market rules related to the purchase of wholesale power in affected RTOs/ISOs, are unjust and unreasonable and, therefore, unlawful.[42] Such a showing requires the Commission to demonstrate that "the existing rates are 'entirely outside the zone of

[40] Voluntary contract-based regulation is at the core of the FPA: "[a]s we have explained elsewhere, the FPA "departed from the scheme of purely tariff-based regulation and acknowledged that contracts between commercial buyers and sellers could be used in ratesetting." *Morgan Stanley Capital Group Inc.*, 128 S.Ct. at 2738 *citing* Verizon Communications Inc. v. FCC, 535 U. S. 467, 479 (2002). As the Supreme Court has stated, "[t]he regulatory system created by the [FPA] is premised on contractual agreements *voluntarily* devised by the regulated companies; . . . ." *Permian Basin Area Rate Cases*, 390 U.S. 747, 822 (1968).

[41] The existing process for implementing reliability must run ("RMR") agreements demonstrate the limits of the Commission's authority with respect to determining whether resources should run. RMR Agreements ensure cost recovery for generation resources that have declared an intent to retire but which the RTO determines are necessary for reliability. Although the Commission sets RMR agreement rates, it is the RTO that decides that a specific generator is necessary to ensure system reliability. If that resource declines to bid into the market or threatens to retire and the RTO's tariffs and agreements authorize it to require the resource to operate, the RTO must offer the resource a just and reasonable rate to continue operating. The Commission's role in the process is limited to determining whether the terms of the RMR agreement are just and reasonable.

[42] See: FirstEnergy Serv. Co. v. FERC., 758 F.3d 346, 353 (D.C. Cir. 2014) (when instituting a Section 206 proceeding, the Commission has the dual burden of demonstrating that the existing rate is unlawful and that the proposed rate is just and reasonable).

reasonableness[.]"[43] Absent this showing, the Commission may not invalidate an existing rate. Thus, to implement the DOE NOPR, the Commission must first determine two things. First, the Commission must find that the reliable and resilient operation of the bulk power system, as that concept has been delineated in the DOE NOPR, is a necessary attribute of just and reasonable RTO/ISO market rules. Second, the Commission must find that the existing wholesale market rules in each affected RTO/ISO result in an unjust and unreasonable rate that fails to provide for procurement of wholesale electricity consistent with that attribute. The DOE NOPR does not make either showing.

On its face, the DOE NOPR provides insufficient evidence to support a finding that the reliable and resilient operation of the bulk power system, as described by the DOE NOPR, is a necessary attribute of just and reasonable RTO/ISO market rules. To begin with, as previously discussed, the DOE NOPR does not properly define resilience. Indeed, the first question the Commission asks commenters to address is, "[w]hat is resilience, how is it measured and how is it different from reliability."[44] It is impossible to determine if fuel security, as conceived in the DOE NOPR, is something that the affected RTOs/ISOs should be required to include in their market rules if there is no understanding of what resilience means and the how generation fuel procurement choices affect achieving whatever definition is ultimately adopted. In this regard, it is important to note that the related but distinct concept of "reliability" has been developed over a century of electric utility operations and is currently administered by NERC, an expert body authorized pursuant to statute.[45] NERC develops reliability rules through a thorough deliberative

[43] *NRG Power Mktg, LLC v. FERC*, at 11 n. 2 (*citing City of Winnfield v. FERC*, 744 F.2d 871, 875 (D.C. Cir. 1984)).
[44] *Request for Information*, Docket No. RM18-1-000 (issued Oct. 4, 2017).
[45] 16 U.S.C. § 824o.

process with multiple opportunities for stakeholder input and ultimate review by the Commission – not a condensed 60-day process with minimal opportunity for stakeholder and expert comment.[46]

In addition to failing to define resilience, the Commission also failed to evaluate whether existing market rules in the affected RTOs/ISOs that the Commission has found to be just and reasonable remain just and reasonable in light of the issues raised by the DOE NOPR.[47] While the DOE NOPR cites to potential retirements of "fuel-secure" generation as a resilience concern, the DOE NOPR fails to acknowledge evidence that NERC has not only found the bulk power system to be reliable, but that it has also found that the reliability and resilience of the bulk power system is, in fact, improving.[48] Furthermore, the DOE NOPR does not address existing efforts by the affected RTOs/ISOs to ensure reliability and resilience, nor explain why such efforts are insufficient to ensure a reliable and resilient bulk power system.

In its 2016 Annual Report, NERC found that the bulk power system is reliable.[49] With respect to resilience, NERC found in its State of Reliability 2016 Report that the bulk power system's resilience to severe weather has steadily improved, and that, in terms of avoided

[46] It is noteworthy that Secretary Perry told Congress that the DOE Proposal was a way to "start a conversation" about energy resilience and reliability. *See* Committee on Energy and Commerce Subcommittee on Energy Hearing, Oct. 12, 2017, *available at* https://energycommerce.house.gov/hearings/department-energy-missions-management-priorities/. If the purpose of the DOE Proposal was to begin a discussion, then adoption of a formal rule at this time would be inappropriate. A Notice of Inquiry would have been more appropriate vehicle to accomplish that.

[47] Notably, in order to make such a determination, the Commission would first be required to evaluate the market rules in each affected RTO and demonstrate that each RTO's individual market rules create an unjust and unreasonable result. *See e.g.*, *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 (2013) at PP 8, 178 (requiring each RTO to demonstrate that its existing tariff was not unjust and reasonable). Evaluating each affected RTO's market rules would be of particular importance given that fuel use among the nation's RTOs varies considerably. For example, while coal-fired generation currently accounts for approximately 55% of electricity generation in the Midcontinent Independent System Operator Inc. region, almost none of the electricity generated in the New York Independent System Operator region comes from coal. Thus, there is no evidence that the DOE Proposal would provide general benefits warranting blanket implementation.

[48] NERC 2016 Annual Report at 12 (issued Feb. 2017); NERC State of Reliability 2016, May 2016, at p 1.; NERC State of Reliability 2017, June 2017 at 5.

[49] NERC 2016 Annual Report at 12 (issued Feb. 2017).

generation outages, winter reliability and resilience improved in 2016 from prior years. NERC further noted that based on its severity risk index ("SRI") calculations,[50] no day in the 2015 calendar year made the top-ten list of most-severe days (as measured by SRI) between 2008 and 2015, "despite the extreme winter weather conditions in 2015 in parts of the Eastern Interconnection that rivaled the polar vortex of 2014."[51] NERC made a similar finding in its State of Reliability 2017 Report, finding that, for the second consecutive year, no day in the 2016 calendar year made the top-ten list of severe days dating back to 2008 despite the existence of days with "extreme weather conditions across North America," and that bulk power system resilience to severe weather continues to improve.[52] Thus, while the DOE NOPR correctly asserts that NERC has recognized the risk associated with retirements of so-called "fuel-secure" generation, the DOE NOPR provides no basis to suggest that existing market rules pose a real threat to grid reliability and resilience (however the latter term is ultimately defined).

The affected RTOs/ISOs have also adopted market mechanisms to ensure the reliable and resilient operation of the power grid and the DOE NOPR provides no evidence that those market rules fail to ensure the reliability of the bulk power system. For example, following the 2014 Polar Vortex, PJM reformed its capacity markets to ensure the availability of sufficient generation to withstand future storm events. Those rules, which do not discriminate among generation types, require generators to effectively guarantee their availability when called upon during extreme conditions or suffer severe economic penalties.[53] These changes were approved by the Commission as just and reasonable and are now in effect. The DOE NOPR does not

[50] The severity risk index is a measure of stress to the bulk power system in any day resulting from generation loss, transmission loss, or load loss components.
[51] NERC State of Reliability 2016, May 2016 at 1.
[52] NERC State of Reliability 2017, June 2017 at 5.
[53] *PJM Interconnection L.L.C.*, 151 FERC ¶ 61,208 (2015).

explain how these existing capacity market rules are insufficient to address DOE's reliability and resilience concerns. Absent a showing that PJM's existing market rules are unjust and unreasonable, the Commission cannot require PJM (or other affected RTOs/ISOs with similar rules) to adopt a new set of market rules along the lines of those proposed.

In addition, many of the affected RTOs/ISOs already have practices to address retiring generation required for reliability. The DOE NOPR provides no evidence that such practices have produced unjust and unreasonable rates. RTOs/ISOs are required to ensure the reliability of their systems and have rules in place to ensure that generation needed for the safe reliability of the bulk power system remains available and is compensated through Reliability Must Run ("RMR") or similar agreements. The DOE NOPR fails to articulate why existing tariff previsions relating to RMR and similar agreements are insufficient to address the concerns raised in the DOE NOPR – namely that "fuel-secure" generation specifically needed for reliability remains available.

In short, the DOE NOPR fails to demonstrate that the existing market rules in each affected RTO/ISO provide for an unjust and reasonable rate for the procurement of wholesale power necessary to guarantee the reliability and resilience of the bulk power system. Thus, until the Commission can make such a showing, the Commission lacks the authority under Section 206 of the FPA to alter existing market rules that it has previously found to be just and reasonable.

c. The DOE NOPR Has Not Been Shown To Be Just and Reasonable

Aside from the fact that the DOE NOPR provides no evidence that existing market rules

that address reliability in each affected RTO/ISO are unjust and unreasonable, the DOE NOPR's proposed solution to the unconfirmed problem would not result in a just and reasonable outcome because there is no nexus between the identified problem – system resilience – and the proposed solution.

If adopted, the DOE NOPR will result in increased wholesale electricity prices, because customers will be required to pay above-market costs to keep out-of-merit generation units operational. Subsidizing one class of generation over another threatens to seriously undermine the competitive wholesale electricity markets created as a result of Order Nos. 888 and 2000 and subsequent market specific refinements adopted by the Commission, threatening to undo one of the Commission's crowning achievements. Thus, there must be a demonstration that the increased cost to consumers and disruption to the markets is just and reasonable, and that there is a direct connection or "nexus" between the need identified and benefit provided for the targeted facility.[54] The DOE NOPR has provided neither.

E. Other

API has submitted numerous comments to various dockets supportive of competitive markets and outlining alternatives for moving forward. The most recent filing was in Docket AD17-11, attached herein. API also commissioned a report by The Brattle Group (also attached herein) that discusses how fuel-neutral attributes and reliability services procured, where appropriate, through market mechanisms can be a means to achieving reliability and resilience aims. As discussed in those documents, performance attributes that can provide

[54] *See*, e.g., *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 Fed. Reg. 43,294 (July 3, 2006), FERC Stats. & Regs. ¶ 31,222 (2006) at P 26 ("Order No. 679"), *order on reh'g*, Order No. 679-A, 72 Fed. Reg. 1152 (Jan. 10, 2007), FERC Stats & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007) (requiring a demonstration of a nexus between the incentive sought and the investment being made).

essential reliability services to maintain grid reliability can be defined in a fuel neutral manner and procured in a competitive system. In fact, some of them already are, such as regulation and reserve services. Recently, FERC has been making an effort to make more of these services market-based, for example, the proposed rule on primary frequency response.[55] API commends these efforts and hopes to see more essential reliability services become market-based.

FERC has exclusive jurisdiction over the interstate, wholesale markets for electricity. It has exercised that jurisdiction to create, to the largest extent possible, efficient and transparent markets. It should not allow intrusions into the markets that result in significant distortion of crucial price signals. FERC has been tasked with ensuring just and reasonable rates for consumers, and the wholesale competitive markets have been very successful in delivering on this mandate. We believe the Commission should defend the integrity of the wholesale markets that have delivered reliability at least-cost to such a large region of the country. Allowing the markets to work and to provide appropriate price signals is the best way to support the evolution of the grid while maintaining its continuing reliability.

III. Regarding Certain Noted Incidents

In justifying the rule, the DOE NOPR makes reference to several incidents as evidence of a need for on-site fuel supplies, and that natural gas cannot be relied upon. API here discusses the record on these incidents.

A. The Polar Vortex

[55] See FERC Docket No. RM16-6: https://elibrary.ferc.gov/IDMWS/docket_sheet.asp

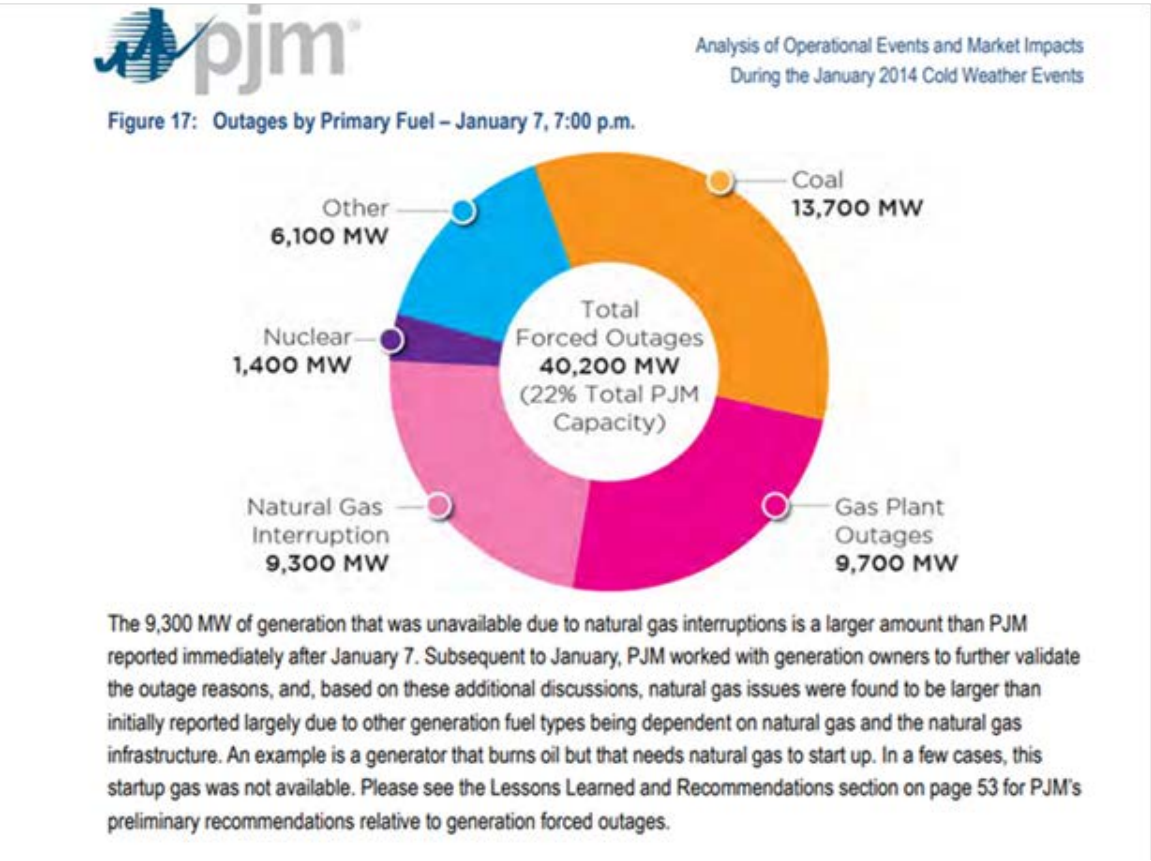
The IHS Markit reports contends that coal and nuclear are more reliable in events such as the 2014 Polar Vortex. According to the report, "The diversity in the generation portfolio allowed nuclear power plants and oil- and coal-fired power plants to back up and fill in for the natural gas–fired resource limitations.[56]" In addition, the report contends that natural gas can have excessive price spikes during extreme weather, stating "In the past three years, the delivered price of natural gas has remained uncertain and difficult to predict owing to numerous cyclical drivers and periodic events that have generated price spikes. On 21–22 January 2014, the delivered price of natural gas at key Northeast delivery hubs—Algonquin and Transco Zones 5 and 6—reached $55–120/MMBtu.[57]"

The report points to this one single price spike during the polar vortex event and fails to note that the lack of deliverability only applied to power generators without firm pipeline capacity and in areas (such as the Northeast) that lacked (and still lack) sufficient natural gas infrastructure. Though noted already in these comments it is worth repeating that *all* types of generation fuel sources had issues with the cold weather, even nuclear. According to testimony from Michael J. Kormos, Executive Vice President-Operations for PJM, coal outages during the Polar Vortex were "primarily due to multiple effects of the extreme cold weather on various components of coal handling and processing facilities. Frozen coal or wet coal, frozen limestone, frozen condensate lines, frozen fly ash transfer equipment, cooling tower basin freezing, and

[56] IHS Markit, "Ensuring Resilient and Efficient Electricity Generation, The value of the current diverse US power supply portfolio," September 2017, p 20.
[57] Id, p 13.

freezing of injection water systems for emissions control equipment were among the numerous causes of coal unit forced outages."[58]

Looking at the performance of natural gas-fired generation that had firm pipeline contracts, natural gas plants were more reliable than coal, according to a report by PJM on the Polar Vortex.[59]



Source: PJM

[58] See: https://www.gpo.gov/fdsys/pkg/CHRG-113shrg87851/html/CHRG-113shrg87851.htm
[59] See: http://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx

During the Polar Vortex, natural gas customers with firm transportation contracts received their natural gas. The limited incidents of natural gas supply interruptions were a result of interruptible contracts, not weather-related factors. The use of these contracts was an economic decision made by generation owners, not an indication of whether or not the natural gas supply infrastructure is reliable or not.[60]

The lesson from the Polar Vortex isn't that one fuel source is superior to another or flattens price spikes; it is that a host of non-fuel related issues caused unforced outages which imperiled the grid, and those issues were addressed by PJM in its capacity performance market reform.

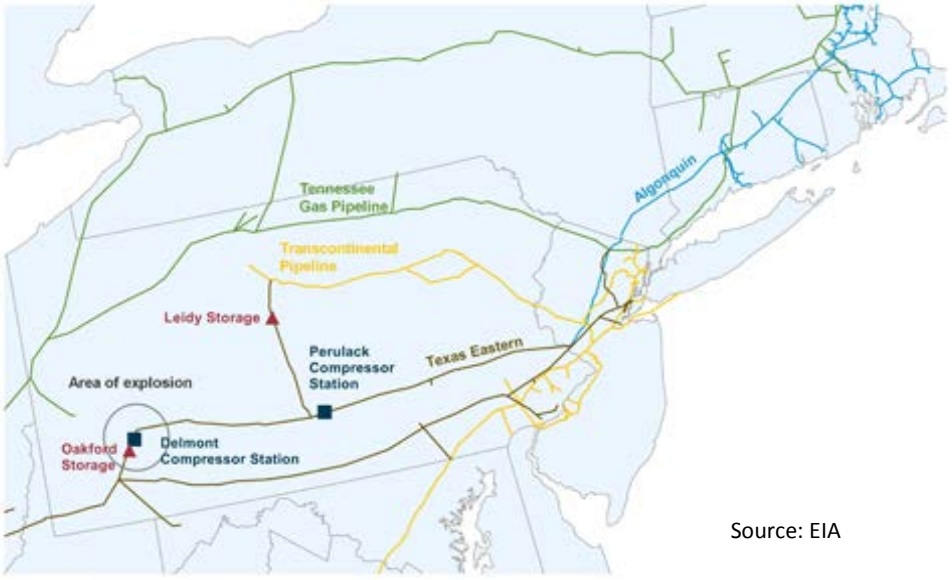
B. Texas Eastern Incident

The Texas Eastern Transmission natural gas pipeline failure is mentioned in the IHS Markit report several times with no details of the incident.[61] On April 29, 2016, an explosion and fire occurred on Spectra Energy's Texas Eastern Transmission ("Tetco") 30-inch natural gas pipeline in southwestern Pennsylvania (see map below), about 40 miles east of Pittsburgh.

[60] Partly, this economic decision was influenced by the inability of merchant generators to receive full cost recovery for higher priced firm transport contracts from the wholesale electricity markets. This issue has been and continues to be examined by the RTOs and FERC, and some pricing reforms have already been implemented. It should be noted that the affordability of firm natural gas transportation capacity improves dramatically for a natural gas-fired unit that's operated as a baseload resource, therefore, as more natural gas capacity operates in this mode, the more affordable firm transport contracts will get.

[61] IHS Markit, "Ensuring Resilient and Efficient Electricity Generation, The value of the current diverse US power supply portfolio," September 2017, pp 4&13.

Texas Eastern Pipeline (Northeast)



Source: EIA

The Delmont compressor has a capacity of 2.6 billion cubic feet per day (Bcf/d); however, the flows through the compressor averaged 1.4 Bcf/d in the preceding 30 days. The company declared a force majeure downstream of the Delmont compressor station and cut off flows between Delmont and the Perulack compressor station.

The pipeline grid in the area is flexible and Tetco used withdrawals from Leidy Storage, which enter at Perulack, as well as additional flows on its own parallel southern line, to compensate for reduced volumes on the damaged pipeline. In addition, pipelines to the north, such as Tennessee Gas Pipeline and Millennium, took on additional volumes to supply Algonquin and compensate for the lost flow. According to EIA, pipeline systems in the affected area have sufficient flexibility to use alternative routes to carry shale production to consumption

markets downstream of the affected section.[62] Four lines of Tetco run parallel in that area and one of the lines was put back in service in early May (about one week later). The entire pipeline capacity was back in service by November 1, 2016.[63]

In terms of price impacts, prices at the Texas Eastern M3 trading hub, which serves customers in the Mid-Atlantic region and downstream of the explosion, increased by 58 cents per MMBtu from $1.27 on April 28 to $1.85 on May 4, 2016. However, the interconnectedness of the natural gas pipeline network creates a liquid and fungible market that prevented the overall prices in the Mid-Atlantic region from spiking as shown in the table below from the EIA. The price increases in the New York market are in line with price increases experienced in other markets around the country. Moreover, by mid-May, despite the pipeline still being offline, prices at Texas Eastern M3 trading hub were trading at price ranges similar to the ranges experienced prior to the explosion.

Prices at Selected Hubs in 2016

Spot Prices ($/MMBtu)	**Thu, 28-Apr**	**Fri, 29-Apr**	**Mon, 02-May**	**Tue, 03-May**	**Wed, 04-May**
Henry Hub	1.80	1.80	1.85	1.96	1.99
New York	1.98	1.99	2.02	2.06	2.13
Chicago	1.76	1.75	1.80	1.91	1.96
Cal. Comp. Avg.*	1.85	1.85	1.89	1.98	2.03
Futures ($/MMBtu)					
June contract	2.078	2.178	2.042	2.086	2.141
July contract	2.253	2.322	2.218	2.254	2.296
*Avg. of NGI's reported prices for: Malin, PG&E Citygate, and Southern California Border Avg.					
Source: NGI's Daily Gas Price Index					

Source: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2016/05_05/#itn-tabs-2

[62] See: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2016/05_05/
[63] See: http://marcellusdrilling.com/2016/08/repair-work-on-exploded-texas-eastern-pipeline-in-pa-25-done/

C. The Aliso Canyon Outage

The IHS Markit report repeatedly refers to the Aliso Canyon storage facility outage of 2015 as an example of infrastructure risks that could negatively impact natural gas supply for electricity generation.[64] Aliso Canyon is an integrated natural gas utility-owned (Southern California Gas Company) storage facility configured such that it is tied to pipelines that directly serve market load. The Southern California Gas Company ("SoCalGas") uses the facility to provide natural gas demand balancing during winter natural gas demand peak periods and to supply natural gas for peaking generation units during the summer electrical peaks. Being at the end of line, geographically speaking, the entire SoCalGas system is dependent upon storage withdrawals to meet peak heating-day market demands. However, the natural gas pipeline and storage network is different in other regions of the U.S., where storage operators interconnect with multiple pipelines and other storage facilities from which they can access supply and transport natural gas.

State regulators decided to shut down the Aliso Canyon storage facility to avoid potential risk. There was no catastrophic failure of the facility or even a portion of the 114 wells. Only one well failed at the facility and so, in an abundance of caution, the other 113 were temporarily sealed until they could be tested to ensure their integrity and safety.[65] The steps taken in the Aliso Canyon incident provide an example of regulatory action to mitigate risk, but the consequences of such actions need to be clearly understood. However, in an emergency situation, state regulators have considerable flexibility regarding what actions to take.

[64] IHS Markit, "Ensuring Resilient and Efficient Electricity Generation, The value of the current diverse US power supply portfolio," September 2017, pp 4, 12, 20, 38

[65] Natural Gas Council study, "Natural Gas Council White Paper, Natural Gas Systems: Reliable & Resilient," July 2017.

D. Hurricanes

The DOE NOPR cites hurricanes as evidence of a need to act to subsidize 'fuel-secure' resources. The natural gas system is not particularly vulnerable to weather-related events. Natural gas pipelines are predominantly underground and protected from the elements and thus are very resilient in the face of extreme weather events. The wide geographic dispersion of production areas further reduces the vulnerability of the supply to localized weather events. Additionally, most natural gas production now occurs onshore, and as a result, the potential for hurricane impact on natural gas production has dramatically diminished.[66]

Looking at the recent severe hurricanes, electricity access issues were due mainly to downed transmission lines and not from any sort of fuel inadequacy. When Hurricane Harvey hit Texas, the strongest hurricane to make landfall in the state since 1961, natural gas continued to provide for residents' electric and thermal needs. Electricity outages that occurred can be largely attributed to damage to the electric transmission and distribution systems.[67] According to EIA, Harvey temporarily downed hundreds of high-voltage transmission lines, including six 345 kV lines and more than two hundred 69 kV-128 kV lines.[68]

On-site fuel storage provided no advantage in maintaining electric delivery. In fact, in some facilities natural gas was able to deliver where other fuels were not - NRG Energy's report to the Public Utilities Commission of Texas ("PUCT") referenced two coal fired units, W.A.

[66] Ibid.
[67] For example, see: http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/47552_9_953419.PDF
[68] See: https://www.eia.gov/todayinenergy/detail.php?id=32892

Parish Unit 5 and Unit 6, as having to switch to natural gas for the first time since 2009, because heavy flooding prevented coal delivery from its on-site storage facility.[69]

Nuclear plants had similar difficulties during the recent hurricanes as nuclear power plants are required, for safety reasons, to reduce output in advance of hurricane force winds and to shut down at least two-hours prior to wind speeds reaching 70-75 miles per hour. In Florida, both of the state's nuclear power plants were adversely affected by Hurricane Irma, despite having plenty of fuel. The Turkey Point plant shut down totally when the hurricane arrived on September 10th while the St. Lucie plant was forced to reduce power levels. The plants did not return to full operation until September 18th, eight days after the event.[70]

More than just providing adequate fuel for central power stations, innovative, natural gas-fired distributed energy technologies and Combined Heat and Power Systems provided necessary backup power to businesses and hospitals in hard hit areas, because the natural gas kept flowing. For example, a company called Enchanted Rock, which designs systems to provide on-site natural gas generation at commercial facilities, provided necessary backup power for convenience stores and gas stations in the storm's immediate aftermath.[71] So, while many businesses in Texas were cut off from the electric grid due to destroyed infrastructure, the system that feeds gas-fired generation remained operational.

[69] NRG Energy, "Re: Project 47552 – Issues Related to the Disaster Resulting from Hurricane Harvey." Sent to the Public Utilities Commission of Texas. September 26, 2017. P. 31
http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/47552_30_955924.PDF
[70] See: EIA, https://www.eia.gov/todayinenergy/detail.php?id=32992
[71] See: https://microgridknowledge.com/microgrids-and-hurricane-harvey/

E. The IHS Markit Study and the DOE NOPR Rationale

There are several flaws in the IHS analysis and in the assumptions used to argue that this rule is necessary. These include, but are not limited to:

- The causes of electricity outages are mischaracterized. Most outages are related to transmission and distribution infrastructure damage due to weather events and not to fuel disruptions. An analysis by Rhodium Group shows that between 2012 and 2016, fuel supply disruptions caused less than 1 percent (0.00007% to be exact) of all substantial power outages.[72]
- Both IHS Markit and the DOE NOPR use the term 'baseload' as pertaining to a certain type of generation facility. As noted in the DOE staff report and summarized so succinctly by one of the lead authors, "Baseload generation is an operational mode, not a type of power plant."[73]
- The economic benefits pointed to in the IHS Markit study are based on the past three years of data rather than being based on forecasts which would include increased gas supply. In fact, EIA predicts that natural gas supplies will continue to increase.[74]
- The assumption is that subsidized coal plants will continue to remain in operation for decades and will be replaced by new coal capacity additions. Many coal plants will likely shut down over the next few decades simply due to age and increasing maintenance costs, and probably will not be replaced by new coal plants.

[72] The Rhodium Group, "The Real Electricity Reliability Crisis," October 3, 2017.
[73] Alison Silverstein in Utility Dive: http://www.utilitydive.com/news/silverstein-if-id-written-the-doe-grid-study-recommendations/506274/
[74] See EIA Annual Energy Outlook 2017: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2017&cases=ref2017&sourcekey=0

- IHS Markit and the DOE NOPR assume that states relying on the wholesale electricity markets are producing inferior results with respect to generation cost recovery when compared to those produced by states with regulated generation cost recovery, and yet the data does not support this. Based on EIA data regarding coal plant retirements, of the coal capacity that retired between 2002 and 2016, 21,147 MW were in deregulated states and 34,796 MW were located in states with traditional cost-of-service regulation.[75]
- The IHS Markit study assumes that all early retirements of coal/nuclear plants are replaced by new natural gas plants instead of being replaced by greater utilization of existing natural gas plants and uprates to existing resources of all types, which are far more cost-effective solutions.
- IHS Markit and the DOE NOPR argue that 'premature' coal/nuclear retirements are due to government policies which distort the markets. However, the recent DOE Staff Report found that such retirements are mostly due to the advantaged economics of natural gas generation.[76] That economic advantage is not due to subsidies but due to the competitive nature of the natural gas industry which has spurned technological advancement and created efficiencies that have boosted the supply of natural gas to previously unseen levels at low-cost.

The solution proposed in the DOE NOPR is based on assertions of a need to maintain a certain amount of "fuel-secure" generation in order to address an electric grid reliability and resiliency "emergency," but the evidence presented does not support this.

[75] EIA, "Preliminary Monthly Electric Generator Inventory," September 26, 2017. https://www.eia.gov/electricity/data/eia860M/
[76] DOE, "DOE Staff Report to the Secretary on Electricity Markets and Reliability," August 2017.

IV. CONCLUSION AND RECOMMENDATIONS

As the nation's electricity system continues to evolve in the face of both technological change and state-level policy-making, API recommends the Commission reject adoption of the DOE NOPR and continue to foster competition at the wholesale level. FERC should encourage market-based solutions to any identified resilience concerns. FERC's solutions should focus on just and reasonable rates with non-discriminatory treatment of all assets.

It has been said that the current wholesale power markets are not, in fact, free markets. Imperfection of the market design is not a reason to give up on market structures, which have, and will continue to provide, better long-term outcomes. The Commission already has a docket examining market design issues and price formation,[77] and has made several excellent market design reforms through that effort. The Commission should continue to focus effort on that docket.

API advocates for fuel-neutral, competition-based policies and market structures. We commissioned the Brattle report on Diversity of Attributes (attached herein) in order to outline a point of view where electric grid reliability can be achieved through focusing on the attributes needed to provide the services required to maintain electric grid reliability. Reliability *and resilience* can be achieved through market constructs and may, in fact, already be achieved through the existing market constructs, but as noted in these comments, resilience first needs to be properly defined and, the services required to maintain resilience need to be

[77] See FERC Docket AD14-4, "Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators."

identified, all before the Commission can determine whether there is a problem, let alone propose solutions if a problem is identified.

The Commission should therefore, tackle the question of resilience, first by defining it and the necessary services, then determining whether or not the existing market constructs are sufficiently robust in incentivizing resiliency. After that, if the Commission finds that there is an issue and the markets are not incenting the appropriate services, or not adequately compensating them, only then should an effort be undertaken to develop additional market-based, fuel-neutral solutions.

Because there are so many complex questions, both policy and legal, surrounding the DOE NOPR goals, it requires a careful and thoughtful process conducted in a collaborative manner. This current short proceeding has not provided that process. API is supportive of continued engagement with the Commission to assist in developing methods for ensuring grid reliability and resilience that can work to provide security for both the electric and natural gas systems.

Respectfully submitted,

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AMERICAN PETROLEUM INSTITUTE

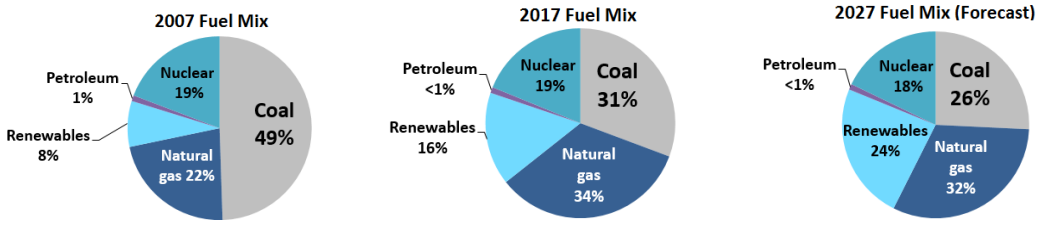
Congress of the United States, House of Representatives
Committee on Energy and Commerce
Subcommittee on Energy

"Part II: Powering America: Defining Reliability in a Transforming Electricity Industry"

Testimony of:
Marty Durbin, Executive Vice President and
Chief Strategy Officer
American Petroleum Institute
October 3, 2017

Chairman Upton, Ranking Member Rush and members of the subcommittee, thank you for the opportunity to testify today. My name is Marty Durbin, and I am Executive Vice President and Chief Strategy Officer for the American Petroleum Institute (API).[1] The increased use of natural gas in electric power generation has not only enhanced the reliability of the overall system, but it has also provided significant environmental and consumer benefits. The abundance, affordability, low-emissions profile and flexibility of natural gas and natural gas-fired generating units make natural gas a fuel of choice. API understands that the bulk power system will continue to rely on multiple fuels, including natural gas, nuclear, coal, hydro, wind and solar, as projected by the Energy Information Administration.

[1] API is the only national trade association representing all facets of the oil and natural gas industry, which supports 10.3 million U.S. jobs and nearly 8 percent of the U.S. economy. API's more than 625 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and API member operations, and investments have added billions of dollars in economic value throughout the nation.



Source: 2017 Annual Energy Outlook, U.S. Energy Information Administration

We also agree that energy policy should be focused on ensuring the reliability and resilience of the nation's electrical grid at a reasonable cost, which reason and research tell us can be best achieved by allowing markets to determine the fuel mix of the generation portfolio.

What is Reliability?

Reliability means the continued operation of the electric grid and is achieved through adequate amounts of "essential reliability services" or "attributes," which keep the electric grid in balance. In general, however, reliability goes beyond just the operational aspects of the grid and extends to the entire national electric system and the ability of its constituent parts to operate. This includes long-term reliable access to fuel for generators, the stability of the fuel supply, the abundance of the resource supply, where it's sourced, the reliability of its production and transportation, and its long-term affordability.

Grid operators have the responsibility of maintaining the operational reliability of the electric grid. Generation owners are responsible for maintaining the integrity of their generating equipment and for ensuring they have adequate fuel supply contracts (and contracts for other operating supplies, such as water) and a portfolio of options in place so they have the ability to meet all their capacity and energy obligations under a wide range of scenarios. The natural gas industry has responsibility for ensuring the reliable operation of the natural gas supply chain and that customers receive their contracted commodity.

It is clear that natural gas generation has exceptional performance characteristics and attributes that can provide a full range of essential reliability services needed by the electric grid to maintain reliability. One important advantage of natural gas generation is its ability to ramp quickly and to cycle on and off in a short amount of time to meet the more rapidly changing levels of load due to increasing amounts of variable renewable energy resources on the grid. With respect to overall reliability, natural gas as a fuel supply is also exceptionally reliable, and the natural gas industry has a long history of providing reliable and continuous supplies to its customers, even in times of adversity, such as extreme weather events.

As noted in a report from the Massachusetts Institute of Technology:[2]

> *"The natural gas network has few single points of failure that can lead to a system-wide propagating failure. There are a large number of wells, storage is relatively widespread, the transmission system can continue to operate at high pressure even with the failure of half of the compressors, and the distribution network can run unattended and without power..."* [3]

In addition to pipeline contracts, dual-fuel capability, and other logistical factors, the geographically diverse production of natural gas and nationwide, interconnected pipeline network that transports the large majority of natural gas, significantly enhances system reliability and redundancy. Further, fuel supply risk is reduced as a result of numerous storage facilities across the nation. This extensive national network of natural gas storage facilities, many underground, makes them much less susceptible to extreme weather events and other natural disasters. Moreover, the existence of many operators, each

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[2] Natural Gas Council, Natural Gas Systems: Reliable & Resilient, July 2017, pages 6.

[3] *MIT, Lincoln Laboratory, "Interdependence of the Electricity Generation System and the Natural Gas System and Implications for Energy Security," May 15, 2013)*

making individual decisions, creates a diversity of operating practices and decisions, decreasing the likelihood of large-scale, multisystem outages.

Natural Gas Generation Is Reliable

With respect to the reliability attributes of generation facilities, a recent PJM system reliability study states "Portfolios composed of up to 86 percent natural gas-fired resources maintained operational reliability.[4] Thus, this analysis did not identify an "upper bound for natural gas."[5]

Reliability is derived from a diversity of attributes in generation, not a diversity of fuel sources. PJM's report notes, "More diverse [fuel] portfolios are not necessarily more reliable."[6]

Essential components of reliable supply resources include the ability for that resource to ramp up and down quickly; to keep pace with demand; to provide frequency response and reactive power to maintain grid stability; to provide energy consistently at baseload levels; to maintain fuel security through storage or transport contracts; to possess multiple sources of fuel; and to utilize domestically produced fuel. Natural gas generation provides all of these attributes. Figure 1 illustrates the reliability attributes of various resources.

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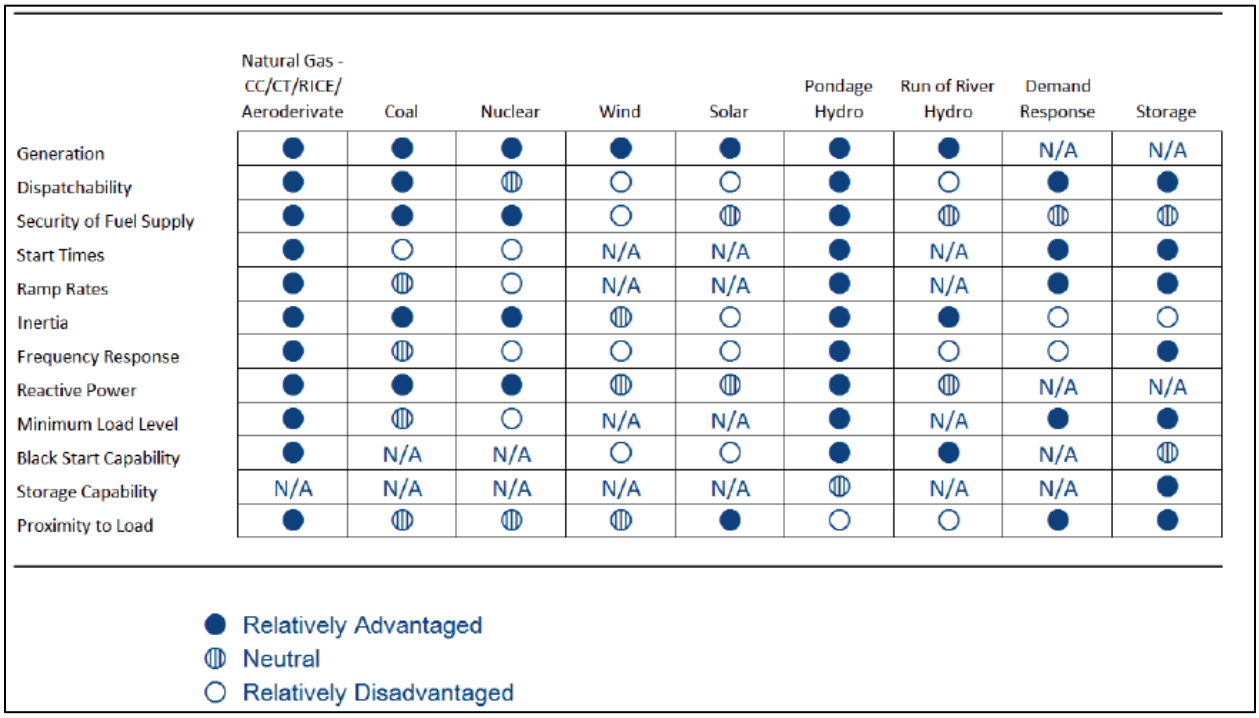
[4] PJM, "PJM's Evolving Resource Mix and System Reliability," March 2017
[5] Ibid
[6] Ibid

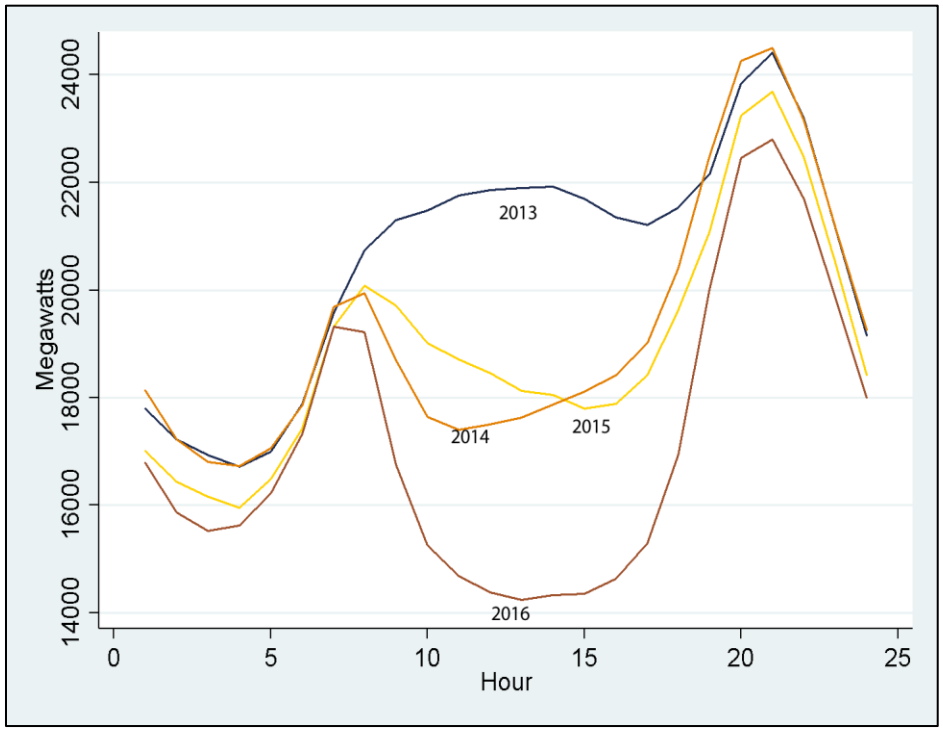
Figure 1. Reliability Attributes and Technology



Source: Brattle Group, Diversity of Attributes

A prime example of how ramping and cycling abilities are needed to maintain grid stability can be found in California. Figure 2 plots average net load profiles that have been averaged across seven days around March 31 to smooth out daily variations. Net load refers to load minus variable renewable generation and represents the load needed to be served by dispatchable generation. Due to the large amount of variable renewable generation, primarily solar, on the California grid, there is a frequent need for flexible dispatchable generation to be able to quickly ramp up and down in response to changes in net load, particularly when the sun starts to get low in the sky while the system is still in peak load conditions.

Figure 2. California Hourly Net Load - March 28 to April 3, 2013-2016



Source: Meredith Fowlie, The Duck has Landed.

Other regions are also starting to see higher penetrations of variable renewable energy resources and natural gas generation's flexibility will be increasingly needed to maintain grid reliability and stability.[7]

Natural Gas Supplies are Reliable and Resilient

Included in the appendix is a recent Natural Gas Council white paper highlighting the historical reliability of natural gas:

> **"The physical operations of natural gas production, transmission and distribution make the system inherently reliable and resilient. Disruptions to natural gas service are rare. When they do happen, a disruption of the system does not necessarily result**

[7] Wind generation in ERCOT is reaching almost 40% of total demand at times; https://www.platts.com/latest-news/electric-power/houston/ercot-sets-record-wind-output-friday-21339374 and in SPP over 50%: https://www.spp.org/about-us/newsroom/spp-sets-north-american-record-for-wind-power/

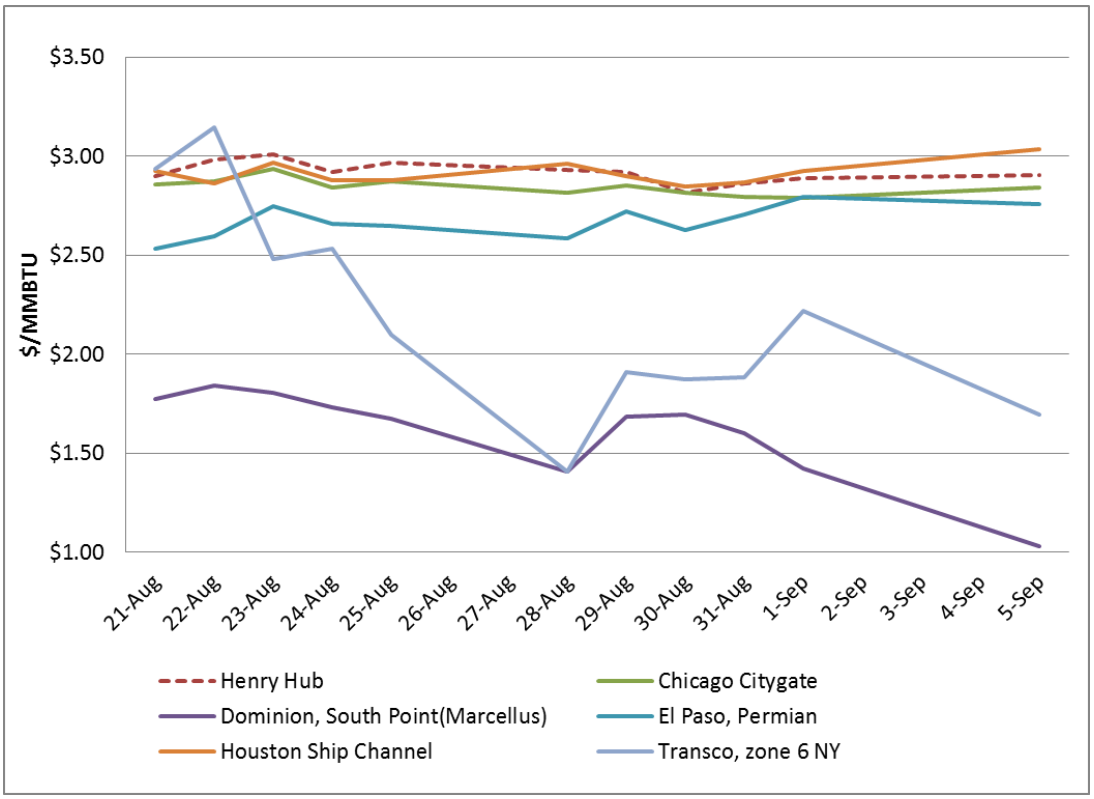
in an interruption of scheduled deliveries of natural gas supply because the natural gas system has many ways of offsetting the impact of disruptions."[8]

The extensive national pipeline system prevents local disruptions, such as construction and maintenance or extreme weather events, from creating widespread disruptions. Also adding to the system's integrity and redundancy is the widespread use of compressor units powered by natural gas, rather than electricity, which significantly enhances the ability to move supply even during power outages.

Hurricane Harvey offers a clear example of the resiliency of the modern natural gas system. While natural gas systems were shut down in the Houston area and large parts of the gulf, the geographic diversity of the natural gas operations kept supplies flowing and prices stable. This is highlighted in the Bloomberg article included in the appendix and in Figure 3 below, which shows stable natural gas prices at several hubs for the weeks affected by Hurricane Harvey.

[8] Natural Gas Council, Natural Gas Systems: Reliable & Resilient, July 2017, pages 6.

Figure 3. U.S. Natural Gas Prices



Source: Platts

The Polar Vortex during the winter of 2014[9] is used by some as a cautionary tale against placing too much reliance on natural gas and an argument for increased on-site fuel. The fact, however, is that during the Polar Vortex, those with firm transportation contracts received their natural gas. It isn't commonly known that the limited incidents of natural gas supply interruptions were a result of interruptible contracts, not weather-related factors. The use of these contracts was an economic

[9] Polar Vortex-like events include: January 6th though January 9th, 2014; January 22nd through January 28th, 2014; February 9th through February 13th; and February 25th through February 28th, 2014

decision made by generation owners, not an indication of whether or not the natural gas supply infrastructure is reliable or not, as is often implied.[10]

The Polar Vortex winter presented broad challenges and was a learning experience for all forms of generation.[11] As a result, many regions took steps to ensure similar issues would not reoccur. For example, PJM developed its Capacity Performance plan, which requires generators to be able to deliver energy when emergency conditions exist. Generators are rewarded for meeting the increased standards for deliverability and are penalized when they do not. PJM puts a premium on resources that are dependable and available. As a result, more natural gas-fired plants have secured firm transportation contracts or added dual fuel capabilities to ensure reliability.

Government regulation and industry standards codify another layer of resiliency. The Transportation Security Administration (TSA) Pipeline Security Guidelines (Guidelines) support the development and implementation of a risk-based corporate security program by pipeline operators to address and document their organization's policies and procedures for managing security-related threats, incidents, and responses. The Guidelines include progressive security measures facilities may use, based on the characteristics of their particular facility and the threat level determined through their risk assessment. Under the guidelines, operators should develop and implement a corporate security plan customized to most effectively mitigate security risks to the company's critical assets. Such plans are comprehensive in scope; systematically developed; and risk-based, reflecting the security environment.

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[10] Partly, this economic decision was influenced by the inability of merchant generators to receive full cost recovery for higher priced firm transport contracts from the wholesale electricity markets. This issue has been and continues to be examined by the RTOs and FERC, and some pricing reforms have already been implemented.

[11] All types of generating units experienced outages for various cold-related issues, for example, frozen coal piles and cooling water systems. See PJM reports: https://www.gpo.gov/fdsys/pkg/CHRG-113shrg87851/html/CHRG-113shrg87851.htm and http://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx

The many guidelines and standards that govern natural gas operators' management of cybersecurity include: TSA Pipeline Security Guidelines, National Institute of Standards and Technology (NIST) Framework for Improving Critical Infrastructure Cybersecurity, Department of Energy (DOE) Cybersecurity Capability Maturity Model (C2M2), ISA/IEC 62443 Series of Standards on Industrial Automation and Control Systems Security, INGAA Control Systems Cyber Security Guidelines, and API Standard 1164 Pipeline SCADA Security. Also, information sharing of cyber threats is another key defense through the Oil and Natural Gas Information Sharing and Analysis Center (ISAC) and through the Department of Homeland Security's National Cybersecurity and Communications Integration Center (NCCIC) and Industrial Control System Computer Emergency Readiness Team (ICS-CERT).

In addition, the National Critical Infrastructure Prioritization Program (NCIPP) categorizes high priority critical infrastructure as either level 1 or level 2 based on the consequences to the nation in terms of four factors—fatalities, economic loss, mass evacuation length, and degradation of national security. To date, no oil or natural gas assets are designated as level 1 (the highest level).[12] Additionally, the Presidential Policy Directive (PPD) 21 (2013) required the Department of Homeland Security to identify critical infrastructure "where a cybersecurity incident could reasonably result in catastrophic regional or national effects on public health or safety, economic security, or national security." The PPD 21 list of "Section 9 Critical Infrastructure at Greatest Risk" does not include any upstream natural gas companies or assets.[13] For a more detailed discussion of natural gas system reliability and resiliency, please see the recent Natural Gas Council white paper on the topic included in the appendix.

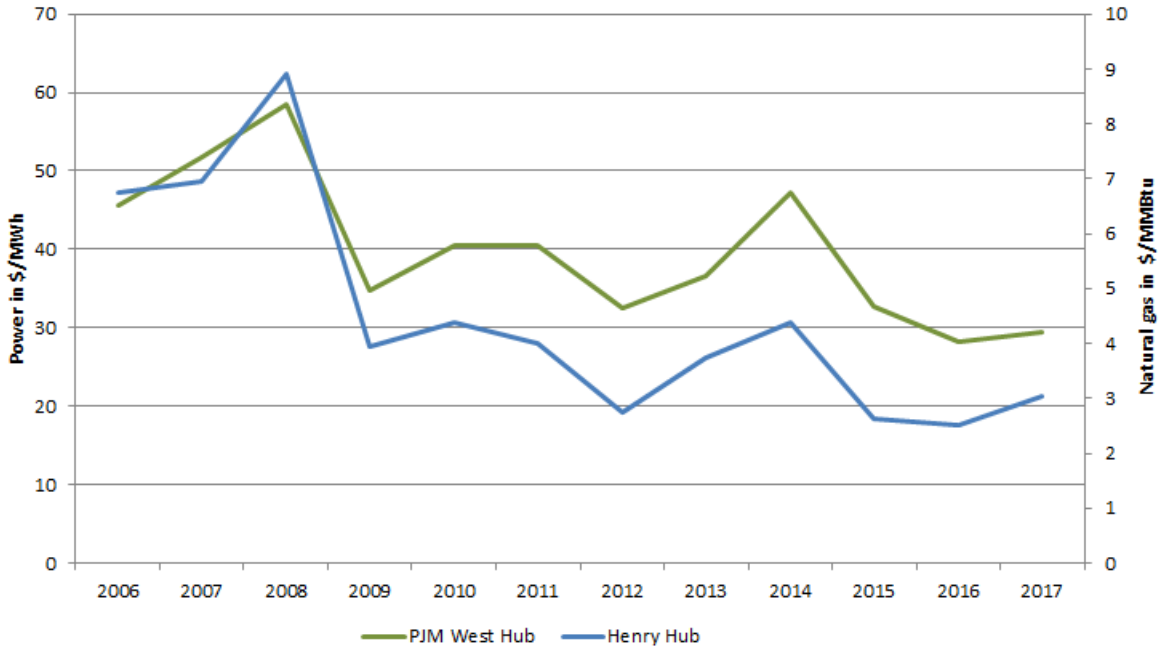
[12] The list of L1/L2 infrastructure is classified, but the Department of Homeland Security has confirmed that no oil and natural gas assets are on the list.
[13] The list of "Section 9" entities is classified; however, API is not aware of any member companies that are on the list.

Abundant Natural Gas Reduces Electricity Costs

Natural gas-fired power plants are one of the most cost-effective forms of generation to build and operate. This has resulted in significant wholesale electricity cost reductions. As an example, since 2008, average annual wholesale power prices in PJM have decreased by almost 50 percent. Market forces have driven these price reductions, thereby reducing costs for consumers and driving additional economic activity.

Figure 4 shows the PJM West Hub electricity prices along with Henry Hub natural gas prices over the past twelve years.

Figure 4. Wholesale Power and Natural Gas Prices

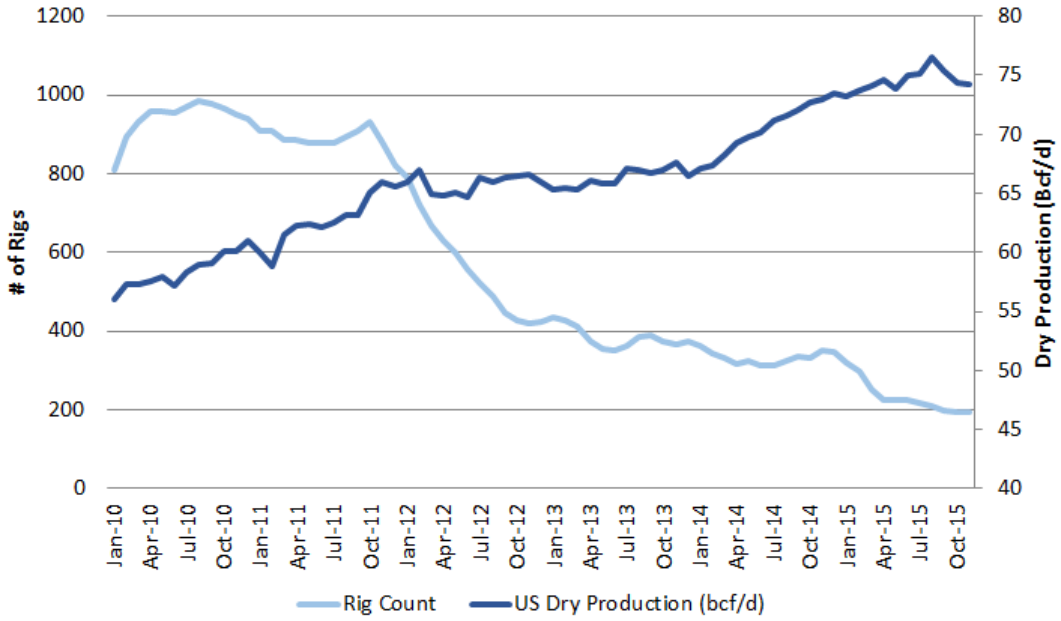


Source: NYMEX and ICE

Competitive markets work by eliminating inefficiencies in the system, thereby driving down prices for customers. Competitive forces in natural gas markets have resulted in the shale gas boom currently providing numerous benefits to the nation. Over the last decade, the natural gas industry has enhanced

efficiencies and reduced costs. As shown in Figure 5, rig counts have fallen drastically while natural gas production has continued to rise. This is due to technological innovations driven by market competition. The same market forces simultaneously improve reliability and resiliency as those become necessary attributes in order to remain competitive.

Figure 5. Natural Gas Production Efficiency



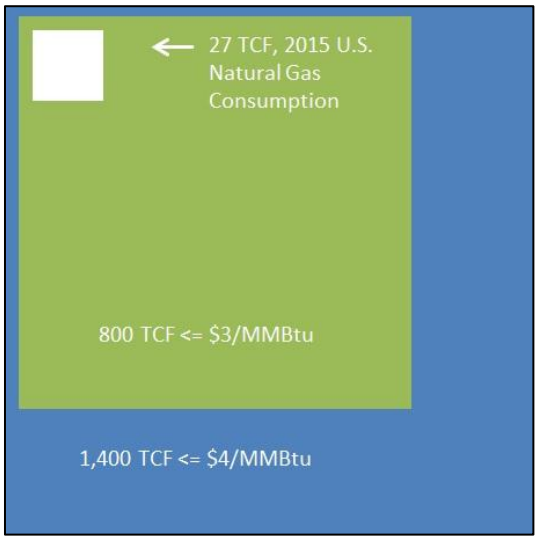
Source: EIA and Baker Hughes

These market-driven increases in efficiencies have resulted in extensive new supplies of natural gas being developed at lower prices than before, further increasing the reliability and resiliency of the supply.

The economics of lower commodity price production levels are measured in IHS-Markit's 2016 report "Shale Gas Reloaded: The Evolving View of North American Natural Gas Resources and Costs." The report identifies 1,400 Tcf of natural gas in the U.S. Lower 48 and Canada that is economically and

technically recoverable at breakeven prices of $4/MMBTU with more than half (approximately 800 Tcf) of this resource base recoverable at prices of $3/MMBTU.[14]

Figure 6. Recoverable Reserves



Source: Data from EIA and IHS-Markit, February 2016

The size of IHS-Markit's resource base and their cost of recovery suggest two conclusions. First, there is sufficient natural gas to meet future demand, even when exports are taken into account. Specifically, the estimated production potential, even at the $3/MMBTU level (roughly 800 Tcf) dwarfs U.S. natural gas demand and expected exports. In 2015, total U.S. natural gas consumption was about 27 Tcf, and EIA forecasts natural gas consumption to range between 32.27 Tcf in the Reference Case to 38.33 Tcf by 2050 in the High Oil and Gas Resource and Technology (High Resource) scenario.[15] Adding natural gas exports to the story doesn't materially change the answer as those do not cross 1 Tcf in any scenario by 2050,[16] which is the last year of EIA's forecast.

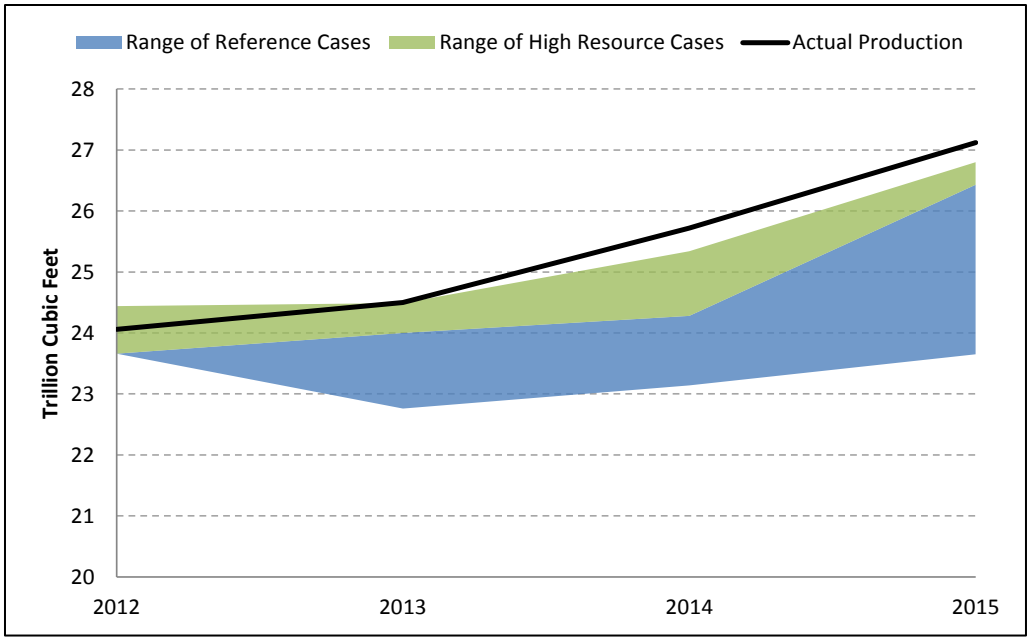
[14] IHS-Markit, "North America's Unconventional Natural Gas Resource Base Continues to Expand in Volume and Decrease in Cost." February 23, 2016.
[15] EIA Annual Energy Outlook 2016, Table: Energy Consumption by Sector and Source.
[16] Ibid

This massive supply figure and relatively low level of exports can, according to IHS, assuage any concerns about export demand pulling prices upward. Clearly, the U.S can be well positioned to be a critical global supplier of natural gas to our allies in Europe and elsewhere and can do so without affecting domestic affordability.

Second, the 800 Tcf of natural gas production that is economical in the $3-$4/MMBTU range (as shown in the IHS-Markit report) explains the sustained low price forecasts in the EIA Annual Energy Outlook's High Resource case. Because the industry has shown its ability to maintain, and even increase, high production levels in lower commodity price environments, the High Resource case price series showing sub $4/MMBTU in the foreseeable future is likely the most representative of current market dynamics.

Each year, for the AEO, EIA conducts a base case analysis and then several alternative scenarios, one of which is the High Resource scenario. In the past few years, EIA has underestimated the impact of technology on natural gas production and the industry's ability to lower production costs. Consequently, the EIA has underestimated the size of the resource base in the High Resource case, as well as the Reference case. Figure 7 compares actual U.S. natural gas production to a range of EIA reference cases in previous AEOs as well as EIA's the High Resource scenario.

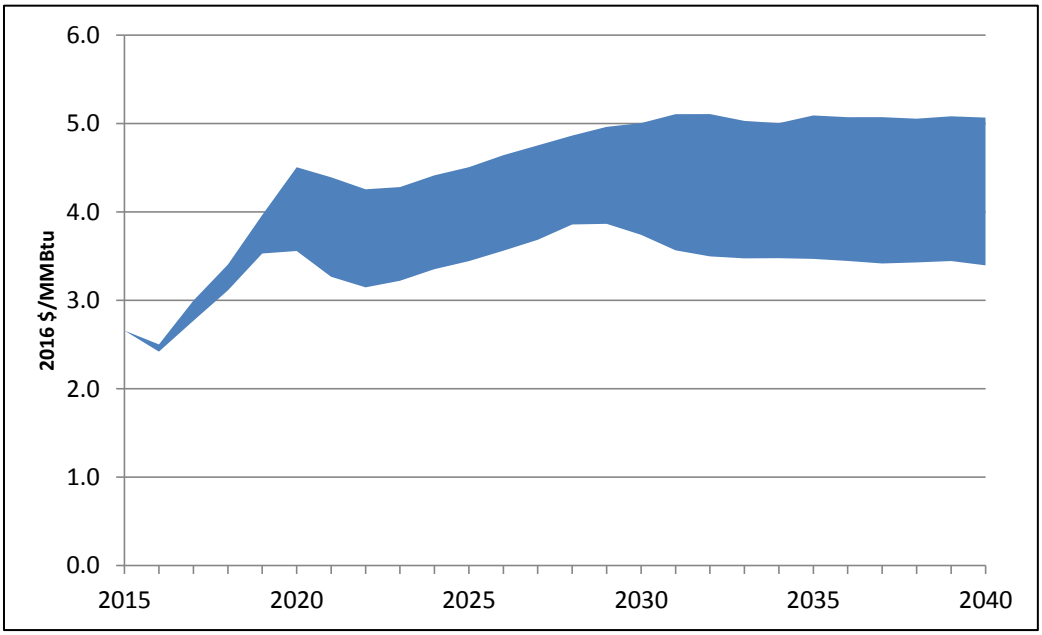
Figure 7. U.S. Dry Natural Gas Production, AEO 2012-2015 Projections & Actuals



Source: EIA, Annual Energy Outlooks 2012 – 2015; Actual Production

Figure 8 maps the corresponding price trajectories for both EIA's Reference Case and High Resource scenario (the former making the upper bound and the latter the lower bound of the chart). The lower bound of the series shows a steady natural gas price forecast within the $3-$4/MMBTU range, which has proven to be sustainable due to the industry's track record of reducing production costs.

Figure 8. EIA AEO 2017 Projection: Henry Hub Spot Price (Reference Case and High Supply Case Range)



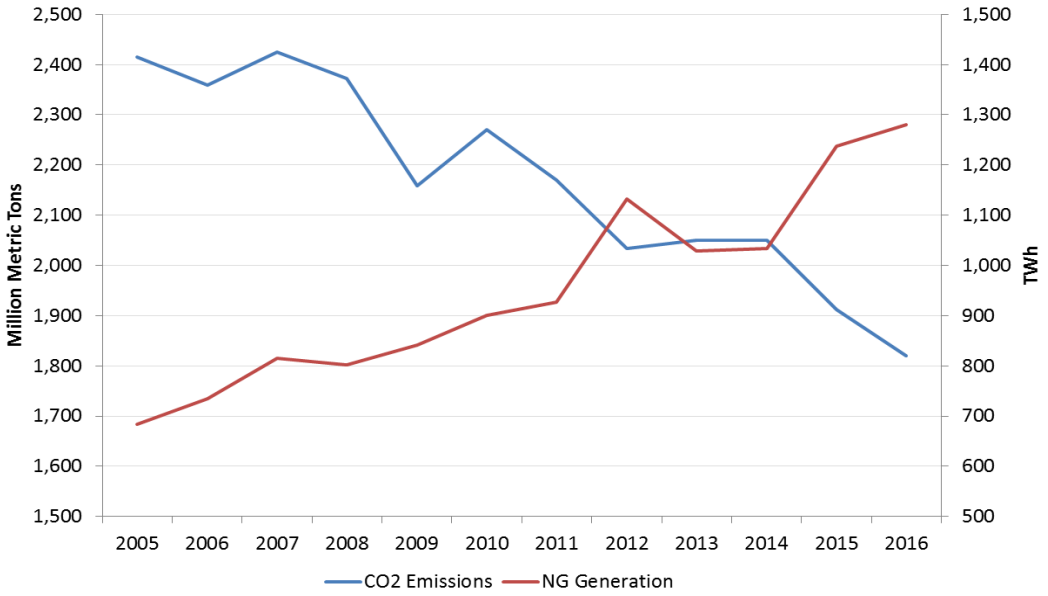
Source: EIA, Annual Energy Outlook, 2017

Natural gas is well positioned to provide a reliable and low-cost source of fuel for electric generation for the foreseeable future, according to both IHS and EIA, and many other natural gas resource base experts.

Natural gas abundance also reduces emissions. Total U.S. electrical sector emissions are down below 1990 levels mainly due to the influx of natural gas generation (1,831 million metric tons in 1990).[17]

[17] EIA

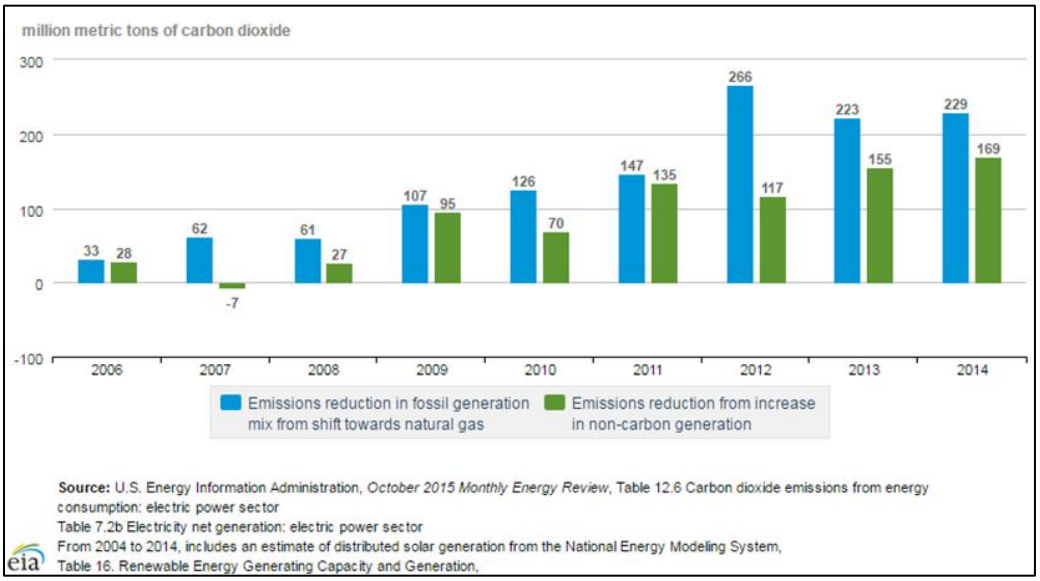
Figure 9. U.S. Electric Sector CO2 Emissions and Natural Gas Generation



Source: EIA, Monthly Energy Review August 2017

According to EIA data, 60 percent of the CO_2 reductions in the electric power sector from 2005 to 2016 have been the result of fuel switching from higher emission generation to natural gas generation. Figure 10 shows the emission reductions from US electric generation that can be attributed to two different economic responses. The blue bars are emissions reductions achieved through shifting from other fossil fuels to natural gas generation. The green shows emissions reductions from increases in non-carbon generation. It is evident from recent historical trends that both responses are important drivers for electric sector emissions reductions, and that natural gas has and will continue to lead the way as it has done while reducing costs to consumers and while increasing the supply base, all without substantial government subsidies.

Figure 10. Electric Sector CO2 Emissions Reductions



DOE Recommendations

Some of the recommendations in the recent DOE Staff Report on Electricity Markets and Reliability were directed at FERC, especially with regard to wholesale electricity market reforms. API has submitted comments to FERC dockets on numerous occasions, discussing the need to adapt wholesale electricity markets to the changing economics of the electric industry and the nature of the electric grid. The most recent comments were in response to a technical conference in May 2017 on state policies and these policies' effects on wholesale electricity market price formation. In those comments, API once again outlines a series of principles that should be adhered to in order to preserve and promote the much-needed and benefits-creating competitive nature of the wholesale electricity markets. These principles are:

- Efficient market design will result in price formation that matches the demand for essential reliability services and performance attributes with the supply.

- Energy market price caps should be lifted to a level sufficient to allow efficient price formation. Concurrent with this, FERC should require each RTO/ISO to settle all smart meters in its footprint on a five-to-fifteen minute basis, which would allow consumers and their retailers to react to the price information in the real-time market thus enhancing demand sector elasticity.
- Ideally, market-clearing prices should reflect the costs of all units that are called to operate, including start-up and no load costs.
- The market-clearing price should reflect the costs of all units that run including block-loaded or ramping units, operating reserves, units providing voltage support or reactive power, or units run in response to reliability events or needs.
- Prices in energy and ancillary service markets should reflect shortage or emergency situations to provide needed investment signals and to reinforce real-time reliability in the face of increased variable output of intermittent renewables.
- Price formation should enable all reasonable and supportable costs incurred in unexpected circumstances, particularly when such costs are incurred in response to operator directives.[18]

Much has already been done with respect to gas-electric coordination through the FERC's Natural Gas – Electric Coordination initiative.[19] All of the changes agreed to in that process by both the electric and natural gas industries have now been implemented. For example, the natural gas industry added additional opportunities for customers to access natural gas pipeline capacity throughout the day. Talks between the two industries continue to progress and, as mentioned earlier, it is important that any further changes are market-based and benefit from the free and competitive market nature of the natural gas system, and are fully supported by both industries.

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[18] Comments of the American Petroleum Institute, FERC Docket No. AD17-11-000, June 22, 2017.
[19] https://www.ferc.gov/industries/electric/indus-act/electric-coord.asp

Conclusion

Market forces, public policy, and environmental policy are driving the ongoing shift in our nation's power generation mix. Natural gas generation is an important and growing part of that mix. Collectively, the environmental advantages, reliability, and affordability of natural gas generation are unmatched by any other form of power generation. Natural gas has earned its market share in the electricity generation space and has provided, and can continue to provide, reliable, low-cost fuel for electricity generation and cost savings to consumers.

The natural gas industry stands ready to work with all stakeholders to ensure that our nation's electrical grid is reliable, safe, and resilient. We urge policymakers to recognize that a free and competitive market-based approach is the best way to ensure that our nation's electricity needs are met affordably, reliably and in the most environmentally responsible way possible.

Summary

Natural gas is a domestically produced, abundant, reliable and low-cost energy resource that lowers energy costs for consumers and spurs economic growth and opportunity for our nation. Natural gas enhances the reliability, decreases the cost, and lowers the environmental impact of the nation's electric system because:

- **Natural gas generation enhances the flexibility of the electricity grid.** Natural gas generation is flexible and fast ramping, and able to cycle off and on in a short period of time. This helps maintain stability and reliability on an electric grid increasingly experiencing net load volatility due to the increase in variable renewable energy resources.
- **Natural gas will remain a stable and low-cost fuel.** According to EIA, based on the past and expected future technical innovations, production growth, and the size of the resource, natural gas prices will remain stable and low for years to come, providing a reliable source of fuel for electric generation.
- **Natural gas' low cost helps to drive down wholesale electricity costs**. Low-cost natural gas continues to provide significant cost savings which may up free up funds for additional investment in other things, such as infrastructure, which, in turn, enhances reliability.
- **The increased use of natural gas in power generation has lowered emissions.** New, clean and efficient natural gas generation has grown considerably as a part of the electric generation mix, which has reduced electric sector emissions to levels not seen since 1990. In 2016, carbon dioxide emissions from power generation were at nearly 30-year lows.
- **The natural gas system is reliable and resilient.** Its geographic diversity in terms of supply provides for multiple flows in all directions across the country. Natural gas companies follow a rigorous set of

guidelines and standards and, due to the market-based nature of the industry, have a vested interest in keeping the product reliably flowing to all their customers.

Natural Gas Systems: Reliable & Resilient

NATURAL GAS COUNCIL

July 2017

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Preamble

Our trade associations, who together comprise the Natural Gas Council and represent the natural gas delivery system from production to consumption, originally researched and developed this white paper to inform a North American Electric Reliability Corporation (NERC) special assessment on any potential risks to bulk power system reliability from a single point of disruption on major natural gas infrastructure facilities (e.g., storage facilities, key pipeline segments, LNG terminals). The facts and data we gathered in the process of preparing information for NERC underscored the exceptional reliability of the natural gas system. It also revealed the need for a comprehensive resource that explains the underpinnings of natural gas reliability, both physical and contractual. The white paper that follows is the result of our joint effort.

The Natural Gas Council
Members:

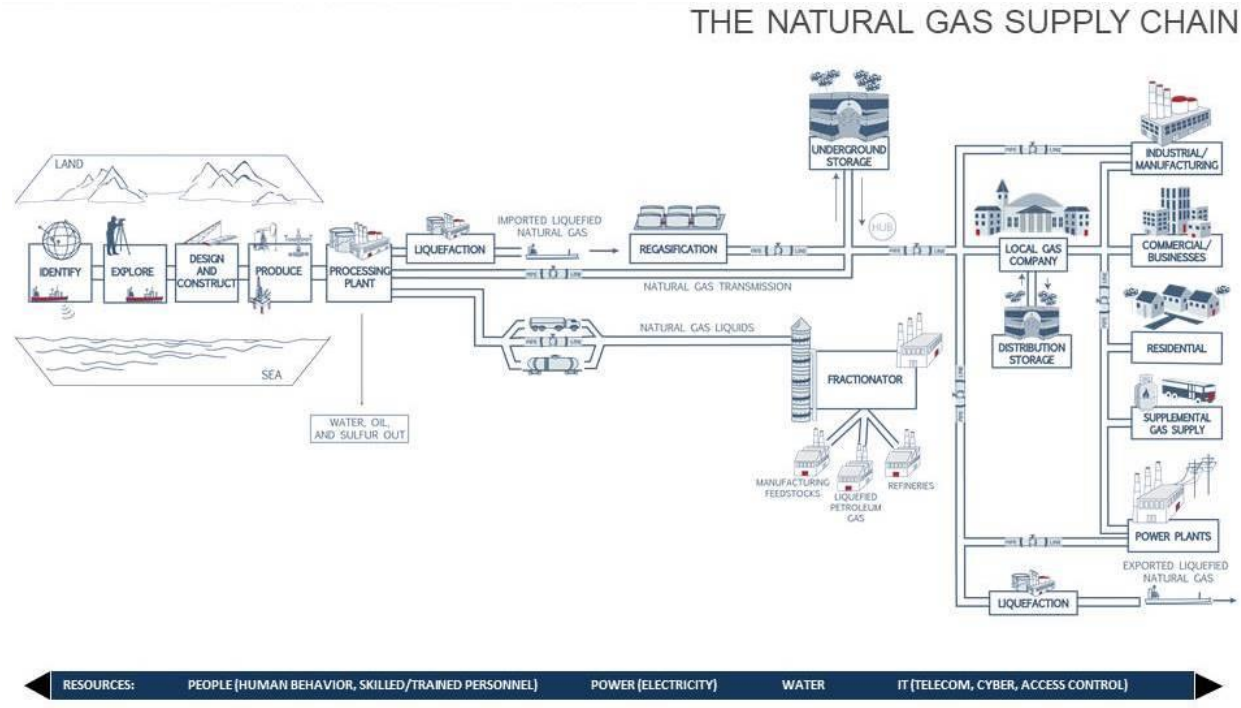
- American Gas Association
- American Petroleum Institute
- Interstate Natural Gas Association of America
- Independent Petroleum Association of America
- Natural Gas Supply Association

July 2017

1. Introduction

The United States has abundant natural gas resources that enable our industry to satisfy customer demand fully. In only a few years' time, the U.S. has become the largest producer of natural gas in the world. Estimates of the gas resource base have more than doubled in the past decade.[1] Since 2010, production has grown almost 30 percent, with government forecasts calling for production to once again reach the record of near 75 billion cubic feet per day this year.[2] The natural gas supply chain is extensive and spans from the production well-head to the consumer burner-tip (see illustration).

Critical Elements of the Natural Gas Supply Chain



Source: The American Petroleum Industry, Oil and Natural Gas Industry Preparedness Handbook, 2016.

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[1] *See* Potential Gas Committee *Biennial Report of Potential Supply of Natural Gas in the United States*, (December 31, 2014), 2015, available here.

[2] See EIA *Short Term Energy Outlook*, May 2017 available here and EIA Natural Gas Summary | Custom Table Builder, available here.

Consumer natural gas demand has grown steadily since 2009 for a variety of reasons: it is abundant, domestic, burns clean and is affordable. Access to abundant, domestic natural gas has given U.S. industrial companies a competitive advantage over their global competition, leading to the resurgence of gas-intensive manufacturing in the U.S. and the creation of more jobs to construct and fill the resulting new and expanded industrial facilities.

At the same time, demand from the power sector has also increased, driven by natural gas's low-carbon emissions, retirements of older coal-fired plants, and the comparatively low cost and small footprint of natural gas-fired power plants.[3] In recent years, greater use of natural gas has produced significant reductions in U.S. carbon emissions because, over its lifecycle, natural gas emits only about half the carbon of other fossil fuels when combusted.[4] Because of these advantages, natural gas is poised to become an even more important part of states' energy portfolios as they seek to meet state clean energy objectives.

Yet, with the forecasted growth in power demand, some – particularly those unfamiliar with natural gas operations and contractual practices – question the ability of natural gas to continue to reliably serve this market. In this paper, we explain how the physical characteristics of natural gas, as well as operational industry practices, provide an extremely high level of reliability and resiliency for gas customers. This paper also explains that while the natural gas industry is physically reliable, if large-volume customers require undisrupted service, they must choose to enter into advance contractual arrangements for "firm transportation" services that ensure pipeline capacity is available when needed to allow the customer to benefit from this

[3] See Leidos (formerly SAIC), *Comparison of Fuels for Power Generation*, 2016, available here.
[4] See National Renewable Energy Laboratory, "*Harmonization of Initial Estimates of Shale Gas Lifecycle Greenhouse Gas Emissions for Electric Power Generation,"* Proceedings of National Academy of Sciences, July 2014, available here.

reliability. This is how a gas-fired generator (or any pipeline system customer) can achieve continuity of service if that is required.

2. Historic Reliability of Natural Gas Network – Due to Operational Characteristics

The physical operations of natural gas production, transmission and distribution make the system inherently reliable and resilient. Disruptions to natural gas service are rare. When they do happen, a disruption of the system does not necessarily result in an interruption of scheduled deliveries of natural gas supply because the natural gas system has many ways of offsetting the impact of disruptions. As noted in a report from MIT: [5]

> The natural gas network has few single points of failure that can lead to a system-wide propagating failure. There are a large number of wells, storage is relatively widespread, the transmission system can continue to operate at high pressure even with the failure of half of the compressors, and the distribution network can run unattended and without power. This is in contrast to the electricity grid, which has, by comparison, few generating points, requires oversight to balance load and demand on a tight timescale, and has a transmission and distribution network that is vulnerable to single point, cascading failures.

The inherent characteristics of natural gas are an important factor that cannot be overlooked. Unlike electricity that travels at the speed of light and flows along a path of least resistance, natural gas moves by pressure. The gas moves through a transportation system with the use of compressors that pressurize the gas to move it over distance. For long distances, compressors are placed at regular intervals to continue the forward movement. In sharp contrast to electricity, natural gas physically moves slowly through a pipeline at an average speed of 15-20 miles per hour, and its flow can be controlled. This allows time for pipeline operators to

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[5] Massachusetts Institute of Technology, Lincoln Laboratory, "Interdependence of the Electricity Generation System and the Natural Gas System and Implications for Energy Security," May 15, 2013.

manage the flow of natural gas and to adjust their operations in the unlikely event of a disruption. Because of the pipeline operators' ability to manage natural gas on their transportation systems, a failure at a single point on the system typically has only a localized effect.[6]

In addition, natural gas production comes from diverse geographic supply areas spread across many U.S. states and Canada. This abundant and stable supply is coupled with a vast number of production wells dispersed over a wide geographic area that contributes to ensuring that overall natural gas production is rarely impacted by isolated local or regional events. In the U.S. today, there are more than a half million producing gas wells[7] spread across 30 states.[8] There are hundreds of natural gas producers, and even the largest U.S. producer contributes less than 5 percent to total domestic supply.[9] In addition, this diversified supply is connected to an extensive pipeline network.

Another valuable and somewhat unique characteristic of natural gas is its ability to be stored after production. Natural gas is most commonly stored underground in depleted aquifers and oil and gas fields, as well as in salt caverns. It can also be stored above ground in storage tanks as liquefied natural gas ("LNG") for use at import and export facilities and at peak shaving plants, or as compressed natural gas ("CNG") for industrial and commercial uses. In addition to the importance of storage as a supply cushion, it provides vital operational flexibility in the event of constraints in the pipeline and distribution network, as storage facilities are widely dispersed on those networks.

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6 More detail about the physical, operational characteristics of the natural industry segments can be found in the Appendices to the 2011 Southwest Cold Weather Event report prepared by the staffs of FERC and NERC. Report on Outages and Curtailments During Southwest Cold Weather Event of February 1-5, 2011 (August 2011), Appendices 8-10 ("Southwest Cold Weather Report").

7 https://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm.

8 https://www.eia.gov/tools/faqs/faq.php?id=46&t=8.

9 http://www.ngsa.org/wp-content/uploads/2017/03/Top-40-2016-4th-quarter.pdf.

The natural gas system[10] is not particularly vulnerable to weather-related events. Natural gas pipelines are predominantly underground and protected from the elements. Therefore, natural gas systems are far more resilient in the face of extreme weather events than electric systems. For example, in 2016, fewer than 100,000 natural gas customers nationally experienced disruptions,[11] while 8.1 million Americans experienced power outages.[12] According to an April 2017 INGAA survey of 51 interstate pipelines, over the ten-year period 2006-2016, pipelines delivered 99.79 percent of "firm" contractual commitments to firm transportation customers at primary delivery points (i.e., the points specified in their contract). As attested to by INGAA's survey data, firm pipeline transportation service historically is extremely reliable.

The wide geographic dispersion of production areas further reduces the vulnerability of the supply to localized weather events. Additionally, most natural gas production now occurs onshore, with offshore production making up only 5 percent of total natural gas production compared with 20 percent in 2004.[13] As a result, the potential for hurricane impact on natural gas production has dramatically diminished.

The operation of the entire natural gas system – production, transmission, distribution and storage – is highly flexible with strong elasticity characteristics. The inherent design of high-pressure and low-pressure gas delivery systems is mechanical by nature. Modern infrastructure has control systems to help monitor, and in some cases operate the pipelines and its components to move the product in a reliable, efficient and effective manner. Operators manage the internal

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10 A detailed diagram of the natural gas industry segments appears at the end of these comments.

11 Source: American Gas Association survey.

12 EIA, Electric Monthly Table B.2 Major Disturbances and Unusual Occurrences, available at https://search.usa.gov/search?utf8=%E2%9C%93&affiliate=eia.doe.gov&query=Electric+Emergency+and+Disturbance+2016

13 EIA – Natural Gas Monthly December 2007 and Natural Gas Monthly April 2017: https://www.eia.gov/naturalgas/monthly/pdf/table_07.pdf.

pressure of the delivery system by controlling the amount of natural gas entering and leaving the system. The process of increasing or decreasing pressure happens relatively slowly in a natural gas system because of the compressible nature of the gas. This compressibility lessens the immediacy of impact and increases the probability of detection. Layered onto this control system architecture are overpressure protection devices, which kick-in should the unlikely need arise to prevent the internal gas pressure from threatening the pipeline's integrity. This was demonstrated on January 7, 2014 during a "polar vortex" weather event that stretched across large parts of the United States and caused total delivered gas nationwide to reach an all-time record of 137.0 Bcf in a single day.[14] Despite the unprecedented performance levels required, the industry honored all firm fuel supply and transportation contracts.[15]

The joint Federal Energy Regulatory Commission ("FERC")-NERC *Southwest Cold Weather Report* made similar findings about the reliability of the natural gas system during another weather-related event. In the first week of February 2011, the southwest region of the United States experienced historically cold weather that resulted in significant impacts on the electric system in Texas, New Mexico and Arizona, and natural gas service disruptions in those states as well. During the 2011 Southwest outages, 50,000 retail gas customers experienced curtailments when gas pressure declined on interstate and intrastate pipelines and local distribution systems due to the loss of some production to well freezing at a time of increased gas

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[14] EIA, Market Digest: Natural Gas (2013-2014), https://www.eia.gov/naturalgas/review/winterlookback/2013/#tabs_Consumption-4

[15] See https://www.ferc.gov/media/news-releases/2014/2014-4/10-16-14-A-4-presentation.pdf and "During each of these cold events, customers who had firm transportation capacity on natural gas pipelines generally managed to secure natural gas deliveries." Also see https://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf at Slide 4.

system demand.[16] In contrast, 4.4 million electric customers were affected over the course of the same event.[17] Nonetheless, the *Southwest Cold Weather Report* found that only 10 percent of the electric generation failures were due to fuel supply problems,[18] and that "[f]uel supply problems did not significantly contribute to the amount of unavailable generating capacity in ERCOT."[19] Further, as noted in the *Southwest Cold Weather Report*, "[n]o evidence was found that interstate or intrastate pipeline design constraints, system limitations, or equipment failures contributed significantly to the gas outages. The pipeline network, both interstate and intrastate, showed good flexibility in adjusting flows to meet demand and compensate for supply shortfalls."[20]

Other characteristics of the natural gas system contribute to its historical operational reliability and system resilience. The natural gas transportation network is composed of an extensive network of interconnected pipelines that offer multiple pathways for rerouting deliveries in the unlikely event of a physical disruption. In addition, pipeline capacity is often increased by installing two or more parallel pipelines in the same right-of-way (called pipeline loops), making it possible to shut off one loop while keeping the other in service. In the event of one or more compressor failures, natural gas pipelines can usually continue to operate at pressures necessary to maintain deliveries to pipeline customers, at least outside the affected segment. "Line pack"[21] in the pipelines can be used, if necessary, to provide operational

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16 Southwest Cold Weather Report at 2.
17 Id. at 1.
18 *Id.* at 140-142
19 *Id.* at 153.
20 *Id.* p. 212
21 Line pack is the volume of natural gas contained within the pipeline network at any given time. It allows gas received in one area of a pipeline system to be delivered simultaneously elsewhere on the system. It can facilitate non-ratable flows and support pipeline reliability as a temporary buffer for imbalances. However, line pack must be kept reasonably stable throughout the system to preserve delivery pressure and system capacity. Thus, line pack neither creates incremental capacity, nor is it a substitute for appropriate transportation contracts.

flexibility, as noted in the *Southwest Cold Weather Report*.[22] As noted above, because of the inherent characteristics of natural gas and the interconnected pipeline system, operators can control and redirect the flow around an outage in one segment. The existence of geographically dispersed production and storage, and its location on different parts of the pipeline and distribution system, also provides flexibility for operators to maintain service in the event of a disruption on parts of the transportation and distribution system.

Similarly, producers use various methods to help ensure operational continuity. Because producers have an economic incentive to continue to flow gas out of the producing field at a constant rate, many techniques are in place to help ensure that operations continue or that any disruption is minimized when a problem arises. While not always possible, producers often rely on more than one processing plant or pipeline rerouting options in a production area, especially when handling a significant level of production. In the unlikely event of an unavoidable disruption of supply at a well or in a field, producers have many other options to balance their supply commitments, including increasing production in other areas or using natural gas they have in storage.

3. The Natural Gas Industry – Focused on Cyber & Physical Security Risks

Cyber and physical security are integral to the natural gas industry. Natural gas pipelines, which move over one-third of the energy consumed daily in the United States, are considered critical infrastructure. All along the natural gas supply chain, from production to delivery, the

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[22] Southwest Cold Weather Report at 68-70.

industry employs a portfolio of tools to help ensure protection of its facilities from both physical and cybersecurity threats.

On the physical security side, fences, routine patrols and continuous monitoring, as appropriate, help protect above-ground facilities such as compressors, well sites, processing plants and meter stations. The natural gas industry routinely holds briefings and workshops to discuss security concerns, and it has developed industry guidelines and identified leading practices to protect facilities and data. Natural gas trade associations and their members regularly run simulated exercises in response/recovery efforts to help prepare in the event of natural or man-made disasters and work closely with government agencies to share threat information and practices.

On the cybersecurity front, the federal government partners with the natural gas industry on cybersecurity frameworks and initiatives to promote situational awareness, mitigating measures and response/recovery. Critical infrastructure sectors, including natural gas, electric, nuclear, financial, telecommunications, information technology and water, use Information Sharing and Analysis Centers (ISACs) as an adaptive tool to share comprehensive analysis of changing threats within the sector, other sectors and federal and state governments. The Energy Sector is represented by the Downstream Natural Gas ISAC, the Oil & Natural Gas ISAC, and the Electricity ISAC. These ISACs work closely with one another and with other critical infrastructure sector ISACs. The federal government promotes ISACs and Information Sharing and Analysis Organizations (ISAOs) as a best security practice.

As discussed at length in the beginning of this document, there is low risk of single point of disruption (regardless of cause) resulting in uncontrollable, cascading effects. Generally, supply and transportation disruptions can be managed through substitution,

transportation rerouting and storage services. Recognizing the pipeline system resilience and redundancy, the federal government continues to partner with industry on cyber as well as physical security matters. This partnership is best experienced through the TSA Pipeline Security Guidelines and various completed and ongoing security initiatives that strengthen the industry's security posture.

One of the most important aspects of cybersecurity in the pipeline space is ensuring the integrity and operability of the Supervisory Control and Data Acquisition (SCADA) system of each pipeline against cyber compromise. From a cybersecurity perspective, natural gas functions are divided across an enterprise network and an operations network (which includes control system, SCADA, and pipeline monitoring). These two networks are generally isolated from each other, and a portfolio of tools and mechanisms is used to improve the prevention, detection and mitigation of cyber penetration. Pipeline safety regulations and standards state that back-up systems cannot be affected by the same incident that compromises the primary control system; thus fail-safes and redundancies must be independent of the cause of the primary mechanism's failure.

In addition, partnership between the private sector and the federal and state governments is a key part of addressing physical and cybersecurity threats to the nation's critical infrastructure. Industry members routinely participate in internal and industrywide security situation simulation exercises – training exercises that present real-world challenges – with government officials and others to ensure that the industry is better prepared for a cyber or a physical emergency.

Just as with pipeline safety, natural gas utilities apply layers of resilience for cybersecurity by employing firewalls and other tools to improve the prevention, detection and

mitigation of cyber penetration. Further, natural gas delivery systems are mechanical by nature and can still be run manually if necessary. Natural gas is moved by using pressure to control the amount entering and leaving the system. Layered onto this control system architecture are devices that detect changes in pressure, which serve as a safeguard to prevent internal gas pressure from threatening pipeline integrity.

Cybersecurity is also a priority in other areas of supply chain, such as production. Many companies orient their overall cybersecurity programs around the NIST Cybersecurity Framework for Improving Critical Infrastructure Cybersecurity. Using this framework and other consensus standards can equip upstream operators with the process and tools they need to prevent cyberattacks.

Cyber risk management at any company is tailored to that company's assets and potential risks and must also be flexible to respond to ever-changing external threats and internal deployment of digital assets. Although one size does not fit all, there are some common features of cyber risk management programs for industrial control systems (ICS) employed by many offshore and onshore oil and natural gas industry companies, including: training and security awareness, segregating process control networks, restricting access to computer hardware used to manage software and industrial control programs, restricting and monitoring vendor access to equipment and systems, and on-site inspections and cyber-related drills.

4. Firm Contractual Arrangements Assure Reliability of Service

Above, we discussed the high level of reliability provided by the natural gas industry in terms of its physical operations and ability to deliver to its customers. Yet, in order to benefit from this reliability, large-volume customers, such as industrial users, electric generators, commercial customers and LDCs, must do their part to ensure continuity of service by

contracting for firm transportation services to meet their own or their customers' obligations. Absent customers' purchasing pipeline capacity on a firm basis, pipelines may not have spare transportation capacity available on their systems, or a higher priority firm transportation customer may bump the non-firm customers' service for reasons unrelated to physical gas or transportation disruptions. On the coldest days (known as "peak days"), when weather-sensitive firm transportation customers are using their full contractual entitlements, there may be little or no interruptible transportation capacity left over for interruptible customers.

In many circumstances, large-volume customers make arrangements to move natural gas from the wellhead to their burner-tip – that is, through the entire supply chain. In 1992, FERC, which regulates interstate natural gas pipelines, required interstate pipelines to unbundle (i.e., separate) their sales and transportation services, and to provide unbundled transportation service on an open access, not unduly discriminatory basis.[23] As a result of this restructuring, interstate pipelines exited the merchant sales function, meaning that they no longer sell the natural gas that they transport through their pipelines, and the rates they charge are only for the movement of gas through their systems. While FERC's restructuring of the natural gas industry created an additional level of responsibility on the pipeline customer to separately contract for supply and pipeline transportation, it has been beneficial in creating competition by giving gas customers a choice of commodity suppliers and pipeline capacity.

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23 The FERC's unbundling of the interstate natural gas pipeline industry was undertaken to improve the competitive structure of the industry to maximize the benefits of the Wellhead Decontrol Act adopted by Congress in 1989. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 636, 57 FR 13267 (April 16, 1992), III FERC Stats & Regs. ¶ 30,939 (1992) at p.4.

4.1. Understanding Contract Options – Firm vs. Interruptible

The interstate pipeline industry today is contract-based. As such, pipeline customers select the type of service (firm or interruptible) for their transportation and storage service based on their desired level of certainty and reliability. Pipeline customers ensure their gas supply reliability by taking responsibility for choosing the portfolio of natural gas transportation and storage services that meets their needs adequately, not unlike what is necessary with other fuels, such as coal and fuel oil. Pipelines schedule their capacity based on a system of nominations, and, when necessary, restrict service based upon the type of service contracted. Broadly speaking, there are two main types of service that pipeline and storage operators offer to customers: (1) firm service, whereby a shipper chooses to pay a monthly reservation charge to the pipeline that entitles it to transport or store a certain quantity of gas each day, assuming the shipper nominates the quantity and delivers to the pipeline the equivalent amount of natural gas at the receipt points specified in the contract; and (2) interruptible service, which is a lower-quality pipeline service provided by the pipeline when it has spare capacity that is either not under firm contracts or not being used that day by firm transportation customers. Within firm service, many pipelines and storage facilities provide "no-notice" service. No-notice service is the highest level of firm service that a customer can contract. It allows for the reservation of pipeline capacity throughout the 24-hour gas day. This reservation of capacity allows the customer to nominate its firm service on a primary basis throughout the day, offering the highest level of flexibility available on a pipeline.

Under the FERC regulations,[24] a firm-service shipper is entitled to "segment" its capacity daily and utilize other delivery points within the path to its delivery point if capacity is available. These delivery points along the route are called "secondary firm points." Once scheduled by the pipeline, the transportation capacity to secondary receipt and delivery points is as firm as primary firm delivery. Primary firm-service shippers receive the most reliable service, because they have the highest priority when scheduling and are the last to be curtailed in *force majeure* (or unexpected emergency) situations. Secondary firm-service shippers are next in priority for scheduling, but once scheduled, they are curtailed *pro rata* with other primary-firm service. Interruptible shippers, if scheduled, can be bumped by higher priority firm shippers until the Intra-day 2 (ID2) scheduling deadline, and interruptible shippers are curtailed before any firm pipeline customers – regardless of whether the interruptible transportation was scheduled. Subject to capacity availability on the pipeline, the option to contract for firm or interruptible service is the decision of the pipeline customer based on the level of service that it requires. If capacity is not available, a pipeline may decide to expand its system to accommodate customers' requirements if firm commitments are made.

"Interruptible" transportation contracts ("interruptible") can be interrupted by a higher priority firm transportation shipper for any reason until 5:30 pm, which is the ID2 scheduling deadline.[25] A pipeline customer chooses the contract that best suits its needs and capability to be

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[24] 18 C.F.R. § 284.7(d).

[25] If existing capacity is fully committed under firm contracts, interstate pipelines are not required to expand their facilities to provide transportation service. See 18 CFR 284.7(f) ("A person providing service under Subpart B, C or G of this part is not required to provide any requested transportation service for which capacity is not available or that would require the construction or acquisition of any new facilities."). This contrasts with the Federal Power Act provisions that impose obligations on electric transmission owners to expand capacity to provide interconnection and transmission services. Federal Power Act section 210 and 211, 16 U.S.C. §§ 824i and 824j. Of

at risk of disrupted service. During a *force majeure* (or unexpected emergency) event applicable to firm pipeline customers, curtailment by interstate pipelines is based on the transportation contract in place, in which case, interruptible transportation contracts that were already confirmed are curtailed first. Interruptible transportation that was not available and never confirmed is not a curtailment of service. **Interstate pipelines do not curtail based on the end-use of the gas: FERC's nondiscriminatory open access regulations preclude this. In fact, an interstate pipeline cannot provide transportation service preferences based on customer classification.**[26]

4.2. Portfolio of Choice

Interstate pipeline customers can decide to secure their fuel supply through a variety of options. For example, they can purchase firm transportation directly from the pipeline, obtain firm capacity rights through capacity release (reassignment) from another firm shipper, or enter into firm bundled transportation/supply contracts with marketers. Natural gas marketers are entities that can aggregate natural gas into quantities that fit the needs of different types of buyers and then can arrange transportation of that gas to their buyers. A marketer coordinates, through various contractual arrangements, all the necessary steps to transport the gas from the wellhead to the customer. Natural gas marketers also offer natural gas supply delivered on a firm basis, which includes both the commodity and the transmission capacity needed for delivery of the gas. By holding a portfolio of physical capacity assets (pipeline transportation and storage) and supply contracts, a marketer can provide flexible and responsive service to customers.

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course, interstate pipelines have an incentive to expand capacity for shippers that commit to firm contracts for the expansion capacity.

[26] 18 C.F.R. §§ 284.7(a)(3) and 284.7(b)(1).

Therefore, a marketer's services can be a reliable alternative source of supply for customers during peak periods, if the marketer holds primary firm transportation capacity to the relevant delivery points.

4.3. LDCs as Pipeline Customers

As part of FERC's natural gas industry restructuring in 1992, LDCs converted their bundled firm pipeline sales entitlements to unbundled firm pipeline transportation rights to meet their state regulatory obligations to serve their firm "core" customers. (This is similar to the post-Order No. 888 conversions made by franchised public utilities to network integration service.) LDCs now purchase their natural gas commodity supply and arrange for the transportation of those commodity supplies on interstate pipelines to their systems. LDCs engage in long-range resource planning to ensure their access to supply and the continuous operations of their systems to ensure reliable service to these firm core customers. The delivery of natural gas to core retail customers is of primary importance to LDCs, and their planning involves assessment of potential supply chain disruptions, including commodity supply and interstate transportation disruptions, as well as disruptions that may impact their own local distribution systems.

4.4. Natural Gas-Fired Power Generation

Similar to LDCs, electric generators and other industrial and large commercial gas users must also arrange fuel supply to meet their respective requirements. These customers typically do not purchase their gas supplies from LDCs under their state-regulated tariffs -- unless they are located on an LDC's distribution system, in which case they may contract to use that system for transportation of their own gas supplies purchased in the wholesale market. More typically, many large commercial gas users are connected directly to an interstate or intrastate pipeline that transports the gas supplies they have purchased separately. Again, these large gas users are

responsible for arranging their own fuel supply and must consider the entire fuel supply chain, from production to their plant.[27] In practical terms, this means taking into consideration congested transportation paths and pipeline scheduling and curtailment priorities when contracting for delivery of their gas supply. Location alone does not guarantee a large-volume customer security of its gas supply. Location is just one part of a bigger picture that includes the contract-based interstate transportation and storage system, and the utility obligations applicable to LDC systems.

5. Regulatory Requirements Are Relevant to Supply Chain Delivery Options

Historically, the natural gas industry has not been vertically integrated; instead each distinct industry segment's price structure is subject to a different regulatory regime. Broadly speaking, the industry consists of three segments: (1) upstream natural gas production, gathering and processing; (2) pipeline transportation and storage; and (3) local distribution.[28] Congress removed all price regulation for natural gas sold by producers in the Wellhead Decontrol Act of 1989, which was followed a few years later by FERC's removal of all price regulation for the sale of natural gas in the wholesale market. Gathering and processing are also not subject to price regulation by the federal government. However, the price, terms and conditions of the interstate transportation and storage of natural gas remain regulated by FERC. Pure intrastate transportation and storage of natural gas is subject to state regulation. The distribution of natural

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[27] *See* Frank Brock and Michael Sloan, ICF, "An Electric Gas Market Calls for Flexibility," 2017, (available at https://www.icf.com/perspectives/white-papers/2017/an-electric-gas-market-calls-for-flexibility?_cldee=cGphZ3RpYW5pQG5nc2Eub3Jn&recipientid=lead-94bc42ae6f47e5118109c4346bb59848-27daa500e3404b359d638cd87a34be6b&utm_source=ClickDimensions&utm_medium=email&utm_campaign=may11-2017-com-ene-energy-digest-newsletter&esid=f789549b-b935-e711-80fd-5065f38a19e1).

[28] A more detailed diagram of the natural gas industry segments appears at the end of these comments.

gas by LDCs is also subject to state regulation. All pipelines are subject to safety regulation by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") or state agencies. Numerous other federal and state agencies regulate various environmental and safety aspects of the natural gas system.

5.1. FERC Regulation of Interstate Transportation and Storage

As noted earlier, FERC's regulation of interstate transportation and storage is contract-based. A pipeline or a storage company's contract is with its pipeline customer. How that pipeline customer chooses to contract for service determines the scheduling of service on the pipeline as well as the firm service curtailment priorities in the event of a pipeline restriction or *force majeure* event. FERC regulations preclude interstate pipelines from undue discrimination in providing service based on the classification of customers. This means that the identity of the customer, whether it is an LDC, electric generator, or a producer, cannot have any bearing on priority of service. In addition, the pipeline is required to honor all firm service contracts.[29] Therefore, level of service that a customer has contracted for is of paramount importance.

5.2. State Regulation of Local Distribution – High Priority Customers.

LDCs are regulated by most states as local gas utilities that have an obligation to serve their firm core customers – the customers for which the system is built to serve reliably. LDC systems are built to serve these firm core customers and others on a "design day" (a forecasted peak-load day based on historical weather conditions). While gas utilities may offer an

[29] FERC gas regulations define "service on a firm basis" as a service that is "not subject to a prior claim by another customer or another class of service and receives the same priority as any other class of firm services." 18 C.F.R. § 284.7(a)(3).

interruptible "bundled" sales service (which includes commodity supply and the transportation of the supply on the local distribution system) and/or a stand-alone interruptible transportation service for the transportation of customer-owned gas on the local distribution system, the LDC may not be able to maintain interruptible transportation service at all times. During periods of high usage and system constraints, often prevalent on the coldest winter days, LDCs may call on interruptible customers to cease gas usage temporarily, upon which these customers generally switch to a back-up fuel, such as fuel oil.[30]

In the event of extreme situations that require action to be taken for reasons that include the need to maintain the operational integrity of the system and/or maintain natural gas service to designated high priority customers, including "essential human need" customers, state statutes and public utility regulations may allow an LDC to curtail services to some customers. Historically, these regulatory requirements give the highest priority to residential and commercial customers without short-term alternatives. As a result, a natural gas-fired power generator relying on an LDC distribution system, particularly on an interruptible basis, needs to consider these regulatory obligations of the LDC and, for example, plan for the use of alternate fuels, maintain on-site fuel storage (such as LNG or CNG), or contract for a higher level of service from the LDC (such as firm transportation or emergency service).

[30] The tradeoff for these customers is a discounted rate for the interruptible natural gas delivery service, compared with firm service rates, and the customers enter into these interruptible contractual arrangements with that prior knowledge.

6. Storage's Dual Role in the Gas Supply Chain

Underground natural gas storage is an integral component of the natural gas supply chain, with a function different than the other components of that supply chain. Storage serves to augment natural gas production, and the location of a storage facility can also provide operational flexibility for the natural gas delivery infrastructure. There are 385 underground storage facilities in the lower-48 states with a total of 4,688 Bcf of working gas design capacity.[31] Natural gas storage enables LDCs and interstate pipeline companies to adjust for daily and seasonal fluctuations in demand, in contrast to natural gas production, which remains relatively constant year-round. Storage helps ensure that customers have reliable service and can provide increased price stability. Natural gas storage operators have consistently provided safe and reliable natural gas storage. Because of the critical importance storage plays in the nation's energy portfolio, natural gas storage operators are continually working to help improve safety and reliability through innovations in equipment, processes and methodologies.

6.1. New storage rules will have minimal impact on deliverability

PHMSA's December 2016 interim final rule promulgating safety regulations for underground storage facilities ("Storage IFR")[32] will have minimal impact on deliverability. In fact, the Storage IFR is intended to reduce the likelihood of future storage incidents and ultimately improve underground storage safety and reliability. The Storage IFR, like natural gas pipeline safety regulations that preceded it, takes a functional integrity management approach to storage safety and standardizes the methodology by which operators will analyze risk at storage

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31 https://www.eia.gov/naturalgas/storagecapacity/.

32 See 81 Fed. Reg. 91,860 (2016).

facilities. The Storage IFR requires operators to develop rigorous risk-assessment programs that will be used to determine which preventative and mitigating measures are appropriate for the specific conditions at any given storage facility.

6.2. Underground Storage Facilities Are Not Identical

The gas pipeline and associated storage network is different in different regions of the United States. How an underground natural gas storage facility is configured and serves its market also differs across the country. Much attention has been focused on the Aliso Canyon underground natural gas storage facility. This particular facility is a prime example of how one facility's operational configuration and the way in which it serves its market differs from others.

PHMSA's underground storage rule was prompted by an October 23, 2015 leak at a SoCal Gas natural gas storage well at the Aliso Canyon storage field in California. Aliso Canyon is an integrated gas utility-owned storage facility tied directly to intrastate pipelines that serve market load. As a result, the gas delivery system in the area is dependent upon storage withdrawals to meet market demand. However, the gas pipeline and storage network is different in other regions of the United States, where storage operators instead interconnect with multiple pipelines and storage facilities from which they can access supply and transport gas.

Based on the event data reported since 1990, including the Aliso Canyon incident, the likelihood of an unplanned release from an underground gas storage well, calculated using the

Center for Chemical Process Safety 5 ("CCPS") American calculation for hazardous process facilities, results in a "very unlikely" to "extremely unlikely" or "remote" classification.[33]

One well failed at the SoCalGas facility at Aliso Canyon and, in an abundance of caution, California State Regulators ordered the other 113 wells to be temporarily sealed until they could be tested to ensure their integrity and safety or plugged and abandoned. To date, 49 storage wells at the Aliso Canyon Storage facility have passed all the tests required under the Division of Oil, Gas and Geothermal Resources' ("DOGGR").

There was no mechanical failure of the other 113 storage wells at Aliso Canyon; the regulator's decision to shut down the entire facility is an example of regulatory action taken to help mitigate risk. Nevertheless, the consequences of such actions to gas and electric reliability need to be clearly understood when gas flows are restricted.

7. Conclusion

The natural gas industry is not susceptible to wide-spread failure from a single point of disruption in the same manner as the electric system because of the dispersion of production and storage, its redundant characteristics from the extensive integrated pipeline and distribution network, and its low vulnerability to weather-related events. The natural gas industry also has in place robust cyber and physical security protocols to minimize disruptions from manmade or computer threats, and has a resilient, interconnected system that allows it to come back on line quickly in the rare case of a disruption.

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[33] American Petroleum Institute, American Gas Association, and Interstate Natural Gas Association of America "Underground Natural Gas Storage: Integrity and Safe Operations," (July 6, 2016) at 10, available at https://primis.phmsa.dot.gov/UNG/docs/AGA%20White%20Paper%20-%20UNGS%20Integrity%20and%20Safe%20Ops%2020160706.pdf.

While the natural gas industry is committed to continuing its high level of reliability, there is an equally important component of assuring continuity of service that remains the responsibility of large-volume customers. These customers should contract for the appropriate level of firm transportation service they require to ensure reliable service. Together, these two components – operational reliability and contractual continuity of service –make natural gas a secure, reliable and resilient choice for customers.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.	Docket No. AD17-11-000

COMMENTS OF AMERICAN PETROLEUM INSTITUTE

I. INTRODUCTION

API is a national trade association representing over 625 member companies involved in all aspects of the oil and natural gas industry. API's members include producers, refiners, suppliers, pipeline operators, and marine transporters, as well as service and supply companies that support all segments of the industry. API advances its market development priorities by working with industry, government, and customer stakeholders to promote increased demand for and continued availability of our nation's clean abundant natural gas resources for a cleaner and more secure energy future. Electricity generation is a significant market for clean-burning natural gas and our members are both producers and consumers of electricity. Therefore, API has an interest in ensuring wholesale electricity market rules and regulations treat natural gas generation equitably, providing a non-discriminatory level playing field for all resource types.

II. COMMENTS

A. The Five Paths

In its Notice Inviting Post-Technical Conference Comments, Federal Energy Regulatory Commission ("FERC" or "the Commission") staff identified five "paths forward

with respect to the interplay between state policy goals and the wholesale markets".[1] Whichever "path forward" is ultimately followed, of upmost importance is maintaining the integrity of the competitive wholesale markets. We believe minimizing the impact subsidies have on price formation is critically important because efficient market operations require price signals based on the actual cost of different alternatives.

(1) Wholesale Market Changes

We identify two market improvements that would facilitate the implementation of an approach consistent with maintaining the integrity of wholesale market competition. First, the Commission should seek to minimize the impact that subsidies have on price formation in wholesale markets for energy and capacity. As noted by Professor William Hogan, "inefficient subsidies raise the overall cost in the system. . . [b]ut at least efficient pricing helps keep the aggregate cost increase as the responsibility of those providing the subsidy."[2] At present, some resources receive technology-specific subsidies provided through a variety of different means. Because these subsidies distort the true cost of the resources, they lead to increased system costs.

Second, in addition to the effect on price formation from subsidies, greater dependence on variable generation resources fostered by those subsidies (e.g. wind and solar photovoltaics) will exert downward pressure on wholesale market prices. In that environment, flexible resources whose revenues have depended primarily on traditional energy and capacity market earnings will need additional revenue from other sources. That revenue could potentially come from more effective real-time price formation as real-time energy prices are allowed to follow

[1] Notice Inviting Post-Technical Conference Comments, May 23, 2017, Docket No. AD17-11-000.

[2] Comments of William Hogan, May 2, 2017, Docket No. AD17-11-000.

the variable resources' ability to generate. Greater penetration of wind and solar resources will increase the need for performance attributes that only flexible resources can provide. For that reason, energy market design should take into account the changing need for the flexible generation required in the integration of renewable energy resources.

There are three important reliability issues caused by greater penetration of variable generation resources. First, the marginal contribution variable generation resources make to reserves tends to decline as penetration increases. Second, reliance on variable generation resources decreases system inertia and increases frequency volatility creating greater need for frequency response products. Third, integrating variable generation increases the variability of net load creating the need for more fast ramping resources. For these reasons, among others, the energy market design needs to support price formation that attracts sufficient quantities of the resources that provide critically needed performance attributes that drive reliability.

Finally, a note on the issue of fuel diversity, a concept often cited by those seeking subsidies as justification for gaining additional out-of-market revenue. Evidence demonstrates that decreased reliance on coal and nuclear energy accompanied by increased reliance on natural gas does not endanger reliability. For example, a recent PJM study found that a portfolio composed of 86% natural gas resources did not endanger reliability.[3] That same study affirmed the importance of other performance attributes for renewables integration noting "PJM could maintain reliability with unprecedented levels of wind and solar resources, assuming a portfolio of other resources that provides a sufficient amount of reliability services."[4]

[3] PJM's Evolving Resource Mix and System Reliability, March 30, 2017, page 5.
[4] PJM's Evolving Resource Mix and System Reliability, March 30, 2017, page 5.

The natural gas supply chain is reliable and resilient and can provide dependable fuel to large amounts of electric generation. Due to its operational characteristics, it is not subject to the electric grid dynamic of cascading failure from a single point of disruption. Natural gas comes from geographically diverse supply basins, transported through an extensive, interconnected pipeline network, with its operational flexibility augmented by natural gas storage facilities. Generators can manage any fuel supply risk by using numerous tools including, but not limited to, directly contracting for the level of transportation services it requires, use of a marketer's portfolio of services to coordinate transportation and delivery of fuel, or utilizing dual-fuel capability.

Security of natural gas pipelines is maintained by the many ways companies manage security risks to prevent incidents from happening, and to recover and respond to incidents should one occur. The Transportation Security Administration (TSA) Pipeline Security Guidelines (Guidelines) drive the development and implementation of a risk-based corporate security program by pipeline operators to address and document their organization's policies and procedures for managing security related threats, incidents, and responses.[5] Natural gas companies manage these risks through risk assessment, business continuity planning, exercise and drills to test and incorporate lessons learned.

(2) Implications

Market reform should encourage long-term decision making by providing greater certainty about the market design. Investors need to know that the market rules are free from

[5] The many guidelines and standards that govern natural gas operators' management of cybersecurity include: TSA *Pipeline Security Guidelines*, National Institute of Standards and Technology (NIST) *Framework for Improving Critical Infrastructure Cybersecurity*, Department of Energy (DOE) *Cybersecurity Capability Maturity Model (C2M2)*, ISA/IEC 62443 Series of *Standards on Industrial Automation and Control Systems Security* and API Standard 1164 *Pipeline SCADA Security*.

continued interference which will, in turn, reduce capital costs for new generation. State policies that create out-of-market payments (e.g. ZECs and RECs) for certain technologies and are allowed to interfere with the market by depressing earnings for all other system resources, creates political risk for investors to manage. Adopting an approach that minimizes the impact that subsidies have on price formation will reduce political risk for investors and encourage the development of long-lived resources.

Integration of variable generation resources requires flexible resources that can provide the performance attributes necessary to ensure reliability. However, if those flexible resources are not correctly valued by markets, the system may not be able to attract/retain sufficient capacity of the type needed to maintain reliability, while correctly priced markets will signal to investors that markets will deliver fair returns to resources that provide the flexibility the system needs.

(3) Near-term and Long-term Sustainability

An approach aimed at getting market prices right will attract the type of investment that the evolving electric system needs while maintaining reliability. This may lead to a decreased reliance on nuclear and coal generation relative to natural gas. Given the abundance of natural gas supply and the robust natural gas delivery system, this should not pose a challenge for grid reliability. As mentioned previously, a PJM study found the system could be operated reliably with high levels of natural gas penetration. The study also found that high levels of renewable penetration will require resources with sufficient flexibility to support this increased penetration.[6] In many cases, natural gas fired generators may be the most economically efficient option for providing flexibility and other essential reliability services to the system. If

[6] PJM's Evolving Resource Mix and System Reliability, March 30, 2017, page 5.

low natural gas prices and increased renewable penetration make the plants that have traditionally operated in a "baseload"[7] mode (i.e. nuclear and coal plants) uneconomic, then those plants should be allowed to retire. Providing subsidies to so-called baseload plants is less likely to ensure future reliability and more likely to increase system costs compared to developing efficient pricing mechanisms for obtaining the flexibility needed by the system.

B. Principles and Objectives

(1) Principles That Should Guide Path Selection

One primary purpose of markets is price discovery. Well-structured markets identify the least-cost resources for meeting demand and set the price to the level needed to match supply with demand. Subsidies that interfere with price discovery reduce the efficiency of markets and will generally result in higher costs and lower economic benefits. When thinking about a path forward, we recommend the Commission consider the following principles:

- Efficient market design will result in price formation that matches the demand for essential reliability services and performance attributes with the supply.
- Energy market price caps should be lifted to a level sufficient to allow efficient price formation. Concurrent with this, FERC should require each RTO/ISO to settle all smart meters in its footprint on a five-to-fifteen minute basis, which would allow consumers and their retailers to react to the price information in the real-time market. This is very important in making the grid more flexible and responsive, which in turn improves the reliable operation of the grid and makes the market more responsive at the same time.

[7] We consider the term 'baseload' to be an outdated concept. The days when the electric grid consisted of a certain set level of 'base' load in need of a set level of 24/7 generation are quickly coming to an end.

- Ideally, market clearing prices should reflect the costs of all units that are called to operate, including start-up and no load costs.
- The market clearing price should reflect the costs of all units that run including block-loaded or ramping units, operating reserves, units providing voltage support or reactive power, or units run in response to reliability events or needs.
- Prices in energy and ancillary service markets should reflect shortage or emergency situations to provide needed investment signals and to reinforce real-time reliability in the face of increased variable output of intermittent renewables.
- Price formation should enable all reasonable and supportable costs incurred in unexpected circumstances, particularly when such costs are incurred in response to operator directives.

(2) Degree of Urgency

These market reforms may require both near-term and long-term solutions. Regions with particularly deep renewables integration will require market changes more rapidly than regions undergoing slower changes to their systems. Given that changes to market rules take time to implement, FERC should begin moving forward towards new market guidance as soon as possible.

Moreover, we note that subsidizing uneconomic plants hurts both consumers and competing supply resources. Uneconomic plants should be allowed to retire as soon as possible to preserve the efficient operation of the markets. Preserving so-called baseload and/or maintaining a diverse fuel supply, in and of themselves, do not effectively contribute to reliability and should not be viewed as reasons to delay the retirements of uneconomic resources.

(3) Role of Markets and State Policy

As state policies alter the resource mix, appropriate quantification and pricing of products becomes very important. With the increasing penetration of renewables, being dispatchable, i.e. able to provide output when needed, becomes more important because the ability to predict when peak net load (load less variable renewable output) will occur is limited. Net load can vary rapidly and a resource's capacity is only valuable if it is available when needed. That type of availability is a function of a unit's maximum possible output, forced outage rate, and its ability to be dispatched on demand. The ability to be available when needed is in part a function of its flexibility in terms of start times and ramping capability.

(4) Steps to Reconcile Markets with State Policy

FERC has exclusive jurisdiction over the interstate, wholesale markets for electricity. It has exercised that jurisdiction to create, to the largest extent possible, efficient and transparent markets. It should not allow state intrusion into the markets that result in significant distortion of crucial price signals. FERC has been tasked with ensuring just and reasonable rates for consumers and the wholesale competitive markets have been very successful in delivering on this mandate. We believe the Commission should defend the integrity of the wholesale markets that have delivered reliability at least-cost to such a large region of the country. While the Commission may support an attempt to balance the interests of states and the interstate wholesale markets, it is vital that that balance does not erode the work done to date. As shown in these comments, allowing the market to work and to provide appropriate price signals is the best way to support the evolution of the grid toward increased renewable penetration while maintaining its continuing reliability.

III. CONCLUSION

As the nation's electricity system continues to evolve in the face of both technological change and state-level policy-making, API recommends that the Commission continues to foster competition at the wholesale level. In essence FERC should:

- Let the markets work;
- Exercise its jurisdiction over the wholesale markets; and
- Remain focused on just and reasonable rates with non-discriminatory treatment of all assets.

For the reasons discussed herein, API requests that the Commission consider the foregoing comments.

Respectfully submitted,

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Diversity of Reliability Attributes

A Key Component of the Modern Grid

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THE Brattle GROUP

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Executive Summary

The United States ("U.S.") electric industry is currently in the midst of a transformation driven by technological innovation, changes in the industry's cost structure, and environmental concerns. Throughout the latter half of the twentieth century, large coal, nuclear, and hydroelectric generators provided the bulk of the country's electricity, while natural gas and oil generators operated only during peak demand hours. Variable energy resources, such as wind and solar photovoltaic ("PV") generators, provided only a small portion of the nation's electricity. Most generators could change output only very slowly, but because virtually all capacity was dispatchable and variations in load were both relatively small and highly predictable, the system operator could readily deal with changes in load.

Over the last decade, reliance on non-dispatchable[1] generation from wind and solar facilities has grown rapidly. At the same time, falling natural gas prices and more stringent environmental regulations have led natural gas generation to replace output from coal, and, to some extent, retired nuclear resources. Because their output varies based on wind speed and solar insolation, wind and solar generators are sometimes described as "intermittent" or "variable energy" resources. Large variations in output from such resources happen with regularity. At high penetration levels even relatively predictable output variations, such as solar output falling at night, can strain the grid operator's ability to manage the system.

State-level environmental policies, net-energy metering, falling capital costs, federal tax incentives,[2] and improving technology make it likely that variable energy generators will constitute an even greater share of U.S. electrical generation in the future. To ensure reliability as variable energy resources' share of total generation grows, the system requirements will change. Grid operators will need access to power plants, storage, and demand response resources that have a diverse set of reliability attributes that can meet these requirements. Some of these

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1 Independent System Operators ("ISOs") can curtail wind and solar generation when needed, providing some control over their output. However, variable energy resources are not dispatchable in the usual sense (beyond curtailment) since their output largely is a function of constantly changing weather conditions outside the control of plant operators.

2 Some tax incentives are phasing out over the next few years, but overall tax incentives remain an important factor.

reliability attributes are new to markets. For example, the California Independent System Operation ("CAISO") is exploring the creation of a market for primary frequency response to address North American Electric Reliability Corporation ("NERC") Standard BAL-003, which defines the amount of frequency response balancing authorities need to maintain frequency within acceptable limits.[3] The products CAISO is considering would be designed to address frequency within the NERC defined measurement period of 20 to 52 seconds.[4] Other reliability attributes, such as the ability to provide reserve capacity, have been traded for years. However, the changing make-up of generation may require even mature markets to rethink the way reliability attributes are priced by markets.

Going forward, all jurisdictions should consider two key principles when determining their needs for reliability attributes. First, variable generation resources can create additional reliability needs for the system. Second, resources with reliability attributes that meet these needs should be appropriately valued. With these two principles in mind, we identify three important issues for market designers and system planners to consider going forward. First, the marginal capacity value of variable generation resources can decrease as penetration increases. Second, obtaining frequency response will be increasingly important as increased reliance on variable generation resources decreases system inertia and increases frequency volatility. Third, fast ramping resources will be critical to integrating variable generation resources that increase the variability of net load.

In the remainder of this paper we identify and describe the attributes that contribute to grid reliability and discuss their importance in the context of a changing grid.[5] We review the ways existing markets compensate resources and provide high-level recommendations for what can be done to improve current market design going forward. We also include a discussion of how ensuring an appropriate diversity of reliability attributes may be different for vertically integrated utilities than for load serving entities operating in deregulated electricity markets.

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3 CAISO Issue Paper, Frequency Response Phase 2, December 15, 2016.

4 NERC Standard BAL-003.

5 The authors note that cost and environmental attributes may also affect market design. This paper focuses solely on reliability attributes and on the appropriate principles for compensating resources that provide those reliability attributes.

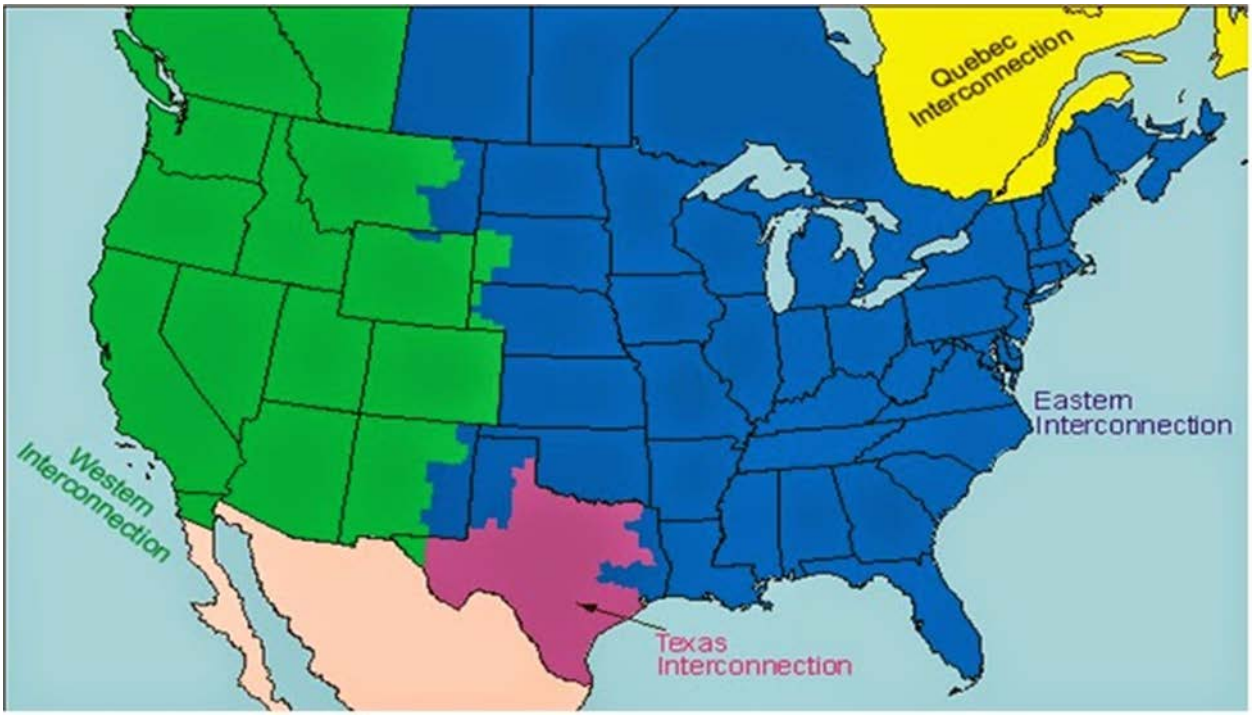
Finally, we conclude by identifying the most important challenges that the changing power system will create for system reliability.

I. Background

A. North American Interconnections

The North American transmission network is made up of four separate grids or alternating current ("AC") interconnections: the Eastern Interconnection, the Western Interconnection, the Texas Interconnection, and Hydro Quebec as depicted in Figure 1. The four interconnections are electrically independent of each other and are only connected together through a handful of low-capacity High Voltage Direct Current ties that allow for relatively small amounts of scheduled power to transfer between the grids. Balancing Authorities ("BAs") within each interconnection balance load (customer demand) and generation (see Figure 2).

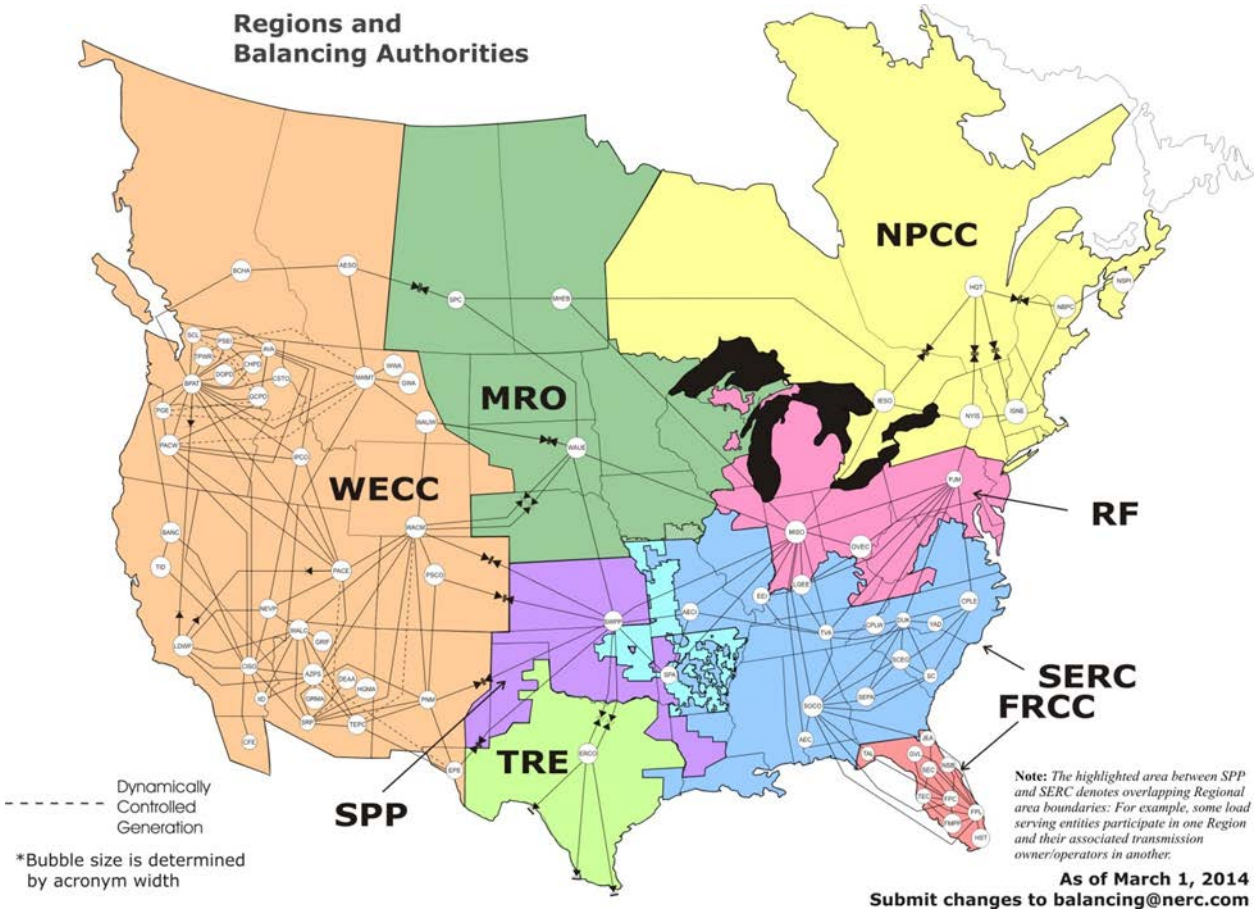
Figure 1
North American Interconnections



Source: North American Electric Reliability Corporation, "Balancing and Frequency Control," January 26, 2011.

There are about 75 BAs in North America; each is connected to neighboring BAs via transmission lines. The BAs are coordinated by 16 Reliability Coordinators ("RCs"). The BAs operate the local systems for which they are responsible, while the RCs are responsible for wide-area coordination.

Figure 2
North American Regions and Balancing Authorities



Source: North American Electric Reliability Corporation website. http://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx

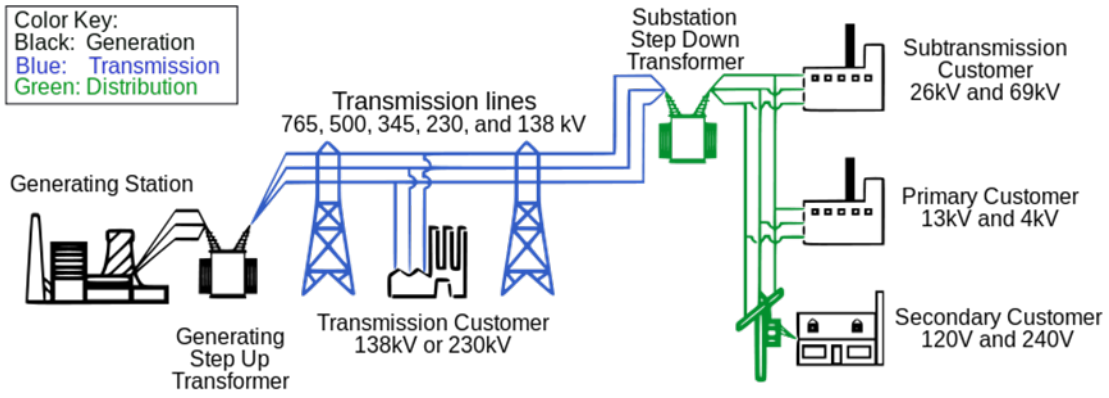
Power system operations focus on three goals, which are: 1) maintain an instantaneous balance of real power between supply and demand across the transmission network; 2) ensure power flows on the transmission system remain within safe limits under a wide range of conditions; and 3) maintain voltage within specified tolerances across the transmission system. Achieving these goals is very complex. Power system operations became more complex over time as the system grew from approximately 130 relatively small "control areas" in the U.S. that roughly corresponded to utilities in 2002 to eight Regional Entities, and seven Regional Transmission Organizations ("RTOs"),[6] that today provide approximately 65% of U.S. generation supply. The

[6] RTOs and ISOs differ slightly in that RTOs meet additional requirements and have greater responsibility for the transmission network. However, the distinction is not crucial to this overview of market structure, and much of the industry uses the two terms interchangeably.

largest RTO, the PJM Interconnection ("PJM"), covers most of 13 states plus the District of Columbia and is responsible for the power supply of about 20% of the nation's population.

The power system is primarily an alternating current system. Electricity flows over a very complex network of transmission lines and transformers from generators to customers. Figure 3 provides a simple illustration of AC power system fundamentals.

Figure 3
Illustration of AC Power System Fundamentals



Over decades, power system operators developed rules-of-thumb to meet the three goals. The solutions differed from region to region but had common high-level elements:

1. Established a level of installed generating capacity above projected peak load to ensure a level of predicted reliability (usually 1 day loss of load in 10 years[7]), a metric known as "resource adequacy."[8]

2. Developed a set of ancillary services that the generation system must provide to deal with variations in customer demand and unexpected power plant outages at time scales from seconds to hours.

3. Developed a set of ancillary services that the generation and transmission system must provide to insure voltage stability on the transmission system.

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7 NERC Rule BAL-502-RFC-02

8 ERCOT does not have a planning reserve margin requirement and relies on market signals to provide new capacity when needed. The NERC reliability planning council TRE has established a target reserve margin but it is not incorporated in the market rules.

4. Developed a set of rules for monitoring the transmission lines and transformers for overloads and potential overloads to ensure that the transmission system can continue to operate in the face of a transmission line failure or a generator outage.

These rules of thumb worked well when power system generation was almost entirely dispatchable and customer demand variations were relatively predictable and small in aggregate.[9] In addition, the power systems of the past were almost all based on generators with large rotating mass that had significant *inertia* that restored the supply-demand balance almost instantaneously after a disturbance. With the addition of significant wind resources about a decade ago and the addition of solar PV resources in the past few years, the nature of the power system began to change. At the same time, market conditions shifted and regulations came into effect that caused some of the baseload coal and nuclear plants that had provided inertia to retire.

Utility scale wind and solar plants are bringing new challenges to the power system due to the variability of their output. These resources cannot be "dispatched"[10] when needed and their output varies with wind and solar patterns with some degree of uncertainty. The result is that "net load" – the difference between customer demand and the output of variable resources – has much higher variance in systems with significant wind and solar penetration. At the customer level, rooftop PV further increases the variability of net load. These developments have resulted in RTOs rethinking their ancillary service needs.

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[9] Dispatch refers to the ability of power plant or system control operators to vary a resource's consumption or generation of electricity to achieve balance between overall electricity supply and system demand.

[10] Modern wind machines can be dispatched down but cannot provide more power than available from the wind when needed.

B. BULK POWER ADEQUACY

Bulk power adequacy refers to having sufficient generating capacity to meet instantaneous demand at all times "… taking into account scheduled and reasonably expected unscheduled outages of system elements."[11] NERC considers the bulk power system to be generation and transmission elements that are connected and operate at 100 KV and higher voltages. Prior to the advent of RTOs/ISOs, regulated utilities planned to meet a very high level of reliability, usually the "one day in ten year" loss-of-load expectation standard described in the previous section. The planning process was fairly simple with the utilities often facing few internal transmission constraints and generators having a large degree of certainty and control over their output. As markets developed these same requirements were adopted by the RTOs/ISOs.

States that are not in RTOs/ISOs today mandate planning reserve margins consistent with the one-in-ten standard. These standards have worked very well over the years. Bulk system-level outages that affect customers are very rare. The outages that customers experience are almost all due to the distribution system. These are the lower-voltage wires and transformers that connect the bulk system to customers.

Most of the RTOs/ISOs have some form of capacity market, with the exception of the Electric Reliability Council of Texas ("ERCOT") and the Southwest Power Pool ("SPP"). A capacity market enables those with available generation to sell the attribute of firm electric power supply to buyers who need assured access to electric power at peak times. All of these markets are designed to maintain NERC reliability requirements. The approach taken by each RTO is different and to some extent is related to the underlying region's generation sector structure. PJM, the New York Independent System Operator ("NYISO"), and the New England Independent System Operator ("ISO-NE") mostly cover states that have deregulated wholesale markets. Those RTOs require that most generators offer into the capacity market. The Midcontinent Independent System Operator ("MISO"), which covers many regulated states, relies more heavily on utility-owned generation and bilateral transactions for capacity with a parallel, smaller market to balance the residual supply and demand. All of the capacity markets have local requirements that recognize transmission constraints. Each RTO's/ISO's reliability standards are derived from a NERC standard described in the next section.

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[11] http://www.nerc.com/files/glossary_of_terms.pdf

The one in ten reliability standard is almost always translated into a *reserve margin*, which is a measure of how much extra capacity is needed over and above peak load to maintain the required level of reliability. Reserve margins are usually in the range of 15% to 20%. One major challenge that arose during the last decade has been how to place variable energy resources into a reserve margin context. Variable resources, such as wind and solar, cannot dependably provide generation when needed during system peak conditions. For example, wind tends to blow hardest overnight and in winter months. On a hot summer day winds are often light in most places resulting in low wind generator output. One of the challenges facing both markets and regulated utilities is how to calculate an accurate capacity value for wind and solar. A widely used method is the effective load carrying capability ("ELCC"). ELCC is a probabilistic measure of the contribution of variable generating units to meeting load at the time of system peak. Wind units generally have an ELCC of between 10% and 30% of their nameplate capacities. Thus, 100 MW of installed wind capacity is equivalent to approximately 10 to 30 MW of a dispatchable plant in terms of contributing to reserve margins.

As penetration of variable resources increases, it will be increasingly important that the concept of ELCC include the marginal value of renewables towards meeting peak net load. Peak net load is the system's highest demand for generation from dispatchable resources. At high levels of renewable penetration additional renewable capacity may have substantially less, or even no, marginal value as a capacity resource. As a simple example, in a system with a peak load that occurs during daylight hours, solar PV will have value as a capacity resource. However, at a high enough level of solar PV penetration, the peak hour of net load could move to a nighttime hour. Because solar PV does not generate during the night, additional solar PV MW will have no additional capacity value.

C. NERC Adequacy Standards

NERC has published a set of mandatory standards that covers all aspects of the bulk power system from generation adequacy to cyber security.[12] One of these, BAL-502-RFC-02, establishes resource adequacy requirements to meet a "one day in ten year" loss-of-load expectation standard. This standard is translated into a planning reserve margin. The idea is to have sufficient capacity online to meet demand at the time of system peak load. This is the first line of defense

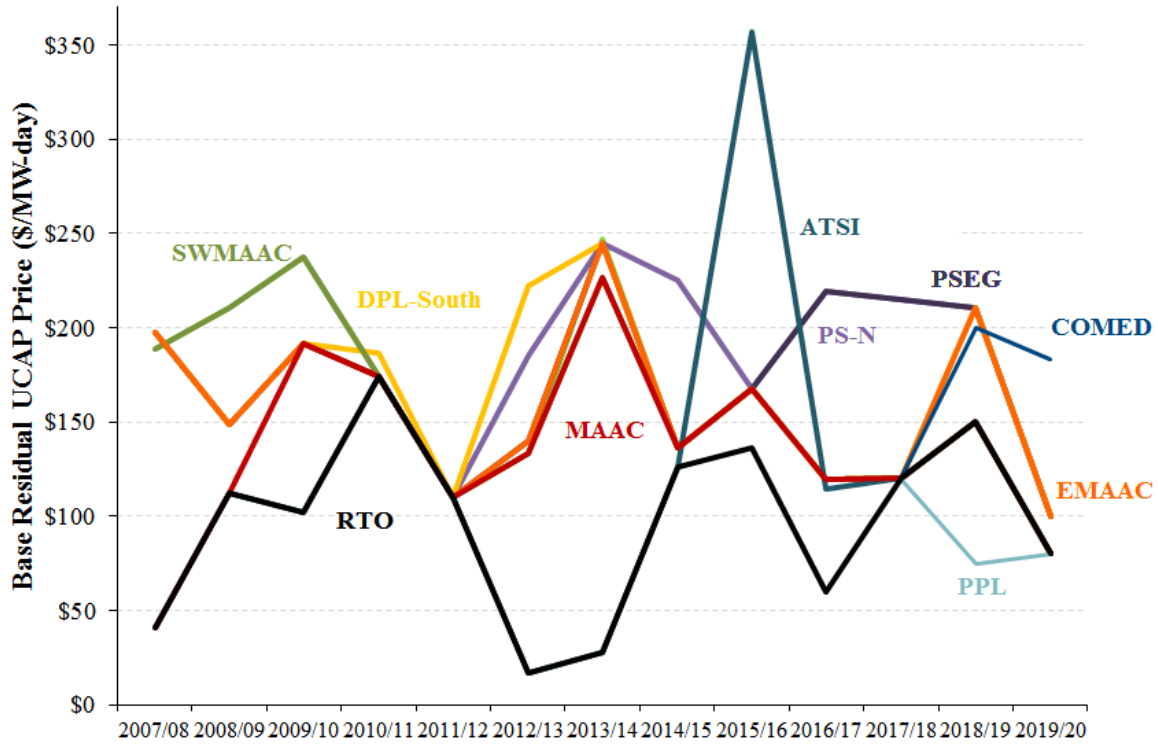
[12] http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf

and is a static requirement based on the estimated capacity that is likely to be available at system peak. The one day in ten year standard had already been used for decades. BAL-50-RFC-02 made the standard an official requirement and specified how to calculate it.

Each RTO or utility establishes a planning reserve margin to achieve the resource adequacy standard. Even ERCOT, which has no requirement to maintain any specific reserve margin, has determined a "target reserve margin." All of the U.S. RTOs except ERCOT and SPP have market mechanisms that compensate market participants for providing capacity. In most instances, RTO capacity requirements have a locational element, recognizing the broad geography of these markets and the internal transmission constraints that can limit the deliverability of remote capacity.

For example, PJM has 27 load delivery areas ("LDAs") in its Reliability Pricing Model ("RPM"). The LDAs are used for evaluating transmission constraints. Auctions for capacity are conducted three years forward and the different LDAs can separate at each auction. When this happens, capacity prices differ across PJM. The RPM prices change with each annual auction as do the separate prices for LDAs that are transmission constrained. Figure 4 shows historical PJM RPM prices in different LDAs.

Figure 4
PJM RPM Prices Over Time[13]



Source: Energy Velocity

[13] In delivery years 2018/19 and 2019/20 graph reflects prices for the Base Capacity product.

II. Requirements and Attributes

The power system faces a number of requirements that may change over time. The system operator needs to:

1. Meet bulk demand;
2. Follow load or net load;
3. Maintain voltages; and
4. Maintain frequency stability.

Generators, storage, and demand response (i.e., resources) have attributes that enable the system to meet each of these requirements. As the power system changes, the attributes necessary to meet these requirements change with it. Key resource attributes include:

1. Generation capability;
2. Dispatchability;
3. Security of fuel supply
4. Start times and ramp rates;
5. Inertia and frequency response capability;
6. Reactive power capability;
7. Minimum load level;
8. Black start capability;
9. Storage capability;
10. Proximity to load.

This section discusses these attributes and explains how they fulfill different requirements for the system.

A. GENERATION

No attribute is more fundamental to system requirements than the ability to generate electrical energy. While resources that lack this attribute may provide valuable services to the grid, the system cannot meet any of its requirements without resources that can generate electricity. Energy efficiency, and to some extent demand response, reduce the need for resources that have

this attribute, but ultimately the system must have resources that generate electricity to serve customer demand when it does appear.

B. DISPATCHABILITY

Dispatchable resources have the ability to change their output or consumption levels in response to an order by the system operator. Dispatchable resources fall into two main categories – dispatchable generation and dispatchable load. Dispatchable generation resources can respond to orders from the system operator to increase or decrease the amount of electricity they send to the grid. Similarly, dispatchable load resources can respond to orders from the system operator to increase or decrease the amount of electricity they withdraw from the grid. Some resources such as storage can both inject and withdraw power from the grid.

Virtually all resources are dispatchable to some degree. However, some resource types have greater capabilities than others. Various factors affect a resource's dispatchability. Thermal units and pondage hydro can be partially or fully derated by outages, reducing their dispatchability. Thus, units with lower outage rates are more dispatchable. For similar reasons, seasonal runtime limits can reduce dispatchability in nonattainment regions. Access to a reliable fuel supply also affects the dispatchability of generation resources. Onsite storage of fuel (generally coal, uranium, distillate oil at gas plants, or dammed water) provides the most reliable fuel supply. Firm contracts for fuel supply (generally natural gas and coal) also provide a reliable source of energy. Variable resources have no control over their fuel supply, which limits their dispatchability.

Most variable energy resources can respond to an order to reduce generation through curtailment or increase their generation when already intentionally curtailed and not on outage. However, the maximum output for such generators at any given point in time is a function of factors (e.g., wind speed, solar insolation, or hydrology) outside the control of the system operator. By contrast, fossil-fueled units can respond to orders to increase generation up to their maximum seasonal output, so long as they are not experiencing an outage.

The system requires dispatchable resources to ensure that electrical output continuously matches electric demand. Without dispatchable resources the system operator would not be able to meet the requirements to: a) meet peak demand; or b) to follow load.

C. Security of Fuel Supply

Security of fuel supply is an attribute that describes the dependability of a resource's energy inputs, or fuel. Generation resources primarily rely on uranium, water, coal, natural gas, oil, wind, and solar energy for fuel supply. Demand response and storage resources do not have fuel supply in the traditional sense, but their ability to supply power does depend on the availability of their inputs. Demand response resources can only respond to instructions from the system operator when consuming electrical energy. Thus, the "fuel supply" for demand response resources is their demand for electricity. Storage resources use stored electricity as a "fuel supply."

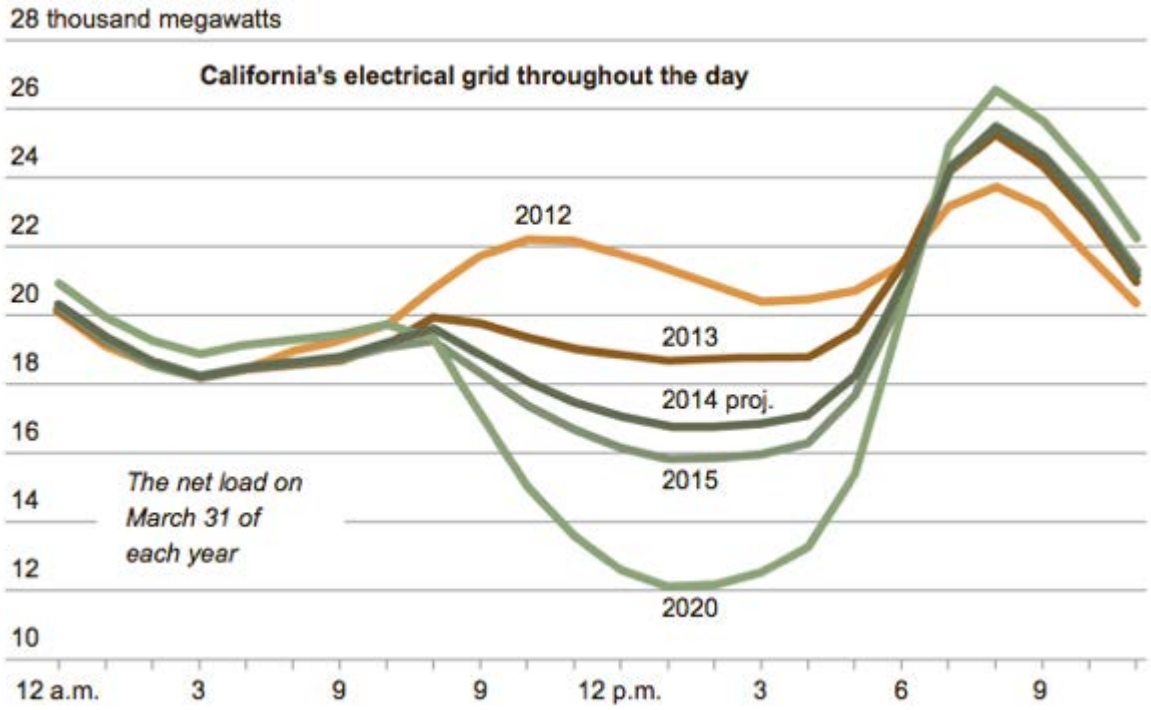
Resources with very secure fuel supplies rarely experience fuel supply interruptions, while resources with unsecure fuel supplies frequently experience fuel supply interruptions. Resources with very secure fuel supplies are especially important to meeting the system requirement to meet bulk power demand.

D. Start Times and Ramp Rates

Closely related to dispatchability, start times and ramp rates determine the speed at which resources can respond to system operators' orders to increase and decrease electricity delivered to the grid. A resource's start time describes the length of time needed to begin delivering energy to the grid when it is not already delivering energy to the grid. In other words, it is the length of time needed to "turn on" the resource. A resource's ramp rate describes the speed at which it can change output levels once it is already delivering electricity to the grid.

The system requires resources that can respond to dispatch orders from the system operator in order to follow load. As net load becomes more variable, the need for resources that can respond quickly will increase. The much discussed California "duck curve," shown in Figure 5, illustrates how higher solar PV penetration has dramatically increased, and is expected to continue increasing, the variability of net load. The dramatic spike occurs because solar PV generation naturally falls when the sun sets. In order to meet this spike, CAISO will need access to resources that it can ramp quickly. This will increase demand for resources with short start time and high ramp rate attributes.

Figure 5
Duck Curve



Source: CAISO

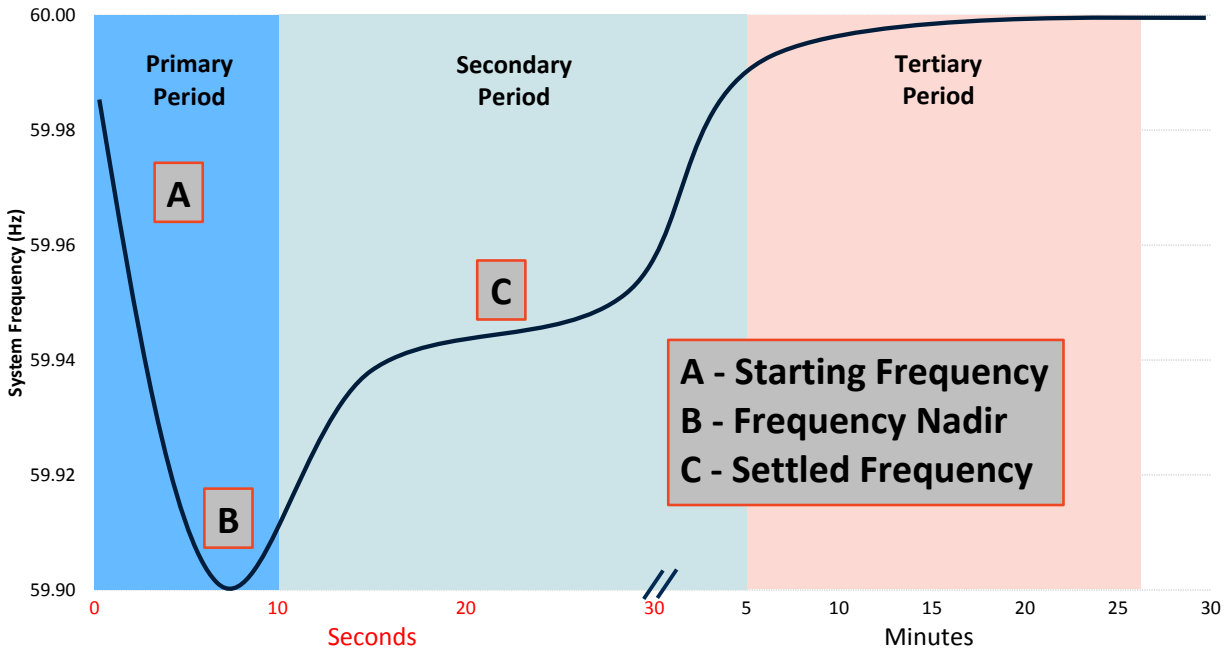
E. INERTIA AND FREQUENCY RESPONSE

Inertia and frequency response are attributes of resources that help the system meet the requirement to maintain frequency stability. The North American power grid is an alternating current ("AC") system that is designed to operate at a constant frequency of 60 hertz ("Hz"). If the grid's frequency deviates too far from 60 Hz, then mechanical failures can occur. To avoid these failures, when large frequency deviations occur automatic safeguards result in load shedding and/or generator shutdowns. For this reason, the system's requirement for stable frequency is critical to reliability.

When demand exceeds supply on the grid, the frequency falls as rotating generators slow down; when supply exceeds demand on the grid, the frequency rises as rotating generators speed up. The heavy rotating turbines have large rotational inertia. When changes to demand occur, leading to transient supply-demand imbalances, the inertia of the turbines resists changes in speed and therefore opposes frequency changes. This helps maintain a nearly constant 60 Hz frequency on the grid by giving the system operator time to adjust generation (or load) to correct the frequency deviation from 60 Hz.

In addition to inertial response, primary, secondary and tertiary frequency response services play a necessary role in maintaining frequency stability by quickly injecting or withdrawing energy. Primary frequency response occurs more quickly than secondary frequency response which, in turn, occurs more rapidly than tertiary frequency response. Turbine governors on synchronous generators and frequency responsive load provide primary frequency response. Primary frequency response occurs automatically over the course of up-to 15 seconds. Secondary frequency response, also called regulation, occurs over a period of 10 seconds to several minutes. The system operator orders regulation resources to inject or withdraw energy from the system as needed using an Automatic Generation Control ("AGC") signal. This shifts the response from primary frequency regulation providers to secondary frequency regulation providers to ensure that the primary frequency regulation resources are ready to respond in case of a subsequent event. Finally, tertiary frequency response occurs over a period of 5 to 30 minutes. This response is also controlled by the system operator and, in the organized markets, it is organized through the real-time energy markets through a change in the generation dispatch. Figure 6 illustrates the timing of different categories of frequency response.

Figure 6
Illustrative Example of Frequency Response



Historically, resources have not been compensated for providing inertia, even though inertia has value because it helps maintain frequency stability. Inverter-connected wind and solar PV

installations do not provide rotational inertia (with the proper equipment, wind farms can provide some synthetic inertia and there has been discussion that other inverter-connected devices may also provide synthetic inertia in the future).[14] As the proportion of generation provided by wind and solar has risen, FERC has raised concerns about the decline in total system inertia, leading to larger and more rapid variations in frequency.[15] Similarly, NERC has raised the concern that, "[w]ind, solar, and other variable energy resources that are an increasingly greater share of the BPS [Bulk Power System] provide a significantly lower level of essential reliability services than conventional generation."[16]

While some regions, such as California, are currently developing market products to address problems caused by lower system inertia, decreases in inertia associated with higher levels of renewables may be offset by increases to inertia from other parts of the system. For example, ERCOT found that under a high renewables scenario, inertia increased in most hours relative to a recent historical scenario because coal generation was displaced by not only renewable generation but also by combined-cycle generation, which has nearly twice the inertia per MW as coal.[17]

Resources have been compensated for providing frequency response services, but the growth of variable renewable generation has led to changes in the markets for those services. The variable nature of wind and solar PV has contributed to greater variability in net load, further increasing the need for frequency response. NERC Standard BAL-003 defines the amount of frequency response that balancing authorities need to maintain frequency within acceptable limits.

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[14] "The kinetic energy stored in rotational parts of wind turbines can be extracted through a control strategy referred to as "synthetic inertia". The control system detects the frequency deviation and adjusts the power flow into the grid based on this. In this way the turbine contributes to the system as if it would have inertia just like conventional units; hence the term 'synthetic inertia'."

The Utilization of Synthetic Inertia from Wind Farms and its Impact on Existing Speed Governors and System Performance; Mohammad Seydi, Math Bollen, STRI, January 2013, pages 6-7.

[15] Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response, Docket No. RM16-6-000, February 18, 2016.

[16] State of Reliability 2015, May 2015, page 16.

[17] Cost-Benefit Analysis of ERCOT's Future Ancillary Services (FAS) Proposal, http://www.ercot.com/content/wcm/key_documents_lists/30517/667NPRR_12a_Cost_Benefit_Analysis_122115.pdf pages iv and 9.

Increased renewable penetration will lead to greater need for resources with inertia and frequency response capability.

F. Reactive Power

The ability to provide reactive power is an attribute necessary for meeting the system's requirement to maintain voltage within certain limits. Increasing reactive power supply leads to local voltage increases; decreasing reactive power supply decreases local voltages. Voltage control in an AC power system is important for the proper operation of electrical equipment, which is designed to operate within certain voltage limits. Voltage control is also needed to enable power flow over the transmission system and to reduce transmission losses. Under sustained and pronounced voltage reductions, generators automatically disconnect from the system to avoid equipment damage. This can lead to cascading generator shutdowns and widespread blackouts.

G. Minimum Load Level

A resource's minimum load level describes the lowest level of electrical output the resource can continuously send to the grid. For example, a generator with a minimum load level of 200 MW and a capacity of 800 MW can continuously generate as little as 200 MW of electricity or as much as 800 MW of electricity. The generator cannot, however, continuously generate only 100 MW of electricity. Dispatchable resources with lower minimum load levels (as a percentage of maximum potential output) are better able to help the system meet its requirement to follow load because the system operator has greater flexibility to dispatch the resource in response to changes in net load. This flexibility gains value as net load variability increases.

H. Black Start Capability

Most generating units need electricity from an external source to start after they have shut down. After a single power plant experiences an outage under normal conditions, the generator can simply draw electricity from the grid. However, to restart after a widespread power outage, generators need resources with black start capability. Black start capability is the ability of a power plant to restart without relying on the transmission network to deliver power.

The black start process generically involves using small generators or storage devices to provide the electricity that can provide sufficient energy to restart a power plant. The restarted plant can, in turn, energize transmission lines enabling plants without black start capability to restart. The

black start attribute is critical to meeting the system requirement to serve bulk power demand in the aftermath of an area-wide outage.

I. STORAGE CAPABILITY

Resources with the attribute of storing electricity help the system meet multiple requirements including meeting bulk demand, following load or net load, and maintaining frequency stability, but not all resources with the ability to store electricity contribute to meeting all of the requirements. To provide capacity and contribute to the requirement to meet bulk demand, storage must be able to provide output for several hours. To contribute to the requirement to follow load, the resource must be able to provide output for at least several minutes. To contribute to the requirement to maintain frequency stability, the resource does not need to store energy for a significant length of time, but it does need to be able to respond rapidly to operator instructions. For the resource to provide primary frequency response, it needs to be able to respond automatically to changes in the frequency.

J. PROXIMITY TO LOAD

The ability to site resources close to load is an attribute that helps the system meet bulk demand and maintain voltages. Resources that are close to load that also have the ability to generate reduce transmission losses and transmission congestion. This helps the system meet bulk demand because the system needs to generate less electricity in aggregate and the transmission system does not need to be as extensive. Proximity is also important for maintaining voltage because reactive power is more effective at controlling voltage when it is located close to the reactive power load.

Early power systems had generators that were quite close to load, often within metropolitan areas. Today, some of those early generating stations in major cities remain in service. Often, those stations have been modernized and upgraded with new, usually gas-fired generators. The Mystic power plant in the Boston area was first developed in 1957 and has been modernized as a gas plant in recent years.[18] These sites remain valuable in part because of their proximity to major metropolitan areas.

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[18] http://www.prnewswire.com/news-releases/new-exelon-power-plant-providing-clean-energy-to-boston-area-71274792.html

As the power system expanded, larger power plants, usually coal-fired and nuclear, were built further away from load with the power being brought to growing load centers by an expanded transmission system. However, modern natural gas plants, storage facilities and rooftop solar are often built close to load, sometimes in major urban areas. Recent gas plant additions in metropolitan areas include a combined cycle at Astoria in New York City, and the Mystic units in the Boston area. In addition, gas peaking plants (gas turbines or reciprocating engines like those under development in Denton, Texas) can be added near load centers because of their small physical and environmental footprints.

K. ATTRIBUTES AND TECHNOLOGIES

Table 1 shows the relative advantages that different technologies have in providing the attributes needed for system reliability.

Table 1
Reliability Attributes and Technology

	Natural Gas - CC/CT/RICE/ Aeroderivate	Coal	Nuclear	Wind	Solar	Pondage Hydro	Run of River Hydro	Demand Response	Storage
Generation	●	●	●	●	●	●	●	N/A	N/A
Dispatchability	●	●	◍	○	○	●	○	●	●
Security of Fuel Supply	●	●	●	○	◍	●	◍	◍	◍
Start Times	●	○	○	N/A	N/A	●	N/A	●	●
Ramp Rates	●	◍	○	N/A	N/A	●	N/A	●	●
Inertia	●	●	●	◍	○	●	●	○	○
Frequency Response	●	◍	○	○	○	●	○	○	●
Reactive Power	●	●	●	◍	◍	●	◍	N/A	N/A
Minimum Load Level	●	◍	○	N/A	N/A	●	N/A	●	●
Black Start Capability	●	N/A	N/A	○	○	●	●	N/A	◍
Storage Capability	N/A	N/A	N/A	N/A	N/A	◍	N/A	N/A	●
Proximity to Load	●	◍	◍	◍	●	○	○	●	●

● Relatively Advantaged
◍ Neutral
○ Relatively Disadvantaged

Other than demand response and storage, all of the technologies listed have the generation attribute. All of the technologies have the dispatchability attribute, but the variable generation resources (wind, solar and run of river hydro) have a disadvantage relative to other technologies. The system operator can dispatch variable generation resources down, but only at times when

the resources are already generating. If wind, insolation, or hydrology conditions prevent generation in the first place, the system operator cannot dispatch the resources down. The system operator's ability to dispatch variable generation resources up is even more limited. In addition to the conditions required to dispatch down, the resources must also be generating less than their maximum potential output at the time. Because variable resource generators have very low variable costs (if any), it rarely makes economic sense to operate the resources in a fashion that would make upwards dispatch viable. Nuclear capacity is less dispatchable than some resources because, in most cases, it is designed to run at its full output level at all times (except when on outage).

Thermal resources and pondage hydro generally have the highest degree of fuel security. Nuclear plants and coal plants maintain local supplies on-site. Nuclear plants store fuel in the reactor core and coal generation resources store coal in "piles". While natural gas is rarely stored in large quantities on-site, some natural gas-fired plants have the capacity to burn distillate oil stored in tanks on-site in the event of a natural gas supply interruption. Pondage hydro stores water (i.e. its fuel supply) in large reservoirs.

Fuel must be delivered to nuclear, coal, and natural gas plants. Nuclear plants store as much as two years of fuel in their reactors. The large storage capacity makes it unlikely that delivery issues will interrupt fuel supply. Coal plants receive their fuel by rail, truck and/or barge. Because most coal plants also store relatively large amounts of coal in their piles, delivery is unlikely to interrupt fuel supply. Natural gas plants receive their fuel by pipeline. Pipeline delivery arrangements to generators can be interruptible or firm. Natural gas pipeline supply can be interrupted due to lack of capacity when demand is very high, but firm supplies have a very low probability of interruption.[19] Pondage hydro must have stored water, but because reservoirs are typically very large, only prolonged drought conditions are likely to affect the security of the fuel supply. Moreover, the restrictions on hydro due to weather usually only limit energy over a long

[19] Firm supply delivered through the natural gas system is highly reliable with New England being a notable exception due to pipeline capacity constraints. Please refer to the Eastern Interconnection Planning Collaborative Gas-Electric Target #3 Final Draft Report for further details, http://nebula.wsimg.com/4f9c07a87edd4a873d447e16208e2b6e?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1.

Additional work on gas-electric system resilience is underway at NERC and across various RTOs/ISOs to better understand and measure the resilience of the integrated gas and electric systems.

period of time; these restrictions do not limit the amount of capacity available to the system operator at any given time (e.g. during a scarcity event).

Run-of-river hydro, demand response, and storage all have a fairly high degree of fuel security, but it is can be less than dispatchable generation resources during scarcity events. While run-of-river hydro almost always has some level of generation, it is impossible to know the exact amount that will be available at any given time. Demand response also has a fairly secure fuel supply. However, there is no guarantee that a demand response resource will be drawing electricity from the system (for example, air conditioners rarely run during the winter). Finally, while electricity from the grid is almost always available to storage, storage cannot simultaneously deliver electrical energy to the grid and draw from it. Because storage can only "store" a relatively limited amount of energy, its fuel security is lower than that of dispatchable generation resources.

Variable generation wind and solar PV resources have lower fuel security. They cannot store fuel (i.e. they cannot store wind or solar energy) and the supply of fuel is frequently interrupted (i.e. the wind speed or insolation falls). As a result, wind and solar PV resources frequently have their fuel supplies interrupted. However, because solar energy is almost always available to some degree during the day, solar PV has a more secure fuel supply than wind.

Newer natural gas combined cyclers ("CCs") and combustion turbines ("CTs"), reciprocating internal combustion engines ("RICE units"), aeroderivatives, pondage hydro, demand response, and storage have relatively short start times and fast ramp rates. RICE units, aeroderivatives, batteries, and demand response are particularly fast. Older natural gas CCs and CTs generally start and ramp more slowly, but are still generally quicker than coal plants. Some coal units have been designed to ramp quickly, but even those units have slow start times. Nuclear plants ramp very slowly and are difficult to start or stop. Because variable resources are largely not controllable, the concept of start times and ramp rates (as presented in this report) do not apply to them.

Traditional turbine-based generators provide inertia naturally, by design. Wind can provide some inertia and additional "synthetic inertia" by using appropriate control functions in its inverter. Inverter-connected solar and batteries could theoretically provide synthetic inertia, but without any rotating mass they would need to rely on stored energy, such as that stored in their capacitors. (It should be noted that both pumped storage and compressed air storage can provide

significant inertia because they generate electricity with turbines). Demand response associated with motor load can provide inertia, though most demand response cannot.

Modern natural gas units, pondage hydro, and storage have an advantage in providing frequency response because in many cases they can provide primary, secondary and tertiary frequency response. While coal can provide primary frequency response, it has a more limited ability to provide secondary and tertiary frequency response because of its slow ramp rate. Because nuclear and variable generators usually operate near their maximum output levels to maximize economic efficiency, they have an even more limited ability to provide secondary and tertiary frequency response under normal circumstances. Demand response could theoretically provide frequency response, but – in practice – the system operator's ability to call demand response is generally limited, reducing its usefulness for providing frequency response.

All generators can provide reactive power, but variable generation resources have less of an advantage than other generators. Reactive power experiences high loss levels and variable generators are usually not close enough to load centers to meet reactive power demand. Moreover, because utility scale wind and solar are often located in areas that are remote from load, they need to generate additional reactive power demand to support local transmission and distribution. This limits the usefulness of variable generation resources for providing reactive power to the system. Demand response and storage do not generate reactive power.

Some modern natural gas units (particularly RICE units) and pondage hydro generally have relatively low minimum load levels. Demand response and storage resources, while not generators, essentially have very low minimum load levels (0 MW for batteries). Coal units often have higher minimum load levels than natural gas plants (measured as the percent of total capability represented by minimum load level) and nuclear units generally operate near their maximum output levels. Because variable generation resources' output is dependent on outside system conditions, the concept of a minimum load level (as defined in this report) does not apply to them.

Natural gas CCs, CTs, RICE units, aeroderivatives, and hydro facilities can all provide black start services. Storage can provide black start, but it would need to remain partially charged at all times to do so reliably. Otherwise, there would be a risk that the storage would be fully discharged during an outage event. Wind and solar can provide black start, but would not be able to do so unless wind or insolation conditions permitted. Coal and nuclear units cannot start

without an outside power source (though a plant may have that power source onsite). Because it cannot deliver electricity to the system, demand response cannot provide black start.

For the purposes of this report, we have defined storage as the ability to store electricity provided to the grid for use, as electricity, at a later time. Many types of resources can store energy onsite or through contracts. However, as we have defined the attribute, only storage and pondage hydro can store electricity for use at another time. Storage directly converts electricity from the grid into another form of stored energy, while pondage hydro indirectly converts grid electricity into stored energy by allowing other resources to serve demand so that it can reduce its output and store water to generate at a later time.

Natural gas (particularly aeroderivatives and RICE units), storage, demand response, and solar (rooftop solar) are relatively easy to site near load. Historically, some coal and nuclear plants have been sited near large industrial facilities and load centers, but more recent installations have been sited a considerable distance from major load centers. Wind can theoretically be sited near load, but the best wind resources are generally remote from the places people live. Similarly, the best hydro resources are generally not close to load.

III. Markets for Attributes

A. Ancillary Service Markets

Ancillary services are essential services the power system needs to provide grid reliability. They are critical services that allow the system operator to meet all four reliability requirements. Ancillary services refer to those services that are necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the transmission system in accordance with good utility practice.[20] Table 2 below summarizes the different categories of ancillary services.

Table 2
Summary of Different Ancillary Service Products

Ancillary Service	Response Time	Description
Regulation	Seconds	Capacity that responds to RTO regulation signals, increasing or decreasing generation to manage short-term imbalances of supply and demand.
Spinning Reserves	Within 10 minutes	Capacity that is online but unloaded and that can respond within 10 minutes in response to a contingency.
Non-Spinning Reserves	Within 10 minutes	Capacity that may be offline (not synchronized with the grid) and can respond within 10 minutes.
Black Start	n/a	Resources that can start up without assistance from a power system.
Frequency Response	Seconds	Generation ensuring the grid frequency stays within a specific range of the nominal frequency.
Reactive Power	n/a	Generation used to compensate for voltage drops within transmission system.

Most ancillary services (except reactive power and black start) require the resource have the capability to respond rapidly to orders from the system operator. This means a resource must

[20] See Federal Energy Regulation Commission (2016), https://www.ferc.gov/market-oversight/guide/glossary.asp, accessed on February 2, 2017

either a) operate below its full output level (in case the system operator orders it to increase output) or b) allow the system operator to order it to reduce output in a case where it may have a positive energy margin. For these reasons, providing an ancillary service generally reduces the amount of electrical energy a resource can deliver to the grid.

Despite their importance, policy and market design had not focused on ancillary services until relatively recently. After the provision of energy, generation resources historically had the capability to provide more ancillary services than systems required. Because of this surplus, in recent years providing ancillary services created only modest incremental costs for the system. However, with higher renewable penetration, ancillary service markets are becoming increasingly important. Renewables increase the uncertainty and variability in net load and make ramps larger, thereby increasing the ancillary service requirements. In addition, higher renewable penetration depresses energy market prices. This reduces margins earned by resources in the energy market and increases the need to compensate resources for the ancillary services they provide.

Responding to the increased need for ancillary services, the U.S. ancillary services markets have been undergoing changes. At the FERC level, Order 784 requires that markets for frequency regulation take into account the speed and accuracy of regulation resources. Traditionally, generators were only rewarded for the amount of regulation services they provided. No additional compensation was offered for providing a more rapid response time or greater accuracy following a regulation signal. For example, battery storage technologies can respond to system changes in a much faster way than traditional generators. Speed and accuracy are important metrics that impact resources' abilities to provide both frequency response and other fast ramping services.

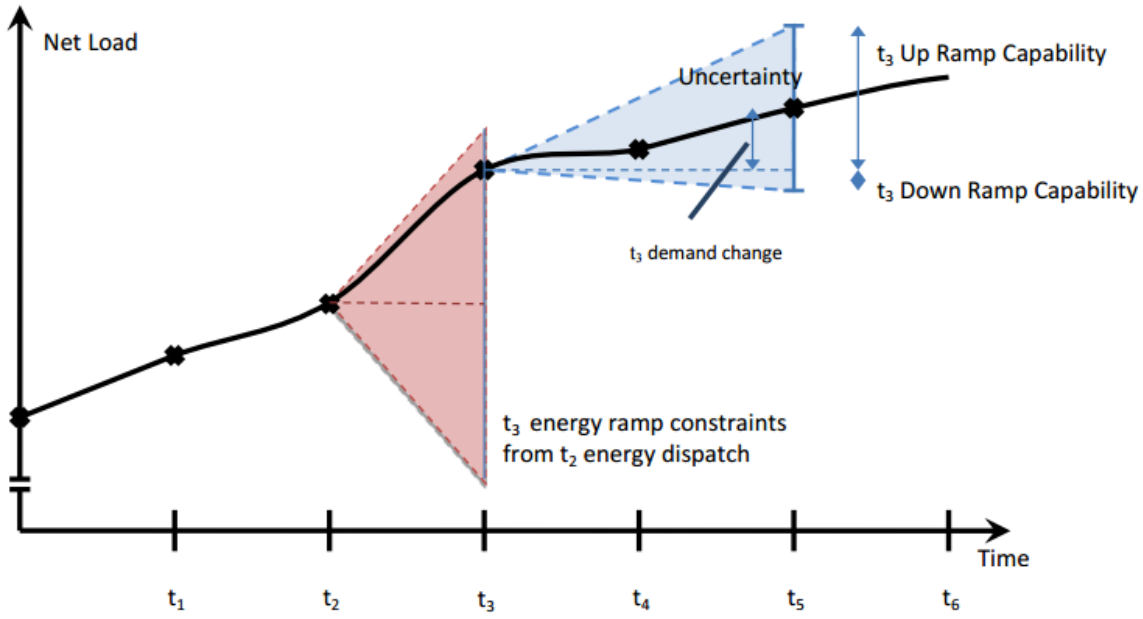
Some ISOs also implemented other reforms in ancillary service markets in order to better reflect the need of the system for flexibility. Both MISO and CAISO have established new ancillary services to manage the challenge of rising variability and uncertainty in net load due to

increasing levels of renewables.[21] These products will help dispatchable resources respond to uncertainty and variability in non-dispatchable resources (including most load and renewables). At a high level, the ramp capability products allow the real-time dispatch algorithm to dispatch resources in a way that reduces the likelihood of future scarcity events. The products are designed to strike a balance between the higher operating costs required to provide additional ramp capability and the avoided costs of prevented scarcity events.

Figure 7 illustrates generically how these ramping products work. The red area illustrates the aggregated ramping capabilities of all online resources between periods t_2 and t_3, imposed as a constraint on generation during period t_3. The blue area illustrates the new ramp capability constraints associated with dispatch for time interval t_3. Prior to including ramp capability products, MISO did not consider any requirements beyond t_3 in dispatch decisions made for period t_3, and CAISO accounted for a deterministic forecast of future load. With ramp capability, the dispatch in period t_3 positions resources such that the range of potential load requirements at t_5 can be met by the available resources.

[21] See https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Ramp%20Capability%20for%20Load%20Following%20in%20MISO%20Markets%20White%20Paper.pdf and https://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf

Figure 7
Illustration of Ramp Product



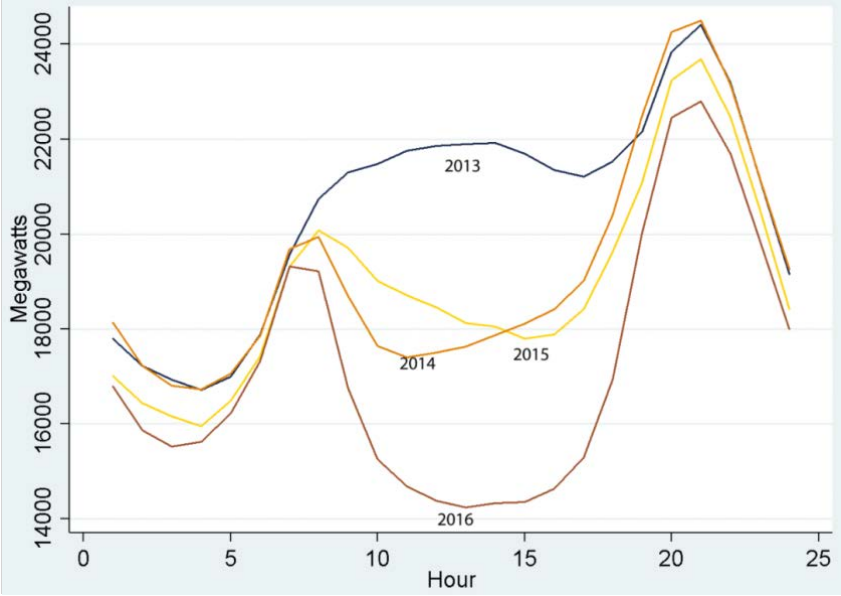
Source: MISO

Both MISO and CAISO established separate up ramp and down ramp products. These products have symmetric features but the auctions clear for separate quantities and prices. The quantities procured of each resource are based on the expected future change in net energy demand and uncertainty in forecast net load. Both MISO and CAISO include ramp constraints in their co-optimization of existing energy and ancillary service products.

B. California Flexible Resource Adequacy Product

Growth in renewables has changed what attributes are valuable for supporting reliability. In light of concerns that the California Renewable Portfolio Standard ("RPS") requirements would increase the need for flexible resources that can ramp quickly, on November 6, 2014 CAISO implemented the Flexible Resource Adequacy ("Flexible RA") product. This product supplements the Flexible Ramping Product by ensuring the market will attract and retain sufficient flexible capacity to achieve the California Public Utility Commission's ("CPUC's") desired level of reliability while integrating California's increasingly high penetration of renewable resources. As shown in Figure 8, growth in solar PV has increased the size of the evening ramp. Specifically, the program ensures enough flexible capacity exists to meet the largest three-hour system ramp each month. Flexible RA resources are procured via bilateral contracts on a multi-year forward basis.

Figure 8
California Hourly Net Load
March 28 – April 3, 2013 – 2016



Source:

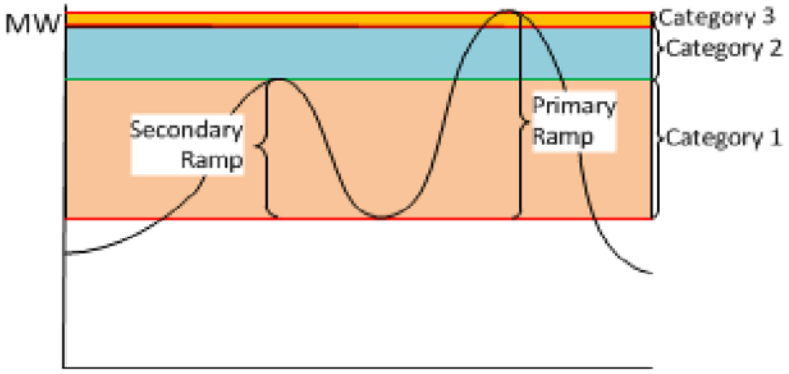
Meredith Fowlie, *The Duck has Landed,* https://energyathaas.wordpress.com/2016/05/02/the-duck-has-landed/

CAISO annually assesses system flexibility needs, accounting for load forecasts, the quantity of renewable resources under its RPS, and renewable generation profiles. CAISO then determines the maximum forecasted 3-hour net-load ramp for each month, calculated as the quantity of

MWs that resources must be ramped or demand must be curtailed across a 3-hour period. CAISO divides flexibility requirements into three product categories:

- **Category 1 (Base Flexibility):** Requirement set by the magnitude of the largest 3- hour secondary net-load ramp.
- **Category 2 (Peak Flexibility):** Requirement set by the difference between 95 percent of the maximum 3-hour net-load ramp and the largest 3-hour secondary net-load ramp.
- **Category 3 (Super-Peak Flexibility):** Requirement set by five percent of the maximum 3-hour net-load ramp of the month.

Figure 9
California Flexible RA Product Categories



Source: CPUC

Once CAISO has determined the total quantity of flexible capacity to procure, it then allocates this requirement across load serving entities ("LSEs"), which must contract for the capacity. Each LSE's obligation is calculated based on its historical contribution to the ISO's largest monthly 3-hour net-load ramp.

Each resource's Effective Flexible Capacity ("EFC") is calculated as the maximum change in net output over a three-hour period. More flexible resources, such as storage, can provide greater flexibility per MW of capacity than inflexible resources with long startup times or high minimum generation levels. The tariff provides specific guidelines for calculating EFC.

C. ERCOT Future of Ancillary Service Reforms

In 2013, ERCOT proposed reforms to the ancillary service markets, collectively referred to as the "Future Ancillary Services" ("FAS").[22] At that time, the design of ERCOT's ancillary services framework was largely unchanged from when it was first established in the 1990s. Although the FAS reforms were ultimately rejected by stakeholders, they serve as a useful example of the types of ancillary service reforms that systems may undertake going forward as deployment of wind and solar resources increase.

The proposed reforms reflect the changing need for ancillary services within ERCOT as inverter-based wind and solar generation displace traditional generation. This transition could result in lower system inertia, thereby increasing reliability risks posed by sudden power imbalances that cause frequency to decay more rapidly than in a system with higher inertia. With less inertia, more reserves are needed to maintain frequency. ERCOT has the additional challenge of not being synchronously connected to neighboring systems, meaning ERCOT itself must manage short-term deviations between load and supply.

ERCOT's proposed FAS reforms were intended to more effectively procure the resources needed to ensure system reliability, based not on the capabilities of specific technologies, but on the fundamental needs of the system. The proposed FAS reforms were multi-faceted, including: (1) enabling a broader range of resources to help meet system needs; (2) more finely tuning requirements to system conditions; and (3) using a procurement approach that better recognizes the relative effectiveness of different ancillary services and resources under different conditions.

The proposed FAS redesign had six main products, ordered below from fastest- to slowest-responding:

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[22] Following description based on two sources:

- ERCOT (2013). ERCOT Concept Paper: Future Ancillary Services in ERCOT. Posted at https://www.ferc.gov/CalendarFiles/20140421084800-ERCOT-ConceptPaper.pdf
- Newell et al. (2015). Cost-Benefit Analysis of ERCOT's Future Ancillary Services Proposal. Prepared for ERCOT. December 21, 2015. Posted at: http://www.ercot.com/content/wcm/key_documents_lists/30517/667NPRR_12a_Cost_Benefit_Analysis_122115.pdf

- **Synchronous Inertia Response Service ("SIR"):** Targeted procurements of inertia under FAS would support system reliability following a disturbance. Inertial response helps to slow the decay in frequency, providing more time for slower-responding resources to respond. Resources are not typically compensated for the inertia they provide; FAS would have provided payment for these resources. SIR would respond immediately to a contingency.
- **Fast Frequency Response Service ("FFR"):** ERCOT would have procured fast-responding resources to slow the decay in frequency following a disturbance, providing more time for primary frequency response ("PFR") to deploy. FFR was designed to accommodate all fast-responding resources, including energy storage. FFR would fully respond to a contingency within 0.5 seconds.
- **Primary Frequency Response Service ("PFR"):** Similar to traditional frequency response products, PFR was intended to re-set frequency closer to defined limits following a contingency. PFR would be provided by generators with governor control or load. PFR would fully respond to a contingency within 16 seconds.
- **Regulating Reserves (Reg):** The FAS proposal included no major changes to the existing Regulation Up and Regulation Down products. These products are intended to balance short-term deviations from the net-load forecast due to unforeseen changes in renewable generation and load. Regulating reserves would follow the ERCOT regulation signal at all times; performance incentives would reward resources that respond more accurately.
- **Contingency Reserve Service ("CRS"):** FAS would have procured fewer contingency reserves, which are slower responding resources intended to help restore the frequency to defined limits. After a contingency, CRS would replace deployed PFR and FRR. CRS would fully respond to a contingency within 10 minutes.
- **Supplemental Reserves ("SR"):** The proposal may have procured SR as a placeholder to fill any additional needs that arise, but ERCOT did not identify any need for SR under anticipated system conditions.

The FAS reforms offered both reliability and economic benefits. Reliability benefits would have included more rapid response to contingencies through SIR and FFR products; ensuring sufficient reserves were available at all times, even immediately after a contingency; and providing incentives for resources to improve performance over time. Economic benefits would have resulted from ERCOT procuring resources to meet a more finely tuned set of requirements. A Brattle analysis found a ten year net present value of the reforms of over $120 million, with a benefit cost ratio of approximately 10. The scenario analyzed had only a modest increase in variable renewables from what was then projected. Although stakeholders rejected the entire slate of reforms, components of the reforms are still under discussion.

In another Brattle study conducted for the Texas Clean Energy Coalition,[23] the authors found that under high wind penetration, a new type of ancillary service would be required to cope with the net load uncertainty caused by wind. Under two scenarios for 2032, one with 26% of ERCOT's energy coming from wind and the other with 43% of ERCOT's energy coming from wind, a new type of ancillary service was needed for system reliability. It was dubbed "Inter-hour commitment option" or ICO. ICO ensures that operators have recourse in the event of net load under-forecast. Resources that supply this service are those that can be brought online within four hours, generally CTs, internal combustion engines ("ICs"), and CCs. The combination of needed non-spin and ICO commitment requirements are a function of renewables and net load forecast uncertainty. With high wind penetration, the study found that up to 9,700 MW of ICO were required for reliable operation of the ERCOT system.

D. CAPACITY MARKETS

Capacity markets are an administrative construct designed to competitively procure sufficient capacity to achieve mandated resource adequacy reliability standards in competitive wholesale markets. NERC-mandated levels of reliability exceed the energy-only equilibrium level that marginal cost based wholesale energy markets alone are likely to attract and retain.[24] As reserve margins rise, the frequency of high priced hours falls and generators earn smaller energy margins. As illustrated in Figure 10, the so-called "missing money" problem reflects the idea that at target levels of reliability, net revenues from the energy market will be insufficient to cover a resource's total going forward costs. This challenge is unique to restructured markets; suppliers in regulated regions earn regulated rates of return on their invested capital, or are under contract with a regulated utility.

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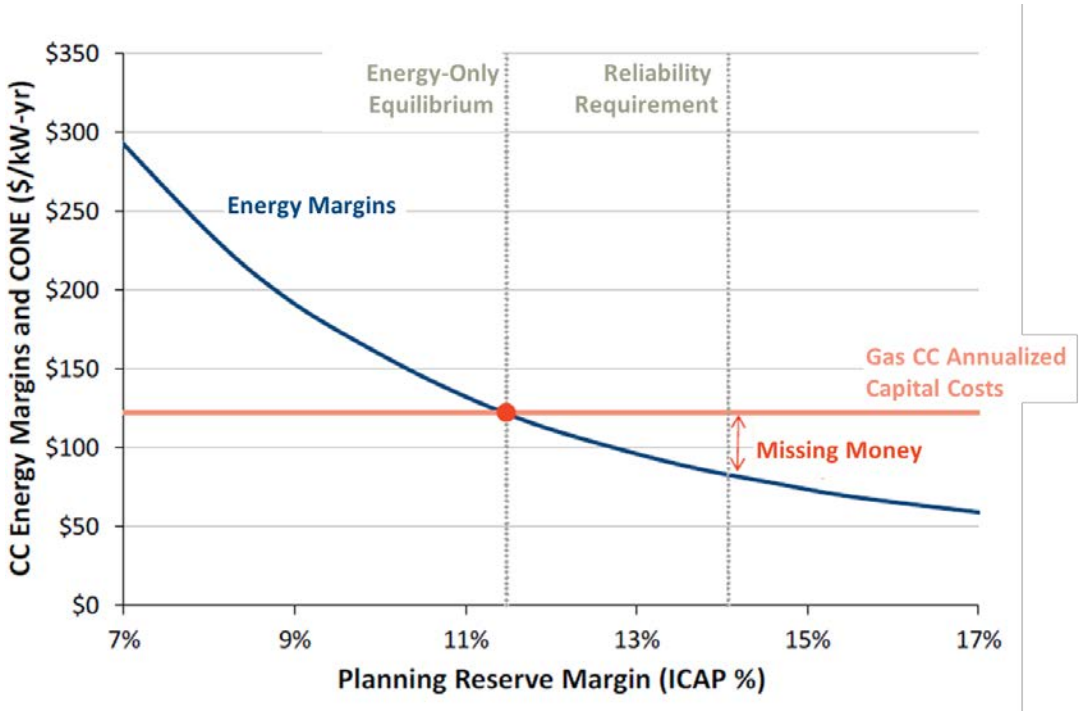
23 http://www.ercot.com/content/meetings/lts/keydocs/2014/0113/5._ERCOT_01_13_14_shavel.pdf

24 The ERCOT energy only market relies on high prices during scarcity hours to attract and retain capacity without a capacity market. During scarcity hours, market prices may reach levels substantially higher than the marginal cost of the most expensive resource in the system.

Figure 10
Illustration of Energy Margins vs. Planning Reserve Margin



Notes:
Illustrative figure, adapted from non-public analyses. Planning reserve margin measured in % installed capacity (ICAP).

PJM established the first capacity market in 1999. Other RTOs followed in the early 2000s as a way to attract and retain sufficient supply to meet mandated reliability standards. Most RTOs have some form of competitive market for capacity, although the design details vary across markets (only ERCOT operates without a mandated reliability standard). These markets can be the primary source of capacity procured (PJM, ISO-NE, and NYISO) or they can be backstop markets in an otherwise bilateral or self-supply environment (MISO and CAISO).[25]

[25] SPP filed a tariff revision at the FERC on March 3, 2017 to implement a mandatory Resource Adequacy Requirement. The proposal establishes penalties for entities that serve load in SPP that fail to have adequate capacity based on a SPP-wide 12% reserve margin. The proposal envisions bilateral capacity trading and bases penalties on the Cost of New Entry ("CONE") for a gas combustion turbine. The penalty for non-compliance increases as the SPP-wide reserve margin falls. See https://www.spp.org/documents/48681/2017-03-03_tariff%20revisions%20to%20implement%20resource%20adequacy%20requirement_er17-1098-000.pdf

Capacity markets are administered by the RTO. The RTO first identifies how much capacity (MW) is needed to achieve the mandated reliability standards, using probabilistic modeling that accounts for uncertainty in projected peak load and generator availability. As described earlier, the most common resource adequacy standard is a loss of load expectation ("LOLE") of one day per ten years, or the so-called 1-in-10 LOLE standard. Once the target level of reliability is determined, the RTO constructs a demand curve to procure that capacity. The demand curve's shape is based on administrative parameters, including a price cap and slope. This shape is set such that a generic new entrant, typically the most common new plant type (generally a gas CC or CT), would earn enough revenue to enter the market if supply were at or below the target quantity. The RTO approximates the generic new entrant's CONE net of energy and ancillary service revenues, or Net CONE, when setting the demand curve. Over time, RTOs have moved from vertical to downward sloping demand curves to reduce year-to-year capacity price volatility.

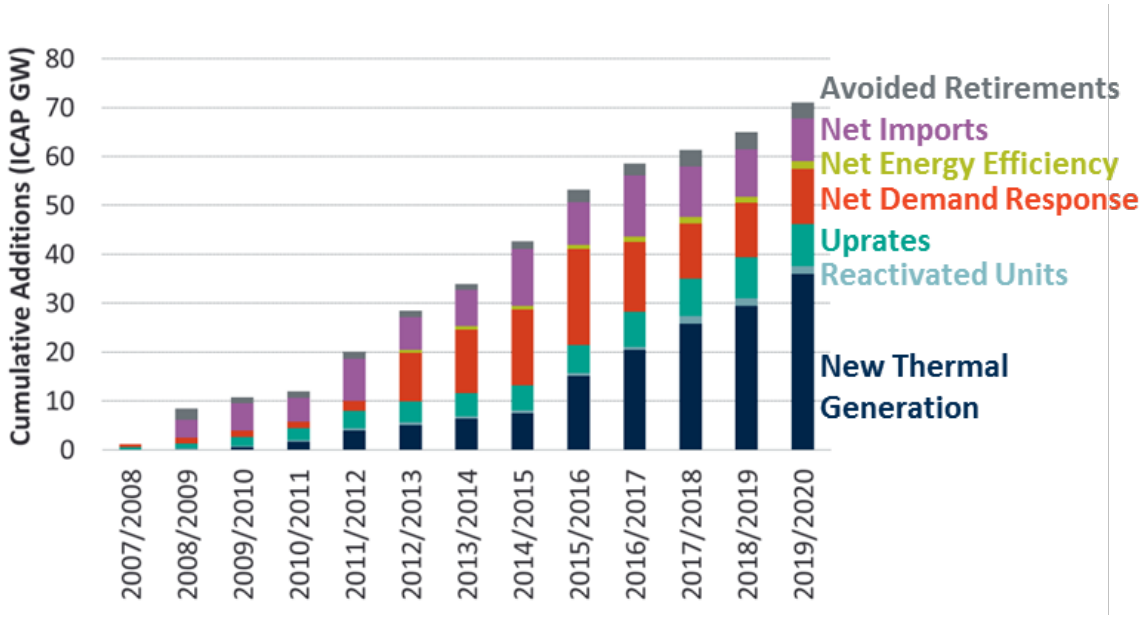
Resources submit competitive offers into the market reflecting their going-forward fixed costs, net of revenues earned on energy and ancillary service markets ($/kW-yr or equivalent). The market clears the lowest cost offers until supply intersects demand. All cleared resources within an RTO zone receive the same price. Prices may separate between zones because of transmission limitations. All resources are derated to an unforced capacity ("UCAP") value that reflects their likely output during peak events, accounting for outages and ELCC deratings. For example, 100 MW nameplate of wind may have 15 MW UCAP value, whereas 100 MW nameplate of gas CTs may have 95 MW UCAP. The goal is to ensure the RTO is procuring a consistent product, irrespective of the type of supplier providing it.

Other design details vary between markets. PJM and ISO-NE procure capacity under one year contracts, whereas NYISO holds separate 6-month summer and winter auctions. PJM and ISO-NE hold base capacity auctions three years forward of the delivery year, whereas NYISO and MISO do not have forward auctions.

Table 3
Summary of U.S. Capacity Constructs

Market	Procurement Method	Forward Period (years)	Delivery Period (years)	Demand Curve
California	Bilateral	Prompt	1	n/a
MISO	Bilateral + Mandatory Auction	Prompt	1	Vertical
NYISO	Bilateral + Voluntary & Mandatory Auctions	Prompt	1	Sloped
PJM	Bilateral + Mandatory Auctions	3	1	Sloped
ISO-NE	Bilateral + Mandatory Auctions	3	1 (7-yr lock-in for new resources)	Sloped
SPP	Bilateral	Prompt	1	n/a

Figure 11
PJM Capacity Additions, 2007/08 to 2019/20



Sources and Notes:

PJM 2007/08 to 2019/20 Base Residual Auction Results. Net imports includes reductions in exports from the 2007/2008 auction.

All jurisdictions continue to refine capacity market designs. PJM's recent "Capacity Performance" reforms serve as one example. Prior to Capacity Performance, PJM paid all resources that receive a capacity supply obligation ("CSO") based on their derated UCAP value. This payment was made regardless of whether the resource was available when needed, such as during a scarcity event. This became problematic in the January 2014 cold snap, referred to as the Polar Vortex, when extreme cold simultaneously forced 22% of PJM's supply out of service during periods of high load caused by the extremely cold weather. Natural gas supply disruptions, mechanical failures, and other factors all contributed to the outages.[26] PJM's Capacity Performance reforms sharpen the incentives for resources with CSOs to be available when needed by penalizing those resources that underperform relative to their UCAP rating and rewarding those resources that over-perform.

[26] http://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx

Appropriately determining the capacity value for variable generation resources is another issue that markets must continuously work to address. As the penetration of wind and solar PV increases, at least two factors will increasingly affect the relative value of variable generation resources versus dispatchable resources. First, the output of wind and solar PV generators is somewhat correlated within most geographic regions. As penetration of each resource type increases, the potential magnitude of an unexpected drop in output during peak hours also increases, reducing the capacity value of incremental wind and solar resources. Second, to maintain reliability the system operator must meet peak load net of wind and solar generation. As wind and solar penetration increases, peak net load hours may shift to hours with less wind and solar output. As a result, at high penetrations each additional MW of wind and solar has less of an impact on reducing peak net load than the previous MW. At low levels of penetration this has little impact, but at higher levels the impact from peak shifting can be significant.

Multiple studies have examined how the capacity value of variable generation resources changes at different penetration levels. MISO has concluded that the ELCC for wind capacity falls as wind capacity increases.[27] A study conducted for Arizona Public Service ("APS") found that under its base case assumptions for solar PV expansion, the marginal ELCC of solar PV would fall from 34.1% of capacity in 2015 to only 5.3% in 2025.[28] Another study, published in 2015, found that while the capacity value of hypothetical solar resources might exceed 40% of nameplate capacity at penetration levels under 2%, the value falls below 20% of nameplate capacity at penetration levels of 15%. The same study found that while the capacity value of hypothetical wind resources is under 20% of nameplate capacity at low penetration levels, the value falls to 10% of nameplate capacity at penetration levels of 15%.[29] These studies demonstrate that market design needs to ensure that compensation to resources reflect their real capacity values and take into account both of the factors described above.

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27 Planning Year 2016-2017 Wind Capacity Credit, page 7. https://www.misoenergy.org/Library/Repository/Report/2016%20Wind%20Capacity%20Report.pdf

28 2013 Updated Solar PV Value Report, SAIC, page 2-7.

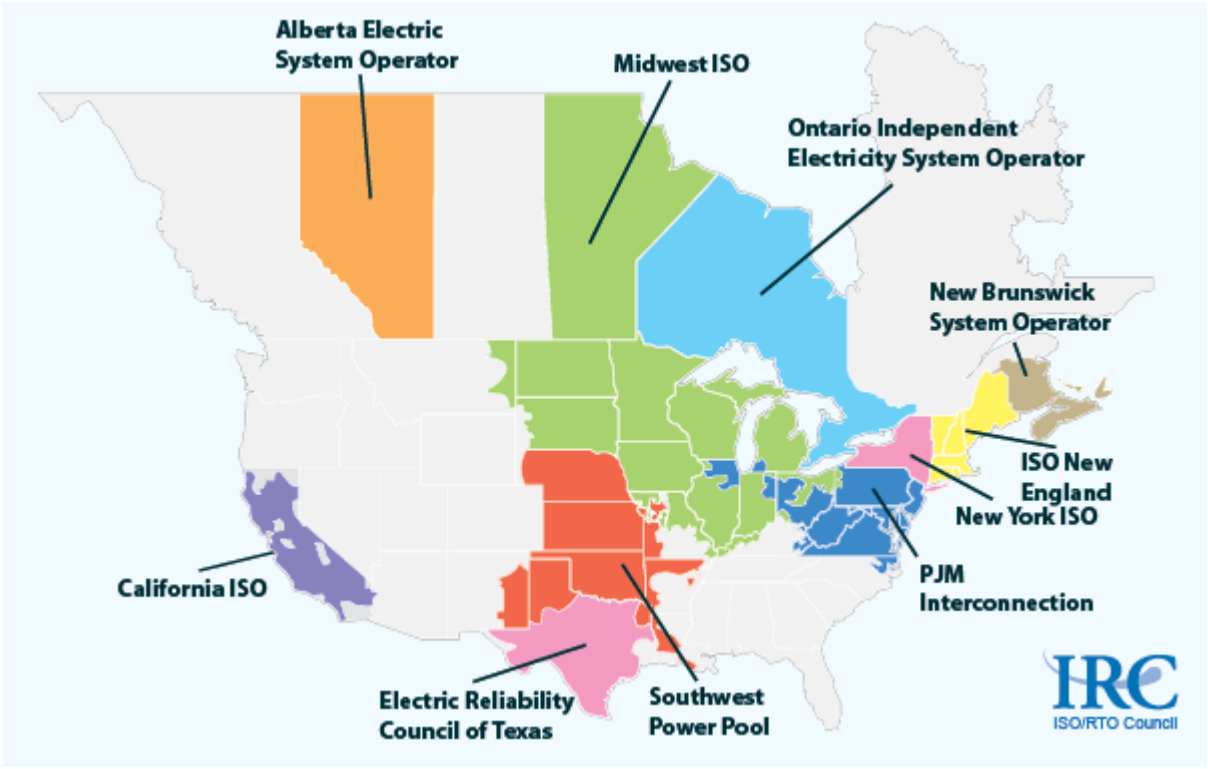
29 Endogenous Assessment of the Capacity Value of Solar PV in Generation Investment Planning Studies, Francisco D. Munoz, Member, IEEE, and Andrew D. Mills, page 8.

E. ENERGY MARKETS

Wholesale energy markets are centralized RTO markets for the electricity commodity in its most basic form. For most system resources, energy markets and capacity markets (described in Section III.D) provide the vast majority of revenue and earnings. Energy markets help the system meet bulk power demand on an instantaneous basis, but in most cases they are not intended to contribute to reliability (ERCOT is the one U.S. exception). Energy markets primarily help the system operator meet the requirement to meet bulk demand, and follow load or net load. Energy markets provide some of the compensation for the generation, dispatchability, start time/ramp rate, and minimum load level attributes described in Section II.

Figure 12 shows the North American RTOs and ISOs.

Figure 12
Map of North America Wholesale Energy Markets



Providing precise details of the energy market rules of each of the seven U.S. RTOs exceeds the scope of this paper, but all share similar rules designed to serve load from the least-cost suppliers available. Dispatch decisions in wholesale energy markets are made by the ISO, which also calculates the market compensation for generators, through an auction process. Load serving entities submit expected load schedules approximately one day in advance. Supply resources also

submit bids one day in advance. The bids generally involve multiple components such as start-up costs, no–load costs, and variable cost components. In most ISOs, these bids are tied to an estimate of the generator's marginal costs, but in ERCOT some resources may bid up to the offer cap (currently $9,000 per MWh).[30]

Based on the load schedule and the energy bids, the ISO conducts a Day Ahead auction that determines the ISO's dispatch instructions to generators. The ISO uses complex optimization software to determine the least-cost way to serve the forecast load in each hour. Prices are a function of the most expensive bid (i.e., the marginal bid) to clear the auction along with the marginal costs of congestion and losses caused by each generator. Because marginal losses and congestion vary by location, the price each resource receives also varies by location. Location specific energy prices are called Locational Marginal Prices ("LMPs"), Locational Based Marginal Prices ("LBMPs"), or nodal prices. The Day Ahead auctions are held for each hour of the next day.[31]

Shortly before the actual delivery of energy, the ISO conducts another balancing or Real Time auction. The purpose of this auction is to correct for any real world deviations from the forecast load, the forecast output from variable generators, and generator availability. The process for determining prices in a Real Time auction is similar to the Day Ahead auction. The Real Time auction results in adjustments to the dispatch instructions the ISO made based on the Day Ahead auction results. Real-time markets operate over shorter time intervals (generally five minutes) with new dispatch instructions and prices generated in each interval.

In energy markets with cost-based bids, the most expensive resource dispatched in every interval covers its variable costs but nothing more. Because resources have significant fixed costs,

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30 https://www.ferc.gov/CalendarFiles/20160629114652-3%20-%20FERC2016_Scarcity%20Pricing_ERCOT_Resmi%20Surendran.pdf

31 The ISO must also determine which units to commit. This is a complicated process and, because of forecast errors, committed units do not always recover their costs. ISOs generally have a "make-whole" mechanism for providing outside of market payments to committed resources that do not recover their variable costs through the market.

marginal resources do not earn enough revenue in the energy markets to justify remaining online. The additional revenue needed to cover costs comes from the capacity market.[32]

[32] For most system resources, particularly generators, ancillary service revenues are not a significant source of revenue.

IV. Diversity of Reliability Attributes in Regulated States

The physical operating requirements required by regulated utilities are not fundamentally different from RTOs. In both cases, reliability standards are set by NERC. However, in regulated regions the state regulator directly approves the resources that utilities develop. Regulators therefore have direct control over how the diversity of attributes is implemented. Most regulated utilities have an Integrated Resource Planning ("IRP") process that identifies resources to be added. Once the regulator approves an IRP, utilities identify and acquire the actual resources via a competitive Request for Proposal ("RFP") process or self-build, overseen by state regulators.

In contrast, deregulated regions rely on market competition to provide some attributes related to reliability. RTOs specify competitive products (e.g. capacity, regulation, etc.) and quantify how much of each product is needed. Market participants then competitively offer to provide each attribute. RTOs procure some reliability attributes (e.g. black start, voltage control, and sometimes capacity) via bilateral contracts, not market competition.

Many regulated utilities explicitly account for diversity of reliability attributes in their IRP process. A recent Brattle review of the IRPs of eight regulated utilities found that all IRPs explicitly stated attributes such as reliability and flexibility were priorities.[33]

Recently, several regulated utilities with high levels of variable renewables have undertaken efforts to improve their management of such resources. These utilities include Xcel Energy Colorado ("Xcel"), Westar Energy, and Puget Sound Energy. In many ways, these reforms are similar to those described above in restructured markets. But the challenges of renewable integration can be even greater for regulated utilities, which often have smaller thermal generation resource bases with which to balance renewables. Utilities need to develop new tariffs that appropriately allocate costs to the resources that impose them on the system, while compensating the resources that offset these costs.

[33] Reviewed IRPs include Ameren, Arizona Public Service, Dominion, Florida Power & Light, Long Island Power Authority, PacifiCorp, Tennessee Valley Authority, and Xcel Colorado.

Xcel

In 2014 FERC approved ancillary service tariff provisions filed by Xcel.[34] Xcel's proposed tariff revisions were in response to rapid growth in variable energy resources ("VERs") in their system; in 2014, Xcel had 2,251 MW of VERs and only 5,000 MW of thermal generation. The proposed changes were two-fold. First, Xcel proposed to allocate the costs of regulation and frequency response services to transmission customers, VERs, and non-VERs in a manner that accounted for their relative contribution to costs or offsetting benefits. Previously, such costs were borne only by native load customers, to the extent they were recovered at all. For example, any regulation and frequency response costs above the established rate due to the addition of intermittent VERs were not recovered. Xcel's proposed rates were $0.18/kW-yr for load, $0.23/kW-yr for non-VER generation, and $1.92/kW-yr for VER generation.

Xcel's second proposed change was to add a new type of reserves called "Flex Reserve Service". This product helps manage sustained, downward wind ramps that can occur due to a loss of wind speed. Such down-ramps can occur over tens of minutes or even a few hours. Xcel calculated 411 MW of Flex Reserve Service would be required. As with regulation and frequency response, the proposal called for costs to be allocated to those transmission customers that create the need for the service.

Westar

Westar is a Kansas public utility located within the footprint of SPP. As a balancing area within SPP, Westar is responsible for maintaining the balance between load and generation in its balancing area. Historically, Westar charged all transmission customers for regulation and frequency response when their generation was used to serve customers in the control area. This charge was calculated by multiplying a regulation requirement percentage of 1.35% by the amount of transmission service and the cost to provide regulation and frequency response. [35]

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[34] 149 FERC ¶ 61,208. Order Conditionally Accepting and Suspending Proposed Tariff Revisions, Subject to Refund, and Establishing Hearing and Settlement Judge Procedures. December 5, 2014

[35] 137 FERC ¶ 61,142. Order Granting Rehearing in Part, Denying Rehearing in Part, Instituting Section 206 Proceeding, and Establishing Refund Effective Date. November 17, 2011.

This arrangement allowed Westar to recover costs associated with serving load within the control area, but did not cover the cost of providing regulation or frequency response to generators within the control area that exported to load outside of the Westar control area. Even though these resources were selling outside of the control area, Westar still needed to procure sufficient regulation and frequency response to cover their generation. It also only accounted for the need for these services due to the variability and intermittency of load, and did not account for the increased need due to variable renewable resources.

In November 2011, FERC approved modifications to the Westar tariff. The approved changes allow Westar to charge for and provide regulation and frequency response to generators that export outside of Westar's balancing area. Westar was also approved to assign higher regulation obligations on variable generation due to their contribution to regulation and frequency response requirements. Westar will refile every 3 years to modify the requirements for dispatchable and variable generation to account for changes in technology and improved management experience.

Puget Sound

Puget Sound Energy is a balancing authority in Washington with responsibility for maintaining regulation and frequency reserve within its control area. As with Westar, Puget Sound proposed updates to their tariff to reflect the cost of procuring sufficient regulation and frequency response to integrate variable generation resources.[36] FERC approved changes to the Puget Sound tariff requiring variable generation resources to purchase regulation capacity equal to 16.77% of their transmission reservation. The regulation obligation for load and exporting dispatchable generation remained unchanged at 2%. These obligations reflected the regulation burden each resource created. Specifically, the obligations were approximated based on the 95% confidence interval of the expected differences between actual and scheduled MW for load, wind, and dispatchable generation. FERC also approved increasing the capacity rate for regulation and frequency response from $5.50/kW-mo to $12.39/kW-mo, reflecting increased costs of the pool of resources that provide regulation.

[36] 137 FERC ¶ 61,063. Order Accepting and Suspending Proposed Tariff Revisions, Subject to Refund, and Establishing Hearing and Settlement Judge Procedures. October 20, 2011.

V. Conclusion

Historically, the U.S. has relied largely on dispatchable generation resources to meet its electricity needs. However, with advances in technology that have driven down costs, non-dispatchable variable energy resources now generate a significant amount of energy. For a variety of reasons related to both policy and economics, the shift towards variable energy resources will likely continue. This change to the system will require the restructured markets and the regulated states to rethink the way they value the different reliability attributes of resources. To a large degree, market designers and planners at vertically integrated utilities are aware of these issues and have begun to take action. However, as the penetration of variable energy resources increases, more work will be needed in rethinking the traditional way resources' contributions to reliability are valued. In both markets and regulated states, ensuring reliability will depend on rules that recognize two important reliability principles. First, integrating variable generation resources can increase the need for resources with the reliability attributes discussed in this paper. Second, reliability attributes should be valued in an economically efficient way.

Going forward system operators in both restructured markets and vertically integrated states will face three issues that are particularly important for reliability. First, the marginal capacity value of variable generation resources with correlated output tends to decrease as penetration increases. To minimize costs and maintain reliability for consumers, it is important that variable generation resources receive compensation for the value of the capacity resources they provide. The potential decline in capacity value must be carefully accounted for or the system may not be able to meet demand during system peak load conditions. Second, increased reliance on variable generation resources will most likely decrease inertia and increase frequency volatility. This will create a greater need for primary, secondary, and tertiary frequency response products. Resources with the ability to provide these services will be necessary to prevent the cascading blackouts that can occur when frequency deviates too much from 60 Hz. Third, increased reliance on variable generation resources will increase the variability of net load. This will create a greater need for resources with fast start times and quick ramping capabilities. These resources will be necessary to ensure that load can be served during a rapid change in net load.

Changes to the composition of the U.S. generating fleet are creating new challenges for maintaining reliability. While addressing these three issues will be particularly important to the electricity grid, all of the attributes identified in this report are important for reliability. The mechanisms for valuing these reliability attributes will differ between restructured markets and

regulated states, and the relative value of different attributes will also vary between different regions. However, in all regions and jurisdictions, ensuring economically appropriate compensation for the attributes identified in this report will be important to maintaining system reliability.

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