Comments to Federal Energy Regulatory Commission (FERC) In Response to Grid Reliability and Resilience Pricing Questionnaire

FERC Docket No. RM18-1-000

October 23, 2017

CORRESPONDENCE AND COMMUNICATIONS SHOULD BE DIRECTED TO
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Background:

Theresa Pugh Consulting, LLC is a firm specializing in energy and environmental regulation and policies. These comments do not represent current clients or former employers; however, they reflect 15 years of experience with public power electric utilities (including coal, natural gas, hydroelectric and nuclear) and 16 years representing manufacturers as electricity users. My concerns also address unintended impacts to the U.S. natural gas industry. Also, I serve on NERC's "Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System" as a non-paid advisor. The policy recommendations or, observations should not be viewed as those from NERC.

Introduction:

These comments are offered to assist the Federal Energy Regulatory Commission's (FERC) Director of the Office of Energy Policy and Innovation, Commissioners, and staff. The purpose of the comments is to answer questions from the FERC's October 4, 2017 Questionnaire and offer practical observations that might expand upon questions asked by the Commission. Some questions asked by FERC are beyond the scope of these comments as they are outside the expertise of my firm and not answered. This filing should not imply an endorsement of organized markets or a recommendation that they be expanded. The purposed of these comments is to prevent more ill thought out mandates that might cause additional market distortions for electric utility customers. <u>Under Section 403(b), FERC may reject or amend the Secretary's proposal</u>. Given the ill-advised nature of the rule that the Secretary has proposed, FERC should exercise full authority under Section 403 to reject the proposed rule. Under the Department of Energy Act, the Secretary has some limited authority to present recommendations to FERC for the adoption of rules, but that authority does not extend to dictating the results of the rulemaking. Instructing FERC to look at reliability or to ensure that RTO/ISO mechanisms are adequate to address must-run units to meet specific, identifiable and verified reliability problems is not inappropriate, but the Department of Energy (DOE) dictating end-results is inappropriate. Only FERC has the authority to make findings that existing rules are not just and reasonable. For more than twenty years FERC has followed this policy and should continue to do so. And, further, the Federal Power Act (FPA) does not give FERC unfettered discretion to change existing rules without undergoing the proper procedures. FERC can only adopt new rules or dramatically alter its existing rules and mechanisms after holding hearings and finding rates, charges, classifications, practices, reasons for making changes.[1]

These comments also address possible inadvertent distortions in the natural gas market that might have tremendous impacts on the exploration/production investments, supply, price and deliverability of natural gas because of consequences in the Utica and Marcellus shale gas regions if FERC implements a policy such as that directed by DOE. If FERC acts too quickly, on a truncated schedule, investments in the upstream exploration and production for natural gas Utica/Marcellus could face a chilling impact as soon as winter 2018.

FERC offered a short timeframe for answering complex questions pertaining to reliability, resiliency and if the current RTO/ISO market compensation system adequately ensures reliability and resiliency. It is my firm's hope that if FERC proceeds that will determine to take a deliberative process beyond the short

[1] 16 U.S.C. Section 824e(a).

timeframe directed by DOE's recommendation. My firm does not question the importance of reliability and resilience nor dismiss the Secretary's directive to FERC to look into reliability and resilience. However, there are many more nuances to reliability and resilience than simply requiring 90 of days of fuel on the ground and paying those generators (presumably coal and nuclear) more than other generators in those markets. Additionally, due to the previous lack of quorum, FERC also has many backlogged cases and taking additional time on this topic may delay many hundreds of millions of dollars in projects.

The Commission asks for definitions and comments on reliability and resilience—for the electric grid. Reliability and resilience are terms that are to be defined and explored by North American Electric Reliability Corporation[2] (NERC), as established by Congress, under Section 212 of the FPA when it was defined as an Electric Reliability Organization (ERO). NERC issues reliability assessments frequently and those determinations should define reliability and where generation does not meet reliability needs. The same is true for resilience. NERC[3] determines reliability based upon many factors but primarily bases its assessment upon reserve margins[4]. My firm's comments primarily focus on reliability since reliability is more closely linked with generation issues—while resilience is generally not really a generation question. However, if NERC determines in the future that there are resilience inadequacies then the resilience concern should be treated in a similar manner avoiding further market distortions. All market distortions are paid for by the consumer—whether residential, commercial, or industrial. Solutions to address any reliability/resiliency issues, if there are any, should always weigh the protections of consumers and not seek to gold-plate or offer permanent plant life extensions. These comments offer alternative approaches to what DOE's directive suggests based upon determinations by NERC on reliability/resilience problems. <u>If NERC does not determine that there are any reliability or resilience issues—then the solutions do not have to be permanent compensation commitments that will (further) distort electric utility markets.</u>

While none of these comments reflect the views of prior employers, my firm's views are informed by working for the public power electric utility sector for 15 years, the manufacturing sector and the oil/gas industry (including the pipeline transmission sector) combined for 19 years. Additionally, I serve on NERC's "Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System" as a non-paid advisor. My firm's opinions, observations and policy recommendations should not be viewed as those from NERC or any prior employers or former clients.

These comments are not meant to imply that restructured wholesale energy markets have achieved their original purpose—to encourage more competition and lower prices to the consumer.

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[2] The objectives for NERC's Reliability Assessments are to identify, assess, and report details about the reliability of the North American BPS and to make recommendations as necessary. NERC identifies potential resource deficiencies and operating reliability concerns, determines peak electricity demand and supply changes, and highlights unique regional challenges. NERC represents the results of collaborative efforts involving the Reliability Assessment Subcommittee (RAS), the Regions, and NERC staff to develop sound technical bases for understanding these potential concerns, changes, and challenges. NERC's summer or winter assessments are intended to enable entities to better anticipate and respond in ways that ensure bulk power reliability. NERC's assessments also provide an opportunity for the industry to discuss their plans to ensure reliability for the upcoming summer period. See for details for most recent 2017 NERC Summer Assessment
http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2017%20Summer%20Assessment.pdf
This summer 2017 assessment indicated no serious concerns about RTO/ISOs. The winter 2017 update will be issued by Nov. 20, 2017.

[3] See details about NERC's process at http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

[4] NERC Summer 2017 Assessment, See pages 22-23, and 27 for specific details about NYISO and PJM
http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2017%20Summer%20Assessment.pdf

Executive Summary:

1. DOE's proposed rule does not present a valid justification for this action by FERC. Further FERC has the authority to undertake consideration of problems in normal hearing processes—not by accepting directives from the Department of Energy under both the DOE and FPA laws.
2. FERC should wait to make any final rulemakings or policy determinations on this topic until the following reports and documents may be reviewed. Most reports will be issued in November or December, 2017. These documents will help inform the Commission in defining reliability:
    - NERC's Winter Reliability Assessment (expected November 20, 2017);
    - NERC's Bulk Electric System Impacts Due to Severe Disruptions on the Natural Gas System" (expected November 14, 2017);
    - Pipeline Hazardous Materials Safety Administration's (PHMSA) (sanitized/anonymous) study on underground natural gas storage facilities/salt domes/depleted wells to inform NERC on reliability of infrastructure. This report should indicate how quickly a significant percentage of the nation's approximate 300 gas storage locations may meet PHMSA's Interim Final Rule (IFR), issued December, 2016. This report may help determine *if* there will be any risks of natural gas storage bottlenecks that could better define or rule out any areas for reliability and resilience issues more clearly. It is essential to know about natural gas storage for the many states that do not have suitable geology for natural gas storage in underground gas storage (UGS) facilities or if those existing facilities must be offline for significant periods in order to fully make repairs, augment safety and monitoring systems or install entirely new systems meet the IFR requirements. There is no evidence that there is such a national gas storage reliability problem. The report may rule out that there are problems and confirm there is adequate natural gas storage for subgrid electric reliability purposes. Confirmation would also give confidence to electric utilities to build natural gas generation when demand justifies it. It could also direct NERC to focusing on any area where there might be a localized problem that might affect bulk electric; and
    - California's root-cause analysis[5] for the Porter Ranch;/Aliso Canyon natural gas storage leak in 2015 and if there are any reasons the cause has application for safety upgrades or design concerns in any of the nation's >300 natural gas storage locations. That report may prove that there are no concerns outside that single location and one-time event. This report has been delayed many times and appears now to be expected by spring, 2018. The findings of this root cause report should be assessed by PHMSA and NERC. The study may reveal that was a single event highly improbable of happening again but merits consideration.
3. Only NERC should make reliability determinations. Individual parties may request that state PUC/PSCs communicate with NERC regarding state specific concerns, but generators and other stakeholders who would benefit financially should not determine reliability.
4. ***If*** NERC advises FERC that there are reliability/resiliency concerns in RTO markets, the solutions should:
    a) respect that RTO markets make generation policy and address fuel diversity needs and have must run rules;
    b) ***If,*** future specific reliability concerns justify a new or revised compensation system is needed for a generator then those compensated should be limited to the size and location of the reliability/resiliency problem. If the reliability problem is small—then the

[5] Conducted or managed by several agencies including California Public Utilities Commission, Department of Conservation's Division of Oil, Gas and Geothermal Resources (DOGGR), California Energy Commission, and other entities of state government. www.cpuc.ca.gov

compensation should be given to those units in need based upon "best of class" meaning those that have upgraded to comply with the Environmental Protection Agency's (EPA) new Mercury Air Toxics Standards (MATS), investment payments made (not just committed) for pollution controls such as new effluent guideline limitations (ELG) and Coal Combustion Residuals (CCR) regulation; and

c) that the coal unit ran for a significant period over the last five years and was not idled. The purpose of this program should be limited to true reliability/resiliency concerns and not to financially compensate all of the hundreds of older coal plants and nuclear plants that exist in ISO/RTOs. Some of those units anticipated to retire appear obsolete and uneconomic- not victims of lower natural gas prices;

5. ***If*** a NERC reliability/resilience determination report demonstrates a change in future years and demonstrate that the theoretical reliability problem has been resolved then those units should no longer receive financial compensation;
6. The compensation system, if it is justified solely based upon NERC reliability/resilience determinations, should be administered through a capacity market and not an energy market system because the energy market approach can distort the electricity pricing for decades;
7. Nuclear power units should have similar requirements for compensation based upon location in an area that NERC determines to be of significant reliability/resilience problems and where the nuclear plants had maintained safety requirements and environmental compliance requirements under appropriate regulations as recently as 2015 and where those nuclear plants ran over at least three years of the last five years. The purpose of the compensation system should be to maintain those that need to be retained in a similar way to "must run" status; and
8. Reservoir hydro-electric power and natural gas fired power plants (with both firm contracts and local natural gas storage and adequacy of pipelines) should not be excluded from compensation IF the infrastructure is proven to be adequate to meet reliability/resilience standards. Simply having firm natural gas contracts in some regions may not be adequate **if** NERC determines a reliability problem with gas storage or delivery infrastructure serving that region. Run of river plants should be considered for compensation if there has been no drought of other conditions that did not allow those hydro units to run four out of the prior five years.

Answers to Questions: "Need for Reform" Section:

1) *What is resilience, how is it measured, and how is it different from reliability? What levels of resilience and reliability are appropriate? How are reliability and resilience valued, or not valued inside RTO/ISOs? Do RTO/ISO energy and or capacity markets properly value reliability and resilience? What resources can address reliability, and in what ways?*

Answer: Resilience and reliability should be defined by NERC, as established under Section 212 of the Federal Power Act (FPA). NERC conducts periodic assessments of electric reliability (generation) and resilience (transmission etc.).

5) *Is fuel diversity within a region or market itself importance for resilience? If so, has the changing resource mix had a measurable impact on fuel diversity, or on resilience and reliability?*

Answer: According to NERC's recent reliability assessment report[6] the changing mix of generation types has not jeopardized grid reliability.

It is my firm's view that generally speaking fuel diversity is preferred to over-reliance upon a single fuel type. But those decisions should be made by individual utilities, state PUC/PSCs and energy authorities. Further, it should not result in an arbitrary determination that all nuclear plants and all coal-fired power

[6] NERC Summer 2017 Assessment http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2017%20Summer%20Assessment.pdf

plants should be compensated in ISO/RTOs. While at this time there is no justification for a rule, should FERC adapt what DOE has recommended, the compensation should be limited to capacity markets (not Energy Markets) AND should apply to those units needed to precisely fit the size of any reliability problem (as determined by NERC). <u>If NERC does not determine a problem exists, no compensation is needed. Furthermore, only the generator's unit that is treated as a must run should be compensated (and not the other generators).</u>

Nor does it mean that natural gas generation should be penalized by financial compensation only given to coal and nuclear plants creating natural gas "deserts" (isolated geographic areas) where neither infrastructure nor natural gas production would find investors/customers. If, for example, PJM had a compensation arrangement for coal and nuclear plants to the disadvantage of natural gas then the states surrounding or in PJM with power plants that would otherwise seek to generate with natural gas because of low natural gas prices would be penalized with too generous of a compensation to coal and nuclear plants. Those surrounding states might not have adequate natural gas infrastructure and this increases the build out costs for those neighboring (non-RTO) utilities that want to generate with natural gas. That generation resource would cost more simply because of the RTO compensation system. IF there was a reliability problem this might be justifiable. But, to date, there is no indication that there is one.

Further, if FERC were to adopt DOE's policy recommendations non-associated natural gas development in the Marcellus and Utica could face very rapid and severe market signals to decrease investments in natural gas development in the Marcellus and Utica. Thus, this not only precludes future fuel diversity options for electric generators, it affects industrial gas users, local distribution utilities (LDCs) and others who rely upon natural gas. DOE has not contemplated that adopting this policy would harm the U. S. economy from vital natural gas as a national economic driver and fuel resource.

<u>**It would be tragic and ironic if this rulemaking simply creates stranded assets in the upstream energy industry segment if located near RTOs/ISOs that only compensate nuclear or coal plants**</u>. It would also not be good for our national economy if only Texas' Permian Basin and Eagle Ford Shale and North Dakota's Williston's natural gas assets are advantaged over shale gas development in other states. As one familiar with the economics of the Permian Basin and Eagle Ford Shale's natural gas production (and related infrastructure investments), it would be wrong to remain silent about the dreadful unintended consequence of DOE's policy would have on natural gas investments in Midwestern/Mid-Atlantic states. Those states include both private investment, profits and tax revenue to localities in West Virginia, Maryland, Pennsylvania, Ohio (especially in dry gas or for non-associated natural gas from oil production). Should FERC apply DOE's directive to policies on RTOs, the rule would not only affect electric utilities but other segments of the energy industry and the manufacturing sector. Many manufacturers rely upon natural gas as feedstock to make a wide variety of products. For example, the steel industry makes critical infrastructure to transport oil and natural gas. FERC needs to tread carefully to avoid broad and significant economic ripple effects throughout our economy.

For nuclear plants to be equally eligible for financial compensation, they must meet all current Nuclear Regulatory Commission's (NRC) safety, environmental and other appropriate regulations and meet "Best in Class" in the same way that eligible coal-generators must meet appropriate EPA's MATS, ELG[7], and coal ash regulations. Further, to avoid an automatic presumption that only nuclear plants would get compensated or dispatched to meet these theoretical reliability gaps, those eligible nuclear plants should have a system to return cost savings the consumers.

<u>Again, solutions to reliability should be exactly that—a solution to a reliability problem—not a compensation system that further distorts energy markets</u>.

[7] Appropriate capital expenditures as of October 23, 2017 because not all generators must make capital outlays for compliance at the same time

Answers to Questions: "General Eligibility" Section:

4) *If technically capable of sustaining output for a sufficient duration (and meeting other relevant requirements), should resources such as hydroelectric, geothermal, dual-fuel with adequate on-site storage, generating units with firm natural gas contracts, or energy storage each of which might have a demonstrable store of energy to draw upon to sustain an electric output, if not necessarily fuel) also be eligible? Why or why not? If technical capability is the appropriate criterion for eligibility, what specific technical capability should be required to be eligible?*

Answer: All these resources (hydroelectric, geothermal, dual fuel) should be eligible with on-site storage coupled with firm contracts or ownership. The eligibility should be determined by NERC's assessment of the size of the problem. If the problem is *de minimis* then firm natural gas contracts may be adequate. If the reliability problem is more significant, NERC's determination on that RTO may indicate if a variety of resources might together compensate for the reliability concern. If NERC should determine that there is a far more significant problem then NERC might advise that having on-site storage for gas-fired generators where natural gas storage is not located close to the power plant. Note: EIA maintains an updated map and list of both underground gas storage, smaller LNG for storage to serve industrials or power plants, as well as hydroelectric.[8]

Answer to Questions on "90-Day Requirement" Section:

1) *The proposed rule defines eligible resources as having a 90-day fuel supply. How should the quantity of a given resources' 90 days of fuel be determined? For example, should each resource be required to have sufficient fuel for 24 hours/day and sustained output at its upper operating limit for the entire 90-day period? Would there be any need for regional differences in this requirement?*

Answer: While there is no doubt that having coal on the ground is better from a reliability perspective, it is not necessarily true to say that reliability requires a 90-day supply on the ground at all times. Requiring a 90-day fuel supply on site (or under the ground of the power plant) is arbitrary and capricious. Currently not all coal-fired power plants purchase and maintain a 90-day supply of coal on the ground at all locations. There are a variety of reasons for this including local fire prevention/suppression public safety standards, physical space (footprint) that might be limited due to the installation of pollution controls (baghouses, SO_2 scrubbers), and coal handling equipment. In some locations with extreme rain, some generators keep less than 90-days supply due to intense rain and have smaller deliveries made more frequently to avoid water logged coal supplies.

The determination of what constitutes reliability should be set by NERC. If NERC determines there is a problem, then NERC and the relevant Planning Authority(s) should make advisories as to what amount of fuel should be maintained on the ground (or beneath the ground if a power generator wanted to own a small LNG plant on site or within a few dozen miles). For some power plants, a 90-day supply might only be needed for winter peak. For others, only a 45-day supply might be needed for the summer peak. FERC should not arbitrarily determine that all power plants need a 90-day supply in order to maintain reliability. Furthermore, local fire, public health and other ordinances must be considered. Additionally, weather (rain, hard freeze) and other factors may need to be considered. Recently at a hearing before the House Energy and Commerce Committee, Representative Gene Green of Texas offered an observation that two coal-fired power plants were deluged with rainwater.[9] The utility switched to natural gas because of the enormous rainfall. Secretary Perry speculated that it would be easy to place a covering over a 90-day coal pile. However, in some locations it is not feasible to provide a covering for a 90-day supply of coal due to limited available space.

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[8] See https://www.eia.gov/naturalgas/storagecapacity/ and https://www.eia.gov/energyexplained/index.cfm?page=hydropower_where

[9] https://www.platts.com/latest-news/electric-power/houston/harveys-rain-caused-coal-to-gas-switching-nrg-21081527. A copy of the referenced NRG report can be accessed at http://www.ercot.com/content/wcm/lists/114741/27706_-_2017.08.30_-__Harvey_Report_to_PUC.pdf

The excerpt from Platts below shows recent examples from both coal and natural gas flooding during Hurricane Harvey in Texas. While Texas is not jurisdictional to this possible rulemaking, the experience is relevant. During Hurricane Harvey both natural gas and coal-fired equipment were affected by flooding but only coal-fired generation was unable to run due to the enormous rainfall or flooding from bayous. While Hurricane Harvey's 50 plus inches of rainfall was extreme and rare—it illustrates that determining which type of generation is more 'reliable" is simply not an easy one. *(Offering this example is **not** meant as any criticism of NRG or any of the utilities in south Texas who were able to maintain electric generation during extraordinary circumstances).*

> Hurricane Harvey and its aftermath dumped so much water on Texas that the Electric Reliability Council of Texas' second-largest generation owner had to switch two units at a big power plant from coal to natural gas, a step that had not been taken since 2009
>
> That is one point made in a report by NRG Energy filed in advance of a Thursday meeting of the Public Utility Commission of Texas, which has at the top of its agenda Project No. 45772, "Issues Related to the Disaster Resulting from Hurricane Harvey."
>
> NRG's report, filed Tuesday, shows the following rainfall totals at its plant sites:
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> - San Jacinto, 162 MW of natural gas-fired capacity: 47 inches
> - W.A. Parish, 2,504 MW of coal, 1,145 MW of natural gas: 38 inches
> - Cedar Bayou, 1,744 MW of natural gas: 36.5 inches
> - Greens Bayou, 715 MW of natural gas: 28 inches
> - T.H. Wharton, 1,025 MW of natural gas: 25 inches.
>
> Two NRG plant sites were evacuated temporarily during the storm -- one due to wind and the other for flooding -- and flooding prevented shift changes, resulting in some power plant staff working extended shifts and staying onsite while their families were displaced by flooding, the NRG report stated.
>
> "The historic rainfall and flooding presented unique challenges for our power plant operations and personnel," NRG said. "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."

2) *Is there a direct correlation between the quantity of on-site fuel and a given level of resilience or reliability? Please provide any pertinent analyses or studies. If there is such a correlation is 90 days*

of on-site fuel necessary and sufficient to address outages and adverse events? Or is some other duration more appropriate?

Answer: Usually but not always.

The supply of on the ground fuel or natural gas-fired generation with natural gas obtained through pipelines and natural gas storage should be decisions made by the generator based upon practical considerations, prices of fuel, proximity to natural gas, and capacity of coal handling and coal-storage on the ground. These determinations should be made by NERC's assessment of reliability.

A 90-day fuel on the ground supply appears arbitrary as it applies to all the generators in RTO/ISOs. In some seasons, due to other generation mixes, including intermittent renewables, a presumption of ninety days may be overly prescriptive. And for a variety of public safety reasons or footprint reasons addressed previously the generator may not always be able to store 90 days' supply on the ground. In some situations, an alternative to a 90-day supply may be sufficient for reliability purposes.

FERC did not ask, but this commenter would offer that where mature and robust natural gas infrastructure can store and deliver natural gas, that natural gas generation may be able to meet the reliability needs. However, gas-fired generators should not solely rely upon line-packing or firm contracts to assert reliability of natural gas for generators located far from gas storage. A mix of generation assets might enable a primarily natural gas generation equal to a nuclear plant or coal fired plant for reliability. Gas-fired generators that have gas in the ground in small LNG tanks should be assessed in similar ways to nuclear and coal-fired generators even if the LNG tank may not hold 90 days. Small, industrial sized LNG tanks can hold gas in the ground in locations where there is no underground gas storage due to ill-suited geology. In those locations, small scale LNG holding perhaps a week's supply of natural gas may prove to be wise. Commenter recognizes that LNG as storage can be expensive.

Any reliability determinations should be made by NERC.

Answers to Questions "Fuel Supply Requirement" Section:

1) *The proposed rule requires that resources must be in compliance with all applicable environmental regulations. How should environmental regulations be considered when determining eligibility? For example, if a unit that was capable of keeping 90- days of fuel on-site was subject to emission limits that would prevent it from running at its upper operating limit for 90 days, should that limit be eligible under this program?*

   Answer: Yes, the units should meet Federal EPA and state environmental regulations to meet air pollution, water pollution, waste management, spill prevention, and other public safety and worker safety standards. In the case of whether a small reliability gap or short-term problems (perhaps a day, week or months) could be met with using dual fuel (oil), and a variance is provided by U. S. EPA to run that oil-fired unit, then it should be compensated if no other lower polluting unit is available. The goal is to address reliability-not create further market distortions. It might be true that an oil-fired unit would emit more SO_2 and other pollutants for that day, week or month until the reliability problem is rectified but it may be wise. Air pollution regulations are designed to protect public health but a one day, one week or perhaps even one-month permit variance to run with suboptimal pollution controls to address electric reliability might be justified. It is unlikely that an oil-fired unit would be dispatched ahead of other generation assets given the price of oil—but it should not be arbitrarily eliminated from consideration if there is a true reliability problem.

3) *Does the vulnerability or non-availability of on-site fuel supplies vary depending upon fuel type, location, region, or other factors?*

Answer: Yes. See answer to Questions (90-day supply) above on pages 7-9. NERC may (or may not) find that there are locational, fuel type or deliverability of fuel issues that are relevant. Vulnerability determinations should not be arbitrary. FERC should review NERC's November 2017 reports as well as other commenters' comments to answer this. There may be justifications for FERC, NERC and U. S. EPA to work together to allow dual fuel oil-fired units to run as must run units for short periods of time in New England during ozone season. Normally oil-fired units are limited by hours or percentage of run time and by ozone (smog) regulations. Oil-fired units are terribly expansive but may be allowed to run in some circumstances in New England. However, for dispatch purposes, whether oil, nuclear, gas, coal or hydro, dispatch should weigh both cost to the consumer and reliability. Oil-fired units should meet spill prevention regulations and fuel storage/handling safety requirements event if U. S. EPA offers short-term waivers to run these units in times of weather-related emergencies or short-term reliability concerns. There are utilities that technically have dual fuel permits but upon deeper consideration many of those utilities have not maintained all their abilities to actually run oi-fired units.

The commenter is aware of only one large 800 MW circulating fluidized bed boilers (CFB) units in PJM regions according to a 2008 internet source[10]. A second, industrial 80 MWCFB industrial boiler is located in Frackville, PA *These comments do not attempt to speak for the owners or claim technical expertise for either of these examples offered. Nor are the comments intended to advantage these two companies over other units. This is merely to offer an observation that CFBs offer fuel flexibility and answer the Commission's question.*

CFB fired generation offers additional reliability opportunities[11] because the unit can burn a wide variety of fuel resources—even together. CFB plants in other locations[12] have been appreciated by generators and storm abatement crews taking downed forest waste, factory waste, forest slash (biomass), tires and other debris that could be burned along with coal. Even 'wetter' coal or coal slurry mix can be burned in CFB plants for those locations that may run into very wet seasons, hurricanes, etc. If there are true reliability problems, RTO/ISOs may want to consider fuel flexibility issues at CFB plants when dispatching (or compensating) generators. CFB generation offers many options on fuel types (wide varieties of coal and moisture in coal, rubber tires, biomass, wood slash waste in storm removal). Most conventional coal generation units cannot handle the fuel varieties as CFB units can handle[13].

Answers to "Other Questions" Section:

4) *What impact would the proposed rule have on consumers?*

   Answer: Without deliberative and comprehensive analysis, this proposed rule could have very broad and negative impacts on both electric utility and natural gas markets affecting industrial and residential consumers. Creating more market distortions in energy markets is not good for anyone—on top of what are already not a true market in RTOs and ISOs.

5) *The commission may take notice of relevant public information, including information in other Commission proceedings? If a commenter views information in other Commission proceedings as*

[10] ftp://pjm.com/planning/project-queues/impact_studies/r04_imp.pdf

[11] Ash buildups and cyclone plugging problems seem to be mitigated at many CFB facilities where operational and engineering changes have bypassed these earlier operational problems. See www.power.org

[12] Michigan, Wisconsin, and Florida

[13] www.cfboiler.ltd and www.powerengineeringinternational.com and www.ge.com and www.amecfw.com

relevant to the proposed rule, please identify that information and explain how it is relevant to the proposed rule. Such information may include a filing previously submitted by the commenter.

Answer: FERC's website and energy trade press articles suggest there is a significant backlog of FERC cases[14] due to the lack quorum of for significant portions of 2017. This collectively reflects as much as $50 billion in investments[15] including $10 billion of pending natural gas pipelines.

FERC would be wise to (a) make appropriate decisions on pending matters before the Commission before taking final steps on this action. (b) recognize catching up on pending projects and mitigating against more delays is the best course of action since NERC's Summer 2017 Reliability Assessment did not suggest there is an imminent reliability concern. For documentation of Chairman Chatterjee's statements about recent delays in FERC see recent October 17, 2017 Energy Bar Association speech[16]. **Placing this policy matter ahead of pending cases is not justified**.

General Recommendations:

Recommendation: FERC should defer to NERC to make any reliability/resiliency determinations. NERC should consider infrastructure issues related to reservoir hydro and natural gas made by appropriate agencies that evaluate safety. These should include PHMSA[17] and FERC's Office of Energy Projects' Dam Safety and Inspections Division, Dam Safety Surveillance, and other safety assessments. Natural gas readiness be considered by NERC including PHMSA's reviews[18] of natural gas storage facilities/semi depleted wells and salt domes to meet their Interim Final Rule (IFR) safety requirements. It is possible that some short- term natural gas deliverability issues may need review by NERC given the timing of changes in gas storage locations to meet new IFR or possible 2018 regulations under the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (PIPES). However, it may be the gas storage locations serving electric generators will have no reasons for concern or that the concerns are small enough to not offer any concerns for the grid. Recommending that NERC review these natural gas deliverability issues stemming from some repairs in gas storage does not suggest that there are grid reliability concerns. Natural-gas generators may be able to determine (and communicate to NERC planning authorities) that natural gas supply, storage, and distribution systems have adequate redundancies to meet reliability needs. Where storage or other significant repairs might be underway, NERC can determine if those are significant enough to merit concerns for the grid. Some gas pipeline, compressor station or gas storage repair issues may never rise to the level of grid reliability but instead cause localized concerns for individual generating units in areas where natural gas infrastructure is not yet robust. Similarly, changes in rail transport logistics and costs for coal have changed in the last few years as coal-generation has declined. If a region sees considerably less coal deliverability by rail or barge, NERC may consider this if it believes these logistical delivery issues are a factor for its reliability determinations. NERC and PHMSA should also study the results of the spring, 2018 "root cause" analysis

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[14] See www.ferc.gov or ferc.capitolconnection.org and many popular press articles including http://www.washingtonexaminer.com/ferc-faces-backlog-as-it-ramps-back-up/article/2630815 and https://www.midstreambusiness.com/ferc%2C%20quorum%2C%20lafleur-1661421

[15] Older May, 2017 article from Bloomberg https://www.bloomberg.com/news/articles/2017-05-05/trump-s-delay-stalls-50-billion-of-energy-projects-in-pipeline

[16] https://www.ferc.gov/media/statements-speeches/chatterjee/2017/10-17-17-chatterjee.asp

[17] https://www.phmsa.dot.gov/

[18] https://primis.phmsa.dot.gov/ung/index.htm and https://energy.gov/sites/prod/files/2016/10/f33/Ensuring%20Safe%20and%20Reliable%20Underground%20Natural%20Gas%20Storage%20-%20Final%20Repor..._0.pdf and https://energy.gov/fact-sheet-ensuring-safe-and-reliable-underground-natural-gas-storage and https://energy.gov/sites/prod/files/2016/10/f33/Ensuring%20Safe%20and%20Reliable%20Underground%20Natural%20Gas%20Storage%20-%20Final%20Report.pdf

for Porter Ranch/Aliso Canyon's gas storage leak failure. If NERC determines that study has broader implications for natural gas storage beyond that single location and event then NERC should take appropriate steps for its next Reliability Assessment or other reports. However, there should be no assumptions made until the root cause analysis is completed. It may prove to be a one-time event due to unique design or operations not relevant in other storage locations.

Recommendation: While not precisely asked in this section, the commenter recommends that compensation(s) be based upon (a) NERC determination of reliability problem and (b) that the generator be paid through a capacity market not energy market. Capacity markets, while far from perfect, are less intrusive into markets and have slightly less risks to cause further market distortions. However, a capacity market should only be used as a last resort after true or free markets fail.

Conclusion:

FERC is to be commended for looking at proven reliability and resilience matters. **But there is no proof that DOE's policy recommendation is solely designed to address a grid reliability problem—or that there is a grid reliability problem**. FERC should take sufficient time to evaluate many of the direct and indirect or unintended consequences including to the natural gas exploration and production sector in Marcellus and Utica before adapting DOE's directive or a variation on that theme. If FERC, determines that RTO/ISO rules have flaws that the RTO/ISOs cannot correct on their own, perhaps a system narrowly designed to address reliability might be possible under a capacity market. While using capacity markets are not optimal this might cause the least disruptive mechanism to energy markets and to the impacts for consumers (residential, industrial or commercial). But a very narrow application of capacity market compensation should be considered a "last resort" after determining the true size of the problem and not apply to all generators with >90 days' supply of fuel on the ground. Further, the use of a capacity market should only be considered by FERC in a separate rulemaking process after weighing comments received in this *solicitation for answers to this questionnaire. Nor is this willingness to suggest this as a last resort an endorsement of capacity markets writ large.*

If FERC determines a policy or rule is needed, consumers may be protected from electricity price sticker shock and FERC must make certain that the "fix must fit the actual problem." **Oversizing the fix to a problem that does not now exist (or might not exist in the future) should not burden consumers with higher electricity costs**. If reliability problems are determined by NERC, reasonable compensation for 'must run' type units should be based upon "best in class" weighing many factors—not just an arbitrary meeting 90-day fuel supply on the ground that would almost always dispatch/compensate only nuclear generation and perhaps dispatch coal generation second. Many operational details matter before assuming that a 90-day supply of fuel is always the only assurance of reliability.

FERC should also weigh the possible unintended consequences to hurt natural gas (including investment in infrastructure and future generation options) by accidentally creating gas deserts in RTO/ISO regions where existing coal and nuclear power plants might receive compensation. Further, if designed poorly, a FERC rule could hurt the natural gas industry's investments in natural gas exploration and production located in or near RTO/ISO markets such as those in Utica and Marcellus. While the majority of the U.S. electricity consumers are not served by PJM and NYISO, the entire country is affected by the future of the U.S. natural gas industry. Like electricity, the natural gas sector can have a significant impact on the U.S. economy.

It would be tragic to the U.S. economy if DOE's directive and FERC's adoption of this policy, inadvertently starves off natural gas in Ohio, West Virginia, Maryland, and Pennsylvania in pursuit of a yet to be defined and proven reliability problem for electric utilities. It is unfortunate that DOE had not weighed this unintended consequence before sending this policy directive to FERC since there is no proven reliability problem. Basic economics suggests that shale gas production in the states in and adjacent he Utica and Marcellus shale formations reduces electricity price sticker shock. Abundance in natural gas supply should help keep natural gas prices lower than if those resources were disadvantaged in so called electricity "markets" or abandoned by investors. Adoption of this policy would likely have a ripple effect through pipeline, gas storage, and related investments to delivery natural gas to consumers. DOE's unjustified directive would choke off a desirable economic driver for domestic natural gas use (and foreign export via LNG terminals).

FERC should not abandon its neutral position on fuels based upon unproven reliability and resilience fears.

Thank you for considering these comments.

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