FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF THE CHAIRMAN

January 24, 2014

The Honorable Ed Whitfield, Chairman
Subcommittee on Energy and Power
House of Representatives
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, D.C. 20515

Dear Chairman Whitfield:

Thank you for your January 10, 2014 letter containing additional questions for the hearing record on "Evaluating the Role of FERC in a Changing Energy Landscape."

Enclosed please find my responses to your questions. I want to thank you again for the opportunity to appear before the Subcommittee on Energy and Power on December 5, 2013.

Sincerely,

Cheryl A. LaFleur /js

Cheryl A. LaFleur
Acting Chairman

cc: The Honorable Bobby Rush, Ranking Member
Subcommittee on Energy and Power

Attachment

Additional Questions for the Record

The Honorable Ed Whitfield

1. Under former Chairman Wellinghoff, FERC's "top initiatives" included: 1) smart grid; 2) demand response; 3) integration of renewables; and 4) Order No. 1000 - transmission planning and cost allocation.

a. In light of Chairman Wellinghoff's departure, how might you redirect FERC's priorities during your tenure as Acting Chairman?

Answer: My goals as Acting Chairman are to understand all perspectives, to work to achieve consensus with my colleagues, and to make objective decisions on the record. With those goals in mind, I have three top initiatives. First, electric grid reliability and security have been a priority of mine since I joined FERC as a Commissioner three-and-a-half years ago. Both the mandatory reliability standards and the process through which those standards are developed have improved in recent years, and I look forward to working closely with NERC to make further progress in these areas. Second, I want to focus on ensuring that the wholesale electric markets work efficiently as the industry sees changes in power supply stemming from various factors such as shale gas development. There is an increasing pressure on competitive electric markets as we enter an investment cycle in which such factors are stressing the system. I believe the Commission must ensure that the markets work fairly to give appropriate investment signals to base load, mid-merit, peaking and variable generation, as well as demand response and energy storage technologies. Third, I want to help ensure that the Commission's rules facilitate robust infrastructure for both the electric and natural gas industries to serve customers.

2. Under your leadership, how might the Commission's work differ from that of former Chairman Wellinghoff on the following critical issues:

a. Order 1000 transmission planning and cost allocation?

Answer: The Commission's work with respect to Order No. 1000 is now focused on implementation. As I stated at the hearing, implementing this rule will be a significant part of our work going forward. Throughout the first half of 2013, the Commission issued orders on each transmission planning region's proposals to comply with the regional transmission planning and cost allocation requirements of the Final Rule. Additional compliance filings responding to the Commission's findings in those decisions have been filed, and the Commission is currently reviewing them. In addition, the Commission is reviewing proposals to comply with the interregional transmission planning and cost allocation requirements of Order No. 1000.

b. Natural gas pipeline permitting?
c. LNG siting?

Answer: In general, FERC acts on both pipeline and LNG projects applications expeditiously. About 92 percent of applications are acted on within a year. To date, and in light of this record, I have not identified specific changes that I believe are needed at this time. However, I am always open to looking for ways to improve the Commission's processes.

d. Organized wholesale electricity markets?

Answer: I will continue to focus the Commission's resources on ensuring that the rules that govern organized wholesale electric markets promote the delivery of reliable power and are non-discriminatory and resource-neutral, resulting in efficient price signals that market participants can rely on to make investment decisions. Particular matters of focus will include: the Commission's ongoing inquiry regarding the performance of the current centralized capacity markets in the Eastern RTO/ISOs, building on a technical conference held last fall and subsequently filed comments; implementing recent rules addressing the integration of variable energy resources into the grid and ancillary service reforms; and timely action on the wide range of issues that arise in rate and tariff filings and complaints placed before the Commission by market operators and market participants. A vital goal with respect to all of these areas is ensuring that electricity can be reliably delivered in the long-term as system needs change.

3. The President has directed EPA to issue proposed regulations limiting emissions of greenhouse gases (GHG) from existing fossil fuel electric generation units by next June.

a. Have you or anyone at FERC had discussions with any EPA or DOE staff, or provided them information, regarding the potential reliability or price impacts of EPA regulation of GHGs from existing fossil fuel units?

Answer: I have not provided EPA or DOE staff any information with respect to specific reliability or price impacts of EPA regulation of GHGs from existing fossil fuel units. I have had general discussions with EPA and DOE regarding the need for FERC to remain engaged as environmental regulations are issued to help maintain reliability and ensure that markets adapt. I have served with Commissioner Moeller as one of FERC's leaders of the FERC/NARUC Forum on Reliability and the Environment, which has provided a structure for conversations concerning these issues. In addition, FERC staff has met with staff from EPA and DOE concerning the upcoming proposed rules regarding GHGs from existing generators. However, those rules have not yet been proposed, and my understanding is that the staff discussions did not address specific reliability or price impacts of those rules. My understanding is that FERC, EPA and DOE staff intend to continue these discussions as the future rules develop. Finally, FERC staff participates in regular conference calls with the RTOs to discuss their efforts to plan the system to meet future needs, including implementation of EPA rules.

b. Are you aware of EPA or DOE conducting any analysis of the potential reliability or price impacts of potential GHG regulations for existing fossil fuel units? If so, what is the content of such discussions and information?

Answer: No, I am not aware of any such analysis. However, the rule has not yet been proposed.

4. Why does Order 1000 permit customers to be charged for transmission lines built by entities their utility does not take service from?

a. Do you support allocating costs for new transmission lines to entities that don't have a customer or contractual relationship with the builder of the line?
b. Please identify the section of the Federal Power Act that gives FERC this authority to allocate costs in the absence of a contractual relationship?

Answer: A central theme of Order No. 1000's cost allocation reforms is that only those that benefit from new transmission facilities developed under Order No. 1000 planning processes should be allocated the costs for those facilities under the region's cost allocation method. I strongly support that principle. It is also important to note, as Order No. 1000 found, that those who benefit from a new transmission facility under Order No. 1000 do not necessarily have a contractual relationship with the utility or developer building that facility. Electricity flows over the transmission grid according to the laws of physics, and not pursuant to voluntary agreements of those who provide and receive transmission service. As Order No. 1000 recognizes, a robust grid with additional capacity and alternative paths for flows of electricity helps bolster grid reliability, reduces congestion in a way that may lower costs for consumers, and can help regions meet public policy requirements. Therefore, reliability benefits, for example, may be realized in the absence of voluntary arrangements. In addition, Order No. 1000 directed public utility transmission providers to consult with their stakeholders in developing cost allocation methods that would appropriately identify the beneficiaries of new transmission facilities in their region in a clear, upfront manner. Thus, Order No. 1000 provided each transmission planning region the flexibility to develop a regional cost allocation method, so long as the method was consistent with certain cost allocation principles, including that the costs allocated are roughly commensurate with benefits.

In Order No. 1000, the Commission relied on the provisions of the Federal Power Act – sections 205 and 206 – that obligate the Commission to ensure that jurisdictional electric rates are just and reasonable and not unduly discriminatory or preferential. In addition, the Commission explained that section 201(b)(1) of the Federal Power Act grants the Commission jurisdiction over the transmission of electric energy in interstate commerce, as well as jurisdiction over all facilities for the transmission of electric energy.

5. Please identify the provisions in the Federal Power Act that give FERC authority over local and regional transmission planning? Please define "region" for the purposes of Order 1000? Please define "benefit" for the purposes of Order 1000?

Answer: Sections 205 and 206 of the Federal Power Act obligate the Commission to ensure that jurisdictional electric rates are just and reasonable and not unduly discriminatory or preferential. Order No. 1000 concluded that regional transmission planning is a practice that affects jurisdictional rates. Moreover, Order No. 1000 builds on the Commission's earlier Order No. 890, which established transmission planning requirements for individual public utility transmission providers at the local level.

Order No. 1000 did not prescribe the size of a transmission planning region, except to state that a single public utility transmission provider by itself would not constitute a transmission planning region for purposes of Order No. 1000. Additionally, Order No. 1000 stated that the scope of a transmission planning region should be governed by the integrated nature of the regional power grid and the particular reliability and resource issues affecting individual regions. On compliance, the Commission has accepted a variety of transmission planning regions of different sizes and configurations, as well as varying numbers of public utility transmission providers.

Order No. 1000 also did not prescribe a particular definition of "benefits," recognizing that regional flexibility to accommodate different approaches was appropriate rather than a one-size-fits-all approach. In response to this directive, public utility transmission providers in each transmission planning region, in consultation with stakeholders, developed and proposed regional cost allocation methods that would identify how benefits would be measured and how beneficiaries would be identified. The Commission has reviewed the proposed cost allocation methods for the individual regions, although several issues related to these proposals are pending on rehearing and further compliance.

6. What metrics are you prepared to measure and report back to Congress that Order 1000 is going to lead to transmission projects being built more expeditiously would allow us to judge whether it has?

Answer: The Commission stated in Order No. 1000 that recent increases in transmission development combined with projections by industry (including the North American Electric Reliability Corp. (NERC), the Commission-certified electric reliability organization) of the need for significant future additional transmission investments, as well as changes in the generation mix driven in part by public policy developments, required action to ensure that transmission planning and cost allocation requirements (first adopted in 2007 in Order No. 890) are adequate to support more efficient and cost-effective transmission facility decisions. The reforms adopted in Order No. 1000 were designed to work together to ensure that more transmission facilities would be considered on a comparable basis in the transmission planning process, increase the likelihood that regional transmission plans would reflect the more efficient or cost-effective transmission solutions to meet regional transmission needs, and improve the ability of those transmission projects to come to fruition. As it did following Order No. 890, the Commission will monitor transmission planning processes to ensure that they are effective in meeting regional transmission needs and supporting the provision of Commission-jurisdictional service at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

7. There is a growing level of convergence in the natural gas and electricity markets. Take New England for example, where I understand there may be a need for a new cost-sharing model to facilitate construction of new gas pipeline capacity, the absence of which is preventing New England consumers from realizing the full benefit of the nation's burgeoning natural gas supplies.

a. Please describe FERC's authority and ability to implement a cost-sharing model that would broaden the scope of responsibility for financing new pipeline capacity.

Answer: At this time, the Commission is not contemplating changing its policy regarding cost recovery for new pipeline construction. Under the Commission's Certificate Policy Statement,[1] the threshold requirement for a finding that a pipeline expansion is required by the public convenience and necessity is that the expansion not be subsidized by existing customers who receive no benefit from the project. However, the pipeline and the expansion customers can agree on how the financial risks of the project might be shared among them. In addition, while the rates of existing shippers cannot be increased to support construction that will not benefit them, where a project combines an expansion with construction that will benefit existing customers, the pipeline can file to increase existing customers' rates to the extent it can demonstrate that the new facilities are needed to improve service to the existing customers.

8. The proper design and operation of wholesale power markets are critical. Investment decisions in these markets are being made today based on existing market rules approved before the shale gas revolution, low load growth, proposed EPA rules, and the rise of intermittent renewables; in other words, under different conditions.

a. Please explain what FERC is doing and plans to do to review and improve market rules so that wholesale markets are sending the proper investment signals in light of structural changes impacting the power sector.

Answer: There is an increasing pressure on competitive electric markets as we enter an investment cycle where market changes are stressing the system. I believe the Commission must ensure that the markets work fairly to give appropriate investment signals to base load, mid-merit, peaking and variable generation, as well as demand response and energy storage technologies. While some of the rules that govern power markets were written and instituted prior to the changes you reference, these rules are flexible, allowing market participants to plan for and act in the markets in a manner that best suits their needs. For instance, while load growth has slowed and our resource mix is changing, these factors are accounted for in long-run load forecasting. Likewise, in day-ahead and real-time markets, market rules allow for market participants to change their offers or reverse their positions if market changes make such a change economically efficient. Investment and day-to-day market decisions are shaped by market forces and implemented within market rules.

However, the Commission does periodically review market rules, *sua sponte*, and continues to do so. For example, one thing I am focused on is the Commission's review of the existing centralized capacity markets to ensure they function efficiently. We recently held a technical conference on these issues and sought written comments following the conference. The Commission is now reviewing the replies. Other areas of work for Commission staff in this area include a review of the current ancillary services products to assess whether they serve the intended purpose and whether system needs have changed to the degree that new or different ancillary service products are necessary.

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[1] 88 FERC ¶ 61,227(1999), order clarifying statement of policy, 90 FERC ¶ 61,128(2000), order further clarifying statement of policy, 92 FERC ¶ 61,094 (2000).

9. Has FERC examined -- in a structured, systematic, transparent manner -- whether the experience with organized electricity markets has been a net benefit for consumers? Has anyone else? Does FERC plan to?

Answer: Yes, FERC has examined the performance of each of the regional transmission organizations (RTOs) and independent system operators (ISOs) in a structured, systematic, transparent manner. On January 20, 2011, the RTOs and ISOs presented the results of a performance measurement exercise initiated by the Commission at an open Commission meeting. Each RTO and ISO enumerated the numerous economic, operational and reliability benefits attributable to the operation of their regional organized wholesale electric markets. (These presentations are available on the Commission's website, http://www.ferc.gov/industries/electric/indus-act/rto.asp, listed under "Conferences.") Associated with this public presentation and discussion, the ISO/RTO Council issued a 2009 State of the Markets Report, with follow up reports issued in 2010 and 2011. The Commission is in the process of updating these performance measurements.

In addition to these reports, additional evidence of the economic, operational and reliability benefits of regional organized wholesale markets to consumers can be inferred from the continued expansion of these markets. On December 19, 2013, Entergy joined the Midcontinent Independent System Operator (MISO) system. On March 1, 2014 the Southwest Power Pool (SPP) is expected to initiate its expanded market by providing a day-ahead energy and ancillary services market. Furthermore, on January 10, 2014, the Western Area Power Administration (WAPA) announced that it would begin negotiations with SPP to join the RTO. Also, effective January 3, 2013, the California Independent System Operator (CAISO) expanded to include a Nevada utility, Valley Electric Association, Inc. In February 2013 CAISO announced a memorandum of understanding with PacifiCorp to develop a regional real-time energy imbalance market (EIM).

10. Baseload electric generating assets have a life span of 40 to 60 years or longer. The forward capacity markets in organized electricity markets typically operate three years ahead. Do you agree there's a fundamental mismatch between the investment recovery profile of electric generating assets and the way merchant markets are structured? Do you think FERC has a role to play in addressing this problem?

Answer:
I noted at the hearing that the Commission has opened an inquiry (Docket No. AD13-7-000) to consider how the current centralized capacity market rules and structures in the Eastern RTO/ISOs are supporting the procurement and retention of resources necessary to meet future reliability and operational needs. Whether the three-year "forward period" that you identify (which is used in two of the three Eastern RTO/ISOs) supports the overall goals and objectives of the forward capacity markets is one of many issues that are under discussion in that proceeding. The Commission held a technical conference in this docket on September 25, 2013, and is currently reviewing post-technical comments submitted by all interested entities to determine whether next steps may be appropriate with respect to the issue you raise, as well as many others.

It is important to note that the centralized forward capacity markets in PJM and ISO-NE are designed to secure the least cost combination of capacity resources needed to meet reliability requirements three years forward (the centralized capacity market in New York ISO operates on shorter timeframe, up to six months forward). Resources that clear in any centralized capacity market receive capacity payments in the specified delivery year along with revenues for selling energy and ancillary services. In this way, a combination of merchant spot and forward markets allow at-risk investors in electricity generating assets an opportunity to recover their costs by selling energy, ancillary services, and capacity on a competitive basis. Capacity revenues are important to all generation types, but they are generally not the largest source of revenue for baseload units that typically earn greater revenues from selling energy and ancillary services.

In addition, in a Staff Report issued in advance of the Commission's technical conference in Docket No. AD13-7-000, FERC staff discussed the tradeoffs inherent in choosing a longer or shorter forward period.[2] For example, Commission staff noted, among other things, that longer forward periods (like the three years currently utilized in PJM and ISO-NE) can increase competition by providing more lead time for new resources to be constructed and compete with existing generation. On the other hand, staff noted that a longer forward period can result in increased economic and resource adequacy risk for customers, since forecasts of needed capacity to meet resource adequacy requirements are generally more accurate closer to the delivery year. As we consider what next steps may be appropriate in our inquiry into centralized capacity markets in the Eastern RTO/ISOs, the Commission will need to balance investor and consumer risk, among other tradeoffs, to ensure that resource adequacy is maintained at just and reasonable rates.

11. EIA, other data and trade group studies show greater levels of construction of generation capacity in non-RTO markets.

> **a. In a period of rapid change in the industry, is there any evidence that RTO markets, specifically the capacity markets, can best address these resource needs, while minimizing adverse impacts on the economy and consumers?**
>
> **b. If not, what changes are most needed to RTO markets to achieve resource adequacy at least cost, in consideration of reliability, consumer impacts, fuel diversity and the environment?**

<u>Answer</u>: To date, the centralized capacity markets in PJM, New York and New England have been successful in meeting resource adequacy needs in those regions. These markets have also had success in attracting a wide range of new resources, including generation capacity, transmission infrastructure, demand response and investments in energy efficiency. For example, PJM recently reported to the Commission that since the inception of its capacity market, the Reliability Pricing Model (RPM), the region has attracted over 28,000 megawatts of new generation, 14,000 megawatts of demand

[2] *Id.* at 11-13.

response, and 1,100 megawatts of energy efficiency.[3] In addition, PJM notes that RPM has played a role in promoting the retirement of uneconomic generation and preventing the retirement of economic generation. Over 47,000 megawatts of existing coal-fired generation in PJM has committed to be available in the 2016 base residual auction, reflecting a decision by the owners of those facilities to retrofit their units to meet environmental compliance requirements. Similarly, New York ISO reports that it has seen its capacity market attract over 10,000 megawatts of new generation, primarily in southeastern New York, and over 1,600 megawatts of new transmission, all into that same area.[4] New York ISO also reports that its capacity market has attracted approximately 1,500 megawatts of demand response, and allowed for significant retirements by uneconomic older generation.

As noted above, however, the Commission has opened an inquiry (Docket No. AD13-7-000) to consider how the current centralized capacity market rules and structures in the Eastern RTO/ISOs are supporting the procurement and retention of resources necessary to meet future reliability and operational needs. The questions you raise are central to that inquiry. For example, the Commission heard testimony at its September 25, 2013 technical conference in that docket on the impacts of changing market conditions - including low natural gas prices, state and federal policies encouraging the entry of renewable resources and other specific technologies, and the retirement of aging generation resources – on the RTO/ISO centralized capacity markets. In addition, the Commissioners and a panel of industry experts discussed possible future directions for the capacity markets in light of these dynamic changes. Following that conference, the Commission issued a request for further written comments, which included questions on these issues. The Commission is now reviewing those comments and considering next steps, including whether changes are needed in light of the rapid changes taking place in the electricity industry.

12. Between 2008 and 2012, the clearing prices in the PJM wholesale energy market during times of high energy demand declined significantly because of the drop in natural gas prices. For example, the clearing price for 150GW in PJM was about $92 in 2008 and $40 dollars in 2012. Similarly, the clearing price for 175GW in PJM was $155 in 2008 and $63 in 2012.

a. Has FERC calculated how much these drops in prices saved consumers during this time period?

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[3] "Statement of Andrew Ott, Executive Vice President – Markets, PJM Interconnection, L.L.C.", prepared for Technical Conference in Docket No. AD13-7-000 (September 25, 2013), *available at* http://www.ferc.gov/CalendarFiles/20130911144119-Ott%20Comments.pdf.

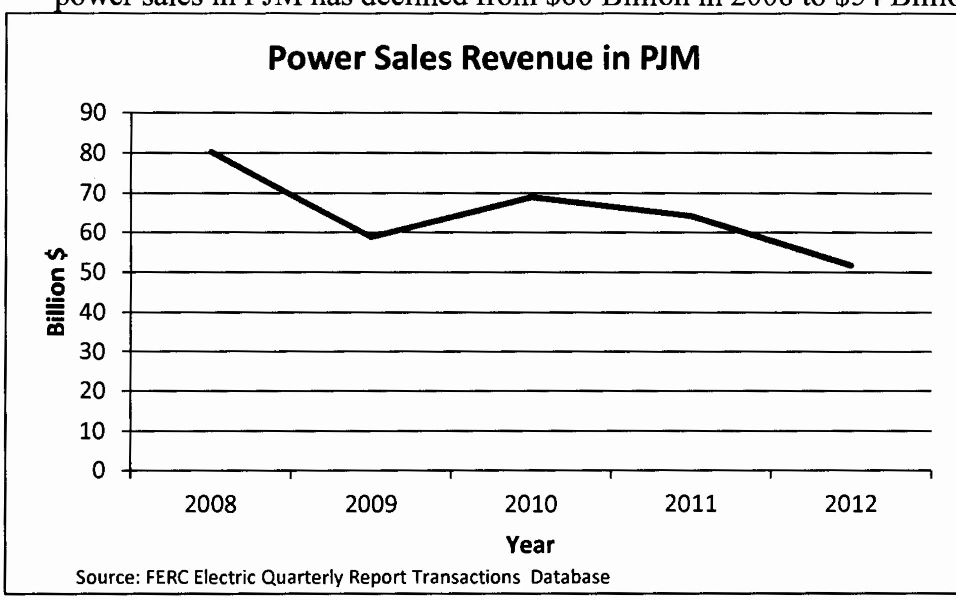
[4] Rana Mukerji, Senior Vice President – Market Structures, New York Independent System Operator, Inc., "Centralized Capacity Markets in RTO/ISOs: The NYISO Perspective", presented at Technical Conference in Docket No. AD13-7-000 (September 25, 2013), *available at* http://www.ferc.gov/CalendarFiles/20130913141158-Mukerji,%20NY-ISO.pdf.

Answer: FERC jurisdiction is over wholesale prices and does not include retail rates to end-use consumers. Retail rates are approved by state regulators and methods for setting rates vary widely among states and for individual utilities within each state. Prices to consumers eventually reflect long term trends in wholesale prices, but the speed and magnitude varies.

It is also noteworthy that EIA tracks retail prices paid by consumers. It reports that the average retail electricity price to residential customers in the Middle Atlantic states increased from 14.88 cents/kWh in 2008 to 15.27 cents/kWh in 2012. However, the price to industrial customers decreased from 8.2 cents/kWh to 7.49 cents/kWh over the same period. State utility commissions may approve a lagged collection by utilities in retail rates of earlier-year procurement costs that have not yet been included in rates. Retail prices encompass both the cost to produce or buy energy for customers as well as the cost to maintain the local distribution system.

b. Looking at the other side of the equation -- with these price differentials, the revenues collected by generators in PJM declined significantly. Has FERC calculated or estimated how much the revenues collected by generators in the PJM energy market decreased over the past three or four years?

Answer: Generator revenue is not likely to directly follow short term market prices, but is affected by longer term price trends and market expectations. Merchant generators and utilities with excess generation typically hedge their forecasted production through long term contracts to mitigate earnings volatility. Generators that are less hedged or that use shorter term contracts to hedge are more exposed to wholesale price movements. While FERC does not track the specific hedging strategies of each generator, it does collect information on all jurisdictional power sales. Commission Staff has observed that the total revenue reported for power sales in PJM has declined from $80 Billion in 2008 to $54 Billion in 2012.



c. Does the current structure in PJM bias towards existing generators?

Answer: The existing PJM mechanism was approved by the Commission as just and reasonable and not unduly discriminatory or preferential. Any entity that has evidence that an existing PJM tariff provision creates an undue bias or preference in favor of existing generators or any other market participant may submit the evidence to the Commission in the form of a section 206 complaint for consideration.

FERC staff observes that 5% of the cleared capacity in the 2015/2016 capacity auction was from new generation resources or additions.

PJM Cleared Capacity vs. Incremental New Capacity by Delivery Year
All Figures are in MW

Delivery Year	Cleared Capacity	Increased Generation	Decrease in Generation	Net New Generation	Demand Response	Energy Efficiency
2011/12	132,221.5	3,576.3	264.7	3,311.6	661.7	-
2012/13	136,143.5	1,893.5	3,253.9	(1,360.4)	7,938.1	632.3
2013/14	152,743.3	1,737.5	1,924.1	(186.6)	2,993.3	101.1
2014/15	149,974.7	1,582.8	1,550.1	32.7	2,514.4	73.1
2015/16	164,561.2	8,207.0	6,432.6	1,774.4	4,200.5	101.3

Source: PJM, "2015/2016 RPM Base Residual Auction Results," Table 7, page 19

13. Under former Chairman Wellinghoff, it seems that FERC's policies promoted certain generation sources – renewables, distributed generation, demand response -- to a degree that threatens all baseload generation.

a. Should demand response, for example, be rewarded in the same way as steel in the ground?

Answer: In energy markets, resources are compensated based on having the same capabilities. In Order No. 745, the Commission stated:

> that when a demand response resource participating in an organized wholesale energy market administered by an RTO or ISO has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test described herein, that demand response resource must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price (LMP).[5]

b. Is the reliability of demand response and renewables as good as fossil fuel or nuclear capacity, which is almost always available? If not, doesn't that threaten the reliability of the grid?

Answer: Demand response, renewables, fossil fuel and nuclear capacity all have different characteristics, and the Commission works to ensure that resources are compensated based on the services they actually provide. In operations, each system operator takes the different resource characteristics into account when scheduling and dispatching sufficient resources, including an adequate reserve margin, to meet the system's daily and hourly needs. To ensure reliability in

[5] Order No. 745 P 2 (2011)

the face of a changing resource mix, the Commission is considering the flexibility of the grid, for example by examining ancillary service offerings and requirements.

14. Are centrally-dispatched markets, such as those operated by Regional Transmission Operators (RTOs), the optimal means to integrate variable energy resources at least cost? Why or why not?

Answer: Centrally dispatched markets have demonstrated their effectiveness in integrating variable energy resources (VERs). The Commission also has undertaken initiatives that will improve integration of VERs both within and outside organized electric markets. In addition to Order No. 1000, which is discussed above, several such initiatives include:

- Order No. 764 (Integration of VERs) – In this Order the Commission adopted two reforms, applicable to transmission providers both within and outside of RTOs and independent system operators (ISOs), which allow VERs to appropriately manage exposure to energy imbalance penalties. These reforms are also intended to eventually allow transmission providers to carry fewer reserves, and thus reduce reserve costs. First, Order No. 764 requires transmission providers to offer customers the option of scheduling transmission service at 15-minute intervals rather than hourly. This reform allows system operators the flexibility to manage their systems effectively and efficiently, while helping transmission customers avoid excessive imbalance penalties by updating their transmission schedules closer to real time. Second, the Order requires new VERs to provide transmission providers with certain data to support the development and deployment of power production forecasting by transmission providers.
- Order No. 784 (Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies) – This order enhanced competition and transparency in ancillary services markets by making it easier for independent providers to sell imbalance energy and reserves. This is expected to decrease ancillary service costs to all generators, including VERs.
- Order No. 792 (Small Generator Interconnection Agreements and Procedures) – In this Order, the Commission amended its *pro forma* small generator interconnection agreements and procedures to ensure interconnection time and costs for all resources, including VERs, remain just and reasonable while continuing to ensure safety and reliability. For example, one of the reforms adopted in this Order provided small generators (up to 20 megawatts), with the option of requesting a pre-application report providing existing information about system conditions at possible points of interconnection, which is expected to help generators make more informed siting decisions.

15. Within regions with security-constrained economic dispatch, how is this dispatch affected by negative or zero-priced offers received from renewable energy resources?

Answer: In RTO-administered markets, security-constrained economic dispatch finds the lowest cost of dispatching resources, based on their bids, to serve load while respecting transmission system limitations. In RTOs' competitive markets, a resource's bids are disciplined by competition and reflect the resource's incremental cost of energy production. A zero dollar bid by an intermittent resource is consistent with competitive bidding - it is consistent with the incremental cost of energy from the resource and usually reflects a resource's contractual obligation to produce its full output regardless of what the market clearing price is. A negative bid usually indicates that a resource is willing to reduce its scheduled output if it is paid its opportunity cost to do so. An overview of how the RTO day-ahead and real-time markets operate generally will be helpful to understanding the zero or negative bidding issue.

First, all RTO administered energy markets apply the same bidding rules to all resources. Thus, intermittent generators, such as wind, have the same bidding requirements as all other resources and are dispatched based on rules that apply equally to all resources. All resources are allowed to bid in day-ahead and real-time energy markets.

Second, all resources have the option to self-schedule. A self-schedule is accomplished by submitting a bid that places the resource at the bottom of the bid stack. In most RTOs that is a bid of zero or the lowest offer permitted by the market rules. In some markets, it can also accomplished by submitting an energy quantity without a price. In this way, the resource assures that it will be scheduled day-ahead and dispatched in real-time consistent with security constraints. Typically resources self-schedule some or all of their output because they have entered into contracts that require them to deliver certain amount of energy.

Third, all resources dispatched at the same time and location receive a uniform market-clearing price that typically exceeds their bid. Thus, a bid of zero or self-scheduling by some resources does not necessarily mean a market-clearing price of zero. However, there are occasions when market clearing prices may be negative, for example, during a low load, off-peak hour when minimum generation levels are greater than load.

Fourth, any resource may submit a bid in the real-time market to signal its willingness to increase or reduce its day-ahead schedule. A negative bid to decrease output in the real-time market indicates the willingness of the generator to reduce its output if it is paid its bid price. For an intermittent resource, the negative bid may reflect, for example, the forgone value of renewable energy credits that would otherwise accrue to the resource owner or to the load serving entity that has contracted with the resource if the resource produced energy. It may also reflect contractual penalties for not delivering full output. Negative bids to decrease output allow intermittent resources to signal their willingness to respond to system conditions and provide a valuable market-based tool for RTOs to deal with oversupply conditions and efficiently balance supply and load.

A dispatch that assures customers will be served at least cost consistent with security constraints is achieved when all suppliers offer their resources on competitive terms. An offer to self-supply, such as a zero bid, indicates that the resource is willing to accept the competitive market-clearing price to provide energy. Thus, market rules that allow for self-scheduling by permitting a zero or negative bid support a competitive market outcome that provides electricity to customers at the least cost and allows RTOs to reliably manage their systems.

16. A recent report commissioned by FERC as part of the National Action Plan on Demand Response noted that "Demand Response is often cited as a means of improving the reliability of the electricity system, yet there is little empirical data to demonstrate this benefit."

> **a. What specific actions is FERC taking to ensure that DR is in fact supporting, rather than potentially impairing, the reliability of the electric system, particularly in regions where DR is increasingly being relied upon as a capacity resource?**

Answer: In February 2013, the Commission directed public utilities to incorporate by reference updated business practice standards adopted by the Wholesale Electric Quadrant of the North American Energy Standards Board to support the measurement and verification of demand response and energy efficiency products in wholesale markets.[6] In addition, I note that Commission staff regularly monitors and reviews reports provided by the organized wholesale markets that address the performance of demand response resources when called upon to maintain reliability.

17. Increasing evidence suggests that some Demand Response providers are being paid a high price to deliver demand response at a future date, but these providers then tum around and buy the product from someone else in the meantime. In many cases they never intended to deliver the service themselves in the first place, but they are able to profit from markets that, at times value DR even more than actual power plants.

> **a. Does FERC support the actions being taken by certain RTOs/ISOs to ensure that DR is a physical product that can actually be delivered to ensure resource adequacy?**

Answer: This issue is pending before the Commission in a contested proceeding. Because these issues remain pending before the Commission in a contested proceeding, I cannot comment on their merits.

> **b. Is there any justification for treating DR providers differently from other capacity resources, such as generation, given that DR is in fact a newer and less understood resource with no track record to rely on?**

Answer: The Commission is committed to ensuring that market rules treat all capacity resources fairly, based on their actual performance.

18. Since the enactment of PURPA in 1979, FERC has never exercised its authority under Section 210 to pursue enforcement actions against a state commission in federal court, as it has chosen to do with the Idaho PUC. States clearly have authority to set the avoided cost for the purchasing utility and set terms and conditions for Qualifying Facilities (QF) that pass muster with FERC. Recently FERC has been accepting many more petitions for

[6] Order No. 676-G (2013).

enforcement, and taking a more aggressive stance toward the state PUC role in determining the terms and conditions of these QF contracts.

a. Why is FERC doing this, and what has changed in either the renewable/QF space, or with the federal-state relationship where FERC feels compelled to do this?

Answer: As noted in your question, FERC pursued an enforcement action under PURPA against the Idaho PUC with respect to a single issue that arose in at least three cases during a short timeframe. I am pleased to report that FERC and the Idaho PUC reached a settlement of that matter last month. I look forward to working with state commissions in a collaborative manner with respect to PURPA and other issues.

19. Earlier this year, Congress unanimously passed the Hydropower Regulatory Efficiency Act. Among other changes, the Act revised how FERC regulates small conduit hydro projects, and required the Commission to investigate a 2-year licensing process for non-powered dams and closed loop pumped storage projects and also conduct pilot projects.

a. Please provide an update on the Commission's activities to date to implement these and the other provisions of the law and outline what additional steps the Commission will take in 2014.

Answer: The Commission began implementation immediately after enactment.
In order to assist developers to take advantage of the opportunities offered by the Act, the Commission updated its website to provide guidance on how to apply for conduit and 10-megawatt small hydropower exemptions, qualifying conduits, and preliminary permit term extensions under certain of the Act's provisions.

Pursuant to section 6 of the Act, the Commission conducted a workshop on October 22, 2013, to solicit input on the feasibility of a two-year licensing process for projects that are located at existing, non-powered dams or are closed-loop pumped storage projects. (Because of the government shutdown, the meeting was held on October 22 rather than by October 8 as required in the legislation.) In addition to testimony received at the meeting, 16 comment letters were filed after the workshop by potential developers, licensees, federal and state resource agencies, trade groups, and other interested parties.

Based on the workshop testimony and written comments, Commission staff developed criteria and a potential schedule for a two-year licensing process and issued a Notice on January 6, 2014, soliciting prospective license applicants to file requests to test the process. The window for filing a request to test the process begins on February 5, 2014, which, under the Act, is the date that the Commission is required to implement pilot project testing; the filing window ends on May 5, 2014. Commission staff will assess the suitability of any proposals to test the process, and if a proposal is deemed suitable, will authorize the prospective applicant to commence process testing.

At our January16, 2014 Open Meeting, Commission staff provided the Commission with an overview of the Hydropower Regulatory Efficiency Act of 2013 and reported on some of the actions the Commission has taken so far in compliance with the Act. Staff's presentation is available on the Commission's website at http://www.ferc.gov/legal/staff-reports/2014/01-16-14-efficiency-act-2013.pdf.

b. What feedback did the Commission receive from the October workshop on the 2-year licensing process? Do you believe that FERC will be able to implement pilot projects in 2014? If not, why not?

Answer: Most of the commenters stated that a two-year licensing process is feasible and offered suggestions for ensuring a high likelihood of success, including that license applicants have a substantive proposal at the onset of the process and that federal and state resource agencies engage in the process. Other commenters stated that a two-year process is feasible provided that the proposed project meets certain criteria, including that the project have minimal environmental effects, minimal controversy at the onset of the two-year process, minimal need for environmental studies prior to licensing, and a small footprint.

The Commission has neither statutory nor budgetary authority to implement pilot projects itself; therefore, pilot projects can be implemented in 2014 only if the Commission receives proposals from potential applicants wishing to test the two-year licensing process. At noted above, the window for filing proposals to test the process begins on February 5, 2014, and ends on May 5, 2014. If the Commission receives a proposal to test the process that meets the requirements stipulated in the Commission's January 6, 2014 Notice, Commission authorization to begin testing could be granted as early as the Spring or Summer of 2014.

c. Did the workshop and comment period reveal any additional licensing issues (either at FERC or any other agency) that Congress would need to address through legislation to better effectuate the intent of the 2-year process? If so, please outline the issues.

Answer: No, however, there was discussion on whether agency mandatory conditioning authority under the Federal Power Act or other federal laws would hinder the feasibility of a two-year process. Commenters stated that an effective remedy would be for federal and state resource agencies with mandatory conditioning authority to be engaged throughout the process, and for license applicants to prepare thorough and complete license applications and proposed projects that are low impact.

d. How is the process for excluding small conduit hydro projects from FERC licensing working? Please provide numbers on determinations sought as well as those granted and or denied, and statistics on the length of time these proceedings have taken.

Answer: The process is working well. Staff prepared guidance on the procedures required in the Act, including a template for the Notice of Intent. This guidance is on the Commission's website, as is a table showing the status of the Notice of Intent requests. To date, 18 Notices of Intent to Construct Qualifying Conduit Facilities have been filed: 16 have been approved, 1 was rejected because it did not meet the qualifying criteria, and 1 is pending. To date, the average processing time from the filing of the Notice of Intent to the Commission's Final Determination is 63 days.

20. Have any of you or any other Commissioner had contact with the White House regarding the President's Climate Action Plan? If so, please describe the nature of the contact.

a. Have any of the activities undertaken by FERC been identified by the Administration as climate-related activities? If so, please identify.

Answer: At the time of the hearing, I had not had any contact with the White House regarding the President's Climate Action Plan. While I have still have not had specific conversations concerning the Climate Action Plan, I have had two discussions with White House staff since the hearing to discuss the need for FERC to remain engaged as environmental regulations are issued to help maintain reliability and ensure that markets adapt and to discuss the appropriate participation by FERC in the President's Quadrennial Energy Review.

21. Were you surprised to see that DOE's most recent Order granting authorization to export LNG partially denied Freeport LNG's request solely on the basis of the volume referred to in their FERC application?

Answer: DOE did not, nor does it need to, consult with us prior to making any of its decisions on the export of LNG as a commodity.

a. Freeport LNG cited the "nameplate" volume capacity in their FERC application. What steps would they be required to take with FERC if they find they are capable of exceeding that? Can they amend their application?

Answer: Yes, Freeport would have to file to amend its application to request authorization to operate its proposed facilities at a higher capacity than the level currently requested.

b. What precedent has DOE set by denying a request based on a FERC application? Do you believe DOE's basis was appropriate?

Answer: DOE's process is their own and we have no basis for commenting on DOE's actions. With respect to LNG, the Commission performs an environmental and safety analysis of a proposed LNG project and does not authorize the import or export of LNG as a commodity.

22. Other than for environmental reasons, do you believe that FERC has the authority to deny an application for an LNG export facility?

Answer: The Commission's role with regard to LNG is to determine whether the facilities being proposed can be constructed and operated safely and whether they are consistent with the public interest. Consequently, the Commission could deny an application based on safety considerations.

23. The license for the Catawba- Wateree Hydroelectric facility located in North and South Carolina expired on August 31, 2008. In 2006, well before the license expired, the project owner and operator timely submitted a relicensing application to FERC, along with a Comprehensive Relicensing Agreement (CRA) that was negotiated with more than 70 public and private stakeholders from North and South Carolina. On July 8, 2013, the National Marine Fisheries Service issued a final Biological Opinion for the project as part of the Section 7 consultation process under the Endangered Species Act. All the federal requirements seem to have been cleared, allowing FERC to now proceed to make a final determination on the relicensing application and issue the new license.

a. What is the status of the Catawba-Wateree relicense application?

Answer: The state of South Carolina denied Duke Energy Carolina, LLC's (Duke Energy) request for Section 401 of the Clean Water Act water quality certification for its project on August 6, 2009. Duke Energy is currently appealing the denial to the South Carolina Supreme Court. The Commission is unable to issue a new license for the project until the state of South Carolina grants or waives certification.

b. What is the Commission's sense of when a final determination of the application will be made so that the surrounding region can finally, after five years of waiting, start to see the economic, public and environmental benefits that will flow from the CRA being implemented as part of the new license?

Answer: A final determination on the application will be made following a grant by South Carolina of water quality certification for the project, or a waiver of certification. The timing of action on the water quality certification is controlled by the state of South Carolina.

24. In May 2013, Big Rivers Electric Corporation ("Big Rivers") submitted to the Midcontinent Independent System Operator, Inc. ("MISO") an Attachment Y notification for Big Rivers' Coleman Generation Station ("Coleman"). In that notification, Big Rivers announced that it would suspend operation of Coleman from September 1, 2013 through December 31, 2015. MISO has determined that continued operation of Coleman is necessary for reliable delivery of the full amount of power to the Century aluminum smelter that is adjacent to Coleman. Consequently, MISO has entered into a System Support Resource ("SSR") Agreement with Big Rivers to enable Coleman's continued operation. The SSR Agreement was filed with the Commission on November 1, 2013, in Docket No. ER14-232-000. The SSR Agreement anticipates monthly costs in excess of $3 million, nearly all of which will be borne by Century. This SSR filing comes on the heels of several other SSR filings by MISO. The costs of these other SSR filings are also being borne by customers in the Midwest.

a. Have MISO and the Commission adequately explored all feasible alternatives to the Big Rivers SSR agreement and other such agreements to reduce or eliminate the need to impose SSR costs on Century or other Midwest consumers?

Answer: Under its Commission-approved Tariff, MISO is required to explore all feasible alternatives before entering into an SSR agreement.[7]

With regard to the SSR agreement and rate schedule for Coleman Units 1-3 owned by Big Rivers Electric Cooperative that are at issue in Docket Nos. ER14-292-000 and ER14-294-000, the Commission issued an order on December 30, 2013 accepting and suspending the SSR agreement and rate schedule, subject to refund and further Commission order.[8] Because these issues remain pending before the Commission in a contested proceeding, I cannot comment on their merits.

With regard to the SSR agreement and rate schedule for the Edwards Unit 1 owned by Ameren Energy Marketing that are at issue in Docket Nos. ER13-1962-000 and ER13-1963-000, the Commission issued an order on November 25, 2013 accepting and suspending the SSR agreement and rate schedule, subject to refund and further Commission order.[9] As such, for the same reasons given above, I cannot comment on the merits of these issues.

The Commission has accepted other SSR agreements and rate schedules, and in doing so, has determined that MISO adequately explored all feasible alternatives to those SSR agreements consistent with its Tariff.

b. Please identify the actions that the Commission has undertaken to explore the following as feasible alternatives to Big Rivers' SSR and other SSRs:

i. Live-line transmission maintenance;

ii. Planning, design, and construction of new transmission facilities; and

iii. Special Protection Schemes

Answer: As stated above, the SSR agreements and rates schedules for the Coleman Units 1-3 and the Edwards Unit 1 are pending before the Commission in contested proceedings and the Commission cannot comment on their merits.

Regarding other SSRs agreements and rate schedules that have been accepted by the Commission, as noted above, in accepting these SSR agreements and rate schedules, the Commission determined that MISO adequately explored all feasible alternatives to these SSR agreements consistent with its Tariff.

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[7] MISO, FERC Electric Tariff, 38.2.7b. System Support Resources, 4.0.0.

[8] *Midcontinent Indep. Sys. Operator, Inc.*, 145 FERC ¶ 61,296, at P 15 2013).

[9] *Midcontinent Indep. Sys. Operator, Inc.*, 145 FERC ¶ 61,163, at P 16 (2013).

The Honorable Fred Upton

1. We often have FERC staff testify before this Committee rather than a FERC Chairman or Commissioner. FERC staff usually explains that they are testifying on their own behalf, and expressing their own views and "not those of the Commission or of any individual Commissioner." This can be problematic. We need to be able to rely on FERC staff's testimony as reflective of the agency's collective views so that we are informed of FERC's position on certain policies and legislation.

a. Will you commit to helping us resolve this disconnect for future hearings featuring FERC staff?

Answer: Because the Commission is a five-member body that speaks officially through its decisions, a staff member cannot commit the Commission to positions on specific matters or policies in areas in which it has yet to issue decisions, i.e., future Commission action. A staff member can, however, speak authoritatively to positions that the Commission has taken up through the present. The disclaimer that staff members give during testimony should not be read to mean that they cannot speak to existing Commission policies in a manner on which the Congress can rely. These limitations are in line with 5 CFR 2635.807(b)(2) (in the context of outside writings, requiring a prominent disclaimer stating that the views expressed do not necessarily represent those of the agency or the US Government).

2. At a hearing last month on H.R. 3301, the North American Energy Infrastructure Act, Jeff Wright from FERC testified about certain concerns with the legislation which involved confusion over whether the legislation would prohibit FERC from fully complying with Section 3 and Section 7 of the Natural Gas Act.

a. If we were to amend the legislation to specifically state that nothing in HR 3301 would affect the need to fully comply with the Natural Gas Act, do you believe that FERC would no longer have concerns with the legislation?

Answer: Yes, the suggested change would address the concerns.

3. A key goal in FERC's Strategic Plan, 2009-2014, calls for safe, reliable, and efficient infrastructure development to integrate new resources.

a. Are you supportive of FERC's goal for infrastructure development included in the plan?

Answer: I strongly support FERC's commitment to development of safe, reliable, and efficient infrastructure that will meet the Nation's energy needs. I also recognize the importance of the Commission's responsibilities with respect to certification of natural gas pipeline infrastructure and LNG terminals, as well as licensing of hydropower projects. FERC's policies, including Order No. 1000, transmission incentives, and generator interconnection also support the development of electric transmission infrastructure. In addition, the Commission works to ensure that the competitive markets work fairly to give appropriate investment signals to base load, mid-merit, peaking and variable generation, as well as demand response and energy storage technologies. Finally, the Commission ensures just and reasonable rates for the transportation of oil and oil products.

b. What enhancements or changes would you consider to this goal?

c. What other changes to FERC's Strategic Plan do you think may be needed?
Answer: I am always open to looking for ways to improve the Commission's processes. I expect that the Commission's strategic plan for FY2014 – FY2018 will be issued early this year. Following that issuance, I would be happy to provide a briefing on the new Strategic Plan.

4. Since states have their own transmission planning processes, why does FERC believe it's necessary to layer on a new federal process? Shouldn't planning for new transmission be overseen by the body that has the authority to approve or disapprove the resulting plans? Isn't that body the state- rather than FERC?

Answer: As an initial matter, concerns about the relationship between Order No. 1000 regional transmission planning process and individual states' integrated resource planning processes have been raised on rehearing before the Commission in some of the Order No. 1000 compliance proceedings. For this reason, I cannot speak to the specifics of those pending cases.

More generally, the Commission has an obligation under the Federal Power Act to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential. Order No. 1000 explained that its transmission planning and cost allocation reforms will help ensure that the rates, terms, and conditions of Commission-jurisdictional services satisfy this statutory standard. Moreover, Commission requirements for transmission planning are not a creation of Order No. 1000; rather, the transmission planning requirements of Order No. 1000 build on Order No. 890, which the Commission adopted in 2007.

It is important to note, however, that the Commission stated clearly that the reforms adopted in Order No. 1000 do not infringe on siting and integrated resource planning decisions that are frequently made at the state level. In addition, the Commission emphasized the benefits of states playing an important role in Order No. 1000 regional transmission planning processes, if they so choose. The Commission also did not assert authority to approve or disapprove the transmission plans that result from the Order No. 1000 regional transmission planning processes.

5. Federal statute divides the jurisdiction of FERC and CFTC between cash markets and derivatives markets, respectively. Section 720 of the Dodd-Frank Wall Street Reform and Consumer Protection Act required CFTC and FERC to negotiate a memorandum of understanding by January 2011 that would integrate energy market oversight and improve information sharing between the two commissions. As of this letter, FERC and CFTC had failed to negotiate such a memorandum because, according to a letter sent to Congress this August by then-FERC Chairman Jon Wellinghoff, "the two agencies disagree over whether

the CFTC should provide FERC with certain data that we believe is critical to our surveillance program to detect and deter energy market manipulation."

a. I understand that to complete its investigations, FERC often must request trading data from CFTC. Is it true that CFTC often takes more than two months to supply that requested data?

Answer: Before responding to your specific questions, it is important to note that on January 2, 2014, FERC and the CFTC signed a memorandum of understanding (MOU) with respect to information sharing, as required by Dodd-Frank. Under the 2005 MOU, it was not uncommon for the process under which FERC received information from the CFTC to take more than two months. The new MOU is intended to result in broader information sharing than currently occurs and is, therefore, a first step toward sharing appropriate data in a timely manner. Of particular importance, the new MOU recognizes that data can be shared for market surveillance purposes. It will be essential for the agencies to work together and to make an institutional commitment to, as well as the resources necessary for, the day-to-day, nuts-and-bolts implementation of the concepts established in this MOU.

b. I understand that CFTC and FERC technical staff have discussed giving FERC investigators the ability to download this data electronically and instantaneously. Is FERC aware of any technical reason why this information sharing is not yet occurring?

Answer: In contrast to the process under the 2005 MOU, a live data feed of relevant trading information would be far more efficient and effective. As the agencies implement the newly signed MOU, FERC is committed to resolving any technical concerns that the CFTC may have with respect to establishing a secure data feed for this information.

c. A letter from then-Chairman Wellinghoff suggests that information sharing is vital to its investigations. When was the last time any of you met with a commissioner of the CFTC to express in person the importance of information sharing?

Answer: During December 2013, I spoke twice with then-CFTC Chairman Gensler to discuss the importance of information sharing. These discussions led to the signing of the above-noted MOU on January 2, 2014. Since Chairman Gensler's departure from the CFTC, I also have spoken with CFTC Acting Chairman Wetjen about the need for prompt and effective implementation of that MOU.

6. When it comes to trading in natural gas and electricity markets, and without simply reciting statutory language, what is your understanding of how FERC defines market manipulation?

Answer: FERC's EPAct 2005 anti-market manipulation authority is based on section 10(b) of the Securities Exchange Act of 1934. After receiving its statutory authority, FERC went through a rulemaking to implement its statutory authority. FERC received extensive comments during the rulemaking process and responded to the comments in the Final Rule, Order No. 670. This Order carefully explains that "[t]he Commission will act in cases where an entity: (1) uses a fraudulent device, scheme or artifice, or makes a material misrepresentation or a material omission as to which there is a duty to speak under a Commission-filed tariff, Commission order, rule or regulation, or engages in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity; (2) with the requisite scienter; (3) in connection with the purchase or sale of natural gas or electric energy or transportation of natural gas or transmission of electric energy subject to the jurisdiction of the Commission." FERC often looks to SEC precedent for guidance on what constitutes manipulation on a case-by-case basis as appropriate under the specific facts, circumstances, and situations in the energy industry. An essential element of our rule, as noted, is scienter—which refers to the state of mind of the individual or company engaging in the conduct. To establish a violation of the rule, the Commission must show that the subject of a market manipulation investigation engaged in the conduct at issue with actual intent or recklessness.

7. Is it your understanding that FERC must prove "fraud' under the Natural Gas Act and Federal Power Act to make a finding of market manipulation?

Answer: In Order No. 670, the Commission noted that unlike common law fraud a violation of the anti-manipulation authority does not require proof of reliance, causation, or damages. Under Order No. 670, however, FERC must still prove scienter, as well as either a fraudulent device, scheme or artifice, a material misrepresentation, a material omission where there was a duty to speak, or a course of business that would operate as a fraud or deceit upon any entity.

8. What is your understanding of what constitutes "impairing a well-functioning market" as FERC has used that term in Order No. 670?

Answer: FERC, in Order No. 670 and subsequent orders in enforcement matters, has stated that for purposes of the anti-manipulation rule, "the Commission defines fraud generally, that is, to include any action, transaction, or conspiracy for the purpose of impairing, obstructing, or defeating a well-functioning market." The type of conduct that may impair a well-functioning market necessarily varies from case to case, but, among other things, includes any fraudulent or deceptive conduct designed to interfere with how prices are established or how markets are supposed to operate when market participants are playing by the rules. Such fraudulent or deceptive conduct can be contrasted with trading in accordance with market fundamentals where there is no scienter. In Order No. 670, the Commission also noted that "if a market participant undertakes an action or transaction that is explicitly contemplated in Commission-approved rules and regulations, we will presume that the market participant is not in violation of the Final Rule."

9. Do you think market participants have fair notice of how FERC defines market manipulation? Do you think market participants have fair notice of how FERC defines "impairing a well-functioning" market?

Answer: Yes, I do think that market participants have fair notice of how FERC defines market manipulation and impairing a well-functioning market. In the Commission's orders implementing its anti-manipulation authority—from Order No. 670 to orders approving settlements, Orders to Show Cause, orders following litigated matters before FERC Administrative Law Judges, and, more recently, Orders Assessing Civil Penalties (in Federal Power Act cases), which have covered a wide range of manipulative conduct, the Commission has striven to set out with as much particularity as possible the prohibited conduct at issue. In addition, as noted in Order No. 670, SEC precedent under Rule 10b-5 may provide useful guidance. That being said, we are early in our work on manipulation cases and I believe the Commission should continue to assess whether additional guidance may be helpful going forward.

10. FERC has been criticized recently by energy expert Professor William Hogan from Harvard University for not giving market participants adequate notice of what constitutes market manipulation. Do you agree with Professor Hogan's conclusion that this lack of clarity is going to imperil the natural gas and electric markets?

Answer: For the reasons stated above, I believe that FERC has given market participants adequate notice of prohibited conduct through regulations, settlements, and orders to show cause. I note that the Commission is early in its work on manipulation cases and I believe it should continue to assess whether additional guidance may be helpful going forward.

11. The Commonwealth of Puerto Rico is shifting its reliance on oil to natural gas as its primary source of electricity generation, reducing its cost of electricity to 22 cents per kilowatt hour by 2015. The Aguirre Offshore GasPort Project (AOGP) is a key element to this strategy. As the Commonwealth initiates the authorization process, what efforts has FERC been engaged in with the Puerto Rico Electric Power Authority (PREPA) and other agencies within Puerto Rico and what challenges are the agencies likely to encounter in completing this project?

Answer: The Aguirre Offshore GasPort Project is being developed by Excelerate Energy, LP in cooperation with the PREPA. Because PREPA is considered a co-sponsor of the proposed project, it is precluded from being a cooperating agency working directly with FERC staff on the Commission's environmental analysis of the project. However, FERC staff has been engaged with numerous other Puerto Rico (PR) Commonwealth agencies; in particular, the PR Planning Board, PR Permits Management Office, PR Environmental Quality Board, PR Department of Natural and Environmental Resources, and PR Department of Health are participating as cooperating agencies in the preparation of the FERC's Environmental Impact Statement. FERC staff and PR agency staff have maintained communication on project-related issues through regularly scheduled conference calls and issue-specific conference calls. In addition, FERC staff has met with various resource agencies on several occasions in PR, the most recent being a November 6, 2013 interagency meeting in San Juan. One of the main topics at this meeting was how to best integrate the various PR permitting requirements into the FERC environmental review process.

The Honorable Ralph Hall

1. In most instances, FERC has been appropriately respectful of the limits of its jurisdiction when it comes to non-jurisdictional entities such as electric cooperatives and others. However, there have been occasions where FERC has crossed that line, at least in the eye of some observers, or has come so close that the jurisdictional limits are for all practical purposes nullified. One example would be some of the orders issued earlier this year on the regional Order 1000 compliance filings. In some of those orders, such as the WestConnect order issued in March, FERC made certain rulings regarding cost allocation for transmission projects that overrode or dismissed the concerns raised by the non-jurisdictional entities about whether they can participate in regional planning without being subject to binding cost allocation. Going forward, how will FERC improve its treatment of non-jurisdictional entities while still pursuing its efforts to overhaul transmission planning?

Answer: In Order No. 1000, the Commission recognized that many of the existing regional transmission planning processes are comprised of both public and non-public utility transmission providers. Importantly, the Commission in Order No. 1000 did not require non-public utility transmission providers to participate in regional transmission planning processes and corresponding cost allocation methods. Instead, the Commission encouraged such participation and noted that the success of the reforms called for in the rule would be enhanced if all transmission owners, including non-public utility transmission providers, participate. I will consider carefully concerns raised by non-public utility transmission providers as the Commission addresses further filings related to Order No. 1000 implementation.

The specific issues raised in your question regarding the Commission's rulings on Order No. 1000 compliance filings, such as the March 2013 WestConnect order, are currently pending before the Commission on rehearing. As a result, I cannot comment on them at this time.

2. In September, 2013, Chair Whitfield together with 11 other Republican subcommittee members sent a letter to former FERC Chairman Wellinghoff asking the Commission to expand its examination of centralized capacity markets. The letter asked for this

examination in light of the Commission's expressed goals in its Order No. 2000: to "'promote efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest price possible for reliable service."'

Commissioner Norris recently issued a statement noting that a great deal of his time since he joined FERC in 2010 has been consumed with regulatory proceedings involving capacity markets, particularly those in the 3 Eastern RTOs. The same is certainly true for market participants, both those that have unbundled and especially those that remain vertically integrated. For such entities, which include many IOUs as well as electric co-ops and public power, meeting their load-serving obligations through self-supply, whether that be owned generation and/or through purchase power contracts, is the best way to achieve that Order No. 2000 goal; and preserving their right and ability to do so is their primary challenge in all these many regulatory proceedings.

Is there any reason why the right to self-supply cannot continue to exist within the capacity markets as currently constructed? Put differently, wouldn't limiting the ability of non-FERC-jurisdictional entities to make their own decisions regarding how best to meet their systems' needs fall outside the line of FERC's jurisdiction? And how would FERC justify such a limitation, given the stated goal of reliable service at the lowest possible cost?

Answer: I noted at the hearing that the Commission has opened an inquiry (Docket No. AD13-7-000) to consider how the current centralized capacity market rules and structures in the Eastern RTO/ISOs are supporting the procurement and retention of resources necessary to meet future reliability and operational needs. The issue you raise regarding the ability of load-serving entities to self-supply their capacity obligations is one of many issues that are under discussion in that proceeding.

To help inform the Commission's inquiry, in August 2013, Commission staff released a Staff Report examining the various design elements that make up the current centralized capacity markets.[10] In that report, Commission staff recognized that some customers may prefer to supply their own capacity outside of the centralized capacity market based on factors such as their view of market risk, desire for long-term arrangements, or business models. Staff noted, however, that the use of a demand curve (a central feature of the Eastern RTO/ISO centralized capacity markets) to approximate customer demand for capacity resources has implications for the ability of load-serving entities to self-supply capacity, including specific kinds of capacity resources they build or acquire to meet policy goals such as state renewable portfolio standards. Staff explained that whether to allow customers to self-supply, and if so, how the self-supply is reflected in the demand and supply curves, can impact the price signals sent by capacity markets. As a result, whether and to what extent load serving entities can opt to self-supply their capacity needs outside of the centralized capacity market varies among the three eastern RTOs/ISOs.[11]

[10] "Centralized Capacity Market Design Elements", FERC Staff Paper (August 23, 2013), *available at* http://www.ferc.gov/CalendarFiles/20130826142258-Staff%20Paper.pdf.

[11] *Id.* at 8-9, 11.

This issue was discussed at length at the September 25, 2013 Commissioner-led technical conference in Docket No. AD13-7-000. Following that conference, the Commission issued a request for post-technical conference comments, which included questions exploring how the current market rules facilitate or hinder the ability of load-serving entities to self-supply, and whether the Commission should consider changes to the current capacity market designs to facilitate these arrangements. The Commission recently received over 1,000 pages of comments in response to that request, including comments regarding the ability to self-supply. The Commission is in the process of reviewing them and considering next steps as appropriate.

3. In the Energy Policy Act of 2005 Congress enacted Federal Power Act section 211A which gave FERC certain limited jurisdiction over large transmitting electric cooperatives that are otherwise not generally FERC-jurisdictional. Since then FERC has at least twice declined to impose 211A on a generic basis and has not to date imposed 211 A conditions on a single co-op. Do you commit to following that precedent, reserving 211 A to be used only if and when needed on an individual case basis?

Answer: Yes, I commit to using the Commission's authority under section 211A to be used only if and when needed on an individual case basis. I do not take the exercise of our authority under FPA section 211A lightly. The Commission has observed in a recent case that it expects that the need to use this statutory authority would be rare.[12]

4. At last Thursday's hearing, we discussed a new technology that has been developed in Texas which will improve the usefulness of LPG- type products by enabling more hydrocarbon constituents to be mixed into them. As I understand it, LPG is a process patented in 1913 by Dr. Walter Snelling of the U.S. Bureau of Mines. FERC and DOE's predecessor agency determined that this product, like other NGLs was not natural gas and not subject to regulation. Since that time, in Texas and throughout the country, LPG has been produced, transported, consumed and freely exported without the need for regulation by the Federal Energy oversight agencies.

LPG is an important contributor to Texas' economy and, with the Shale Gas Revolution, is becoming increasingly valuable. I am not aware of any significant problems that have arisen during the 100 years or so that this regulatory approach has been followed.

My question is this. If there is a new proprietary process that increases the value and utility of LPG-type operations by enabling additional constituents found in petroleum or wellhead gas to be mixed in and if the product of that process is similar in characteristics to LPG, why doesn't it make sense to regulate that process in the same way you regulate LPG, and for that matter, what words in the law prevent you from taking that approach?

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[12] *Iberdrola Renewables, Inc., v. Bonneville Power Administration,* 137 FERC ¶ 61,185 at P 32 (2011).

I ask that you answer this question as promptly as practicable as I am advised by colleagues on the Committee that uncertainty is delaying deployment of these new technologies and achievement of the very substantial environmental and economic benefits which they offer.

Answer: I do not anticipate the Commission changing how it defines "natural gas" for purposes of determining the scope of its jurisdiction under the Natural Gas Act. However, the transportation of natural gas liquids and other liquid hydrocarbons may be regulated under the Commission's rate jurisdiction under the Interstate Commerce Act.

The Honorable John Shimkus

1. Are you aware that the United States Military Academy (USMA) at West Point is at capacity for electric power and how would you describe this situation?

Answer: The USMA is served by Orange and Rockland Utilities (O&R), which serves a population of approximately 750,000 in seven counties in New York, northern New Jersey, and northeastern Pennsylvania. Information obtained by FERC staff, but not yet confirmed with O&R or the USMA, indicates that the USMA is served by two 34.2-kV lines, which supply two substations on the western and southern boundaries of the USMA area. From the substations, power is distributed via 13.2-kV and 4.16-kV lines to various loads. Available information also suggests that the electrical demand appears to be approximately 90 percent of capacity for these facilities.

Like you, I recognize the importance of ensuring the integrity and reliability of the electric system that provides service to the USMA. However, the information summarized above indicates that the delivery of electricity to USMA is a State-regulated distribution function and not within FERC's authority. The responses to questions 2-9 are better addressed by O&R and the New York State Public Service Commission (NYSPSC), which has regulatory authority over distribution systems in the State of New York.

2. Has the transmission system at USMA been substantially upgraded since the 1970s?

Answer: I do not know.

3. What are the expected improvements for a typical transmission system that is 40 years old?

Answer: Many facilities used to deliver electricity are more than 40 years old. While some of these facilities have required improvements or upgrades, it would be difficult to generalize about what is typical for timing and types of improvements or upgrades.

4. Is there a general calculation used by utilities to forecast demand increase that would drive the upgrade of infrastructure?

Answer: No, circumstances and approaches vary by location, types of customers, economic conditions and other factors.

5. Is the age of the transmission system supporting USMA a concern?

Answer: I do not have enough information to express an opinion on the facilities described above.

6. Are utilities obligated to provide power requisite with current and future demand?

Answer: Any such obligation for entities such as USMA depends on State law, and would be better addressed by the NYSPSC.

7. Who is responsible for the funding of upgrades?

Answer: For facilities such as those described above, this responsibility depends on State law, and would be better addressed by the NYSPSC.

8. Are utility companies obligated to submit master plans or capital improvement plans? If so, what has been submitted with regard to USMA?

Answer: FERC imposes no such obligation. I do not know if the State of New York does.

9. How does USMA's electric energy use affect the neighboring communities, such as Highland Falls and Fort Montgomery?

Answer: I do not know.

The Honorable Michael C. Burgess

1. Commissioners, I join many of my colleagues who are concerned about a growing trend within Federal agencies to expand their jurisdiction without being given the authority by the Congress. Just because some long time government employee or employees may be predisposed one way or another, we are a nation of laws and even agencies are not exempt

from the limitations placed on them by statutes we have passed that give them their jurisdiction.

There seems to be a good deal of uncertainty as to how FERC and DOE are regulating natural gas and natural gas export and exactly what "natural gas" is. I hope that, as new processes for recovering, transporting and storing hydrocarbons are developed, FERC and DOE will adhere to a strict construction of the statutory definition and not try to reach out and regulate products which are liquid, like LPGs, or which are specially manufactured to meet customer needs. Do you agree that we should interpret the law wherever possible in ways which minimize regulatory impediments?

Answer: I do not anticipate the Commission changing how it defines "natural gas" for purposes of determining the scope of its jurisdiction under the Natural Gas Act. However, the transportation of natural gas liquids and other liquid hydrocarbons may be regulated under the Commission's rate jurisdiction under the Interstate Commerce Act.

The Honorable David B. McKinley

At our hearing on December 5th, we discussed the definition of "natural gas," the application of that definition to Natural Gas Liquids and the effect of that application on new "solvation" technologies which produce liquid mixtures of selected natural gas and NGL constituents. I understand that these mixtures are similar in characteristics to LPG but can be effectively used to capture and transport any or all of the gas constituents that come out of the wellhead. As I noted, this technology can be extremely useful in capturing and recovering the significant volume of gas that is currently being flared in West Virginia and in alleviating the glut of certain gas constituents like ethane that currently exists in our region.

It is my understanding that the deployment of this technology in my state and others (Mr. Hall raised similar issues in his questioning) is being delayed by uncertainty as to whether FERC and DOE will treat this new mixture of gas and NGL constituents as a liquid like LPG and thus not subject to export controls and other regulatory strictures applicable to "natural gas" or, in the alternative, whether the natural gas definition will be stretched to cover this new technology and delay its implementation. I was heartened by the Chairman's assurance that there are no plans to redefine natural gas under the Natural Gas Act but would like answers to the following questions in order to resolve the uncertainties which are currently impeding the deployment of these new technologies.

1. My understanding is that both DOE and FERC have historically concluded that NGLs such as Propane, Ethane and LPG are not "natural gas" and may be produced, transported and exported without being subject to the facility siting and other regulatory restrictions which apply to natural gas. Are you aware of any policy reason for deviating from this approach and regulating either NGL facilities (particularly those other than pipelines) or the transportation and use of NGLs in a manner different than that which has

been historically followed? Hasn't the current approach been essentially problem free? Is there any reason to expand jurisdiction and move into an area which has been problem free?

Answer: The Commission has no pending proposal dealing with these technologies. However, I do not anticipate the Commission changing how it defines "natural gas" for purposes of determining the scope of its jurisdiction under the Natural Gas Act. However, the transportation of natural gas liquids and other liquid hydrocarbons may be regulated under the Commission's rate jurisdiction under the Interstate Commerce Act.

2. As a matter of policy, should the mixtures created by new technologies which alter LPG, by incorporating into it additional hydrocarbon constituents found in wellhead gas, be treated like LPG, to which it is most similar in characteristics, or like pipeline quality natural gas, which is subject to regulation by FERC and DOE? Shouldn't it be our policy to minimize regulatory interference with business decisions where there is no demonstrated need for regulation?

Answer: See Question 1.

3. As a matter of law, how can it be determined that a process which mixes various constituents of wellhead gas, including Methane, into Propane and other NGLs to create a mixture of natural gas and natural gas liquids which is similar in characteristic to LPG, is either "natural gas unmixed" or a "mixture of natural and artificial gas" within the meaning of the Natural Gas Act of 1938.

Answer: See Question 1.

As I indicated at the hearing, uncertainty regarding these issues is delaying deployment of important new technologies which can be of great import in preventing waste and environmental harms while, at the same time, creating jobs and helping West Virginia's economy.

The Honorable Jerry McNerney

1. In California, we have a number of statutory and regulatory requirements that not only require development of new generation, but also the type of new generation. Is it the Commission's intent to let the ISOs (or in our case the States) lead in deciding whether capacity markets are necessary and, if so, to design them to reflect the unique features of the relevant market?

Answer: The Commission has given RTO/ISO regions flexibility to determine, in consultation with their stakeholders, the best mechanisms for meeting resource adequacy needs. This approach is reflected in the varied approaches taken by different RTO/ISOs across the country. In addition, where regions have chosen a centralized capacity market, the Commission has provided significant flexibility as to market design and has not mandated a "one size fits all" approach.

2. My understanding is that some of the current capacity markets require local utilities to buy from the market. Public power utilities in Northern California just built a highly efficient and clean gas plant in my district. Will they be able to utilize this resource and self-supply, rather than being forced onto the market?

Answer: Yes, the public power utilities in Northern California will be able to utilize their resources, including this new gas plant, to self-supply their capacity requirements. Some of the public power utilities that have ownership interest in this new plant are within the footprint of the organized market administered by the California Independent System Operator (CAISO). They are not members of CAISO, however, they do at times choose to sell into and buy from the CAISO market. Although load serving entities located within the CAISO footprint must submit supply plans to CAISO that show that they have procured adequate resources, nevertheless, how capacity procurement is done is not subject to CAISO's market rules. In short, according to CAISO rules, all load serving entities, including public power utilities, can self-supply from owned resources or enter into bilateral contracts to satisfy their capacity requirements, and thus these public power utilities can use the capacity and energy from this new plant to serve their members' needs.

3. There has been recent discussion about whether FERC might push for lower returns for transmission investment. Can you comment on what you see FERC's role being at this time in providing a clear, consistent market signal for the transmission investment that this Committee has believed to be important for a number of years?

Answer: The Commission has a number of cases pending on return on equity for electric transmission facilities, including complaints that seek to lower the allowed returns earned by transmission owners. Because these issues remain pending before the Commission in contested proceedings, I cannot comment on their merits. In addressing these cases, I will be mindful of establishing returns that are just and reasonable for both investors and consumers and provide adequate regulatory predictability through a principled outcome.

The Honorable Eliot L. Engel

The Commission has been focused on implementing policies which provide significant advantages to demand response resources relative to traditional generation, presumably because of their superior environmental impact. Yet, in some areas up to 1/3 of this demand response isn't the type use reduction and demand side management we normally conceive of when we're talking about demand response. Instead, a great deal of this

actually appears to be load shifting rather than demand reduction and the load is being shifted from low emitting generation sources to inefficient, diesel-fueled, backup generators, that don't have environmental controls.

1. How this is consistent with the purported environmental benefits DR is supposed to bring?

<u>Answer</u>: Providing appropriate competitive opportunities in organized electric markets for emerging resources such as demand response promotes efficient market outcomes and, therefore, just and reasonable rates for consumers. The Commission's initiatives with respect to demand response, in both generic proceedings such as the rulemakings that led to adoption of Order No. 719 and Order No. 745 and in response to filings related to individual RTOs and ISOs, have focused on promoting these goals. The Commission does not have statutory authority with respect to whether and how demand response resources comply with relevant environmental regulations. The EPA has conducted recent proceedings related to environmental regulation of certain behind-the-meter generators that can facilitate demand response. Individual states also may have environmental regulations that affect activities of demand response resources.

A second problem seems to be that when this bundled demand response commits to provide system reliability 3 years ahead of time, it simply does not show up when it is needed.

2. What is the Commission doing to ensure these demand response resources are real, and are fully committed to meet their obligations for providing system reliability?

<u>Answer</u>: In February 2013, the Commission directed public utilities to incorporate by reference updated business practice standards adopted by the Wholesale Electric Quadrant of the North American Energy Standards Board to support the measurement and verification of demand response and energy efficiency products in wholesale markets. In addition, I note that Commission staff regularly monitors and reviews reports provided by the organized wholesale markets that address the performance of demand response resources when called upon to maintain reliability. Commission staff has also initiated enforcement actions against demand response providers that had engaged in manipulative actions so seek compensation for demand response that was not actually provided. The Commission has ruled on and continues to consider a number of cases in the energy and capacity markets that relate to ensuring that the rules governing demand response performance and compensation are just and reasonable.

<u>The Honorable Gene Green</u>

The liquefied petroleum gas (LPG) industry is an important component of the Texas oil and gas industry. In Texas, the Railroad Commission administers and enforces state laws and rules related to LPG, while the Environmental Protection Agency is responsible for

oversight and regulation of emissions and clean air standards, and the U.S. Department of Transportation regulates some aspects of transportation.

1. New technologies have now entered the marketplace for producing LPG-like products, called Compressed Gas Liquids that are customized blends of gas and gas liquids. How can we ensure that these new Compressed Gas Liquids products and facilities are similarly regulated to the LPG industry?

Answer: The Commission has no pending proposal dealing with these technologies. However, I do not anticipate the Commission changing how it defines "natural gas" for purposes of determining the scope of its jurisdiction under the Natural Gas Act. However, the transportation of natural gas liquids and other liquid hydrocarbons may be regulated under the Commission's rate jurisdiction under the Interstate Commerce Act.

The Honorable Mike Doyle

Manufacturing companies argue that they are overpaying for natural gas as a result of interstate pipeline rates. FERC needs to assure consumers that pipeline companies are charging a "just and reasonable" rate as required under the Natural Gas Act.

1. What is FERC doing to ensure that consumers are not overcharged?

Answer: FERC conducts a yearly review of natural gas pipeline rates. FERC requires interstate natural gas pipeline or storage companies to file a FERC Form No. 2 or 2-A (Form 2) report, which provides detailed financial and operational information from the prior calendar year. FERC uses the Form 2 information to determine whether to investigate the rates charged by interstate natural gas pipeline or storage companies by calculating the earned equity return for each of the pipelines or storage companies filing Form 2. Since 2009, the FERC has initiated ten NGA section 5 rate proceedings to investigate whether rates charged by certain interstate natural gas pipelines or storage companies were just and reasonable. These proceedings resulted in various benefits to the pipeline or storage company's customers, such as reduced transportation rates, reduced fuel retention rates, a revenue sharing mechanism, agreements to provide detailed revenue data, and, depending on the circumstances, agreements to file or to refrain from filing section 4 cases. Seven of the cases resulted in lower rates for customers totaling $194 million per year.

In addition to using its investigative authority to conduct section 5 rate proceedings, the Commission closely monitors all rate change filings made by jurisdictional gas pipeline and storage operators. In order to determine whether a rate increase is just and reasonable, the Commission routinely suspends such tariff filings to ensure a refund liability for the filing entity and sets the matter for hearing. Most such cases result in Commission-approved settlements that establish appropriate rates and provide for refunds and reductions in future rates. Over the period 2008-13, the cumulative savings to customers from gas pipeline rate settlements (both one-time refunds and ongoing reductions in rates) totaled $3.35 billion. This is another means by which the Commission assures that interstate gas pipeline and storage customers are not being overcharged.

The Natural Gas Supply Association conducts a study every year using Form 2 data that pipelines are required to file with the FERC. The latest report indicated that that pipelines are overcharging by $3 .4 billion. This seems to be a problem in the sense that these dollars are coming from consumers.

2. Some have suggested that one way to address the issue would be reform of the Natural Gas Act to ensure that customers (after proving that they have been overcharged by interstate pipelines) can receive a refund back to the date of a filed complaint- a change that would give gas customers the same protections afforded under law to electricity customers since 1988. What are your thoughts on this?

Answer: I agree that the challenge with a NGA section 5 proceeding is that any new rate, term, or condition has only prospective application and support adding a refund provision to section 5 of the NGA because such a provision would encourage prompt resolution by removing the incentive to engage in protracted litigation in order to postpone having to pay any refunds that might be ordered to customers.