Responses of Douglas Smith to Additional Questions for the Record

Energy and Power Subcommittee Hearing
on "Federal Power Act: Historical Perspectives"
September 7, 2016

<u>The Honorable Morgan Griffith</u>

1. **Do you believe that the markets are adequately compensating baseload plants for their unique attributes (including dependability and reliability) they provide the grid?**

   Organized electricity markets run by regional transmission organizations (RTOs) and independent system operators (ISOs) provide market-based compensation for generators, including baseload plants, for delivery of energy, ancillary services, and in some cases capacity. Because the auction results are based on market conditions, they may provide revenues to generators that are above or below a generator's actual costs.

   Some regions have reformed elements of their markets to better recognize the value of highly reliable generators. PJM and ISO-NE have recently made changes to their capacity markets, in response to supply shortages during extremely cold winter conditions in January 2014, to recognize the reliability benefits of generators with secure fuel supply arrangements, and to penalize more harshly generators that cannot deliver on capacity commitments.

2. **What reforms do you think could be made to ensure baseload plants—particularly coal-fired power plants—are adequately compensated for these attributes?**

   One approach is to make adjustments to organized market structures to ensure that all valuable attributes of a generator are recognized, and paid for, in the market. As mentioned above, PJM and ISO-NE have recently made changes to their capacity markets in order to recognize the reliability benefits of generators with secure fuel supply arrangements, and to penalize more harshly generators that cannot deliver on capacity commitments. Such reforms do not assure, however, that all coal-fired plants will find it economic to continue operating, given low electricity prices, low natural gas prices, and costs of environmental compliance.

   Where vertically integrated utilities exist, and the costs of utility-owned generation are recovered primarily through cost-of-service retail rates, the decisions about whether to maintain or retire baseload plants are made in the utility resource planning process, subject to state regulatory oversight, not in response to wholesale market conditions.

3. **If baseload units are forced to close—by a combination of market dynamics, unfavorable market rules, and escalating regulatory costs—will it require a major restructuring of transmission infrastructure?**

As a general matter, additions and retirements of generation, the location of such additions and retirements, and changes in load drive transmission planning decisions, and in particular decisions about whether additional transmission infrastructure investment is needed. The effect of any particular generating unit retirement, or addition, on the need for new transmission infrastructure is inherently case-specific. There are often numerous factors that play into transmission planning decisions.

A. Have the cost and impact of massive new transmission facilities been evaluated if major baseload stations continue to close?

The transmission planning regions plan for transmission development in light of projected changes in load and generation. For example, PJM has authorized more than $29 billion in transmission upgrades and additions since 2000 to address a wide range of needs, including alleviating congestion, ensuring system reliability, and replacing outdated infrastructure.[1] The Brattle Group projected in 2015 that of an anticipated $120-160 billion in national transmission investment over the next decade, between $10-20 billion might be specifically attributable to coal plant retirements.[2] There is significant uncertainty in this estimate because of uncertainty about the role of factors such as the Clean Power Plan and potential coal-to-gas conversions.

4. **What effect do renewable energy subsidies and mandates have on the grid and our bulk power supply—particularly on reliability?**

Federal incentives, such as the production tax credit and the investment tax credit, and State incentives, such as renewable portfolio standards, have been a significant driver for investment in renewable generation resources. The bulk of the recent investment has been in intermittent renewable generation such as solar and wind generation. According to the Energy Information Administration, coal-fired generation accounted for 33% of U.S. electric energy generation in 2015; natural gas-fired generation accounted for 33%; wind accounted for 5% and solar accounted for 1%.

In areas of the country with high levels of intermittent renewable penetration, the need for generators that can ramp up and down quickly had grown significantly. In California, for instance, daily net load patterns now follow a "duck curve," with solar

[1] *See* PJM Interconnection, "PJM Board Approves $636 Million Investment in Transmission Projects" (Aug. 9, 2016), *available at* www.pjm.com/~/media/about-pjm/newsroom/2016-releases/20160809-rtep-news-release-market-efficiency-project.ashx.

[2] *See* Pfeifenberger, Chang, and Tsoukalis, Brattle Group, "Investment Trends and Fundamentals in US Transmission and Electricity Infrastructure" (July 15, 2015), *available at* http://www.brattle.com/system/publications/pdfs/000/005/190/original/Investment_Trends_and_Fundamentals_in_US_Transmission_and_Electricity_Infrastructure.pdf?1437147799.

accounting for significant generation midday, but need for other resources ramping up steeply in the late afternoon.[3]

A. How are baseload units affected by these market preferences?

Generally, non-market incentives for renewable generation support greater levels of investment in renewable generation than would otherwise occur. Wind and solar generation typically have no fuel costs and very low operating costs, and so are able to economically make quite low bids into organized energy markets, creating a downward pressure on energy market prices. In some cases, the incentives are based on the output of the plant (e.g., the production tax credit, the generation of renewable energy credits under a State renewable portfolio standard), which may make it economical for renewable generators to make negative energy price bids (i.e., where they would pay to deliver energy in the market) in some cases. This is good for ratepayers, as it puts downward pressure on energy prices. It reduces revenues for baseload generators, however, because renewable generators have lower bids than some baseload generators and are thus displacing some baseload generation, and because it generally pushes down market clearing prices.

B. Have these preferences contributed to the closure of certain baseload units—particularly coal-power units?

Many existing coal and nuclear generators have found current and foreseeable electricity market conditions challenging, and some have made an economic decision to retire plants before the end of their useful lives. Coal plant owners face added challenges as compliance with current and future environmental regulatory requirements necessitates additional investment in pollution control equipment or other compliance costs. Generation unit retirements are typically attributable to the confluence of multiple cost and market factors, which may include flat demand for electricity, low natural gas prices, low wholesale electricity prices, environmental compliance requirements and costs, and unit lifespan or relicensing issues. I am not aware of analysis showing that renewable energy incentive policies have been the primary cause of baseload coal plant retirements. I expect that low natural gas and electricity prices, and the prospect of additional environmental compliance costs, are likely more significant economic drivers.

[3] *See* California ISO, "What the duck curve tells us about managing the green grid" (2016), available at: https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

The Honorable Paul Tonko

1. **It is clear that today's grid is different than 20 years ago, and it is continuing to change rapidly. Mr. Smith's testimony explained how different technologies and grid management techniques are testing the boundaries between federal and state jurisdictions. Tomorrow's grid will raise even more questions with the growth in storage capacity and microgrids.**

    A. **Are there any lessons we can learn from FERC's actions in the 1980s and 1990s on how to plan for these impending changes, which will make our grid and electricity markets even more complicated than they are today?**

It will be important for both FERC and Congress to be alert to how the regulatory arrangements, and in particular jurisdictional assignments, may need to be adjusted in order to ensure that beneficial technology deployment and market changes can be accomplished. In some cases, FERC has chosen to interpret its jurisdiction in a manner that leaves certain decisions to State oversight. For instance, in Order No. 888, FERC chose not to exercise jurisdiction over the transmission component of bundled retail rates, and the Supreme Court sustained this decision. More recently, FERC has chosen to interpret its jurisdiction over wholesale sales in a manner that allows States to set net metering policies without FERC interference. In some areas, it may not be possible to craft appropriate boundaries between the jurisdiction of Federal and State regulators through FERC interpretation of the current Federal Power Act. In such areas, Congress may need to make adjustments to the Federal Power Act itself.