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Chairman Whitfield, Ranking Member Rush and Members of the Committee, thank you for the invitation to appear before you today. My name is Tony Clark and I am honored to serve as a Commissioner of the Federal Energy Regulatory Commission.

A central focus of FERC's job is to help ensure the provision of reliable, affordable energy to the American people. This mission supports a vibrant economy, and the health, safety and quality of life of our nation. FERC accomplishes its goals through a number of actions, including our oversight of jurisdictional markets, our responsibilities for bolstering reliability, and our duty to oversee the prudent development of certain energy infrastructure.

My submitted testimony focuses on those areas of the Commission's responsibility that relate to energy infrastructure. Necessarily, that discussion will lead me to provide some comments on the Environmental Protection Agency's recently finalized rules related electricity sector CO2 emissions under section 111(d) of the Clean Air Act.

The Commission plays an especially important role in the siting of hydroelectric and natural gas infrastructure.

With regard to hydropower licensing, the Commission continues to advance Congress' initiatives in the Hydropower Regulatory Efficiency Act of 2013 by processing conduit exemptions and preliminary permit extensions.

Since issuance of the Act through November 24, 2015, staff has received notices of intent to construct 67 qualifying conduit facilities, 39 applications for extensions of permit terms, and no small hydropower exemption applications for projects between 5 and 10 MW. Of the 67 conduit facilities, 55 have been qualified, 8 were rejected because they did not meet the criteria set forth in the Act, and the remaining 4 are pending. Of the 39 applications for permit extensions, 20 were granted and 19 were denied due to lack of diligence.

On October 22, 2013, in compliance with the Act, the Commission staff held a workshop to investigate the feasibility of a two-year process for the issuance of a license for hydropower development at non-powered dams and closed-loop pumped storage projects. Participants discussed whether such a process is feasible, presented ideas on the details of a two-year licensing process, and discussed potential criteria for identifying projects that may be appropriate for a two-year licensing process. On January 6, 2014, the Commission issued a notice soliciting pilot projects to test a two-year process. The notice also established certain criteria that a proposed project must meet to qualify to test a two-year process. In response, two pilot project proposals were filed. Commission staff rejected one because the project did not meet the criteria specified in the January 6, 2014 Notice.

The Commission did, however, notice a proposal for Kentucky River Lock & Dam No. 11 Hydroelectric Project No. 14276 on June 3, 2014. Commission staff held a technical conference with the applicant and interested parties on June 19, 2014, to discuss the project's proposed two-year process plan and schedule. On August 4, 2014, Commission staff approved the proposal to test the two-year process for the project, including a proposed license application due date of May 5, 2015. The prospective applicant filed a license application for the project on April 16, 2015. After a series of staff information requests, advisory phone calls, and responses by the applicant, on September 25, 2015, Commission staff issued notice that the application was ready for environmental analysis notice. Comments, recommendations, terms and conditions were due by November 24, 2015. The next step in the process is issuance of staff's environmental document.

On a separate hydropower topic, I feel it important to highlight for the Committee that the number of projects that will begin the relicensing process will substantially increase beginning in FY 2016 and continue well into the 2030s. Between FY 2016 and FY 2030, over 500 projects, which represent about 50 percent of our licensed projects and about 30 percent of the generating capacity under Commission jurisdiction, will begin the pre-filing consultation stages of the relicensing process. For those of you that have licensed projects in your districts, I am sure you will want to be up-to-speed on these matters because hydropower relicensing is the sort of issue that can generate considerable constituent interest.

Once new licenses are issued, the license implementation phase will begin. Currently, the Commission's license compliance and administration division is processing over 3,500 license-related filings per year. This workload is certain to increase given the number of projects to be relicensed.

Many of these projects now on the eve of relicensing were first licensed in the early to mid-1980s. This was prior to enactment of modern environmental standards, including those of the Electric Consumers Protection Act of 1986, which first directed the Commission, when issuing licenses, to give equal consideration to energy conservation, fish and wildlife protection, recreational opportunities, and environmental quality, and required that licenses be granted upon the condition that the project adopted shall, in the judgment of the Commission, be the one best adapted to a comprehensive plan encompassing fish and wildlife protection, irrigation, flood control, and water supply.

As we work through this period of substantial relicensing, I hope you and your staff members will see FERC as a resource to help provide background on the various projects and the Commission's regulatory process.

Moving to natural gas; within the natural gas sphere of our responsibilities, since I last appeared before you, the Commission has continued its work related to the siting of interstate pipelines and LNG export facilities. With regard to pipeline projects, although the Commission's work is perhaps more visible than it has ever been, the Commission's pipeline certification activity itself is within the historical norm as shown by the table below:

Major Projects				
Year	**Number of Projects**	**Capacity (MMcf/d)**	**Miles of Pipeline**	**Horsepower (HP)**
2005	17	8,746.4	703.0	123,036
2006	19	8,480.6	1,241.4	306,557
2007	28	18,874.2	2,591.2	849,110
2008	24	13,954.2	2,084.1	648,838
2009	23	9,781.0	953.9	728,129
2010	21	9,079.1	1,568.6	496,994
2011	15	4,032.8	303.8	280,255
2012	18	4,449.0	193.1	145,920
2013	17	7,308.9	262.9	185,011
2014	20	10,999.9	418.6	472,932
2015-Nov	20	9,537.0	262.9	292,490
Totals		**105,243.1**	**10,583.5**	**4,529,272**

In addition, the Commission continues to carry out its responsibilities related to the siting of LNG facilities. As of November 2015, the Commission has authorized 7 LNG export projects, totaling 10.62 Bcf/d in capacity. Another 10 projects have pending formal applications in various stages of review totaling 12.53 Bcf/d in capacity. Not included in these totals are the 12 other projects that are in the "pre-filing" stage.

The ongoing demand for natural gas infrastructure is not surprising given the changes occurring in the energy world. A combination of affordable natural gas and certain state and federal environmental policies have sharply increased electricity generation from natural gas and renewables, often at the expense of coal.

Working within the statutes passed by Congress, FERC has the responsibility to ensure that this infrastructure is sited the right way, which is accomplished through a siting process that allows various parties and stakeholders to be heard via a record that is compiled with both written submissions and public testimony.

While the Commission is generally able to handle most energy projects in a timely matter – in the last 10 years, 92% of all applications have been processed and completed within 12 months, I believe it is fair to observe that infrastructure development and siting is becoming more challenging.

Infrastructure, be it related to natural gas, large hydropower projects, electric transmission or generation (the last two being sited at the state level) engenders a level of opposition that was rarely seen in the past.

In years gone by, intervention in regulatory proceedings tended to be driven by those most directly affected by the energy project – for example a landowner who would prefer an energy project be located on "Site A" rather than "Site B." The regulatory process is well equipped to consider and weigh these sorts of comments, and we still do receive a fair amount of this type of intervention in our cases. In fact, as a Commissioner, I have always viewed this type of intervention as particularly critical to our work because it helps develop a complete record regarding where infrastructure is both well and poorly suited.

But today there is an increasing trend towards "Just Say No" intervention. This intervention is designed to block entire classes of infrastructure projects – either through outright denial or through a strategy of defeat through delay. It is not opposition based on a particular project or its location; it is an opposition to all infrastructure as a matter of ideology. Often this opposition is from those expressing concern about climate change and carbon emissions.

The irony is that much of this infrastructure is being necessitated by the very regulations that are being promulgated in the name of reducing carbon intensity in the electric generating sector.

In the case of gas pipelines, it is in large part to fuel generators that are either replacing higher carbon emitting baseload coal plants or being paired with variable energy resources like intermittent wind and solar.

In the case of electric transmission lines, it is often to facilitate geographically distant renewables, and to optimize their use to compensate for their inherent intermittency.

I believe a major challenge for energy regulators over the next several years – both at the federal and state levels – will be to grapple with this tension of dealing with policies that necessitate large infrastructure projects in an era of heightened infrastructure opposition.

Dealing with these issues will be even more important should the Environmental Protection Agency's new 111(d) carbon regulations come to pass. For if infrastructure development is largely delayed or blocked, I have difficulty envisioning affordable or reliable ways for utilities to meet the EPA mandates.

These 111(d) rules put regulatory commissions at the state and federal level in a very precarious position. The rules are not ours; they are the product of the EPA. Yet nearly all of the potential negative outcomes fall squarely on our shoulders, whether related to affordability or reliability. While I continue to have concerns related to potential market impacts and jurisdictional issues, for the purposes of this testimony, I will highlight the potential tension between 111(d) and infrastructure.

In this regard, I note the timelines contained in the EPA's rules. While the final rule, as compared with the draft rule, extended state compliance timelines by up to 2 years, it is worth remembering how long it takes infrastructure projects to be developed.

Final state implementation plans would not be due, in many cases, until 2018. Compliance targets begin in 2022. Yet major pipeline and transmission projects can take anywhere from 3-12 years, or longer, to accomplish from concept to in-service completion.

I would emphasize that if a generation resource shift is compelled prior to necessary infrastructure completion, electric reliability could be a challenge, but regardless, affordability will almost certainly suffer. Substantially higher energy costs have been the result everywhere this has occurred, and it will not be any different in this case if expanded infrastructure is not built in time to meet the generation mix changes required by the regulation.

This problem, at least from an affordability standpoint, will be compounded in certain parts of the country, where there is a significant risk of infrastructure assets being stranded years before the end of their useful lives. This means consumers will be paying not just for the new infrastructure, but also for the previous investments in assets that are being retired to comply with the EPA regulation.

The impact of this rule will not be evenly felt because of the nature of the EPA targets themselves. To be perfectly honest, some states don't have all that difficult a road to compliance. This is often related not so much to any particular policy choice the state made, but rather to the vagaries of the math behind the state-by-state targets set by EPA in relation to the nature and vintage of a state's legacy electric generation fleet.

For example, some states have older conventional plants that were just recently retired or are soon to be retired for reasons other than environmental regulations. These states may find targets that are relatively easy to meet because they will get full carbon reduction credit for the retirement of assets that were due to be retired anyway. It can be argued this has more to do with luck than planning.

At the other end of the spectrum are states like my home state of North Dakota. Between the draft and final rules, the state's emissions reduction target skyrocketed from 11% to 45%. In North Dakota, actual emissions were down 11% between 2005 and 2014, despite a rapidly growing economy. Utilities during that timeframe built a significant amount of wind power, in part as a hedge against carbon regulatory risk. Unfortunately, it turned out to be a hedge for which they will receive no credit. Additionally, the state's coal fleet is still relatively young, and has thus incurred recent investments for environmental compliance. In fact, North Dakota is proud to be one of only a few of states in full attainment of EPA's National Ambient Air Quality Standards. Nonetheless, the state was given an emissions reduction target so punitive that I struggle to conceive of a way it can meet it in an affordable manner. Indeed, the North Dakota Health Department has estimated the annual cost of compliance if the state adopted an emissions credit trading program could top $400 million per year; a staggering figure for a state of less than 750,000 people.

I hope Committee members understand how problematic this is for states like North Dakota that did not fare so well under the EPA's state-by-state emissions target math. Such states stand to see a huge transfer of wealth out of them, and will receive little in quantifiable environmental benefits in return given the worldwide nature of carbon emissions.

Mr. Chairman and Committee Members, that completes my submitted testimony, I would be happy to answer any questions you may have.