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POLICY ISSUES FACING INTERSTATE DELIVERY NETWORKS FOR NATURAL GAS AND ELECTRICITY

HEARING

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

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POLICY ISSUES FACING INTERSTATE DELIVERY NETWORKS FOR NATURAL GAS AND ELECTRICITY

THURSDAY, JULY 12, 2018

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The Committee met, pursuant to notice, at 10:03 a.m. in Room SD–366, Dirksen Senate Office Building, Hon. Lisa Murkowski, Chairman of the Committee, presiding.

OPENING STATEMENT OF HON. LISA MURKOWSKI, U.S. SENATOR FROM ALASKA

The CHAIRMAN. Good morning, everyone. The Committee will come to order.

It was just one month ago today that we conducted an oversight hearing on the Federal Energy Regulatory Commission, the FERC. We had all five Commissioners here; it was good to see them. I don't know, maybe we jinxed the whole thing.

[Laughter.]

I think we recognize, clearly, the value of the FERC. They are the key deliberative body under our oversight. They have regulatory responsibility of our nation's crucial midstream, interstate delivery systems that move energy from where it is produced to where it is needed.

Last month's hearing prompted follow-up questions about natural gas transportation and electric transmission, energy systems that are squarely within the core of FERC's jurisdiction. Today we will have an opportunity to dive more deeply into these issues, which really have a very significant impact on our nation's capacity to deliver energy.

After we began planning for this hearing, we learned there was going to be another vacancy on the Commission. While that news did not prompt today's hearing, it certainly underscores the need for us to remain focused on the FERC in general and on natural gas transportation and electric transmission, in particular, our lifelines for affordable, clean, diverse, and secure energy.

Today's hearing is also the latest in a series that we have held over the last two years to highlight the significance and outline the benefits of interstate energy delivery infrastructure for our nation. Those benefits include energy affordability and security along with job creation and economic development.

As I see it, there are three common threads that run through the entire record that we have compiled over the past couple years.

First, that the nation needs more robust energy delivery infrastructure. Second, thus far, private capital and a skilled workforce have been available to expand and upgrade today's energy delivery system assets, but I underscore thus far. And the third thread is that energy delivery networks face genuine challenges that threaten to impede progress and thwart delivery system improvements that are otherwise within our reach.

Regulatory uncertainty brought on by delay or, even worse, deadlock at the FERC, is increasingly of concern. What's more, the denial of necessary state approvals for projects on political grounds, or the failure of other federal agencies to meet FERC-established schedules, are problems that have to be addressed.

Our witnesses today include two former FERC Chairmen, one Republican and one Democrat, both of whom remain active leaders in the energy sector, and we thank you for that.

We are also joined by a leading and very successful energy investor and an experienced practitioner now serving as the General Counsel of the company that, according to his testimony, "owns or operates . . . natural gas pipelines constituting the largest natural gas network in North America."

My main takeaway from their written testimony is that now more than ever the United States needs balanced, merits-based energy regulation that is predictable and prompt. For our country to reap the benefits of the natural gas revolution and renewable power technologies and to keep our power supply reliable and secure, we must have dependable, financially sustainable, and expanding interstate delivery networks.

Our witnesses can offer informed, bipartisan, and practical observations for building on successes and avoiding regulatory pitfalls. As members consider their testimony, I would hope that they will also ask how our Committee can encourage and assist FERC to move its work along thoughtfully but promptly and maintain a balanced non-partisan approach to energy law and regulation.

I will introduce each of the panelists after Senator King provides opening remarks on behalf of—well I don't know if they are on behalf of Senator Cantwell, but we welcome you as you are helping lead this Committee this morning.

Senator King.

STATEMENT OF HON. ANGUS S. KING, JR., U.S. SENATOR FROM MAINE

Senator KING. Thank you, Madam Chair.

I am delighted to be with you and to participate in another of an important series of hearings on the issue of energy infrastructure.

As a former Governor of Maine, this is an issue that I have been thinking of, thinking about, and concentrating on for about 30 years. I have seen significant changes in the energy picture in New England and, in some cases, additional infrastructure constraints, which I'm sure we will talk about today, because New England is at the end of the pipe, literally. Then we have to be thinking about how energy enters our region.

I have often thought in terms of Maine that it reminds me of the story Golda Meir used to tell that Moses tramped around the Middle East for 40 years and settled in the only place without oil.

[Laughter.]

In Maine, we are in a similar situation unless we can discover how to make energy out of granite.

In any case, we do have significant problems in New England, principally because of constraints in the wintertime. During a cold snap which occurred this past winter, early in January, the price of natural gas in New England went up by a factor of ten. That has profound impacts on our consumers and on our industry. It is something that we have to continue to talk about.

We need to talk about electrical line capacity as well as pipeline capacity, but I think we also need to talk more broadly about alternative solutions.

I have a friend in Maine who says there is rarely a silver bullet but there is often silver buckshot, which means a multiplicity of solutions added together will create a solution to the problem.

One of the areas that I am particularly interested in is the role that storage and distributed energy and demand response can play in creating a grid that is more balanced.

One of the concerns I have had in dealing with these issues for a number of years is that the grid is like a church that is built for the service on Easter Sunday morning but has substantial excess capacity the rest of the time. How can we utilize the grid more efficiently?

I think we are headed in a place where we will with electric vehicles, storage, and demand response. We can more efficiently utilize the grid without the necessity of necessarily investing in new infrastructure, again, to handle peak periods which can be dealt with in alternative ways.

So those are some of the things that I am thinking about. I enter this hearing in an unaccustomed mode of not having my mind made up. I am genuinely seeking your input, suggestions, and thoughts, and I look forward to your testimony.

I also want to commend the Chair for holding this series of hearings, because I think it is very important. We have to think about not only today and tomorrow, but we also have to think about the day after tomorrow. This involves economic considerations, energy considerations, and technological considerations. I look forward to you all helping us sort out some of those issues.

Thank you, Madam Chair.

The CHAIRMAN. Thank you, Senator King.

We will begin with testimony from each of our witnesses. Again, we thank you for being here this morning.

I would ask that you try to keep your statements to about five minutes. Your full written statements, of course, will be incorporated as part of the record. We appreciate that you all submitted your testimony in advance, on time. I always like to reward good behavior. Thank you for helping us be more prepared for this particular hearing with your statements.

We will lead off the panel this morning with Mr. J. Curtis Moffatt, who is the Vice President and General Counsel for Kinder Morgan. We welcome you.

Mr. James Murchie will be following him. He is the President, Founder and CEO for Energy Income Partners, LLC. Welcome.

The Honorable James Hoecker, Hecker——

Mr. HOECKER. Hecker.

The CHAIRMAN. Hecker. I knew what it was, and I looked at it and I still said Hoecker. Hecker. He is the Executive Director and Counsel at WIRES, and he is the Senior Counsel at Husch Blackwell LLP. He is also a former FERC Chairman. He was appointed by President Clinton several years ago. We welcome you back.

And an individual who is well known to the Committee here, Joseph Kelliher, who is the Executive Vice President for Federal Regulatory Affairs at NextEra Energy. He, also, is a former FERC Chairman, appointed by President George W. Bush. So we welcome you back to the Committee.

We thank you all again for being here.

Mr. Moffatt, if you would like to lead the panel off this morning, thank you.

STATEMENT OF J. CURTIS MOFFATT, VICE PRESIDENT AND GENERAL COUNSEL, KINDER MORGAN, INC.

Mr. MOFFATT. Good morning, Chairman Murkowski, Senator King and members of the Committee. I am Curt Moffatt and serve as the Vice President and General Counsel of Kinder Morgan. Thank you for the opportunity to testify. And as you mentioned, our written testimony has been submitted for the record.

Kinder Morgan owns or operates approximately 70,000 miles of natural gas pipelines, constituting one of the largest natural gas networks in North America. Our pipelines transport or store approximately 40 percent of all natural gas consumed in the United States every day. Our gathering and transmission assets connect the major consumer markets to every important natural gas resource play in the United States.

I joined Kinder Morgan in 2014. I began my legal career as an Advisor to the first Chairman of the Federal Energy Regulatory Commission, and he was also the last Chairman of the Federal Power Commission. During this period, President Carter proposed and Congress enacted the legislation to create DOE and the National Energy Act which included the Natural Gas Policy Act of 1978. Assisting in the implementation of that legislation and its development laid the groundwork for the competitive natural gas markets that we enjoy today.

Chair Murkowski, Kinder Morgan's take-home message for the Committee has three parts.

The first is natural gas is essential to the U.S. economy for its industrial base, its residential, its commercial uses and to a certain extent, generating electricity. Pipelines are also a practical means to transport and distribute natural gas. It's the only practical means. And the current federal legal framework of the Natural Gas Act is essential to ensure that we can construct the necessary pipelines. The history of the continued Congressional recognition of the importance of natural gas development in the United States is instructive to the Committee's current inquiry.

First, the Natural Gas Act in 1938. Congress specifically recognized the contribution that natural gas could make to the nation's well-being. It also recognized that the locations where natural gas is produced, frequently, are long distances from where consumers live and work; that the only means of transporting natural gas to those consumers is through pipe, pressurized pipelines that cross several states; and that a comprehensive federal regulatory framework is needed to ensure that the pipelines could be constructed and gas delivered in both interstate and foreign commerce. The basic components to that framework are certificates of public means and necessity, federal eminent domain and comprehensive economic regulation.

The second is in 1978. The Congress enacted the Natural Gas Policy Act in the face of natural gas shortages in the interstate market that led to the deregulation of the price of natural gas and the integration of the transportation storage services utilizing both intrastate and interstate transportation systems.

The third component is the Energy Policy Act of 2005. Congress affirmed FERC's preeminent regulation of LNG facilities and introduced a concept of a pre-filing process. In addition, the Act established FERC as the lead agency for coordinating all federal agencies involved in permitting of interstate pipelines and complying with NEPA by requiring that all federal agencies cooperate with the Commission and comply with deadlines set by the Commission.

Over the 80 years since passage of the Natural Gas Act, the Federal Energy Regulatory Commission and Federal Power Commission, I believe and we believe, has consistently implemented the requests of Congress as embodying those statutes which with judicial approval. Today the Commission balances the objectives that are required under the Natural Gas Act through the 1999 policy statement.

Kinder Morgan believes an on balanced policy statement has served the nation well. It reflects a process that can balance all of the regulatory and legal requirements required of the act of NEPA, and the Federal Energy Regulatory Commission, with the changes made in 2005, has the authority to guide the other agencies.

At bottom, what we recommend is vigilant oversight by the Congress and by the relevant Committees of the work of the Federal Energy Regulatory Commission and also the other federal and state agencies that must consider and grant permits to make sure they're working together and benefiting the interstate commerce and the ability to build the infrastructure needed to move natural gas from production to market.

Thank you.

[The prepared statement of Mr. Moffatt follows:]

Senate Committee on Energy and Natural Resources

Testimony of
J. Curtis Moffatt
Vice President and General Counsel
Kinder Morgan, Inc.

Hearing to Examine Interstate Delivery Networks for Natural Gas and Electricity
July 12, 2018

INTRODUCTION

Good morning Chairman Murkowski, Senator Cantwell and Members of the Committee. I am Curt Moffatt and serve as Vice President and General Counsel to Kinder Morgan, Inc. Thank you for the opportunity to testify today on this very important subject.

ABOUT KINDER MORGAN

Kinder Morgan owns or operates approximately 70,000 miles of natural gas pipelines constituting the largest natural gas network in North America. Our pipelines transport approximately 40 percent of the natural gas consumed in the U.S. and connect the major consuming markets to every important natural gas resource play in the U.S., including the Eagle Ford, Marcellus, Bakken, Utica, Uinta, Permian, Haynesville, Fayetteville and Barnett.

Development of the revolutionary shale plays across the United States has been an unrecognized "disruptive technology." It has unlocked trillions of cubic feet of natural gas which has fueled an increasing demand for natural gas and created a tremendous need for more energy infrastructure. As a result, we invest billions of dollars each year to operate and maintain our existing system and to evaluate, permit, expand existing assets and construct new pipelines. All of this has occurred while the cost of gas to consumers has been falling.

I joined Kinder Morgan in 2014. I have enjoyed a 40 year career as an attorney with a focus on natural gas regulation and environmental policy. I was fortunate to serve in my early career as a legal advisor to the last Chairman of the Federal Power Commission and the first Chairman of the

Federal Energy Regulatory Commission (hereinafter "FERC"). During this period, President Carter proposed and the Congress enacted legislation to create the Department of Energy and the National Energy Act, including the Natural Gas Policy Act of 1978 (hereinafter "NGPA"). It was an exciting time working on these legislative initiatives and their implementation. These important legislative achievements paved the way for the dynamic, competitive markets enjoyed today.

After government service, I practiced law in Washington and was a partner for twenty years at Van Ness Feldman. In addition to representation of the Kinder Morgan companies, I also served as counsel to numerous other interstate natural gas pipelines over thirty five years. Indeed, I have represented one of the Kinder Morgan pipelines, Natural Gas Pipeline Company of America, since 1979.

In addition to my legal work, I am Chairman of the Board of Visitors for the Nicholas School of the Environment at Duke University. I also am the Vice Chairman of the Board of the Caron Treatment Centers, a not for profit provider of treatment addiction disorders.

TAKE HOME MESSAGE

Chairman Murkowski, before I delve into the details of my testimony, let me state Kinder Morgan's "take home" message for the Committee. Our domestic natural gas resources are a natural treasure. They provide enormous benefits to the nation's economy and our citizens' way of life. To enjoy these benefits, the natural gas must be transported from the producing regions to the places where it is consumed. We need pipelines to do that. There simply is no other practical means to transport natural gas. Natural gas is essential to the U.S. economy and pipelines are essential to transport it.

THREE INITIAL OBSERVATIONS:

First, the Natural Gas Act of 1938 (hereinafter "NGA") with its structure of certificates of public convenience and necessity, federal eminent domain and comprehensive economic regulation, has resulted in a privately-owned and financed, integrated transportation and storage network that today powers our economy and is the envy of the world. Judicial decisions over the last 80 years have upheld the NGA and consistently affirmed the Congressional intent to implement comprehensive regulation of the transportation and sale for resale of natural gas in interstate commerce.

Second, as some of us may recall, in the mid to late 1970s, the United States experienced severe natural gas shortages because of the disconnect between the commodity price-regulated interstate market and the commodity price-deregulated intrastate market. Schools and hospitals were closed because they could not be heated and manufacturing facilities were shut down due to the lack of natural gas. In response, the Congress enacted the NGPA. The NGPA was bi-partisan. It paved the way for the deregulation of the commodity price in both the intrastate and interstate markets and led to the integration of transportation and storage services utilizing both intrastate and interstate transportation systems. And it worked.

Third, just over a decade ago, with the passage of the Energy Policy Act of 2005 (hereinafter "EPAct 2005"), the Congress affirmed and refined the Federal Energy Regulatory Commission's (hereinafter "FERC" or "Commission") regulation of liquefied natural gas facilities under section 3 of the NGA. It also introduced the concept of a pre-filing process for LNG facilities, including the examination of a required pipeline interconnect to deliver natural gas to the facility. That process is available today to all major interstate pipeline certificate proceedings.

EPAct 2005 also directed that the Commission be the "lead agency" for the purposes of coordinating all federal authorizations needed by an interstate pipeline and for complying with the National Environmental Policy Act of 1969 (hereinafter "NEPA"). As the lead agency, FERC has the authority to establish a schedule for federal and state authorizations required under federal law. In addition, EPAct 2005 amended the NGA to allow a certificate applicant to file a civil action with the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") for review of an order or action of a federal or state agency to issue, condition, or deny any permit required under federal law. By requiring all other federal agencies to cooperate with the Commission and comply with deadlines set by the Commission, and by establishing a process for an applicant to appeal an agency's delay to the D.C. Circuit, the Congress reaffirmed the original intent of the NGA to govern the development of a national integrated interstate transportation system.

Reviewing this history, it is clear that the Commission and its predecessor agency have implemented effectively, and with consistent judicial approval, the Congressional mandates in the NGA, the NGPA and EPAct 2005. Those mandates enable a privately funded, capital intensive, natural gas industry to deliver critical low-cost energy to the largest economy in the world and increasingly other world economies as well.

ROLE OF NATURAL GAS IN THE U.S. ECONOMY

In recent years, the United States has shifted from being dependent on imports for its energy supply to becoming one of the world's leading producers of oil and gas. This trend, which can continue if markets are permitted to function efficiently, is facilitating billions of dollars of investment in the U.S. manufacturing sector, creating thousands of high-paying U.S. jobs, and providing households and businesses with additional disposable income through lower energy costs. According to the Energy Information Administration, the city gate price of natural gas, (the place where long-haul pipelines deliver to local distribution companies), has fallen from approximately $8 per thousand cubic feet in 2007 to under $4 so far this year.

Today, many people think of natural gas primarily as a fuel for generating electricity due to its obvious economic and environmental advantages over other fossil fuels used for power generation. However, the power sector only accounts for approximately one third of natural gas consumption in the U.S. The remainder is consumed in the industrial, commercial, and residential sectors. Indeed, the natural gas pipeline network was constructed to serve these needs and, at one time, the use of natural gas for electric generation was discouraged.

In 2017, the industrial sector accounted for about 35% of U.S. natural gas consumption. Industrial facilities use natural gas as a fuel for heating; for combined heat and power systems; and as a process fuel or feedstock to produce chemicals, fertilizer, automobiles and many other products. The chemicals, food, metals, paper, minerals, wood products, and textiles industries provided 5.5 million jobs and almost $3.3 trillion of economic output in the U.S. in 2015. The chemicals industry alone employs 811,000 people in the U.S. and for every one job created in the chemicals sector, 6.8 jobs are created in other sectors.

Commercial users accounted for about 12% of U.S. natural gas consumption in 2017 to cook; heat buildings and water; operate refrigeration and cooling equipment; dry clothes; and provide outdoor lighting. There are more than 5.4 million commercial natural gas customers, which include schools, colleges and universities; hospitals and health care providers; laboratories; hotels; warehouses and storage facilities; professional offices; government buildings; and various other kinds of commercial businesses. More than half of the commercial buildings in the U.S. use natural gas as an energy source, and, as a result of the recent growth in U.S. natural gas production, prices for commercial consumers of natural gas have fallen significantly since 2007.

Roughly half of the residential homes in the United States use natural gas for space heating, to heat water, to cook, and to dry clothes. In 2017, the residential sector used approximately 17% of all natural gas consumed in the U.S. Homeowners have seen their heating bills decline significantly in the last 10 years due to the increased availability of low priced natural gas.

Electricity generation accounted for approximately 34% of U.S. natural gas consumption in 2017, and one third of electricity consumed in the U.S. is supplied by natural gas power plants.

Madam Chair, I believe it is important to highlight these statistics. All too often the debate regarding the use of natural gas and the development of natural gas pipelines is framed exclusively around the use of natural gas to generate electricity and the resulting greenhouse gas emissions. Some object to the use of certain technologies to produce natural gas and thus argue that the pipeline infrastructure is harmful to the public interest. While largely beyond the Congressional mandates to the Commission under the NGA, these arguments are misguided and short-sighted when the entire story of the role of natural gas in the nation's economy is forthrightly considered. Perhaps more importantly, the use of natural gas for electricity generation has lowered GHG emissions from electric power generation by 28% since 2005 and is essential to an increased reliance on renewable generation.

As indicated above, since the shale revolution began, natural gas prices have fallen sharply with enormous benefits to industrial, commercial and, most importantly, residential consumers. Americans cannot benefit from our natural gas wealth, however, unless we are able to develop the infrastructure needed to transport it to consumers. Kinder Morgan currently has natural gas pipeline projects, representing potential investments of approximately $5 billion, in various stages of evaluation, permitting and construction. However, these are very challenging times for any company seeking to build a new pipeline or even expand and modernize an existing pipeline. Before we (or any other natural gas company) even think about starting the permitting process for a project, we undertake a comprehensive internal analysis to determine if there is a need for a proposed project, if the benefits of the project outweigh the impacts, and whether the financial commitment is a sound investment. If we determine that a proposed project is worth pursuing, then, and only then, do we begin the formal development process.

CONGRESSIONAL RECOGNITION OF THE IMPORTANCE OF NATURAL GAS

Madam Chairman, the history of natural gas development in the United States is instructive to the Committee's current inquiry. Eighty years ago, Congress specifically recognized the contribution that natural gas could make to the nation's well-being when it enacted the NGA. Section 1 of that Act declares that "the business of transporting and selling natural gas for ultimate distribution to the public is affected with a public interest, and that Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the public interest."

In enacting the NGA, the Congress recognized that the locations where natural gas is produced frequently are long distances from where consumers of gas live and work; that the only means of transporting natural gas to those consumers is through pipelines that cross several states; and that a comprehensive federal regulatory framework is needed to ensure that the pipelines could be constructed and the gas delivered to consumers.

The Congress also recognized that the private sector is better suited to finance and construct this needed infrastructure than the government. Thus, Section 7 of the NGA provides that a certificate to construct and operate an interstate natural gas pipeline "shall be issued" to any qualified applicant who demonstrates that the project "...is or will be required by the present or future public convenience and necessity..."

Over the decades, the Commission, its predecessor agency, and the Courts have implemented and interpreted the NGA in a manner that has resulted in a nationwide natural gas transportation network that is the envy of the world.

As noted earlier, in the mid to late 1970s the U.S. experienced severe natural gas shortages. In response, the Congress enacted the NGPA. One of the pillars of the NGPA was to set in motion the deregulation of the natural gas industry, including deregulating the price of the commodity, thereby creating incentives for producers to explore for and develop new sources of natural gas. That deregulation, combined with U.S. technology and ingenuity, has resulted in our current ability as a nation to produce trillions of cubic feet of natural gas from shale formations at historically low prices.

This vast resource, however, is of little value to us if we cannot transport it to the homes, businesses and factories where it is consumed. During the four decades since enactment of the NGPA, the FERC has done an outstanding job of guiding and authorizing the construction of a fully integrated, competitive and safe pipeline system to serve the transportation needs of natural gas producers and consumers.

Most importantly, this infrastructure development has been accomplished by the private sector with private financing. Government does not require that pipelines be built and taxpayer dollars have not and will not pay for the development of this critical infrastructure. Consumers that utilize the transportation services of the natural gas infrastructure will, over years of service, financially support the pipeline as market forces permit.

NATURAL GAS PIPELINE DEVELOPMENT AND PERMITTING PROCESS

Under Section 7 of the NGA the Commission regulates the siting, construction, and operation of interstate natural gas pipelines. Before a pipeline developer can construct a pipeline, it must receive a certificate of public convenience and necessity (hereinafter "certificate") from FERC. A certificate authorizes the pipeline owner to construct and operate the proposed pipeline facilities in accordance with numerous terms and conditions imposed by the Commission, including applicable environmental, health, and safety regulations. In addition, the certificate subjects the pipeline to: (1) comprehensive regulation of the rates the pipeline can charge its customers; and (2) terms of service provided to those customers.

The Committee should be aware that there are many projects that pipelines evaluate but for which an application is never filed with the FERC. These projects may fail for a host of reasons including market economics or the lack of an environmentally acceptable route.

FERC's evaluation of an application for a certificate is guided by its **1999 Statement of Policy**, which sets forth procedural steps and substantive factors. There are two basic components to this evaluation: (1) an economic balancing test; and (2) an evaluation of environmental impacts under NEPA.

Economic Balancing Test

In its economic balancing test, FERC measures the need for and benefits of the project against any adverse economic impacts. In effect, this is a sliding scale approach in which the greater the adverse effects, the greater the public benefits must be in order to balance those adverse impacts. If the benefits outweigh the adverse impacts, the project is deemed to be in the "public interest".

If the project is an expansion of an existing pipeline, the threshold step in this balancing test is to determine whether the project can support itself financially without relying on subsidies from current customers. By not allowing the pipeline developer to rely on subsidization from existing customers, FERC places the pipeline developer at risk for any pipeline capacity that is not sold. This creates a strong incentive for pipeline developers to not overbuild infrastructure that is not needed by the market.

In the next step, FERC evaluates whether the project applicant has eliminated or minimized adverse effects of the proposed project on the applicant's existing customers; existing pipelines and their customers in the same market; and affected landowners and communities. With respect to impact on existing customers and other pipelines, FERC begins from a pro-competitive position; it presumes that the benefits of access to new gas supplies likely will outweigh any negative impacts on existing competitors.

The economic balancing test incentivizes project applicants to eliminate or minimize any adverse impacts, including environmental impacts on land owners and communities. To a significant degree, adverse effects can be eliminated or minimized by carefully selecting the proposed right-of-way, locating the project in existing utility corridors, and negotiating right-of-way agreements with landowners. FERC balances any residual adverse effects against the need for and public benefits of the project. As a practical matter, pipelines make routing changes throughout the pre-filing and certification process to address landowner and environmental concerns.

The primary way applicants demonstrate need is through binding contracts from customers for capacity on the proposed pipeline. Pursuant to these contracts, commonly for 10 years or longer, customers commit to pay demand charges for capacity in the pipeline regardless of whether the capacity ultimately is used. Customers can be end users such as manufacturers and power plants; local gas distribution utilities who procure and then sell and deliver natural gas directly to consumers; producers who need to transport produced gas to trading hubs or directly to end users; or marketers who have purchased gas available in the commodity market and need to transport it to their customers.

The Commission also identifies and evaluates other public benefits that point to the need for the project. Such benefits often include meeting unserved demand for natural gas, eliminating bottlenecks, providing access to new supplies, reducing costs to consumers, providing new interconnects that improve the reliability and resiliency of the pipeline network, increasing electric reliability, and advancing clean air objectives.

As the Committee heard at its FERC hearing in June, the Commission has initiated a reevaluation of its 1999 Policy Statement. As part of that review, one question the Commission is considering is whether to continue to rely upon contracts for capacity in the proposed pipeline as an indication of the required need for the project. Reliance upon such contracts has been a bedrock of the private financing of these capital intensive projects for the 80 years since the passage of the NGA. Originally, these contracts were in the form of contracts for gas supply which dedicated gas reserves for sale to the pipeline, and contracts for the pipeline to deliver the gas to regulated retail utilities. With the unbundling of the natural gas markets, pipelines no longer own the gas they transport. Now pipelines only execute contracts to provide transportation services to the customers that own the gas. Nevertheless, the Commission's inquiry is the same: Does the pipeline have binding agreements that demonstrate that customers will utilize its services?

Today, there are thousands of individual transportation and storage transactions pursuant to which gas is transported from the wellhead to market hubs and then downstream to the end user. All of these various types of contracts and services together contribute to robust, economically efficient, and liquid natural gas markets. Continued reliance upon contracts is the bedrock that supports the Nation's capital-intensive, privately financed natural gas infrastructure.

Another question raised is whether contracts with an affiliate of the pipeline developer are somehow a less reliable indicator of the need for the project. It is perfectly natural in our view that an entity that has invested millions of dollars in facilities for either the production or the consumption of natural gas also would be willing to execute a contract to transport the natural gas to market. Kinder Morgan welcomes partners into its projects. Given the significant development costs incurred to permit and construct a project, sharing the associated risk and reducing the capital outlay when faced with several years of substantial expenditure before any return is realized is prudent. Because agreements with affiliates are a prudent, and often necessary, basis for developing a project, such agreements definitely are a valid indicator of project need.

While it is currently popular to question the economics of the affiliate relationship, many pipelines are joint ventures. It is not a question of an affiliate paying itself. The demand charges are paid to a separate corporate entity which has invested equity and debt to privately finance the development and operation of the pipeline. The shipper's affiliate is no different than the Kinder Morgan affiliate taking the development risk of the pipeline and making sound economic decisions. The costs are real, whether paid to an affiliate or a third party.

NEPA Analysis

FERC also undertakes a comprehensive analysis of the social and environmental impacts of the project under NEPA. For all major pipeline projects, the NEPA review results in an Environmental Impact Statement ("EIS"). It is important to recall that the NGA predates NEPA by about 30 years. NEPA is a procedural statute intended to inform a decision maker about the environmental consequences of a proposed action.

FERC is the "lead" agency in NEPA reviews of certificate applications by interstate pipelines, but coordinates closely with other federal agencies, tribes, and state and local governments (referred to as "cooperating agencies").

In the NEPA process, FERC staff works with the other cooperating agencies to perform a thorough independent review of anticipated impacts of the project on such resources as geology, soil, groundwater, surface water, wetlands, aquatic resources, vegetation, wildlife, special status species, cultural resources, land use, recreation, aesthetics, socioeconomics, air quality, climate change, noise, reliability and safety.

A key aspect of the NEPA analysis is consideration of alternatives to the project. These include a "no action" alternative, in which the project is not constructed; system alternatives, such as using existing, modified or other proposed facilities; design alternatives, such as different pipe diameters and electric versus gas-powered compressor stations; and route and siting alternatives. FERC staff also considers alternatives proposed by the cooperating agencies and by other stakeholders that comment during the NEPA process. Where need is established, FERC frequently includes multiple conditions, route changes, and other requirements with which the project must comply in the order granting the certificate and authorizing the project.

Consistent with the two-part analysis under the Policy Statement, if FERC determines through the economic balancing test that there is not sufficient need for the project or through the NEPA analysis that the impacts of the project outweigh the benefits, it will dismiss the application. Most projects that are not fully supported will not reach this stage however, since development of a project and preparing the FERC application requires a significant investment, one that is only made for real projects. In rare cases where an applicant has not been able to show any need for the project in the form of contracts, the Commission will dismiss the application without reaching the environmental issues.

Process Is Critical

FERC's certificate determination only occurs after an extensive deliberative process of stakeholder engagement and outreach. There are two phases of this process. In the first phase the pipeline proponent begins the route selection process, consults with landowners and local and state governments, and prepares the extensive analyses needed to support the project. These activities will occur whether as part of the formal FERC-sponsored pre-filing process or informally.

Prior to filing an application for a certificate, the project proponent reaches out to and consults with landowners, state and local officials, other agencies, tribes and other stakeholders. The pipeline also prepares a series of draft "resource reports" upon which the NEPA review is based. In addition, during pre-filing, FERC staff will conduct site visits, review the draft resource reports and provide comments to the applicant on alternatives to the project, siting concerns, right-of-way modifications, and additional studies, surveys and mitigation measures that are needed. This process is iterative over many months and is conducted on the public record.

If the project applicant continues development of the project after the feedback and modifications recommended during the pre-filing process, it will initiate the second phase of the process by filing a formal application for a certificate. During the formal application phase, FERC staff prepares the required NEPA document and conducts the economic balancing test.

During the years of project development and review, environmental studies and reports are continually being developed to facilitate both the environmental and public review but also to minimize the impact of construction of the project. In both the pre-filing and application phases, there are substantial opportunities for stakeholder engagement and input. It also is an iterative process through which modifications requested and recommended by FERC staff and stakeholders are studied and in many instances incorporated into the project.

The 1999 Statement of Policy is a market-driven policy that the Commission has employed to adapt to rapid changes in the natural gas market over the past two decades. FERC's flexible implementation of the Policy Statement has facilitated the development of the infrastructure needed to support competitive natural gas markets which, in turn, have provided substantial benefits to consumers. FERC's pipeline review process allows for public input at multiple stages and addresses those comments by imposing conditions designed to minimize environmental and landowner impacts. And its robust oversight during construction and operation ensures compliance with those conditions.[1]

LANDOWNER AND LOCAL ISSUES; THE USE OF FEDERAL EMINENT DOMAIN

An essential concern in the effective implementation of the NGA is the relationship between the pipeline applicant and the property owners and state and local political subdivisions impacted by the proposed infrastructure. The pipeline industry recognizes both the actual impact and the fear of hypothetical impacts of a proposed project on individual landowners. Moreover, applicants understand that addressing landowner concerns is a process encompassing many years from initial contact through reclamation and restoration of the right of way.

These relationships and the obligations that attend to them are of paramount importance to the applicants and numerous industry and associated construction partners. The Commission has a best practices guide for industry to follow. All companies have numerous training programs, tracking systems, internal audits and other tools to assure meaningful, responsive and respectful engagement. Individual companies and member trade associations work

[1] I ask that an Energy Law Journal article entitled *Considering The Public Convenience And Necessity In Pipeline Certificate Cases Under The Natural Gas Act*, that explains in detail the evolution of FERC's application of the public convenience and necessity standard, be entered into the record and considered part of my testimony.

diligently to update and improve processes, outreach and reduction of impacts where possible.

Any reasonable observer of FERC's oversight in this regard can review the resource reports and the hundreds of data requests and responses in each docket and conclude that the Commission and its cooperating state and federal agencies analyze and address all potential issues for every foot of the project. Commission orders issuing certificates contain numerous environmental conditions, some applicable to all projects and some specifically targeted to the individual project under review. There are a plethora of post certificate requirements, including environmental training and monitoring as well as reports on construction to the Commission. The Commission regularly sends environmental inspectors to ensure compliance with the terms of its orders.

The right of eminent domain is not controlled by the FERC. Congress granted that right in the NGA. The Commission properly tries to minimize its use; as does the industry. It is better to get along with landowners and negotiate a resolution than to have to battle it out in court. This authority is, in practice, used only as a last resort. Over the last ten years, Kinder Morgan has been able to secure consensual right-of-way contracts with 96% of the 4266 tracts needed for its projects. Nevertheless, the need for a right of federal eminent domain is another bedrock of the NGA, especially when some landowners "Just Say No" and are not interested in reaching an agreement regardless of the amount of compensation and conditions offered by the pipeline.

CURRENT CHALLENGES

While Kinder Morgan believes that the Commission has done a commendable job of implementing Congressional intent to promote and develop a national integrated natural gas pipeline system, we also believe that the job is not finished. To take full advantage of our abundant natural gas resources, we will need to continue to connect sources of supply with consumers in different locations via pipelines.

As the Committee is fully aware, this is not an easy task. Most applications for an NGA Section 7 certificate filed at FERC these days are opposed by environmental NGOs, as well as a limited number of impacted landowners and even some Governors. The reasons for this opposition vary.

As noted above, while pipelines frequently achieve voluntary right-of-way agreements with 90 – 95% of all landowners affected by a project, some landowners will not agree to a pipeline easement regardless of the terms and compensation. Organized opposition is becoming more widespread. Many pipeline facilities were constructed years ago in rural areas. Yet today these same areas are populated suburbs whose residents are likely to oppose any modifications to these existing facilities.

Opposition by certain State governments and environmental NGOs, in contrast, often is driven by policy agendas and politics designed to discourage the production, transportation and consumption of natural gas. This often is referred to as the "keep it in the ground" agenda. This opposition is based primarily upon the premise that 100% the natural gas is going to be combusted to generate electricity. Typically, there is no recognition that two-thirds of all gas consumption is in the residential, industrial and commercial sectors. Nor is there any recognition of the significant savings homeowner and consumers have realized due to the abundant supplies of natural gas. Finally, even when the gas is going to be used for power generation, there is little acknowledgment of the greenhouse gas emission reductions gained by using natural gas instead of higher carbon content fuels or the role that gas generation plays in supporting renewable generation.

As discussed above, FERC, through application of its 1999 Policy Statement, works very hard to address legitimate concerns about the social, cultural and environmental impacts of pipeline construction. Nevertheless, FERC currently is reevaluating the Policy Statement and seeking recommendations on how the procedures and balancing embodied therein can be improved. Kinder Morgan will be filing detailed comments in response to the FERC Notice of Inquiry on the 1999 Policy Statement with specific recommendations for changes that hopefully will improve the certification process.

All decision making processes have room for improvement and we anticipate that FERC will identify and implement changes to the manner in which it implements the 1999 Policy Statement. Kinder Morgan supports changes that will make the certification process more efficient, transparent and less adversarial.

However, we will not support any changes by FERC that will undermine the basic intent and purpose of the NGA and the NGPA. Specifically, we believe there are two fundamental principles that must be maintained. The first is that it is FERC's mandate to ensure the continued development of a comprehensive integrated pipeline transportation system to ensure that the United States can enjoy the benefits of its enormous natural gas resources. The second is that the market place, not the government, should determine when to construct components of this transportation system and that the private sector should continue to bear the risk of financing the infrastructure.

RELATED AGENCY PERMITTING PROCESSES

In addition to needing an NGA certificate from FERC, interstate natural gas pipelines also require certain permits and authorizations from the states in which they will be located. In recent years, there has been an increased effort by some state agencies to delay, impose conditions on, or deny necessary permits and authorizations for reasons that are not related to the law under which the permit or authorization is sought. For example, before a project can be constructed, Section 401 of the Clean Water Act requires an applicant to obtain from any state in which the project will be located a certification that the project will comply with state water quality standards. One state has refused to issue these certifications to natural gas pipelines, not because it has determined that the projects will violate state water quality standards, but because it is opposed to natural gas pipelines crossing the state.

The Commission has attempted to address unreasonable delays by issuing certificates conditioned on compliance with applicable state or local regulation, thus allowing the project to proceed with certain activities while it continues to pursue the needed state or local permit. However, despite the federal preemption aspects of the NGA, FERC's ability to address unreasonable conditions or denials is quite limited. Although the Congress attempted to address this in EPAct 2005 by adding Section 19(d) to the NGA, the results have been mixed. While the states do have a legitimate role to implement applicable state or federal requirements, the exercise of that authority must be consistent with the specific purpose of the law and the federal preemption embodied in the NGA.

CONCLUSION

The Congress demonstrated significant foresight eighty years ago when it enacted the NGA and laid the groundwork for the production, transportation and use of one of our nation's most valuable natural resources. But the jobs, convenience, economic and clean air benefits of that natural resource only can be realized if there is a transportation system to deliver the natural gas to the ultimate consumers. Natural gas pipelines provide that service. This Committee and the Congress should ensure that they can continue to do so.

Thank you for your attention and I look forward to your questions.

CONSIDERING THE PUBLIC CONVENIENCE AND NECESSITY IN PIPELINE CERTIFICATE CASES UNDER THE NATURAL GAS ACT

Robert Christin, Paul Korman, and Michael Pincus[*]

"Those who cannot remember the past are condemned to repeat it."
– George Santayana[1]

Synopsis: The Constitution provides that the regulation of interstate commerce is the province of the federal government. In the Natural Gas Act, Congress delegated the determination of whether interstate pipeline projects were in the public convenience and necessity to the Federal Power Commission, now the Federal Energy Regulatory Commission. Since the earliest days of regulation, the Commission has grappled with opposition to proposed pipeline construction, while relying on private contracts to demonstrate market demand for a new pipeline project. Although the details of exactly how the Commission ultimately determines whether a project can proceed have changed over time, the Commission has continued to rely on private contracts. The Commission's policy has now evolved to the point that the financial risk of a project is placed on the investors in the pipeline project. The Commission's environmental review of a project proceeds on a parallel track, and can result in significant route changes and environmental mitigation conditions, reducing the environmental impacts of a project. However, the Commission continues to rely on the existence of contracts for use of the pipeline as the best evidence of market demand.

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1. GEORGE SANTAYANA, THE LIFE OF REASON: INTRODUCTION AND REASON IN COMMON SENSE 172 (Marianne S. Wokeck & Martin A. Coleman eds., MIT Press 2011).

I. INTRODUCTION

Applications for authorization from the Federal Energy Regulatory Commission (Commission) to construct new gas pipeline infrastructure currently face unprecedented levels of opposition.[2] But, the arguments typically raised by opponents are not new. The same objections to pipeline construction have been raised since the early days of the Commission. Landowners do not want a pipeline on their property and they resent pipelines' use of eminent domain to acquire rights-of-way. Environmental groups challenge the adequacy of the Commission's environmental review. Both groups object to reliance on contracts or precedent agreements, especially agreements with company affiliates, as evidence that a project is required by public convenience and necessity.[3] Pipelines remain, however, the only method of large-scale transportation of natural gas from supply basins to demand centers.[4]

In 1999, the Commission issued a statement that revisited its policy for certificating new construction under section 7 of the Natural Gas Act (NGA).[5] The 1999 Policy Statement mandates that, before granting certificates, the Commission must first determine that the new pipeline infrastructure is required by the present or future public convenience and necessity.[6] The Policy Statement also addressed several major issues raised historically in pipeline certificate cases and provided guidance for their resolution. Among other things, the Policy Statement adopted an economic balancing test that weighs the public benefits of a project against its adverse impacts.[7] The Policy Statement continued the Commission's historical

2. *See* Written Testimony of Comm'r Tony Clark, Fed. Energy Reg. Comm'n, Before the Committee on Energy and Commerce Subcommittee on Energy and Power United States House of Representatives Hearing on Oversight of the Federal Energy Regulatory Commission, at 5-6 (Dec. 1, 2015), https://www.ferc.gov/CalendarFiles/20151201095914-Clark-12-01-2015.pdf ("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.").

3. *See, e.g.*, *Transcon. Gas Pipe Line Co.*, 157 F.E.R.C. ¶ 61,095 at PP 3-6 (2016); *Fla. Se. Connection, LLC*, 154 F.E.R.C. ¶ 61,080 at P 77 (2016), *order on reh'g*, 156 F.E.R.C. ¶ 61,160 (2016).

4. This fact was explicitly recognized at the time of passage of the NGA. *See To Regulate the Transportation and Sale of Natural Gas in Interstate Commerce and for Other Purposes: Hearing on H.R. 11662 Before Subcomm. on Interstate and Foreign Commerce*, 74th Cong. 57 (1936) (Statement of Col. William T. Chantland, Attorney in Charge of Legal Work, FTC Utilities Division) ("As pipe lines are the only present method of transportation of natural gas, and as the principal markets, actual and potential, are at long distances and across many State lines from the big reserve areas, the States have been helpless to cope with such transportation problem.").

5. Policy Statement, *Certification of New Interstate Nat. Gas Pipeline Facilities*, 88 F.E.R.C. ¶ 61,227 (1999), *corrected by*, 89 F.E.R.C. ¶ 61,040 (1999), *clarified by*, 90 F.E.R.C. ¶ 61,128, *clarified by*, 92 F.E.R.C. ¶ 61,094 (2000).

6. 92 F.E.R.C. ¶ 61,094 at PP 1-2.

7. *Id.*

reliance on market forces as evidenced by contracts or precedent agreements as indicators of the need for a project.

The reliance on precedent agreements or contracts is disciplined, however, by a pricing policy that puts the risk of unsold or overbuilt project capacity on the sponsor. The Commission thus defined the circumstances that would determine whether a project was required by the public convenience and necessity.

The Policy Statement formally adopted principles that the Commission began implementing over thirty years ago to address changes that occurred as the natural gas industry matured, including the consideration of market forces to identify the need for gas and protection for consumers by allocating risk to project sponsors.[8] The Commission's separate environmental review process, guided by the National Environmental Policy Act of 1969 (NEPA), ensures that any environmental impacts are properly disclosed, reduced, and mitigated. These remain effective tools for determining that a proposed pipeline construction project is required by the public convenience and necessity. Indeed, in 2016 the Commission rejected one project for lack of market support,[9] and two other pipeline projects proposed to serve New England were cancelled, or put on hold, due to lack of market support.[10]

Since 1999, the Policy Statement has been used effectively to identify projects that serve the public interest while protecting consumers and other interest groups. The Policy Statement was developed as a result of Commission experience over many decades and in response to changes within the pipeline industry. It has been a long journey. Today, the Commission's approach is under renewed attack. This article reviews some of the many steps of that journey in the hope that they need not be repeated.

II. THE NATURAL GAS ACT

In 1927, the U.S. Supreme Court ruled that the states lacked authority to regulate the interstate transportation or sale for resale of natural gas because regulation of interstate commerce was the province of the federal government.[11] Consequently, interstate gas pipelines were entirely unregulated. In 1936, the Federal Trade Commission (FTC) issued an extensive report on the natural gas industry, including, among other things, ineffective regulation of pipeline construction.[12]

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8. 88 F.E.R.C. ¶ 61,227 at 3-5, 19-26.

9. *Jordan Cove Energy Project, L.P.*, 154 F.E.R.C. ¶ 61,190 at P 48, *order denying reh'g*, 157 F.E.R.C. ¶ 61,194 (2016). *See also Turtle Bayou Gas Storage Co.*, 135 F.E.R.C. ¶ 61,233 at P 37 (2011) (denying certificate to construct gas storage facility because applicant had not secured any subsurface property rights and had not provided evidence of a specific need for the project), *reconsideration denied*, 139 F.E.R.C. ¶ 31,033 (2012).

10. *See e.g.*, Jon Chesto, *Kinder Morgan Shelves $3 Billion Pipeline Project*, Boston Globe, at 4, Apr. 20, 2016, https://www.bostonglobe.com/business/2016/04/20/kinder-morgan-shelves-billion-new-england-pipeline-project/iEafnAP2P41o0B9tmM0lEI/story.html; Brian Dowling, *Gas Giant Spectra Delays $3 Billion NE Pipeline Project*, Boston Herald, Dec. 28, 2016, http://www.bostonherald.com/business/business_markets/2016/12/gas_giant_spectra_delays_3_billion_ne_pipeline_project.

11. *See e.g.*, Missouri v. Kan. Nat. Gas Co., 265 U.S. 298, 309-10 (1924); Pub. Utils. Comm'n of R.I. v. Attelboro Steam & Elec. Co., 273 U.S. 83 (1927).

12. FED. TRADE COMM'N, ANNUAL REPORT OF THE FEDERAL TRADE COMMISSION FOR THE FISCAL YEAR ENDED JUNE 30, at 34-40 (1936) (hereinafter FTC REPORT), https://www.ftc.gov/sites/default/files/documents/reports_annual/annual-report-1936/ar1936_0.pdf.

Congress responded by passing the Natural Gas Act (NGA),[13] which extended the authority of the Federal Power Commission (FPC or the Commission) to include regulation of the interstate transportation or sale for resale of natural gas.[14] Almost eighty years old, the NGA remains a critical and powerful federal regulatory statute, as relevant today as it was when it was enacted. Section 1 of the NGA declares that "the business of transporting and selling natural gas for ultimate distribution to the public is affected with a public interest, and that Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the public interest."[15] The House Report on the bill explained that "[t]he basic purpose of the present legislation is to occupy this field in which the Supreme Court has held that the States may not act."[16] Thus, Supreme Court precedent and the statute establish the preeminent federal role in pipeline certification.

Section 7(c)(1)(A) of the NGA provides that a natural gas company, or person that will be a natural gas company, requires authorization in the form of a certificate of public convenience and necessity from the Commission before it may "undertake the construction or extension of any facilities therefor, or acquire or operate any such facilities" for the transportation or sale for resale of gas in interstate commerce.[17] Section 7(e) of the NGA provides that the Commission shall grant

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13. 15 U.S.C. §§ 717-717w (2006).

14. Previously, the FPC had been responsible for regulating certain hydroelectric activities and for regulating the transmission and wholesale of electricity in interstate commerce. *See* Federal Power Act, 16 U.S.C. §§ 791a-825r (1920). The FPC was succeeded by the Federal Energy Regulatory Commission in 1977. *See* Department of Energy Organization Act, 42 U.S.C. § 7172 (1977). "Commission" as used throughout this article refers to either the FPC or to the Federal Energy Regulatory Commission depending on the context. References to the Commission prior to 1977 apply to the FPC. References to the Commission after 1977 apply to the successor Federal Energy Regulatory Commission.

15. 15 U.S.C. § 717(a).

16. H.R. Rep. No. 709, 75th Cong., 1st Sess. 2 (1937).

17. Section 7(c) of the NGA provides :

> (c) Certificate of public convenience and necessity
>
> (1)(A) No natural-gas company or person which will be a natural-gas company upon completion of any proposed construction or extension shall engage in the transportation or sale of natural gas, subject to the jurisdiction of the Commission, or undertake the construction or extension of any facilities therefor, or acquire or operate any such facilities or extensions thereof, unless there is in force with respect to such natural-gas company a certificate of public convenience and necessity issued by the Commission authorizing such acts or operations: *Provided, however*, That if any such natural-gas company or predecessor in interest was bona fide engaged in transportation or sale of natural gas, subject to the jurisdiction of the Commission, on February 7, 1942, over the route or routes or within the area for which application is made and has so operated since that time, the Commission shall issue such certificate without requiring further proof that public convenience and necessity will be served by such operation, and without further proceedings, if application for such certificate is made to the Commission within ninety days after February 7, 1942. Pending the determination of any such application, the continuance of such operation shall be lawful.
>
> (B) In all other cases the Commission shall set the matter for hearing and shall give such reasonable notice of the hearing thereon to all interested persons as in its judgment may be necessary under rules and regulations to be prescribed by the Commission; and the application shall be decided in accordance with the procedure provided in subsection (e) of this section and such certificate shall be issued or denied accordingly: *Provided, however*, That the Commission may issue a temporary certificate in

a certificate to any qualified applicant if it finds that the proposed project is or will be required by the present or future public convenience and necessity.[18] Thus, prior to construction, if the Commission finds that a company has demonstrated that the project is required by the public convenience and necessity, the Commission must grant the certificate.[19]

Once a company enters into the business of transporting gas in interstate commerce it becomes a "natural gas company"[20] providing services that are "affected with a public interest."[21] Natural gas companies operating under the NGA are regulated by the Commission and their rates and terms and conditions of service are subject to review and approval under the NGA. Once a pipeline enters interstate service, it may not abandon jurisdictional facilities or service without prior Commission approval.[22]

> cases of emergency, to assure maintenance of adequate service or to serve particular customers, without notice or hearing, pending the determination of an application for a certificate, and may by regulation exempt from the requirements of this section temporary acts or operations for which the issuance of a certificate will not be required in the public interest.
>
> (2) The Commission may issue a certificate of public convenience and necessity to a natural-gas company for the transportation in interstate commerce of natural gas used by any person for one or more high-priority uses, as defined, by rule, by the Commission, in the case of—
>
> (A) natural gas sold by the producer to such person; and
>
> (B) natural gas produced by such person.

15 U.S.C. § 717f(c).

18. Section 7(e) of the NGA provides:

> (e) Granting of certificate of public convenience and necessity
>
> Except in the cases governed by the provisos contained in subsection (c)(1) of this section, a certificate shall be issued to any qualified applicant therefor, authorizing the whole or any part of the operation, sale, service, construction, extension, or acquisition covered by the application, if it is found that the applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of this chapter and the requirements, rules, and regulations of the Commission thereunder, and that the proposed service, sale, operation, construction, extension, or acquisition, to the extent authorized by the certificate, is or will be required by the present or future public convenience and necessity; otherwise such application shall be denied. The Commission shall have the power to attach to the issuance of the certificate and to the exercise of the rights granted thereunder such reasonable terms and conditions as the public convenience and necessity may require.

15 U.S.C. § 717f(e).

19. Although section 7(c)(1)(b) of the NGA requires that in certificate cases the "Commission shall set the matter for hearing," the Commission and the courts have not interpreted this provision to require a trial-type evidentiary hearing unless material facts are in dispute that cannot be resolved on the basis of written pleadings. *See, e.g., El Paso Nat. Gas Co.*, 65 F.E.R.C. ¶ 61,276 at P 61,866 (1993) (citing S. Union Gas Co. v. FERC, 840 F.2d 964, 970 (D.C. Cir. 1988); Cerro Wire & Cable Co. v. FERC, 677 F.2d 124 (D.C. Cir. 1982); Citizens for Allegan County, Inc. v. FPC, 414 F.2d 1125, 1128 (D.C. Cir. 1969)). The Commission has not set a certificate case for a trial-type hearing since 1998. *See Granite State Gas Transmission, Inc.*, 82 F.E.R.C. ¶ 61,232 at P 61,890 (1998).

20. "'Natural-gas company' means a person engaged in the transportation of natural gas in interstate commerce, or the sale in interstate commerce of such gas for resale." 15 U.S.C. § 717a(6).

21. 15 U.S.C. § 717(a).

22. Section 7(b) of the NGA provides:

> (b) Abandonment of facilities or services; approval of Commission
>
> No natural-gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, without the permission and

The Supreme Court has explained that the NGA "permits the relations between the parties to be established initially by contract."[23] Subject to the Commission's regulatory oversight of their rates and terms and conditions of service, interstate gas pipelines remain private enterprises, owned by their stockholders and dependent on private contracts to market their services. Thus, the NGA is based on the underlying assumption that private contracts will provide the basis for determining the market need for new construction.

III. INTERPRETING THE MEANING OF "PUBLIC CONVENIENCE AND NECESSITY"

The NGA does not define "public convenience and necessity," but instead leaves interpretation of that phrase to the regulatory agency. At the time the NGA was enacted by Congress, a number of other regulatory statutes required agencies to issue certificates based on a determination of the "public convenience and necessity." The legislative history to the NGA notes that,

> [t]here are similar provisions requiring certificates of public convenience and necessity for extensions of service in the Interstate Commerce Act (U.S.C. 1934 title 40 sec. 1 (18-20)); the Communications Act of 1934 (U.S.C. 1934 title 47 sec. 214) and the Motor Carriers Act U.S.C. 1934 title 49 secs. 306, 307, 308).[24]

Thus, the concept of a regulatory agency determining whether a private entity's proposal was in the public convenience and necessity was an established practice when the NGA was enacted. Quoting its interpretation of an analogous statute, the Supreme Court explained the Commission's role in interpreting the phrase "public convenience and necessity" as used in the NGA: "The Commission is the guardian of the public interest in determining whether certificates of convenience and necessity shall be granted. For the performance of that function the Commission has been entrusted with a wide range of discretionary authority."[25] Thus, courts have allowed the Commission significant freedom to decide under what circumstances it should issue a certificate for pipeline construction.

> approval of the Commission first had and obtained, after due hearing, and a finding by the Commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.

15 U.S.C. § 717f(b).

23. United Gas Pipe Line Co. v. Mobile Gas Serv. Corp., 350 U.S. 332, 339 (1956). *See also Kern River Gas Transmission Co.*, 117 F.E.R.C. ¶ 61,077 at PP 62-63 (2006) (Commission's role to ensure that the rates offered and accepted as a result of individual negotiations are just and reasonable), *order on reh'g*, 123 F.E.R.C. ¶ 61,056 (2008), *order on reh'g*, 126 F.E.R.C. ¶ 61,034, *order on reh'g*, 129 F.E.R.C. ¶ 61,240 (2009), *reh'g denied*, 133 F.E.R.C. ¶ 61,162 (2010), *order on initial decision*, 136 F.E.R.C. ¶ 61,045 (2011), *order on reh'g*, 142 F.E.R.C. ¶ 61,132, *order on reh'g*, 145 F.E.R.C. ¶ 61,042 (2013); Morgan Stanley Capital Grp., Inc. v. Pub. Util. Dist. No. 1 of Snohomish County, 554 U.S. 527, 531-34 (2008).

24. Committee on Interstate Commerce, Interstate Transportation and Sale of Natural Gas, S. Rep. No. 75-1162, at 5 (Aug. 9, 1937).

25. FPC v. Transcon. Gas Pipeline Co., 365 U.S. 1, 7 (1961) (quoting United States v. Detroit & Cleveland Navigation Co., 326 U.S. 236, 241 (1945)).

IV. EVIDENCE OF THE PUBLIC CONVENIENCE AND NECESSITY UNDER THE NGA

In one of its earliest proceedings, the Commission defined public convenience and necessity to mean:

> a public need or benefit without which the public is inconvenienced to the extent of being handicapped in the pursuit of business or comfort or both—without which the public generally in the area involved is denied to its detriment that which is enjoyed by the public of other areas similarly situated.[26]

The Commission adopted a list of seven elements that it considered the minimum requirements to demonstrate that a project was required by the public convenience and necessity.[27] From the outset, evidence required to support a pipeline project relied in part on a showing based on private contracts. In *Kansas Pipe Line* the Commission stated:

> We are of the opinion that applicants who contend that "public convenience and necessity" require or will require the construction of facilities for the transportation of natural gas must show that they possess a supply of natural gas adequate to meet those demands which it is reasonable to assume will be made upon them.[28]

In this original case, the applicants presented a precedent agreement to meet the supply requirement.[29] The Commission relied on the precedent agreement for issuance of a conditional certificate, but stated:

> We could not issue an unconditional certificate of public convenience and necessity nor authorize the issuance of such an unconditional certificate until we had received assurance in the form of a contract satisfactory to us that the reserve of natural gas purportedly available to the Kansas Company is actually available upon firm commitment.[30]

The *Kansas Pipe Line* requirement to show evidence of "potential customers" was less strict. Based on the testimony of "witnesses who are men of long experience," the Commission noted that it was not the practice to attempt to secure firm commitments from prospective customers for a pipeline extension into a territory where no physical connections existed, stating:

> We see no reason to require applicants before us to submit firm commitments for the sale of natural gas in all cases; it is, we feel, enough if applicants show that on the basis of experience in similar territory, there are reasonable grounds for anticipating that customers will be attached to the proposed facilities.[31]

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26. *In re Kan. Pipe Line & Gas Co.*, 2 F.P.C. 29, 56 (1939).

27. *Id.* at 55. Under the test established, applicants were required to show that (1) they possess a supply of natural gas adequate to meet those demands which it is reasonable to assume will be made upon them (*id.* at 40); (2) there exist in the territory proposed to be served customers who can reasonably be expected to use such natural-gas service (*id.* at 45); (3) the facilities for which they seek a certificate are adequate (*id.* at 46-47); (4) the costs of construction of the facilities which they propose are both adequate and reasonable (2 F.P.C. at 53); (5) the anticipated fixed charges or the amount of such fixed charges are reasonable (*id.* at 54); (6) the rates proposed to be charged are reasonable (*id.* at 54-55); and (7) the anticipated fixed costs or the amount of such fixed costs (such as operating and maintenance expenses, depreciation, taxes, and return) must be reasonable (*id.* at 54).

28. *Id.* at 40.

29. 2 F.P.C. at 41 ("Though there is not at present a firm contract in existence . . . for the sale and purchase of natural gas, the terms of that contract have been agreed upon between the parties.").

30. *Id.*

31. *Id.* at 45.

The factors identified in *Kansas Pipe Line* were developed when pipelines were aggregators of supply meant to support the pipeline's merchant function. The focus of the Commission's inquiry was on the sufficiency of gas reserves to support the proposed pipeline.[32] These factors were strictly applied by the Commission for many years, and remain memorialized in the current list of exhibits required to be included in pipeline certificate applications.[33] However, the weight given to individual factors has changed significantly in response to changes in the industry and as a result of the Commission's decades-long experience implementing the NGA. Historically, the Commission had always required pipelines to have executed firm contracts and supporting market data equivalent to the total capacity of its proposed facilities before it could commence construction of a new project.[34] Adequacy of supply is no longer a significant consideration in most cases where new pipeline infrastructure is proposed.[35]

32. As the Commission has explained:

> The natural gas industry in 1939 was dramatically different from the industry that exists today. In 1939, the development of a national natural gas pipeline grid was in its beginning stages. Furthermore, pipelines rendered gas service as merchants of natural gas-by purchasing gas from producers, transporting that gas to a delivery point, and ultimately selling the gas to local distribution companies or industrial end-users. The rate charged for this service was a bundled charge representing, generally, the cost of the gas added to certain costs associated with the construction and operation of the transporting facilities.

Order No. 555, *Revisions to Regulations Governing Authorizations for Construction of Nat. Gas Pipeline Facilities*, III F.E.R.C. STATS. & REGS. ¶ 30,928, at P 30,224, 56 Fed. Reg. 52,330 (1991), *order on reh'g and postponing effective date*, 57 F.E.R.C. ¶ 61,195 (1991), *order withdrawing amendments*, 62 F.E.R.C. ¶ 61,249 (1993). Order No. 555 was withdrawn by the Commission on March 16, 1993, and is referred to in this article solely for its discussion of the Commission's regulatory history. The order withdrawing the Order No. 555 regulations states:

> Although the Commission postponed the effective date of the final rule, the regulations adopted therein were codified in the 1992 edition of the Code of Federal Regulations . . . Codification of the non-effective, Order No. 555 regulations understandably has generated considerable confusion in the industry, particularly among practitioners before the Commission. To alleviate this confusion, the Commission is withdrawing the amendments adopted in Order No. 555.

Revisions to Regulations Governing Authorizations for Construction of Nat. Gas. Pipeline Facilities, 58 Fed. Reg. 15,481 (1993) (to be codified at 18 C.F.R. pts. 2, 154, 157, 284, 375 & 380). No subsequent order was issued in the proceeding. *See also* [Regs. Preambles 1991–1996] F.E.R.C. STATS. & REGS. ¶ 30,965.

33. 18 C.F.R. §§ 157.14(a)(8)–(19).

34. *Id.*; *see also Questar Pipeline Co.*, 59 F.E.R.C. ¶ 61,363 at P 62,369 (1992).

35. Order No. 436, *Regulation of Nat. Gas Pipelines After Partial Wellhead Decontrol*, 33 F.E.R.C. ¶ 61,007 at PP 61,815-16, 61,925 (1985), *order on reh'g & clarification*, Order No. 436-A, [1982–1985 REGS. PREAMBLES] F.E.R.C. STATS. & REGS. ¶ 30,675 (1985), *order on reh'g*, Order No. 436-B, [1986–1990 REGS. PREAMBLES] F.E.R.C. STATS. & REGS. ¶ 30,688, *order denying reh'g*, Order No. 436-C, 34 F.E.R.C. ¶ 61,404, *order denying applications for reh'g*, Order No. 436-D, 34 F.E.R.C. ¶ 61,405, *reconsideration denied*, Order No. 436-E, 34 F.E.R.C. ¶ 61,403 (1986), *vacated and remanded*, Associated Gas Distribs. v. FERC, 824 F.2d 981 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988), *readopted on an interim basis*, *Regulation of Nat. Gas Pipelines After Partial Wellhead Decontrol*, Order No. 500, [1986–1990 REGS. PREAMBLES] F.E.R.C. STATS. & REGS. ¶ 30,761, *order granting extension of time*, Order No. 500-A, 1986–1990 F.E.R.C. Stats. & Regs., Regs. Preambles ¶ 30,770, *order on reh'g*, [1986–1990 REGS. PREAMBLES] F.E.R.C. STATS. & REGS. ¶ 30,772, *order on reh'g*, Order No. 500-C, [1986–1990 REGS. PREAMBLES] F.E.R.C. STATS. & REGS. ¶ 30,786 (1987), *order modifying dates*, Order No. 500-D, [1986–1990 REGS. PREAMBLES] F.E.R.C. STATS. & REGS. ¶ 30,800, *order denying reh'g*, Order No. 500-E, 43 F.E.R.C. ¶ 61,234, *order extending date*, Order No. 500-F, [1986–1990 REGS. PREAMBLES] F.E.R.C. STATS. & REGS. ¶ 30,841 (1988), *order denying reh'g*, Order No. 500-G, 46

V. EVOLUTION TO A COMPETITIVE INDUSTRY

After industry restructuring in the 1970's, the practice of analyzing applications for pipeline construction set out in *Kansas Pipe Line* went from unwieldy to untenable.[36] Gas shortages caused by federal regulation of producer rates led Congress to enact the Natural Gas Policy Act of 1978 (NGPA).[37] The NGPA was intended to provide investors with incentives to develop supply and thus increase the availability of gas to the interstate market. Instead of rates set by the Commission for interstate sales of gas by producers, the NGPA set rates for the "first sales" of gas and began the phased decontrol of wellhead gas prices to permit market forces to play a role in supply and demand.[38] Producer deregulation culminated with the Natural Gas Wellhead Decontrol Act of 1989, which removed all price ceilings dictated by the NGPA as of January 1, 1993.[39]

During the same period, a maturing pipeline industry led to a nationwide pipeline grid, which allowed increasingly efficient transportation transactions (e.g., through backhauls, displacement, and exchanges).[40] When the NGA passed, many markets had two or more pipeline suppliers. The Commission believed that pipeline-on-pipeline competition altered its regulatory role.[41]

In 1985, the Commission issued Order No. 436 to adapt its regulatory framework to the changed circumstances of the industry. The goal of Order No. 436 was to retain utility-type regulation over interstate transportation, while allowing the gas commodity market to competitively develop.[42] To do this, the Commission promulgated Order No. 436, which establishes a voluntary program for pipelines that would agree to offer non-discriminatory, open-access transportation to third-

F.E.R.C. ¶ 61,148, *final rule*, Order No. 500-H, [1986–1990 REGS. PREAMBLES] F.E.R.C. STATS. & REGS. ¶ 30,867 (1989), *order on reh'g*, Order No. 500-I, [1986–1990 REGS. PREAMBLES] F.E.R.C. STATS. & REGS. ¶ 30,880, *aff'd in part & remanded in part*, Am. Gas Ass'n v. FERC, 912 F.2d 1496 (D.C. Cir. 1990), *cert. denied*, 111 S. Ct. 957 (1991), *order on remand*, Order No. 500-J, [1991–1996 REGS. PREAMBLES] F.E.R.C. STATS. & REGS. ¶ 30,915, *order on remand on "double crediting" issue*, Order No. 500-K, [1991–1996 REGS. PREAMBLES] F.E.R.C. STATS. & REGS. ¶ 30,917, *reh'g denied*, Order No. 500-L, 55 F.E.R.C. ¶ 61,489 (1991); *see also* Order No. 555, III F.E.R.C. STATS. & REGS., at 30,225-26.

36. *See generally*, Order No. 555, III F.E.R.C. STATS. & REGS., at 30,225 ("As the industry has continued to evolve since issuance of Order No. 436, it has become apparent that requiring a traditional *Kansas Pipe Line* analysis for construction of facilities to be used for open-access transportation may be inefficient, unwieldy, and unnecessary.").

37. 15 U.S.C. §§ 3301–3432.

38. *See generally* Order No. 636, *Pipeline Serv. Obligations & Revisions to Regulations Governing Self-Implementing Transp. Under Part 284 of the Comm'n's Regulations: Regulation of Nat. Gas Pipelines After Partial Wellhead Decontrol*, 59 F.E.R.C. 61,030 at 14 (1992), *order on reh'g*, Order No. 636-A, 60 F.E.R.C. 61,102 (1992), *order on reh'g*, Order No. 636-B, 61 F.E.R.C. ¶ 61,272 (1992), *aff'd in part & remanded in part sub nom.*, United Distributors Cos. v. FERC, 88 F.3d 1105 (D.C. Cir. 1996), *cert. denied*, 520 U.S. 1224, *order on remand*, Order No. 636-C, 78 F.E.R.C. ¶ 61,186 (1997), *reh'g denied*, Order No. 636-D, 83 F.E.R.C. ¶ 61,210 (1998).

39. Pub. L. No. 101-60 § 2(b), 103 Stat. 157, 158 (1989).

40. FTC REPORT, *supra* note 12, at 34-40.

41. 33 F.E.R.C. ¶ 61,007, at P 61,815.

42. *Id.* at P 61,816.

party customers.[43] Pipelines agreeing to participate would receive blanket certificates to provide transportation through their existing systems without prior authorization for each transaction.[44]

As an incentive for pipelines to provide non-discriminatory transportation on a self-implementing basis, Order No. 436 also established Optional Certificate Procedures, which provided expedited treatment for applications on new services.[45] The adopted procedures allowed an applicant to institute new jurisdictional services and to construct and operate facilities for the new service. These new regulations established a rebuttable presumption that, subject to review under NEPA, a project would be required by the public convenience and necessity subject to the condition *that the applicant must accept the full risk of its proposal.*[46] The risk condition was applied through rate conditions, which effectively prevented an applicant from shifting unrecovered costs to other customers.[47]

As the industry continued to evolve following issuance of Order No. 436, it became apparent to the Commission that the traditional *Kansas Pipe Line* factors used to analyze applications to construct facilities for open access transportation, "may be inefficient, unwieldy, and unnecessary."[48] Applicants for Optional Expedited Certificates did not have to supply certain Exhibits required in *Kansas Pipe Line*,[49] but the program was not popular and relatively few such certificates were issued.[50] The Commission began to apply "at risk" conditions to case specific applications for construction that had not been filed under the Optional Expedited Certificates regulations. Initially, the conditions were case specific, but eventually a consistent policy emerged:

> [W]e do not intend to abandon our responsibility to ensure that present and future customers do not make inappropriate contribution to the costs associated with newly constructed facilities. This we intend to accomplish by placing the pipelines at risk for the costs associated with their new facilities in the event all of the newly constructed capacity is not subscribed under firm contracts at the time the pipelines file to include the costs in their rates.[51] This can be accomplished in various ways. For example, the Commission could limit a pipeline's cost recovery to only the capacity for which it has firm contracts for service to satisfy the at risk condition. The Com-

43. *Id.* at P 61,846.

44. *Id.* at P 61,839.

45. *Id.* at P 61,911.

46. 33 F.E.R.C. ¶ 61,007, at PP 61,911, 61,926.

47. *Id.* at PP 61,918-19.

48. Order No. 555, III F.E.R.C. STATS. & REGS. at P 30,225.

49. 33 F.E.R.C. ¶ 61,007, at P 61,924.

50. Presumably, in the view of the pipeline industry, the risk of under recovering costs outweighed the presumption in favor of a certificate. Our research reveals only 20 Optional Expedited Certificates issued for major construction projects between 1988 and 2001. Application for the last such certificate had been pending before the rule was repealed in 2000.

51. "The duration of these contracts would have to be at least equal to the term required to meet the Commission's contract standard in traditional 7(c) certificates. We note that most construction is supported by contracts with terms of ten years or more." Order No. 555, III F.E.R.C. STATS. & REGS at 30,227. *See also* 65 F.E.R.C. ¶ 61,276 at PP 62,270-71 (setting forth a new "threshold requirement" for evidence demonstrating applicant has "long term (*e.g.*, [ten]-year) executed contracts or binding precedent agreements for a substantial amount of the firm capacity of the proposed facilities").

> mission also could determine that it would set rates based on 100[%] of the new facilities' capacity irrespective of the volumes subscribed to. These and other approaches would allow the Commission to ensure that ratepayers do not pay for unused capacity. . . . But to provide certainty to these applicants, we will place [the applicants] at risk by allowing them to recover only the costs associated with the capacity for which they have executed firm contracts.[52]

In sum, the Commission recognized in Order No. 555 that since 1985, when Order No. 436 was issued, processing certificate applications by closely analyzing them under the standards set out in *Kansas Pipe Line* was causing unreasonable delay and interfering with the efficient operation of competitive markets for both the sale and transportation of gas.[53]

In Order No. 436, the Commission recognized that, "market forces could be relied on to determine the ultimate need for the facilities as long as the consumer was protected."[54] The Commission's reliance on market forces to determine need and on risk conditions to protect consumers was developed in the Optional Certificate Procedures of Order No. 436.[55] This approach was later refined by applying risk conditions in case specific certificates.

VI. THE POLICY STATEMENT

On September 15, 1999, the Commission issued the Policy Statement to provide industry guidance concerning how the Commission would evaluate proposals for certificating new construction.[56] Issuance of the Policy Statement was based on information that the Commission had received in the course of several other proceedings, as well as on the Commission's experience evaluating proposals for new pipeline construction.[57] The Policy Statement specifically considered comments that the Commission had received in an earlier rulemaking proceeding on short-term natural gas transportation services.[58] In the notice of that rulemaking proceeding, the Commission said that it was considering how best to balance "market demand against potential adverse environmental impacts and private property rights in weighing whether a project is required by the public convenience and necessity."[59]

A. *The Notice of Proposed Rulemaking*

By 1999, when the Policy Statement was issued, the Commission had settled on the practice of requiring market support in the form of contracts for 25% of a new pipeline project in order for the Commission's Staff to begin processing the application. In order to receive a final certificate, the applicant needed to have

52. Order No. 555, III F.E.R.C. STATS. & REGS at 30,227.

53. *Id.* at 30,225-26.

54. *Id.* (discussing 33 F.E.R.C. ¶ 61,007, at P 61,911).

55. 33 F.E.R.C. ¶ 61,007, at P 61,911.

56. 88 F.E.R.C. ¶ 61,227, at P 61,737.

57. *Id.* at P 61,230.

58. *Id.*; *See also* Notice of Proposed Rulemaking, *Regulation of Short-Term Nat. Gas Transp. Servs.*, [1996–2000 REGS. PREAMBLES] F.E.R.C. STATS. & REGS. ¶ 32,533, at 33,489 (1998).

59. 88 F.E.R.C. ¶ 61,227, at P 61,737.

"[ten]-year firm commitments for all of its capacity" or be able to show that revenues would exceed costs.[60] An applicant unable to show that level of commitment could still receive a certificate but would be subject to a condition putting the applicant "at-risk" for any unsold capacity.[61] The Commission did not distinguish among the contracting parties, affiliates, producers, local distribution companies (LDCs), or marketers.[62]

Yet, the Commission also noted that landowners and communities had become increasingly active in objecting to the taking of their land by eminent domain for pipeline right-of-way.[63] The Commission believed that "by relying almost exclusively on contract standards to establish the market need for new projects, the current policy made it difficult to articulate to landowners and community interests why their land must be used for a new pipeline project."[64] Thus, over fifteen years ago the Commission recognized the need for its policies to address the perception that pipelines served private, not public, interests.

In the NOPR in Docket No. RM98-10-000, the Commission asked for comments on three options:

> One option would be for the Commission to authorize all applications that at a minimum meet the regulatory requirements, then let the market pick winners and losers. Another would be for the Commission to select a single project to serve a given market and exclude all other competitors. Another possible option would be for the Commission to approve an environmentally acceptable right-of-way and let potential builders compete for a certificate.[65]

In addition, the Commission asked commenters to address several other issues including: whether the Commission should look behind precedent agreements or contracts presented as evidence of market demand to assess independently the need for additional gas service; whether the Commission should apply a different standard to precedent agreements or contracts with affiliates; and whether a different standard should apply to project sponsors who did not plan to use eminent domain to acquire right-of-way.[66] Thus, the Commission anticipated many of the issues raised by today's pipeline opponents.

The Commission identified specific goals for its new policy:

> An effective certificate policy should further the goals and objectives of the Commission's natural gas regulatory policies. In particular, it should be designed to foster competitive markets, protect captive customers, and avoid unnecessary environmental and community impacts while serving increasing demands for natural gas. It should also provide appropriate incentives for the optimal level of construction and efficient customer choices.[67]

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60. *Id.* at P 61,743.

61. *Id.*

62. *Id.* The Commission did not require contracts to support projects designed to provide system benefits, such as improved reliability, access to new supplies, or more economic operations.

63. *Id.* at P 61,744.

64. 88 F.E.R.C. ¶ 61,227, at P 61,744.

65. *Id.* at P 61,737; [1996–2000 REGS. PREAMBLES] F.E.R.C. STATS. & REGS. ¶ 32,533, at 33,490.

66. 88 F.E.R.C. ¶ 61,227, at PP 61,737-38; [1996–2000 REGS. PREAMBLES] F.E.R.C. STATS. & REGS. ¶ 32,533, at 33,489-90.

67. 88 F.E.R.C. ¶ 61,227, at P 61,743.

A large number of stakeholders submitted comments. These are summarized in the Policy Statement. The issues raised then were much the same as issues that confront the Commission today in deciding on applications for new pipeline projects. Landowners still object to losing property by eminent domain. Pipeline opponents still argue that precedent agreements are not sufficient evidence of the public convenience and necessity, that affiliate contracts are a sham, and that the Commission does not give adequate consideration to environmental factors.

B. The Policy Adopted

The adopted 1999 Policy Statement considered all of these issues, and continues the Commission's long history of reliance on contracts or precedent agreements as "important evidence of demand for a project;" however, the Commission no longer requires contracts for any specific percentage of new capacity.[68] Instead, the Policy Statement focuses on the impact of the project on relevant interest groups balanced against the project's benefits.[69]

In order to receive a certificate for a new project, an applicant is expected to eliminate or at least minimize any potential adverse effects on three key groups with interests most likely to be affected by a pipeline construction project. The applicant's existing customers must not be required to subsidize a project that does not benefit them. Other pipelines and their customers must not be exposed to unfair competition.[70] Landowners and communities along the new pipeline's route should not be subjected to eminent domain where right-of-way can be acquired by good faith negotiation. A project is considered to be required by the public convenience and necessity where an applicant can show that public benefits outweigh any residual adverse effects on these aforementioned interest groups.[71]

A broad range of public benefits may be offered as proof that a project is required by the public convenience and necessity, and these benefits can be supported by any type of relevant evidence.[72] The goal must be to show that benefits outweigh adverse effects and therefore that the public interest will be served by the project. But the real linchpin of the policy is the pricing that is dictated by the prohibition on subsidies and places the risk on the project's investors.

68. *Id.* at P 61,748.

69. *Id.*

70. The Policy Statement does not preclude certificating more than one pipeline to serve a given market. To the contrary, it is established that the Commission may find that the public convenience and necessity requires certificating pipelines that compete with each other for a market. *See* Alabama-Tennessee Nat. Gas. Co. v. FPC, 417 F.2d 511, 516 (5th Cir. 1969) ("Section 7(g) makes clear the Commission's power to grant more than one certificate of public convenience and necessity for one service area."); N. Nat. Gas. Co. v. FPC, 399 F.2d 953, 964-65 (D.C. Cir. 1968) (certification of two pipelines to serve a given market could provide incentives for the pipelines to improve service and reduce costs in order to retain and attract customers); Cincinnati Gas & Elec. Co. v. FPC, 389 F.2d 272, 276-77 (6th Cir. 1968); *Chatanooga Gas. Co. v. E. Tenn. Nat. Gas Co*, 35 F.P.C. 917, 924-25 (1966) (certification of new pipeline to serve market where there was an existing pipeline granted precisely because lower rates are anticipated from the new carrier).

71. 88 F.E.R.C. ¶ 61,227, at P 61,745.

72. "The types of public benefits that might be shown are quite diverse but could include meeting unserved demand, eliminating bottlenecks, access to new supplies, lower costs to consumers, providing new interconnects that improve the interstate grid, providing competitive alternatives, increasing electric reliability, or advancing clean air objectives." *Id.* at P 61,748.

1. Incremental Pricing and the Prohibition Against Subsidies

The Commission recognized that as the industry became more competitive, the Commission needed to adapt its policies to provide the correct regulatory incentives. The prior policy had a bias for rolled-in pricing that sent the wrong price signals. Rolled-in pricing hid the cost of pipeline expansions because projects were subsidized by existing customers.[73] Accordingly, the Commission adopted a "threshold requirement."[74] To establish the public convenience and necessity of an expansion, pipelines would need to support new projects without ever relying on subsidies from existing customers. The Commission adopted a policy of incrementally pricing new pipeline projects, thus allowing the market to decide when new projects were financially viable and placing all of the risk of overbuilding on the pipeline.[75]

2. The Market as Evidence of the Need for a Project

Numerous commenters had urged the Commission to let the market determine the need for new pipeline capacity and not substitute its judgment.[76] The prohibition against financial subsidies was responsive to these requests and solved several problems at once. By putting the economic risk of a new project on its sponsor, the Commission increased the significance of contracts as indicators of true need. The Commission has described this as a two-step process for determining the economic viability of a project in the following way:

> The first step, which occurs prior to the certificate application, is for the pipeline to conduct an open season in which existing customers are given an opportunity to permanently relinquish their capacity. This first step ensures that a pipeline will not expand capacity if the demand for that capacity can be filled by existing shippers relinquishing their capacity. The open season policy was not changed by the recent Policy Statement. The second step is that the expansion shippers must be willing to purchase capacity at a rate that pays the full costs of the project, without subsidy from existing shippers through rolled-in pricing.[77]

Investors are highly unlikely to put capital at risk for projects that lack a genuine market—a point true for both existing pipelines and for new pipelines without existing customers. Pipelines have no incentive to enter into sham precedent agreements with affiliates for the same reason. If there is no throughput, the pipeline will not recover the cost of service. Therefore, the Commission's "concern with precedent agreements is whether they are long-term in nature and whether they are binding," not whether the agreement is with an affiliate.[78] To the extent

73. *Id.* at P 61,745.

74. *Id.* at P 61,792.

75. *Id.* at P 61,746; Order Clarifying Policy Statement, 90 F.E.R.C. ¶ 61,128, at P 61,391. *But see* William B. Tye & Jose Antonio Garcia, *Who Pays, Who Benefits, and Adequate Investment in Natural Gas Infrastructure*, 28 ENERGY L. J. 1, 41 (2007) (arguing that "bias in favor of incremental pricing may push too many costs onto new users, while existing customers enjoy benefits at no cost").

76. 88 F.E.R.C. ¶ 61,227, at P 61,738.

77. 90 F.E.R.C. ¶ 61,128, at P 61,392 (footnote omitted).

78. *Transcon. Gas Pipe Line Corp.*, 81 F.E.R.C. ¶ 61,104, at P 61,382 (1997), *reh'g denied*, 82 F.E.R.C. ¶ 61,084 (1998), *pet. dismissed*, Brooklyn Union Gas Co. v. FERC, 190 F.3d 369 (5th Cir. 1999); *see also Greenbrier Pipeline Co.*, 103 F.E.R.C. ¶ 61,024, at P 17 (2003) ("The fact that the marketers are affiliated with the project sponsor does not lessen the marketers' need for the new capacity or their obligation to pay for it under

an affiliated LDC or electric utility is a shipper, the state regulatory agency can review the prudence of the state regulated entity's contract.[79] Additionally, the requirement for incrementally-priced rates helps address nearly all of the objections typically raised in pipeline certificate proceedings for new projects.

> Existing customers of the expanding pipeline should not have to subsidize a project that does not serve them. Landowners should not be subject to eminent domain for projects that are not financially viable and therefore may not be viable in the marketplace. Existing pipelines should not have to compete against new entrants into their markets whose projects receive a financial subsidy (via rolled-in rates), and neither pipeline's captive customers should have to shoulder the costs of unused capacity that results from competing projects that are not financially viable. This is the only condition that uniformly serves to avoid adverse effects on all of the relevant interests and therefore should be a test for all proposed expansion projects by existing pipelines. It will be the predicate for the rest of the evaluation of a new project by an existing pipeline.[80]

The Commission found that the policies adopted in the Policy Statement had converged with those of the Optional Expedited Certificate procedures, as both programs operated to place the risk of a new project on the pipeline.[81] Accordingly, the Commission repealed the Optional Expedited Certificate rule in 2000.[82]

3. The Balancing Test and Review Under the National Environmental Policy Act

The balancing of adverse effects and benefits under the Policy Statement is largely focused on economic interests and proceeds separately from the Commission's environmental analysis of a project.[83] The Commission explained in the

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the terms of their contracts."), *reh'g denied*, 104 F.E.R.C. ¶ 61,145 (2003), *reh'g denied*, 105 F.E.R.C. ¶ 61,188 (2003).

79. *See generally*, *Granite State Gas Transmission, Inc.*, 83 F.E.R.C. ¶ 61,194, at P 61,820 (1998); *Paiute Pipeline Co.*, 151 F.E.R.C. ¶ 61,132, at P 33 (2015) (affiliate LDC's prudence in exchanging lower cost system capacity for capacity on pipeline expansion project is matter for resolution by state public utility commission), *order on reh'g*, 153 F.E.R.C. ¶ 61,292 (2015), *order on reh'g*, 155 F.E.R.C. ¶ 61,267 (2016).

80. 88 F.E.R.C. ¶ 61,227, at P 61,746.

81. 90 F.E.R.C. ¶ 61,128, at P 61,390. We note as well that the Policy Statement effectively incorporates a principle adopted in Order No. 555 (even though the regulations issued by that order were later withdrawn), namely, that a pipeline should bear the risk of new capacity that does not benefit its existing customers. *See, e.g.*, Order No. 555, III F.E.R.C. STATS. & REGS at 30,228 (project that does not satisfy the Kansas Pipe Line criteria will be placed at risk for underutilization of facilities).

82. Order No. 615, *Optional Certificate and Abandonment Procedures for Applications for New Service Under Section 7 of the Natural Gas Act*, 65 Fed. Reg. 45,856 (2000) (to be codified at 18 C.F.R. pt. 157). Referring to its notice of proposed rulemaking in the proceeding, the Commission said:

> The Commission explained that because the optional certificate program operates under a rebuttable presumption that proposals under which the pipeline applicant will assume the financial risks associated with the project are in the public interest, the Commission does not weigh the public benefits against the adverse effects in considering such applications. The Commission stated that it-believes that it will be better to consider all certificate applications under the broader criteria articulated in the Policy Statement.

Id. at 45,857.

83. The separation of the environmental analysis under the Policy Statement is consistent with a practice adopted in 1990 when the Commission began issuing "preliminary determinations" in pipeline certificate cases. *See, e.g.*, *Colo. Interstate Gas Co.*, 52 F.E.R.C. ¶ 61,003 (1990). Preliminary determinations addressed all issues

Policy Statement that "[o]nly when the benefits outweigh the adverse effects on economic interests will the Commission then proceed to complete the environmental analysis where other interests are considered."[84] Section 102 of NEPA requires that the Commission prepare an environmental impact statement (EIS) for "proposals for . . . major Federal actions significantly affecting the quality of the human environment."[85] The "twin aims" of NEPA are to "place[] upon an agency the obligation to consider every significant aspect of the environmental impact of a proposed action" and "ensure[] that the agency will inform the public that it has indeed considered environmental concerns in its decision-making process."[86] NEPA also requires the agency preparing an EIS to consider carefully the "scope" of its analysis, which is defined by Council of Environmental Quality regulations as "the range of actions, alternatives, and impacts to be considered in an environmental impact statement."[87] For smaller projects, the Commission generally prepares an environmental assessment (EA), which is meant to be a "concise public document . . . that serves to . . . [b]riefly provide sufficient evidence and analysis for determining whether to prepare an [EIS] or finding of no significant impact."[88] In practice, the Commission's EISs and EAs prepared by its staff are often voluminous, and ultimately recommend a number of environmental mitigation conditions intended to decrease and minimize the environmental impacts of the proposed pipeline project, which are adopted by the Commission in its certificate orders.

The Commission has explained that the balancing test under the Policy Statement "precedes an environmental analysis" and that it does not err "by failing to balance project need and benefits against adverse environmental impacts."[89] Opponents of Commission-regulated projects often claim that the approach of performing the economic balancing test before considering the environmental impacts of a project falls short of the review required by the NEPA. But, while NEPA can inform the Commission's decision whether a project is required by the public convenience and necessity, that argument ignores the goals of NEPA requiring the Commission "to consider every significant aspect of the environmental impact of a proposed action" and to disclose to the "public that it has indeed considered

in a proceeding except environmental issues. A preliminary determination decided under what condition a certificate would be granted subject to favorable environmental review. Issuance of the actual certificate and review of the environmental issues were the subject of a later order. *See id.* Once common, preliminary determinations are now rare. None have been issued since 2009. *See Ruby Pipeline, L.L.C.*, 128 F.E.R.C. ¶ 61,224 (2009), *order on clarification*, 131 F.E.R.C. ¶ 61,007 (2010). Today most significant construction projects follow the Commission's "optional" pre-filing procedures which results in preparation of an environmental document early in the process of Commission staff's review of a certificate application. *See* 18 C.F.R. § 157.21 (2012).

84. 88 F.E.R.C. ¶ 61,227, at P 61,745.

85. 42 U.S.C. § 4332(2)(C) (1975); *see also* 40 C.F.R. § 1502.3 (1978).

86. Balt. Gas & Elec. Co. v. Nat. Res. Def. Council, Inc., 462 U.S. 87, 97 (1983) (citing Vt. Yankee Nuclear Power Corp. v. Nat. Res. Def. Council, Inc., 435 U.S. 519, 553(1978); Weinberger v. Catholic Action of Haw., 454 U.S. 139, 143 (1981)).

87. 40 C.F.R. § 1508.25 (1977).

88. 40 C.F.R. § 1508.9(a).

89. *Midwestern Gas Transmission Co.*, 116 F.E.R.C. ¶ 61,182, at P 37 (2006).

environmental concerns in its decision-making process."[90] Opponents' arguments simply fail to consider the reality of the Commission's certificate process. In theory, a pipeline project could have an environmental impact so severe that it would offset all other public benefits and could not meet the requirements of the public convenience and necessity.

Nothing prevents the Commission from finding that a project would not be required by the public convenience and necessity solely for environmental reasons. As a practical matter, though, an application for such a project would almost certainly never be filed.

Virtually all significant projects are now subject to the Commission's "optional" pre-filing procedures.[91] Under these procedures, applicants begin early outreach to stakeholders and other permitting agencies and do not file applications until Commission staff has reviewed and commented on the environmental exhibits. Projects that might otherwise have significant adverse effects can be mitigated through rerouting or by the numerous environmental conditions applied to all construction certificates.[92] For example, one recent project considered 282 route variations, almost all of which were identified by landowners, government officials, and other stakeholders and incorporated 214 of those route variations into its proposed route.[93] The Commission's order will generally recognize the incorporation of environmental conditions through language finding that subject to the conditions in the order, the project is in the public convenience and necessity.

VII. CONCLUSION

The federal government has exclusive authority under the Commerce Clause of the Constitution to regulate the transportation of natural gas in interstate commerce. Pipelines are the only feasible method of transporting natural gas over long distances and Congress delegated the regulation of interstate pipeline construction to the Commission pursuant to the NGA. In reviewing the Commission's performance of these regulatory responsibilities, appellate courts recognize that the decision to grant or deny a certificate application is "a matter peculiarly within the

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90. *Balt. Gas & Elec. Co.*, 462 U.S. at 97 (citing *Vt. Yankee Nuclear Power*, 435 U.S. at 553; *Weinberger*, 454 U.S. at 143).

91. *See* 18 C.F.R. § 157.21. The Commission's pre-filing procedures were issued in compliance with section 311(d) of the Energy Policy Act of 2005 to establish mandatory procedures requiring prospective applicants to begin the Commission's pre-filing review process at least six months prior to filing an application for authorization to site and construct a liquefied natural gas terminal. Pub. L. No. 109-58, 119 Stat. 594 (2005). However, applicants for other facilities subject to the Commission's jurisdiction under the NGA may elect to undertake the pre-filing process on a voluntary basis prior to filing applications. 18 C.F.R. § 157.21(b). As a practical matter, applicants for major construction projects almost always participate in the pre-filing process.

92. For example, a typical Commission order authorizing 686 miles of pipeline construction in the southeast United Sates contained twenty-seven environmental conditions. *Fla. Se. Connection*, 154 F.E.R.C. ¶ 61,080, at App'x B (2016).

93. 154 F.E.R.C. ¶ 61,080, at P 71; *see also Constitution Pipeline Co.*, 149 F.E.R.C. ¶ 61,199, at PP 109, 112 (2014) (noting the pipeline made changes to over 50% of its proposed 124-mile-long pipeline route in order to address concerns from landowners and that another ninety-seven route variations were adopted by the pipeline or imposed by the Commission through the environmental review process), *reh'g denied*, 154 F.E.R.C. ¶ 61,046 (2016).

discretion of the Commission."[94] A court will not substitute its judgment for that of the Commission as long as the Commission's decision was "reasoned, principled, and based upon the record."[95]

This article reviews the development of the Commission certificate policy in response to calls for new procedures to evaluate pipeline certificate applications. We think there is no need for such new procedures. The Commission's evaluation of certificate applications under the principles adopted in the Policy Statement continues to satisfy the standards set by the statute and the courts. A competitive market cannot function efficiently if participants are unable to respond timely to market signals. The Commission's reliance on contracts as the best evidence to determine project need has a long and successful history. When the market will not support a project, it does not go forward. For example, Independence Pipeline Company applied for a certificate to construct a 400-mile pipeline from the Midwest to Leidy, Pennsylvania in 1997. The project received a certificate in 2000.[96] In mid-2002 the project sponsors cancelled the project because of insufficient customer support.[97] More recently, two other pipeline projects were cancelled or put on hold due to lack of market support.[98]

The Commission's policy of incremental pricing puts the financial risk of new projects on the pipelines and provides a strong incentive that disfavors unneeded projects. This approach adopted in the Policy Statement is consistent with the statute and sound economic principles. Instead of picking winners and losers, the Commission evaluates the public convenience and necessity of pipeline construction projects based on the demonstrated willingness of investors to risk capital in the market place.

94. *E.g.*, *Minisink Residents for Envtl. Prot. v. FERC*, 762 F.3d 97, 106 (D.C. Cir. 2014) (and cases cited therein).

95. *Id.*

96. *Indep. Pipeline Co.*, 92 F.E.R.C. ¶ 61,022 at P 2 (2002), *reh'd denied*, 92 F.E.R.C. ¶ 61,268 (2000), *clarifying order*, 96 F.E.R.C. ¶ 61,279 (2001).

97. 100 F.E.R.C. ¶ 61,082.

98. 88 F.E.R.C. ¶ 61,227, *corrected by*, 89 F.E.R.C. ¶ 61,040 (1999), *clarified by*, 90 F.E.R.C. ¶ 61,128, *clarified by*, 92 F.E.R.C. ¶ 61,094 (2000).

The CHAIRMAN. Thank you, Mr. Moffatt.
Mr. Murchie, welcome.

STATEMENT OF JAMES J. MURCHIE, CEO AND CO-FOUNDER, ENERGY INCOME PARTNERS, LLC

Mr. MURCHIE. Thank you, Madam Chair, Senator King, members of the Committee. My name is Jim Murchie. I am a Co-Founder and CEO of Energy Income Partners. We call it EIP for short. I'm joined here today by my colleague, Sam Brothwell, who is sitting behind me.

Founded in 2003, EIP is a registered investment advisor that oversees about $6 billion of client assets. Our clients invest primarily through mutual funds and separately managed accounts and are primarily individual investors seeking income and inflation protection.

EIP invests this capital in equity securities of publicly traded energy infrastructure companies located primarily in the U.S. with some investments in Canada and some nominal investments overseas. EIP invests in companies that operate natural gas and petroleum pipelines and related storage and terminals, regulated power generation, transmission and distribution, as well as developers and operators of renewable energy selling power on long-term contracts. Our investment strategy seeks stable cash flows being generated by regulated assets with modest growth.

EIP is unusual in that as a specialist in the energy income investing, it invests in both hydrocarbon infrastructure and electric power infrastructure. In the age of specialization and institutional asset allocation by asset category, specialist investment managers in the energy infrastructure space are either midstream investors, you know, hydrocarbons which today really means they're MLP investors or separately they're electric utility investors.

Because the energy system itself does not follow these tidy asset allocation categories, I think EIP has a unique perspective on how these different areas interact.

Our original fund which started in 2003 has generated double digit compounded annual returns that exceed the returns of the S&P 500 and most other relevant indices. The returns have been up of roughly a six-percent yield with a balance from appreciation of the underlying share prices.

I'd like to highlight the two main points that were in our written testimony that we submitted earlier in the week.

The first is that our success as investors is a direct result of selecting the best management teams that operate under regulatory regimes that are demanding but fair, consistent and predictable. Investors and regulated businesses do well when all the stakeholders involved with these assets do well, and we have found that means safe, reliable energy at a low cost to the consumers with the least impact on the environment. By contrast, companies that give short shrift to issues of worker and public safety, system reliability and environmental stewardship also tend to be pro-allocators of capital, have higher operating costs and usually have, as a result, poor relationships with their regulators and other stakeholders and from our perspective, more importantly, they also tend to have lower shareholder returns. We invest in a commodity industry where low costs win out. We try to own the low-cost way of transporting the lowest cost forms of energy. That's how we win. Our partners in this are the management teams of the companies we own and the regulatory regimes under which they operate.

Environmental impact is the second point we made in our testimony. The U.S. energy infrastructure system has successfully attracted billions of dollars in capital expanding the natural gas pipeline system that has resulted in significant growth in gas-fired power generation which, in turn, has led to a 40 percent decline in coal-fired power generation over the last ten years and has facilitated, as backup power, significant growth in wind and solar generation. When viewed from this perspective, the construction of new natural gas pipelines has played a critical role in the U.S. reducing its CO_2 emissions by over 13 percent from their peak in 2005. The opposition to new natural gas pipeline construction because increased use of gas will increase greenhouse gases ignores the benefit of gas-fired generation versus coal-fired generation, misses the symbiotic relationship between gas and renewables, threatens to chase away capital and slow the progress we've enjoyed in generating cleaner energy at lower costs.

My firm and I appreciate the opportunity to present the testimony to the Committee today and look forward to the questions.

Thank you.

[The prepared statement of Mr. Murchie follows:]

TESTIMONY OF
JAMES J. MURCHIE
CEO AND CO-FOUNDER
ENERGY INCOME PARTNERS, LLC

BEFORE THE
U.S. SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

REGARDING
NATURAL GAS PIPELINE DEVELOPMENT

JULY 12, 2018

Madam Chair and Members of the Committee:

My name is Jim Murchie. I am Co-founder and CEO of Energy Income Partners, LLC or EIP for short. EIP is a Registered Investment Adviser that oversees about $6 billion[1] of client assets. EIP advises or sub-advises six mutual funds (five of which are New York Stock Exchange listed funds), two investment partnerships and hundreds of separately managed accounts for individuals and institutions. EIP invests all of these client assets in equity securities of publicly traded energy infrastructure companies located primarily in the U.S. with significant investments in Canada and nominal investments overseas. EIP invests in companies that operate natural gas and petroleum pipelines and related storage and terminals, regulated power generation, transmission and distribution as well as developers and operators of renewable energy selling power on long term contracts. Our investment strategy seeks stable cash flows being generated by regulated assets with modest growth.

EIP was established in 2003 and is an outgrowth of my personal investments in energy infrastructure dating back to the late 1990s. My firm and I appreciate the opportunity to present testimony to the Committee today.

I am joined here today by my colleague Sam Brothwell. The investment team at EIP is comprised of six individuals, including myself and Sam; we all have extensive energy and financial industry experience. My own experience includes 8 years at British Petroleum and its predecessor company the Standard Oil Company of Ohio, 5 years at the well-known Wall Street research house Sanford C. Bernstein and 2 years at Julian Robertson's Tiger Management. Sam

[1] As of June 30,2018

has worked in the industry at Public Service of New Mexico and Questar as well as on Wall Street at Merrill Lynch and Wells Fargo and has testified before the Federal Energy Regulatory Commission on pipeline ratemaking policy.

EIP's original fund which started in 2003 has generated a double digit compounded annual growth rate that exceeds the returns of the S&P 500, the PHLX Utility Sector Index, the Alerian MLP Index and the NAREIT REIT Index over the same time period.[2] Such outperformance is rare as recent studies by Standard & Poor's have shown that, on average, about 94% of active fund managers have underperformed their benchmarks over the last 15 years.[3] We believe EIP's success in achieving these returns is a result of three main factors. The first is our long-term investment horizon, the second is our focus on investing in companies with stable and predictable earnings and the third is that EIP does not adhere to the typical asset allocation guardrails imposed on most money managers by institutional investors that would pigeonhole us into being either a "utility" manager or an "MLP" manager.

One of the tenets of EIP's approach is a focus on total or absolute investment returns rather than returns relative to index benchmarks. In assessing both past and forecasted returns, we disaggregate the portion of the investment return contributed by dividend yield from the portion of the return contributed by share price appreciation. Separating these two components is critical to understanding how we invest and what factors we seek in our portfolio companies to maximize our returns. The yield component of our returns is about 6%, the balance has come from appreciation of the underlying share prices.

While share prices fluctuate daily, the long-term driver of share price appreciation is growth in per-share earnings and dividends. For investment managers with a short investment horizon, these fluctuations are far more important to their strategy and approach. Since those short-term fluctuations are caused so often by transient factors in the news for the economy, an industry or a particular company, it is those short-term factors that most investment managers focus on. Watching most portfolio managers speak on television business programs provides a good window into this investing style.

The higher yield of our portfolio over time versus the stock market averages (the yield on the S&P 500 is currently 1.9%[4]) is mostly a result of a higher dividend payout ratio, which is the portion of a company's earnings paid to its shareholders each quarter. Higher payout ratios tend to be found in companies with more stable earnings and in slower-growing mature industries. Stability of earnings matter because dividends are viewed by investors a little like the coupon payment of a bond. A dividend cut is a broken promise and often indicates more serious problems at a company. As a result, company boards of directors strive to set dividends at a level they will never have to cut. The more stable the earnings, the higher the payout ratio can

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[2] Source: Bloomberg. The references to the performance of account is not representative of other EIP accounts that may not have experienced the same performance described above. Past performance is no guarantee of future results.
[3] Source: SPIVA ® U.S. Scorecard, S&P Global, Year-End 2017.
[4] Source: Bloomberg. Data as of July 3, 2018.

be. Slower growing industries also tend to have higher payout ratios because there are fewer growth opportunities requiring reinvestment of earnings.

We believe that pipelines and related storage as well as certain electric and natural gas utilities possess both of these attributes. Energy is a mature business (U.S. primary energy demand grows less than 1% per year[5]) and these businesses tend to operate under federal or state jurisdiction that earn allowed rates of return on their invested capital.[6] That means that they are less subject to the cycles of the economy, commodity prices or changes in the rate of inflation. Businesses that have these allowed rates of return are often referred to as Regulatory Asset Base businesses or RAB for short.

In the early history of the electric and natural gas industries, these regulated asset base businesses represented an alternative to public ownership. Today, the vast majority of electric and natural gas transportation infrastructure in the United States is owned by publicly traded corporations and publicly traded partnerships. By contrast, over 85% of water and sewer infrastructure is owned by municipalities and special government districts.[7] That U.S. energy consumers enjoy some of the lowest electricity and natural gas rates in the OECD is partially the result of an abundance of available capital to build and maintain energy infrastructure at reasonable cost, in our view. Again, by contrast, many municipal water systems are today reaching the end of their useful life and are increasingly being sold to investor-owned publicly traded utilities that can access the capital needed to modernize their pipes and related equipment without unduly increasing rates charged to consumers. Infrastructure assets have long—but not infinite—lives, and over time face stricter safety and environmental standards as well as ongoing technological evolution in the sources and uses of the products they transport that require constant reinvestment.

This RAB model in the U.S. traces its history back to a famous speech given by Sam Insull at the June 1898 (that's **eighteen**-ninety-eight) meeting of the National Electric Light Association, the forerunner of today's Edison Electric Institute. Insull had left the General Edison Electric Company (now General Electric) as Thomas Edison's right-hand man to head up what became Commonwealth Edison in Chicago. He was arguing for a regulated investor-owned utility framework that would benefit all stakeholders, including the customers buying the electricity during a time when the electric industry was in its "Wild West" infancy. Here's the essence of his message:

"Acute competition necessarily frightens the investor, and compels corporations to pay a very high price for capital....The best service at the lowest possible price can only be obtained....by exclusive control of a given territory being placed in the hands of one undertaking.....The more certain this protection is made, the lower the rate of interest and the lower the total cost of

[5] Sources: BP Statistical Review of World Energy: June 2018; U.S. Energy Information Administration (EIA)
[6] Sources: BP Statistical Review of World Energy: June 2018; U.S. Energy Information Administration (EIA).
[7] Source: American Water Investor Presentation: June 2018.

operation will be, and consequently the lower the price of the service to public and private users."[8]

Recognizing that regulation has since evolved to bring the benefits of competition to utility consumers, the essence of Insull's message remains as relevant today as it was 120 years ago; *that risk and cost of capital are highly correlated.* The regulatory framework under which pipelines and utilities operate reduces risk, takes advantage of scale, and is critical to achieving reliable, low cost service to customers, while providing reasonable and competitive returns to investors. The regulatory model articulated by Insull has resulted in an extensive U.S. energy infrastructure system that provides abundant energy to businesses and consumers at prices that are among the lowest in the developed world.[9]

The yield component of EIP's returns for its clients is a direct result of a regulatory framework that provides stable and more predictable earnings that allows for a payout ratio well above that for other industries or the stock market as a whole. As most of the investors in our funds and other investment products are individuals, this higher yield is a critical component of the investment return they are seeking.

Nonetheless, the growth component has been a larger contributor to our returns. At first glance it seems incongruous to have enjoyed growth in earnings and dividends from an industry whose unit demand grows at less than 1%.[10] There are two factors that explain the difference. The first is that unit demand growth of about 1% might still result in sales growth of 2-4% depending on the rate of inflation. This matches the average dividend growth over the last 15 years for the utility and MLP indices of about 4%.[11] The second factor is our successful stock selection as we have been able to identify companies with higher than average growth rates.

In assessing our own track record, we have found that higher growth rates result from our ability to select companies with good management teams operating under consistent and balanced regulation. If we can get these two parts right, a third component kicks in, which is a lowering of the company's cost of debt and equity financing also referenced in Insull's 1898 speech.

While we analyze financial statements and valuation like all other fund managers, our extreme focus on the quality of management is unusual among investment managers but consistent with our long-term approach. It is the management teams that determine where their competitive advantages lie and how to best allocate capital. It is the management teams that work with the regulators at the state and federal levels. It is the management teams that hire and retain the best employees. It is the management teams that determine the safety and environmental record of the company. All these activities determine a company's ability to deliver energy to its customers in

[8] Source: Insull, Samuel. "Standardization, Cost System of Rates, and Public Control" (1898). Reprinted in S. Insull, Central-Station Electric Service, 34–47. Chicago: Privately Printed, 1915.
[9] Based on electricity pricing data sourced from U.S. Energy Information Administration as of December 2017 and the European residential electricity prices sourced from Eurostat as of December 2017.
[10] BP Statistical Review of World Energy: June 2018; U.S. Energy Information Administration (EIA).
[11] Source: Bloomberg. MLPS are represented by the Alerian MLP Index. Utilities are represented by the PHLX Utility Sector Index.

an economical, safe, reliable and responsible manner. Companies that consistently do this well over time tend to have superior shareholder returns. Companies that give short shrift to issues of worker safety, system reliability and environmental stewardship also tend to be poor allocators of capital, have higher operating costs and usually have poor relationships with regulators and other stakeholders. They also tend to have lower shareholder returns.

Just as the quality of management teams varies, so does the tenor of regulation, so all else equal, we seek the best regulatory constructs that we can find. One recent success is reflected in a portfolio shift we made several years ago to increase our weighting in state-regulated natural gas utilities also known as Local Distribution Companies or LDCs.

The leak and tragic explosion of a natural gas utility pipeline in San Bruno, California in 2010 and a similar incident in New York City in 2014 led many state regulators to encourage the accelerated replacement of old pipe through the use of incentives and rate tracking mechanisms that added regulatory certainty, facilitating a step change in the pace of investment. This, in turn, has driven improved worker and public safety, system reliability and perhaps even a reduction in fugitive releases of methane, a potent greenhouse gas. Shareholders also benefitted from lower regulatory risk and higher rates of earnings and dividend growth, and as those higher growth rates were recognized in the market, these stocks traded at higher valuations. Those higher valuations reduce the cost of equity just as a higher credit rating lowers the cost of debt. Lower capital costs benefit consumers, who ultimately bear the cost of utility financing.

The case of accelerated pipe replacement for LDCs and the regulatory structures that enabled them at the state level are a great example of the Regulatory Asset Base regulated model working for all stakeholders.

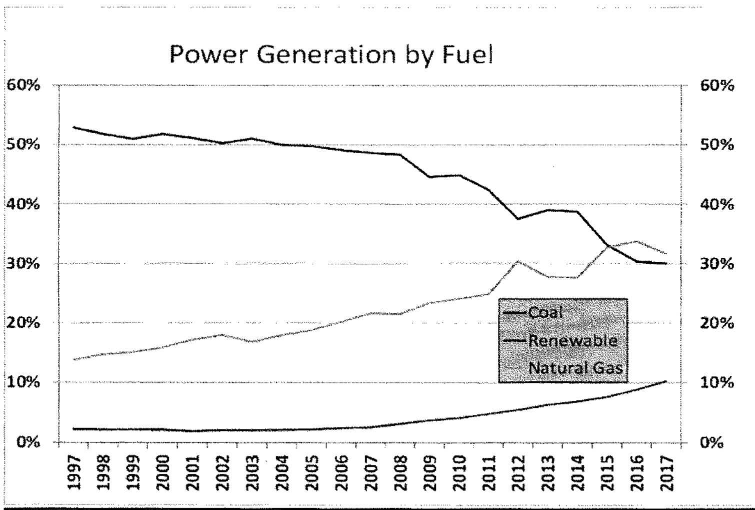
I once met a financial adviser who derided regulation as "a lot of red tape." My response was that so-called "red tape" consists of extensive public hearings, the consideration of all relevant testimony by regulators and oversight by an independent judiciary that insures that regulatory decisions have considered all the evidence and are arrived at by reasoned judgment and are therefore neither arbitrary nor capricious. This process, *so long as it follows established law and procedures*, protects all stakeholders including customers, the environment, as well as investors.

The 120-year history of these industries is also one of technological advancements that have driven lower costs, better worker and public safety, increased reliability and lower emissions of pollutants of all kinds. That holds true today as technological advances continue improving the performance and cost-effectiveness of renewable energy resources such as wind, solar, and energy storage the costs of which have declined about 70% over the last 8 years and have emerged as the most cost-effective source of new supply in many regions of the U.S.

Increased use of renewables, however, has actually been facilitated by another technological advancement: shale gas. The dramatically lower cost of natural gas has shifted electricity generation away from coal in favor of natural gas and increasingly, renewables. Contrary to the public debate pitting fossil fuels against renewables, natural gas and renewables actually complement each other because of the intermittent and variable output of wind and solar and the flexibility of gas-fired generation to respond quickly to the rapid changes in output from wind and solar that coal and nuclear generation lack. As battery costs decline, more of this back up function can be borne by storage of electricity in the future. But cleaner generation of electricity is *happening now* in large part because of the availability of cheap natural gas.

The graph in Exhibit 1 shows how electricity generated by natural gas and renewables has grown while generation from coal has declined. These changes have led to a 13.2%[12] decline in U.S. CO_2 emissions since their peak in 2005. Emission of other pollutants such as sulfur dioxide, nitrous oxides and mercury are also lower.[13]

Exhibit 1 – Electricity Generation: Coal, Natural Gas and Renewables



Sources: U.S. Energy Information Administration, Electric Power Monthly, February 2018.

Germany, by contrast, embarked on a bold strategy which accelerated in 2011 with Fukishima to eliminate nuclear power and fully embrace renewable wind and solar. While on a path to achievement, this initiative came at great cost to the country's electricity consumers as German residential electricity prices have risen nearly 45% in the past decade. Retail customers in Germany today pay about 35 cents per kilowatt hour vs around 13 cents in the U.S. and 22 cents for the rest of Europe.[14] Germany's initiative has had another almost surely unintended consequence; lacking access to abundant and reliable sources of natural gas as a back-up fuel for renewables, Germany continues to rely on lignite, a domestic but environmentally hostile fuel.

[12] Source: BP Statistical Review of World Energy: June 2018
[13] Source: US Environmental Protection Agency Website
[14] Eurostat, UBS Research, U.S. Energy Information Administration Electric Power Monthly, December 2017.

Since these goals were laid out in 2011, Germany's CO2 emissions have actually increased by 0.4% while over this same time frame the U.S. has lowered its CO2 emissions by 5.3%.[15]

It is in this context that we view the debate about the Greenhouse gas (GHG) impact of permitting new natural gas pipelines. To be direct, we view the debate as a false choice. When regulators and the courts are asked to address the impact of a particular new natural gas pipeline on GHGs, the discussion centers around considering the impact upstream of the pipeline (more natural gas production) and downstream of the pipeline (more natural gas usage). Missing from the discussion, in our view, is recognition that natural gas pipeline infrastructure enables natural gas to reduce coal usage, reducing power plant emissions of all kinds, including CO2 and further facilitates adding more renewables to the mix.

From a portfolio management perspective, we see uncertainty surrounding pipeline certification and approval as a growing risk that we must factor into how and where we allocate our investor's capital. These risks affect primarily the growth component of our returns but in the rare case of an existing pipeline being shut down, the impact could also affect the dividend payments of the company that owns that pipeline.

Perhaps more important than any changes we would make to the EIP portfolios are fund redemptions by investors as they see the cancellation of new pipeline projects due to objections by regulators as well as some of the recent rulings by FERC as risks that outweigh the rewards of a 6% portfolio yield. We believe that this flight of capital from the equity securities of companies that own federally regulated pipelines has had a negative effect on valuation and therefore a negative effect on the cost of capital for building new pipelines which is ultimately paid for by consumers.

As investors in a capital-intensive commodity industry we recognize that lower costs ultimately win out. And in our analysis, we include the costs of externalities like pollution and safety because under our system of government the cost of those externalities are eventually paid for by those who cause them. *In short, we want to own the low-cost way of shipping the lowest-cost form of energy.*

While natural gas pipelines are a significant part of our portfolio, so too are operators and developers of low cost renewable power, including a growing number of utilities that recognize the opportunity in aligning their strategy with the direction of public policy. In the future we expect to have a significant investment in companies providing infrastructure for electric vehicles as we see them as eventually being the low-cost, higher performance means of transportation.

We believe our investment success in the future will be directly impacted by policy makers' and regulators' ability to use our existing regulatory construct to facilitate rather than frustrate the increased adoption of these new technologies that improve the reliability, cost, safety and environmental impact of our domestic energy system. Because adoption of these new

[15] Source: BP Statistical Review of World Energy: June 2018

technologies cuts across industries and therefore the mandate of the relevant regulatory agencies, there is an important role to play for policy makers as well as regulators.

Our investors have benefitted from great management teams operating essential businesses under a consistent rule of law administered by regulation that balances consumer and investor interests to the benefit of all. We will continue to manage the allocation of the capital we are entrusted with to seek fair returns and minimize risk by investing in well-run companies operating under the guidance of balanced, reasoned and predictable regulation.

This concludes my testimony. Thank you for the opportunity to share my Firm's views on these very important issues.

The CHAIRMAN. Thank you, Mr. Murchie.

Mr. Hoecker, welcome.

STATEMENT OF HON. JAMES J. HOECKER, EXECUTIVE DIRECTOR AND COUNSEL, WIRES, AND SENIOR COUNSEL, HUSCH BLACKWELL LLP

Mr. HOECKER. Thank you and good morning, Chairman Murkowski, Senator King and members of the Committee. I'm Jim Hoecker. I'm here today on behalf of an organization called WIRES, that's a trade group that promotes investment in electric transmission in the U.S. and Canada.

Thank you very much for the opportunity to address the Committee about these current energy delivery issues that tend to fall within the jurisdiction of the FERC, an agency of which I was a member and Chairman three Administrations ago. I remain an advocate, however, for FERC's pro-market agenda. Moreover, I support its tradition of bipartisan and predictable regulation of these capital intensive industries and on that much and probably much more Joe Kelliher and I probably agree.

Energy policy works best when we work together and achieve results for consumers. Competition and markets have been the common threads in FERC's regulation for a generation now.

Now, as I noted in my prepared testimony and as Senator King mentioned, the means of producing and delivering natural gas and electricity have changed enormously in the intervening years. These industries will experience even greater change as the economy relies more and more heavily on electricity fueled increasingly by natural gas and renewables. There remain limits on where and how quickly we can build infrastructure, however, under current law and regulation which needs to catch up in some ways to the realities of today's interstate power marketplace.

WIRES commends the Committee, of course, for focusing on energy delivery networks today. That focus reinforces my belief that we are now ready to tackle the hard questions: Are we building the right facilities? Are we building them in a timely fashion? Are we responding in a proactive way to the potential of a more electrified economy and accommodating and incorporating new technologies? Now finally, are we fostering efficient development in order to create and add benefits for consumers?

I can see unequivocally that the private sector stands ready to make needed investments in the grid of the future, but challenges remain. Consumers will pay up to $4 billion in congestion costs annually, and a substantial share of all transmission facilities are at the end of their useful lives. In regions of the country and offshore where new clean energy resources abound, there is limited or nonexistent delivery capability.

Despite several years of work, FERC's Order 1000 has been unsuccessful in fostering transmission between and among regional markets. Permitting interstate electric transmission, moreover, remains a complex, protracted and costly process that goes on for a decade or more. In addition, we are reminded all too often of the costs of not hardening and modernizing the grid and transmission, I think, offers a fuel neutral solution to achieving grid resilience. Moreover, the transmission grid must be enabled to carry the vital task of integrating new distributed resources and technologies into the system for the benefit of consumers.

During all this, the industry continues an important quest for predictable and stable returns on its investments that are made and incentives to meet needed investments in the future.

As we move ahead, WIRES looks forward to working with this Committee and FERC to build the infrastructure that delivers the secure, reliable and low-cost energy that we all depend on.

Thank you for listening.

[The prepared statement of Mr. Hoecker follows:]

BEFORE THE COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

Hearing To Examine Interstate Delivery Networks for Natural Gas or Electricity
July 12, 2018

Testimony of James J. Hoecker
Executive Director and Counsel, WIRES
Senior Counsel, Husch Blackwell LLP
Former Chairman, FERC

Chairman Murkowski, Ranking Member Cantwell, and Members of the Committee –

I am Jim Hoecker, here today on behalf of WIRES. I thank you for the opportunity to address the Committee about the current electric transmission issues and the future state of our high voltage electric grid.

WIRES (www.wiresgroup.com) is a non-profit trade association with an international membership, dedicated to developing and providing information to policymakers and stakeholders about the benefits of investing in the network of wires, substations, and technologies and facilities that deliver large amounts of electricity for domestic, commercial, and industrial uses. Over the past decade, I believe our efforts have resulted in an appreciation for the value of the high-voltage grid and the need to continuously strengthen and modernize it. This Committee's focus on energy delivery networks today is commendable and it suggests to me that we must now move from understanding the importance of infrastructure to more difficult questions -- are we building the right facilities and are we building them in a timely fashion? Are we responding in a proactive way to the potential of a more electrified economy and accommodating and incorporating new technologies? Finally, are we fostering efficient development in order to create net benefits for consumers? To answer those questions, WIRES has sponsored or produced a battery of studies about the benefits of a more robust transmission system to help ensure that we meet the challenges of an economy that is destined to be much more highly electrified in the coming decades. A more extensive, highly integrated, upgraded transmission system is needed to meet the demands of the electrified future. The "challenges" that exist specific to transmission, and my focus this morning, include:

- A continued need to invest to replace aging facilities and reduce costly congestion still exists, despite significant investments of private capital in the past decade;
- A complex regulatory regime has made project authorization a protracted and inefficient process and has failed to produce effective regional and interregional project planning; and
- Even after a decade of desperately needed transmission investment, there is widespread misunderstanding of how transmission benefits consumers of electricity.

The "opportunities" for transmission to serve the public interest in new ways are equally great and deserve to be better understood. They include:

- Transmission's important function as an integrator of renewable resources and distributed technologies make additional investment critically important.
- Investing in a more robust transmission grid will make a major contribution to making the grid more resilient.
- Transmission investment must now be focused on the further electrification of the American economy, making forward-looking and pro-active transmission planning a necessity.

In support of this testimony, I attach for reference the comments that WIRES recently filed at the Federal Energy Regulatory Commission ("FERC") about why transmission investment is critical to the resilience of our electric system (Appendix A) and a recent paper addressing perceptions about the need for, and the value of, continued transmission investment (Appendix B). Appendix C is a graphic comparison of the services provided by transmission and those provided by distributed technologies, demand response, and other localized solutions, demonstrating that transmission is a necessary complement to support these technologies.

Today's Grid Challenges.

The level of transmission investment in recent years essentially made up for a quarter century of underinvestment, replaced aging facilities (some nearing a century old), and addressed short term reliability issues. Industry and policy makers should not rest easy, however. Continued investment is not optional if we are to meet challenges of an electrifying economy, install modern digital technologies, deploy and serve more distributed resources, enhance regional and interregional energy markets, lower electricity prices for consumers (now a declining share of the cost of living virtually everywhere), and strengthen the grid against physical, cyber, and natural disruptions. Many systems still operate with old and inefficient technologies that invite reliability problems and poor transfer capabilities. Consequently, consumers still pay $4 billion in congestion costs each year in organized markets alone, even though congestion costs on the grid have been halved.[1] Although old facilities have been replaced or upgraded at an unprecedented pace in the last decade (about $15-20 billion annually), many of the transmission systems we still rely on today were designed and built from the late 1940s to the 1970s. They have reached or exceeded their useful lives and replacing those assets will cost nearly $60 billion in the next five years alone.[2] Moreover, transmission facilities are often inadequate or non-existent in regions that have enormous potential to produce low-carbon, highly cost-competitive renewable energy resources and natural gas generation.

These challenges are surmountable but the task has proven difficult. Indeed, no energy delivery system is more deliberately planned, regulated and overseen at more levels of government or more subject to debate than the transmission grid. The reasons for this are partly historical; we are building an integrated, regional, and multi-state network at the intersection of local, state, and federal regulatory jurisdictions. I believe Congress recognized the problems that created back in 2005, recognizing the national interest in a multi-state, multi-regional transmission grid, particularly one that could bring location-constrained renewable resources to major load centers. We nevertheless still face these challenges today. The more important and extensive a proposed transmission project is, the more likely

[1] Gramlich, Rob, "*Bringing the Grid to Life: White Paper on the Benefits to Customers of Transmission Management Technologies,*" (March 2018).

[2] Pfeifenberger, Hannes, Chang, Judy, and Tsoukalis, John, *"Investment Trends and Fundamentals in US Transmission and Electricity Infrastructure,"* (July 2015); Freedman, Mark, Anderson, Norman, Hill, Jeff, Acosta, Daniel, and Ferrer, Santiago, *"Maximizing the Job Creation Impact of $1 Trillion in Infrastructure Investment,"* (March 2017).

that affected states will fall into prolonged disagreement about who benefits and how the public interest should be served. It's an old story with few solutions and a considerable amount of uncertainty. For example, FERC's Order No. 1000 sought to address these issues and placed the issue of interregional transmission planning on the table for discussion. Unfortunately, Order No. 1000 did not suggest a workable path forward beyond the need to establish regional planning processes.

Another challenge is protracted transmission development cycles. Compared to the 3-4 years needed to permit and construct natural gas pipelines, the planning, siting, permitting, and construction of transmission lines frequently require a decade or more. Environmental reviews are a part of the problem, in my estimation, not because of the complex resources they legitimately protect but because they are largely uncoordinated in their procedures, regulatory authorities, and timelines.

Additionally, an important consideration surrounding any investment in infrastructure is its cost. Coming after a quarter century of underinvestment when the nation invested next to nothing in the grid, the new investment cycle was needed and undertaken. Despite the new round of grid investment that corrected what was proving to be a hazardous course, transmission still remains the smallest component of electricity bills on average (10-12%), while the overall cost of electricity continues to fall. Critics have characterized transmission costs as "exploding" in the Western U.S., in the context of recent collaborative efforts in that region to greatly expand and integrate energy markets. But this is only half the story, as these developments have led directly to regional economies of scale, more competition, and efficiency in delivering energy from remote parts of the West. Among the most significant benefits of transmission in this modern era are, and will continue to be, delivery of cost-competitive resources – including renewable resources, energy storage, and new technologies -- that will save consumers money, enhance reliability, and help reduce emissions regionally. Given that generation costs are a significant component of electricity bills, the net benefits to consumers will dwarf transmission costs in the short run and especially over time.[3] In fact, a robust transmission system will be a platform upon which even

[3] Several studies support this contention. The Southwest Power Pool ("SPP") concluded in its paper *The Value of Transmission* that a group of major transmission investments in that region between 2012 and 2014 would yield $12

neighborhood distributed resources can participate in the competitive electricity market.

Today's Grid Opportunities

Transmission gives us the optionality to adapt to whatever the future holds, and a modern and resilient transmission system will be the most valuable energy asset we have. Indeed, the decentralization of electric generation resources and the new technologies do not spell the end of the wired network of transmission lines. Those resources and technologies will depend more than ever on the grid for their economic justification and deployment. In an effort to learn more about the economic and operational relationship between transmission and new technologies like energy storage, demand response, and distributed and utility-scale generation (known collectively as "market resource alternatives"), WIRES sponsored a study[4] which remains state-of-the-art. It shows the complementarity of transmission and emerging technologies. In most cases the two work together to provide net consumer benefits. Put another way, each technology is capable of providing specific services, and transmission is capable of providing virtually all services.[5] As new technologies grow and become cost-competitive, they too will depend on the grid for market access.

The high-voltage grid must also be storm- hardened and modernized for an environment that can be hostile to our electrified society. In WIRES' recent comments to FERC in its consideration of grid resilience issues, WIRES argued that the Commission must be proactive in this area, given that its jurisdiction over transmission planning is far more extensive than that for generation and fuel supplies. We made several specific proposals, which the Commission is currently evaluating along with the

billion in net present value benefits to consumers over 40 years and a 3.5:1 benefit to cost ratio. *"The Value of Transmission,"* A Report by Southwest Power Pool (January 2016). Similarly, the Midcontinent Independent System Operator, another regional grid manager whose territory spans much of the central U.S. and Canada, analyzed several current grid upgrades and found net consumer benefits ranging from 2.2 -3.4:1. MTEP17 MVP Triennial Review, *"A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio,"* produced by Midcontinent Independent System Operator (September 2017).

[4] London Economics International (Frayer and Wang), *Market Resource Alternatives: An Examination of New Technologies in the Electric Transmission Planning Process*, produced for WIRES (October 2014).

[5] "We observe that individual MRAs are generally not capable of providing all of the same services that transmission provides for the same tenure and geographical dimension. With the exception of utility-scale generation in limited circumstances, no single MRA is a workable substitute for transmission. *Id.*, at p. 12. *See* Appendix C for a graphic representation of these services from the study.

comments of many others. To distill it down, we recommended that (1) the Commission make decisions about the extent to which resilience is deliberately planned for; (2) generic transmission planning principles include the objective of a more resilient grid; (3) the Commission should take a fresh look at its authority to plan for resilience; and (4) clarify the responsibilities of regional planners.[6]

In sum, WIRES urged FERC to consider that viable markets supported by robust energy delivery networks are at least as capable of strong and flexible responses to natural events and man-made assaults against our energy economy as other solutions that have been proposed.

Finally, WIRES wants to draw your attention to the (increasingly likely) prospect that the electricity industry will escape the prevailing paradigm of anemic utility sales growth. Flat demand for electric power is a product of a number of factors, most notably the progress in photovoltaic solar development and energy efficiency.[7] Under new laws and technologies, consumers can often choose to self-generate and reduce their demand for utility services. This tends to depress demand growth but it may also mask another transformational change that will afford transmission additional opportunities. In its recent paper, The Brattle Group projects a doubling of electricity demand by 2050 if transportation and heating were to become largely electric. Growing demand for electric vehicles, the declining cost of renewable generation, a potential imperative to reduce carbon in the atmosphere, improvements in battery technology, and other developments already call into question current supply and demand

[6] Comments of WIRES, *Grid Resilience in Regional Transmission Organizations and Independent System Operators* (Docket No. AD18-7-000), May 9, 2018. These comments were accompanied by a study from The Brattle Group, *Recognizing the Role of Transmission In Electric System Resilience,* which stated that "[t]he power system can be vulnerable to disruptions originating at multiple levels, including events where a significant number of generating units experience unexpected outages. The transmission system provides an effective bulwark against threats to the generation fleet through the diversification of resources and multiple pathways for power to flow to distribution systems and ultimately customers. By providing customers access to generation resources with diverse geography, technology, and fuel sources, the transmission network buffers customers against extreme weather events that affect a specific geographic location or some external phenomenon (unavailability of fuel and physical or cyber-attacks) that affect only a portion of the generating units." At p. 3

[7] The National Renewable Energy Laboratory ("NREL") hypothesizes that PV generation could comprise 30 percent of projected 2050 consumption, depressing annual demand growth to 1.0 percent or less for the indefinite future. On the other hand, analysts also think that NREL's estimate of PV's potential is "unlikely" and "even if achieved utility sales of electricity would still represent over 60 percent of electricity production. A future without utility scale electricity production and, perhaps more importantly, without transmission and distribution network connecting centralized generation with load, is therefore very unlikely." The Brattle Group, *Electrification: Emerging Opportunities for Utility Growth*, January 2017, at p. 3-4.

assumptions. The requirements of intermittent nature of both distributed resources near load centers and utility scale renewable generation in low-cost regions of the country will make the transmission network a valuable infrastructure with which to diversify resources and reduce the cost of integrating and dispatching those resources. This is the "electrification" scenario, now so widely talked about and studied. WIRES plans to embark on a major study this year to better understand and define how this delivery network must be configured and planned in anticipation of this potential transformation in how we use electrical energy.

To conclude, WIRES believes it is necessary to take proactive steps to achieve the policy and regulatory certainty that will support needed transmission investment. We must look beyond the debates that have surrounded implementation of Order No. 1000, and instead build on the positive achievements of the last two decades and act pursuant to the larger trends that are shaping our electric system and the larger economy. As the mix of electric generation resources continues to change, as the economy becomes more electrified, and as new technologies seek their place in the energy system, transmission is the common element that will support all future needs and provide a hedge against uncertainties and potential costly outcomes. The time is now to be proactive in encouraging additional investments in our nation's most crucial infrastructure: the electric transmission system.

Thank you for this opportunity.

APPENDIX A

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Grid Resilience in Regional Transmission Organizations and Independent System Operators	)))	**Docket No. AD18-7-000**

COMMENTS OF WIRES

WIRES[1] respectfully submits the following comments in response to the January 8, 2018 *Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures* issued by the Federal Energy Regulatory Commission ("FERC" or "Commission") in the above-captioned docket.

WIRES strongly supports the Commission's efforts to ensure increased resilience of the electric power system, including its rejection on policy and legal grounds of the Secretary of Energy's proposal to provide out-of-market relief for certain sources of electric generation.[2] WIRES believes grid resilience will only increase in importance as the economy continues to become more dependent on reliable electric power. At the same time, cyber and physical threats, as well as natural events of unparalleled ferocity and unpredictability pose new challenges to our increasingly electrified economy. Since electric power disruptions are most likely to arise through the disruption of distribution and transmission systems, the Commission's determination to help achieve greater resilience in bulk electricity markets must focus on the key role of critical transmission infrastructure in supporting overall system resilience. In fact, it is particularly appropriate and important that the Commission re-focus this resilience proceeding on the planning, financial support for, and development of electric transmission because the

[1] WIRES is an international non-profit trade association of investor-, publicly-, and cooperatively-owned transmission providers, transmission customers, regional grid managers, and equipment and service companies. WIRES promotes investment in electric transmission and progressive state and federal policies that advance energy markets, economic efficiency, and consumer and environmental benefits through development of electric power infrastructure. For more information, visit www.wiresgroup.com.

[2] Grid Resiliency Pricing Rule, 82 Fed. Reg. 46940 (proposed October 10, 2017) (to be codified at 18 C.F.R. pt. 35).

interstate high-voltage grid is more squarely within its plenary jurisdiction[3] and responsibilities than is resource adequacy at the generation level, notwithstanding the importance of addressing fuel supply problems that threaten generation reliability. Specifically, WIRES believes that proactive transmission planning must be made more integral to any resilience strategy, just as resilience must be a strong component of transmission planning. To that end, WIRES recommends Commission action in the following areas:

- In assessing how to move forward in the area of grid resilience, especially as it pertains to the role of more robust transmission infrastructure, the Commission should swiftly and aggressively evaluate the extent to which RTOs and ISOs should be obligated to integrate (or to demonstrate that they have integrated) resilience planning into their regional and interregional transmission planning processes.[4] Each region should be afforded flexibility to implement such integration in a manner that reflects the characteristics of that region, subject to oversight of the Commission.

- The Commission should update its Order No. 890 transmission planning principles to include resilience as a separate and distinct planning driver for RTOs and ISOs.

- The Commission should clarify that it has authority under the Federal Power Act to include resilience in its lawful transmission planning regime, similar to its authority to promote reliable operation of the Bulk Electric System (BES).

- FERC should also clarify that regional planning responsibilities of RTOs and ISOs include planning for resilience, especially in WIRES' view the prevention or mitigation of loss or disruption of critical transmission infrastructure and its services.

In support of these recommendations, WIRES respectfully submits the following Comments and the appended paper on transmission and resilience written by economists and utility analysts at The Brattle Group, entitled *Recognizing the Role of Transmission in Electric System Resilience.*

[3] *New York v. FERC*, 534 U.S. 1, 16-17, 19-20 (2001); *S. Carolina Pub. Service Authority v. FERC*, 762 F.3d 41 (D.C. Cir. 2015).

[4] *E.g.,* "[T]he Commission should articulate in this docket that the regional planning responsibilities of RTOs include an obligation to assess resilience. After confirming that resilience is a component of such planning, the Commission should also consider initiating rulemakings or other proceedings to further articulate the role of RTOs in resilience planning to include, among other things, thresholds to mitigate and build." Comments and Responses of PJM Interconnection, L.L.C., (PJM Comments) at p. 81.

I. Defining Resilience to Incorporate Transmission Network Considerations

A. Grid Resilience Has Many Components

The Commission's goals in this proceeding are to (1) develop a common understanding or definition of resilience, (2) determine how each ISO and RTO assesses resilience in its footprint, and (3) ascertain whether the Commission ought to take action in furtherance of a more resilient grid, based on the information submitted herein. In WIRES' view, resilience as generally defined[5] entails the identification and mitigation of vulnerabilities and threats to the system, plus the ability to absorb, adapt to, and recover from disruptive events as they occur. There is a critically important human resource and coordination component to resilience as well. Resilience is distinguishable from reliability in the sense that a reliable system may not be resilient, and resilience does not ensure that lights stay on day-to-day. Fundamentally, resilience focuses on low-frequency, high-impact disruptions; however, the Commission is cautioned not to unduly limit the category of system vulnerabilities or potential impacts for which it might require planning, preparation, or recovery measures, recognizing that the frequency and extreme impact (in economic, environmental, or human terms) of events and developments that are unprecedented or occur without warning can be difficult to predict.

Commenters in this proceeding offer several similar definitions of resilience. Whichever the Commission concludes will help it support strengthening of the grid, there is no silver bullet for achieving an optimally resilient electric system. Industry and the Commission must plan for the unforeseeable by taking into account the various processes, practices, and investments that could contribute to preventing or effectively resolving the effects of system disruptions without undue delay. Most RTO/ISO comments focus on what has been called "precaution-based

[5] Resilience is defined by the DOE and the National Infrastructure Advisory Council ("NAIC") as the ability to reduce the magnitude and/or duration of disruptive events, including physical changes to infrastructure known as "hardening." Reliability is defined by the North American Electric Reliability Corporation ("NERC") as a function of adequacy, which is the ability of the system to supply aggregate electric power and energy at all times. *See* U.S. Department of Energy, *Staff Report to the Secretary on Electricity Markets and Reliability*, August 2017, at pp. 61-63 ("*DOE Staff Report*") *See also*, the important consensus study report of The National Academy of Sciences, *Enhancing the Resilience of the Nation's Electricity System* (2017), which takes a comprehensive view of grid resilience, offers a series of practical recommendations in moving toward a more resilient grid, and recognizes the importance of involving state and regional grid operators, emergency preparedness organizations, and national and state regulators. (https://doi.org/10.17226/24836.) For a description of NERC's enterprise activities that support the NAIC outcome-focused framework for addressing resilience challenges, see Mark Lauby, "Resilience Framework", WIRES Winter Meeting, at http://wiresgroup.com/docs/WIRES%20Winter%20Mtg%202018%20Lauby.pdf

strategies" to advance resilience, meaning identifying vulnerabilities and employing industry best practices to thwart or mitigate the economic or adverse health effects of potential power disruption, and "discourse-based strategies" that raise awareness, share information, and initiate collective action.[6] On the whole, the recommended solutions involve operational flexibility and coordination, improving generation services, and market reforms.[7] In WIRES' view, these precautionary, coordination, and mitigation strategies must also focus directly on infrastructure investment solutions. Most disruptions of consumers' access to electricity occur at the distribution level[8] but are a distinguishable resilience challenge from disruptions of the high-voltage transmission service which, while quite infrequent, can result in widespread and possibly prolonged power outages and resulting damage. The transmission system must therefore be prepared to withstand disruptions and to mitigate the potentially broad or severe consequences that flow from severe weather, physical attack, or disruption of generation supplies or system operations. In such cases, the resilience that a robust and integrated transmission network provides is of critical importance.

Regional power markets, grid infrastructures, and operating circumstances differ but, as a rule, generation and fuel supply policies offer only a limited hedge against potential disruption. Moreover, while distributed resources are important for rapid recovery, they are of limited long-term capability without the grid's transfer capabilities.[9] A robust grid offers resource diversity and operational flexibility that is critically important to both prevent and recover from service disruptions. Transmission investment ensures system stability and productivity during normal operations and optionality when disruption strikes. New investments in transmission expansion and upgrades that reflect deliberate consideration of the benefits of this optionality will add

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[6] PJM *Comments* at p. 14 *et seq.*

[7] On the operations side, transmission owners and operators manage and operate key resilience and reliability measures, including emergency drills, spare parts inventories, mutual assistance, long-term system planning, routine monitoring, operation scheduling, dispatch and maintenance, and system restoration and recovery. Silverstein, "Transmission and power system resiliency," presented at WIRES Winter Meeting, at http://wiresgroup.com/docs/WIRES%20Winter%20Mtg%202018%20Silverstein.pdf

[8] According to the Department of Energy's *Quadrennial Energy Review* (2017), failures on the distribution system are typically responsible for more than 90 percent of electric power interruptions, both in terms of the duration and frequency of outages. Such interruptions of service, while unpleasant, are relatively routine, often predictable, and typically of short duration. *See* the appended study by The Brattle Group (Chupka and Donohoo-Vallett), *Recognizing the Role of Transmission in Electric System Resilience*, prepared for WIRES (May 9, 2018), at p. 7.

[9] *See* London Economic International, *Market Resource Alternatives: An Examination of New Technologies in the Electric Transmission Planning Process*, a Report for WIRES (October 2014) available at www.wiresgroup.com

immeasurably to system reliability and resilience. Conversely, an inadequate network of transmission facilities left unprepared and not fully modernized to ensure resilience against threats to system stability and operations will increase the risk of greater and more prolonged economic losses from unanticipated events.[10] To the extent resilience is predicated on having multiple ways to respond effectively to adverse events and developments not yet foreseen, or perhaps not foreseeable, a robust transmission network that affords operators the ability to marshal diverse resources may be the best investment compared to even fuel-secure generation resources.

WIRES' recognizes that a variety of measures will contribute to making the electric system more resilient, including access to diverse sources of electric generation, essential ancillary services such as frequency and voltage support, resource flexibility in the form of storage and other new technologies, storm hardening of infrastructure, mutual assistance programs, and reliable supplies of fuels like natural gas as well as long-term plan to address the vulnerability of substations and transmission system to high impact, disruptive events. It expects the Commission will receive numerous thoughtful comments in this proceeding.

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[10] The vulnerabilities of specific grid components demonstrates the risks of inadequate transmission: For example, substations and transmission systems are critical to get power from generators to load, so increasing the resilience of the transmission system is just as important as improving the resilience of supply resources. A generator with sufficient fuel supplies cannot contribute to increased reliability and system resilience if the congested transmission system prevents it from delivering its energy. As the generation and fuel mix in regional markets changes and evolves, and as climate and technological disruptions pose new challenges to the grid, another cycle of transmission expansions and upgrades will be a top priority.

Second, measures that ensure protection of the transmission system from potential physical or cyber intrusion provide more consequential risk mitigation than the concerns about the unavailability of on-site fuel. Damage to transmission and distribution structures and substations can take weeks to repair, even assuming replacement parts are available.

Third, some parts of the transmission system are extremely over-used, potentially leading to severe operational constraints that make it vulnerable to outages of individual elements. Transmission planning predicated on establishing a more flexible and more liquid bulk electricity markets would result in at least as great an enhancement to reliability and resilience of the electric system as any other major investment. The CEO of the North American Electric Reliability Corporation ("NERC") acknowledged as much when describing the most pressing reliability issues in North America. In a letter to the Secretary of Energy, cited in the DOE Staff Report, the NERC CEO made clear that electric transmission is one of the critical methods of addressing reliability concerns in a more decentralized electric system environment where generation is also being retired, when he stated: "Because the system was designed with large, central station generation as the primary source of electricity, significant amounts of new transmission may be needed to support renewable resources located far from load centers.." *DOE Staff Report*, at pp. 62-63.

Recommendations for action may vary widely depending on local and regional risks and conditions. That said, WIRES maintains that robust transmission facilities and interconnections will be essential to mitigating risks faced by virtually any electric power system.

The RTO/ISO responses in this proceeding generally emphasize the need for timely operational responses to disruptions. However, they acknowledge that resilience will also be measured by the robustness of the physical infrastructure and its inherent ability – as an integrated network -- to withstand shocks or absorb them and still provide operators with options for bringing additional generation and technological resources to bear on a problem. The existence of alternative supplies of energy and the means to deliver them through transmission, the grid's inherent flexibility, and broader access to an assortment of technologies – from storage to microgrids, demand response, and other distributed resources – are the essential characteristics of a fully developed and integrated wired network.

B. The Benefits of Transmission Should Be Central to This Proceeding

The multiple benefits of electric transmission investments are well-documented. The blackouts of the 1960s (e.g., in New York City) triggered the expansion of regional transmission interconnections such that neighboring regions could assist each other under adverse circumstances. A number of studies have found that expansion and integration of transmission links today would provide additional benefits due to the diversity of loads and resources and the dispatchability of new technologies.[11] These studies support the proposition that the U.S. is not investing in enough transmission infrastructure, particularly transmission designed to deploy new technologies or interregional transmission, to ensure that all customers have access to lower cost energy resources and that wholesale energy markets can discipline electricity prices.[12] In fact, the 2017 DOE Staff Report acknowledges that the flexibility and resource

[11] The results of several U.S. and European analyses of the benefits of diverse kinds of transmission projects are summarized in The Brattle Group, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning Is Key To The Transition To A Carbon-Constrained Future*, June 2016 ("Brattle 2016 Study"), Section III, at pp. 6 – 11. Domestic studies by the Southwest Power Pool, the Midcontinent ISO, the Eastern Interconnection States Planning Council, the Eastern Interconnection Planning Collaborative, and the Western Electricity Coordinating Council show that forward-looking planning of regional and interregional transmission that takes into account the range of benefits of transmission results in substantial net benefits to consumers, the economy, and the environment.

[12] Interregional transmission planning is still in its infancy and, despite the call for it in Order No. 1000, interregional projects are not developing as expected or as needed. Improving interregional planning and expanding interregional interties would provide a unique opportunity to improve the resilience of the nation's grid. *See also*, The Brattle Group, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of An Insufficiently Flexible Electricity Grid*, April 2015 ("Brattle 2015 Study");

integration benefits provided by transmission contribute to both resilience and consumer savings:

> Transmission investments provide an array of benefits that include providing reliable electricity service to customers, relieving congestion, facilitating robust wholesale market competition, enabling a diverse and changing energy portfolio, and *mitigating damage and limiting customer outages (resilience) during adverse conditions.* Well-planned transmission investments also reduce total costs. . . .
>
> A robust transmission system is needed to provide the flexibility that will enable the modern electric system to operate. Although much transmission has been built to enhance reliability and meet customer needs, continued investment and development will be needed to provide that flexibility.[13]

C. The Special Insurance Value of Robust Grid Infrastructure

Transmission provides a significant measure of insurance against risks associated with future uncertainties.[14] For instance, regardless of how fast load grows or precisely how much renewable generation is built in one location versus another, a robust transmission grid facilitates the delivery of low-cost electricity. Such insurance comes with widening options for the future, which in turn will be very valuable as both federal and state policymakers consider a variety of possible strategies for meeting future energy needs,

The industry (through NERC reliability standards) has been improving reliability-based planning of the transmission grid. Planning to meet immediate reliability objectives differs from economics-driven planning or planning transmission to meet public policy goals. In 2015, a study written for WIRES by The Brattle Group discussed extensively the "insurance value" of a more robust transmission grid from an economic planning perspective.[15] Economic transmission planning should be modified to ensure consideration of this insurance value against economic disruptions caused or exacerbated by insufficient transmission. If transmission planning were to include serious consideration of the long-term benefits of a more

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The Brattle Group, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investment,* July 2013; *Also,* Southwest Power Pool, *Benefit Metrics Manual*, May 8, 2017. All are available at www.wiresgroup.com.

[13] DOE Staff Report, at p. 75 (emphasis added).

[14] For further discussion of transmission planning as a risk mitigation tool, *see* the appended study by The Brattle Group, *Recognizing the Role of Transmission in Electric System Resilience*, at pp. 16-19.

[15] Brattle 2015 Study, at pp. 17, 36-37, 40.

resilient regional and interregional grid, such an improvement would likely produce significant reliability and resilience benefits that would dwarf the benefits of prolonging the operation of power plants that the market has already determined are uneconomic and excessively costly to operate.

II. SPECIFIC COMMENTS AND RECOMMENDATIONS

A. Holistic Transmission Planning Supports Resilience

In a 2015 study for WIRES, The Brattle Group delineated the benefits of holistic and anticipatory transmission planning:

> One of the most strategically significant aspects of major new transmission projects that is seldom taken into account explicitly in the planning phase is the multiple purposes that transmission might serve. That is, a well-designed transmission system enhancement will not only enable the reliable transfer of electricity from Point A to Point B—it will also strengthen and increase the flexibility of the overall transmission network. Stronger and more flexible networks in turn, create real options to use the transmission system in ways that were not originally envisioned.[16]

Consistent with Brattle's findings, WIRES has long advocated for transmission planning that seeks to evaluate and capture the full range of potential benefits of proposed projects. Resilience is another such driver, but RTOs and ISOs are under no current obligation to conduct the kind of risk-based analyses that commenters are developing in this and other proceedings. In general, the current practice of focusing almost exclusively on reliability needs tends to steer policymakers and regulators away from regional and interregional transmission planning approaches that can reduce risks and long-term customer costs. Planning for reliability is a well-understood first resort because the benefits are near term and quantifiable. Beyond the important task of hardening local systems, developing infrastructure, and instituting practices that ensure resilience present a different set of planning problems because risks differ among locales and regions and across time. Identifying system vulnerabilities is a first step.

However defined, grid resilience entails "hardening" the larger, interconnected system against low-frequency, high-impact (and potentially high cost) threats and configuring that system to prevent or reduce disruptions. Planners are always faced with uncertainty, but making the grid more resilient requires them to discern potential risks and clear trends

[16] *Brattle 2015 Study*, at p. 5. Economists at the Brattle Group strengthen that point in the paper appended to these Comments.

surrounding major threats, and to try to understand these uncertainties in terms of their potential magnitude and timing. If transmission infrastructure can be more proactively-planned, policy makers, operators, and customers will ultimately have a much wider range of valuable options with which to cope with future challenges. They will be able to choose among those options with lower risks and costs. Ensuring, for example, that major load centers are served flexibly by diverse kinds of resources that are accessible through several major and possibly redundant delivery paths is critical insurance against extended disruptions and escalating consumer costs.

B. New Approaches to Planning Infrastructure for Resilience

As noted earlier, while resilience is closely related to a traditional conception of reliability, it is also fundamentally unique because it seeks to achieve a different end state – namely, a power grid that can withstand or quickly recover from low-frequency, high-impact events, and one in which key system vulnerabilities have been considered and mitigated. Efforts to proactively plan the transmission grid to be more resilient will require consideration of a unique set of parameters and criteria. Broadly conceived, transmission planners seeking to bolster resilience must: 1) conduct an assessment of system vulnerabilities, 2) evaluate a set of low-frequency, high-impact events and model their impacts on the system, and 3) develop criteria to evaluate mitigation strategies to address the identified vulnerabilities. Complicating matters, resilience planning can be evaluated by traditional benefit-cost analysis only when the potential threat is identified; however, it is difficult to identify low probability threats or to assess the likelihood of such potential threats.

To be clear, current forms of transmission planning may have the "side effect" of promoting resilience because transmission, by its very nature, is integral to the successful delivery of power from generation to load. However, existing transmission planning drivers (reliability, economics, and public policy) are not necessarily designed or intended to provide a basis for addressing resilience as a primary rationale for investment. Thus, today's processes may not result in the desired end state – a more resilient power delivery system. To remedy this, WIRES believes that resilience must now be expressly considered as a transmission planning driver, to be studied and incorporated within any regional and interregional RTO planning process. RTOs and ISOs should report annually on the extreme events considered in their specific resilience-focused scenarios and on the actions, if any, arising from their review of the grid's performance and resilient characteristics.

WIRES notes that, in answering the Commission's request, the RTOs and ISO's have offered a range of views on how, or whether, resilience is currently being addressed within each of their regions. Like these commenters, WIRES acknowledges the importance of efficient operations, better monitoring and control technology, physical interconnectedness between systems, and trained personnel[17] in promoting resilience. PJM notes in its comments that resilience is related to reliability, but it also affirms the distinctive nature of resilience. PJM also recognizes the crucial role that transmission planning plays in ensuring resilience.[18] On both counts, WIRES agrees. By contrast, other regions largely confine their responses to a description of existing processes, and thus do not fully address resilience or its implications for transmission planning. ISO-New England, meanwhile, focuses largely on fuel security, an important issue in its own right (especially in that region) but only one part of a comprehensive approach to resilience.

WIRES contends that RTOs and ISOs should play a central role in addressing resilience through transmission-focused solutions, as part of a broader resilience strategy. Of course, utility efforts to harden systems, replace aging infrastructure, and coordinate operations offer clear resilience benefits and should be recognized in any policy actions taken by the Commission.[19] However, as regional transmission planners and operators, RTOs and ISOs are well-placed to identify regional vulnerabilities and consider mitigation strategies as part of their regional transmission planning processes.[20] In fact, effective transmission planning can be the

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[17] These strategic components of resilience are exemplified by the recent observation by Admiral Jim Eckelberger , Board Chairman of the Southwest Power Pool, to the effect that an RTO must look externally, not just internally, for the ingredients of real resilience – stating that SPP's interconnection to ERCOT is "next to zilch", to the West it is "good but not great", and to the east the interconnections "has been almost academic, as opposed to real." FERC ought to study "much more about how can neighbors help neighbors. It's part of the deficiency of our national system, and it ought to be highlighted." Quoted in *Megawatt Daily, FERC Resiliency Effort Needs Broader Coordination Study: SPP Stakeholders*, at p. 4, Feb. 26, 2018.

[18] "PJM is actively evaluating how to incorporate resilience into the planning process, including discussions regarding (a) making sure that system changes done as part of the Regional Transmission Expansion Plan do not make the [Bulk Electric System} less resilient, (b) developing procedures to compare solution alternatives and ensure selection of the alternative that enhances resilience, and (c) developing resilience criteria where the system has vulnerabilities that require mitigation. . . .To be clear, RTO resilience planning not only includes traditional transmission planning, but also an enhanced role in guiding regional restoration planning efforts." PJM Comments, at p. 33.

[19] Individual utilities have an important role to play in ensuring resilience, as these utilities constitute the first line of defense against potential threats.

[20] Increasingly, RTOs utilize scenario planning in anticipation of possible developments 10 to 15 years (or more) in the future. Those needs may include differences in locations and rates of load growth, different locations and rates of renewable generation, and thermal generation retirements. These changes involve determining the long term needs for transmission expansions and upgrades in anticipation. *See, e.g., Joint Comments of the Electric Reliability Council of Texas, Inc. and the Public Utility Commission of Texas*, at p. 9. ("Comments of ERCOT and PUCT").

most critical element of ensuring system resilience. For example, as part of its scenario planning to correct reliability criteria violations, ERCOT develops a corrective action plan that "typically involves building new transmission facilities."[21] Planning for resilience should likewise incorporate transmission solutions. As stated by the PJM Interconnection, "System resilience should be a consideration in the evaluation of planning solution alternatives so that PJM can select solutions that enhance the resilience of the system and address other system needs. Furthermore, resilience vulnerabilities that are significant enough to warrant a transmission system enhancement designed specifically to mitigate the resilience vulnerability could be designed and integrated into the (Regional Transmission Expansion Plan]."[22]

In short, WIRES advocates for further action to ensure that planning processes exist that will directly address grid resilience. WIRES respectfully requests the Commission to do the following:

- First, the range and complexity of resilience issues argue for extending this Commission proceeding in order to consider generic enhancements to the RTO/ISO transmission planning processes established under the Commission's authority to ensure that strong and cost-effective grid infrastructure is a principal tool for anticipating and mitigating the risks and heavy costs that disruption of bulk power markets could impose on the health and economic welfare of the American public. In WIRES' view, grid resilience can only be ensured if regional and interregional transmission enhancements are part of the solution. The Commission should examine whether, in pursuit of a more resilient grid, it should require RTOs and ISOs to integrate (or demonstrate that they have integrated) resilience planning into their regional and interregional transmission planning processes. While planning for resilience necessarily entails coordination and facilities expansion across regions and between markets, each region should be afforded such flexibility as is needed to promote and enhance grid resilience in a manner that reflects the operating characteristics of that region, including the

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[21] *Id.*, at p. 7. "When planning new transmission projects, ERCOT strives to build greater resilience into the system. This includes considering the geographic diversity of transmission lines serving a load center. . . . When appropriate, ERCOT has also conducted studies to determine the potential contingency impacts of placing a proposed line in a common right-of-way with one or more existing transmission lines." *Id.*at p. 8

[22] Comments of PJM, at p. 50

likelihood of particular adverse events or threats. However, as the above-cited RTO/ISO observations demonstrate, planning for adequate transmission investment is an accepted, valuable, and workable part of making any regional grid or any interregional systems more resilient.[23]

- Second, in order to make certain that RTOs and ISOs can effectively carry out any Commission planning directives that might come from this proceeding, FERC should first clarify that resilience is included in its existing statutory authority to promote reliable operation of the Bulk Electric System (BES). This is essential given the newness of resilience as a planning issue and the potential risks that uncertainty or ambiguity could create for RTOs/ISOs and Commission policy. Likewise, certainty in the administration of new policy must be provided by clarifying that the regional planning responsibilities of RTOs and ISOs also includes planning for resilience.

- Finally, the Commission should update its prescribed planning principles and criteria as they apply to resilience objectives through its rules or tariff requirements for regional grid operators and planners. That should entail updating its Order 890 transmission planning principles to include resilience as a planning driver.

CONCLUSION

WIRES anticipates that the Commission's focus on resilience can and should drive significant portions of its electric power policies. It also anticipates that, together with reliability issues, the economic benefits of a more integrated electric power system, the need to deploy and dispatch new technologies, the bulk power market's evolution, and public policy, transmission development will be driven by the need for greater resilience in the continuous delivery of electricity. In that sense, this proceeding can be part of a larger focus and initiative that prepares the grid for a more intensely electric and economically dynamic future. WIRES looks forward to further Commission deliberations on the role that transmission grid upgrades, modernization, and planned resilience will play in determining the future health and effectiveness of the North American economies.

[23] Similar recommendations are made by the PJM Interconnection in response to several of the Commission's questions. PJM Comments at pp.32-34, 40-41, 48-52.

WIRES wishes to thank the Commission for initiating this proceeding and considering WIRES' Comments about the importance of transmission investment as a resilience strategy.

Respectfully submitted,

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APPENDIX

"RECOGNIZING THE ROLE OF TRANSMISSION IN ELECTRIC SYSTEM RESILIENCE"

The Brattle Group (May 9, 2018)

Recognizing the Role of Transmission in Electric System Resilience

PREPARED FOR

WIRES

PREPARED BY
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May 9, 2018

THE Brattle GROUP

This report was prepared for WIRES. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

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Executive Summary

Resilience of the electric power system is the ability of the nation's electricity infrastructure to prevent or diminish damage from high-impact, low-probability events without undue disruption and to rapidly restore service when such disruptions occur. The robustness and flexibility of the high-voltage transmission grid will be critical to the FERC's consideration of electric system resilience for two reasons that track the definition of resilience itself:

- First, the transmission grid can absorb the damage potentially arising from multiple local generator outages without customer service disruptions by providing access to a network of technologically diverse and geographically dispersed set of power supplies. When sufficiently robust to maintain the flow of power under stressful conditions, transmission systems are inherently resilient.
- Second, the transmission sector has been pursuing investments in both physical assets and operational changes that strengthen the ability of the regional and inter-regional transmission grid to keep operating when challenged by adverse events and to aid the rapid restoration of service when damage and customer outages do occur.

The Federal Energy Regulatory Commission (FERC) can recognize the central role of the transmission grid in promoting electric system resilience by: (1) continuing to support an array of investments to strengthen the transmission grid and (2) expanding the role of resilience in regional and inter-regional transmission planning to build upon and expand the inherent resilience benefits that the transmission grid already provides.

Transmission planning has thus far focused primarily on the distinguishable (and valid) need for reliability in the short run. Accounting for the "insurance value" of a more flexible and robust transmission grid in the long-run can protect consumers from costly disruption during severe adverse events that likely will happen without forewarning of their timing, location, and severity. Like any insurance policy, transmission-focused planning and investments could provide cost-effective solutions to address fuel security concerns in some regions without requiring a redesign or rethinking of the competitive generation markets that have produced substantial consumer benefits. Finally, the FERC should consider resilience in addition to the Order 1000 goals of reliability, economics, and public policy, as a planning objective for both regional and inter-regional transmission expansion to help insure against large-scale disruption of electricity supply. This would represent an important step forward in transmission planning analysis and improve overall electric system resilience.

I. Introduction

The business of generating, transmitting and delivering electric power has always involved a singular focus on "keeping the lights on" under all possible conditions, regardless of what labels – such as "reliability" or "resilience" – are used to describe the primary goal. Recently, concerns about the security and availability of generating fuels such as natural gas have been identified as potential threats to the resilience of the electricity system. This recent focus on generation has diverted attention from other key segments of the industry – particularly the high-voltage transmission grid – that traditionally have been and should continue to be a central focus of efforts to enhance resilience. This study explores the important role that transmission plays in grid resilience and how policies and investments directed at strengthening the transmission system can cost-effectively enhance the resilience of electricity supply.

In contrast to the well-developed and intensively-managed issue of electric service reliability, the understanding and analysis of electricity grid resilience is still developing. The concept of resilience focuses on how critical infrastructure manages through and, when necessary, recovers from high-impact, low-probability events such as severe weather or physical or cyber-attacks. For this report, we follow the widely-cited 2009 National Infrastructure Advisory Council (NAIC) definition of infrastructure resilience as:

> The ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and or rapidly recover from a potentially disruptive event.[1]

This definition was expanded upon in a follow-up 2010 report, *A Framework for Establishing Critical Infrastructure Resilience Goals*, to include a resilience construct based on robustness, resourcefulness, rapid recovery, and adaptability as shown in Figure 1.

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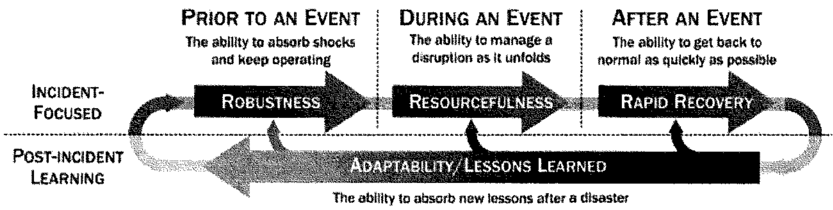
1 National Infrastructure Advisory Council, *Critical Infrastructure Resilience: Final Report and Recommendations*, September 8, 2009, p. 17.

Figure 1: The Sequence of the NIAC Resilience Construct



Source: National Infrastructure Advisory Council, *A Framework for Establishing Critical Infrastructure Resilience Goals: Final Report and Recommendations by the Council*, October 19, 2010.

The evolution of the modern bulk power system, from municipal central stations serving local customers to large regional and interregional networks connecting distant resources to growing loads, has been driven by the inextricably linked goals of resilience, reliability, and economics. Increasing the geographic size or "footprint" of the bulk power system through transmission interconnection allows customers to capitalize on economies of scale and scope in energy, capacity, and reserves. As far back as the 1965 blackout that affected 30 million customers in the eastern United States and Canada, the recommendation has been to move toward more connected systems. The official report on the 1965 blackout states, "Isolated systems are not well adapted to modern needs either for purposes of economy or service" and recommended "... an acceleration of the present trend toward *stronger transmission networks within each system and stronger interconnections between systems* in order to achieve more reliable service at the lowest possible cost."[2]

As the connection between bulk power generation and the local distribution system to serve retail customers, the transmission system is critical to the overall performance of the power sector and its resilience when challenged by infrequent but significantly adverse events. Strengthening the resilience of individual generators or the generation fleet overall will not increase the overall resilience of the system if the power cannot be delivered into an intact distribution system to serve customer loads. This applies within a recognized transmission region within Regional Transmission Organizations (RTOs) and between regions. Within regions, the

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[2] Federal Power Commission, "Report to the President on the Power Failure in the Northeastern United States and the Province of Ontario on November 9-10, 1965," December 6, 1965. p. 43 (emphasis added).

transmission network connects a diverse set of generators to distribution systems that serve customers. Inter-regionally, the transmission network connects neighboring systems to increase overall reliability and resilience by providing access to additional generation resources to increase benefits of trading across regions and for providing resources during emergency situations. Finally, transmission has been recognized as critical infrastructure since the resilience concept was defined, and therefore policies and investments to strengthen the transmission system have been central to the electricity industry's overall effort to promote and enhance resilience.[3]

This report highlights how existing transmission contributes to power system resilience and describes how evolving policies and new investments in transmission will further enhance power system resilience. In the next section, we explain how the transmission system helps maintain or restore power in cases where multiple simultaneous generation failures might threaten customer disruptions. We follow this with a discussion of how policies and investments in the transmission system mitigate vulnerabilities of the transmission system to high-impact low-probability events that can compromise resilience, and then we conclude by discussing how transmission owners and operators anticipate future resilience challenges through preparation and planning.

II. The Transmission Network Enables Bulk-System Resilience

The power system can be vulnerable to disruptions originating at multiple levels, including events where a significant number of generating units experience unexpected outages. The transmission system provides an effective bulwark against threats to the generation fleet through the diversification of resources and multiple pathways for power to flow to distribution systems and ultimately customers. By providing customers access to generation resources with diverse geography, technology, and fuel sources, the transmission network buffers customers against extreme weather events that affect a specific geographic location or some external phenomenon (unavailability of fuel and physical or cyber-attacks) that affect only a portion of the generating units. In addition to other economic and reliability benefits, these resilience benefits occur both within and between regions.

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3 See, for example, *Hardening and Resiliency: U.S. Energy Industry Response to Recent Hurricane Seasons*, U.S. Department of Energy, August 2010.

On a regional basis, transmission networks provide customers with access to a variety of generators, where resource and fuel diversity decreases the vulnerability to common mode failures and promotes resilience. For example, the transmission networks provide Southern California customers access to hydropower from the Pacific Northwest, nuclear energy from Arizona, solar and wind power from neighboring states, and natural gas generation from neighboring states. As a result of this diversity, customers did not experience interruption when the 2.2 GW San Onofre nuclear power plant unexpectedly shut down in 2012 and then officially retired in 2013. Likewise, southern California customers did not experience outages from the 2011-2016 drought, which affected the state's entire hydropower fleet,[4] or the 2015 Aliso Canyon gas leak, which affected natural gas availability for a whole fleet of generating plants in southern California. While the fuel diversity among generators may exist over geographic regions, customers only benefit from such diversity when these resources are interconnected through the transmission network.

The broad geographic scope of the transmission system provides resilience to the system. For example, severe or extreme weather events typically affect only a portion of the region served by the wider grid. During and following such an event, customers in the affected regions are able to draw power from unaffected generating plants through the regional transmission system. For example, during a cold snap in January 2018 that significantly affected MISO South, power flows from MISO into MISO South (parts of Arkansas, Louisiana, Mississippi and Texas) briefly exceeded the contractual regional directional transfer (RDT) limit, enabling MISO South to avoid load shedding. By drawing power from the rest of MISO, the southern region maintained power delivery during a period of record demand and significant generator outages.[5]

The diversity of the resources interconnected through the transmission network also provides robustness to cyber or physical attacks waged against a specific generator type, fuel source, or utility service area. From a reliability perspective, the bulk power system is designed to withstand outages, and a certain level of unexpected generator outages are part of standard

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4 According to the California Department of Water Resources, this included four of the driest consecutive years on record, 2012-2014. California Department of Water Resources, "Water Year 2017: What a Difference a Year Makes," September, 2017. p.2

5 See "Exceeding transmission limits prevented MISO South blackouts in Jan: IMM" by Mark Watson, *MW Daily*, March 27, 2018.

operating and planning procedures within the power system. From a resilience perspective, should multiple units within a region or a type of generating station across regions become unavailable to supply power, operators will be able to draw from other, unaffected and available resources to the extent enabled by the transmission network.[6]

If an adverse event overwhelms the regional ability to absorb or manage the event, inter-regional transmission connections allow regional operators to "lean" on neighbors for emergency support. Thus, in cases where generation outages in one region threaten reliability, interties with neighboring regions can substitute for the inadequate generating capacity within that region. The weaknesses associated with lack of inter-regional transmission were vividly on display during the 1965 Northeast Blackout, which affected more than 80,000 square miles and 30 million customers across the United States and Canada with most outages lasting several hours.[7] Recognition that stronger interregional transmission links could have prevented these outages led to the expansion of the transmission grid into the large regional networks we rely on today.

The reliability benefit of such regional and interregional transmission network has not changed since. A 2013 study that Brattle and Astrape Consulting conducted for FERC found that interties offer substantial benefits from both a physical reliability and economic perspective:

> Strong interties with neighboring regions provide both economic and physical reliability value during peaking conditions. Load and generation diversity mean that the most extreme scarcity conditions are unlikely to occur at the same time in neighboring markets.[8]

As the quote above implies, when regional resource adequacy is threatened because of a lack of generation diversity, then interties with neighboring systems with a different fuel and technology mix (one less affected by the conditions adversely affecting specific regional

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6 This does not negate the potential for events for which insufficient power is capable of importing into the region or regions with units unexpectedly out of service.

7 A tripped relay in Ontario caused the outage, which then cascaded through New York and New England; all service was restored within 14 hours. Additional interregional transmission capacity could have mitigated the outage. See Federal Power Commission, "Report to the President on the Power Failure in the Northeastern United States and the Province of Ontario on November 9-10, 1965," December 6, 1965.

8 See Johannes P. Pfeifenberger, Kathleen Spees (Brattle) and Kevin Carden, Nick Wintermantel (Astrape) *Resource Adequacy Requirements: Reliability and Economic Implications*, September 2013, p. 57, found at https://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf.

resources) can provide a cost-effective alternative to retaining or building new resources to address generation diversity or overreliance on a particular fuel. One of the steps taken by PJM during the Polar Vortex episode in the Eastern U.S. in January 2014 was to access energy and reserves from adjacent regions on an emergency basis, which helped manage shortages within the RTO.[9] The potential value of creating resource diversity through inter-regional interconnection is well illustrated by ISO New England's analysis of diminishing its heavy reliance on natural gas combined with natural gas delivery constraints.[10] One option studied to address the current lack of fuel diversity in New England is the expansion of interregional transmission from New York, Quebec, and New Brunswick designed in part to access more hydro and other renewable generation facilities located in Canada.[11]

The ability for transmission systems to increase reliability and resilience of regional or inter-regional power systems is dependent upon the strength of interconnections. This strength depends both on the number of lines and the capacity of those transmission lines. In its comment to FERC, PJM noted that transmission designs that are "robust and electrically dense" (compared with sparse networks) provide resilience benefits.[12] A dense network with many interconnections is more resilient as power can flow over many parallel routes. The ability for that power to flow, however, is dependent upon having sufficient capacity. Thus, to realize resilience benefits, the transmission network must be able to provide capacity beyond the normal day-to-day level, and perhaps even beyond the anticipated stress scenario utilization of the facilities.[13] Transmission planning should take into account the potential resilience value of investments when considering expansion projects.

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9 See *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events,* PJM Interconnection, May 8, 2014, p. 19-20.

10 See for example, ISO New England, "Operational Fuel-Security Analysis," January 17, 2018.

11 Ibid.

12 *Comments and Responses of PJM Interconnection, L.L.C.*, Docket No. AD18-7-000, March 9, 2018, p. 43.

13 Transmission lines are typically rated for both "normal" and "emergency" operation, with the "emergency" rating available for short time periods of overloading. For the transmission system to accommodate unanticipated and potentially large flows for a sustained period, the headroom created through emergency ratings may be insufficient.

III. Transmission System Investments Improve Electricity System Reliability and Resilience

Although recent concern surrounding electric system resilience has focused on fuel security and resource adequacy, inadequate generation almost never results in customer outages. Instead, the vast majority of customer outages occur from damage to distribution systems caused by such events as severe storms. According to the Quadrennial Energy Review:

> Failures on the distribution system are typically responsible for more than 90 percent of electric power interruptions, both in terms of the duration and frequency of outages. Damage to the transmission system, while infrequent, can result in more widespread major power outages that affect large numbers of customers and large total loads.[14]

Because the transmission system has been designed to withstand contingencies and adverse conditions, the transmission network routinely experiences severe weather events without causing customer outages. When the robustness of the transmission infrastructure is overwhelmed, however, sustained and widespread customer outages can occur, for example when extreme weather topples transmission towers across a wide region or operators are unable to manage grid instability arising from faults or outages. Due to their broad impact, these rare events are extensively studied *ex post* to advance understanding of vulnerabilities and explore and adopt measures to reduce future impacts. As a result, much of the analysis of resilience in the bulk power system focuses on high-impact, low probability events that directly affect transmission, which has supported some policy reforms and investments to address transmission resilience issues. Nevertheless, much more can be achieved, and we discuss the evolving policies and investments relating to transmission planning, physical infrastructure development and operations below, using the four NIAC resilience elements – robustness, resourcefulness, rapid recovery, and adaptability – as a framework to describe their overall role in responding to a resilience threat or event.[15]

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[14] U.S. Department of Energy, *Transforming the Nation's Electricity Sector: The Second Installment of the QER,* January 2017, Chapter 4 "Ensuring Electricity System Reliability, Security and Resilience" p. 4-29.

[15] It should be noted that transmission and distribution facilities share some failure modes, particularly extreme weather damage. Because distribution facilities are more vulnerable to storm damage, some of the programs that we highlight below primarily focus on distribution infrastructure; however,

Continued on next page

A. DEVELOPING A MORE ROBUST TRANSMISSION NETWORK

The robustness of the transmission network, its ability to absorb shocks and continue functioning, continues to be enhanced by the hardening of existing infrastructure and increasing connectivity within and between regions. Hardening the current infrastructure makes it less vulnerable to equipment failure as a result of major events, such as severe weather or human attack. This hardening of the existing infrastructure can include upgrading the physical strength of existing infrastructure (e.g., storm resilience), relocation of assets to less vulnerable locations, increasing transmission system capacity and connectivity, adding physical or cyber security, and improving operational practices.

Storm damage to the transmission network frequently results in reinvestment into more robust infrastructure. While not nearly as vulnerable to storm damage as local distribution systems, the transmission network has suffered damage from especially severe weather events, such as the catastrophic ice storm that hit New England and Eastern Canada in 1998. That storm resulted in the collapse of 770 transmission towers,[16] and in eastern Maine, a damaged switch affected about 40% of Eastern Maine Electric Coop's customers for nine hours.[17] Overall, the transmission damage which, combined with extensive damage to distribution systems, caused outages affecting hundreds of thousands of customers for three weeks or more. Hurricane Katrina in 2005 destroyed 1,515 transmission structures and forced 300 substations offline.[18] Likewise, Superstorm Sandy affected over 200 transmission lines across the northeast and mid-Atlantic.[19]

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storms can damage high voltage power lines and substations through flooding, high winds, ice accumulation and other modes that can and do affect both transmission and distribution elements.

16 National Academies of Sciences, Engineering and Medicine, 2017, *Enhancing the Resilience of the Nation's Electricity System*, p. 13.

17 Jones, Kathleen and Nathan Mulherin, U.S. Army Corps of Engineers, *An Evaluation of the Severity of the January 1998 Ice Storm in Northern New England: Report for FEMA Region 1*, April 1998.

18 These events are described in National Academies of Sciences, Engineering and Medicine, 2017, *Enhancing the Resilience of the Nation's Electricity System*, p. 13. It should be noted that when severe weather damages both transmission and distribution systems, attributing the length of customer outages to restoring transmission or distribution may not provide an accurate appraisal of the relative impacts for specific cases.

19 Office of Electricity Delivery and Energy Reliability U.S. Department of Energy, *Comparing the Impacts of Northeast Hurricanes on Energy Infrastructure*, April 2013.

After the 2004-2005 hurricane season in Florida, the state legislature ordered the Public Service Commission to "conduct a review to determine what should be done to enhance the reliability of Florida's transmission and distribution grids during extreme weather events, including the strengthening of distribution and transmission facilities." The resulting program included inspection, forensic analysis of failed transmission structures and a schedule for upgrading and replacing vulnerable equipment.[20]

In response to physical attacks, utilities have added physical security measures following the creation of the NERC Critical Infrastructure Protection (CIP) standards. In April 2013, PG&E's Metcalf Transmission Substation was targeted by gunman, resulting in the damaging of 17 transformers. Former FERC Chairman Jon Wellinghof referred to the attack as "the most significant incident of domestic terrorism involving the grid that has ever occurred."[21] The attack caused more than $15 million in damage and took nearly a month to repair, but did not result in service disruption to customers due to the resilience of the local transmission and distribution system.[22] In Nogales, Arizona, a failed attempt to detonate an explosion at a peaking plant by igniting the diesel fuel tank in June 2014 would have affected 30,000 customers if the attack had damaged the adjacent substation. As a large infrastructure system with thousands of exposed assets, including substations and transmission lines, individual assets are vulnerable to physical attack,[23] and the CIP standards, authorized under FERC Order 802, were put in place following the Metcalf substation attack. These standards require utilities to identify and protect

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[20] Florida Public Service Commission, *Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather*, July 2007.

[21] Smith, Rebecca, "Assault on California Power Station Raises Alarm on Potential for Terrorism," Wall Street Journal. Published February 4, 2014.

[22] Barker, David, "FBI: Attack on PG&E South Bay Substation wasn't Terrorism," SF Gate. Published September 11, 2014.

[23] In addition to the incidents discussed here, transmission insulators are frequent targets for vandalism, and transmission lines may be targeted for protest. For example, in the 1970s, protesting against a new transmission line in Minnesota, a group called the Bolt Weevils shot out over 5,000 insulators and destroyed 8 transmission towers.

Minnesota Historical Society, Minnesota Powerline Construction Oral History Project, Ed Schrom narrator and Edward P. Nelson interviewer, 1981.

key assets.[24] As physical threats to the system increase and new assets are identified as critical to system operation, transmission owners will continue to enhance physical security.

The robustness of the transmission system also has been enhanced by increasing the connectivity of the network and the transfer capabilities on those connections. When unanticipated failures do occur on the network, increased connectivity can help diminish the impact on the system and may lessen the importance of any single element failure. Essentially, operators can re-route power in response to economic, reliability, or resilience events. The 1965 blackout was an illustration of the lack of interconnectivity, but following the blackout, the transmission capacity was increased within and between New England, New York, and the mid-Atlantic regions, greatly improving the power system's reliability and resilience.

Nationally and across regional networks, transmission system regulators and operators have responded to resilience challenges by improving operational practices and creating standardization and information sharing protocols. In reaction to the 1965 blackout, NERC was created and initially established voluntary protocols. Forty years later in 2005, NERC guidelines and protocols that set forth common reliability metrics, definitions, and requirements became mandatory, in part as a response to the operational failings that precipitated the blackout that affected the U.S. Northeast/Midwest and Canada on August 14, 2003.

A December 2015 cyber-attack in Ukraine that resulted in service interruptions to 225,000 customers clearly demonstrated the potential impact of a cyber-attack on the transmission and distribution sectors. These attacks disconnected seven 110 kV substations and twenty-three 35 kV substations for three hours through disruption of the Supervisory Control and Data Acquisition System (SCADA). While focused mostly on a local transmission and distribution system assets, the event highlighted the potential vulnerability of regional power system networks to malicious cyber intrusion. In March 2018, the Department of Homeland Security issued an alert outlining how Russian government cyber actors were actively targeting U.S. energy and other critical

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[24] These key assets are those that, "if rendered inoperable or damaged as a result of a physical attack, could result in instability, uncontrolled separation, or cascading within an interconnection." NERC Standard CIP-014-2. p.1

infrastructure sectors.[25] Although cyber-attacks against U.S. utilities have not yet caused sustained reported damage, the vulnerability is widely acknowledged and the industry has been actively sharing information and establishing protocols to harden against such an attack for nearly two decades. As far back as 2000, NERC established the Electricity Information Sharing and Analysis Center (E-ISAC) to share information on potential vulnerabilities, and in 2018 the Department of Energy (DOE) launched its own Office of Cybersecurity, Energy Security, and Emergency Response to prepare for and respond to cyber-attack, physical attacks, and storm damage.

B. AMELIORATING DAMAGE ARISING FROM AN EVENT

Investments in sensing equipment and control operations can allow transmissions system operators to react more quickly and effectively to system disturbance by isolating the damage and re-routing power to non-damaged areas. Re-routing power and isolating damaged areas relies on operators having access to up-to-date information on component status and access to tools and technology to re-route power flows without causing more problems. Ongoing investments in sensing equipment and potential investments in technologies that allow operators greater control of flows increase the ability of operators to manage an event as it unfolds.

Operator responses to transmission events can be prophylactic, adapting the system to accommodate a particular asset approaching failure, or responsive to an event, such as a physical attack, on the grid. Whether anticipatory or responsive, transmission owners have installed additional sensing equipment to the transmission system to provide system operators with accurate real-time system status information. For example, during hurricanes in Florida, operators were unaware in real-time of flooding in substations. Without this knowledge, operators were unable to triage the situation by removing the substations from service. In response to the outages caused by damaged substations, Florida Power and Light installed real-time water monitors at 223 substations to allow the company to proactively shut-down substations to limit and mitigate damage.[26]

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[25] See U.S. Computer Emergency Readiness Team (US-CERT) Alert TA 18-074A, "Russian Government Cyber Activity Targeting Energy and Other Critical Infrastructure Sectors" found at https://www.us-cert.gov/ncas/alerts/TA18-074A.

[26] This type of investment also enhances rapid recovery by avoiding repair or replacement needs.

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During the 2003 Northeast/Midwest U.S. blackout, operators did not have access to accurate information on the wider-system status, which could have helped limit the blackout's reach. The 2003 blackout was, at a high level, caused by transmission line outage in combination with operator errors. The initiating event for the blackout was a transmission line that was heated up through heavy usage, sagged, came into contact with vegetation, and then tripped offline. When that transmission line tripped offline, power flowed through alternative routes, overloading those lines, and causing cascading failures before operators were able to understand and react to the event. While the power system is planned to withstand the loss of one or several major elements, operators were initially unaware of the system outages and then failed to communicate with neighboring systems. The cascading blackout resulted in the loss of power to over 50 million customers in Canada and the United States, and the outage lasted for up to four days in some areas.[27] The economic cost of this event has been estimated between $4 billion and $10 billion.[28] In response to the need to understand and communicate operational status, over 800 phase measurement units (PMUs) that provide real-time system-status data were installed, and this data is shared within and across regions.[29] The measurements from these devices could have allowed operators to isolate the transmission failure and prevent the wide-area outages in the 2003 blackout.

New technologies and tools have the potential to allow transmission operators greater control over the flows on the network and proactively manage events. One of the central challenges to operating the transmission system is that flows on individual transmission lines are largely dictated by physics rather than a system operator's preferences or needs. The ability to actively control power flows would allow an operator to avoid, for example, overloading certain lines that may result in cascading failures. Technologies such as Flexible AC Transmission System (FACTS)

Continued from previous page

Florida Power and Light, "FPL expects approximately 4.1 million customers may lose power at some point as a result of Hurricane Irma." News release published September 8, 2017.

27 U.S.- Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* April 2004. p. 1

28 National Academies of Sciences, Engineering, and Medicine. *Enhancing the Resilience of the Nation's Electricity System.* Washington, DC: The National Academies Press. 2017. p.13

29 North American SynchroPhaser Initiative, *PMUs and synchrophasor data flows in North America as of March 19, 2014,* No date.

devices and "topology control" can enhance a system operator's availability to respond to events, as well as increase the efficiency of unit dispatch.[30] Investment in FACTS devices have the potential to allow operators to change flows by modifying transmission line properties through power electronics. Likewise, transmission switching, which is actively used by ISO/RTOs, allows operators to re-route flows by disconnecting and reconnecting lines; however, this is usually executed on longer timescales (*e.g.*, seasonal). Several RTOs have analyzed new approaches that would allow topology control on operational timescales.

C. RECOVERING QUICKLY TO RESTORE SERVICE AFTER AN EVENT

Rapid recovery following a transmission event requires the inspection, replacement or repair of damaged transmission system components. These actions can require specialized workforces and components that can be expensive for individual utilities to maintain or replace; specialized workforce personnel might include helicopter pilots, and required components may include multi-million dollar assets such as large transformers. In response, utilities have been expanding sharing agreements to improve restoration time through increased access to components and workforces.

The most visible recovery initiatives in the power sector are utility mutual assistance programs, which dispatch lineman and other skilled workers to respond to large-scale events; these programs have reacted to major resilience events through a focus on nation-wide events and reorganization for improved efficiency. Electric companies organize into voluntary Regional Mutual Assistance Groups (RMAGs) and respond to regional and national events that affect multiple regions. For example, during the 2012 derecho that caused more than four million customers to lose power across the mid-Atlantic and Ohio, crews came from as far as Canada, Texas, and Wyoming to restore power,[31] and restoration following Superstorm Sandy involved crews from all RMAGs.[32] The scale of the response required for Superstorm Sandy revealed weaknesses in the organization for national-scale responses, and as a result, three RMAGs in New England consolidated into a single entity and the Edison Electric Institute (EEI) members

30 Topology control refers to the re-routing of power by adding and remove transmission lines from service.

31 Edison Electric Institute, *Understanding the Electric Power Industry's Response and Restoration Process,* No date. p. 4

32 Ibid. p. 5

developed a framework to coordinate national responses.[33] EEI runs storm drills to prepare utilities for the nation-wide events as well table-top drills with federal organizations.[34] The scale and duration of these events qualify as tests to resilience, and although they involved damage to both distribution and transmission system elements, the repair to the transmission system was a necessary part of the restoration process.

In addition to personnel, utilities maintain spare components and form pools to maintain spare components that are too expensive or difficult to obtain for restoration purposes. There are currently industry-led sharing programs, including NERC's Spare Equipment Database, Edison Electric's Spare Transformer Equipment Program (STEP), SpareConnect, Grid Assurance, Wattstock, and the Regional Equipment Sharing for Transmission Outage Restoration (RESTORE) group. The RESTORE group, for example, includes 28 utilities that agree to sell equipment to other members following a triggering event.[35] Several of these groups arose from vulnerabilities associated with the availability of Large Power Transformers (LPTs), which have limited domestic production capabilities, long lead times, and cost millions of dollars each. Utilities also maintain stockyards with spare conductors, towers, and related equipment for restoration purposes.

D. LEARNING RESILIENCE LESSONS

Because transmission resilience events have the potential to affect a broad geography, the events are closely studied and frequently result in changes to the system and system operations. That is, lessons learned provide the basis for improvements that reduce the impact of similar future events. These studies of transmission-related events mark the importance of the event and range from storm reports required by state governments to reports by the Federal Emergency Management Agency (FEMA), NERC, DOE, and others. As discussed in the sections above, these reports have resulted in actions including transmission line hardening, increased sharing of threat information, changes in reliability planning and system design standards, and improvements to wide-area sensing.

33 Fishbach, Amy, "Tactical Tips for Utility Mutual Assistance," T&D World. Published August 30, 2017.

34 Ibid.

35 Peter Maloney, "28 utilities join RESTORE program to boost grid resilience, reliability," Utility Dive, October 4, 2017.

IV. Anticipating Resilience Challenges

The ongoing policy reforms and investments in the transmission sector largely reflect an adaptive response to major events and disturbances. However, the industry also proactively plans for unprecedented events that could plausibly threaten grid resilience. We highlight two of these activities below: war-game type response simulations and enhanced transmission planning.

A. Operational Response Exercises

As mentioned above, cyber-attacks in the U.S. have not yet disabled a significant transmission component or system, but the industry intensively prepares for that threat. In addition to the information sharing discussed previously, utilities practice responding to physical and cyber-threats through national simulations. NERC organizes biennial exercises, called GridEx, that allow utilities, law enforcement, federal agencies, and other operators of critical infrastructure systems to test and improve protocols in case of attack. The GridEx exercises include two day simulations for utilities and their partners as well as a one day executive-level tabletop game. Thus far, NERC has executed four GridEx events with 2017's GridEx IV drawing participation from over 450 entities, including water utilities, oil and natural gas companies, and telecommunication utilities.[36] The executive tabletop game in 2017 included participants from the White House National Security Council, DOE, the Department of Homeland Security, FEMA, the Department of Defense, the Federal Bureau of Investigation, the state of Maryland, the state of Virginia, and the National Guard in Illinois and Wisconsin.[37]

The GridEx simulations result in recommendations for policies, procedures, and investments within the power sector to increase readiness, including recommendations for regional and national programs and tools. During GridEx III, the need for cyber mutual assistance, analogous to the RMAGs for physical infrastructure, was highlighted. In response, a Cyber Mutual Assistance (CMA) program was developed that provides a pool of cyber security experts that are able to assist during an event, and the CMA program now includes more than 140 organizations, including natural gas and electric utilities, regional transmission operators, and independent

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[36] NERC, *Grid Security Exercise GridEx IV: Lessons Learned*, March 2018. p. 1

[37] *Ibid.* p.2

system operators across the United States and Canada.[38] Likewise, GridEx IV identified the need for alternative communications when actors were unable to communicate effectively due to a simulated communications blackout and produced a recommendation to establish contingency plans and make use of existing federal communication programs.[39]

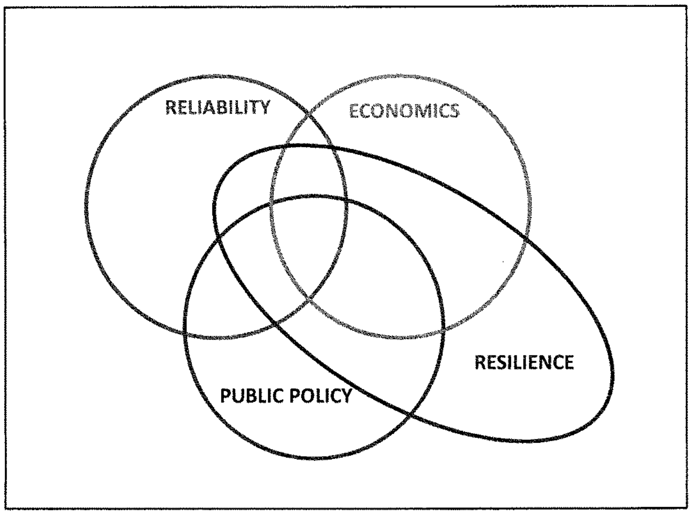
B. TRANSMISSION PLANNING

The goals for transmission planning arising from FERC Order 1000 are sometimes listed as reliability, economics and public policy; so-called "multi-value projects" serve these needs by enhancing reliability, increasing market efficiency and supporting public policies. It is reasonable to ask how "resilience" might fit into this framework, although that is not straightforward to answer. Resilience is related to reliability, but broader. It is a public policy goal, but other public policy goals, such as support for clean energy, may also be considered. Resilience is an economic issue in the same way that insurance and disaster preparedness has an economic dimension. In other words, resilience can involve all three Order 1000 objectives while remaining distinct in some ways. The Venn diagram below in Figure 2 shows the relationship between resilience and other transmission planning objectives, where resilience encompasses the entire area where economics, reliability and public policy intersect. This representation suggests that transmission planning that appropriately values economics, reliability and public policy objectives will also further resilience goals, and that considering resilience will enhance the benefits attributed to multi-value projects. It also suggests that stand-alone "resilience projects" could warrant consideration in planning processes, although that possibility remains unlikely in the current environment. Regardless of the degree of potential overlap between resilience and the other goals, however, a valuation of potential resilience benefits should help inform a more comprehensive analysis of the benefits of transmission projects.

[38] Electricity Subsector Coordinating Council, *The ESCC's Cyber Mutual Assistance Program,* January 2018.

[39] NERC, *Grid Security Exercise GridEx IV: Lessons Learned,* March 2018. p. 15

Figure 2: The Relationship between Transmission Planning Objectives



Reliability planning for the transmission system already incorporates some high-impact, low-probability events, such as single or multiple large contingencies during 90th percentile peak load conditions, or simultaneous outages of the largest transmission and generation facilities during summer heat waves. To further incorporate potential resilience considerations, more extreme conditions could be evaluated, such as situations where a significant portion of the generating fleet becomes unavailable for an extended period of time, when assessing the expected benefits of constructing and sizing of a proposed transmission line.

Such assessments of low-probability, high-impact events are sometimes included in the economic assessment of transmission investments. For example, in a 2015 study, The Brattle Group recommended that "anticipatory" transmission planning also assess the economic benefits that might arise in unlikely but extremely adverse scenarios, in order to fully capture the insurance value of transmission.[40] The Brattle study examined the 2004 analysis of a second Palo Verde to

[40] Johannes Pfeifenberger, Judy Chang, and Akarsh Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, The Brattle Group, April 2015. See also Johannes Pfeifenberger and Judy Chang, *Well Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the*

Continued on next page

Devers line (PVD2) that would enable imports from Arizona into California. One high-impact, low-probability event considered was a long-term outage at the San Onofre nuclear plant—an outcome that actually occurred in 2012. While the case study focused on the economic benefits from lower-cost replacement power enabled by the PVD2 line, comparable reliability and resilience benefits would arise if other conditions impaired generation availability elsewhere in California.

Both economic and reliability benefits are highly correlated with resilience benefits, although these benefits (e.g., protection against high costs and possible service disruptions) are typically quantified in the context of analyzing a less extreme range of adverse conditions or scenarios. Quantifying the expected benefit of transmission under more severe disruptions will augment the overall benefits from transmission investment. Because additional transmission capacity can enhance the overall level of reliability and resilience of the bulk power system, planning should increasingly assess the potential resiliency benefit of adding transmission within and between RTOs and other market areas. A 2013 Brattle Group report for WIRES found that estimating the benefits of mitigating the impacts of extreme events and system contingencies was crucial to a comprehensive analysis of transmission benefits:

> Transmission upgrades can provide insurance against extreme events, such as unusual weather conditions, fuel shortages, and multiple or sustained generation and transmission outages. Even if a range of typical generation and transmission outage scenarios are simulated during analyses of proposed projects, production cost simulations will not capture the impacts of extreme events; nor will they capture how proposed transmission investments can mitigate the potentially high costs resulting from these events. Although extreme events occur very infrequently, when they do they can significantly reduce the reliability of the system, induce load shed events, and impose high emergency power costs. Production cost savings from having a more robust transmission system under these circumstances include the reduction of high-cost generation and emergency procurements necessary to support the system. Additional economic value (discussed further below) includes the value of avoided load shed events.
>
> The insurance value of additional transmission in reducing the impact of extreme events can be significant, despite the relatively low likelihood of occurrence.

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Transition to a Carbon-Constrained Future, The Brattle Group, June 2016, pp 6-11 for a synopsis of studies that address the economic benefits of transmission, including under severe adverse conditions.

> While the value of increased system flexibility during extreme contingencies is difficult to estimate, system operators intrinsically know that increased system flexibility provides significant value. One approach to estimate these additional values is to use extreme historical market conditions and calculate the probability-weighted production cost benefits through simulations of the selected extreme events. For example, a production cost simulation analysis of the insurance benefits for the Paddock-Rockdale 345 kV transmission project in Wisconsin found that the project's probability-weighted savings from reducing the production and power purchase costs during a number of simulated extreme events (such as multiple transmission or nuclear plant outages similar to actual events that occurred in prior years) added as much as $28 million to the production cost savings, offsetting 20% of total project costs.[41]

Transmission planning should incorporate resilience considerations. In addition, transmission options should be considered to address resilience concerns such as regional resource shortage or fuel diversity/security issues. Secure electricity imports enabled by expanded transmission may provide cost-effective resilience benefits even in cases where generation fuel security is identified as the proximate resilience threat. Analysis of interregional transmission proposals could also incorporate the potential to avoid or mitigate damage from high-impact, low-probability events that pose resilience threats.[42] Because resilience is a systemic issue, the design of public policy to enhance resilience should look broadly at potential solutions.

V. Conclusion

Transmission has occupied a central role in the discussion of critical infrastructure resilience since that discussion began over a decade ago, and it continues to play an important role in the current resilience debate because:

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[41] See Judy Chang, Johannes Pfeifenberger, J. Michael Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, Prepared by The Brattle Group for WIRES, July 2013, p. 39; for additional detail on the Paddock-Rockdale analysis see American Transmission Company LLC, Planning Analysis of the Paddock-Rockdale Project, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference #75598) pp. 50-53.

[42] Of course, interregional transmission planning faces unique challenges. See Johannes Pfeifenberger, Judy Chang, and Akarsh Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of An Insufficiently Flexible Electricity Grid*, April 2015, pp. 25-37.

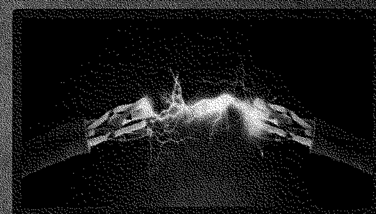
- Transmission can *enable* or *enhance* resilience, for example, when power from neighboring regions can flow to a region beset by outages of available generation (e.g., multiple outages associated with a particular fuel or technology);
- The transmission sector has *invested steadily* in enhanced reliability and resilience owing to rare but significant, widespread customer outages that can occur when transmission systems suffer physical damage or operations fail to avoid or contain delivery outages; and
- *Additional investments* in transmission expansion, innovative technology and operational controls can enhance grid resilience cost-effectively in the face of emerging threats.

The current focus on increasing the resilience of generation fleets in certain regions should not obscure or divert attention from the importance of the transmission grid to the overall resilience of the power system. Even as the generation fleet faces new and intensified challenges, the transmission system is needed to deliver the generated power to the distribution system and retail customers. Because the critical role of transmission to system reliability and resilience has long been recognized, continuous improvements have made the transmission more resilient over the past decades. Continuing attention and focus on transmission operation and investments will be necessary to identify and address existing and new threats to power system reliability and resilience.

APPENDIX B

A WIRES Report

THE TRUTH ABOUT THE NEED FOR ELECTRIC TRANSMISSION INVESTMENT: SIXTEEN MYTHS DEBUNKED



London Economics International LLC
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WIRES

www.WIRESgroup.com

SEPTEMBER 2017

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The Truth about the Need for Electric Transmission Investment: Sixteen Myths Debunked

WIRES

WIRES' PREFACE

WIRES[1] presents this excellent white paper by **London Economics International (LEI)** in response to many myths and long-held beliefs about investment in electric transmission that influence the thinking or actual decisions of policy makers, regulators, and the public about the need for, and benefits of, this critical infrastructure. For example, many people believe that lower demand for electricity means that the electric transmission system does not need to be upgraded or expanded. Others are persuaded that fixes or improvements to a facility or system in another service territory, state or region do not benefit them and are properly someone else's responsibility.

In reality, all North American economies will become more dependent on electricity as communications, banking, transportation, heating, automated manufacturing, and other developments drive our future economy and life styles and increase the need for electricity. The reliability and resilience of the electric system will consequently become more critical to us all. Despite this prospect, WIRES contends that regulators, public policy makers, industry, and the public, which stands to benefit from a robust grid, often bring outdated assumptions, misconceptions, and fallacies into their decisions about transmission investments.

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[1] WIRES is an international non-profit association of investor-, member-, and publicly-owned entities dedicated to promoting investment in a strong, well-planned, and environmentally beneficial high voltage electric transmission grid. WIRES members include integrated utilities, regional transmission organizations, independent and renewable energy developers, and engineering, environmental, and policy consultants. WIRES' principles and other information are available on its website: www.wiresgroup.com.

Yet, the truths about why we need to invest in the grid are not always self-evident. Therefore, WIRES has asked LEI to take a fresh look at the most fundamental misconceptions about transmission investment. These "myths" can often inflict a significant cost on investors in transmission and on customers because they contribute to protracted project delays and discount the importance of the flexibility and resilience that a robust grid provides. It is important to confront the myths that LEI identifies because they can frustrate even the most beneficial infrastructure projects. Modernization of the transmission grid that has been inherited from the last century will create an increasingly integrated and technology-driven network that binds regional power markets together and widely delivers economic, reliability, and environmental benefits. It should be accompanied by recognition that changes are needed to the regulatory system in which transmission planning and public interest determinations continue to be made under uncoordinated state and federal regulatory regimes. Those decision making processes may also require modernization.

In this paper, the LEI analysts identify the most pervasive and problematic myths from a policy-making point of view. They rebut those misconceptions and document why those myths are outdated, fallacious, or have no basis in fact. The paper then provides case studies that demonstrate why these myths about transmission investment are not supportable.

Myths can be very difficult to identify as such because they often contain an element of truth or fact. WIRES does not minimize the difficulties associated with siting major transmission infrastructure or the need for assurance that these investments will bring commensurate benefits to local, state, or regional economies and consumers of electricity. However, consideration of the benefits and burdens of such considerable investments deserve reasoned evaluation, free of ingrained misconceptions about transmission's fundamental but changing role in the present or future electrified economy. It is time to discard mythology and instead objectively consider the benefits that grid expansions, upgrades, and reinforcements can deliver to the economy and to consumers.

* * * * * *

WIRES submits this LEI paper for our readers' consideration and solicits the readers' comments, which may be submitted to www.wiresgroup.com We also acknowledge and thank the team of experts at London Economics, led by Julia Frayer, Eva Wang, and Marie Fagan and their colleagues from whose ingenuity and grasp of the industry's intricacies we all can learn.

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September 12, 2017

THE TRUTH ABOUT THE NEED FOR ELECTRIC TRANSMISSION INVESTMENT:

SIXTEEN MYTHS DEBUNKED

September 2017

Prepared for
WIRES

By
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LONDON ECONOMICS

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SYNOPSIS

WIRES commissioned London Economics International LLC ("LEI") to provide a White Paper on the myths and truths about transmission investment. The views of key decision makers regarding the need for transmission investment are often governed by widely-believed but outdated or inaccurate myths regarding the key drivers for investment, such as: trends in electric demand and supply; the cost of infrastructure and who should pay for it; benefits of investment; and the interplay between transmission and various new technologies. This White Paper identifies the principal myths surrounding consideration of transmission projects in regulatory, industry, and political circles and then explains why those myths are typically baseless, false, and misleading. The paper uses real-life examples of transmission investment projects to debunk these harmful misconceptions. In order to offer a more accurate portrayal of the need to invest in transmission infrastructure, this White Paper concludes with recommendations for practical and feasible improvements to the process of evaluating transmission projects.

BIOGRAPHICAL NOTE

Julia Frayer, Managing Director

Julia is the Managing Director at LEI with more than 20 years of experience providing expert insight and consulting services in the power and infrastructure industries. Julia specializes in the analysis and evaluation of electricity assets; she has worked extensively in the US, Canada, Europe, and Asia on issues that range from market analysis and valuation of electricity generation and wires assets, to policy development and strategy consulting. She has authored numerous studies and performed expert testimony on issues regarding transmission and generation investment, wholesale market design, energy procurement, renewable investment strategies, and policy analysis.

Eva Wang, Director

Eva is a Director at LEI. She is involved in many of the firm's modeling projects and price forecasting engagements, including evaluation of infrastructure investment opportunities and market rules changes. Recently, she headed the analytical team in charge of examining the costs and benefits of proposed transmission projects in New England.

Marie Fagan, PhD, Managing Consultant

Marie is a Managing Consultant and Lead Economist at LEI. With over 25 years of experience in research and consulting for the energy sector, Marie's focus at LEI relates to electricity and natural gas transmission, as well as broader strategic questions around investment for LEI's private clients.

Barbara Porto, Consultant

Barbara is a Consultant at LEI, where she provides research and analysis support to the firm's many engagements. Barbara recently supported a major client in its regulatory initiatives to implement incentive-based rates.

Jinglin Duan, Consultant

Jinglin is a Consultant at LEI, lending her technical skills to the firm's project evaluation and litigation engagements. Jinglin recently led an in-depth macroeconomic analysis of the impacts of construction of a transmission project.

London Economics International LLC ("LEI") is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity generation and distribution, water and wastewater provision, and natural gas distribution, with a suite of proprietary quantitative models to produce reliable and comprehensible results. LEI has offices in Boston, Chicago, and Toronto.

DISCLAIMER

The opinions expressed in this White Paper, as well as any errors or omissions, are solely those of the authors and do not represent the opinions of other clients of London Economics International LLC.

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Table of Figures

1 Introduction and roadmap to this report

Why are there myths around transmission investment?

Myths are sprouted from small "seeds" that are grounded in reality but then grow to be "larger than life." The factual foundations begin to fade, and the embellishments soon become the focus of the story. With respect to transmission investment, myths have arisen as a shorthand to help navigate the complexities of transmission investment decisions. Unfortunately, trying to simplify the decision of investors and system planners down to a sound bite of several words creates inaccuracies and gives rise to myths that undermine beneficial investment opportunities.

Transmission investments are complex and large-scale, and they require careful evaluation, forward-looking analysis, and long-term commitments. Key issues in the decision-making process include the following considerations:

- **Transmission investment decisions are multi-faceted.** Electric transmission investment is a highly regulated, complex undertaking which involves many decision-makers.

- **Transmission investment is large-scale.** This creates almost an immediate natural tendency to consider deferral and smaller-scale, sometimes piecemeal, options because the costs and consequences of ***not*** pursuing a large-scale investment are typically ignored because they are more difficult to come to grips with.

- **Transmission investment requires long-term commitments and planning.** It can take 10 to 15 years to plan, permit, and construct new transmission, and sometimes much longer. Once built, transmission projects typically have economic and operating lives that are more than 50 years.

It is tempting to tame these complexities by relying on familiar myths to guide transmission investment decisions. However, as this report shows, using outdated myths to guide investment will result in missed opportunities for benefits to the power system, transmission users, and to electricity consumers. This report uses real-life examples to debunk the myths around transmission investment.

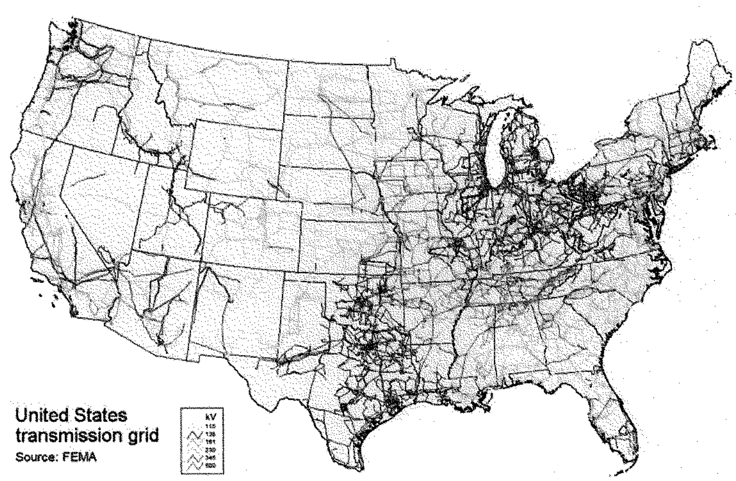
Roadmap

In Section 2, we briefly explain the important changes to the transmission system over the past two decades and the new realities that have resulted for the transmission system. In sections 3-7 we identify the myths and replace them with the new realities, or truths, about transmission. In Section 8, we provide recommendations for practical and feasible improvements to the process of evaluating the need for transmission investment to reflect these new realities. Some of the recommendations are already being practiced by system planners - if other decision-makers adopt these recommendations then their decisions around investment would more truly reflect the value that transmission investment brings to consumers and the power grid.

2 Why do we need transmission?

Electricity service is not simply about which power plants are running. Keeping the lights on involves an integrated network of resources, including: transmission lines, substations, control equipment, and local distribution lines (see Figure 1 below). Transmission infrastructure also ensures that the system is "reliable," meaning that the lights stay on even when power demand surges or an individual power plant goes offline.

Figure 1. The United States electric transmission grid



Source: Federal Emergency Management Agency ("FEMA")

Transmission investments are generally grouped into three categories:

- **Reliability:** Projects that are necessary to resolve a reliability issue (such as keeping the lights on);
- **Economic**: Projects that, while not necessary to resolve a reliability issue, allow cheaper generation to reach more load; and
- **Public policy:** Projects that assist in meeting public policy goals (e.g., lines built to support state renewable portfolio standards ("RPS") by, for example, allowing new remote wind generation to access load centers).

Investing in each of these three types of transmission requires long-term planning and a coordinated effort to ensure transmission is built where and when it is needed. The "drivers" of the need for new transmission were simple and straightforward: growing demand for electricity in a utility's service territory and the location of its power plants. The benefits of a new line were often taken for granted by the regulator, as long as the costs seemed reasonable and it was a straightforward exercise to allocate costs to consumers.

2.1 The evolving role of transmission

In the past, most transmission projects were developed by "vertically integrated" utilities that served a well-defined service territory and built power lines to connect its plants with its consumers, and consumers would only take services from this utility.

Nowadays, however, many regions of the US are served by independent power generators who own only power plants, and transmission and distribution utilities who focus only on delivering electricity to consumers. Even in areas where a single utility provides all services to consumers (and owns its own generation along with its wires businesses), there are now rules and regulations that require open access of the transmission system and "arms-length" considerations between the generation and transmission businesses. Independent system operators known as Regional Transmission Operators ("RTOs") or Independent System Operators ("ISOs") are now operating across the North American grid, and are in charge of the system planning and evaluation of transmission projects. Meanwhile, non-traditional investors are now allowed to 'compete' with utilities to build and own transmission projects. The line between consumers and producers is also blurring. Not only do consumers in some states have the right to choose their own supplier, but they also have an option to invest in their own generation facilities, thanks to the evolution of technology and regulatory reforms. In addition, many states have targets for renewable investment, which often call for additional transmission facilities to connect new generations with the load centers.

Thus, over the past few decades, the simple drivers of transmission have become less relevant, and new realities are driving the sector.

2.2 From myths to truths

Many common misconceptions around transmission investment have evolved from high-level generalizations about why transmission investment is needed and has led to oversimplification of the cost and benefits. These common misconceptions - "myths" - are detached from realities, or "truths," about transmission, and impose great challenge on efficient transmission development to meet current and future transmission needs.

These myths generally fall into five different categories, namely: (i) myths about power demand; (ii) myths about power supply; (iii) myths about alternatives to transmission; (iv) myths about costs; and (v) myths about benefits of transmission investments. We have identified a total of sixteen myths (see Figure 2) that need urgently to be corrected to better help system planners make informed decisions[1]—a topic which will be discussed in detail in the following sections.

Figure 2. Common myths around transmission investment

POWER DEMAND	1	Transmission is only built to meet current demand
	2	Demand is not likely to grow, no need for more transmission
POWER SUPPLY	3	Generating plants retire and new ones can use the same transmission lines
	4	No grid congestion, no need for more transmission
ALTERN-ATIVES	5	Local reliability issues can be addressed using alternatives
	6	Transmission is the most expensive option for resolving local reliability issues
	7	Customers tend to opt for new technologies and bypass the grid if they can
	8	New technologies are working well and can be easily scaled up to address grid stress
COSTS	9	There has already been enough investment in transmission so we don't need more
	10	Transmission projects are large and lumpy with high price tags
	11	Large transmission investment might end up underutilized
	12	Large transmission projects may be prone to overbuilding
	13	Large transmission investments involve complex cost allocation schemes that are unfair to consumers
BENEFITS	14	Customers on the receiving end are the only ones who benefit
	15	Transmission should only be built for resolving reliability issues – benefits are uncertain for non-reliability projects
	16	Transmission investment is risky because the costs are certain but the benefits are not

[1] Some of the sixteen myths are bundled together in the detailed discussions in Section 3 through Section 7.

3 Myths and truths about electricity demand

There is more to electricity demand than what meets the eye. Even if the overall growth in traditional sectors of the economy that use electricity is not strong, electricity needs can be driven by new economic activities and new consumer uses for electric power.

3.1 Myth: Transmission is only built to meet current demand, which is not likely to grow. Constructing more transmission in anticipation of the unforeseeable future is a waste

A common misconception is that transmission is built solely to meet current peak demand. Given that the electricity demand growth is likely to be slow or even flat thanks to a low population growth rate in the US and energy efficiency improvements, there is no need for further investment in transmission—at least not in the near future.

3.2 Truth: Transmission is not only built to meet current demand, but also to manage evolving consumer behavior and new economic activities

Even if "top-line" growth seems slow, electricity demand growth may accelerate in the near future as new consumer uses for electricity develop in new locations. Even as the US economy becomes more energy-efficient, the economy constantly evolves, as do consumer patterns of usage. For example, electric vehicles ("EV") sales have been emerging, and more and more homes are heating with electricity. In addition, specific local areas have experienced economic booms and therefore resulted in a large increase in electricity demand. It can take decades to plan and build a new transmission line—much longer than it takes for new uses of electricity to take hold—so it is best to plan ahead rather than waiting until transmission capacity constrains economic activity and consumer behavior.

A rapid penetration of EVs, as illustrated in Figure 3, will lead to higher demand for electricity and may require new transmission and distribution infrastructure. Although transportation electricity demand is currently very small compared with other end-uses, it is the fastest-growing aspect of electricity demand, with a compound annual growth rate of 2.4% per year, compared to the compound annual growth rate of the total load of 0.6%.[2] Many utilities are actively planning for these new loads by installing charging stations and other new infrastructure. For instance, in January 2017, three major investor-owned utilities in California—Pacific Gas and Electric Company ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas & Electric ("SDG&E")—submitted plans to the California Public Utilities Commission ("CPUC") to build EV infrastructure over the next five years.[3]

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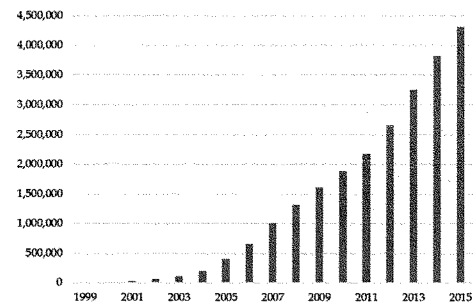
[2] Energy Information Administration. "Monthly Energy Review." July 2017. Table 7.6. Electricity End Use, data from 2000-2015.

[3] Greentech Media. "California Utilities Seek $1B to Build Out Electric Vehicle Infrastructure." January 24, 2017. <https://www.greentechmedia.com/articles/read/california-utilities-seek-1b-to-build-out-electric-vehicle-infrastructure>

Figure 3. Cumulative sales of electric vehicles in the US

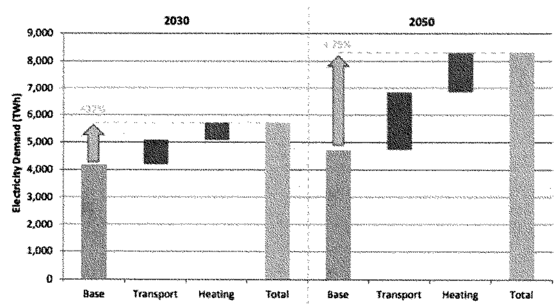


Source: Alternative Fuels Data Center. US Department of Energy. US HEV Sales by Model. January 2016. <http://www.afdc.energy.gov/data/10301>

Note: The figure shows the sales of both hybrid electric vehicles ("HEVs") and plug-in electric vehicles ("PEVs")

The increased popularity of electricity for home heating could also impact the seasonal and daily pattern of electricity demand and require new transmission upgrades. Figure 4 below shows an excerpt from another WIRES-commissioned analysis which demonstrates the profound implications from electrification of the transportation and heating sectors in the US. This analysis finds that by 2050, full electrification of land-based transportation could increase total electricity demand by 2,100 TWh (or 56% of 2015 electricity sales) and that full electrification of heating would increase electricity demand by about 1,500 TWh (or 40% of 2015 electricity sales).

Figure 4. Incremental electricity sales due to electrification of heating and transportation



Source: Brattle Group. "Electrification Emerging Opportunities for Utility Growth." January 2017.

3.2.1 Case study: Data center in Pennsylvania, New Jersey, Maryland Interconnection ("PJM") needed new transmission service

Data centers are a good example of a new use of electricity that has been growing rapidly driven by technology advancement. Electricity consumed in data centers in PJM increased from about 30 billion kWh per year in 2000 to 70 billion kWh per year in 2014.[4] In some cases, this economic activity added a brand-new end-use that required a new transmission service in affected regions. In PJM, the construction of data centers in the Dominion Virginia Power zone ("DOM") required new transmission lines. The increasing demand in the region from this activity has also been incorporated by the ISO in their long-term resource planning, as is stated in the PJM Load Forecast Report:

> *"The forecast of the DOM zone has been adjusted to account for substantial ongoing growth in data center construction, which adds 130-500 MW to the summer peak from 2017 through 2021."*[5]

3.2.2 Case study: Shale oil and gas boom in Texas drove need for more transmission

The need for more electricity can also arise quickly in specific locations driven by new technology. Shale oil and gas development, for example, has created a significant load on the electricity system in areas of western Texas that were previously sparsely populated and with limited consumption of electricity. Even though the significance of such type of load demand growth might be zeroed out when viewed from a national level, it is crucial for sustaining regional economic activities and growth.

The fast-growing oil and gas industry in the Permian Basin (which lies in New Mexico and West Texas) is one example of how regional fuel production activities induce investment in transmission infrastructure. By 2016, oil production has reached two million barrels per day, double the level of 2011.[6] This has driven up electricity demand markedly in the Electric Reliability Council of Texas ("ERCOT")'s Far West zone, where the Permian Basin is located (see Figure 5). As a consequence of the unprecedented load growth, western Texas experienced transmission congestion, meaning that there was no available capacity on the line to transmit energy from lowest-cost plants, and thus loads had to be served by less-efficient, more-costly plants.

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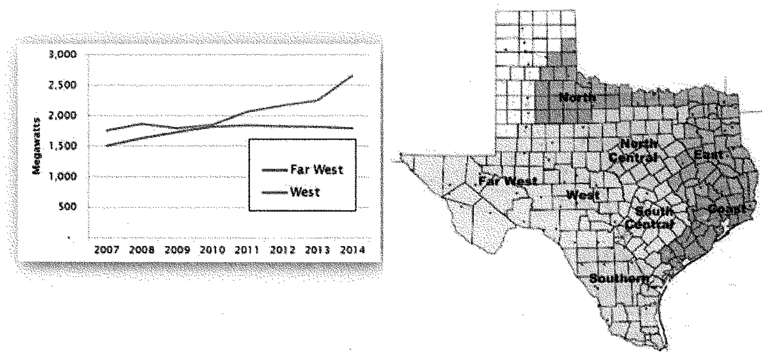
[4] Lawrence Berkeley National Laboratory, LBNL-1005775. *United States Data Center Energy Usage Report.* June 2016.

[5] PJM Resource Adequacy Planning Department. "PJM Load Forecast Report." January 2017. <http://www.pjm.com/~/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx>

[6] Energy information Administration and Texas Railroad Commission.

Figure 5. Maximum peak-hour electric power load, ERCOT West and Far West weather zones



Source: Energy Velocity, ERCOT

ERCOT, the transmission system operator for most of the state, noted that it was taken by surprise by the high demand for electricity triggered by the development of shale oil and gas:

> *"TDSPs [Transmission/Distribution Service Providers] and ERCOT did not fully appreciate the significant increase in energy intensity that was associated with the production operations for unconventional drilled wells used for the tight oil/shale plays versus operations associated with for the historical conventional drilling."*[7]

The ERCOT Board recently endorsed a transmission project that includes two new 345-kV lines to help address future reliability concerns in the growing region of Far West Texas. In the area where the project will be developed, peak electricity demand had increased from 22 MW in 2010 to more than 200 MW in 2016, and it is projected to exceed 500 MW by 2021.[8]

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[7] Energy Ventures Analysis. "West Texas Sensitivity Study Prepared ERCOT." June 2016.

[8] ERCOT. "ERCOT Board approves transmission project in West Texas." June 14, 2016. <http://www.ercot.com/news/releases/show/126322>

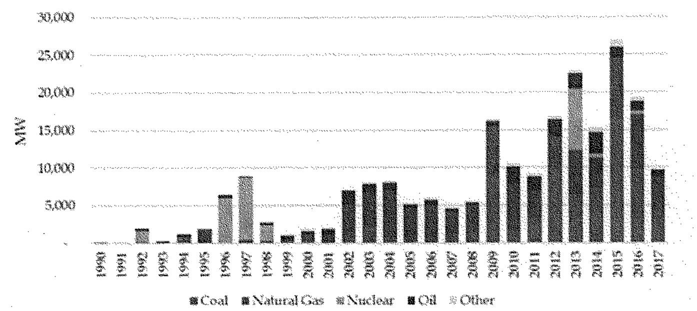
4 Myths and truths about electricity supply

Myths around electricity supply usually stem from misconceptions about how generation is connected with demand centers through the grid, or the idea that a transmission line can only provide one kind of benefit to the power system.

4.1 Myth: Retiring power plants will create room on the grid for new plants

Thousands of power plants in the US have reached the end of their useful lives in recent years (see Figure 6). As a result of the retirement of old power plants, there is a belief that there will be excessive spare transmission capacity on the system, and in sufficient quantities to interconnect new power plants. This faulty belief leads to the myth that investing in transmission to integrate new generation is not necessary.

Figure 6. US power plant retirements through June 2017



Source: Third party data provider

4.2 Truth: New power plants are not always built in the same place as retiring power plants

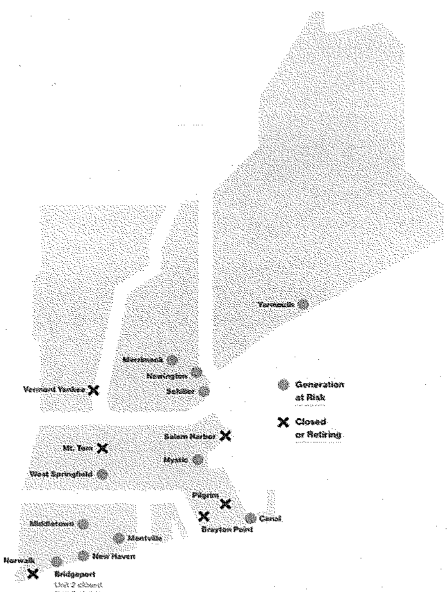
New power plants are not always built in the same locations as retiring power plants. New power plants are sited based on availability of fuel or other national resources needed for electricity production. For example, new wind plants are typically far from urban load areas or located where the grid is already at its performance limit. As a result, capacity freed up by retired power plants may not be utilized by new generation, without additional transmission infrastructure.

4.2.1 Case study: In New England, additional transmission is needed to bring new resources to market

In New England, more than 4,200 MW of generation is expected to have retired between 2012 and 2020, equivalent to almost 15% of the region's current (2017) generation fleet. According to the ISO-NE, an additional 5,500 MW of oil and coal capacity are at risk for retirement in coming years, and uncertainty also surrounds the continued operation of 3,300 MW of nuclear plants.[9]

Most of these retired or "at risk for retirement" power plants are located fairly close to load centers in central and southern New England (see Figure 7). Potential locations for new gas-fired generation are limited due to the lack of natural gas pipeline capacity and limited ability to access gas resources in many parts of the region.

Figure 7. Major planned retirement of non-gas-fired generators in New England



Source: ISO-NE. "2017 Regional Electricity Outlook - Retirements of Non-Gas-Fired Power Plants." <https://www.iso-ne.com/static-assets/documents/2017/02/2017_reo.pdf>

In the renewable generation sector, most of the new onshore wind power projects proposed to meet states' renewable portfolio standards ("RPS") targets are located in northern New England (mostly in Maine). While Maine has the best wind resources in the New England region, it is far

[9] ISO-NE. "Status of Non-Price Retirement Requests." August 15, 2016.

from load centers and the transmission system there is already constrained.[10] The independent system operator for New England, ISO-NE, stated the need plainly: "transmission improvements are needed to interconnect more wind power."[11]

4.3 Myth: The system is not congested so we do not need more transmission

Historically, congestion was seen by engineers as one significant symptom of an inefficient and constrained transmission system. This outdated and simplified conception leads to another myth, which states that transmission investment is only needed where there is congestion on the transmission system, or in other words, where the grid is constrained and performing inefficiently. If there is currently no congestion, building new transmission lines or upgrading existing lines is deemed unnecessary.

4.4 Truth: Some transmission needs arise even in uncongested energy markets

Although congestion relief is certainly one of the benefits of transmission, it is not the only factor that should drive investment.

Reliability problems, which could lead to voltage or thermal overloads and result in service interruptions for consumers, are not necessarily coincident with periods with congestion. Traditional transmission planning methods will consider a variety of system conditions, including various stressed transfers and generation outage profiles, that can identify key weaknesses in the transmission system even if significant congestion is not occurring on a day to day basis. In the case of the Greater Boston area in New England, for example, crucial reliability issues were identified by ISO-NE, even with full consideration of local generation. Therefore, even if there is no significant transmission related congestion under typical system conditions, there can be very critical reliability needs. In addition to reliability issues, there may be other economic or policy needs driving investment.

4.4.1 Case study: Greater Boston project addressed reliability in a normally uncongested system

In 2009, New England's transmission system operator, ISO-NE, reported that Greater Boston and Southern New Hampshire did not have adequate transmission resources to meet future demand reliably.[12] However, after 2009, there were important changes to the New England

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[10] ISO-NE. "2017 Regional Electricity Outlook." January 2017. *Note:* ISO-NE is conducting assessments to evaluate the potential economic effects on the regional power system resulting from different scenarios of wind integration and infrastructure improvements. The studies cover areas in Maine, as well as offshore wind development near Rhode Island and Southeast Massachusetts.

[11] ISO-NE. "Key Grid and Market Stats – Transmission." Accessed June 6, 2017. <https://www.iso-ne.com/about/key-stats/transmission>

[12] ISO-NE. "Greater Boston Transmission System. Needs Assessment Review – Solution Study Initiation." July 16, 2009. <https://www.iso-ne.com/static-

system, which would not only reduce congestion, but were also expected to solve the reliability problem. These changes included slower load growth, plant retirements, and new generation investment. However, though these changes reduced congestion across New England, there were still reliability problems in the Greater Boston area.[13]

To address the reliability issues, in 2015, ISO-NE selected a transmission investment plan with various upgrades to the existing infrastructure and new construction.[14] As of January 2017, five projects were completed and 12 additional projects were under construction. The whole investment plan is expected to be fully completed by 2019 to address identified transmission reliability needs in New England.[15]

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assets/documents/2016/02/07_16_2009_greater_boston_transmission_system_needs_assessment_review_solution_study_initiation_redacted.pdf>

[13] ISO-NE. "Greater Boston 2023 Solutions Study Status Update." November 20, 2013.

[14] ISO Newswire. "ISO-NE selects all-AC transmission solution to address grid reliability needs in Greater Boston." February 12, 2015. <http://isonewswire.com/updates/2015/2/12/iso-ne-selects-all-ac-transmission-solution-to-address-grid.html>

[15] Eversource. "Investor Call". February 22, 2017. Page 18. <https://www.eversource.com/Content/docs/default-source/Investors/2016-q4-and-y-e-financial-results.pdf?sfvrsn=0>

5 Myths and truths about alternatives to transmission

New technologies and alternatives to transmission can provide solutions to electric system needs that do not involve traditional transmission infrastructure. Alternatives to transmission come in a variety of forms and can include both demand-side (e.g. energy efficiency and demand response programs) and supply-side resources (e.g. utility-scale generation, distributed generation, energy storage, and smart grid technology).

There are several related myths about these alternatives to transmission, and they all reflect a misconception that there are cost-effective substitutes for every benefit and service that can be provided by transmission.

5.1 Myth: Transmission by wire is old technology. There are new and more cost-effective substitutes for transmission

It is widely perceived that as distributed generation, such as behind-the-meter solar PVs and energy storage, is becoming more economic and more widely installed, it allows consumers to bypass the grid to satisfy their demand. In addition, energy efficiency and demand response programs are scaling up across the country, contributing to falling electricity demand. It is widely perceived that as distributed generation, such as behind-the-meter solar PVs and energy storage, is becoming more economic and more widely installed, it allows consumers to bypass the grid to satisfy their demand. In addition, energy efficiency and demand response programs are scaling up across the country, contributing to falling electricity demand. These alternatives are sometimes deployed to alleviate pressure on the grid, making transmission no longer the only solution that addresses the need for some transmission services. However, it is a misconception that transmission solutions are the most costly and time-consuming choice, and that alternatives are perfect substitutions for transmission.

5.2 Truth: Non-transmission alternatives ("NTAs") are not always apples-to-apples substitutes for transmission

While NTAs can meet some of the same technical needs of the system that drive transmission investment (for example, in solving certain reliability problems with system overloads or providing market efficiencies, like reducing congestion and motivating production cost savings), they are rarely a complete substitute to transmission as the benefits of NTAs (also known as market resource alternatives ("MRAs")) and transmission will vary in terms of tenure (duration), locational dispersion, and even functional impact (in terms of reliability versus market impacts).

Figure 8 provides a comparison of services that can be provided by transmission as well as various MRAs. Although often overlooked, it is important to recognize that transmission investment and MRAs are often complements to each other rather than substitutes. Individual MRAs/NTAs typically can provide only a partial suite of the services that transmission provides, and usually can meet only very specific and local needs.

Figure 8. Services provided by transmission lines versus MRAs

		Transmission	Energy Efficiency	Demand Response	Distributed Generation	Energy Storage
What	Energy	●	◑	◑	◕	●
	Capacity	●	◑	◑	◕	●
	Ancillary Services	●	○	◑	◕	●
	Reduce system losses	●	◑	◑	◕	●
When	Long lifespan	●	◕	○	●	●
	Continuous basis	●	◕	○	○	●
Where	Regional	●	◑	◑	○	○
	Local	●	●	●	●	●
	Micro	●	●	●	●	●
How	System/Wholesale	●	○	○	○	●
	Customer/Retail	○	●	●	●	○
	TOTAL	●	◑	◔	◑	◕

● Provided ○ Not provided

Source: London Economics International. *A WIRES Report on Market Resource Alternatives: An Examination of New Technologies in the Electric Transmission Planning Process.* October 2014. Pg. 13.

NTAs are also not necessarily cheaper—they may even undermine reliability when viewed in the context of the larger system in the long term or require often costly solutions at the end-of-life. For example, load reductions by demand-side resources, such as energy efficiency and demand response, are difficult to measure and are not necessarily permanent, which creates additional stress and risk to the system management and planning process.

Similarly, most distributed generation resources rely on intermittent technology—solar and wind —and are not able to provide services on a continuous basis on their own (without energy storage). They also present a challenge for system planners and operators who must manage the intermittency and attendant dispatch uncertainty for these distributed resources.

While energy storage resources can provide many of the same services as transmission, they are currently more expensive and less expansive than transmission in terms of geographical reach. With the exception of pumped hydro storage, energy storage technologies have not been widely deployed to date on a commercial scale, and are generally not yet cost competitive with other MRAs and transmission per unit of electricity produced or delivered.

6 Myths and truths about the cost of transmission

Transmission projects can be large-scale projects, and as such their costs are high on stakeholders' radar screens. However, costs should not be evaluated in a vacuum—one should also consider benefits of transmission investment, and those benefits need to be evaluated comprehensively. Electricity cost savings, reliability improvements, and local economic benefits all contribute to the benefit side of the investment decision.

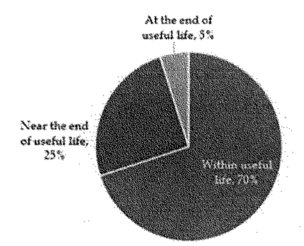
6.1 Myth: There has already been a substantial amount of investment in transmission, and many of the assets are fairly new so we do not need more

Investment in electric transmission has exhibited strong growth over the past few decades. From 1997 through 2012, annual US transmission investment rose $2.7 billion to $14.1 billion, a rate of 12% annually.[16] In 2015, annual transmission infrastructure investment reached a record of $20.1 billion for the US.[17] This has spawned a new myth: given this great amount of past investment dollars, there is no need for new investments on the current transmission system.

6.2 Truth: Assets are aging and some need replacement or refurbishment

Much of the US transmission system was built in the 1950s to 1970s with the boom in the economy post-World War II. By 2014, 30% of US transmission infrastructure was at or near the end of its useful life, according to the Edison Electric Institute (see Figure 9).

Figure 9. Current transmission infrastructure age, relative to useful life



Source: Edison Electric Institute ("EEI") / Harris Williams Co. "Transmission & Distribution Infrastructure." Summer 2014.
<http://www.harriswilliams.com/sites/default/files/industry_reports/ep_td_white_paper_06_10_14_final.pdf>

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[16] EIA. "Investment in electricity transmission infrastructure shows steady increase." August 26, 2014. <https://www.eia.gov/todayinenergy/detail.php?id=17711>

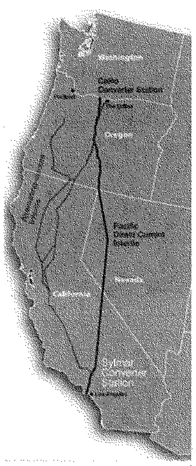
[17] EEI. "Transmission Projects: At a Glance." December 2016.

Many elements of the transmission system need ongoing maintenance, repair, and upgrading, or in some cases complete modernization, as exemplified by the recent experience of the Pacific Direct Current Intertie ("PDCI").

6.2.1 Case study: The 45-year old Pacific Direct Current intertie ("PDCI") needed refurbishment

The PDCI is a high-voltage direct current system ("HVDC") 846-mile transmission line connecting the Oregon/Washington border, with Los Angeles. The transmission line carries hydroelectricity generated by the 31 dams of the federal Columbia River power system. Converter stations at the two endpoints convert the power from direct current ("DC") to the alternating current ("AC") used by the rest of the grid (see Figure 10).

Figure 10. The Pacific Direct Current Intertie



Source: Bonneville Power Administration. <https://www.bpa.gov/news/pubs/FactSheets/fs-201604-Celilo-Converter-Station.pdf>

The line went into service in 1970 with a capacity of 1,440 MW and has had numerous additional investments since then to meet increased capacity and reliability needs. Most recently, during 2014 to 2015, the Bonneville Power Administration ("BPA") invested $320 million to modernize the Celilo Converter Station at the north end of the transmission line. The project replaced vintage equipment, such as transformers, with new equipment that is faster, more reliable, and easier to maintain. It also reduced the converter station's footprint by half. Most notable among Celilo's new equipment are new transformers and digital controls to replace 40-year-old analog equipment. The upgrade was completed in 2016. As is demonstrated by the PDCI project, substantial investment is continuously needed to keep critical, existing facilities in good working order. Moreover, such maintenance and incremental investment allows system operators to capture incremental capacity improvements.

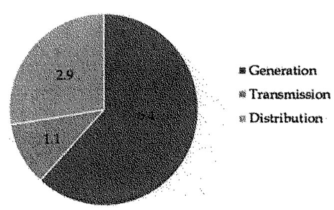
6.3 Myth: Transmission projects have large up-front costs which will be passed onto consumers

Transmission projects are often big and carry high price tags. In the US, the average cost for a 'typical' transmission project can range from $30 million to $300 million, depending on its scale. An interregional long-distance transmission project can cost as much as $1 billion or even more.[18] It is a myth that the best way to avoid high electricity bills for end-users is to avoid high price tags of large transmission projects.

6.4 Truth: The 'price tag' for construction of new transmission projects is recovered gradually, with only modest impacts on consumers at any given point in time

The cost of a transmission investment is spread over many years, over hundreds or even thousands of consumers, and over millions of kilowatt hours. Transmission costs account for only a small portion of the final electricity bill—typically around one cent per kilowatt hour, or 10% of the retail price (see Figure 11).[19]

Figure 11. Average retail electricity prices by service category, 2015 (cents per kilowatt hour)



Source: Energy Information Administration, Electricity Supply, Disposition, Prices, and Emissions. <https://www.eia.gov/outlooks/aeo/data/browser>

For an individual transmission project, even a large one, the impact is even smaller. A $2 billion project in a state the size of New York, multiplied by 18% (a rule-of-thumb for calculating annual revenue requirements), divided by an assumed 159,169 GWh of electricity consumption

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[18] Ibid.

[19] EIA. Factors affecting electricity prices. Accessed on July 11th, 2017. <https://www.eia.gov/energyexplained/index.cfm?page=electricity_factors_affecting_prices>

(New York state's 2016 consumption level), would cost consumers far less than a penny per kWh consumed, only around $0.00225/kWh.[20]

In contrast, generation (supply-related costs) accounts for the largest share of the electricity bill in the US, generally about 60%.[21] Drivers that impact the cost of generation, especially drivers such as fuel prices, have by far the largest impacts on monthly electricity bills and dwarf the incremental costs from transmission projects. In addition, transmission investments for projects designed to allow lower-cost generation resources to reach demand centers and to increase market competition help to lower costs of generation for end-users.

6.5 Myth: Large infrastructure investments might end up underutilized

Transmission planning is based on long-term commitments and must take into consideration potential future needs. However, failing to understand the complex evaluation process for transmission investment gives rise to the concern that the future is uncertain and that these future needs we are forecasting today may never come to fruition. These uncertainties lead to the myth that the transmission projects we are building for future need will very likely end up being underutilized.

6.6 Truth: Large projects are subject to detailed cost/benefit analyses, to help ensure their ultimate usefulness

Investment uncertainties around new transmission infrastructure can be quantified and analyzed comprehensively to mitigate the chances of a "bad" decision. For instance, transmission projects between Midcontinent Independent System Operator ("MISO") and Southwest Power Pool ("SPP") are required to have a benefit/cost ratio of 1.25 to the entire MISO region.[22] Such a benefit/cost ratio calculated for a range of future scenarios provides a high degree of certainty that the transmission investment will be prudent.

6.6.1 Case study: MISO evaluates a wide variety of benefits and imposes a high benefit-cost threshold to mitigate risk of underutilization

MISO gauges the value of proposed transmission projects under a variety of future policy and economic conditions across multiple quantitative benefit metrics. In its "Portfolio Economic Benefits Analysis," MISO acknowledges and considers a variety of qualitative benefits, such as enhanced generation policy flexibility, increased system robustness, decreased natural gas risk,

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[20] New York state demand was 159,169 GWh in 2016, NYISO. "2017 Gold Book." April 2017.

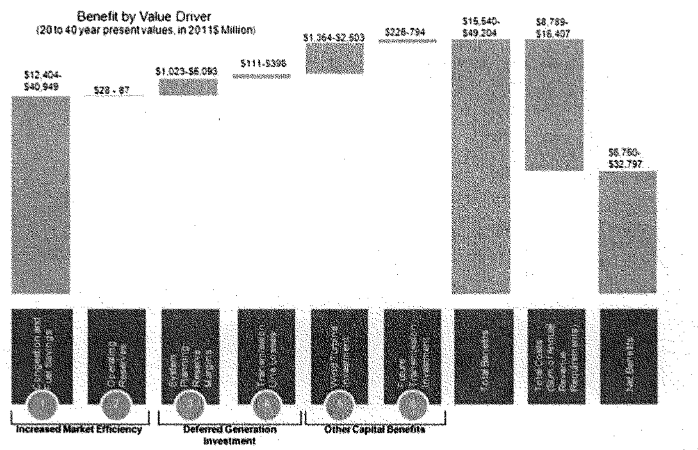
[21] U.S. Energy Information Administration, Annual Energy Outlook 2017, Reference case, Table 8: Electrical supply, disposition, prices, and emissions.

[22] FERC. Order Reject Tariff Revisions. Nov.30, 2015. Docket No. ER15-2705-000.

decreased wind generation volatility, local investment, and job creation, as well as carbon reduction (see Figure 12).[23]

MISO requires all its Market Efficiency Projects ("MEPs") to have a benefit/cost ratio of at least 1.25. MISO also imposes a higher hurdle for Multi-Value Projects ("MVPs"), expecting these to have benefit/cost ratios under all scenarios ranging from at least 1.8 to 3.0. These measures help to ensure economic efficiency and necessity of transmission investments at the early planning stage and avoid undue transmission expansion that could end up being underutilized.

Figure 12. Portfolio of economic benefits for Multi-value project in MISO's MTEP 2016



Source: "MISO Transmission Expansion Plan (MTEP16)." MISO. 2016. <https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20Full%20Report.pdf>

6.7 Myth: Transmission projects may be prone to overbuilding

A common belief is that large infrastructure investments that are paid for by consumers, like transmission projects, are prone to "gold-plating," or in other words, over-sizing and over-spending beyond what is actually needed. Concerns that the costs of initially unused myth that will become a cost burden on consumers lead to the myth that smaller, piecemeal projects may be a better choice, because they have the appearance of lower up-front cost commitments.

[23] "MISO Transmission Expansion Plan (MTEP16)." MISO. 2016. <https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20Full%20Report.pdf>

6.8 Truth: Transmission projects go through stringent and comprehensive cost-benefit evaluations to avoid overbuilding

Multiple avenues for avoiding and correcting "gold-plating" exist. For large transmission projects, a stakeholder review is required by FERC, the ISOs/RTOs, and the state agencies to ensure that investments are appropriate. Other venues for ensuring projects are sized appropriately for benefits and market activities include competitive procurements, where market forces are harnessed to control costs.

"Gold-plating," or overbuilding, is often raised as an objection to transmission projects when stakeholders do not understand the benefits and focus exclusively on costs. However, it is equally, if not more, important to support long-term grid reliability as reliable electric service will contribute to economic activity in a region. Deferring investment in transmission may result in risks of service interruption and higher costs in the future.

6.8.1 Case study: PJM studied many options for AP-South congestion relief as part of stakeholder review to ensure an optimal transmission investment

In 2015, PJM began a stakeholder process and an extensive analysis process to examine efficiency, reliability, and congestion relief solutions along the AP-South corridor near the Pennsylvania-Maryland border.[24] The AP-South Congestion Relief Solution study analyzed 41 proposals (see Figure 13).

Based on the results of the initial study, PJM selected four projects that could each potentially solve the congestion problem and were well above the required benefit-to-cost threshold of 1.25. Of the four, Transource's Project 9A provided the greatest congestion benefits and highest benefit-to-cost ratio. However, based on feedback from PJM stakeholders and in an effort to develop the most robust solution, PJM conducted additional sensitivity analysis studies to assess different combinations of several similar proposals in the same region. The second study again demonstrated that Project 9A consistently provided the most benefits across the scenarios studied. The PJM Board finally approved Project 9A in August 2016. The project, which is required to be in-service by 2020, has an estimated cost of $320.19 million and an expected 15-year congestion and load payment savings of $622 million and $269 million, respectively.[25] Notably, Project 9A was one of the largest projects proposed of the 10 finalist projects, whose costs ranged from $40 million to $230 (except Project 9A).[26] Project 9A was nevertheless the most effective investment from the perspective of PJM and consumers.

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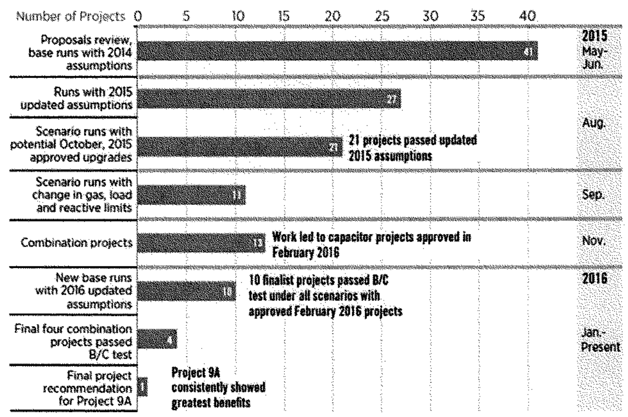
[24] PJM. "PJM Regional Transmission Expansion Plan 2016." February 28, 2017.

[25] Ibid.

[26] PJM. "Transmission Expansion Advisory Committee Market Efficiency Update." March 10, 2016. <http://www.pjm.com/~/media/committees-groups/committees/teac/20160310/20160310-market-efficiency-update.ashx>

Therefore, it is important to evaluate both the costs and benefits of a transmission investment, rather than focusing only on the costs, and a stringent and transparent evaluation process will include all the relevant costs and benefits.

Figure 13. PJM's review of options for AP-South congestion relief



Source: PJM. "PJM Regional Transmission Expansion Plan 2016." February 28, 2017.

6.8.2 Case study: AEP's 765-kV transmission project was novel in 1970s – but has since served as the backbone of its system

In 1969, American Electric Company ("AEP") developed the world's first 765-kV transmission line, a 68-mile line between Kentucky and Ohio.[27]

In 1966, when AEP first proposed this interstate ultra-high voltage transmission project, it was criticized as bold and unnecessary given engineering practices at that time. However, when the project was put into service, it eventually became the backbone of the electricity network in the Midwest by efficiently enabling interconnection of 1,300 MW generating units to serve the growing regional economy. Currently, AEP has over 2,100 miles of 765-kV network.[28]

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[27] AEP. "The Evolution of American Electric Power: Past, Present & Future." February 19, 2015. <http://energyweek.utexas.edu/files/2015/07/Crowder.pdf>

[28] Heyeck, Michael. "The Next Interstate System: 765-kV Transmission." *ELP. Electric Light & Power*. January 2007. <http://www.elp.com/articles/print/volume-85/issue-1/sections/td/the-next-interstate-system-765-kv-transmission.html>

Transmission investment must take into account long-term needs of the system and consider the technology that best achieves those needs. Investments perceived as "overbuilding" at one point can prove themselves as imperative to sustain a reliable and efficient grid system.

6.9 Myth: Project costs for interregional transmission projects are often unfairly allocated

Cost allocation is a challenge that frequently comes up, especially for interregional transmission projects. Determination of costs and benefits of a transmission project can be very complicated and the results can vary among stakeholders and variances can also arise under different methodologies. Opponents to transmission investments claim that cost allocation settlements can take years and result in long-term suspension and delay of transmission projects, causing electricity consumers and project developers to potentially be exposed to investment risks. Hence, a myth arises that large, interregional transmission projects should be avoided when possible.

6.10 Truth: Cost allocation issues are not insurmountable and can be resolved with both standard and customized solutions

Cost allocation is not a "new" issue. Transmission investment costs have been successfully allocated to different consumers since utilities first started charging for their services.

Significant progress has been made in developing and implementing standardized, widely-accepted cost allocation frameworks in recent years. ISO-NE, for example, has a default cost allocation mechanism for determining local and regional transmission costs. The MVPs in MISO are being developed based on a wide agreement of allocating the costs among benefiting states. The SPP region also uses a cost allocation mechanism for new electric transmission called "Highway/Byway" which was approved by FERC in 2010.[29] Meanwhile, customized tariff-based solutions, like in the case of the Tehachapi project in California described below, are possible where appropriate.

6.10.1 Case Study: Regional and local transmission cost allocation in ISO-NE - a standard solution

ISO-NE has established a well-accepted cost allocation scheme which has facilitated major transmission investments. Since 2003, ISO-NE/NEPOOL has adopted a default cost allocation mechanism, approved by FERC, which allocates transmission costs among six states and many different classes of consumers.[30] Every year, ISO-NE conducts a Regional System Plan ("RSP") which identifies a list of transmission projects that are expected to meet the reliability needs and

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[29] FERC. "Order Accepting Tariff Revisions. Southwest Power Pool, Inc. Docket No. ER10-1069-000." June 17, 2010. <https://www.ferc.gov/whats-new/comm-meet/2010/061710/E-7.pdf>

[30] FERC Technical conference on Connecticut infrastructure. *Allocating the Cost of New Transmission in New England.* January 6, 2005. <https://www.ferc.gov/CalendarFiles/20050124145350-Whitley,%20Cost%20Allocation.pdf>

bring economic benefits to the New England region. ISO-NE reviews the reliability of design proposed by transmission owners and determines what costs should be regionalized and what portions should be localized.[31]

Specifically, projects with 115kv and above capacity identified in the RSP are categorized as regional benefit upgrades, whose costs are allocated in proportion to each ISO-NE state's peak electricity demand, and are funded through a pool-wide postage stamp rate[32] for their regional network service. Smaller projects (generally less than 115kv and those which do not provide regional benefits) are categorized as local benefit upgrades, whose costs are allocated through a license plate rate.[33]

6.10.2 Case study: Tariff-based cost allocation for Tehachapi project – a customized solution

The Tehachapi Renewable Transmission Project ("TRTP") in California provides an example of a customized tariff-based solution to cost allocation for an inter-regional transmission project.

The Tehachapi area is one of California's leading resource areas for wind energy, but there was limited transmission infrastructure in the region to bring the wind energy to market.[34] Southern California Edison ("SCE") developed the TRTP 500 kV transmission line to deliver the wind energy to load centers in Los Angeles and San Bernardino counties, which allowed development of the wind resources of the Tehachapi area.

Segment 3 of this project was developed under a FERC-approved Location Constrained Resources Interconnection tariff ("LCRI"). Transmission owners paid upfront, and generators must pay pro-rata shares of costs when they interconnect and come in-service.[35] The TRTP line was energized in 2016.

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[31] Fink, S. et, al. "A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations." NREL. February 2011. <http://www.nrel.gov/docs/fy11osti/49880.pdf>

[32] Under a "postage-stamp" rate design, the costs of all existing transmission facilities in a large region are "rolled-in" and allocated to all consumers according to each consumer's share of the region's total load. As a result, the rate is the same for each consumer in the large region akin to a postage stamp that ensures delivery across the U.S., regardless of the distance.

[33] Under a "license plate" rate design, the rates for transmission vary by zone, rates can be differentiated based on distance or other metrics between zones.

[34] SCE. "The Tehachapi Renewable Transmission Project: Greening the Grid—Celebrating California's Progress in Renewable Energy." March 2010.

[35] Ibid.

7 Myths and truths about the benefits of transmission

The benefits of a transmission project could be geographically widespread and take various forms. One needs to take a holistic view to assess the benefits of transmission projects, which will also help decision makers and transmission consumers to better understand the costs of transmission objectively.

It is critical to recognize that the potential benefits of a transmission project go way beyond meeting regional energy demand—they could also include storm hardening, increased competition in wholesale power markets, congestion relief, deferral of new generation or other upgrades, expanded economic activity, increases in state or local property tax collections, and numerous other attributes that may impact local economies.

7.1 Myth: Consumers on the receiving end are the only ones who benefit

It is widely accepted that transmission projects benefit the consumers who are receiving the power, but it is a myth that consumers on the receiving end of the transmission line (where the power is "sinking") are the only ones who benefit and that it is unfair for consumers in the regions along the route to also some of bear the cost.[36]

7.2 Truth: Benefits can be geographically and demographically widespread

From a geographic perspective, a state that is a source of supply ("source") may see benefits from the construction of the transmission line, including economic benefits during construction, economic benefits from taxes or other payments once the project is complete, as well as economic opportunities in the future for the development of new generation. Transit states or regions will see benefits from property taxes collected from the transmission operator in addition to potential electricity cost savings and environmental benefits. "Sink" locations, i.e. the receiving end, will see local economic and reliability benefits from more access to electric power and could also see "knock-on" effects from local economic boom from construction activities.

7.2.1 Case study: TransWest Express

The TransWest Express Transmission Project, a 600kV, 725-mile long transmission line, was proposed to provide 3,000 MW of capacity to deliver approximately 20,000 GWh/year of wind energy generated in Wyoming to Arizona, Nevada, and southern California. As of June 2017, TransWest Express has received approval from the Bureau of Land Management for its proposed right-of-way, and construction is expected to take place during 2018 to 2020.

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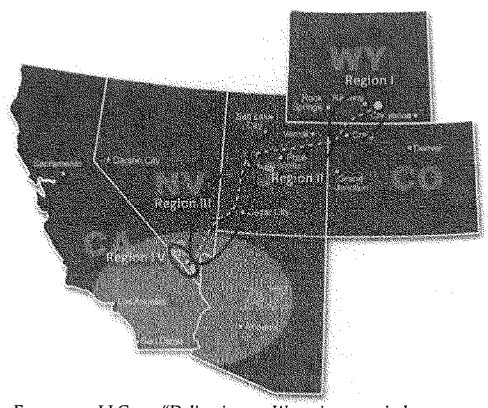
[36] Prepared by The Brattle Group, for WIRES. *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments.* July 2013. "WIRES Preface and Commentary." Pg. 4.

Projected benefits of the line are not limited to the availability of energy to consumers on the receiving end. Four distinct economic regions along the transmission lines were identified as benefiting from increases in direct and indirect employment (see Figure 14). According to TransWest's preliminary economic impact study, direct employment associated with the construction of each region would average approximately 203 jobs over the construction period, and secondary employment is expected to reach, on average, 89 jobs over the construction phase.[37] Obviously, all regions along the route, not only the "sink," will benefit from construction activities of this project in terms of local economic growth and employment increase.

Figure 14. TransWest Express project route



Source: TransWest Express LLC. "Delivering Wyoming wind energy to the West." <http://www.transwestexpress.net/index.shtml>

7.3 Myth: Transmission should not be built for any reason other than for resolving reliability issues

It has been argued that transmission is only needed where there are reliability issues on the grid and that, as a result, non-reliability projects are not justifiable.

[37] *TransWest Express EIS. Section 3.17 – Social and Economic Resources.* Western Energy. April 2015. Docket: DOE/EIS-0450. <https://eplanning.blm.gov/epl-front-office/projects/nepa/65198/78887/90846/06-Chapter3.17-SocialandEconomicResources.pdf>

7.4 Truth: A transmission project initiated for reliability reasons may have other economic benefits and vice-versa

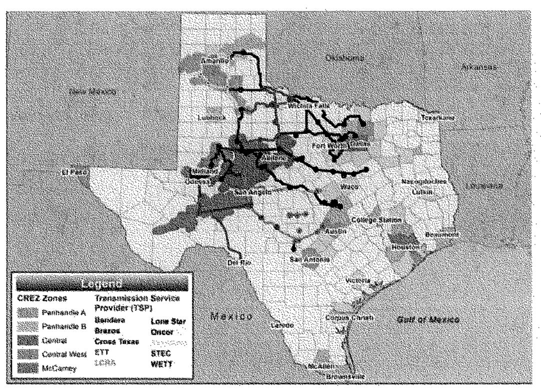
This myth overlooks the fact that transmission investment targeting reliability will naturally bring about other benefits, such as reducing system costs or providing a variety of economic benefits such as supporting local industries, and potentially motivate other investments.

New York and Texas are single-state RTOs, and thus state policy and oversight of the transmission system are easier to coordinate than in RTOs that encompass multiple states. Transmission investments in these states for purposes other than reliability are good examples of the reality of the multi-faceted nature of benefits. The Texas Competitive Renewable Energy Zones ("CREZ") initiative was aimed at achieving renewable policy goals, but also reduced system-wide wholesale electricity prices and has other benefits. In New York, when identifying a recent "public policy" project, the state examined broad categories of transmission benefits.

7.4.1 Case study: Texas built the CREZ lines based on policy drivers, with additional economic benefits to consumers

In 2008, the Public Utility Commission of Texas ("PUCT") established CREZ to encourage the building of long-distance transmission lines to bring wind power to the grid and to consumers. The goal of the CREZ initiative was to allow the delivery of energy produced by renewable resources (primarily wind) in the West and South zones to the load centers in North, South, and Houston zones (see Figure 15).

Figure 15. Competitive Renewable Energy Zones and transmission lines (completed)



Source: Warren Lasher, Director of System Planning, ERCOT. *The Competitive Renewable Energy Zones Process*, August 11, 2014. <https://energy.gov/sites/prod/files/2014/08/f18/c_lasher_qer_santafe_presentation.pdf>

The impetus for CREZ came from the then-governor of Texas, Rick Perry, and concerns over the high fossil fuel prices at the time (2003). However, by the time the final recommendations of Perry's policy group, the Texas Energy Planning Council ("TEPC") were released, renewable energy, namely wind, had gained a central role in the energy plan. As Texas's abundant wind resources are far from load, the eventual legislation that resulted from the Governor's committee included support for the development of high-capacity long-distance transmission lines, as well as an increase of Texas's RPS requirements.

The CREZ transmission expansions were completed in January 2014, enabling dispatch of 18,500 MW of wind capacity.[38] Since the completion of the lines, wholesale energy costs system-wide (not just in ERCOT West, where most of the wind plants are located) have reflected the low cost of wind generation. Sporadic hourly negative real-time prices ERCOT-wide began after the CREZ system was energized and have persisted throughout 2015 (54 hours), 2016 (128 hours) and 2017 (35 hours as of July 2017)—even during summer months. Negative prices were seen in not only in one zone, but all across the system. These low energy prices are a concrete and measurable benefit to consumers (though they are challenging for some generators given the current market design). Thus, the CREZ lines not only helped meet renewable policy goals, but have provided electricity market benefits to consumers. An additional benefit is that CREZ lines can accommodate solar power, which tends to generate more during non-windy hours. Some of the CREZ lines have also provided system access to new consumers (see Section 3.2.2 for oil and gas developments). As such, CREZ projects have reinforced system reliability as well.

7.4.2 Case study: New York examined broad categories of transmission benefits to justify transmission investment

In 2015, New York Public Service Committee ("PSC") identified a very precise set of transmission upgrades in its footprint that would be necessary pursuant to the state's policy goals.[39] These upgrades would provide a 375 MW increase in the Central-East interface voltage transfer limit,[40] as well as increase by 939 MW the UPNY/SENY interface normal transfer limit.[41]

These upgrades are expected to reduce transmission constraints between the western and eastern regions of New York, which in turn will ease the downward pressure on western New

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[38] Malewitz, Jim. "$7 Billion CREZ project near finished, aiding wind power." October 14, 2013. <https://www.texastribune.org/2013/10/14/7-billion-crez-project-nears-finish-aiding-wind-po/> and ERCOT. *Competitive Renewable Energy Zones: Transmission Optimization Study*. April 2008.

[39] NY PSC. *Order Finding Transmission Needs Driven by Public Policy Requirements*. Case 13-E-0488. December 17, 2015.

[40] The C/E interface is typically voltage limited, therefore voltage limits were the focus of NYISO's evaluations.

[41] NYISO. *AC Transmission Cases: Updated Powerflow Analysis*. NY PSC Case 13-E-0488. October 8, 2015 (posted October 14, 2015).

York energy prices. In addition, the New York PSC also identified significant environmental, economic, and reliability benefits that could be achieved by relieving the transmission congestion in New York. The project continues to move forward—as of July 2017, the selection process of the to-be-constructed project and transmission sponsor is under way.

7.5 Myth: Transmission investment is risky, because transmission benefits are uncertain, while the costs are certain

Failing to understand the multi-faceted nature of transmission investment benefits, or evaluating a transmission investment in a short-sighted manner will inevitably bring about another myth: the benefits of transmission investments touted by developers are often intangible or "uncertain," but consumers are required to pay for the costs regardless whether benefits materialize. Due to this uncertainty of benefits, some stakeholders argue that large and costly transmission projects should not be pursued.

7.6 Truth: Transmission investment risks can be managed

Any investment involves uncertainty and risk. Yet risks can be managed through prudent analysis and decision-making. For example, some ISOs/RTOs specifically set high benefit-to-cost ratio thresholds to ensure that risky projects are not undertaken (see discussion in Section 6.6). Other ISOs/RTOs, such as CAISO and MISO, also evaluate a broad set of scenarios to test whether benefits are robust across a wide range of uncertain outcomes.[42]

Uncertainty is also bi-directional. In other words, the actual benefits could be larger than estimated benefits. This is especially true if the benefit analysis was conservative.

Furthermore, not all benefits of transmission investment are immediate or obvious; some may be hard to quantify and others may have different values for different stakeholders. However, as explained in-depth in Section 7.2 and Section 7.3, benefits of transmission investment take various forms, are spread extensively geographically, and last for decades (as described in other WIRES white papers, see Figure 16).

[42] CAISO. *Transmission Economic Assessment Methodology.* June 2004. See also Section 6.6 for discussion of the MISO evaluation process.

Figure 16. Potential benefits of transmission investments

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Production cost savings as traditionally estimated
1a-1i. Additional Production Cost Savings	a. Reduced transmission energy losses
	b. Reduced congestion due to transmission outages
	c. Mitigation of extreme events and system contingencies
	d. Mitigation of weather and load uncertainty
	e. Reduced cost due to imperfect foresight of real-time system conditions
	f. Reduced cost of cycling power plants
	g. Reduced amounts and costs of operating reserves and other ancillary services
	h. Mitigation of reliability-must-run (RMR) conditions
	i. More realistic representation of system utilization in "Day-1" markets
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects
	b. Reduced loss of load probability or
	c. Reduced planning reserve margin
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses
	b. Deferred generation capacity investments
	c. Access to lower-cost generation resources
4. Market Benefits	a. Increased competition
	b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants
	b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
7. Employment and Economic Development Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, increased load serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion-hedging value, and HVDC operational benefits

Source: WIRES. "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments." July 2013.
<http://wiresgroup.com/docs/reports/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf>

8 From myths to reality: Recommendations for a change of perspectives in investment planning and decision-making

To avoid myths and to think about transmission investment realistically, decision makers need to adopt a comprehensive and consistent approach to evaluating the costs and benefits of transmission.

LEI recommends that this approach recognize a common set of evaluation criteria (or metrics) across all types of transmission projects (see Figure 17). Even if a project has been proposed for reliability, for example, it might also have benefits related to market efficiency and/or policy. Applying a broad set of metrics to every transmission investment would ensure that all potential benefits would be captured for evaluation.

Figure 17. Evaluation metrics should be comprehensive and consistent

Evaluation metric
Price reduction benefits
Production efficiency gains
Generation capacity cost savings
Environmental benefits
Competitive market benefits
Load diversity benefits
Public policy benefits
Macroeconomic benefits
Reliability benefits
Fuel diversity benefits

8.1 Costs and benefits should be evaluated as a whole package

Some benefits of a transmission project tend to increase over time with both load growth and fuel price inflation. At the same time, costs tend to leave an impression of being "front-loaded," although in fact, the investment costs are typically spread over many years in rates to consumers, and decline over time as capital cost is depreciated. Transmission investments have benefits and cost lives that extend well beyond 40 years. In spite of this, many transmission investment decisions are made based on comparisons of costs and benefits over a much shorter period than the typical 40-year useful life of the asset, for example, for the first 10 years of a project. Requiring a comparison of the first 10 years of estimated benefits with annual transmission consumer costs for the same number of years raises the benefit-to-cost threshold that projects must overcome.[43] Instead, we recommend analysis of benefits over a longer period

[43] The Brattle Group. *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*. July 2013. Pg. 17.

to better match the life of the investment. In addition, it is important for benefits of investments to be measured against an accurate view of the world of not doing the project. Frequently, opportunity costs are ignored even though the costs of a reliability shortfall are well recognized.[44]

There are many other dimensions of costs and benefits that need to be paired accurately to ensure that sound decisions are being made, as discussed below.

8.2 Transmission alternatives need to be examined comprehensively

As noted previously, alternatives to transmission (NTAs and MRAs) and transmission investment offer a range of different types of benefits. While it is true that MRAs can provide valuable services, transmission infrastructure tends to provide a broader array of benefits that accrue to a wider variety of parties over a larger geographical dimension (as well as to local areas). Thus, an optimal process is not one that poses an either/or decision (treating transmission and MRAs as substitutes), but one which treats them as potential complements, and asks "how much of each should we use in this circumstance?" When considering the costs, the cost of subsidies provided to some distributed generation such as behind-the-meter solar PV should also be included as an indirect cost. In addition, positive and negative externalities should be considered, thereby evaluating indirect benefits or costs on various stakeholders.

8.3 Recognize that certainty of costs and uncertainty of benefits can be an illusion

It is easier to perceive the costs of an investment than to envision its benefits. The cost of an investment is up-front (at least when described in capital spending terms) and "known" while benefits can be of varying magnitudes over time and will depend upon how the future unfolds. In addition, it is difficult for most stakeholders to perceive the cost of not taking action. However, there are real costs to inaction—system reliability can hamper local economic activities (for example, if there is simply insufficient electricity to meet demand, some economic activities will need to be interrupted). Inaction can also increase the cost of electricity (due to the lack of efficient resources and rising congestion when existing transmission capacity is "used up").

8.4 Plan for the future

Not only is transmission a long-lived asset, its required siting, permitting and construction time frames are also lengthy, as noted previously. Thus, investors need to project drivers for transmission investment many years into the future, so that when the transmission development project is finally completed and energized, it will be the right size, and in the right place. For example, the timing of many nuclear license expirations (for the 2030s and early

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[44] Frayer, Julia, et al. *Estimating the Value of Lost Load—Electric Reliability Council of Texas.* LEI. June 2013. <http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf>

2040s) seems far into the future right now; but a transmission development process that begins in 2018 and takes 10-15 years to complete will result in a project that will serve the market for many years *after* those nuclear plants retire.

8.5 Overcome the natural human tendency to over-rely on recent experience

Looking out over the long term, developing realistic assumptions for forward-looking investment analysis and system planning is not straight forward. The use of scenario analysis to understand and quantify some of the uncertainties in long-term investment can be valuable. Scenarios should include a "business as usual" scenario, as well as alternative scenarios that contain various transmission solutions and technically-suitable alternatives, or alternative values for drivers (such as varying assumptions for future natural gas prices, economic activities and consumer behavior patterns around electricity use).

Scenario analysis is built on plausible futures that are intended to envelop the range of outcomes, not just outcomes that mirror recent experience. If all the scenarios were to identify meaningful benefits, that suggests that even if one were uncertain about the future, there would be benefits to the investment regardless of which scenario was actually realized.

8.6 Plan for the unexpected

A "most-likely" analysis cannot capture the impact of unlikely but extreme events. These events can have expensive consequences for consumers. For example, during the winter of 2013/14, the coldest winter in 20 years in many places,[45] there were in fact three "Polar Vortexes" that extended across the Eastern seaboard of the US. Many ISOs/RTOs saw unprecedently high winter peak loads and experienced very high energy prices (see Figure 18). For instance, the NYISO set a new record winter peak load of 25,738 MW, and requested voluntary reduction from about 900 MW of its demand resources.[46] ISO-NE reached a peak just short of its all-time historic peak and also called for demand response resources to be ready for deployment.[47] PJM and some providers in South Carolina had to cut voltage in their areas by 5%, while South Carolina Electric & Gas was forced to disconnect some consumers to ensure that the power grid could remain within safe operating limits and could withstand a worsening of the emergency.[48]

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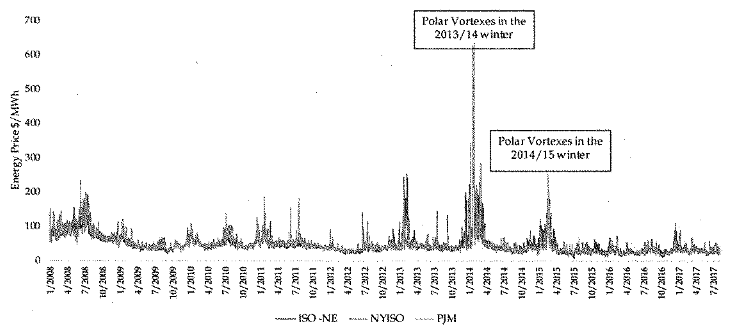
[45] NERC. *Polar Vortex Review.* September 2014. <http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf>

[46] NYISO. *Winter 2013-2014 Cold Weather Operating Performance.* March 2014. <http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2014-03-13/Winter%202013-1014%20NYISO%20Cold%20Snap%20Operations%20EGCW-MIWG.pdf>

[47] FERC. *Winter 2013-2014 operations and market performance in RTOs and ISOs.* April 1, 2014. <https://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf>

[48] Kemp, John. "U.S. power grid survived polar vortex, but only just: Kemp." *Reuters.* October 3, 2014. <http://www.reuters.com/article/us-usa-power-weather-kemp-idUSKCN0HQ4TB20141003>

Figure 18. Energy price hikes in New England, New York, and PJM during Polar Vortexes



Note: The figure presents rolling hourly LMPs for the Internal Hub in ISO-NE, New York City (Zone J) in NYISO, and PSEG zone in PJM, from January 2008 to July 2017.

Source: Third-part data provider.

A system-wide blackout can amount to billions of dollars of economic losses. For example, the total cost of a 12-hour system-wide outage in MISO, which has an outage cost of $3,500/MWh and an average hourly load of 76,850 MWs, would amount to $3.2 billion.[49] Prior economic studies have pinpointed economic losses from the blackout of 2003 to as much as $4-$10 billion.[50] A transmission line can help moderate consumer rate hikes due to weather driven events and could in some circumstances make the system more resilient and insure against an expensive system-wide blackout.

8.7 Conclusion

Decision-making around transmission investment is complex and multi-faceted, and each transmission project is unique to some degree in the mix of benefits it can provide to consumers and the electric system. As we have shown, relying on outdated myths can handicap the decision-making process, mistakenly reject valuable transmission investment, and result in missed opportunities to benefit consumers. We must strive to correct the myths in our thinking about transmission investment and must also move the investment analysis in a direction which will allow us to avoid the trap of making more "myths." In doing so, we can thereby ultimately support more informed transmission investment decision-making in the future.

[49] MISO Market Subcommittee. "Evaluating Energy Offer Cap Policy Market Roadmap." May 3, 2016 and Energy Velocity (data for average hourly load in 2016).

[50] U.S. Department of Energy, U.S.-Canada Power System Outage Task Force. "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations." April 2004. <https://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf>

9. Appendix: Acronyms

AC	Alternating Current
BPA	Bonneville Power Administration
CPUC	California Public Utilities Commission
CREZ	Texas Competitive Renewable Energy Zones
DC	Direct Current
DOE	US Department of Energy
DOM	PJM Dominion Virginia Power Zone
EEI	Edison Electric Institute
EIA	US Energy Information Administration
ERCOT	Electric Reliability Council of Texas
EV	Electric Vehicles
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
IPP	Independent Power Producer
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
LCRI	Location Constrained Resources Interconnection
LEI	London Economics International LLC
MEP	Market Efficiency Project
MISO	Midcontinent Independent System Operator
MRAs	Market Resource Alternatives
MVP	Multi-Value Project
NERC	North American Electric Reliability Corporation
NTAs	Non-transmission Alternatives
NYISO	New York Independent System Operator
PDCI	Pacific Direct Current Intertie
PEVs	Plug-in Electric Vehicles
PG&E	Pacific Gas and Electric Company
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PSC	Public Service Committee
PUCT	Public Utility Commission of Texas
PV	Photo Voltaic
RPS	Renewable Portfolio Standard
RSP	Regional System Plan
RTO	Regional Transmission Organization
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SPP	Southwest Power Pool
TEPC	Texas Energy Planning Council
TRTP	Tehachapi Renewable Transmission Project

APPENDIX C

Service Provided by Market Resource Alternatives Compared to Transmission Services

		Transmission	Energy Efficiency	Demand Response	Distributed Generation	Energy Storage
What	Energy	●	◑	◑	◕	●
	Capacity	●	◑	◑	◕	●
	Ancillary Services	●	○	◑	◕	●
	Reduce system losses	●	◑	◑	◕	●
When	Long lifespan	●	◕	○	●	●
	Continuous basis	●	◕	○	○	●
Where	Regional	●	◑	◑	○	○
	Local	●	●	●	●	●
	Micro	●	●	●	●	●
How	System/Wholesale	●	○	○	○	●
	Customer/Retail	○	●	●	●	○
	TOTAL	●	◑	◔	◑	◕

● Provided ○ Not provided

Source: London Economics International. *A WIRES Report on Market Resource Alternatives: An Examination of New Technologies in the Electric Transmission Planning Process.* October 2014. Pg. 13.

The CHAIRMAN. Thank you, Mr. Hoecker.

Mr. Kelliher, welcome.

STATEMENT OF HON. JOSEPH T. KELLIHER, EXECUTIVE VICE PRESIDENT–FEDERAL REGULATORY AFFAIRS, NEXTERA ENERGY, INC.

Mr. KELLIHER. Thank you.

Chairman Murkowski, Senator King, members of the Committee, thanks for the opportunity to testify today. I'm appearing on behalf of NextEra Energy which is one of the largest energy holding companies in the United States. NextEra owns or operates 47,000 megawatts of electricity in 33 states. We're the largest electric generator in the country and we have the most diverse electricity supply of the largest generators. We also operate a large electricity transmission grid, and we have gas pipeline businesses that we own and operate. So we have an interest in both sides of the infrastructure issues that you're looking at today.

I want to commend you for holding this hearing. The importance of energy infrastructure is not very well understood, but strong energy infrastructure is the foundation for competitive electricity and gas markets and it's necessary for delivering benefits to customers.

The energy infrastructure investments that have been made up to this point made it possible for the U.S. electricity supply to evolve in recent years allowing the deploying of new technologies and the retirement of uneconomic generation. New gas pipeline infrastructure enabled the nation to secure the benefits of the shale gas revolution and strengthening, in my view, strengthening the energy infrastructure is the real resilience issue. The resilience associated with onsite fuel is insignificant by comparison.

Regulatory policy plays an important role in securing the necessary investment for energy infrastructure and affects the risk of that investment. Regulatory policy determines how long it takes to approve and site new facilities. And it's important that energy— that regulatory policy governing energy infrastructure development be highly merits-based and non-political and that there be a reasonable level of regulatory certainty and that those decisions be fairly predictable and timely. FERC, in my view, is ideally suited to make those decisions because of its long-standing commitment to merits-based decision-making and its status as an independent agency.

Very large-scale investments are needed to maintain and strengthen our energy infrastructure but there are challenges that face interstate natural gas pipeline and electric transmission development. Those challenges are different confronting those two, both the grid and the pipeline development. The primary challenge to interstate pipeline development is the siting process. Siting of pipelines is governed, as Mr. Moffatt pointed out, it's governed by the exclusive siting provisions in the Natural Gas Act where FERC is charged with certificating pipelines it determines are in the public convenience and necessity. Although FERC has exclusive jurisdiction to certify pipelines, there usually is a need for approvals from other federal agencies and state agencies acting under federally delegated authority such as the Clean Water Act.

Pipeline siting though, however, has become highly litigious involving advocacy groups that are dedicated to blocking infrastructure development. Some states, also, have been very aggressive in their use of federally-delegated authority to effectively veto projects.

FERC pipeline certification is governed by the 1999 policy statement and last December FERC announced that it would review the policy statement and I support that review. I think after 20 years, it's reasonable to review whether the policies that are reflected in the policy statement are sound. I do believe that the descriptive policy statement is sound and no major reforms are warranted, but I think there's some changes that FERC could make to how it issues the certificate orders for individual projects that are warranted and would make those orders more consistent with the policy statement. Under the policy statement, FERC determines whether a proposed project is in the public interest by balancing the project benefits against adverse impacts and practice this balancing is not very transparent in the certificate orders.

Applicants do put evidence in the record about project benefits. Those benefits are typically not discussed in the certificate orders themselves. And I think there's a need for FERC to be more transparent in the balancing of benefits and adverse impacts and in the certificate orders. I think there's also a need for FERC to clarify whether and how environmental impacts should be weighed in this balancing and whether environmental review is governed by NEPA or by the Natural Gas Act itself.

There are different challenges that face electric grid development. One challenge in particular is uncertainty about the level of return on equity that FERC will allow for investment. In response to abnormal conditions in financial markets a few years ago, FERC reformed the methodology that it uses to determine return on equity, or ROE. Those reforms, however, were challenged in court last year and the DC Circuit vacated the orders where FERC adopted its new methodology. It's very important that FERC act in the near future to clarify its policy toward ROE and remove this regulatory uncertainty which underpins future grid investment.

There are also challenges around the RTO transition planning process. There have been some concerns about Order 1000, how well it's working. One area of Order 1000 that has been a success, and I think we should consider whether that success should be expanded, is on the competitive development. FERC 1000 has encouraged competition and development of regional projects. I think there's been some significant successes in some regions and perhaps that success should be reinforced and broadened.

With that, I look forward to answering any questions the Committee might have and, again, I commend you for holding the hearing.

Thank you.

[The prepared statement of Mr. Kelliher follows:]

Statement of Joseph T. Kelliher
Executive Vice President-Federal Regulatory Affairs
NextEra Energy, Inc.

Committee on Energy and Natural Resources
United States Senate

July 12, 2018

"Policy Issues Facing Interstate Delivery Networks for Natural Gas and Electricity"

Overview

Thank you for inviting me to testify today on policy issues facing interstate delivery networks for natural gas and electricity. I am testifying on behalf of NextEra Energy, Inc. NextEra Energy is one of the leading energy holding companies in North America, owning through its subsidiaries approximately 46,790 MW of net generating capacity in 33 states in the U.S. and 4 provinces in Canada, as of December 31, 2017. NextEra's operations are conducted primarily through two business units: 1) Florida Power & Light, a vertically integrated public utility operating in peninsular Florida, and 2) NextEra Energy Resources, the parent company of NextEra Energy's competitive generating and trading businesses. NextEra Energy Transmission is the parent company of our competitive electric transmission business. NextEra Energy also has a natural gas production business and a natural gas pipeline business, operating an interstate natural gas pipeline in Florida and intrastate pipelines in Texas. We have an ownership interests in two other interstate natural gas pipelines, an operating project in the Southeast and a pipeline under construction in the MidAtlantic.

I commend you for holding this hearing. The relationship between the strength of our energy infrastructure and our ability to achieve other energy policy goals is not widely understood. A strong energy infrastructure is the foundation of competitive electricity and natural markets, essential for delivering benefits to electricity and natural gas customers. Energy infrastructure investments made it possible for our electricity supply mix to evolve in response to changing market conditions and allowed the deployment of new solar and wind technologies. New interstate natural gas pipeline infrastructure enabled the Nation to secure the benefits of the shale gas revolution. A more robust power grid and interstate pipeline network will do more to strengthen energy delivery system resiliency than any other factor.

Regulatory policy plays an important role in securing the necessary levels of infrastructure investment and affects the level of risk associated with that investment.

Regulatory policy also determines how long it takes to site and license or certificate infrastructure facilities. Unpredictability in siting decisions at a minimum involves the risk of significant delays in project operations, resulting in harm to both customers and markets.

It is important that regulatory policy governing investment and siting decisions be highly merits-based and nonpolitical, that there be a reasonable level of regulatory certainty, that decisions be fairly predictable, and that decisions also be timely. FERC is ideally suited to make infrastructure decisions because of its longstanding commitment to merits-based decisionmaking and its status as an independent agency not subject to control by the political branches. FERC's long history of merits-based decisions has helped produce our strong interstate natural gas pipeline network and interstate power grid.

Primary Challenges and Opportunities for Energy Delivery Networks and their Customers

The primary opportunity for energy delivery networks is the significant level of investment necessary to develop the energy infrastructure our country needs. Estimates are that $90 billion will be invested in electricity transmission projects between 2017-20, and that up to $100 billion in investment in interstate natural gas pipelines will be needed between 2018-35. The infrastructure improvements that will result from those investments will benefit the customers of electricity and natural gas networks.

Current electricity and natural gas markets are highly dynamic. We are experiencing the most dramatic changes in the U.S. electricity supply in a hundred years, driven by low natural gas prices and steady improvements in solar and wind technologies. Older, uneconomic generation facilities have retired in favor of newer technologies that are more efficient and have superior operational flexibility. These improved technologies have significantly improved the diversity of U.S. electricity supply; we now have more diversity in our electricity supply than at any point in the past.

However, today's electric grid was developed to deliver yesterday's electricity supply. As our electricity supply mix changes, we need a different grid, one capable of delivering more renewables and new, efficient natural gas generation, while accommodating the retirement of older, uneconomic generation facilities. Changes in the U.S. electricity supply mix were only possible because of robust investment in transmission. New investments in transmission must keep pace to support continued evolution of the U.S. generation fleet.

Similarly, the shale gas revolution shifted production into new supply regions and increased domestic production, creating the need for an expanded interstate pipeline network to move gas to markets. Without those investments in energy infrastructure the customers would have lost the benefits of the shale gas revolution.

Indeed, there is a relationship between our changing electricity supply mix and the shale gas revolution, since the availability of plentiful low cost gas put tremendous downward pressure on electricity prices. The driver of the retirement of uneconomic nuclear and coal generation is primarily economic, a consequence of low natural gas prices. The U.S. has been able to reap the benefits of our changing electricity supply mix and the shale gas revolution because of investments in energy infrastructure.

But there are challenges to developing the energy infrastructure our country needs.

Challenges to Interstate Pipeline Development

The challenges facing interstate natural gas pipelines and electric transmission facilities are different. The primary challenge in development of interstate natural gas pipelines is the siting process, a challenge that has increased in recent years. Siting of interstate natural gas pipelines is governed by the exclusive siting provisions in the Natural Gas Act, where FERC is charged with certifying pipelines that it determines are in the public convenience and necessity. Although FERC has exclusive jurisdiction to certificate or license interstate pipelines, usually there is a need for approvals by other federal agencies, such as the U.S. Army Corps of Engineers for Section 404 permits, and state agencies exercising delegated authority under federal laws such as Section 401 of the Clean Water Act.

The pipeline siting process has become highly litigious, involving advocacy groups dedicated to blocking infrastructure development. Opponents of energy infrastructure frequently file stay requests to suspend project construction and to even suspend the operation of completed projects after commercial operations have begun.

Some states have been very aggressive in their use of federally delegated authority to effectively veto certificated projects. There is limited ability to police use of delegated authority by the states in this manner under current law.

Last December, the Commission announced it would conduct a review of its 1999 gas certificate policy statement. I believe there is merit in reviewing Commission policies from time to time to consider whether there is a need for reforms. In my view, the certificate policy statement is sound and no major reforms are warranted. However, I believe the Commission should consider changes to its certificate orders to assure consistency with the certificate policy statement. Under the policy statement, the Commission determines whether a proposed pipeline is in the public interest by balancing project benefits against adverse impacts.

In practice, this balancing is not very transparent in the certificate orders themselves. Many applicants put evidence in the record about project benefits, such as securing access to new resource basins, lowering gas prices, introducing or increasing competition among pipelines, reducing the number of captive markets, and providing gas access to unserved markets. However, certificate orders typically do not discuss project benefits, focusing instead on how much of a proposed pipeline's capacity is committed through precedent agreements. There is little doubt that precedent agreements are the best measure of demand for new pipeline capacity, but precedent agreements speak to the need for a project rather than project benefits. There is a need to clarify whether and how environmental impacts should be weighed in this balancing, and whether the Commission's environmental review is under the auspices of the National Environmental Policy Act of 1969 or part of the broader public interest determination in the Natural Gas Act.

Another challenge to natural gas pipeline development is the increasing and unpredictable length of the process. The Commission certificate process takes much longer than previously. For major pipeline projects, the certificate process has two stages, the pre-filing process and the formal certificate process. The pre-filing process, an informal process developed to encourage early resolution of issues such as a project's route, used to routinely take 6-8 months and now takes up to 12 months. The certificate process used to regularly take 9-11 months and now takes 24 months or longer. Altogether, a process that used to reliably take two years or less now takes up to three years. That extra year is a year of lost customer benefits, and an additional margin of risk imposed on pipeline developers. FERC recognizes the importance of timely decisionmaking, and has invited ideas on process reforms to improve timeliness in its notice of inquiry on the certificate policy statement issued earlier this year.

One factor that has contributed to the length of the certificate process is delays in approvals from other federal agencies. If these delays are driven by resource limits at these agencies, the cost incurred by these agencies could be reimbursed by pipeline developers in a manner consistent with how the costs of other federal agencies in the hydropower licensing and relicensing process are recovered from hydropower licensees.

Challenges to Electric Transmission Grid Development

As I noted earlier, the challenges to development of electric transmission facilities are different than those confronting natural gas pipelines. One significant challenge to electric transmission grid development is uncertainty about the level of the return on equity (ROE) that FERC will allow for investments in new electric transmission facilities. This is relatively more important when it comes to electric transmission investments than pipeline investments, since pipeline projects are usually anchored by negotiated rate contracts, relying less on tariff or recourse rates than electric transmission projects that rely exclusively on tariff rates.

It has long been recognized that FERC has a legal duty to allow a reasonable return on investment. But FERC has discretion on how to set ROE in a manner consistent with legal principles. A few years ago, in response to abnormal conditions in financial markets, FERC reformed the methodology it uses to determine ROE for electricity grid investments, the Discounted Cash Flow methodology (DCF). FERC decisions on ROE have long attracted legal challenges and this new methodology was challenged in court. In April 2017, the U.S. Court of Appeals for the D.C. Circuit ruled in *Emera Maine* that FERC had not adequately explained its new methodology and vacated the orders where FERC adopted its new policy.

To be clear, the current uncertainty in ROE policy is the result of a court decision, not any action taken by the current Commission. However, only the Commission can clarify its policy with respect to ROE and reduce regulatory uncertainty. On remand, FERC could choose to reaffirm its commitment to the two step DCF methodology or choose to make different modifications to its DCF methodology. But it is critical that FERC adopt a methodology that attracts sufficient grid investment and provides certainty to the regulated community.

Another challenge to development of electricity transmission infrastructure in regional transmission organizations (RTOs) is the regional planning process. Regional transmission planning is governed by Order No. 1000, a major FERC transmission planning rule. Electric transmission planning both inside and outside RTOs centers on reliability needs, not economic benefits. The RTO planning process is resource intensive and lengthy, but allows the collective needs of each region to be effectively met by regional solutions. Cost recovery through the RTO tariff involves disputes about cost allocation methodologies.

Concerns have long been expressed that the RTO transmission planning process does not place an emphasis on project cost and there is no effective FERC prudence review to disallow excessive costs. In part due to those concerns Order No. 1000 embraced competition for transmission projects with regional cost allocation, in the belief that competition would police excessive costs more effectively than after the fact prudence review. Some RTOs have embraced competition for regionally funded transmission projects, with demonstrated benefits and cost savings. However, the competitive processes in most regions have been limited by state policies and RTO practices that restrict the scope of projects subject to competition. The result is most projects are subject to minimal cost review, calling into question whether the cost of RTO transmission projects is higher than necessary to meet reliability needs.

One question before FERC is whether it still believes there is a need for some discipline in the cost of RTO transmission projects, and, if so, whether the better course is broader use of competition or resort to after-the-fact prudence review.

The greatest challenges confronting electric transmission development are those faced by new entrants seeking to build competitive transmission projects. In some states, new entrants are not eligible for siting by state and local agencies, which makes it more difficult to secure land rights necessary to construct new transmission facilities. Some states have raised barriers to new entry, enacting laws establishing a right of first refusal that grant state regulated utilities a preference or exclusive rights in development of transmission projects over new entrants.

Conclusion

Continued development of the U.S. energy infrastructure is important to support the evolution of the U.S. electric generation fleet and secure the benefits of the shale gas revolution. There are challenges facing development of the interstate electric transmission grid and interstate pipeline network, challenges that have grown in recent years. Regulatory policy plays an important role in securing the necessary investment for energy infrastructure and affects the risk associated with that investment. Regulatory policy also governs siting of interstate energy delivery systems. It is important that regulatory policy be highly merits-based and provide a reasonable level of regulatory certainty to attract investment.

The CHAIRMAN. Thank you, Mr. Kelliher.

And thank each of you, I appreciate all you have contributed, gentlemen.

I am going to start out with a broader question directed to all of you and I appreciate that, I think, each of you has referenced the need for a balanced, fair, and transparent regulatory approach. I think we all recognize that that benefits all.

There is a lot of discussion about where we are right now when it comes to energy policy and our infrastructure. On the one hand, you have an effort and it is very, very far over to one side, but it is an effort that would say we have to stop any and all use of fossil fuels altogether, kind of the "keep it in the ground" approach. On the other hand, you have a direction, an approach, that says we need to support our cleaner forms of energy, certainly making sure that energy is affordable. We have issues, as you have pointed out, Mr. Kelliher, clearly in the siting of new pipeline and infrastructure.

What I would like to hear from you is what are the issues or the inherent dangers, if you will, if we restrict through our regulatory process here, pipeline development, either restricting it or slowing it down? I believe it was you, Mr. Hoecker, that mentioned things like congestion costs. Mr. Murchie, you recognized the environmental benefits that natural gas brings to us. Can you speak to the consequences if our infrastructure is not allowed to keep up with not only the demand but the desire for affordable and clean and efficient energy sources? I will just start at this end, and we will go down the line.

Mr. MURCHIE. Thank you, Madam Chairman.

First, I'd like to emphasize that we focus a lot on the generation of electricity. We shouldn't lose sight of the role of natural gas in basic industries, residential heating and commercial.

Generation for natural gas is utilized about a third of natural gas in the United States. Industrial sector uses far more. Residential is at about 17 percent, 13 percent and commercial is at 17 percent.

So for years natural gas has served markets other than electric generation. It has external benefits to electric generation. When it was not as plentiful and not as low cost as it is today, we were the backup. We were the future for intermittent generation from renewable sources.

Clearly, if we make gains on efficiency, that's the fifth fuel. But natural gas supports renewable development in the longer term but right now we are achieving significant reductions in emissions. But we are not here to compete with other fuels. The economy, economic choices, will make that result.

Right now, you've got very low cost natural gas. We've become an enemy to many because of the benefits of our technology and our capital formation and our production. Building pipelines does not cause the production. Production creates the need for the pipelines.

The CHAIRMAN. Let me try to keep everybody moving.

Mr. Murchie, I think it was you that said there was a symbiotic relationship between the natural gas the renewables.

Mr. MURCHIE. Yeah, so as everybody knows energy demand is not smooth over the course of the day or the course of the year and if storage is a cheaper way of bridging that gap, as it is with natural gas, then storage is part of that. In electricity, storage is expensive. The cost is coming down, but when you have wind and solar that generate energy when they feel like it, you need backup. And you can cycle up natural gas-fired generation much more easily and, more importantly, safely than you can a baseload coal plant or a baseload nuclear plant. So that's the symbiotic relationship.

There's also a cannibalization effect going on. I mean, the lower costs of natural gas has made it more competitive in the electric power market, and so the coal plants that have been shutting down are shutting down because they have become the high cost way of generating electricity. So the market has worked.

And in answer to your question, what's the impact if we don't build more gas pipelines or if we slow the infrastructure development? You know, again, as an investor in a commodity business, it always comes down to cost. If the result is an allocation of capital or use of resources that are less than optimal, then the costs will simply be higher. The question is from a policy statement whether those costs are worth it. One of the, I think everybody here used the word predictable on the regulatory regime discussion more than once. I did not put them up to that.

But the other cost here is the cost of financing. I was talking to one CEO recently who described a discussion with a staffer, I think in the prior Administration, and they were looking at pipeline tariffs and couldn't understand why they were so expensive because it couldn't possibly cost $3.00 or $4.00 a barrel to move oil 1,500 miles. And he said, well the cost is the cost of financing the steel in the ground. But 80 percent of the cost is the financing, the debt and equity that it takes to build that pipeline, not to spin the compressors and to employ the few people that are in the control rooms.

The CHAIRMAN. I am almost a minute and a half over my time and out of respect to my colleagues I want to be able to turn to them, but know, Mr. Hoecker and Mr. Kelliher, I am coming back to you with that same question.

Senator King.

Senator KING. Thank you.

Mr. Murchie, I object to the characterization of renewables as making power when they feel like it.

[Laughter.]

Mr. MURCHIE. I didn't want to get into a religious discussion, who was in charge of when the wind blows or when the sun shines.

Senator KING. I don't either.

I think one of the issues that is troubling me is that we are talking about additional expenditure, and you just pointed out that we are talking about significant investment in long-term assets—20-, 30-year, 40-year assets, and significant capital investment. What worries me is stranded investment.

Mr. Kelliher, you represent a company that has one of the most diverse energy backgrounds in the country. My question is, are we in danger of saddling either ratepayers or taxpayers with significant infrastructure long-term investments that may, in 10 or 12 years, turn out to be, in fact, stranded because of new developments in storage, renewables, or integration of renewables?

I have a secondary question for you about integration of renewables, but give me your thoughts on that first question.

Mr. KELLIHER. Are you referring to pipeline investment or transmission investment?

Senator KING. Both. Either.

Mr. KELLIHER. For pipeline investment, there's not really that risk because their companies are putting themselves out. They're taking the risk of developing new projects.

Senator KING. But are they? The New England pipeline proposal was that the ratepayers of all of New England would take that risk.

Mr. KELLIHER. That was a unicorn. That was an unusual proposal where you had a project where the market demand for that project is not apparent. The New England pipeline system is adequate for all but 12 days of the year. The reason they were proposing to flow it through the ISO New England tariff is there's not market support for a 12-day pipeline.

Senator KING. So, generally, you would say that the risk is being taken by the investors.

Mr. KELLIHER. By the pipelines and the shippers, right? The pipeline has the large investments that they have to make to build the project, then there's typically shippers who will sign contracts of some term. It won't be life of the project, but they'll sign some terms of some reasonable length.

Senator KING. But on the electrical transmission side, if it goes in at the rate base, the ratepayers are taking that risk.

Mr. KELLIHER. It's—yeah, outside the RTO it's typically built as part of a vertically integrated company. You make a showing to your state regulator. It's a prudent investment. In the RTOs it really emerges from the planning process.

Something I tried to speak to in my written testimony was there's not really a very effective check on the cost of RTO transmission projects currently. There's not any effective FERC prudence review process. Order 1000 had sought to encourage competition in order to police excessive costs in the RTO transition planning process. Some regions have really embraced competition like California and there's been some really impressive cost savings that resulted. Other regions have not embraced competition.

Senator KING. Talk to me a minute about your company's experience with integrating renewables into a larger facility.

Mr. KELLIHER. Sure.

We are the largest wind company in the world, and we're the largest wind and solar company in North America. We build in the regions that have the best quality resource. Our wind tends to be, by and large, in the upper Midwest to Texas, so, the center of the country. We have very large solar facilities and we, again, tend to concentrate where the solar resource is best.

We are seeking development, wind and solar, in the Northeast. The resource isn't as good and siting is more challenging.

Senator KING. What about the question of integration—the conventional wisdom for wind years ago was the grid can only take 10 percent because of the variability.

Mr. KELLIHER. Yes.

Senator KING. What has been your experience?

Mr. KELLIHER. That all of those statements have been proven false over time.

There used to be a view that somehow if more than 10 percent of the supply of a region came from wind or solar, the whole grid would collapse. There have been times where the Southwest Power Pool, the SPP region, has had, I think, up to 60 percent of their power at points come from wind. So, there used to be a belief there was somehow a natural ceiling of 10 percent, then it was 15 percent, but those ceilings have been shattered with no threat to reliability.

Senator KING. What about the question of the long-term price of natural gas? I fear that we are making a lot of investments and a lot of bets based upon what could be an anomalous period of ultra-low natural gas prices.

I always like people that come to the hearings that I am in to come away with one bit of useful information. There is an app called ISO to Go that tells you in five-minute increments what is going on in the New England grid. What the price is, but also what is the source of power. At this moment it has just gone up a percent. Sixty-two percent of the electricity in New England is coming from natural gas.

My question is, we are building the infrastructure, we are building the plants, and we are doing it during a period of what could prove to be anomalously low prices. What kind of risk is that?

Twenty-five years ago, New England was unduly dependent upon oil. Now we are 62 percent natural gas. What happens if natural gas prices return to $6.50, $7.00, $8.00 per billion cubic feet? Anybody want to talk about that?

Mr. Moffatt.

Mr. MOFFATT. Senator, first I think that it's been very hard to tell how much natural gas we have. When I started in 1977, the Hugoton Field was going to stop producing, and it's still producing. When we also——

Senator KING. Stable Island——

Mr. MOFFATT. Pardon?

Senator KING. Stable Island on the other hand is not——

Mr. MOFFATT. Stable Island, on the other hand, didn't, but you have other production now coming from Marcellus and Utica. Certainly the production coming out of the Permian was not what was expected.

We built the Rockies Express pipeline to move Western gas to the East Coast because there was not production. By the time we completed the pipeline, it turned around and went the other direction because of Marcellus.

Senator KING. I am out of time.

Mr. MOFFATT. So, technology is great.

Senator KING. You are saying going forward the price of natural gas is going to be close to what it is?

Mr. MOFFATT. Absolutely, absolutely.

Senator KING. Okay, we are on the record here.

Mr. MOFFATT. Yes, sir.

Senator KING. We will all know in a few years.

Thank you. Thank you, Madam Chairman.

The CHAIRMAN. Thank you, Senator King.

Senator Barrasso.

Senator BARRASSO. Thank you, Madam Chairman.

Mr. Moffatt, just to kind of follow up on a couple things. In your testimony you highlight issues associated with permitting the natural gas pipelines between states, the interstate, and you explain that these pipelines need approval from both the FERC, the Federal Energy Regulatory Commission, as well as the states where the pipeline is going to be located. Well, one of these state approvals is called the Water Quality Certification Authority. It is delegated to the states under the Clean Water Act in Section 401. In some cases, in my opinion at least, I believe states have abused the authority to block projects for political reasons not really having to do with water quality at all, but they are using that permit as basically a stop action form rather than dealing with clean water itself.

Could you please explain how the Federal Government might be able to address some of these, what I believe are, unreasonable actions by certain states to block what is critical infrastructure for energy for our country?

Mr. MOFFATT. Yes, thank you, Senator, for that question.

Mr. Kelliher's company and our company have suffered from similar situations. We've been trying to get a permit out of the State of Massachusetts, certainly New York has utilized that, is well known.

I think that the FERC needs to be more bold in exercising their lead agency authority, and I believe that we recently had a DC Circuit case that urged them to do that and they are stepping up. I suggested in my testimony that the Committee in its oversight encourage the Committee, encourage the Commission, to exercise that.

You did in the Congress in 2005, give us additional tools to go to court where we can go to the DC Circuit for unnecessary delay. We had to do that on an air permit out of Nashville, Tennessee, for a project. Then you gave us other authorities to try to truncate successive state administrative procedures which we did have to utilize on our Connecticut expansion project in Massachusetts. There are mixed results.

I think more leadership out of the Executive Branch, from EPA with clear guidance to the states when implementing their delegated authorities, is welcome.

I don't think there was anything more incongruous than to have the Obama Administration put forth the Clean Power plan, have Gina McCarthy go to New York and say the one thing we have to do is build more natural gas pipeline infrastructure and then have the EPA file varied disingenuous, in my view, comments to the FERC on a NEPA document. The Administration needs to be in support of the entirety of the process.

To me, guidance from the Executive Department to the Executive Branch agencies, whether it's Department of Interior, Commerce, Coast Guard, whoever, should be in sync with the Administration's policy.

Senator BARRASSO. I want to follow up with you, and then I am going to ask Mr. Kelliher to jump in if he has anything to add.

Recently the FERC began this review of approving new natural gas pipelines. During the 20 years that the current process has been in place, the pipeline industry, I believe, has undergone significant expansion, with thousands of jobs, billions of dollars of investment. I think we need to continue to build more capacity.

In many parts of the country, though, I think, the pipelines are really needed for heating and power generation especially during extreme weather conditions. I mean, we saw a Russian tanker bringing LNG into Boston Harbor. And you talk about the changes in some of these prices. Well, there was a complete lack of ability to get the power that was needed at a time when people were desperate for energy.

What changes can be made to the Commission's certificate policy statement that are going to enhance the ability of pipeline companies to build this needed pipeline capacity? Then I am going to ask Mr. Kelliher if he wants to join in as well.

Mr. MOFFATT. Senator, I think the situation in New England is not as much about the FERC process on infrastructure. It is really economics.

We tried to develop, and Senator King mentioned it earlier, the Northeast Direct project. It was a multibillion dollar project. We needed 1.2 to 1.3 billion cubic feet of contracts to support the financing that it was going to cost. We were going to be putting out billions of dollars before we received a dime in compensation for that investment. We did have contracts with LDCs for traditional residential, commercial, industrial load for 450 million cubic feet a day, virtually half. We needed supply contracts for the supply from the producer side of it, and then we needed about 450 million cubic feet from the power generation.

The structural issues with the New England ISO to provide the economic underpinning for the generators to make the contract commitments for the pipe are inherent to New England ISO needs to be worked out.

We had another problem which was over supply coming out of Marcellus, crashed the price in 2014–15 and suddenly our suppliers that's had the supply contracts, they didn't have the credit to back up the project.

So that project died more from economics in the very competitive market than it did from FERC process. I think that we would have been able to get through the FERC process if we had had the financial support.

Senator BARRASSO. Mr. Kelliher, do you have anything to briefly add?

Mr. KELLIHER. No, I agree with that. I don't think that the hurdle there was the FERC process, it was the lack of clear market support.

Senator BARRASSO. Thank you, Madam Chairman.

The CHAIRMAN. Thank you, Senator.

Senator MANCHIN. Thank you, Madam Chairman.

We have an all-star lineup here, and it's good to have you all here with the expertise you do have.

I come from the State of West Virginia which has an awful lot of energy and has done the heavy lifting for a long time. With that being said, people are now surmising that certain parts of my energy portfolio is not needed.

I would like to get your input on all-in energy policy, and I know you know the President is moving on the Defense Act. I am very much in favor of that, and I appreciate very much looking at the defense of our country and the resiliency of our grid system. I know other people have a different take on that.

Mr. Hoecker, can you give me your reflections on an all-in energy policy and the direction the President is going on this?

Mr. HOECKER. Thank you, Senator.

I think that, as Chairman Murkowski asked, we aren't gravitating toward extremes in terms of energy solutions. This is an evolution and one I think of as being prudently engineered by regulators but driven by the marketplace.

I think that the coal still has an enormous role to play as baseload generation and will for the relatively near future, foreseeable future, whatever that might mean.

Senator MANCHIN. Would you put nukes in the same position too?

Mr. HOECKER. I'm sorry?

Senator MANCHIN. Would you put nuclear plants in that same category?

Mr. HOECKER. That's a tougher question, but I think that the economics there aren't particularly good right now for nuclear. So there are some serious questions there. Down the road, I think, we will see natural gas becoming more important and other forms of fossil energy becoming less important to the generation mix. Probably renewable energy and other technologies will increase their participation in the marketplace.

Senator MANCHIN. The only thing I would say is that when you look at it, it is market driven. Everything we know in a capitalist society is market driven, to an extent, except when we need it, for the defense of our country.

We have a situation right now. We don't produce one ounce of the rare earth minerals that we consume tremendously in every product that we use and in most of our defense products. Now we are getting caught in the crosshairs. We are figuring out if we can get back into the game so we are not dependent.

I am afraid the same thing is happening with energy too. I know when I talk about having an all-in energy policy in West Virginia, we have been blessed with them all—Marcellus, Utica, and we've got Rogersville coming on. It has not even been tapped yet. So we have been blessed. And we still have the coal, and the best met coal, in the world that everyone is seeking.

When people start bequeathing that out and you have a modern coal-fired plant with all of the pollution controls, we believe that it is imperative for the security of the grid system to have that backup and consistency for the defense of our country, as well as for the demand needed.

I think during the polar vortexes and the bomb and all these weather phenomenons, that if it had not been for the backup of coal and with gas coming on strong—

I would recommend to all of you, and Mr. Moffatt, you might want to speak to this. I would give you all a suggestion, being a former Governor, on how you can get your pipelines permitted much easier through the states by sharing the revenue. Give me an MCF mileage on your transmission cost, and I will guarantee you the floodgates will open. Why they won't do it is just pure greed. And I say that in the most respectful manner.

[Laughter.]

If you share a little bit of that revenue, these states can buy into it, they will be the greatest facilitator you have ever seen. The counties that get it, and all we are talking about is an MCF mile so every state that it passes through gets treated fairly. Hopefully you will take that back as a recommendation, because I have seen it work on grid lines.

Mr. MOFFATT. I certainly will take that back, Senator.

We do have initial financing costs that are quite extraordinary on our projects, and we always stimulate a lot of tax base wherever we——

Senator MANCHIN. Yes, but the delay of building these lines costs you a tremendous amount.

Mr. MOFFATT. They do.

Senator MANCHIN. But you could cut that cost.

I have seen it in a 500-megawatt line that we were putting in and could not get it done until they start sharing a little bit, and I will tell you——

Mr. MOFFATT. Believe me, we do, in siting our plants, engage in quite a bit of community support in those towns and cities and counties that we do impact.

To be honest, in my 40 years I haven't heard the concept of sharing on an MCF mile basis, but I will certainly take it back.

Senator MANCHIN. It makes sense. It makes all the sense in the world, and we are talking about a fraction, but it is guaranteed revenue. Forget about who drills the hole, just get a little bit of the action off of the thing that happens all the time—transmission.

Mr. MOFFATT. Right.

Senator MANCHIN. And the states can help you through the permitting process. You are held up in every state right now, because there is no benefit or gain other than promise of jobs or taking the product out of their state.

We are a production state. We are trying to keep some of that product in West Virginia through our storage facility hubs.

Mr. MOFFATT. Right.

Senator MANCHIN. But with that we want to make sure we produce the product that the country needs, but I would hope that you would look at that because I can tell you we would be very receptive.

Mr. MOFFATT. I will.

Senator MANCHIN. Okay, thank you, sir.

The CHAIRMAN. Thank you, Senator Manchin.

Senator Cassidy.

Senator CASSIDY. Great testimony, thank you very much.

Three of you commented on the fact that natural gas generation enables the plummet of renewables, fast acting, relatively low cost. One of you said, safe, safer than the alternatives.

Now, let me ask, Mr. Kelliher, you mentioned the experience you have with renewables. Does the absence of fast acting, we can bring it up in a second, backup inhibit the deployment of renewables? And I don't know the answer to this. I am just asking.

Mr. KELLIHER. I'm sorry, does the absence of natural gas facilities——

Senator CASSIDY. I am sorry, if you are going to try and convert your grid supply to renewables from a baseload of coal or nuclear, clearly, you have to be able to respond to increased demand. So if you are going to shut down a coal plant which is providing baseload to substitute in a renewable and on that particular day the sun and the wind decide to take a break, as Mr. Murchie would suggest, do you have in your algorithm, we have to have the presence of natural gas backup in order to make this conversion from baseload of coal and nukes to a renewable centric, more renewable centric, grid?

Mr. KELLIHER. First of all, a lot of coal plants in the competitive markets don't really operate as baseload units, right? The concept of baseload units meant, it used to mean, that the really cheap stuff that also happened to be very inflexible so it would take hours to start, hours to shut down. It just so happened that that cheap stuff used to be the very inflexible resource but it didn't really matter if you were running it all the time.

But now, coal plants are not the cheap stuff anymore. So they don't operate——

Senator CASSIDY. I get that.

But if you are going to deploy large amounts of renewable, it almost seems that you would, if you have a mandated presence of that backup in case the sun and wind are not cooperating.

Mr. KELLIHER. There's others. There's hydro resources. There's gas, fast starting gas facilities. There are——

Senator CASSIDY. So it sounds like you are answering yes, I accept that gas and hydro would be fast acting, but you have to have that backup power.

Mr. KELLIHER. Well, there used to be, when we were talking earlier about there was a notion that whether there was some natural ceiling to renewables. That's—there used to be another——

Senator CASSIDY. I guess I am not expressing my question because your answer is not coming back to my question. Does anybody else comprehend my question?

Mr. Moffatt?

Mr. MOFFATT. Yes, yes, sir.

I think if you look at the emergence of natural gas-fired generation back after PURPA was repealed and the prohibition on natural gas-fired generation was repealed, it did emerge more as an intermittent resource as opposed to a baseload resource. Natural gas-fired generation really did not deploy except in the State of Texas—they, sort of, moved in symbiotic. So they were there. They were there as peakers or there to provide that backup. So it did create a basis for confidence in emerging wind and in emerging solar. I think that now you have a strong force of natural gas-fired generation that is there whether it's going to be operated and deployed on a baseload basis or, you know, more wind will be built and more solar.

I do think they work together, you know, there are going to be downtimes for wind and downtimes for solar. Storage may emerge so that you will depend less on the gas-fired generation. But I've been in this business since President Carter, 40 years ago, and we've been working on storage for 40 years. And so, when it will come, it will come, but we need to be prepared in the interim.

Senator CASSIDY. Now let me ask because this is a headline that's out right now, "Heat wave sparks major power outages around Los Angeles." Clearly California has been in the forefront in going away from fossil fuel and nukes toward both conservation, hydro, and renewables but this does suggest that they had a lack of generation capacity.

Mr. MOFFATT. I believe that one of the problems facing California right now is that they have relatively low flow of hydro so that is a restriction on the available resources.

Also, Southern California Gas Distribution Company has a number of outages on their pipelines so that gas has difficulty getting in for the gas-fired generation in the base.

So, there are some other externalities that are causing the situation right now in Los Angeles. They also have Aliso Canyon storage down. So there's a lot of things working against Southern California at the moment, but nothing is structural.

Senator CASSIDY. I guess, if you will, it shows the concept that if you have insufficient peak backup you can have problems but theirs is not necessarily due to policy rather it is due to a confluence of events.

Mr. MOFFATT. I believe that's correct.

Senator CASSIDY. Yes, sir.

Mr. KELLIHER. And Los Angeles is served by Los Angeles Department of Water and Power, LADWP. I do not think they have very high renewables in their electricity——

Senator CASSIDY. Got it.

Mr. KELLIHER. I'm not positive, but I think they rely less on renewables than the IOUs, then they——

Senator CASSIDY. Got it.

I thank you all very much.

The CHAIRMAN. Thank you, Senator Cassidy.

Senator Cantwell.

Senator CANTWELL. Thank you, Madam Chair, and I thank the witnesses and my colleague, Senator King, for being the Ranking Member today and helping make this hearing go so well.

Yesterday I was quite surprised to see that the President issued an Executive Order that takes the power to select administrative law judges (ALJs) from the Office of Personnel and gives it to the heads of agencies employing them.

I have grave concerns about this across the board, but the one example I know best is in the area of the Federal Energy Regulatory Commission and the issues as they relate to the Power Act.

So, Mr. Kelliher, you were Chair when we amended the Federal Power Act. You developed FERC's market manipulation authority.

I can just tell you how many times during that process the State of Washington and our utilities were going to the administrative law judge for findings as it related to the damage that was being done in the Enron crisis. We depended on those law judges in a very, very specific way.

They hold hearings. They weigh evidence. They find facts. They make initial decisions on whether the violations occurred, what penalties are appropriate, and then they send that up to you, as it related to FERC. Due process requires that they be fair and independent and insulated from political pressure. Are you concerned that if we switch this to a process where you would hire political people that it could create some issues with due process and legal proceedings?

Mr. KELLIHER. You have the advantage of me. I haven't read the Executive Order. I saw an article on it, but I haven't read it.

But I can talk about the importance of having independent, qualified ALJs because when Jim Hoecker and I were at FERC, it varied from agency to agency. But at the agency, the Chairman hires, makes the decision on the ALJs. But that's after, my understanding is, it's after they've gone through some LPM screening process so they're deemed to be qualified. They meet some kind of qualification. And then typically the Chief LJ would present three or four candidates, and you would choose one.

I thought that process worked very well, but the screening assured that you had qualified candidates to choose from, and I think that's extremely important given the matters at FERC that are entrusted with ALJs.

There's another agency I won't name because I don't want to embarrass that other agency. They had a very small complement of ALJs. They had one that seemed to despise the agency and would always rule against the agency, and they had one that people would consider would never possibly rule against the agency. That could be the outcome if ALJs are chosen and they're not as qualified and not as independent. You could end up with—and that outcome is not great for a party, right? You would know from which ALJ got your case what the outcome of your matter would be. So, it should be independent, qualified folks that a Chairman chooses from, I think.

Mr. HOECKER. I agree with that completely, Senator.

We have historically, as heads of the agency, hired ALJs off a list, a civil service list. A lot of them come from other agencies like the Social Security Administration and they are hired based on their ability to run cases and an understanding of the Federal Rules of Civil Procedure and so forth. And that's really what you need, not a political appointee.

Senator CANTWELL. Well, I thank you for that. And I can tell you, I agree. I don't know if we will have to do legislation here, but the fact that the President thinks he can change this by Executive Order and put at jeopardy the notion that, as you just said, Mr. Kelliher, an agency would then shop for the employee or the Administrative Law Judge that would rule for them or against them, what have you, is just very bothersome. We want people to be selected. These issues are such critically important matters.

When I think about the cases that came before the Administrative Law Judges in the Enron case, utilities and ratepayers really had to understand what was happening to them with such egregious manipulation. The notion that somebody could be sitting there who had already been hired by, you know, a political process that basically said, "Oh, don't worry about that," is very concerning.

And you want very experienced personnel. You want people who the Office of Personnel Management have verified to have the professional experience to do these jobs as well.

So, I thank you. I thank you.

Thank you, Madam Chair.

The CHAIRMAN. Thank you, Senator Cantwell.

Senator Daines.

Senator DAINES. Chair Murkowski and Ranking Member Cantwell, thank you very much for holding this hearing today.

This hearing, I think, is most timely as I just lead a letter to FERC discussing the importance of natural gas pipelines to our economy and the need to make sure that any discussions or decisions that come from their ongoing review not interrupt or slow the process for approving new natural gas pipelines.

This comes on the heels of a visit I just made last week to Russia. You know, 30 percent of Europe's energy needs are being met by Russia, and 50 percent of Germany's energy needs are being met by Russia.

This gives America an incredible opportunity both from an economic viewpoint as well as national security and positive geopolitical consequences for the United States to supply more natural gas to Europe. The world will be a much, much better and safer place if it reduces its dependence on the Middle East and Russia for its energy needs.

We are currently faced with the need to replace a Commissioner at FERC, and I hope we can do that expeditiously. It is critical for our energy independence as a state and a nation to have a Commission that is able to approve and move quickly on our nation's priorities. I look forward to working with my colleagues and the Chairman on this important issue.

As I stated many times before this Committee, the energy sector is one of the pillars of Montana's economy. With Colstrip, with hydro facilities, Montana is a net energy exporter. That means, we need to have the ability to transmit, ship and pipe our energy to and through other states.

Unfortunately, we have seen instances where one state can interrupt and shut down projects that are necessary to other states. For example, in Montana, this has become a big issue with the State of Washington blocking coal from the Crow Tribe and they cannot get coal to our allies in Japan and Asia Pacific. We see the same issue with states blocking pipelines that would deliver affordable, clean, natural gas to heat homes in the cold New England winters. We have seen repeatedly the abuse of Section 401 of the Clean Water Act to stop sensible projects like the Millennium Bulk Terminal and natural gas pipelines and Congress needs to take action on this.

Mr. Kelliher, as a former Chairman of FERC, as someone who has spent decades working on these issues, would you agree that we need to tailor Section 401 of the Clean Water Act to focus on protecting water quality rather than allow it to be used as a political pawn?

Mr. KELLIHER. I would agree that when states issue 401 permits that any conditions that are in those permits should be directly related to water quality matters that shouldn't go afield of that. The concern is that in some cases states seemed to have imposed conditions that are totally unrelated to water quality.

Senator DAINES. Yes.

Mr. KELLIHER. In one gas pipeline case, it was an attempt to change the route of the pipeline, something that by federal law is expressly reserved to FERC.

So to me, the question is well if that happens, what should the remedy be? What should the recourse be? Should EPA—this came up a little bit earlier in discussion with Senator Barrasso.

Senator DAINES. Maybe I will focus the question. What are some actions that Congress could take to refocus Section 401?

Mr. KELLIHER. Well, one would be amending 401 but it would seem to be, almost, it would seem to be arguably an unnecessary amendment to say well, you're—if a state is given delegated authority to issue water quality permits that it would seem unnecessary to say and they shouldn't include conditions that are completely divorced from water quality permits in those permits.

But it could be EPA guidance might be sufficient to explain what are the limits on state water quality permitting authority. It could be that there's a need for some kind of appeal say under the Coastal Zone Management Act states can find that some proposed activity is inconsistent with a state coastal zone plan, coastal zone management plan. There's recourse in that you can appeal to the Commerce Department. You can say the state is actually inconsistent with the statute.

So, there is that appeal, you know, that would be a possible legislative solution of well, let's allow appeal here. Could there be a provision to appeal a state 401 permitting decision to EPA and let EPA rule as to whether the state permit went too far afield.

Senator DAINES. Thank you for the thoughts on that, and it is very helpful as a former Chairman on FERC.

I have one last question here for Mr. Hoecker. There has been a lot of discussion on Capitol Hill on the need to invest in America's infrastructure. I have been a proponent of making sure that doesn't only mean roads and bridges, very important. In fact, we had a great hearing yesterday with the Senator from Maine, the Ranking Member in the National Parks Subcommittee, regarding an infrastructure bill we are looking at for our national parks.

So we need to think more broadly what this means. I would argue that pipelines, terminals, transmission lines and other energy infrastructure is also a part of the broader infrastructure discussion in our nation. It is not just capital or money that we need the most to expand our energy infrastructure. What we really need is permitting reform, because a lot of this infrastructure that I am talking about there is provided within the private sector. We need less regulations and expedited approvals.

My question is this, Mr. Hoecker. As a former FERC Chairman and now counsel to WIRES, what do you believe are the three most important priorities for either Congress or FERC to help facilitate the development of energy infrastructure?

Mr. HOECKER. Thank you, Senator. That is a great question.

Our focus this morning has been on a lot of natural gas pipeline issues, but I can guarantee you that it's much tougher to build an electric transmission line across multiple states for the very reasons that you mention. I think there are some modest ways legislatively to begin to remedy that, at least as far as promoting cooperation between the states or giving FERC some limited authority in the area of interstate or cross border, inter-regional types of transmission lines. That is something that the Commission, the FERC, intended to promote not on a jurisdictional basis, but on a policy basis in Order 1000. It hasn't materialized.

I think the second recommendation would be for FERC to be more active in improving that order and promoting and incentivizing the development of interstate transmission.

The interesting thing, of course, is that we focus on the difficulties that natural gas pipelines are having along line pipelines, but FERC is the only agency that has the ability to determine what's in the public interest. It issues a certificate. It is the lead agency on NEPA review. It also sets the rates. And it does not have that breadth of authority for electric transmission.

The siting for electric transmission resides with the states, and Congress' effort in 2019 in the Federal Power Act to remedy that with a federal backstop has failed.

Senator DAINES. Thank you.

I am more comfortable talking about pipelines as a chemical engineer than I am about the law, but I will say that I believe our founding fathers anticipated this and had enumerated powers in Article 1, Section 8 on the Commerce Clause that this may be where this has to be finally decided.

Thank you.

The CHAIRMAN. Thank you.

Senator Cortez Masto.

Senator CORTEZ MASTO. Thank you, Madam Chair and Ranking Member. Thank you for this hearing.

Gentlemen, thank you so much.

I am juggling two hearings today, so I appreciate the written testimony that you provided ahead of time to enable us to prepare.

Mr., is it Hoecker?

Mr. HOECKER. Hoecker, yeah.

Senator CORTEZ MASTO. Hoecker and Mr. Kelliher, let me start with you. In 2009 Congress gave WAPA borrowing authority for the purpose of constructing, financing, facilitating, operating, and studying construction of new or upgraded electric power transmission lines and facilities that have a terminus within WAPA's region and that deliver electricity from a renewable resources.

To implement its borrowing authority, WAPA created the Transmission Infrastructure Program, or TIP. This program has proved to be beneficial to many communities across the West. For example, an example of TIP includes WAPA's partnership with TransWest to build a high voltage transmission line extending 730 miles through Nevada which is near Boulder City over to South Central Wyoming, providing California, Arizona, and Nevada with direct access to Wyoming's high capacity wind-generated and gas-generated electricity. However, TIP has been proposed for elimination in the President's budget.

I am interested to hear your views on the benefits of this program and generally how programs like these have helped the growth of transmission infrastructure in the West.

Mr. HOECKER. Well, the Western has been very instrumental in helping preserve reliability in Western markets. They owned Path 15 which brought electricity from Canada into California at a time of significant need.

They have—both Western and other power marketing agencies have the ability under law to effectively partner with some private transmission developers and utilize their authority under law to site transmission that would otherwise be sighted solely under state authority.

So, I think it's been important, and particularly important in the West, although there is an example in the Southeast where CEPA, in an effort to utilize that authority, was actually nullified because the project was withdrawn, but I certainly resonate your remarks. It's something that we wouldn't want to lose.

Senator CORTEZ MASTO. Thank you.

Mr. Kelliher, do you have any other——

Mr. KELLIHER. I think there's also a lot of benefits that come from those kinds of approaches.

Mr. Hoecker referred to Path 15. Path 15 was a choke point in California that contributed not just to the California blackouts, but to the manipulation of California market. It made the market more vulnerable to manipulation.

And that joint venture between WAPA and the private sector relieved that bottleneck. And I think that's what inspired other legislative provisions that were in the '05 Act and including TIP. So I think it's positive and it's the kind of thing that has a lot of merit.

Senator CORTEZ MASTO. Thank you. I appreciate your comments.

Mr. Kelliher, let me continue with you. Nevada is a big proponent of battery technology, and as you well know, we have a large battery factory, Tesla, the Gigafactory there in Nevada. We recently created an Energy Bill of Rights in the State of Nevada that actually protects home energy generation and storage. And thanks to the declining costs of better technology and the growing industry of battery storage, deployment at a utility scale is accelerating at a rapid pace.

I am curious if you still see barriers, and what barriers there are, that exist for battery storage deployment and what we can do to address those barriers.

Mr. KELLIHER. NextEra is actually the number one utility scale storage developer in the country, so thank you for the question.

[Laughter.]

We think there are some buyers in the RTO markets in part because storage is a product that is very, it's unique in the world of FERC. At FERC you have generation and you have different forms, you have energy, capacity, you have transmission.

Battery storage actually provides every, well all those products. So, it cuts across the usual product lines and so it's something that doesn't fall neatly within the market rules of the current RTOs.

FERC, knowing that, issued a major storage rule earlier in the year to promote storage and lower those barriers requiring the

RTOs to come up with platforms, market rule platforms, that facilitate storage deployment.

But now the question. That's the beginning of something rather than the end of something. A final rule is normally the end of something, but now the issue goes to every single region and it's important that when those regions act to set up those platforms, those market rule platforms, they actually really be truly supportive of storage.

But in terms of entry to utilities, we have, we've done a lot of storage deals with individual utilities outside of RTOs and think that that's gone well when the utility is interested and supportive. We've done it with for-profit investor-owned utilities, as well as other governmental utilities. So we think the barrier is more in the RTOs, but FERC is acting to lower it.

Senator CORTEZ MASTO. Okay. Thank you.

Thank you, Madam Chair.

The CHAIRMAN. Senator Gardner.

Senator GARDNER. Thank you very much, Madam Chair.

Thanks to all of you for being here today.

Mr. Moffatt, there is obviously a very significant and tremendous natural gas supply in the U.S. Rocky Mountains, including Utah, Wyoming, and Colorado. Just a few years ago, the U.S. Geological Survey determined that recoverable natural gas supplies in the Piceance Basin in Colorado is 40 times larger than initially thought.

With U.S. market demand for natural gas being largely satisfied by supply from other natural gas producing regions, the only way for U.S. Rocky Mountain gas producers to contribute to U.S. energy dominance is to export that natural gas to our allies.

In order for natural gas producers in my state to get their gas to overseas markets, they need FERC to approve a West Coast LNG export terminal. The fact is our allies are seeking a U.S. supply of natural gas to hedge against infills from Russia, the Middle East, from others. In other words, exporting U.S. natural gas to our overseas allies is a national security imperative. To be clear, our allies not only want to be able to import U.S. natural gas, but they are looking to diversify their natural gas supplies as well within the United States and that includes having an LNG export terminal, as I mentioned, on the West Coast.

I am going to ask a series of questions. You can, kind of, combine the answer if you want. One, what more could FERC be doing to enable Colorado's gas to get to markets, both international and domestic? Two, what concerns do you have about FERC's discharge of its responsibilities with the respect to pipeline certificates or LNG exports that would be of interest to the Committee? What do you recommend this Committee do in our oversight role to help spur the development of resources in our states including personnel and employee issues at FERC?

Mr. MOFFATT. Thank you, Senator, for the question.

Kinder Morgan, as you may know, has a lot of assets in the Rocky Mountains, moving in all directions, and we have good inner connectivity for the Rocky Mountain supply to go to markets. A lot of the issues for the Rocky Mountain supply is market. There are supplies from other regions in the country. So, you know, for example right now we're seeing our TransColorado pipeline because the Permian restrictions being utilized, but it was largely empty. And so, market shift, the infrastructure is there. The market will seek the transport, and we'll get it out.

We also own and operate Ruby Pipeline which was built to take natural gas from the Rockies to Jordan Cove.

Senator GARDNER. Right.

Mr. MOFFATT. We are hopeful that it will finally move in the second wave of LNG.

I believe that the Commission is doing everything reasonably well with respect to both the pipelines and for LNG siting. LNG is interesting because it's a manufacturing process, so we've got to interact with PHMSA on all of the authorizations for the safety of the process. Our LNG is using one type of technology. Jordan Cove has got another. The Gulf Coast projects have their own technologies. So, it's a complicated area. But I do honestly believe the agencies are moving with fair dispatch and are doing pretty well.

I would think the Administration should be encouraged to do what it's doing in promoting natural gas. I would be remiss if I didn't say that the tariffs on steel are a problem for anyone acquiring steel to build infrastructure, including the amount of steel piping in LNG terminals is significant. Those kinds of barriers aren't helpful at the moment. I think for those of us have the Gulf Coast infrastructure, we're momentarily relieved that China has left imported LNG off of their list of tariffs.

This is a brave new world. That's affecting, I believe, people signing up, not being sure what's going to happen with the trading between our countries for Jordan Cove. We are advocating to resolve those issues as quickly as possible. And believe me, we have many assets in the West that are now earning five percent a year on our assets, if we're lucky, that are basically because there's so much supply and so much competition. We support you in wanting Jordan Cove to get built, but I think it's not a matter of infrastructure as much as it's a matter of markets.

Senator GARDNER. Thank you, Mr. Moffatt. I have to go back to another hearing right now on the tariff matter itself. I thank you, Madam Chairman and thank the rest of the witnesses for being here.

Thanks.

The CHAIRMAN. Yes, I know that is an important part that nobody has really addressed this morning, but when you think about regulatory certainty, that is one thing that everyone is certainly hopeful. Then you have the volatility that is outside of that regulatory process, how you factor all that in, the impacts on investment and what that portends as well.

I said I was going to be coming back to you, Mr. Hoecker and Mr. Kelliher, with the same question that I had directed to Mr. Moffatt and Mr. Murchie about the dangers, the concerns, if we are not looking outward when it comes to adequate infrastructure. If you would both care to address that. We have hit on it through responses in other questions, but I want to give you that opportunity.

Mr. HOECKER. Certainly. I think we anticipate, and I'm viewing some studies that are coming out of NREL and the Bradley Group and others, the prospect of an enormous ramp up in electricity demand over the next quarter century. It's even predicted that electricity demand may double by 2050.

It's something we need to prepare for and the grid right now is not sufficiently integrated or strong to carry the additional generation that will be needed to serve that demand.

What happens if we don't build this? Well, prices go up. Right now, building the capital across the building transmission are relatively low and these are financing capital markets. We don't know where there are some risks that down the road that it will be more expensive to build the infrastructure we need. The benefits to consumers are not going to flow. The job creation benefits that come from building infrastructure will be delayed.

I think there are lots of reasons to begin to move more proactively in planning the grid of the future and there are lots of folks in the industry, in academia, looking at what that grid should look like and what kinds of resources should it be able to exploit, both as a matter of natural resources and technology.

We think that in anticipating a more electrified American economy and a more integrated North American energy economy, that the time to act is now and to be more proactive. I hope that message gets through to FERC as well, which has struggled over the last seven or eight years to try and turn Order 1000 into a more productive exercise.

The CHAIRMAN. Mr. Kelliher?

Mr. KELLIHER. It's an interesting question. I'd like to answer it as a, sort of a counter factual. What would things look like today if we hadn't made the large investments in infrastructure going back to say, summer of 2005?

Summer 2005, the price of natural gas was $9.00. Now it's $3.00, sometimes lower. That didn't just happen. It happened because the natural gas supply basins changed, that that production only could have made it to market with really large-scale investments into new gas pipelines.

If we had static pipeline network and we still saw the improvements in shale gas technology, prices would not be $3.00 now. They might be $6.00, they might be $7.00. I'm just, sort of, guessing at numbers. And we probably would have been thrilled, thinking, not knowing that they could have been $3.00. We'd have said, wow, the price of natural gas went from $9.00 to $7.00. That's fantastic because at the time the expectation was $9.00 would be, sort of been the medium. They might actually be higher than that.

Now, if gas prices were $7.00 or $6.00, gas is the driver of electricity prices, wholesale electricity prices. Suddenly a lot of uneconomic generation that has now retired or is poised to retire would be economic.

So, we would not have seen the changes in our electricity supply that have occurred in recent years. Natural gas would not be the number one source of electricity supply. It would probably still be coal. We'd have a less flexible fleet.

You know, I think the short answer would be, gas prices would not be $3.00. Electricity prices would not be where they are today. Everything would be 25 to 50 percent higher, and the economy would suffer as a consequence. So, I think, the infrastructure investments have made all of that possible. It would not have happened otherwise.

The CHAIRMAN. I appreciate that.

Senator King mentioned in his opening statement the reference that sometimes we build the infrastructure out as if it is a church awaiting Easter mass and Christmas and that much of the time you have underutilized capacity there. This is the big problem that we face.

We are trying to find that right spot for where we are today, but also anticipating the needs of the future. It is, kind of, the Goldilocks situation. Is it too big for where we are today; is it too small, or is it just right?

Very quickly, because my time has expired, but use my Goldilocks analogy. Are we too big, too small or just about right for today and then five years from now what do we look like? This is rapid round.

Mr. Moffatt?

Mr. MOFFATT. I think we are about right. I think the market forces that you see clearing prices and meeting supply needs is there.

We do——

The CHAIRMAN. What about five years?

Mr. MOFFATT. Five years from now, I think it's going to be the same.

The CHAIRMAN. Alright.

Mr. MOFFATT. I think that the residential, commercial, industrial uses are not going to change. There may be on the margin some change in how we generate electricity, but we're still using electricity.

If we have major efficiency, then yeah, we may become obsolete. I don't think we'll be obsolete because of renewables.

The CHAIRMAN. Okay.

Mr. Murchie?

Mr. MURCHIE. Yes, and I generally agree with that, but Senator King's question before about stranded assets, I think, is an important one because behind your question is, are the things we're building today going to be obsolete? Who is going to pay for that cost? And as Mr. Kelliher said, in the natural gas world, it's the investors. It would be my clients if we were to not allocate our capital accordingly.

And so, the issue is we're never going to get this right. There will be mistakes made and the question is who will pay the costs and are those costs going to be borne by those people who are best able to or who are responsible for those costs? So, if there are regulatory changes that were unanticipated, then those costs could be borne by people who, through no fault of their own, are now paying more for electricity and gas. I think investors are willing to take that risk so long as that, you know, the reward is commensurate.

And so, we see enormous changes, again, on the electricity side because Curt's point about most of natural gas being used for things other than electricity. That doesn't move much.

When you talk about storage on the grid, one of the largest pieces of storage on the grid in the future will be batteries between four wheels. That will be part of the storage on the grid. They will charge at certain times of the day and it will reduce over the 24-hour cycle of electricity.

If markets are designed properly, the risk will be borne by those who can best take them and if you make a mistake as an investor, well, that's the system we're operating under.

The CHAIRMAN. Mr. Hoecker, Mr. Kelliher, are we just about right, right now? Where are we going to be in five years?

Mr. HOECKER. Madam Chair, I think it's especially hard to make predictions, especially about the future and we are eternally in that dilemma.

But we, at least on the transmission side and I try to make the case that transmission is a special case because what it gives us is the ability to adapt to whether we have gas generation, more renewable generation, whether nuclear has a renaissance, the kinds of technologies that are coming along, storage, demand response and so forth.

The common thread, the tie that binds is the adequacy of the grid. If we begin to plan five-year increments at a time without looking down the road at what these long-lived assets can do for our economy, we're going to miss some opportunities and apropos of what Joe said earlier, you know, we need to take reasonable risks, but I think where we're at is a pretty good spot. The lights are on today and I think they'll be inexpensive to turn on for a while.

The CHAIRMAN. Hopefully they are going to be on tomorrow too. So much for my lightning round.

Mr. Kelliher, I've got to give you the final say here.

Mr. KELLIHER. I think, in terms of, I'll give you an answer on the electric side and the pipeline side.

On the pipeline side, I've great confidence that the investment level will continue to be right really just because the nature of how projects are developed. Pipelines are for profit enterprises. They have large scale, either national, regional networks. They see a market or customer interest and they really are very aggressive in pursuing it, typically in a competitive fashion. That dynamic won't change. That will still be there five years from now, and they're looking for economic benefits.

On the electric side, the focus on, at least the RTO transmission planning is on reliability need, not economic benefit. So, I think, I'm not trying to be qualified, on the electric side, I think the investment will still be just about right to satisfy that floor reliability needs. It won't necessarily be just right to satisfy resiliency which is harder to quantify and the plant doesn't even really focus on the economic need. It focuses on the reliability needs. So, I think it's, it will be adequate for that. Will it be adequate for those higher purposes or greater level of investment? I'm not sure.

The CHAIRMAN. Thank you.

Senator King.

Senator KING. Thank you, Madam Chair.

First, the most profound observation I ever heard about fossil fuel prices goes back to the '70s or '80s where a professor at the University of Maine said, "Fossil fuel prices in the future will always be the opposite of what you think today."

[Laughter.]

Because if you think they are going to be cheap and you act accordingly, that will increase demand and they'll be expensive. If you think they are going to be expensive and act accordingly and conserve, there will be an excess and they will be cheap. I think that is pretty true, that it has been proven true over the years.

A couple of points.

One, I think there will be growth in the grid over the future, but I don't think the growth in the grid necessarily will be proportional to the growth in electricity demand.

Mr. Hoecker, you talked about how growth in electricity demand could be 50 percent or 100 percent. I agree with you, but I think it is going to be in different areas.

Electric cars. Electric cars can come under the grid if they are charged at night without adding a single wire or a single pole, and yet, that would add significantly to electricity demand.

I don't think you necessarily meant to imply that, but I think we need to separate the grid from electricity demand, because the grid does have a lot of excess capacity. I hope that we are headed into a future where we can talk about things like peak load pricing and time of day pricing to encourage utilization of electricity when there is excess capacity on the grid.

Number two, it is funny for those of you watching this hearing, you can tell people from the states where they generate, where they make electricity. I mean, where they have fossil fuel and where they don't, there is a lot of talk about more exports and those kinds of things.

I need to put on the record as I have in practically every hearing, I am gravely concerned about an exponential increase in the export of natural gas and LNG.

This Congress cannot repeal the law of supply and demand. If we have a significant, and I mean it is proposed, there is something like 14 LNG terminals pending before FERC. If that happens, and if we get to the level of exports that people are now talking about, it will affect prices in the United States. I think we will be giving away one of our substantial advantages that we have over the rest of the world that has been brought about by the shale revolution.

Finally, Mr. Kelliher, the question I wanted to ask you is, and you put a term into our lexicon that, I think, we should all think about, the 12 days. You mentioned the 12 days. That is that peak period when the gas supply into New England was not adequate. What would you do about the 12 days if you were head of ISO or czar of New England?

Mr. KELLIHER. Thanks.

If I were king of ISO, I would, I mean, I think their planning has shown that the correct economic solution is more dual-fueled capacity. So, burn fuel oil on those 12 days. It's more expensive than natural gas, except it's not during those 12 days. That's what the approach of New York is. New York has, relies much more heavily on dual-fueled generation than in New England.

My understanding ISO New England has pointed out that more dual-fueled capacity actually is the economically correct approach. But they've also pointed out, it's an approach that's resisted by the states in the region. They don't want to license dual-fueled facilities.

So, ISO New England——

Senator KING. Dual-fuel and storage, traditional storage with LNG coming in?

Mr. KELLIHER. Yeah, it's, sort of, maybe, the same level of LNG coming in but more dual-fuel facilities so that during those 12 days, you're not buying the most expensive gas, you're burning fuel oil that you already have in hand onsite.

Senator KING. Demand response might have a role?

Mr. KELLIHER. Sure, yeah, yeah.

I think ISO New England has done a very good job encouraging demand response and I think they've, I would commend them for pointing out dual-fuel is the economically correct approach but that the states oppose it so they're left with the next best alternative and that's——

Senator KING. Well, I know it worked. I know it happened this winter, because I walked to the shore in my home town of Brunswick and saw on the horizon the Cousins Island oil plant emitting, you know, you could see something coming out of it and I don't think it had run for 10 years, but it was running in January because of that very issue.

Well, thank you very much. This has been a very informative hearing.

Mr. HOECKER. Senator, could I interject?

Senator KING. Yes, sir.

Mr. HOECKER. I thought your point about EVs, electric vehicles, is a very good one and I agree completely with you that——

Senator KING. You can always interrupt to say you thought a point I made was a very good one.

[Laughter.]

Mr. HOECKER. Yes.

Senator KING. Perfectly okay.

Mr. HOECKER. Well, I would have interrupted more often then. [Laughter.]

I think that it will drive expansion of the distribution systems and the high voltage systems. We're doing a study this year that will explain that relationship.

But I don't think it's fair to say that there is excess capacity on the grid everywhere. I think, it's like saying there's excess capacity on certain stretches of the interstate highway system. The fact is that it's an integrated network and that is its primary benefit. Some places it's very congested and needs to be upgraded or expanded. In other places, it's nonexistent. I mean, a lot of the renewable energy that is locked up in your state and in the Great Plains has no market because there's no delivery capability.

So I think it has to do with the unique nature of the integrated network, and I'm glad we're using that word because is really what we're talking about. That doesn't mean that all transmission that can be conceived by the mind of man needs to be built, but it does mean that we need to use it as a lever——

Senator KING. Sure.

Mr. HOECKER. ——to get to a different energy economy.

Senator KING. Thank you.

Thank you very much. I appreciate it.

The CHAIRMAN. Senator Cortez Masto, any follow-up?

Senator CORTEZ MASTO. No.

The CHAIRMAN. Well, I just will end, since we have two former Commissioners of the FERC with us today and we know we're going to have this opening coming up.

I would ask you if you have any words of advice in terms of characteristics that we might want to be looking for in a prospective nominee?

Mr. HOECKER. Well, that's a very tough question. I've long advocated that the members of the Commission should include some seasoned economists, industry engineers, not just lawyers, as much as I love lawyers, but I think that those diverse skills have served the Commission well in the distant past, and I think that would be a good idea.

I think, basically, you want somebody with a kind of judicial temperament, someone who doesn't have a particular axe to grind who can make independent decisions.

The CHAIRMAN. More and more it seems that they need to come with a crystal ball, but Mr. Kelliher, what would you advise that we look for in terms of characteristics?

Mr. KELLIHER. I think they need someone who is comfortable with criticism.

[Laughter.]

Someone who is not, doesn't, that doesn't scare them, that prospect doesn't scare them, someone who is independent by temperament, someone who will follow the record, and someone who will actually try to work with their colleagues. I think FERC has a long history of that, but only up to a point.

I mean, it's not supposed to be 5–0 on everything. It's okay to dissent, but you should try to work out a reasonable compromise with your colleagues. Four is a scary number, because four has the tendency to divide evenly sometimes.

Hopefully the Administration will be relatively quick nominating someone who is independent, willing to take criticism for the correct decision, and will try to work toward compromise but dissent when necessary.

When I dissented, I always considered it a personal failure, because that meant I was right, of course, but I failed to persuade my colleagues.

[Laughter.]

It was a failure of persuasion, so I was always sad about dissenting.

Mr. MOFFATT. Senator, if I might?

The CHAIRMAN. Mr. Moffatt.

Mr. MOFFATT. As someone who has $35 billion of regulated assets, what are we looking for in terms of our regulator?

I think it would benefit, not so much for the economist, but people who understand capital markets, including how we raise equity, and how we raise debt.

People who understand some of what we've seen recently with the Commission's order, the market surprise and market reaction, and the potential for decisions at the Commission to make the sector either very costly to finance or one in which we're having difficulty attracting equity and debt. That's very problematic. So, I think we have to focus less on a politician——

The CHAIRMAN. You're talking about tax——

Mr. MOFFATT. ——and more on people that understand capital markets informing capital.

The CHAIRMAN. Yes.

Mr. Murchie.

Mr. MURCHIE. Yeah, I didn't put him up to that.

[Laughter.]

So yeah, in considering the answer to that question, I guess our vote would be someone with a lot of experience, because if you had a lot of experience, then you've been doing it long enough to understand that there are capital market consequences to the optics of decisions.

It's one thing for us to make portfolio decisions based on knowledge of the companies, the industry, the management teams, but the movements of capital within our $6 billion portfolio are minuscule compared to the movements of money in and out of sectors by individual investors who are getting their information from the six o'clock news. The optics of how these decisions are communicated are just as important to those people and the way they move capital around is the underlying substance.

The CHAIRMAN. Yes, I appreciate that.

We will have an opportunity to be reviewing whomever may be sent forward, but I appreciate your insight on that.

We are doing a lot of talking right now about nominees at different levels and different capacities, and I think about the role of the FERC and the significance of the decisions that come out of the Commission on our overall, just our overall national economy, the impact on jobs, the impact on really, our ability to engage in any level of commerce. And it is so important that we get these policies right. But in order to help develop, shape, and advance them, we have to have the men and the women that are in place.

Senator Hoeven, I have been filibustering waiting for your arrival.

[Laughter.]

Knowing that it was imminent.

We have had a very good discussion with a great panel here this morning talking about our infrastructure, whether it is our pipeline, our electric transmission, just had a little bit of a discussion about the upcoming vacancy on the FERC and the need for somebody that has experience, that has some understanding of the markets overall and who has a strong backbone and is not afraid of a little criticism.

We are pleased that you were able to make it over from your other committees to share your issues and concerns with this panel. I will now turn to you.

Senator HOEVEN. Thank you, Madam Chairman, I appreciate it very much, and I know you are wrapping up. I appreciate the patience and the diligence of all of our witnesses today.

It is such an important issue and, you know, how do we bring people together on this whole issue of interstate transmission whether it is natural gas pipelines, whether it is oil pipelines, whether it is transmission lines.

We have gotten to the point now where whether you are a fan of traditional energy or renewable energy, we all have to work together because we have to get the energy from where it is produced to where the consumers are.

Then we also have the issue of federalism, state's rights and then the Federal Government's ability to have the national infrastructure and really, international infrastructure, that we need.

I guess I would just like each of the witnesses to give me their thoughts in terms of the one or two things that we can do to really get this issue moving in terms of getting that public support in place so that we can go ahead and build this needed infrastructure.

Let's start with you, Mr. Moffatt.

Mr. MOFFATT. Thank you, Senator.

One area that we haven't touched on today are landowners that we impact and communities that we impact as we try to build, particularly linear, infrastructure.

I think that for the interstate pipelines we're working very hard on making sure we understand what our guidelines are on landowner rights and how we interact with landowners and abutting landowners and communities diligently, consistently, and honestly. In building a linear project we're going to be, we're going to go through this process for seven years, even in the best case, from the time we stake the right-of-way until the time we reclaim it. So we have to build that relationship with landowners which I believe we do.

Nobody really likes a project in their backyard and with social media, the noise, I believe, is louder than people realize. We've had, over the last ten years on our interstate projects, over 4,000 different land agreements with landowners. Only 141 have gone to condemnation and compensation. Every one else has been negotiated. It's over time they gain more information. We gain more information, but from our standpoint the process reasonably works, if the regulators want it to work and, you know, it's a political issue, state and local, but for the most part I think it works well if we all cooperate and we do talk.

Now I know with Nebraska you've had some other circumstances with Keystone XL for a long time. I was representing TransCanada, so I lived some of those battles before joining Kinder Morgan. Some of that, that's politics and other policy issues which I don't know how you resolve given what you mentioned about federalism and state's rights.

Senator HOEVEN. Seven years, realistically that is what it is now.

Mr. MOFFATT. Right.

Senator HOEVEN. Do you see that——

Mr. MOFFATT. Yeah, because if you want to just stick around, really quickly, we'll see a market dislocation where added infrastructure might work. We will then analyze the engineering and the routing and what the constructability is of the project, then we go try to find people who are willing to sign contracts to pay for it, then we have to develop the resource reports, go through the various procedures at a commission and under any set of guidelines can be two years—then it's usually two years of construction and one year of reclamation of the right-of-way. So it's a seven-year process, even in the best case and that's with everybody moving diligently.

Senator HOEVEN. That is pretty sobering, isn't it, when you say it is seven years in the best case for needed energy, to move energy around the country. Think if somebody's got a problem today, and they need energy.

Mr. MOFFATT. Yes.

Senator HOEVEN. You come in and say, best case scenario, we can maybe get you some transportation and transmission built in seven years.

Mr. MOFFATT. In the intrastate market, we can probably do it in two years.

Senator HOEVEN. Other thoughts on that? This is the issue and it is a very, very important pressing issue.

Mr. MURCHIE. So, picking up where Mr. Moffatt left off on, you know, landowners and why do we have the right of eminent domain when a gas pipeline gets approved.

From our perspective, perhaps the role of regulators and government is to fix market failures, market imperfections. And the three that were, sort of, discussed today were diversification of energy as a separate goal, obviously, the cleanliness of it and the provision of reliability in surplus capacity. You could argue that those three things are market failures, that the free market would not come up with on its own.

Everybody always argues that we should have an energy policy, but it's really because they have an axe to grind on an export or something like that. But if there is an energy policy, maybe it should be directed only to those things where the market fails. Maybe those three issues would go a long way to getting people to understand that, you know, while their land is being taken, it's being taken for a greater good, just like it is with a highway. Perhaps that's where the debate should focus on where the market failures are because that's the role of policymakers and regulators.

Senator HOEVEN. Sir?

Mr. HOECKER. Senator, you know, to me this is a leadership issue and not necessarily a knowledge issue.

We have studies coming out yesterday from the Energy Information Administration on the benefits of HVDC, big HVDC projects. NREL, the National Renewable Energy Lab, is just about to release a study on building transmission across major market seams. We've talked about electrification of the economy this morning.

But all of these things are a lot of experts talking to each other. And you point out something that's really quite important and that is that in order to bring states along, in order to have a collaborative effort, in order to reassure the public that what we're talking about when we talk about infrastructure is not anti-environment, in fact, it's, at least as far as transmission is concerned, it's the other way around.

That requires setting some goals, talking about what the grid needs to become, where we need to go and having policymakers and folks like yourselves but also FERC and the Secretary of Energy beginning to articulate what the grid of the future, what the energy market of the future needs to look like and why we need to invest in it.

Senator HOEVEN. Thank you——

I beg the indulgence of the Chair. I apologize for running over.

Mr. KELLIHER. On the gas pipeline side, I think some actions that could help would be FERC to reaffirm its gas certificate policy statement they're conducting or review. They should basically reaffirm that policy, I believe. There might be a need for, some changes might be appropriate, but basically reaffirm their certificate policy statement.

One issue on the gas side is the FERC process does take longer than it used to. The FERC pipeline certificate process used to routinely take two years, now it takes three years. The Chairman has identified time limits as being important to him, so hopefully FERC could get back to more of a two year timeframe, rather than three.

In terms of other federal agencies, that does result in some delays in pipeline construction operation. If those agencies have legitimate resource concerns, like basically, they don't have enough resources to act in a more timely manner, there's a model in the FERC hydro side where other federal agencies can recover the cost of work they've done in the hydro licensing/relicensing case through FERC. So, if they, if the reason they're slow is lack of resources, there's a way that those costs could flow through FERC and be allocated toward all pipeline licensees.

We talked earlier about how some states are using their clean water act authority, perhaps improperly, to impose conditions on related to water quality. We talked about some ideas where legislatively or through EPA guidance, that could be checked.

On the electric side, I can't come up with as long of a list, but the biggest one would be for FERC to clarify its policy on return on equity so that you know what you're going to get when you invest in transmission.

And part, the ownership is so different of the electric grid and the pipeline network. You basically have 20, 30 large scale, for profit corporations that have large networks on the pipeline side. On the electric side, you have more than 400 owners, very few of them have even a regional, kind of, scale system, a third of the grids owned by non-profit entities, government utilities and cooperatives. So you have hundreds of hands yanking the levers on really what are large regional machines. It's hard to see that you'll ever have the siting be as timely on the electric side as the gas side.

If I told someone who builds electric transmission that we were crying, but I was crying here today about a three-year FERC siting process, they would laugh in my face——

[Laughter.]

——and say, I'll take that tomorrow for transmission. And transmission siting is done not at the federal level, but at the state and local level. Some states every single local government sites a transmission line. There's not a state siting body.

Senator HOEVEN. Madam Chairman, it really is a rubix cube, isn't it?

I mean, we want to find solutions here, but it is complicated. You bring up real issues that we need to address the challenges because of the complexity of how we do that.

So, thank you so much.

Again, I really want to thank the Chair for her patience, I appreciate it.

The CHAIRMAN. No, thank you, Senator Hoeven, for the question and I think it really does hit to so much of what we are dealing with. We are trying to anticipate what we need to build to, we need to address the immediacy of the needs today, sometimes the crisis needs today. There is no real silver bullet here, to go back to Senator King's analogy, maybe some silver buckshot out there, but it is complicated.

But to hear just from the FERC regulatory process, we have gone from an expectation that it is going to be a two year process to just automatically, it is going to be three. It seems to me that there are some areas that we can look to very directly and say, there has to be a better way.

Thank you for shining the light on some of these very, very important issues. We clearly have a lot of work to do, and we will be working together.

Thank you, gentlemen, for the time that you have given the Committee. If members have additional questions that they might want to submit to you for the record, you should anticipate those as well.

Thank you very much.

With that, the Committee stands adjourned.

[Whereupon, at 12:03 p.m. the hearing was adjourned.]

APPENDIX MATERIAL SUBMITTED

U.S. Senate Committee on Energy and Natural Resources
July 12, 2018 Hearing
Policy Issues Facing Interstate Delivery Networks for Natural Gas and Electricity
Questions for the Record Submitted to Mr. J. Curtis Moffatt

Questions from Chairman Lisa Murkowski

Question 1: Over the past few years, it has become increasingly clear that this nation is facing a fundamental choice when it comes to energy policy. Down one path is a hard-edged effort to stop using fossil fuels altogether, and down the other is the continuation of our existing policy of supporting ever cleaner forms of energy, while ensuring that energy is still affordable.

- Please describe the political and regulatory risks that needed pipeline and LNG facilities will not be built over the next ten years.

The primary political risk will emanate from interest groups and elected officials who advocate for an immediate end to the use of fossil fuels regardless of the consequences of such action to consumers, manufacturers and the overall U.S. economy. If this anti-fossil fuel perspective is translated into official federal policy, either through Congressional legislation or Executive Branch regulatory requirements, the likely result will be confusion surrounding development of needed pipeline and LNG infrastructure and increased cost of project development for those facilities that do get built.

There also is a degree of political risk created by the fact that the Federal Energy Regulatory Commission ("FERC" or "Commission") will not have a full contingent of Commissioners beginning in a few weeks. Given the distinct possibility that an evenly divided Commission will be unable to achieve the majority needed to issue pipeline certificate orders for a number of pending projects, it is imperative that the White House promptly nominate someone for the soon to be open Commissioner's position and that the Senate confirm that individual in a timely manner. As I testified, it would be helpful to the Administration's energy agenda to nominate an individual with a background in the natural gas industry and experience with capital intensive infrastructure projects.

The most likely source of regulatory risk lies with the processes and judicial review that will accompany the issuance of state and federal permits. Other federal and state

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agencies have certain prescribed authorities to issue permits and other authorizations for construction and operation of natural gas pipelines. The most immediate and visible threat is from delay, inaction or rejection of such permits. If these agencies exercise their permitting authority simply to impede the construction of natural gas pipelines the impact will be serious. While the project proponents may have litigation avenues available to challenge such actions by state and federal permitting agencies on federal preemption grounds or on grounds that their actions are arbitrary or exceed their legal authority, the continued delays and uncertainty created by such actions will affect the availability of investment capital for pipelines and LNG facilities. Recently, it also has become necessary for the permitting agencies to provide well documented records in support of the decisions. Opponents of the projects are now seeking judicial review of permits outside of the Natural Gas Act certificates.

In addition, current trade policies that place tariffs and quotas on certain imported products threaten the availability of material that, at least in the short term, cannot be domestically sourced in the quantities and specifications needed to ensure robust development of pipeline and LNG facilities. Retaliatory tariffs and quotas on natural gas or LNG exports also could impact infrastructure development.

- In your view, what are the best ways to ensure that these risks do not materialize?

In our view, there are two primary ways to address these risks. First, it is critically important that all participants in the natural gas "value chain" – producers, pipelines, local distribution companies, electric utilities, manufacturers, and end-use consumers – work diligently to educate their customers, opinion leaders, elected officials and other stakeholders on the overwhelming benefits that the availability and use of natural gas in all types of applications provides to the U.S. economy and consumers. Second, it is incumbent upon the Congress to be vigilant that the regulatory agencies charged with implementing numerous resource management and environmental statutes are acting in a manner consistent with those statutes as well as with the intent and directives of the Natural Gas Act of 1938 ("NGA"), Natural Gas Policy Act of

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1978 ("NGPA") and the Energy Policy Act of 2005 ("EPAct 2005") and are not taking actions designed to thwart FERC's implementation of those latter statutes. Over the 80 years since the enactment of the NGA, FERC (and its predecessor the Federal Power Commission) has been a faithful steward of Congressional policies. The vast interconnected pipeline network and storage grid that serves a transparent and economically efficient natural-gas-commodity market is evidence of the achievements.

- Shouldn't FERC Commissioners be equally receptive to needed pipeline infrastructure regardless of the political party of the person holding the Office of the President of the United States?

FERC is an independent agency with responsibility to implement Congressional directive and intent as embodied in the NGA, NGPA, and EPAct 2005. The Congressional directives to the FERC in these statutes is unambiguous – to facilitate the development, construction and operation of a nationwide network of interstate and intrastate natural gas pipelines for the benefit of the nation and its citizens. The regulatory agencies have always been populated by members of either major political party or, occasionally, political independents. As evidenced by the prior decades of regulatory achievements, and the success in implementing Congressional directives, the Commissions have pulled together to develop and implement national energy policy. Certainly, when the President nominates an individual to serve on a regulatory commission, and the Senate confirms the nomination, it is anticipated that the individual commissioners will act consistent with the law to fulfill the public policy mandates as established by the Congress because of their dramatic impact on the economy, consumers and increasingly international trade and geopolitical issues.

- During the eight years of the Obama Administration, FERC's policies resulted in significant investment into needed pipeline infrastructure—is now the time for Commissioners at FERC to be considering major changes that could discourage needed infrastructure?

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As is evident by the public debate that occurs with respect to each significant infrastructure project and the increased federal and state judicial actions being undertaken by project opponents, the implementation of the provisions of the NGA and other permitting statutes are under increasing scrutiny. In response to this heightened scrutiny, Kinder Morgan supports FERC's initiative to review and refresh its 1999 Pipeline Certificate Policy Statement ("1999 Policy Statement"). The comments that Kinder Morgan filed in response to the Commission's Notice of Inquiry generally recommend that FERC "stay the course". We believe that FERC's implementation of its Policy Statement over the last two decades has resulted in a robust and efficient interstate natural gas transportation system. It also has resulted in well-developed and complete analyses of the economic, social and environmental issues supporting a determination of the public interest and strong protection of the environment with forceful mitigation conditions and close oversight of construction and remediation. The Policy Statement is a sufficiently robust framework for analysis and decision-making to account for changes in the markets and the regulatory environment since 1999. Kinder Morgan anticipates that FERC will not make dramatic, harmful changes to its Policy Statement and its processes for considering certificate applications. This updated affirmation of the Policy Statement will create a stronger platform from which FERC can fulfill and defend its findings in each case.

A copy of Kinder Morgan's comments on the Policy Statement that were filed at FERC is attached.

Question 2: Since consumers of energy should not be paying for wasteful overbuilding of pipeline infrastructure, FERC has policies to ensure that the network does not become "gold plated." But, at the same time, the pipeline network should not become outdated, unreliable, and insufficient to meet demand.

- On a one to ten scale, with one being a failing delivery grid, and ten being an excessive, or "gold-plated" grid, where do you think today's pipeline network is?

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Assuming that 5.5 on the proposed scale constitutes a fully integrated, modern, reliable, efficient, well maintained and cost-effective national transportation system for natural gas, we believe today's pipeline network is about a 4.5. A higher rating is not warranted at this time because certain needed projects have been difficult to permit or develop. Specifically, there are bottlenecks in the current network and other locations where it has proven impossible to construct needed pipeline infrastructure because of state and local opposition. It certainly cannot be argued that the current network is "gold plated." Since all interstate pipelines are privately financed and their rates subject to FERC oversight and regulation, there is no incentive for pipeline owners and investors to "gold plate" any projects. Moreover, the efficient and transparent, competitive natural gas commodity markets and basin differential pricing for transportation services significantly limit any "gold plating" practices. But there are numerous incentives for the pipeline owners to continue to invest in routine maintenance and system upgrades reflecting up-to-date technology to improve efficiency, safety and to reduce fugitive emissions. Pipeline operators, including Kinder Morgan, engage regularly in such maintenance and system efficiency programs. Unlike many other types of transportation infrastructure, the safety and environmental operating criteria, coupled with the rate-making policies of FERC, enable pipeline operators to maintain their systems – but prevent gold-plating them. In today's competitive markets, a pipeline has only an "opportunity" to recover its cost of service and no "guarantee" that it will do so.

- On that same one to ten scale, where do you think the network will need to be five years from now? What are the leading risks that could derail this result?

Ideally, the network will be at 5.5 on the scale. If this is achieved, it means that the current bottlenecks have been addressed and sufficient additional infrastructure has been developed to meet new market demand and resulting production. The leading risks are the political and regulatory risks identified above.

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Questions from Senator Joe Manchin III

Question 1: Late last year, FERC announced it would undergo a review of the Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities issued in 1999. The nearly two-decade-old Policy Statement was originally meant to ensure pipeline certification decisions issued under the National Gas Act ensured a reasonable balance between responding to market demands and impacts to the environment and landowners. That process is meant to ensure that a pipeline is truly necessary. But, in light of the shale gas revolution and ongoing pipeline constraints, it seems to me there is certainly ongoing need for pipeline expansion. The transformation seen in the energy market over the last fifteen years has largely been a result of the onset of the shale gas revolution. I absolutely support examining and updating regulations as a part of good governance. I also want to make sure that progress is not unnecessarily hampered.

- I am curious what you think is the ideal product that could come out of the review?

Kinder Morgan believes that the 1999 Policy Statement provides an effective framework for the evaluation of proposed pipeline projects in a manner that balances the complex and competing interests in a comprehensive and holistic manner consistent with the intent of Congress to foster the orderly development of a national natural gas pipeline transportation system. The Commission's policies – developed over several decades – also implement a robust environmental review and detailed implementation and mitigation conditions. The Commission also has developed, and the industry and its contractors have embraced, a very effective construction and reclamation oversight program of environmental, technical and safety inspectors. With these policies in mind, an ideal result of FERC's review of the Policy Statement will be a reaffirmation of the Policy Statement with some modifications to provide greater flexibility in application of the pre-filing process and a commitment from FERC to better utilize its authorities under EPAct 2005 as the designated lead agency to enforce schedules and deadlines on cooperating agencies.

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Additional benefits of the review will be a better public understanding of the scrutiny every project undergoes and a greater focus on improving coordination between federal agencies in the National Environmental Policy Act ("NEPA") process and the follow-on permitting process. Congress hopefully will conduct greater oversight of the inconsistent and harmful practices of some federal and state permitting agencies delaying or rejecting projects for reasons outside the scope of what the specific permit at issue is intended to protect. In certain areas, minor legislative procedural adjustments may be necessary.

Question 2: Do you believe national security should be a consideration in the certification process?

Yes. But neither the NGA nor the Policy Statement needs to be modified to single out national security as a consideration. Rather, the overall focus of the certification process – to foster the development of a transportation system that allows the U.S. to reap the substantial benefits of its natural gas resources – accommodates a national security component. Sound implementation of the NGA and Policy Statement will enhance national security by ensuring a resilient and reliable transportation and storage infrastructure. It is clear that national security questions can arise with respect to availability of natural gas supplies for domestic consumption as well as for exports to industrial and power generation markets around the world. Natural gas supplies increasingly are a geopolitical consideration as well as an economic one. FERC's implementation of the NGA does and will accommodate these domestic and international security considerations.

Question 3: One of the major criticisms I hear from folks in my state that oppose various pipelines and other energy infrastructure is that the FERC and associated permitting agency processes do not allow for enough public engagement. As you know, there are several major pipelines being developed in the mid-Atlantic and Northeast – several in my state. I support the environmentally responsible development of energy infrastructure if that development includes public

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engagement – particularly for landowners along the pipeline route. As Governor, I found that when owners and communities were "dealt in", they were more likely to become partners in the process.

- How do you suggest improving opportunities for the public to get a better opportunity to be heard and for comments to be registered while not sacrificing an efficient and timely permitting process?

Kinder Morgan and the entire natural gas pipeline industry agree with the importance of both landowner relations and community relations. Kinder Morgan employees are members of these communities, and the company stresses strong landowner and community relations with respect to not only the development and construction of transportation and storage infrastructure, but also, if successful, the operating life of the assets. Pipeline operators understand that the development of a project from the first conceptual walking of a proposed right-of-way through to full remediation after construction is a multi-year process that brings stress and disruption to landowners and abutting landowners as well as neighborhoods and communities. Outreach begins at the earliest stages of project development through public meetings and individual communications. Over the ensuing months and years, as various types of surveys and consultations are undertaken, additional detailed information is developed. Communications are maintained through social media, direct communication and individual follow-up when useful. In many cases, we have been operating in these communities for over fifty years and we intend to continue to be good neighbors into the foreseeable future and beyond.

Over the years, Kinder Morgan has improved its communications with landowners and communities and we always are looking for ways to improve. With respect to individual landowners from whom survey or right-of-way options are sought, trained company personnel or trained contractors are in direct communication throughout the process. Surveys and negotiations are expected to be conducted in a courteous and respectful manner. In this regard, company representatives are trained with respect to the appropriate conduct of such discussions. Finally, the Interstate Natural Gas

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Association of America ("INGAA"), as it has done from time to time, recently updated its landowner commitments as part of the review process of the 1999 Policy Statement.

A copy of the INGAA comments to FERC and the associated landowner commitments is available at http://www.ingaa.org/File.aspx?id=34843.

Kinder Morgan consistently is working to improve our communication processes in other ways, including development of regular newsletters regarding the progress of a project, and community outreach and engagement. We recognize that this is our responsibility as a good corporate citizen. We would caution, however, that while significant efforts are made and opportunities to engage abound, as public leaders we must recognize that opposition is often disguised as an inability to receive information or have input. We recognize that some opposition will never be persuaded. However, we always will commit to respectful, courteous engagement as we pursue the approval, construction and operation of transportation infrastructure.

Question 4: In your comments regarding the 1999 FERC review, will you be looking at ways to enhance the role of the public? Ensure landowners are appropriately compensated and – if not – seek ways to improve that?

In the attached KM comments filed with FERC, Kinder Morgan has identified some of the initiatives that it has taken over the last couple of years to enhance landowner communications. Kinder Morgan has had a strong record of securing rights-of-way by bilateral negotiation and mutual agreement. These negotiations are beneficial for all parties concerned in that it saves time and avoids legal fees associated with court condemnation and valuation proceedings. Kinder Morgan believes that its right-of-way agreements are fair and reflect just compensation.

Below is a chart that shows the high degree of success in securing rights-of-way for our FERC-regulated projects without resorting to eminent domain authority.

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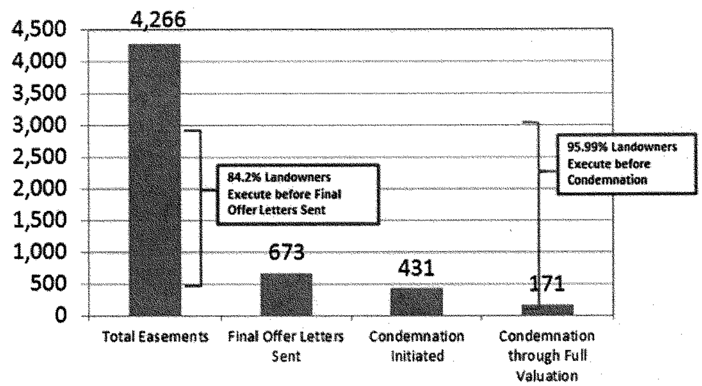

Easements Executed by Kinder Morgan Entities Over Last 10 Years for NGA 7(c) Projects

Questions from Senator Tammy Duckworth

<u>Questions</u>: On December 5, 2017, a Kinder Morgan natural gas pipeline exploded killing two people and injuring two other individuals. According to the report, Kinder Morgan suspects the explosion was caused by a third-party line strike. Although third-party damage is difficult to prevent, there are best practices and tools available to promote safe digging and work around natural gas pipelines. With 78 percent of Illinois households using natural gas to heat their homes and numerous interstate pipelines crossing the State, safety must be one of your top priorities. In response to the explosion in December, what new policies, practices and tools are you using to prevent third-party strikes?

Kinder Morgan always is concerned by any injury or loss of life due to third-party line strikes. The case you reference in your question was a particularly difficult situation. As detailed in the Pipeline and Hazardous Materials Safety Administration's Failure Investigation Report for this incident, the operators of the farm were aware of the location of the pipelines on the property because of their past use of the Illinois One

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Call System (also referred to as "JULIE"). One Call Systems, when used, prompt pipeline companies to locate and mark a pipeline prior to the commencement of any excavation work near the pipeline by third parties. Additionally, there were permanent pipeline markers at a road crossing and at a fence adjacent to the location, and the operators of the farm previously received multiple mailings from Kinder Morgan entitled "Our Pipelines in Your Community" and "Working & Digging Near Pipelines." These mailings identify the importance of using the One Call System each time prior to starting work and advise what to do in the event of a leak. Unfortunately, regarding this particular line strike, no such One Call notification was made by the operators of the farm prior to the work.

Kinder Morgan routinely monitors encroachments and work around its facilities. Any excavation discovered near our pipelines without a valid One Call is immediately remedied and followed up by communication with the entity responsible for the encroachment, including state and local entities currently exempted from One Call requirements. In addition, we monitor our rights-of-way for appropriate signage, and we communicate regularly with people who live near the pipeline to remind them of the presence of the pipeline as well as the One Call System and the need to use it. There are no "new" policies, practices or tools being deployed. Kinder Morgan remains committed to the execution of the existing protocols in place.

- As a national company, what are the most effective State policies in place for mitigating third-party strikes and what further actions can the Federal Government promote to reduce these risks?

The most effective tools in place nationally are the state initiatives to implement One Call statutes at the state and local levels. Kinder Morgan, along with other infrastructure companies, continue to encourage both state and federal authorities to discontinue exemptions for governmental subdivisions from the One Call requirements. In many less populated communities, public infrastructure maintenance is a common cause of third-party strikes or near misses. So long as

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such entities are exempt, the most effective action the industry can take is to educate and encourage compliance with One Call programs. An additional recommendation is for Congress and the state agencies to increase efforts to enforce the obligation on third parties to make One Call notifications and to wait for the pipeline operator to mark their lines before proceeding.

Questions from Senator Catherine Cortez Masto

Questions: Energy infrastructure can sometimes contribute to local economies even more directly than other large infrastructure projects through competitive rates and operation as a business partner – what is the best way that the federal government can engage with local governments and encourage local investment?

The Congress and the federal agencies and regulators can encourage state and local governments to support the federal policies regarding development of needed energy infrastructure. Every project will add to the local tax base, provide jobs during development and construction, provide competitive energy for the local residents, and attract businesses and manufacturers.

- What alternatives can the federal government consider to encourage growth and local project development rather than walking back regulations more broadly?

The federal government provides incentives for local governments to invest in local infrastructure projects through numerous provisions of the Internal Revenue code, including tax free municipal bonds. There may be other alternatives to consider, but Kinder Morgan has no position on such alternatives. We would, however, question the premise that "regulations" do not limit development of local infrastructure projects. State and local governments constantly are challenged to contain the costs of maintaining and constructing infrastructure projects. Regulations that provide no discernable benefit but add costs and delay to projects should be reconsidered and either revised or repealed.

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Questions from Senator Shelley Moore Capito

Question 1: The Utica and Marcellus shale plays under production in West Virginia contain significant quantities of natural gas liquids (NGLs) such as ethane. Stakeholders are looking into creating a natural gas liquids storage hub to facilitate a regional market for NGLs and downstream processing and manufacturing in Central Appalachia. I believe that the economic benefits of this downstream economic opportunity is certainly within the "national interest" but may be outside the current analyses of FERC certificate reviews. The case is similar to the indirect economic and foreign policy benefits from the export of liquid natural gas (LNG) that may not be appropriately reflected by the current regulatory procedures of the Commission.

- As FERC considers reopening the 1999 Pipeline Policy Statement, do you believe that it would be appropriate for FERC to promote a more expansive national interest analysis into the benefits of downstream NGL processing and LNG exports in its certificate reviews for relevant project applications?

Kinder Morgan believes that LNG exports and downstream NGL processing are two uses of the nation's natural gas resources that contribute significantly to the national interest and that are contemplated in the Natural Gas Act. As such, LNG exports and NGL processing need to be expressly recognized and valued by FERC when it conducts its analysis to determine whether there is a public need for a proposed project. Contracts for capacity on a proposed pipeline signed by a producer of natural gas or NGLs, or by an NGL processor, or by an LNG exporter demonstrate that there is a need for the project. Private entities that sign binding contracts that obligate them to pay millions of dollars for capacity in a pipeline do not do so for no reason. They have natural gas to sell or they need natural gas to produce other products. These shippers are not the only beneficiaries of the pipeline; production and export of natural gas and the use of NGLs also create substantial jobs and economic opportunity that are beneficial to the national interest. Indeed, the exports of LNG to European and Asian countries can make a significant contribution to improving the U.S. trade balance with these countries.

- Is this something FERC is currently doing and, if so, are these benefits weighted appropriately in these reviews?

We believe that FERC's implementation of the NGA and the 1999 Policy Statement appropriately evaluates these considerations. FERC's reliance upon market participants to make binding financial commitments as a significant showing of public need has worked well and is consistent with confidence in private markets and private financing of the necessary infrastructure. The significant role of the NGA in the natural gas markets is necessitated by the fact that pressurized pipelines are the only means of efficient transportation of natural gas. Given its natural gaseous state, there are no other transportation alternatives. In this regard, FERC has developed the correct precedent and it should be maintained.

However, several commenters on the 1999 Policy Statement, including the Attorneys General of six states and the District of Columbia, are urging FERC to abandon its market test to determine public convenience and necessity and to substitute the Commission's judgment as to whether a particular project is needed and the utilization of natural gas is appropriate. This is dangerous territory. FERC has no authority under the Natural Gas Act or otherwise to determine that one use of natural gas is more deserving than another. The competitive, transparent energy markets are a better barometer of public need.

- Does FERC have adequate policy tools, personnel, and resources necessary for reviewing applications for projects related to serving NGL storage, processing, and downstream manufacturing?

Kinder Morgan is not in the best position to determine whether the Commission has the necessary complement of personnel and resources to review all applications on a

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timely basis. To date, Kinder Morgan's experience has been reasonable with respect to review and approval of its projects. However, it is imperative that the Commission has adequate funding and staff to review applications, conduct public meetings and open houses, and draft responses to the numerous comments and pleadings filed in the dockets. A shortage of staff or funding that results in delayed consideration of critical information or inadequate responses to stakeholder concerns will undermine public confidence in the FERC process. Approval of the natural gas infrastructure will certainly support the further development of related facilities for NGLs and downstream industrial and manufacturing uses of NGLs as well as natural gas as a feedstock.

- How about for LNG export terminals?

As mentioned above, to ensure the nation achieves the benefits associated with export of U.S. natural gas resources it is important for FERC to have sufficient resources to evaluate and analyze the large volume of information submitted in the review and approval process for any infrastructure project. FERC itself has identified the need for recruiting more qualified engineers to assist with the workload related to review of LNG terminals. This identified need is supported by our experience. The agency also is facing what the rest of the economy is facing: the retirement of an aging workforce. This reality certainly is a major concern for any company that requires timely federal action.

Question 2: In your testimony and its addendum, you underscore the importance of the Natural Gas Act of 1938 and subsequent statutes in promoting the development of our robust natural gas market. The Natural Gas Act addressed the problem of natural gas production states hording their natural gas resources at the expense of their neighbors. Today, regulatory policies, like some states' abuse of Clean Water Act Section 401, are creating the opposite problem: production states cannot get natural gas to other regions due to political intervention by states along the proposed pipeline route. New York's blanket Section 401 prohibition of pipeline projects has limited New England's access to Utica and Marcellus gas production in West Virginia and Pennsylvania, driving up the region's electric costs and driving its dependence on oil and Russian LNG for electric generation to make up for fuel shortfalls during cold weather events.

- Can you elaborate on the challenges posed by these regulatory obstacles and how they are at odds with congressional intent in energy statutes dating back to the Natural Gas Act of 1938?

The challenges posed by states that utilize regulatory or statutory authority to impede, limit or prevent the construction of otherwise compliant natural gas pipelines are substantial. Not only are these states acting contrary to the intent of Congress as expressed in the NGA, NGPA and EPAct 2005, their actions also are inconsistent with the interstate commerce clause of the U.S. Constitution and in many cases the purpose of the very permits that they are using to delay or deny actions. Moreover, as your question points out, such activities by one state have the effect of denying to the citizens of every other connected state the economic and environmental benefits of the U.S. natural gas resources. This is not what the framers of the Constitution had in mind when they established the Commerce Clause or the Supreme Court when it has enforced the doctrine of preemption.

As I also testified, many of these issues are probably most expediently handled by consistent, aggressive oversight by Congress of its federal environmental and resources statutes and their implementation by federal and state agencies to ensure that implementation is consistent with national energy policies.

In some circumstances, there is a tension between the objectives of the NGA and its emphasis on the development of infrastructure and federal environmental and resource statutes whose is protection or conservation of resources. Resolution of these tensions and effective infrastructure development require Executive Branch agencies to act cooperatively in carrying out their respective responsibilities. FERC is empowered to only do so much. So, Congress needs to be engaged to make sure that the Executive Branch is on top of its game and a coherent national policy is achieved.

THE UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Certification of New Interstate Natural Gas Facilities	)))	Docket No. PL18-1-000

COMMENTS OF THE KINDER MORGAN ENTITIES
ON NOTICE OF INQUIRY

The Kinder Morgan Entities,[1] individually and jointly, hereby submit their comments in response to the Federal Energy Regulatory Commission's ("Commission" or "FERC") Notice of Inquiry ("NOI")[2] issued April 19, 2018, seeking comments to help the Commission explore whether, and if so how, it should revise its approach under its currently effective policy statement on the certification of new interstate natural gas facilities[3] to determining whether a proposed natural gas project is or will be required under the present or future public convenience and necessity, as that standard is established in Section 7 of the Natural Gas Act ("NGA").[4] As discussed in these comments, the Commission's Policy Statement provides an effective framework for the evaluation of proposed projects as it allows for the balancing of complex interests in a comprehensive and holistic manner, consistent with the Commission's goal of fostering the orderly

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1 For purposes of this pleading, the Kinder Morgan Entities are: Natural Gas Pipeline Company of America LLC; Tennessee Gas Pipeline Company, L.L.C.; Southern Natural Gas Company, L.L.C.; Colorado Interstate Gas Company, L.L.C.; Wyoming Interstate Company, L.L.C.; El Paso Natural Gas Company, L.L.C.; Mojave Pipeline Company, L.L.C.; Bear Creek Storage Company, L.L.C.; Cheyenne Plains Gas Pipeline Company, L.L.C.; Elba Express Company, L.L.C.; Kinder Morgan Louisiana Pipeline LLC; Southern LNG Company, L.L.C.; and TransColorado Gas Transmission Company LLC. These entities individually and jointly make these comments.

2 *Certification of New Interstate Natural Gas Facilities*, 163 FERC ¶ 61,042 (April 19, 2018) ("NOI").

3 *Certification of New Interstate Nat. Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *corrected by*, 89 FERC ¶ 61,040 (1999), *clarified by*, 90 FERC ¶ 61,128, *clarified by*, 92 FERC ¶ 61,094 (2000) ("Policy Statement").

4 15 U.S.C. 717f (2018).

development of natural gas infrastructure. The Kinder Morgan Entities, while recognizing that periodic review and assessment of the Commission's policies is appropriate, urge the Commission's continued reliance on the Policy Statement as it remains a very effective tool for evaluating whether an applicant has demonstrated that a project is required by the public convenience and necessity. In addition, the Kinder Morgan Entities have participated in the development of and hereby adopt and incorporate the Comments of the Interstate Natural Gas Association of America ("INGAA") being filed in this proceeding on July 25, 2018.

I. Description of Kinder Morgan, Inc. and the Kinder Morgan Entities

Kinder Morgan, Inc. ("Kinder Morgan") owns or operates approximately 70,000 miles of natural gas pipelines, including interstate and intrastate transmission pipelines as well as gathering pipelines, constituting the largest natural gas network in North America. Kinder Morgan's natural gas pipelines are connected to every important natural gas resource play, including the Bakken, Eagle Ford, Marcellus, Permian, Utica, Uinta, Haynesville, Fayetteville, and Barnett, that will play a significant role in meeting the nation's long-term natural gas supply. Kinder Morgan's operations serve the major natural gas consuming areas of the conterminous United States.[5] Kinder Morgan is one of the largest natural gas storage operators in North America, with approximately 1.2 trillion cubic feet of total gas storage capacity in underground facilities. Kinder Morgan also operates over 15 gas processing plants, and two liquefied natural gas terminals.

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[5] The interstate natural gas pipelines owned and/or operated by Kinder Morgan include Natural Gas Pipeline Company of America LLC (which serves areas in the Midwest including the high-demand Chicago area and the Gulf Coast); Tennessee Gas Pipeline Company, L.L.C. (which serves areas through the South, Midwest and Northeast including New York City and Boston); Southern Natural Gas Company, L.L.C.; Elba Express Company, L.L.C. and Kinder Morgan Louisiana Pipeline LLC (which serve the southeastern United States); Colorado Interstate Gas Company, L.L.C., Wyoming Interstate Company, L.L.C.; Cheyenne Plains Gas Pipeline Company, L.L.C.; and TransColorado Gas Transmission Company LLC (which serve areas in the Rocky Mountain region); and El Paso Natural Gas Company, L.L.C. and Mojave Pipeline Company, L.L.C. (which serve Southwestern and California areas).

II. Congressional Mandates Enable Natural Gas Industry to Deliver Critical Low-Cost Energy

A. Role of Natural Gas in the U.S. Economy

In recent years, the United States has shifted from being dependent on imports for its energy supply to becoming one of the world's leading producers of oil and gas. This trend, which can continue if markets are permitted to function efficiently, is facilitating billions of dollars of investment in the U.S. manufacturing sector, creating thousands of high-paying U.S. jobs, and providing households and businesses with additional disposable income through lower energy costs. According to the Energy Information Administration, the city gate price of natural gas, (the place where long-haul pipelines deliver to local distribution companies), has fallen from approximately $8 per thousand cubic feet in 2007 to under $4 so far this year.[6]

Today, many people think of natural gas primarily as a fuel for generating electricity due to its obvious economic and environmental advantages over other fossil fuels used for power generation. However, the power sector only accounts for approximately one-third of natural gas consumption in the U.S. The remainder is consumed in the industrial, commercial, and residential sectors. Indeed, the natural gas pipeline network was constructed to serve the needs of residential, commercial and industrial loads.

In 2017, the industrial sector accounted for about 35% of U.S. natural gas consumption. Industrial facilities use natural gas as a fuel for heating; for combined heat and power systems; and as a process fuel or feedstock to produce chemicals, fertilizer, automobiles and many other products. The chemicals, food, metals, paper, minerals, wood products, and textiles industries provided 5.5 million jobs and almost $3.3 trillion of economic output in the U.S. in 2015. The

[6] U.S. Energy Info. Admin., Natural Gas Prices (June 29, 2018), https://www.eia.gov/dnav/ng/ng_pri_sum_a_EPG0_PG1_DMcf_a.htm (last visited July 18, 2018).

chemicals industry alone employs 811,000 people in the U.S. and for every one job created in the chemicals sector, 6.8 jobs are created in other sectors.

Commercial users accounted for about 12% of U.S. natural gas consumption in 2017 to cook; heat buildings and water; operate refrigeration and cooling equipment; dry clothes; and provide outdoor lighting. There are more than 5.4 million commercial natural gas customers, which include schools, colleges and universities; hospitals and health care providers; laboratories; hotels; warehouses and storage facilities; professional offices; government buildings; and various other kinds of commercial businesses. More than half of the commercial buildings in the U.S. use natural gas as an energy source, and, as a result of the recent growth in U.S. natural gas production, prices for commercial consumers of natural gas have fallen significantly since 2007.

Roughly half of the residential homes in the United States use natural gas for space heating, to heat water, to cook, and to dry clothes. In 2017, the residential sector used approximately 17% of all natural gas consumed in the U.S. Homeowners have seen their heating bills decline significantly in the last 10 years due to the increased availability of low priced natural gas.

Electricity generation accounted for approximately 34% of U.S. natural gas consumption in 2017, and one-third of electricity consumed in the U.S. is supplied by natural gas power plants. The use of natural gas for electricity generation has lowered greenhouse gas emissions from electric power generation by 28% since 2005 and is essential to an increased reliance on renewable generation.

As indicated above, since the shale revolution began, natural gas prices have fallen sharply with enormous benefits to industrial, commercial and, most importantly, residential consumers. Americans cannot benefit from our natural gas wealth, however, unless we are able to develop the infrastructure needed to transport it to consumers. Kinder Morgan currently has natural gas pipeline projects, representing potential investments of approximately $5 billion, in various stages of evaluation, permitting and construction. But these are very challenging times for any company seeking to build a new pipeline or even expand and modernize an existing pipeline. Before the Kinder Morgan Entities (or any other natural gas company) even think about starting the permitting process for a project, the Kinder Morgan Entities undertake a comprehensive internal analysis to determine if there is a need for a proposed project, if the benefits of the project outweigh the impacts, and whether the financial commitment is a sound investment. If Kinder Morgan Entities determine that a proposed project is worth pursuing, then, and only then, does the Kinder Morgan Entities begin the formal development process.

B. Congressional Recognition of the Importance of Natural Gas

The history of natural gas development in the United States is instructive as FERC evaluates its policies around authorizing pipeline certificates pursuant to the legal mandates of the NGA. Eighty years ago, Congress specifically recognized the contribution that natural gas could make to the nation's well-being when it enacted the NGA.[7] Section 1 of the NGA declares that "the business of transporting and selling natural gas for ultimate distribution to the public is affected with a public interest," and that "Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the public interest."[8]

In enacting the NGA, the Congress recognized that the locations where natural gas is produced frequently are long distances from where consumers of gas live and work; that the only means of transporting natural gas to those consumers is through pipelines that cross several states;

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7 15 U.S.C. §717 (2018).

8 15 U.S.C. §717(a) (2018).

and that a comprehensive federal regulatory framework is needed to ensure that the pipelines could be constructed and the gas delivered to consumers. At the outset, however, Congress elected to explicitly set forth in the NGA that the production and gathering of natural gas would be exempt from the Commission's jurisdiction.[9]

The Congress also recognized that the private sector is better suited to finance and construct this needed infrastructure than the government. Thus, Section 7 of the NGA provides that a certificate to construct and operate an interstate natural gas pipeline "shall be issued" to any qualified applicant who demonstrates that the project "is or will be required by the present or future public convenience and necessity[.]"[10]

Over the decades, the Commission, its predecessor agency, and the Courts have implemented and interpreted the NGA in a manner that has resulted in a nationwide natural gas transportation network that is the envy of the world.

In the mid to late 1970s, the U.S. experienced severe natural gas shortages. In response, the Congress enacted the Natural Gas Policy Act of 1978 ("NGPA").[11] One of the pillars of the NGPA was to set in motion the deregulation of the natural gas industry, including deregulating the price of the commodity, thereby creating incentives for producers to explore for and develop new sources of natural gas. That deregulation, combined with U.S. technology and ingenuity, has resulted in our current ability as a nation to produce trillions of cubic feet of natural gas from shale formations at historically low prices.

This vast resource, however, is of little value to the United States if the natural gas cannot be transported to the homes, businesses, and factories where it is consumed. During the four

[9] 15 U.S.C. §717(b) (2018).

[10] 15 U.S.C. §717(f) (2018).

[11] 15 U.S.C. §§ 3301 *et seq* (2018).

decades since enactment of the NGPA, the Commission has done an outstanding job of guiding and authorizing the construction of a fully integrated, competitive, and safe pipeline system to serve the transportation needs of natural gas producers and consumers.

Most importantly, this infrastructure development has been accomplished by the private sector with private financing. Government does not require that pipelines be built and taxpayer dollars have not and will not pay for the development of this critical infrastructure. Consumers that utilize the transportation services of the natural gas infrastructure will, over years of service, financially support the pipeline as market forces permit.

C. The Legacy of Creating an Open Access Market

As the Commission mentioned in the NOI, the series of Commission Orders beginning with Order No. 436,[12] continuing with Order No. 636[13] and finishing with Order No. 637[14]

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12 *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 436, 50 Fed. Reg. 42408 (Oct. 18, 1985), FERC Stats. & Regs., Regulations Preambles (1982-1985) ¶ 30,665 (1985), *order on reh'g*, Order No. 436-A, 50 Fed. Reg. 52217 (Dec. 23, 1985), FERC Stats. & Regs., Regulations Preambles (1982-1985) ¶ 30,675 (1985), *order on reh'g*, Order No. 436-B, 51 Fed. Reg. 6398 (Feb. 24, 1986), FERC Stats. & Regs., Regulations Preambles (1982-1985) ¶ 30,688 (1986), *order on reh'g*, Order No. 436-C, 34 FERC ¶ 61,404 (1986), *order on reh'g*, Order No. 436-D, 34 FERC ¶ 61,405 (1986), *order on reh'g*, Order No. 436-E, 34 FERC ¶ 61,403 (1986), *vacated and remanded*, *Associated Gas Distribs. v. FERC*, 824 F.2d 981 (D.C. Cir. 1987).

13 *Pipeline Serv. Obligations and Revisions to Regulations Governing Self-Implementing Transp. and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636, 57 Fed. Reg. 13267 (April 16, 1992), FERC Stats. & Regs., Regulations Preambles (1991-1996) ¶ 30,939 (1992), *reh'g denied in part, reh'g granted in part and clarified*, Order No. 636-A, 57 Fed. Reg. 36128 (Aug. 12, 1992), FERC Stats. & Regs., Regulations Preambles (1991-1996) ¶ 30,950 (1992), *reh'g denied and clarified*, Order No. 636-B, 61 FERC ¶ 61,272 (1992), *notice of denial of reh'g*, 62 FERC ¶ 61,007 (1993), *aff'd in part and remanded in part sub nom. United Distributors Cos. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *order on remand*, Order No. 636-C, 78 FERC ¶ 61,186 (1997), *reh'g denied and clarified*, Order No. 636-D, 83 FERC ¶ 61,210 (1998).

14 *Regulation of Short-Term Natural Gas Transp. Serv. and Regulation of Interstate Natural Gas Transp. Serv.*, Order No. 637, 65 Fed. Reg. 10156 (Feb. 25, 2000), FERC Stats. & Regs., Regulations Preambles (1996-2000) ¶ 31,091 (2000), *order on reh'g*, Order No. 637-A, 65 Fed. Reg. 35705 (June 5, 2000), FERC Stats. & Regs., Regulations Preambles (1996-2000) ¶ 31,099 (2000), *reh'g denied*, Order No. 637-B, 92 FERC ¶ 61,062 (2000), *pet. for review granted in part, denied in part and dismissed in part sub nom. Interstate Natural Gas Ass'n of Am. v. FERC*, 285 F.3d 18 (D.C. Cir. 2002), *order on remand*, 101 FERC ¶ 61,127 (2002), *order on reh'g*, 106 FERC ¶ 61,088 (2004), *pet. denied sub nom. Am. Gas Ass'n v. FERC*, 428 F.3d 255 (D.C. Cir. 2005).

(collectively, the "Open Access Orders"), changed the landscape of the natural gas business in a material way. No other open access program in any other industry can claim the success of the Open Access Orders to create market hubs and total fluidity and reliability across the natural gas grid. In 1996, after the majority of the litigation surrounding Order No. 636 was complete and for the most part natural gas pipelines had fully implemented their open access tariffs required by Order No. 636, the Commission began to grapple with the correct formula to guide construction of natural gas infrastructure in the open access environment. Specifically, the Commission wrestled with how to implement their statutory mandate under Section 7(c) of the NGA once natural gas pipelines had become transporters of natural gas and not buyers and owners of the commodity being carried from the wellhead to the marketplace. After a series of bumps along the way,[15] the Commission found the sweet spot in combining the concerns and requirements of stakeholders, investors, customers, and pipelines in order to implement natural gas infrastructure projects in an open access environment through the issuance of the Policy Statement in 1999.

The Policy Statement is still relevant today because the open access markets created by the Commission in the Open Access Orders remain so strong. Since 1999, even though the locations of supplies and the markets and demands for natural gas have changed from time to time, the investment in natural gas infrastructure has adjusted to shifts such as the import of liquefied natural gas ("LNG") to the export of LNG, the growth and expansion of natural gas use at electric generating plants, and the location of supplies from the offshore Gulf of Mexico to the onshore shale fields. The key to any policy statement and the Commission's responsibility is the 1976 quote from the Supreme Court on page 6 of the NOI, "[i]n the case of the Power and Gas Acts, it

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15 *Pricing Policy for New and Existing Facilities Constructed by Interstate Natural Gas Pipelines*, 71 FERC ¶ 61,241 (1995).

is clear that the principal purpose of those Acts was to *encourage* the *orderly* development of plentiful supplies of electricity and natural gas at reasonable prices."[16]. This mission of the Commission has not changed since 1938, which is to ensure that the public has access to natural gas and thus support the efficient development of natural gas under the NGA. It is FERC's business to create a positive and orderly environment for the development of natural gas infrastructure. By "encouraging the orderly development…at reasonable prices," any policy statement developed by the Commission must (i) ensure certainty of access of natural gas supplies to shippers and the public, (ii) not create unnecessary or burdensome barriers to construction, whether from a permitting or economic standpoint; and (iii) allow for certainty and timeliness in the processing of natural gas infrastructure applications. Accordingly, the Kinder Morgan Entities support the conclusion that it is acceptable for the Commission to assume that contracting parties will use long-standing economic principles to make prudent decisions how they want to invest their capital and contract for services and that there is no need to materially alter the Policy Statement that has supported the principles of open access transportation developed over the last thirty years.

III. Specific Comments to the NOI

A. Potential Adjustments to the Commission's Determination of Need

The Commission, in its NOI, is requesting comments on whether changes in the natural gas industry necessitate adjusting the current methodology for evaluating the need for proposed natural gas infrastructure projects. As the following comments demonstrate, the Policy Statement continues to provide a comprehensive and effective framework for project evaluation. The Commission has appropriately adjusted its application of the Policy Statement over the last two

[16] *NAACP v. Federal Power Commission*, 425 U.S. 662, 669-670 (1976) (emphasis added).

decades. While periodic review and assessment of the Commission's policies is appropriate, the Policy Statement remains a very effective tool for evaluating whether an applicant has demonstrated that a project is required by the public convenience and necessity.

1. The Current Policy Statement Remains as Effective and Relevant Today as it Did When First Developed by the Commission

The NOI emphasizes that the natural gas industry has evolved significantly over the last decade.[17] Such changes include burgeoning production volumes, increases in exports, surges in demand, and changes in contracting patterns.[18] While the Commission has correctly identified changing tides in the industry, many of the supply and demand characteristics evident in today's markets are emblematic of the conditions which necessitated creation of the Policy Statement nearly two decades ago. The Policy Statement was developed as a needed response to a regulatory framework which had been radically overhauled in the preceding 30 years. From the gas shortages of the 1970s, to the adoption of open-access transportation in the 1980s, to a fully unbundled transportation grid in the 1990s, the natural gas industry was in a state of nearly constant change in the years leading up to the issuance of the Policy Statement in 1999. Amidst this change, one constant was that the U.S. energy markets were in need of new pipeline infrastructure. Since adoption of the Policy Statement, the Commission has approved 423 pipeline applications (including capacity and horsepower additions) yielding an additional 213 Bcf per day of approximate capacity to the gas transportation system.[19]

Infrastructure development naturally creates stakeholder tensions. The construction of airports, dams, ports, railways, roadways, and pipelines all face similar challenges regardless of

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[17] Notice of Inquiry at PP. 19-22.

[18] *Id.*

[19] https://ferc.gov/industries/gas/indus-act/pipelines/approved-projects.asp, (last visited July 19, 2018).

project sponsor. For the pipeline industry, these challenges have remained constant for many years.

> Applications for authorization from the Commission to construct new gas pipeline infrastructure currently face unprecedented levels of opposition. But, the arguments typically raised by opponents are not new. The same objections to pipeline construction have been raised since the early days of the Commission. Landowners do not want a pipeline on their property and they resent pipelines' use of eminent domain to acquire rights-of-way. Environmental groups challenge the adequacy of the Commission's environmental review ... Pipelines remain, however, the only method of large-scale transportation of natural gas from supply basins to demand centers.[20]

While regulatory frameworks may vary from industry to industry, the need for consistency is essential for the orderly development of critical energy infrastructure. The Policy Statement provides exactly that type of consistency. For nearly two decades, the natural gas industry has had precise standards for the Commission's evaluation of pipeline infrastructure projects. In 1999, the Commission stated that:

> [T]he Commission is issuing this policy statement to provide the industry with guidance as to how the Commission will evaluate proposals for certificating new construction. This should provide more certainty about how the Commission will evaluate new construction projects that are proposed to meet growth in the demand ... In considering the impact of new construction projects on existing pipelines, the Commission's goal is to appropriately consider the enhancement of competitive transportation alternatives, the possibility of overbuilding, the avoidance of unnecessary disruption of the environment, and the unneeded exercise of eminent domain.[21]

In the instant proceeding, the Commission lists nine environmental and market factors that have changed significantly since adoption of the Policy Statement in 1999. However, those

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20 Robert Christin, Paul Korman, and Michael Pincus, *Considering the Public Convenience and Necessity in Pipeline Certificate Cases Under the Natural Gas Act*, 38 ENERGY L.J. 115 (2017).

21 Policy Statement, 88 FERC ¶ 61,227 at 61,737.

fundamental changes – including increases in supply, demand, and exports – have not changed the Commission's underlying statutory charge of ensuring that proposed energy infrastructure is required by the public convenience and necessity.[22] The certainty and clarity afforded by the Policy Statement has led to the development of a robust and efficient pipeline grid with very few stakeholders seeking review of the Commission's certificate orders (which is a reliable barometer of the Commission's efficacy). In addition, the Commission's measured approach to approving pipeline projects has resulted in a financially healthy pipeline industry. It has been nearly thirty years since a major interstate pipeline company has filed for bankruptcy. If the Commission were engaged in the haphazard approval of pipeline projects (as some have alleged), this would not be the case. A pattern of hollow approvals would have invariably resulted in financial failures. To the contrary, the Commission's disciplined implementation of the Policy Statement has led to a flourishing interstate pipeline industry which has played a vital role in unlocking U.S. energy independence.

2. The Commission's Policies Incorporate Reliable Protections to Ensure Project Applicants Adequately Demonstrate Market Need

Many opponents of the current Policy Statement focus their criticisms on the fact that the Policy Statement gives undue weight to precedent agreements as evidence of project demand. This argument is incomplete at best. The Policy Statement is actually much broader in terms of its requirements for demonstrating project need. In addressing this subject, the Commission stated as follows:

> Rather than relying only on one test for need, the Commission will consider all relevant factors reflecting on the need for the project. These might include, but would not be limited to, precedent agreements, demand projections, potential cost savings to

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[22] 15 U.S.C. §§ 717-717w (2017).

> consumers, or a comparison of projected demand with the amount of capacity currently serving the market. The objective would be for the applicant to make a sufficient showing of the public benefits of its proposed project to outweigh any residual adverse effects...[23]

Project sponsors also may submit independent, third-party market data beyond precedent agreements in support of their applications.[24] This type of data may serve as a preliminary indication that new pipeline infrastructure is needed. If intrinsic fundamentals so indicate, potential anchor shippers will be contacted and initial project discussions will follow. It is at these earliest stages of project development that a project sponsor begins compiling its demonstration of project need. Many of these early analyses eventually make their way into the pipeline's certificate application.

One of the fundamental underpinnings of the Commission's certificate process is that new interstate pipeline development be preceded by a fair open season process through which potential shippers will be apprised of new projects and given an opportunity to bid for capacity.[25] An open season is intended to provide transparency and ensure that new capacity is allocated in a not unduly discriminatory manner. An open season will also provide a project sponsor with valuable information regarding market interest that it can use to properly size the project.[26] While the open

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[23] Policy Statement, 88 FERC ¶ 61,227 at 61,747.

[24] See, for example, (i) Mexico's Secretaría de Energía's *Five Year Plan for the Expansion of the National Integrated Transportation and Storage System of Natural Gas 2015-2019* filed by El Paso Natural Gas Company, L.L.C., in Docket No. CP18-332-000, (ii) Comisión Federal de Electricidad's proposed initiatives to meet growing energy demands, including development of a Gas Pipeline's Development Strategy referenced by Sierrita Gas Pipeline LLC in Docket No. CP13-73-000, (iii) "*Questar: Mid-continent Returns Beat Rockies*," Natural Gas Intelligence ("NGI") – November 3, 2008; "*Piceance Basin Producers Pull Back – Who's Next?*" NGI – November 24, 2008; "*Encana Sets Flexible Plan for 2009, Cuts Colorado Capex*," NGI – December 15, 2008; and "*Outlook: Production, Solid Contracts to Sustain Pipeline Build*," NGI – January 12, 2009, referenced by Ruby Pipeline, L.L.C., in Docket No. CP09-54-000, and (iv) Gas Research Institute, Baseline Projection Data Book, at Page Sum 20 (1998 edition) (30 Tcf by 2015) cited by Wyoming Interstate Company, L.L.C., in Docket No. CP05-54-000.

[25] *Pine Prairie Energy Center, LLC*, 135 FERC ¶ 61,168 (2011).

[26] *Id.*

season process may precede or follow the execution of precedent agreements, it is nevertheless a critical component of the Commission's certificate process.[27] The market need analysis, however, does not end there. While open seasons stimulate demand and aid pipelines in assessing market interest, the truest indication of market need is the execution of binding precedent agreements that anchor a project. Open seasons remain a critical component of the Commission's certificate process, but precedent agreements are the essential backbone to the successful outcome of a project for reasons further articulated below.

3. Precedent Agreements Remain the Most Effective Indicator of Need

Precedent agreements provide the most objective demonstration of need for proposed pipeline projects. The reason precedent agreements are such a good barometer of project need lies in the amount of market analysis that precedes entering into a definitive agreement. Before entering into binding precedent agreements, pipeline companies engage in a wide range of business development activities to assess project viability. Such activities include meeting with prospective customers; analyzing basis differentials (or "spreads"); assessing existing and proposed project alternatives; gauging short-term and long-term supply and demand fundamentals; evaluating route impacts; forecasting construction, operating and maintenance costs; estimating the cost of obtaining capital, etc., etc. These preliminary business development activities provide the inputs for rigorous economic analyses which take into consideration, *inter alia*, project costs (including the cost of capital), rates, return on investment, and terminal value. Only after thoroughly assessing market and economic fundamentals will pipelines proceed to negotiating and finalizing binding precedent agreements. This level of project scrutiny is necessitated by the millions (and sometimes billions) of dollars required to develop a major interstate pipeline project.

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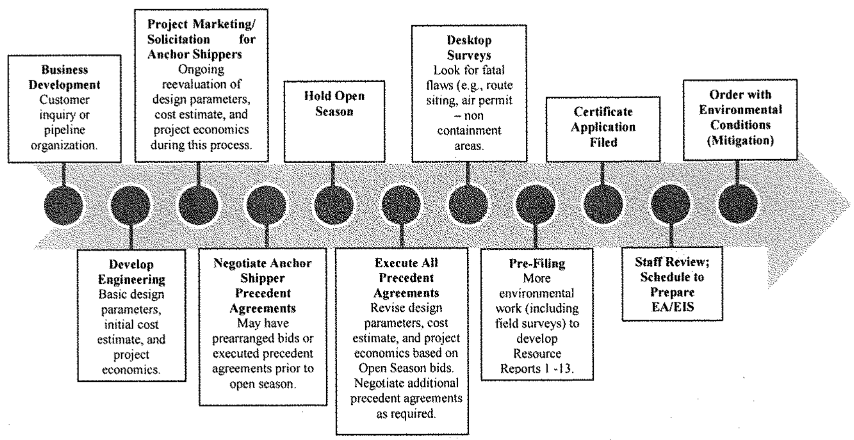
[27] *Millennium Pipeline Company, L.L.C.*, 140 FERC ¶ 61,045 (2012).

Compounding the complexity of project investment decisions is robust pipeline-on-pipeline competition. Gone are the days when building infrastructure from the Gulf of Mexico to northeast local distribution companies or from Rocky Mountain production basins to West Coast population centers will yield decades long contracts at maximum rates. Natural gas production basins are much more prevalent – and regionalized – than just a few years ago. With unprecedented pipeline interconnectivity, natural gas is increasingly dispatched on marginal economics. For pipelines, this means that project revenues are typically not as secure as they were a half century ago, and for shippers, the intrinsic value of pipeline capacity is exceedingly dynamic. Both pipeline companies and their shippers must be satisfied that the value proposition for a project will exist throughout the term of their initial contracts (and beyond). As a result, both pipeline companies and shippers utilize fulsome economic analyses to ensure a project will be viable over its projected life. Moreover, detailed project analysis ensures that corporate directors and officers are fulfilling their fiduciary duties of care and loyalty to the shareholders of their companies. Hastily developed projects with poor economics may leave pipelines – and their shareholders – with unmarketable capacity for which the pipeline may have no viable means of recovering its costs.

Evaluation of Project

Each step could result in a decision not to build



Fortunately, the Commission's Policy Statement, working in tandem with natural market forces, has proven tremendously effective. In short, the market works and does not support projects that cannot be sustained.[28] Continued vigilance and discipline by the Commission will play a vital role in ensuring that needed projects are developed (and that unneeded projects are not). Nonetheless, industry stakeholders can rest assured that precedent agreements are not entered into haphazardly. An executed agreement between willing industry participants reflects a strong indication of project need.

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[28] See, for example, *Turtle Bayou Gas Storage Company, LLC*, 135 FERC ¶ 61,233 (2011), and *Jordan Cove Energy Project, LP, and Pacific Connector Gas Pipeline, LP*, 157 FERC ¶ 61,194 (2016).

4. The Certificate Policy Statement Provides the Commission Ample Authority to Analyze All Aspects of a Proposed Project

The Policy Statement in no way limits the Commission's ability to engage in more thorough project analysis on a case-specific basis. In 1999, the Commission stated that:

> [T]he Commission is issuing this policy statement to provide the industry with guidance as to how the Commission will evaluate proposals for certificating new construction. ... In stating the evaluation criteria, it is the Commission's intent to evaluate specific proposals based on the facts and circumstances relevant to the application and to **apply the criteria on a case-by-case basis.**[29]

The Commission has recognized that its obligation is not merely to determine whether there are precedent agreements to support a proposed project; rather, it must conduct a holistic analysis to examine whether the public interest as a whole will be served. In its Policy Statement, the Commission stated that its policy "should be designed to foster competitive markets, protect captive consumers, and avoid unnecessary environmental and community impacts while serving increasing demands for natural gas. It should also provide appropriate incentives for the optimal level of construction and efficient customer choices."[30] Under normal circumstances (as detailed above), an executed precedent agreement between willing industry participants reflects a strong indication of project need. There are, however, circumstances in which a more detailed analysis will be warranted.[31] In such cases, it is noteworthy that the Policy Statement allows for, and encourages, a thorough and rigorous project analysis.

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29 Policy Statement, 88 FERC ¶ 61,227 at 61,737 (emphasis added).

30 Policy Statement at 61,743. See also *Atlantic Coast Pipeline, LLC*, 161 FERC ¶ 61,042 at P 25 (2017) (including among factors to be considered the possibility of overbuilding, the avoidance of unnecessary disruptions of the environment, and the unneeded exercise of eminent domain).

31 See *Motion for Leave to Intervene and Comments of Colorado Interstate Gas Company, L.L.C.*, and *Motion for Leave to Answer and Answer of Colorado Interstate Gas Company, L.L.C.* (filed April 9, 2018, and May 23, 2018, respectively, in Docket No. CP18-102-000).

5. Precedent Agreements Between Affiliated Parties and Non-Affiliated Parties Provide Equally Strong Support for a Proposed Pipeline Project

As detailed in Section III(A)(3) above, precedent agreements provide the most objective demonstration of need for proposed pipeline projects. This holds true regardless of whether potential shippers are affiliated with the project sponsor. In recent proceedings, the Commission has stated that "as long as the precedent agreements are long-term and binding," FERC does "not distinguish between pipelines' precedent agreements with affiliates or independent marketers in establishing the market need for a proposed project."[32] The Commission further stated a marketer's affiliation with the project sponsor "does not lessen the marketer's need for the new capacity or their obligation to pay for it under the terms of their contracts."[33] The Commission recognized that "in a competitive environment, the marketer still must offer its commodity at competitive prices to attract customers" and that "affiliated marketers are potentially subject to greater regulatory oversight than non-affiliates."[34]

This logic continues to be sound today. Neither a pipeline nor its affiliated companies has any incentive to invest in projects which lack bona fide market support. Moreover, both pipelines and their affiliated customers have independent fiduciary duties to their shareholders (as detailed above) which necessitate a robust economic and market analysis of a project prior to entering into a precedent agreement. Under the existing Policy Statement, the pipeline bears the risk for any new capacity that is under-utilized.[35] This creates a powerful and effective disincentive for a

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32 *Millennium Pipeline Company, L.P., Columbia Gas Transmission Corporation*, 100 FERC ¶ 61,277 at P. 57 (2002). See also *PennEast Pipeline Company, LLC*, 162 FERC ¶ 61,053 (2018).

33 *Id.*

34 *Id.*

35 Policy Statement, 88 FERC ¶ 61,227 at 61,747.

pipeline to enter into a spurious precedent agreement simply for the purpose of obtaining Commission approval.

The cost and risk of developing new energy infrastructure is unprecedentedly high. Pipelines go to great lengths to attract customers in an effort to diversify risk over a large portfolio of shippers. It is in the industry's and customers' overall best interest to encourage pipeline operators to mitigate risk to the greatest extent practicable. If a pipeline has an affiliate desiring to enter into a precedent agreement, the value of that customer should not be discredited simply because the shipper is an affiliate.

For all of the reasons stated above, the Commission should not dilute the significance of precedent agreements solely on the basis that they are entered into with affiliated entities.

6. There is No Benefit to Evaluating Project Need on a Comparative or Regionalized Basis

For many years the Commission employed the *Ashbacker* doctrine in which it would evaluate mutually exclusive, competing proposals and issue a certificate only after an exhaustive comparative review of each proposal.[36] Such proceedings were wrought with inefficiency. In the mid-1980s, Kern River Gas Transmission Company, Mojave Pipeline Company, and Wyoming-California Pipeline Company became embroiled in a proceeding to build competing pipelines into southern California.[37] The proceeding took over three years to disentangle. Thankfully the Commission has since abandoned that approach. In *Weaver's Cove Energy*, the Commission states:

> It has been Commission policy for well over a decade, however, to permit the market to decide which projects are best suited to serve

[36] *Ashbacker Radio Corp. v. FCC*, 326 U.S. 327 (1945).

[37] *Mojave Pipeline Company, et al.*, 42 FERC ¶ 61,351, *reh'g denied*, 43 FERC ¶ 61,306 (1988); *Wyoming-California Pipeline Company*, 44 FERC ¶ 61,001 (1988).

> the infrastructure needs of an area. The Commission believes that approach best serves the public interest and allows for the most efficient, cost effective, and timely development of energy infrastructure. Approval of a variety of projects benefits the public by allowing it to choose which proposals offer the most attractive and timely service.[38]

Such is the case today. Competition in the marketplace has fostered the development of an efficient and seamless pipeline network. Turning back the clock to the *Ashbacker* era would reintroduce costly and protracted regulatory proceedings in which the Commission would be asked to pick "winners" and "losers." Such administrative adjudications are a poor substitute for competition. In the current regulatory environment, multiple pipelines often compete for the same market with the best projects gaining market support and advancing to the Commission for approval in a timely, efficient manner. In this type of competitive environment, the winners and losers are chosen by economic market conditions. This leads to the development of a more sustainable pipeline grid and a less arbitrary decision-making process than that which would be developed under a framework of administrative litigation.

B. Commission Policy Appropriately Provides Pipelines the Flexibility to Work With Landowner Interests in Accordance with the Size and Scope of a Given Project Without Mandating a One-Size-Fits-All Approach

In the NOI, the Commission is seeking comments regarding the consideration of eminent domain authority and landowner interests in pipeline certificate application proceedings. Specifically, the Commission requests comments on the questions of whether adjustments to the consideration of pipeline companies' potential use of eminent domain authority in the Commission's certificate review process are necessary and whether the Commission's certificate process adequately considers landowner issues. As addressed previously in these comments, the

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38 *Weaver's Cove Energy, LLC; Mill River Pipeline, LLC*, 112 FERC ¶ 61,070 (2005).

Policy Statement continues to provide a comprehensive and effective method for reviewing proposed natural gas infrastructure projects, which includes appropriate identification and evaluation of the potential exercise of eminent domain authority and landowner impacts in certificate application reviews. Further, in issuing its final rule regarding landowner notifications in Order No. 609 in 1999 (the same year as the issuance of the Policy Statement), the Commission recognized the need for early landowner notification to ensure that landowners who may be affected by a proposed natural gas pipeline project have sufficient opportunity to participate in the Commission's certificate review process and implemented regulations to that end.[39] The Commission's current framework in the Policy Statement is effective for consideration of the potential exercise of eminent domain and landowner interests, in conjunction with the Commission's robust and early landowner notification requirements in Order No. 609[40] and Section 157.6(d) of the Commission's regulations.[41] The Commission has refrained from mandating a "one size fits all" approach for pipelines engaging with landowners. This flexibility allows pipelines to tailor engagement to take into account the size and scope of a given project, the particular regional differences between such projects, and historic relationships.

In developing and designing a pipeline project, the Kinder Morgan Entities endeavor to minimize the impact of the project on landowners and on environmental and cultural resources. Pipeline projects, developed and implemented over a multiple year period beginning with initial field surveys through construction and restoration activities, result in temporary impacts to landowners. Accordingly, the Kinder Morgan Entities work with affected landowners as a "good

39 *Landowner Notification, Expanded Categorical Exclusions, and Other Environmental Filing Requirements*, Final Rule, Order No. 609, 89 FERC ¶ 61,023 (1999).

40 *Id.*

41 18 C.F.R. 157.6(d) (2018).

neighbor" and view landowner relationships as long-term commitments that require transparency and trust.

The Kinder Morgan Entities comply with the landowner notification requirements established by the Commission in Order No. 609,[42] recognizing that these requirements, which provide for early and thorough notification of proposed projects, provide landowners with sufficient time and opportunity to become involved in the Commission's project review process and to have meaningful participation in that process. The landowner notification requirements, applicable to all NGA Section 7(c) certificate applications, include detailed notifications letters to be sent by the pipeline applicant to all affected landowners, as defined in Section 157.6(d)(2) of the Commission's regulations,[43] after a certificate application has been filed with the Commission and a formal notice of the application has been published by the Commission, as well as notifications placed in newspapers in each county in the proposed project area. The Kinder Morgan Entities, in compliance with Section 157.10(c) of the Commission's regulations,[44] also place complete copies of certificate applications in accessible central locations in each county in the proposed project areas.

Kinder Morgan has endorsed and implements "America's Natural Gas Transporters Commitment to Landowners," developed by the Interstate Natural Gas Association of America ("INGAA"), to build and maintain strong, positive relationships with landowners.[45] These commitments are built on the following core principles:

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[42] Order No. 609, *supra*.

[43] 18 C.F.R. § 157.6(d)(2) (2018).

[44] 18 C.F.R. § 157.10(c) (2018).

[45] As discussed in INGAA's comments submitted in this proceeding, INGAA has updated and revised its explanation of these commitments and included the updated "Commitment to Landowners" document as an attachment to its filed comments.

(1) Respect and Trust
(2) Accurate and Timely Information
(3) Negotiate in Good Faith
(4) Responding to Issues
(5) Respect the Regulatory Compact
(6) Eminent Domain
(7) Outreach;
(8) Industry Ambassadors
(9) Ongoing Commitment to Continuous Improvement

Throughout project development efforts and its ongoing operation and maintenance activities for its pipeline infrastructure, the Kinder Morgan Entities implement these commitments in their engagement with landowners on a respectful, accurate, clear, and timely basis.

In addition to the required outreach to landowners and other project stakeholders (federal, state, county, and municipal governments, regulatory agencies, and American Indian Tribes), the Kinder Morgan Entities, depending on the scope, location, and interest in a proposed project, engage in complementary outreach activities prior to filing certificate applications for proposed projects and throughout the certificate review and implementation processes for projects. For proposed projects that have limited impacts on land and resources or that have limited interest from stakeholders, the Kinder Morgan Entities will address issues raised on a case-by-case basis with landowners or other interested stakeholders. For proposed projects that are larger in scope or have generated significant interest from landowners and other stakeholders, the Kinder Morgan Entities often implement additional outreach efforts, including but not limited to: (1) presentations, meetings, and discussions with landowners and other affected stakeholders on a regular basis, and (2) written outreach and notifications to affected landowners (including periodic newsletters and project websites that are updated on a regular basis throughout the duration of a project). These presentations, meetings, discussions, and written updates provide landowners and other affected stakeholders the opportunity to learn more about the project, question the company on the need for and impacts of the project, and provide their comments and concerns regarding project impacts.

The Kinder Morgan Entities view this landowner and community outreach engagement as a critical element to ensure that affected landowners, government officials, regulatory agencies, and other interested groups are informed about pipeline projects and potential impacts, as well as to gather information from the public that is used in the development of projects, including avoidance and/or minimization of impacts. The comprehensive and iterative approach to landowner and community outreach and to designing projects taken by the Kinder Morgan Entities for its projects minimizes impacts to landowners and to the environment while still achieving the purposes of proposed projects.

Engaging in a comprehensive outreach process to educate potentially impacted landowners, governmental officials, and regulatory federal agencies about the benefits and impacts of the Project is consistent with the Commission's goal, as set forth in Order No. 609,[46] to provide early and thorough notification of proposed projects to potentially affected landowners so that those landowners have sufficient time and opportunity to participate in the project review process at the Commission. The Kinder Morgan Entities' commitment to landowner and community engagement is also consistent with the Policy Statement, which clearly identified landowner interests as a critical interest that must be considered in the evaluation of proposed natural gas infrastructure projects.

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[46] Order No. 609, *supra*.

1. The Current Framework in the Policy Statement Appropriately Considers the Potential Exercise of Eminent Domain in Certificate Application Reviews

Under Section 7(h) of the NGA, a pipeline company with a Commission-issued certificate order has the right to exercise eminent domain to acquire the land rights necessary to construct and operate the certificated pipeline facilities in the event that the company is unable to reach a voluntary agreement with a landowner.[47] The Commission, in the Policy Statement, clearly identified the potential exercise of eminent domain as an essential component in the evaluation of proposed pipeline construction projects:

> In considering the impact of new construction projects on existing pipelines, the Commission's goal is to appropriately consider the enhancement of competitive transportation alternatives, the possibility of overbuilding, the avoidance of unnecessary disruptions of the environment, and the unneeded exercise of eminent domain.[48]

The threshold requirement set out in the Policy Statement for establishing the public convenience and necessity for existing pipelines proposing an expansion project is that the pipeline must be prepared to financially support the project without relying on subsidization from existing customers.[49] Among other things, this threshold requirement helps to address the various interests that may be adversely affected by a proposed project, including landowners. This threshold requirement ensures that landowners are not subject to the exercise of eminent domain for projects that are not financially viable.[50]

47 15 U.S.C. 717f(h) (2018).

48 *Policy Statement*, 88 FERC ¶ 61,227, at p. 61,737 (emphasis added).

49 *Id.*, 88 FERC ¶ 61, 227, at p. 61,746.

50 *Id.*

The Commission recognized in the Policy Statement that the interests of landowners whose land may be condemned for new pipeline easements under eminent domain rights conveyed by the Commission's certificate order are one of the major interests that may be adversely affected by a proposed pipeline project. Accordingly, landowner interests were identified in the Policy Statement as interests that that must be considered by the Commission in its review of a proposed natural gas pipeline project.[51]

As an example of the Commission's consideration of landowner interests in certificate application reviews, in a recent *Order Issuing Certificate* for Southern Natural Gas Company, L.L.C.'s ("Southern") Fairburn Expansion Project, Southern reduced the width of permanent easement for a portion of the pipeline lateral to benefit nearby residents and to preserve a wildlife habitat, and two commenting parties requested that the Commission require Southern to reduce the width of permanent easement for the entire length of the lateral to benefit vegetation, wildlife habitat, and local aesthetics. The Commission evaluated the request and found that the request was not feasible for the remaining portions of the pipeline lateral due to required setbacks near electrical transmission line support towers and an existing liquids pipeline. Along with the portions of the lateral where permanent easement was reduced, the Commission found that the co-location of the lateral adequately minimizes overall impacts on vegetation, wildlife, and aesthetics.[52] In Tennessee Gas Pipeline Company, L.L.C.'s ("Tennessee Gas") 300 Line Project certificate order, the Commission addressed a number of landowner concerns regarding potential impacts of that project.[53] In response to a specific landowner request that Tennessee Gas did not

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51 *Id.*, 88 FERC ¶ 61,227, at pp. 61,747-48.

52 *Southern Natural Gas Company*, 162 FERC ¶ 61,122, at P 31 (2018).

53 *Tennessee Gas Pipeline Company*, 131 FERC ¶ 61,140, at PP 58-79 (2010).

need a new access road to be constructed on the landowner's property, the Commission agreed and prevented Tennessee Gas from constructing and using the new access road.[54]

In the Policy Statement, the Commission offered guidance on the evaluation of the public benefits and adverse effects of a proposed project. The Policy Statement explains that the more interests adversely affected or the more adverse impact a proposed project would have on a particular interest, the greater the showing of public benefits from the project would be required to balance the adverse effects. The Commission provided several examples of how it would apply a sliding scale of benefits that would need to be demonstrated depending on the adverse impacts of a project. The Commission acknowledged that it may not always be possible for a pipeline company to acquire all necessary pipeline rights-of-way easements through negotiation, though companies may minimize the effect of a project on landowners by acquiring as much pipeline right-of-way as possible.[55] In the Policy Statement, the Commission recognized that the framework established in the Policy Statement for review of projects would ensure that a few holdout landowners would not be able to veto a project, so long as the pipeline company provides support for the benefits of the proposed project that justify the issuance of a certificate order and the exercise of eminent domain rights. Essentially, the Commission recognized in the Policy Statement that the strength of the benefit showing to be made under the Policy Statement is proportional to the applicant's proposed exercise of eminent domain.[56]

In addition, the Commission, in establishing the landowner notification requirements in Order No. 609,[57] recognized that a certificate holder's right to use eminent domain is a statutory

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[54] *Id.* at P. 68.

[55] *Id.*, 88 FERC ¶ 61,227, at pp. 61,749.

[56] *Id.*

[57] Order No. 609, *supra*.

right imposed by Congress under NGA Section 7(h) if the certificate holder cannot otherwise reach agreement with the property owner.[58] The Commission in Order No. 609 also recognized that it does not have the authority to deny eminent domain authority to a certificate holder.[59]

The Kinder Morgan Entities do not recommend that the Commission change the manner, as set forth in the Policy Statement, in which the potential use of eminent domain is weighed against the showing of the need for a project. As implemented by the Commission since 1999, the Policy Statement has proven to be flexible enough to resolve issues related to specific projects while allowing the Commission to take into account the various interests that must be considered in the pipeline review process, including landowner interests and the potential exercise of eminent domain. It is not possible to reliably estimate the amount of eminent domain usage that a particular project may require during the pendency of the certificate review process. As discussed below, even for projects where opposition to a project is initially high, easement negotiations are successful with the vast majority of landowners.

2. The Kinder Morgan Entities Implement Measures in Developing Projects to Reduce the Need to Use Eminent Domain Authority

The Kinder Morgan Entities seek to acquire necessary land rights for their projects, including rights-of-way and easements, by negotiation where possible to minimize reliance on eminent domain. Using eminent domain authority following issuance of a certificate order by the Commission is considered to be a "last resort" by the Kinder Morgan Entities as such legal proceedings tend to have a negative impact on the long-term relationship between a pipeline

58 Order No. 609, *supra* at 84.

59 *Id.*, *citing FPC v. Tuscarora Indian Nation*, 362 U.S. 99, 123-24 (1960); *Columbia Gas Transmission Corp. v. Exclusive Natural Gas Storage Easement*, 776 F.2d 125, 129 n. 1 (6th Cir. 1985) (holding that issuance of a certificate authorizing a pipeline to operate any facility gives the pipeline the right to condemn the necessary easements).

company and the landowner that can potentially last for several generations. Also, the timing of the eminent domain process can be cumbersome to a project schedule since the filing of condemnation actions cannot be initiated until the certificate order is issued by the Commission, and the court process can vary from jurisdiction to jurisdiction and may itself take a long time and result in additional legal costs. Changes to schedules/spreads (to avoid properties that are in the condemnation process and then come back to the property at a later time) during the construction process can be difficult and expensive to implement.[60]

The Kinder Morgan Entities utilize various methods to minimize the use of eminent domain authority in their project development activities. In designing and developing projects, the Kinder Morgan Entities identify (with the assistance of landowners, regulatory agencies, and other stakeholders) major and minor route alternatives and deviations for the proposed project facilities and, after review and consideration of those alternatives and deviations, select the proposed routes, locations, and facilities that would offer the least impact to landowners and the environment. Another method used to minimize the use of eminent domain authority is siting new pipeline facilities to take advantage of existing energy infrastructure and pipeline corridors to the greatest extent possible. In many cases, proposed pipeline facilities are located parallel and adjacent to, and, in many cases, overlap existing utility easements (either pipeline or electric powerlines). This paralleling and overlapping of easements is commonly referred to as co-location. In addition, the Kinder Morgan Entities refine the route of proposed facilities throughout the project design process by incorporating information gained from field surveys and landowner and other stakeholders, all in an effort to minimize impacts and the potential use of eminent domain authority following the

[60] Generally, a best practice for pipeline construction provides for the construction spread to move linearly so that each step (marking the corridor; clearing and grading; trenching; stringing; pipe preparation (bending, welding, x-ray, weld coating, and coating repair), and lowering in; backfilling and grade restoration; hydrostatic testing and tie-ins; and clean-up and restoration) is performed sequentially.

issuance of a certificate order for a proposed project. The Kinder Morgan Entities also minimize impacts to landowners and the environment by looping[61] their own pipeline infrastructure where possible.

A review of the Kinder Morgan Entities' major infrastructure pipeline projects proposed, certificated, and constructed during the past 10-year period demonstrates the Kinder Morgan Entities' commitment to minimizing the use of eminent domain authority. Over the past 10 years, the Kinder Morgan's Entities have proposed, filed, and received certificate authority for, and constructed 22 major pipeline and/or compression addition projects in all regions of the United States.[62] For those projects, 4,266 easement or right-of-way agreements were obtained by Kinder Morgan Entities through negotiations with affected landowners. Only 431 condemnation actions were initiated for those projects, with the majority settling prior to the condemnation action reaching the valuation stage. The total number of condemnation actions for which a settlement was not reached and valuation determined by the court was 171, primarily associated with one project. For 17 of the 22 Kinder Morgan Entities' projects, easement agreements or settlements were reached with all affected landowners. The table below provides detailed information regarding eminent domain actions pursued by the Kinder Morgan Entities over the past 10 year period for major pipeline and/or compression addition projects:

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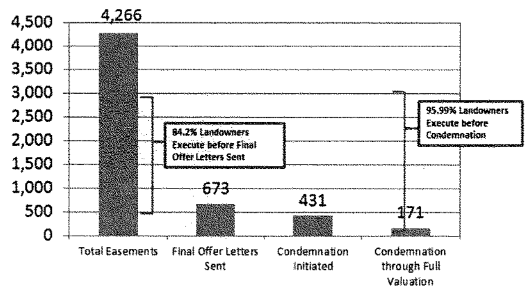
[61] Pipeline loops are those pipeline segments which are laid parallel to, and connected to, another pipeline and used to increase capacity along existing pipeline facilities. These lines are connected to move larger volumes of gas through a single pipeline segment.

[62] For purposes of this review, the projects identified all involved the filing of a NGA Section 7(c) certificate application and 10 miles or more of pipeline and/or compression additions.



Easements Executed by Kinder Morgan Entities Over Last 10 Years for NGA 7(c) Projects

Nevertheless, the Kinder Morgan Entities strongly contend that eminent domain authority is necessary and cannot be eliminated from the NGA as one of the tools available to interstate pipeline companies in order to facilitate the development and implementation of infrastructure projects. The information provided above demonstrates that the Kinder Morgan Entities negotiate in good faith with affected landowners to secure the necessary land rights for their projects and that those easement negotiations are successful with the vast majority of affected landowners. In those few instances when Kinder Morgan Entities are unable to secure the necessary land rights for certificated projects through good faith negotiation with landowners, the Kinder Morgan Entities must have the ability to file condemnation actions to obtain those land rights. Even with willing landowners, condemnation actions may be necessary to "clear title" due to the status of the property or other issues beyond the control of the landowner or pipeline company (e.g. the property is in a probate proceeding, disputes between multiple landowners of one property, or issues with title to the property in question). In addition, the condemnation process provides a fair means to determine valuation by the court in the event the valuation of the easement is the primary reason that the pipeline and the landowner have been unable to execute a negotiated agreement.

Without the statutory right of eminent domain, landowners may have unreasonable expectations regarding compensation for easement rights for interstate natural gas facilities, as compared to other energy sectors that typically pay annual royalty payments to landowners for easements or production rights. Using eminent domain authority may be necessary when a pipeline company and a landowner are not able to reach agreement due to dramatically different views of what constitutes just or fair compensation for an easement. The eminent domain authority conveyed to interstate natural gas pipeline companies for certificated projects by NGA Section 7(h) sets realistic expectations for landowners regarding the fair market value for an interstate natural gas pipeline on their property. This authority granted to pipelines by the U.S. Congress under NGA only after a certificate order is issued reflects an inherent balancing between the rights of pipeline companies to obtain the necessary land rights to proceed with natural gas projects certificated by the Commission after a finding that such projects are in the public convenience and necessity, and the rights of affected landowners to receive fair market value for those land rights after the Commission has reviewed the natural gas projects and determined that such projects meet the public convenience and necessity standard of NGA Section 7(c), and are consistent with the Policy Statement.

3. The Commission's Certificate Review Process Adequately Takes Landowner Interests Into Account and Encourages Landowner Participation in the Process

As discussed in detail above, the Commission's current certificate review process set forth in the Policy Statement and in its regulations provide significant opportunities for landowner involvement in the process. Under Section 157.6(d) of the Commission's regulations,[63] for all NGA Section 7(c) certificate applications, an applicant is required to notify all affected landowners

[63] 18 C.F.R. § 157.6(d) (2018).

and other stakeholders (including towns, communities, and local, state, and federal governments and agencies) involved in a project after a certificate application is filed and the Commission issues a public notice of the application that is published in the *Federal Register*. As a supplement to the direct notifications provided to affected landowners and other interested stakeholders, applicants are also required to have newspaper notices published in each county affected by a project. The Commission's regulations provide a detailed definition for "affected landowners" in Section 156.7(d)(2),[64] which includes not only those landowners directly impacted by a proposed project, but also abutting landowners and landowners within a certain proximity to proposed compressor or LNG facilities.

The Kinder Morgan Entities note that these Commission-required notifications do not represent the first project notifications that affected landowners and other interested stakeholders receive. Prior to submitting a certificate application to the Commission for a proposed project, the Kinder Morgan Entities would have contacted affected and abutting landowners to obtain permission for civil and environmental surveys for properties where proposed project facilities and construction workspace would be located, and those landowners may also have been invited to attend open house or informational meetings to learn more information and ask questions about the proposed project. In addition, federal, state, county, and municipal governmental officials for affected areas are contacted by the Kinder Morgan Entities to introduce the project and answer questions. Regulatory agencies and American Indian Tribal authorities that may have permitting or consultation authority for the proposed project are also contacted early in the development process to discuss a proposed project and its proposed impacts and potential mitigation prior to the certificate application filing and the Commission-required notifications.

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[64] 18 C.F.R. § 157.6(d)(2) (2018).

A detailed list of the information that the landowner and stakeholder notifications must include is set forth in Section 157.6(d)(3) of the Commission's regulations.[65] In addition to project-specific information such as a project description and a map, the notifications must include a summary of the landowner's rights at the Commission and in eminent domain proceedings in the applicable state, information on how the landowner may obtain a copy of the certificate application, and a copy of the Commission's notice of the certificate application (which provides information on how a landowner may intervene in the certificate proceeding and/or provide comments to the Commission regarding the proposed project). Applicants are also required to provide landowners with a copy of the most recent version of the Commission's landowner pamphlet, *An Interstate Natural Gas Facility on My Land? What Do I Need To Know?*,[66] that explains the Commission's certificate review process and answers a number of questions that landowners may have about a proposed natural gas infrastructure project impacting their property. This pamphlet provides clear details on how a landowner may make their views about a proposed project known to the Commission and explains the intervention process for pending certificate applications. In addition, the pamphlet provides Commission contact information and resources for landowners, including the Commission's toll-free Landowner Helpline.[67]

The Commission's pre-filing process (when used) and certificate processes encourage landowner and other project stakeholder involvement and participation throughout the certificate review process. The pre-filing process (which is mandatory for LNG projects and voluntary for natural gas projects) provides opportunities for the applicant, landowners, and other stakeholders to identify environmental and other impacts from proposed projects and to develop avoidance,

[65] 18 C.F.R. § 157.6(d)(3) (2018).

[66] https://ferc.gov/resources/guides/gas/gas.pdf, (last visited July 19, 2018).

[67] *Id.*

minimization, and mitigation strategies for those impacts. Applicants host open house meetings in the project area during the pre-filing process for landowners and other stakeholders to learn about the project, ask questions, and gather information from the applicant and the Commission staff attending the meetings. During the pre-filing process, the Commission issues a notice of intent to prepare an Environmental Impact Statement ("EIS") or Environmental Assessment ("EA") and establishes a scoping period to gather public comments on the proposed project, and conducts scoping meetings to give stakeholders opportunities to provide verbal and written comments regarding the project.

After an applicant files a certificate application for a project (whether using the pre-filing process or the traditional filing option), the Commission issues a public notice of the application (published in the *Federal Register* and sent to all stakeholders), and requests interventions, comments, and protests during the intervention period. Persons that are interested in intervening, commenting, and/or protesting have the option to submit documents electronically through the Commission website or by mailing documents to the Commission. If using the traditional process with no pre-filing process, the Commission issues a notice of intent to prepare an EIS or EA and establishes a scoping period to collect comments on the proposed projects after the certificate application is filed. All stakeholders (whether intervening parties or not) receive a copy of the Commission's intent to prepare an EA or EIS, and have the opportunity to provide comments to these notices, as well as to review and provide comments on the EA or draft and final EIS. The Commission reviews and takes into consideration all comments received during the certificate process in its review of the proposed project.

The Kinder Morgan Entities supplement these notification and outreach requirements with additional outreach efforts to landowners and other project stakeholders, as detailed above. These efforts include (1) early and ongoing communication with interested landowners and other stakeholders as facility designs are reviewed and modifications considered, and (2) timely notifications to federal, state, county, and municipal government officials, regulatory agencies, and leaders of American Indian Tribes to ensure that all stakeholders have access to project information in a timely fashion. Meetings with landowners and other project stakeholders are held on a regular basis throughout the duration of a project to provide information on the need for the project, the potential location of project facilities and impacts of the project, including demonstrating the difference between temporary construction impacts and the long-term impacts of having a pipeline easement located on a landowner's property. The Kinder Morgan Entities' objective in implementing comprehensive stakeholder outreach for proposed projects is to identify and resolve issues raised by stakeholders in a timely fashion.

The Kinder Morgan Entities believe that the Commission's current certificate review process adequately takes into account landowner interests and encourages landowner participation in certificate review. However, the Kinder Morgan Entities recognize that landowners may face a difficult decision in determining whether (1) to formally intervene in a certificate application proceeding and therefore have rights as a party (which include the right to seek rehearing of the certificate order at the Commission and to file an appeal of the certificate order following issuance of a rehearing order with the U.S. Circuit Courts of Appeal), or (2) to provide comments and participate in the process on an informal basis, including communications directly with Commission staff during the certificate review process. This same choice is also relevant to American Indian Tribes who have an historic interest in land to be impacted by a proposed project. The Kinder Morgan Entities would support the Commission's review of Section 385.2201 of its regulations,[68] governing off-the-record communications in contested on-the-record proceedings, to provide opportunities for affected landowners and American Indian Tribes to communicate with Commission staff as needed regarding project concerns even in those proceedings where landowners and American Indian Tribes have elected to intervene and have rights as a party.

The Kinder Morgan Entities would also request that the Commission look for opportunities in its pre-filing and certificate review processes to encourage affected landowners to grant pipeline companies the necessary access to survey potential project locations as early in the project development process as possible. The laws of certain states provide mechanisms for pipeline companies to be granted access to properties for survey purposes prior to the issuance of a certificate order by the Commission, but these mechanisms are not available in every state. The information to be obtained through the field surveys (including civil surveys, geotechnical surveys, wetland and waterbody delineation surveys, rare species habitat assessments and presence/absence surveys, and cultural resource surveys) allows pipeline companies to fully evaluate each property and gather specific survey and resource information that is unique to each property. However, the Kinder Morgan Entities also ask the Commission to acknowledge that in the event landowners refuse to provide access to their properties for survey activities, the lack of access for survey purposes should not impact the Commission's review of a pending certificate application. Section 157.8(a)(1) of the Commission's regulations[69] specifically states that the Commission may not reject a certificate application solely on the basis of Environmental Reports that are incomplete because the pipeline applicant has not been granted access by affected landowner(s) to perform required surveys.

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[68] 18 C.F.R. § 385.2201 (2018).

[69] 18 C.F.R. § 385.8(a)(1) (2018).

The Commission has sufficient data to complete its environmental review of a project pursuant to the National Environmental Protection Act of 1969 ("NEPA")[70] without all field surveys being completed, and may rely on data obtained through publicly available sources (where available and reliable) or through high resolution aerial imagery of the proposed location of project facilities. The high resolution aerial imagery may be used to photo-interpret the boundaries of wetlands and waterbodies, ecological communities, and rare species habitat for areas with no access for survey purposes. The Commission, in issuing certificate orders with conditions requiring issuance of all federal clearances for a project prior to the commencement of project construction, recognizes that all resource boundaries, though, will require field verification to comply with other federal statutes (such as the Endangered Species Act of 1973)[71] and for the issuance of environmental permits. The Commission's practice of issuing conditional certificates has consistently been affirmed by courts as lawful.[72]

C. Environmental Impacts

The Commission's consideration of environmental impacts for proposed interstate natural gas pipeline projects should follow the NEPA guidelines that are well-established for agency review. Under the NEPA regulations, the FERC has broad authority to gather the appropriate data

70 42 U.S.C. §§ 4321 *et seq.* (2018).

71 16 U.S.C. §§ 1531 *et seq.* (2018).

72 *Mountain Valley Pipeline LLC, Equitrans, L.P., Order on Reh'g*, 163 FERC ¶ 61,197, at P 81 (2018), *citing Del. Riverkeeper Network v. FERC*, 857 F.3d 388, 399 (D.C. Cir. 2017) (upholding Commission's approval of a natural gas project conditioned on securing state certification under section 401 of the Clean Water Act); *see also Myersville Citizens for a Rural Cmty., Inc. v. FERC*, 414 U.S. App. D.C. 438, 783 F.3d 1301, 1320-21 (2015) (upholding the Commission's conditional approval of a natural gas facility construction project where the Commission conditioned its approval on the applicant securing a required federal Clean Air Act air quality permit from the state); *Del. Dep't. of Nat. Res. & Envtl. Control v. FERC*, 558 F.3d 575, 578-79 (D.C. Cir. 2009) (holding Delaware suffered no concrete injury from the Commission's conditional approval of a natural gas terminal construction despite statutes requiring states' prior approval because the Commission conditioned its approval of construction on the states' prior approval); *Pub. Utils. Comm'n. of State of Cal. v. FERC*, 900 F.2d 269, 282 (D.C. Cir. 1990) (holding the Commission had not violated NEPA by issuing a certificate conditioned upon the completion of the environmental analysis).

and review natural gas transmission infrastructure applications to ensure that a proper analysis has been performed to determine the environmental impact of the proposed agency action. As part of such analysis, the FERC also has the right to attach conditions to certificate orders and cause applicants to mitigate the environmental impact and reduce the environmental impact of the particular project as much as possible to ensure a finding of no significant environmental impact,[73] and regularly does so. Implementation of an agency policy that goes beyond the tenets of NEPA is unnecessary and even in conflict with the NEPA regulations which require an agency to "commence preparation of an environmental impact statement as close as possible to the time the agency is developing or is presented with a proposal (§1508.23) so that preparation can be completed in time for the final statement to be included in any recommendation or report on the proposal. The statement shall be prepared early enough so that it can serve practically as an important contribution to the decision-making process and will not be used to rationalize or justify decisions already made (§§1500.2(c), 1501.2, and 1502.2)."[74] Accordingly, the NEPA analysis should be part of the decision making process used by FERC to make a determination of public convenience and necessity, and an environmental analysis separate from the prescribed NEPA process seems redundant and superfluous.

But the NEPA analysis is only part of the overall NGA analysis of the public convenience and necessity review for proposed interstate natural gas projects. Neither the NGA nor NEPA requires the Commission to weigh environmental concerns over all other considerations: "The Commission's primary responsibility under the NGA is to determine if the proposed facilities are required by the public convenience and necessity. The term "public convenience and necessity"

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73 See *Transcontinental Pipe Line Corp.*, 69 FERC ¶ 61,143 (1994).

74 40 CFR § 1502.5 (2018).

connotes a flexible balancing process, in the course of which all the factors are weighed prior to final determination."[75] The Commission must "weigh all relevant factors in exercising its responsibilities under the NGA. A flat rule making one factor dispositive in the certificate decision is contrary to the Commission's responsibility to consider and balance all relevant factors."[76]

With regard to the Commission's treatment of greenhouse gas effects of a natural gas pipeline project, Kinder Morgan supports the current standard developed under the NEPA case law that these effects should be included in the analysis if they are "reasonably foreseeable."[77] Specifically, the U.S. Court of Appeals for the D.C. Circuit stated that, "[t]he phrase 'reasonably foreseeable' is the key here. Effects are reasonably foreseeable if they are 'sufficiently likely to occur that a person of ordinary prudence would take [them] into account in reaching a decision.'"[78]

With respect to the applicability of this standard to the acquisition of greenhouse gas data from upstream natural gas production, such information is not "reasonably foreseeable" for at least two primary reasons. First, for many projects, the location of the specific source or supply or the actual production field is not identifiable. Generally, the receipt point for gas deliveries to a pipeline is located at a pipeline interconnection or hub as a means to transport the gas to a market-area delivery point or interconnection. The Commission's policies since Order No. 636 have generally been configured to promote the establishment of "hubs" or "market centers."[79] Consequently, natural gas is aggregated or pooled across several pipelines from various production sources and quite possibly the actual production source is unknown even to the shipper of the gas

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75 *Islander East Pipeline Co.*, 102 FERC ¶ 61,054 (2003).

76 *Id.*

77 *See Sierra Club v. FERC*, 867 F.3d 1357 (D.C. Cir. 2017) p. 19 ("*Florida SE Connection*").

78 *Id.* citing *EarthReports, Inc. v. FERC*, 828 F.3d 949, 955 (D.C. Cir. 2016).

79 *See* Order No. 637 at pp. 11-12

who purchases it from the pooling point or hub. As referenced in Order No. 637, natural gas customers have many options including "relying on monthly and daily spot markets to obtain gas supplies."[80] Robust hubs, market centers, and customer optionality have contributed to greater price discovery and a market-oriented industry that ultimately benefits consumers through lower prices and greater flexibility. The Commission should continue to view these developments as vital and positive and be wary of unintended consequences that would result from requiring a greenhouse gas test that is incompatible with such innovations.

Even for pipeline projects more directly purposed for transporting production from a particular production area, most fields have more than one owner or operator at multiple wells. Further, each operator likely has different drilling protocols based on the location of the rigs and the drill and the greenhouse gas information is likely different for each operator. Additionally, the information regarding the greenhouse gas effect of drilling may not be available because the well operator may not be the same party that is selling the gas into the interstate natural gas market. Often producers use marketing arms to manage the sale and transportation of the gas. Moreover, the FERC's policy regarding flexible receipt points means that shippers have the opportunity to use various points and that decision can change for a shipper at least three to four times a day. Even shippers that are producers do not normally transport gas directly from a particular well. Producers and gatherers aggregate gas for transportation to a specific receipt point that interconnects with an interstate pipeline and designate the source of the gas through the pre-determined allocation ("PDA") process prescribed by the NAESB standards and adopted in pipeline tariffs. In addition to volume or receipt point adjustments, the PDA for the designated working interest owners can also change in each nomination cycle. Accordingly, in most

80 *Id.*

situations, the indirect effect of the greenhouse gas associated with natural gas production is not easily obtainable, accessible or even estimable. Again, FERC should avoid requiring a greenhouse test that is incompatible with FERC's long-standing policies that provide for open access transportation for producers, gatherers, and their marketing agents to get gas to market.

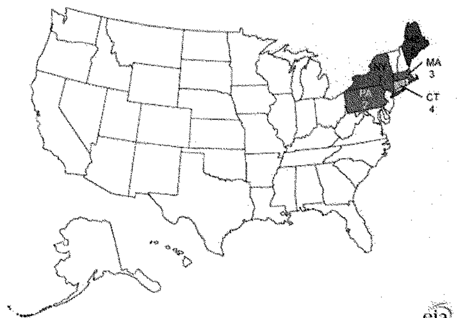
Second, specific information regarding production and gathering is not regulated by the FERC and not associated with operations performed by an interstate pipeline company. As a result of unbundling, pipelines do not purchase gas from producers and are not generally in contractual privity with the owners of gas for sale that may have access to the relevant information regarding the effects of drilling and greenhouse gas emissions. Accordingly, the ability to obtain drilling and operational information would be difficult for pipeline companies to obtain, as the producer may or may not have an interest in the pipeline project and would most certainly under Section 1(b) of the NGA not be obligated to provide such information to the FERC unilaterally. The operation of wells or fields is often regulated by state oil and gas agencies, so the greenhouse gas information may be obtainable through those organizations if they are made public by such agencies. However, as stated above, the purchase of gas for interstate transportation, even by producers themselves, does not typically take place at the well-head. Accordingly, deregulation makes it impossible to extract greenhouse gas information from producers as production operations were intentionally made non-jurisdictional by Congress.

On the market end, as the D.C. Circuit Court of Appeals found in *Florida SE Connection*,[81] some information may be reasonably available depending on the end-use. Again, it seems appropriate to use the current reasonableness standard to determine if the information is reasonably available rather than require the information to be presented and potentially deny access to end-

[81] *Florida SE Connection, supra.*

use markets that cannot provide the information. For example, local distribution companies that provide natural gas service to industrial, commercial and residential customers ("LDC") may be in a similar situation to producers. They manage the natural gas requirements of various parties and are typically regulated as to such deliveries by the respective public service commission of the relevant state. Nominations to various LDC customers may be fluid depending on the season or day of the week. To estimate the greenhouse gas emissions of an LDC's customers does not necessarily seem particularly useful or reliable. This highlights the aspect of the need to take into account the associated greenhouse gas reductions or benefits that a pipeline project may provide in the event such natural gas usage displaces fuel oil in homes—fuel oil still being the major heating source for homes in the Northeastern United States.

Top five residential heating oil consuming states, 2016



Source: U.S. Energy Information Administration, *Fuel Oil and Kerosene Sales, Adjusted Sales of Distillate Fuel Oil by End Use.* December 2017

The Commission should use care in not implementing a strict requirement regarding the inclusion of greenhouse gas information, which would result in the reduction of access to natural gas pipeline infrastructure by certain shippers because such information is impossible to quantify. In addition, if the Commission were to impose a requirement for a pipeline to provide greenhouse gas information, such requirement should have the same standards for quantifying benefits as well as impacts. Finally, any requirement should be equitable among the various users of natural gas. For instance, the Commission should not be able to deny access to an LDC and agree to access by an electric generating facility just because an electric generation facility often can provide greenhouse gas data, since it must provide such to the EPA, and an LDC cannot reasonably estimate such data?

Regardless of the arguments by certain public interest groups that are against the development of natural gas infrastructure in any situation and who will reject a finding of no significant environmental impact no matter how detailed or thorough, the Commission's responsibility under the NGA is to encourage development of natural gas infrastructure, not create policies that inherently stifle development or arbitrarily allow one shipper an advantage to access over another shipper. It is FERC's business to create a positive (and orderly) environment for the development of natural gas. Alternative analysis may be required to be part of an EIS or EA developed pursuant to NEPA requirements, but that does not mean that FERC policy should be inherently biased against or even neutral to the construction of natural gas infrastructure. FERC should shy away from creating policies that reinforce the perception that natural gas infrastructure projects are inherently harmful to the public interest. It is acceptable for the Commission to be a proponent of natural gas development even as it addresses the legitimate concerns of true stakeholders and complies with its NEPA responsibilities. The existing Policy Statement provides sufficient structure to allow the Commission to carry out its responsibility under NEPA effectively and there has been no demonstrable evidence presented that the Commission's policy has not worked and served the nation and industry well over the past nearly 20 years.

In addition, there is no need for FERC to develop policies in 2018 anticipating what the market for natural gas will be like in 2030 or some other date in the future. The balance that the Kinder Morgan Entities are advocating, as reflected in the Policy Statement, is to let the market decide the purpose and need for natural gas and then the development of projects will adjust up or down as the demand for natural gas changes. The Policy Statement is flexible and resilient and should continue to be the basis for determining the public convenience and necessity for a pipeline project.

D. FERC Process Improvements

Section D of the NOI requests comments on how to improve the transparency, timing and predictability of the Commission's certification process. Specifically, the Commission requests comments on whether to consider changes to the pre-filing process, how to best ensure effective participation by interested stakeholders, ways for the Commission to work more efficiently with other agencies, and projects that should appropriately be subject to a shortened process. The Kinder Morgan Entities support efforts to make the certification process more efficient, transparent and less adversarial.

1. Pre-Filing Review Process Must Remain Flexible and Should Be Improved to Avoid Increasing Overall Pipeline Project Review Time and "Second Bites at the Apple"

The Commission first adopted a voluntary, collaborative process for the construction of natural gas facilities and hydrostatic licenses, codified at Section 157.22[82] and Section 4.34,[83]

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[82] *Collaborative Procedures for Energy Facility Applications*, Order No. 608, 64 Fed. Reg. 51209 (Sep. 22, 1999), FERC Stats. & Regs., Regulations Preambles (July 1996 – December 2000) ¶ 31,080 (1999) ("Order No. 608").

[83] *Regulations for the Licensing of Hydroelectric Projects*, Order No. 596, 62 Fed. Reg. 59802 (Nov. 5, 1997), FERC Stats. & Regs., Regulations Preambles (July 1996 – December 2000) ¶ 31,080 (1999).

respectively of the Commission's Regulations, in 1999, the same year as the adoption of the Policy Statement. In announcing the new process, the Commission explained that

> [I]t will be up to the applicants and other participants in the process to decide which issues will be covered in each collaboration. We emphasize the flexibility of the pre-filing process and are open to working cooperatively with potential applicants and participants to design pre-filing processes that are helpful to all concerned and lay the foundation for expeditious proceedings on gas applications and full compliance with the NGA, NEPA and other applicable statutes.[84]

These pre-filing procedures worked well because the Commission's Staff was willing to assess each project on an individual basis and not demand strict adherence to the pre-filing guidelines.

Subsequent to Order No. 608, Congress passed the Energy Policy Act of 2005 ("EPAct 2005") that was signed into law by President George W. Bush.[85] Section 311(d) of EPAct 2005 required the Commission to promulgate regulations requiring prospective applicants for authorization to construct LNG terminals[86] to comply with the Commission's pre-filing review process, beginning at least six months prior to filing an application. The Commission fulfilled this obligation in Order 665, which made the pre-filing review process mandatory for applicants of LNG terminal and related jurisdictional natural gas facilities[87] to participate in the pre-filing review

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84 Order No. 608, *supra* at 9.

85 *Energy Policy Act of 2005*, 42 U.S.C. § 13201 *et seq.*

86 The definition of LNG terminal as included in Section 311(b) of the EPAct 2005, states, "LNG terminal includes all natural gas facilities located onshore or in State waters that are used to receive, unload, load, store, transport, gasify, liquefy, or process natural gas that is imported to the United States from a foreign country, exported to a foreign country from the United States, or transported in interstate commerce by waterborne vessel."

87 18 CFR 153.2(e) (2018) provides that "[f]or purposes of this part and § 157.21, *related jurisdictional natural gas facilities* means any pipeline or other natural gas facilities which are subject to section 7 of the NGA; will directly interconnect with the facilities of an LNG terminal, as defined in paragraph (d) of this section; and which are necessary to transport gas to or regasified LNG from:

(1) A planned but not yet authorized LNG terminal; or

(2) An existing or authorized LNG terminal for which prospective modifications are subject pursuant to section 157.21(e)(2) to a mandatory pre-filing process."

process.[88] The Commission added related jurisdictional pipeline and other natural gas facilities from the original requirements described in EPAct 2005 to ensure that an LNG project would connect to a feasible pipeline or other facilities.[89]

Order 665 also provides that prospective applicants *may elect on a voluntary basis* to undertake the pre-filing process to filing applications for other facilities subject to the Commission's jurisdiction under the NGA. The Commission encouraged pipelines to consider the pre-filing process where it might "expedite approval of a contemplated project that are directly interconnected with an LNG terminal".[90] Reserving the option to use the pre-filing process on a voluntary basis ensures that pipelines are able to implement new projects on an expeditious basis. The Kinder Morgan Entities request that the Commission continue to recognize that not all pipeline projects involve complicated or complex issues that would benefit from participation in a pre-filing process. Moreover, a pipeline project that takes advantage of the pre-filing process should not be punished by giving opponents "second bites at the apple" when the project moves from the pre-filing phase to the certificating phase or increasing the overall review time for the project.

The most challenging aspect of the pre-filing review process as it has been implemented is the requirement to file drafts Resource Reports 2 through 9 and 11 within sixty days of the end of the scoping comment period (as well as revised versions of draft Resource Reports 1 and 10 reflecting initial comments on those two reports, which are required to be filed within 30 days after the Commission approves the use of the pre-filing process for a particular project).[91] Gathering

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88 *Regulations Implementing Energy Policy Act of 2005; Pre-Filing Procedures for Review of LNG Terminals and Other Natural Gas Facilities*, 70 Fed. Reg. 70426, (Oct. 18, 2005), 113 FERC ¶ 61,015 (2005), ("Order No. 665.")

89 *Id.* at ¶¶ 16-19.

90 *Id.* at ¶ 22.

91 18 C.F.R. §157.21(f)(10) (2018).

the detailed and comprehensive information required for these resource reports depends upon external factors, including survey access, weather conditions, and detailed engineering status. Providing resource reports with gaps during the pre-filing process resulting from the limited information collected to date does not expedite the environmental review by FERC Staff and may require a complete review and revision prior to filing a certificate application. The information requests submitted by Commission staff in response to the draft resource reports generally point out deficiencies in information that the pipeline company is aware of due to the status of surveys and the compilation of survey reports, and detailed engineering design. The Guidance Manual for Environmental Report Preparation,[92] most recently updated in February 2017, provides clear details of the requirements needed for the Environmental Report to be submitted with a certificate application, which are followed by project applicants, notwithstanding participation in the FERC's pre-filing process.

The Kinder Morgan Entities request the Commission eliminate the requirement to file Resource Reports 2 through 9 and 11 or, in the alternative, require the Director of the Office of Energy Projects ("OEP") to adjust the pre-filing procedures for pipeline projects on a case-specific basis as provided by Section (x) of the Commission's Regulations.[93] The Commission should require that the information to be submitted during the pre-filing process be specifically tailored to only the issues raised during the scoping period while the applicant continues to develop the project prior to filing a certificate application. Responses to comments regarding the specific

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[92] *Guidance Manual for Environmental Report Preparation for Applications Filed Under the Natural Gas Act* (2017), https://www.ferc.gov/industries/gas/enviro/guidelines/guidance-manual-volume-1.pdf (last visited July 19, 2018)

[93] Order No. 665 specifically recognized "that in some instances certain required filings may not be applicable or may not need to be filed again." Accordingly, the Commission authorized the Director of the OEP or the Director's designee to "[a]pprove, on a case-specific basis, and make such decisions and issue guidance as may be necessary in connection with the use of the pre-filing procedures in §157.21, 'Pre-filing procedures and review process for LNG terminal facilities and other natural gas facilities prior to filing of applications.'"

issues raised in the pre-filing process would be reflected by the applicant in the Environmental Report to be submitted with the certificate application.

In addition, the Commission should consider clarifying the purpose and scope of its formal pre-filing procedures. The formal pre-filing process is designed to enable FERC, project sponsors, and other stakeholders to identify environmental and safety concerns early in the development of the project to minimize and avoid impacts. The pre-filing process should facilitate discussions between these parties and provide a platform for collaboration and issue spotting. When used properly, a pre-filing docket can be an effective way to streamline the certificating process by eliminating issues prior to initiating the formal certificate process. But in some instances, project opponents have used the formal pre-filing process as a vehicle simply for voicing contrarian positions and inundating the docket with unproductive protests. The Commission's certificate process affords project opponents ample opportunities to advocate their concerns but the pre-filing process is not the appropriate forum to do so. The pre-filing process should not be a referendum on natural gas generally or the need for a particular pipeline project, but rather an opportunity to problem solve around environmental and safety issues and facilitate a more efficient certificate process.

2. The Commission Must Fulfil its Legislative Mandate Under EPAct 2005 to Coordinate All Required Federal Authorizations and NEPA

EPAct 2005 also directed the Commission to be the "lead agency" for the purposes of coordinating all federal authorizations needed by an interstate pipeline and for complying with the NEPA. As the lead agency, FERC provides the NEPA reviews of certificate applications but coordinates with other federal agencies, tribes, and state and local governments ("Cooperating Agencies"). The Kinder Morgan Entities encourage the Commission to take a more active "lead agency" role. The Commission should focus on routinely meeting with Cooperating Agencies to build meaningful long-term relationships and to provide more education of the NGA certificate review process. A larger program staff would allow the Commission to take a regional approach to Cooperating Agencies and facilitate and improve timely communication regarding applications. The Kinder Morgan Entities encourage the Commission to embrace the statutory role granted by Congress to further the purposes of overseeing orderly infrastructure development under the NGA and ensuring administrative efficiency.

As the lead agency, the Commission also has the authority to establish a schedule for federal and state authorizations required under federal law. The Kinder Morgan Entities request that the Commission incorporate this into the certificate process. Specifically, Section 385.2013(a) of the Commission's regulations, which was adopted by the Commission following the issuance of EPAct 2005, provides that:

> [E]ach Federal agency or officer, or State agency or officer acting pursuant to delegated Federal authority, responsible for a Federal authorization must file with the Commission within 30 days of the date of receipt of a request for a Federal authorization, notice of the following:
>
> 1. Whether the application is ready for processing, and if not, what additional information or materials will be necessary to assess the merits of the request;
> 2. The time the agency or official will allot the applicant to provide the necessary additional information or materials;
> 3. What, if any, studies will be necessary in order to evaluate the request;
> 4. The anticipated effective date of the agency's or official's decision; and
> 5. If applicable, the schedule set by Federal law for the agency or official to act.[94]

This information will allow the Commission to monitor the respective timelines for Cooperating Agencies prior to the Notice of Schedule, which provides the ninety (90) day federal authorization decision deadline. By requiring all other federal agencies to cooperate with the Commission and comply with deadlines set by the Commission, and by establishing a process for an applicant to

[94] 18 C.F.R. 385.2013(a)(1-5) (2018)

appeal an agency's delay to the D.C. Circuit, Congress reaffirmed the original intent of the NGA to govern the development of a national integrated interstate transportation system with EPAct 2005.

3. Classes of Projects that Should Appropriately Be Subject to a Shortened Process

a) The Commission Should Expand 18 CFR § 157.210 and Authorize Mainline Natural Gas Facilities under Automatic Authorization

The blanket construction certificate program was adopted by the Commission in 1982 to provide an administratively efficient means for the Commission to authorize a generic class of routine activities, without subjecting each minor project to a full, case-specific NGA section 7 certificate proceeding.[95] In instituting the blanket certificate program, the Commission explained:

> [T]he final regulations divide the various actions that the Commission certificates into several categories. The first category applies to certain activities performed by interstate pipelines that either have relatively little impact on ratepayers, or little effect on pipeline operations. This first category also includes minor investments in facilities which are so well understood as an established industry practice that little scrutiny is required to determine their compatibility with the public convenience and necessity. The second category of activities provides for a notice and protest procedure and comprises certain activities in which various interested parties might have a concern. In such cases there is a need to provide an opportunity for a greater degree of review and to provide for possible adjudication of controversial aspects. Activities not authorized under the blanket certificate are those activities which may have a major potential impact on ratepayers, or which propose such important considerations that close scrutiny and case-specific deliberation by the Commission is warranted prior to the issuance of a certificate.[96]

The two specific categories of blanket certificate filings described above that a blanket certificate holder may make are:

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95 *Interstate Pipeline Certificates for Routine Transactions,* 47 Fed. Reg. 24254 (June 4, 1982). *See also Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 436, *supra,* ("The blanket certificate rules set out a class of transactions, subject to specific conditions, that the Commission has determined to be in the public convenience and necessity.")

96 47 Fed. Reg. 24254.

1. Automatic Authorization (first category) allows specified eligible activities to be authorized subject to the holder notifying potentially affected landowners at least 45 days prior to the commencement of construction or at the time it initiates easement negotiations, whichever is earlier. The cost limit for this type of activity is $12 million for calendar year 2018.

2. Prior Notice Authorization (second category) allows specified eligible activities to be authorized subject to a 60-day public notice period. The cost limit for this type of activity is $33.8 million for calendar year 2018.

In Order No. 686, the Commission expanded the scope and scale of activities that may be undertaken pursuant to blanket certificate authority.[97] Order No. 686 authorized additional categories to be included in the blanket certificate program, including adding Section 157.210 of the Commission's regulations to allow blanket certificate holders to acquire, construct, modify, replace, and operate natural gas mainline facilities, including compression and loop line facilities. The Commission required prior notice for the newly added categories with limited exception for storage out of concern about the Commission's lack of experience under the blanket program in supervising these activities.[98]

The Commission should expand its regulations to allow modifications to mainline natural gas facilities under blanket automatic procedures if the project is below the blanket automatic cost limit. The Commission has gained significant experience since 2006 in supervising such projects. Blanket certificate projects, whether constructed pursuant to automatic or blanket certificate authority, are subject to the environmental compliance conditions in Section 157.206(b) to ensure that actions that could cause a significant adverse impact on the human environment are not conducted under blanket certificate authority, but are instead subject to case-specific review.

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97 *Revisions to the Blanket Certificate Regulations and Clarification Regarding Rates*, Order No. 686, 71 Fed. Reg. 63680 (Oct. 19, 2006), FERC Stats. & Regs., Regulations Preambles (2006-2007) ¶ 31,231 (2006).

98 *Id.* at ¶ 15.

b) The Commission Should Authorize All Auxiliary Installations under Section 2.55(a)

In 1949, the Commission issued Order No. 148 and defined auxiliary installations that are not jurisdictional. The Commission detailed in Section 2.55(a) that "auxiliary installations" were not "facilities" for the transportation of natural gas because they are only auxiliary or appurtenant to such facilities and "only for the purpose of obtaining more efficient or more economical operation of authorized transmission facilities."[99] Examples of the types of installations include "valves; drips; pig launchers/receivers; yard and station piping; cathodic protection equipment; gas cleaning, cooling and dehydration equipment; residual refining equipment; water pumping, treatment and cooling equipment; electrical and communication equipment; and buildings."[100]

Section 2.55(a) provides the pipeline industry the ability to install such facilities necessary for safety, security, and other related purposes ancillary to the provision of interstate pipeline transportation services. For example, auxiliary installations, such as additional in-line inspection capability, sufficient cathodic protection and communication equipment, all support pipeline safety efforts. Communication installations also are an important part of securing the nation's vital interstate pipeline system from external risks.

Work performed in accordance with Section 2.55(a) did not have a right-of-way or workspace limitation until the Notice of Proposed Rulemaking entitled "Revisions to the Auxiliary Installations, Replacement Facilities, and Siting and Maintenance Regulations"[101] that led to Order

99 Order No. 148, 14 Fed. Reg. 681 (Feb. 16, 1949).

100 18 C.F.R. § 2.55(a)(1) (2018).

101 *Revisions to the Auxiliary Installations, Replacement Facilities, and Siting and Maintenance Regulations*, Notice of Proposed Rulemaking, FERC Stats. & Regs., ¶ 32,696 (2012) ("2012 Auxiliary Installation NOPR").

790,[102] 790-A,[103] and 790-B.[104] The 2012 Auxiliary Installation NOPR proposed and Orders 790, 790-A, and 790-B ultimately revised the language of the Commission's regulations to state that all activities related to the construction of auxiliary installations must take place within a company's certificated right-of-way using previously approved work spaces. The Commission promulgated this change without acknowledgement that it was a change or providing a factual basis or material theoretical threat to justify the change. In addition to the changes described in Section 2.55(a), the Commission also amended its regulations to provide for certain five-day advance landowner notification for auxiliary installations and replacement projects under Section 2.55.[105]

The changes to Section 2.55(a) resulting from Orders 790, 790-A, and 790-B have limited efficiencies, slowed the enhancement of pipeline integrity activities, and increased the cost of such facilities. The Kinder Morgan Entities had previously reviewed and addressed environmental and cultural landmark concerns connected to auxiliary installation projects through streamlined processes and informal consultation with relevant local, state, and federal agencies. This approach enabled pipelines to work closely with the pertinent state and federal agencies to accomplish the installations promptly but in an environmentally and culturally sensitive manner. Orders 790, 790-A, and 790-B converted all auxiliary installations outside of existing rights-of-way and historical workspaces into NGA jurisdictional facility construction that require certificate authorization and formal agency consultations. This heightened consultation process requires more time but does

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102 Order No. 790, 78 Fed. Reg. 72794 (Dec. 4, 2013), FERC Stats. & Regs., Regulations Preambles (2008-2013) ¶ 31,351 (2013).

103 *Revisions to Auxiliary Installations, Replacement Facilities, and Siting and Maintenance Regulations*, Order No. 790-A, 79 Fed. Reg. 70056 (Nov. 25, 2014), III FERC Stats. & Regs., Regulations Preambles ¶ 31,361 (2014)

104 *Revisions to Auxiliary Installations, Replacement Facilities, and Siting and Maintenance Regulations,* Order No. 790-B, 80 Fed. Reg. 50558 (Aug. 20, 2015), III FERC Stats. & Regs., Regulations Preambles ¶ 30,371 (2015).

105 Order No. 790, *supra.*

not without leading to a different result (i.e., an auxiliary installation is sited to not have a significant impact on such resources).

Kinder Morgan Entities support maintaining the five day landowner notification as required in Section 2.55(c) prior to engaging in work under Section 2.55(a) related to auxiliary installations, but request that the Commission reconsider and find that auxiliary installations are exempt from NGA jurisdiction and that no right-of-way or work space limitations apply to auxiliary installations under Section 2.55(a).

IV. CONCLUSION

WHEREFORE, the Kinder Morgan Entities respectfully request that the Commission take these comments into consideration in reaching its decision in this proceeding.

Respectfully submitted,

<u>/s/ J. Curtis Moffatt</u>
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Dated: July 25, 2018

U.S. Senate Committee on Energy and Natural Resources
July 12, 2018 Hearing
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Questions for the Record Submitted to Mr. James Murchie

Questions from Chairman Lisa Murkowski

Question 1: Over the past few years, it has become increasingly clear that this nation is facing a fundamental choice when it comes to energy policy. Down one path is a hard-edged effort to stop using fossil fuels altogether, and down the other is the continuation of our existing policy of supporting ever cleaner forms of energy, while ensuring that energy is still affordable.

- Please describe the political and regulatory risks that needed pipeline and LNG facilities will not be built over the next ten years.
- In your view, what are the best ways to ensure that these risks do not materialize?
- Shouldn't FERC Commissioners be equally receptive to needed energy infrastructure regardless of the political party of the person holding the Office of the President of the United States?
- During the eight years of the Obama Administration, FERC's policies resulted in significant investment into needed pipeline and transmission infrastructure—is now the time for Commissioners at FERC to be considering major changes that could discourage needed infrastructure?

Mr. Murchie's Answer to Senator Murkowski's Question 1:

Please describe the political and regulatory risks that needed pipeline and LNG facilities will not be built over the next ten years.

In your view, what are the best ways to ensure that these risks do not materialize?

The challenges to permitting and new construction of energy infrastructure have historically come not at the federal level but primarily from other jurisdictions such as the municipal, county, state and special district levels. In most cases, these challenges relate specifically to local concerns regarding the impact of the new project as it relates to disturbance of the air or water, excess noise or traffic during construction, safety, etc. of *nearby residents.*

At the federal level, FERC ("the Commission") has approved over 400 pipeline applications since the 1999 Policy Statement was issued regarding certification of new natural gas pipelines. Over this time only 2 applications for new pipelines were rejected.[1] Likewise, since the 2006

[1] "Natural Gas Pipeline Certification – Policy Considerations for a Changing Industry" a white paper by Analysis Group, November 6, 2017, page 12.

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Order 679 promoting transmission investment through pricing reform, there has been a marked increase in power transmission investment. The Army Corps of Engineers (ACE) has in some cases presented obstacles to new pipeline construction that have led to significant delays, but these delays are not the result of any policy *per se* that we are aware of and probably better fit into the category of local concerns given the nature of ACE's responsibilities. Nor are we aware of any project cancellations due to lack of approvals from ACE. It is at the state and local levels that the Constitution Pipeline project in New York and the Northern Pass Transmission line in New England met their demise.

Nonetheless, we agree with many observers that it is increasingly difficult to permit and construct new energy infrastructure. We believe that this difficulty increasingly arises from efforts to stop any and all fossil fuel development by applying pressure at the state and local level to block development in furtherance of national and global environmental policy objectives. While many participants in the energy infrastructure industry believe that state and local siting authority is being abused by these interests, our federalist system affords them this right and an independent judiciary provides a route of appeal to remedy any abuse.

From our perspective as investors, responsibility for successful new infrastructure development lies with the management teams of the energy infrastructure companies, who are usually well skilled in gaining FERC as well as state and local approval for projects. The better management teams do a thorough job of community outreach by proactively seeking comment and addressing concerns of all who might be affected by a new pipeline or transmission project. That this is, in some cases, no longer sufficient to overcome state and local objections advocating "keep it in the ground" has led to calls for a policy response at the federal level.

As investors we are wary of new policies at the federal level that would serve to override local concerns, as this ultimately tends to backfire. We have had countless discussions with the management teams of our portfolio companies about pipeline permitting and the clear pattern that emerges is that communication with and involvement of local communities is critical to successful infrastructure development. A review of academic literature on the subject offers the exact same conclusion[2].

Rather than instituting new rules at the federal level that would place limits on local approval authority, we think it is incumbent on the industry to do a better job convincing the public – perhaps with the help of federal policies - of the benefits of new energy infrastructure. These benefits include increased employment and economic activity, lower energy costs and greater reliability, while reducing reliance on energy sources that pollute the environment. Our written testimony noted that we view the "keep it in the ground" versus "drill, baby, drill" debate as a false choice. Over the last ten years, it is our view that the reduction in coal-fired power

[2] See for example "From nuclear to renewable: Energy system transformation and public attitudes" by Nick Pidgeon and Christina C. Demski, Bulletin of The Atomic Scientists, Vol 68, 2014 - Issue 4 and "Explaining "NIMBY" Objections to a Power Line: The Role of Personal, Place Attachment and Project-Related Factors by Patrick Devine-Wright, Sage Journals Reprints.

generation and attendant increase in the use of renewables has been facilitated in large part by the increased generation of electricity from natural gas extracted from shale. These supply shifts have necessitated thousands of miles of new natural gas pipelines which in turn have led to a significant reduction in emissions of sulfur dioxide, nitrous oxides, mercury, CO2 and other pollutants from coal-fired power plants[3].

Industry associations tend to represent discrete segments of energy infrastructure, such as pipelines, gas distribution, and electricity and therefore, in our view, lack a well-coordinated effort to counter their opponents' narrative. The industry has a great story to tell; lower cost, cleaner energy being delivered in a safer and more reliable way, while on the whole achieving the Greenhouse gas (GHG) reduction objectives many of its opponents seek. However, industry falls short in communicating that. When a team is losing the game on the field, it can either seek to change the rules of the game or field a better team. An effort to change permitting rules risks disenfranchising stakeholders and emboldening opposition. In our view, the industry needs to up its own game before seeking to change the rules.

At the federal level, however, we do believe there is a need for a policy change allowing for a broader, more holistic evaluation of GHG emissions than the narrow view currently taken by FERC in its evaluation of the environmental impact of a new natural gas pipeline.

Our written testimony submitted on July 10, 2018 stated:

"It is in this context that we view the debate about the Greenhouse gas (GHG) impact of permitting new natural gas pipelines. To be direct, we view the debate as a false choice. When regulators and the courts are asked to address the impact of a particular new natural gas pipeline on GHGs, the discussion centers around considering the impact upstream of the pipeline (more natural gas production) and downstream of the pipeline (more natural gas usage). Missing from the discussion, in our view, is recognition that natural gas pipeline infrastructure enables natural gas to reduce coal usage, reducing power plant emissions of all kinds, including CO2 and further facilitates adding more renewables to the mix....Because adoption of these new technologies cuts across industries and therefore the mandate of the relevant regulatory agencies, there is an important role to play for policy makers as well as regulators."

This shortcoming is underscored by FERC's partisan divide on this very debate, illustrated by the FERC order Denying Rehearing (Docket No. CP14-497-001) in the New Market Project dated May 18, 2018, a 3-2 decision that was split along party lines based on differing views of the measurability of the project's impact on GHGs. Missing from each side's legal arguments—and the record—is a comprehensive and holistic assessment of the subject pipeline's GHG impact in the context of the entire energy system, including the impact on the use of other fuels like coal and renewables.

[3] EIA February 2017

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The D.C. Circuit Court of Appeals, in its decision on *Sierra Club v. Federal Energy Regulatory Commission 827 F.3d 36 (D.C. Circuit 2017)*, spoke to the need to comprehensively address a proposed infrastructure project's environmental impact, whether negative or positive. While FERC's approval of the Southeast Markets Pipeline Project (also known as the Sabal Trail project) did contemplate end-use downstream GHG emissions as well as their offset in terms of displaced coal generation in Florida, the Court found FERC's analysis lacking in depth and rigor:

> *"The effects an EIS is required to cover "include those resulting from actions which may have both beneficial and detrimental effects, even if on balance the agency believes that the effect will be beneficial." 40 C.F.R. § 1508.8. In other words, when an agency thinks the good consequences of a project will outweigh the bad, the agency still needs to discuss both the good and the bad. In any case, the EIS itself acknowledges that only "portions" of the pipelines' capacity will be employed to reduce coal consumption. See J.A. 916. An agency decision maker reviewing this EIS would thus have no way of knowing whether total emissions, on net, will be reduced or increased by this project, or what the degree of reduction or increase will be. In this respect, then, the EIS fails to fulfill its primary purpose."*

Nonetheless, while the DC Circuit Court's decision was two-to-one, the dissenting opinion objected to *any* review of downstream GHGs where the siting authority for such downstream facilities are outside the purview of FERC. While one could argue legal precedent on both sides, *consideration of the GHG impact of an infrastructure project – on the system as a whole – should not hinge on a legal technicality.* Nor should it hinge on political balance of the five FERC commissioners, which speaks to the third part of the question.

Shouldn't FERC Commissioners be equally receptive to needed energy infrastructure regardless of the political party of the person holding the Office of the President of the United States?

The answer to this question is clearly yes. As investors, we prefer stable and predictable regulation that doesn't turn 180 degrees every four years. The GHG issue is politically charged and, in our view, may threaten the impartial, reasoned and apolitical tenor that has defined FERC's historical rulemaking. The recent split decisions at both the DC Circuit Court and the FERC in Sabal Trail and the New Market Project suggest that the threat of such a wholesale quadrennial policy shift is real. These divisions put at risk the regulatory stability that would attract capital at the lowest possible cost. Since the cost of capital makes up the bulk of the cost of energy infrastructure, higher capital costs risk driving higher energy bills for consumers.

During the eight years of the Obama Administration, FERC's policies resulted in significant investment into needed pipeline and transmission infrastructure—is now the time for Commissioners at FERC to be considering major changes that could discourage needed infrastructure?

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In our view, the success in building thousands of miles of new energy infrastructure during the Obama Administration was, ironically, in part due to the distraction provided by the Keystone XL project (KXL). It's almost as if the KXL project served as the singular venue for the "keep it in the ground" advocates to engage in battle with the "drill, baby, drill" advocates. When the project was cancelled, President Obama said:

> *"For years, the Keystone pipeline has occupied what I, frankly, consider an overinflated role in our political discourse. It became a symbol too often used as a campaign cudgel by both parties rather than a serious policy matter. And all of this obscured the fact that this pipeline would neither be a silver bullet for the economy, as was promised by some, nor the express lane to climate disaster proclaimed by others."* President Barack Obama at the speech rejecting the Keystone Pipeline November 6, 2015.

Now, no longer focused on one project, the battle between these two forces has dispersed, with FERC becoming one of many venues. While it is incumbent upon FERC to conduct thorough analysis with the engagement of all stakeholders, the Commission should be guided by its core mission as it contemplates changes to its 1999 policy statement on pipeline certification. Above all, that process should—again—remain thorough, objective, and devoid of political influence.

While some fear the Notice of Inquiry regarding Certification of New Interstate Natural Gas Facilities has opened a Pandora's Box of issues that have long been settled, it affords FERC the opportunity to show it is dedicated to its mission to "assist consumers in obtaining reliable, efficient and sustainable energy services at reasonable cost through appropriate regulatory and market means." FERC needs to demonstrate that its track record over the last 19 years of approving over 400 natural gas pipeline projects while rejecting only two is a result of adherence to its mission and not having a bias in favor of the pipeline industry. Those who are familiar with the process recognize that the high approval rate reflects the rigor of FERC's vetting process which eliminates applications from projects that will not pass muster. To others, the high approval rate could suggest a bias toward approval.

As investors we fear the cost of excess pipeline capacity as much as advocates for consumers who worry that unneeded costs will burden ratepayers because the pipeline companies will not achieve their targeted returns on capital. But we also fear investing in an energy industry suffering from a lack of sufficient infrastructure as this sends price signals at the supply end that discourage production while increasing prices at the demand end, hurting consumers.

Question 2: Since consumers of energy should not be paying for wasteful overbuilding of pipeline and transmission infrastructure, FERC has policies to ensure that the network does not

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become "gold plated." But, at the same time, the pipeline and transmission networks should not become outdated, unreliable, and insufficient to meet demand.

- On a one to ten scale, with one being a failing delivery network, and ten being an excessive, or "gold-plated" network, what do you think of today's pipeline and transmission networks?

- On that same one to ten scale, where do you think the networks will need to be five years from now? What are the leading risks that could derail this result?

Mr. Murchie's Answer to Senator Murkowski's Question 2:

On a one to ten scale, with one being a failing delivery network, and ten being an excessive, or "gold-plated" network, what do you think of today's pipeline and transmission networks?

Energy deregulation that began in the 1980s, along with subsequent legislation and regulatory rulings have left the U.S. with a complex energy infrastructure system comprised of regulated and competitive markets. The competitive markets use price signals to attract investment when there is insufficient infrastructure capacity. Conversely, regulation seeks to assure reliable and adequate supply through provision of a just and reasonable return to owners while protecting customers from constraint-driven opportunistic price spikes. As investors in energy infrastructure, it is our view that this complex system has for the most part accomplished the goal of providing a system that is not gold plated yet is, for the most part, sufficient and robust in its capacity relative to demand. Despite a few regional imbalances, we think that a 7-8 on the scale of 10 is where we are and where we should strive to be in the future.

In our view, the reason 5 is not the right number is because the entire energy system should be designed to have sufficient reserve capacity for extreme weather or other unforeseen events. Unlike other privately financed industries, robust and reliable energy infrastructure is a public good that - like civil infrastructure - underpins national security and economic health. The challenge is to build in excess capacity without gold-plating the system. It is our view that the current mix between competitive and regulated markets is mostly achieving this objective.

As we discussed in our testimony, the largest cost of a pipeline or power transmission system is not the operating cost, it's the capital cost. That capital cost is, in turn, heavily dependent on stability and predictability of earnings. If the industry under-builds and creates disruptions as happened in the Enron era (in particular, the California electricity markets), or overbuilds as has happened in the gas pipelines built 10-12 years ago to serve some of the early shale plays, it disrupts that earnings stability and raises the cost of financing which is ultimately borne by the consumer.

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As investors we also suffer if a system is "gold-plated." Higher costs risk customer backlash, competitive disruption, and stranded investment; as investors we have the same interest as regulators in terms of balancing supply and demand with maximum economic efficiency. We appreciate the oversight provided by a regulatory process that seeks to ensure there is demand for new infrastructure before it gets built.

On that same one to ten scale, where do you think the networks will need to be five years from now? What are the leading risks that could derail this result?

As noted above, we believe 7 to 8 on a scale of 10 is appropriate. That said, it is difficult to conclude that New England has sufficient energy infrastructure capacity given the shortages and price spikes that have occurred during recent extreme weather events. But as mentioned above, the impediment to new natural gas pipeline and power transmission capacity is not federal, but rather at the state and local level. While New England's higher energy costs, in part, result from a lack of capacity, it is the citizens of New England who, through their elected and appointed officials, are choosing to forego new energy infrastructure development. The question that must be asked at the federal level is whether the choices being made by the New England states in some material way impose costs on the rest of the country such that federal action is required. As investors in energy infrastructure across all of North America, we see an opportunity cost in foregone investments, but we cannot see that there are any real costs being incurred by the non-New England parts of our portfolio.

In our view, part of the dynamic in New England stems from the mismatched tenor of assets and liabilities of our hybrid system of competitive and regulated markets. Some will point to the inability or unwillingness of merchant power producers to sign 20-year precedent agreements that pipeline developers require to underwrite investment in new pipelines. The unwillingness of merchant power producers to sign long-term contracts stems from their highly cyclical cash flows and attendant lack of balance sheet capacity as well as the fluidity of competitive commodity markets. The reluctance of pipeline companies to build projects "on spec" owes to the unwillingness of their investors (both debt and equity) to take those risks, preferring instead the potentially lower but more predictable cash flows of a 20-year contract. While some New England electric utilities contemplated a tariff-based mechanism to address this market failure, that proposal ran afoul of existing statutes, regulations and accepted practice.

Apart from demand-side bottlenecks, the abundant production and attendant over-supply of natural gas in some regions of the U.S. may also create impediments to development should FERC approval require demonstration that a public need would be met. Today, prolific production of "associated" gas that accompanies crude oil has overwhelmed gas pipeline takeaway capacity out of the Permian Basin of western Texas and eastern New Mexico. Lacking local demand, producers are forced to flare the excess natural gas, wasting a valuable resource and polluting the air. In this example, development of needed natural gas infrastructure might not be justified by local convenience and necessity, but international exports would allow

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abundant American natural gas production to beneficially offset coal use and facilitate renewable energy development in other regions of the world as it has done in the United States.

Question 3: In December, this Congress lowered tax rates, and part of my expectation in lowering those rates was my expectation that FERC would be looking at those rates and how such reduced rates would reduce energy costs for Americans. FERC recently issued a series of tax orders while the trading markets were open, and some observers believe that this resulted in an over-reaction by the markets. While we want consumers to benefit from the lower tax rates, we don't want badly-timed orders resulting in pointless market swings.

1. Did FERC's series of tax orders impact the investment climate? If so, how?
2. What are your thoughts on how FERC should go about releasing its market-moving orders?
3. Do you have any thoughts on how FERC should decide in advance whether a contemplated order will be market moving?

Mr. Murchie's Answer to Senator Murkowski's Question 3:

Did FERC's series of tax orders impact the investment climate? If so, how?

Markets don't like uncertainty or surprises. FERC's revised policy statement that eliminated recovery of income taxes in tariffs of pipelines held in publicly traded partnerships (more commonly known as master limited partnerships or MLPs) was a shock to the market. March 15 was a bad day for anyone invested in regulated pipeline assets, and the portfolios advised by my company, Energy Income Partners, were no exception. About fourteen billion dollars of market value was lost in one day but the losses were concentrated in the equity prices of four companies. These four companies (all publicly traded partnerships that are heavily dependent on FERC regulated pipelines), suffered an average loss of about 37% over the subsequent two and a half months as the companies communicated the impact on earnings and markets absorbed the news[4]. For these 4 companies this 37% loss in market value amounted to nearly $8 billion.

The largest cost of a pipeline or power transmission system is not the operating cost, it's the capital cost. That capital cost is, in turn, heavily dependent on stability and predictability of earnings. As discussed in my written testimony, the cost of financing and the level of risk

[4] Source: Bloomberg. The four companies are Enbridge Energy Partners LP, TC Pipelines LP, Spectra Energy Partners LP and Dominion Energy Midstream Partners LP, price change and loss in market value is from March 14, 2018 to May 31, 2018.

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perceived with a given business activity or investment are positively correlated. FERC has for many years been viewed as a stable, transparent, and largely apolitical regulator, all of which translate into a relatively low level of investment risk. FERC's policy changes, even those viewed by markets as less favorable, have always been carefully constructed through an open and inclusive process. The Commission's actions on March 15 were, in our view, seen by the capital markets as an abrupt departure from that process.

The form and substance of the policy change were a negative surprise on several fronts. One, while FERC had previously issued a notice of inquiry on tax policy, the matter had been dormant since the prior administration. Two, past practice would suggest that the most comprehensive reform of U.S. tax law in over three decades would have at least afforded the opportunity for further discovery and commentary. There was none. Three, the D.C. Circuit Court's remand of the roughly 20-year old MLP tax policy issue was not viewed by investors as an outright repudiation of Commission policy, but a demand for justification. The commentary submitted to the Commission by interested parties subsequent to the March 15 ruling are a compendium of issues that should have been hashed out in public hearings prior to the issue of any new policy statement. Instead, at a stroke, twenty years of accepted practice were swept away, leaving uncertainty in its place.

What are your thoughts on how FERC should go about releasing its market-moving orders?

We believe the market's reaction was driven as much by the way the announcement was made as by the substance of the policy change itself. The announcement was made during market hours, suggesting indifference or a lack of understanding of its potential impact on share prices in the market. In our experience, material and potentially market-moving information is best released via major news outlets and via a company or agency's website simultaneously and in the morning hours before financial markets open for trading.

Do you have any thoughts on how FERC should decide in advance whether a contemplated order will be market moving?

FERC is not new to the handling and dissemination of sensitive and potentially market-moving information. The potential unintended or untimely release of confidential information likely precludes most third-party consultation as well as widespread discussion of sensitive matters within agency walls. In our view, the experience and institutional knowledge of Staff should guide new and inexperienced Commissioners in this realm. As I further noted in my July 12 answer to the Chairman's question regarding desirable qualifications in a Commissioner nominee, I would re-emphasize that familiarity with the functioning of capital markets would inform the formulation as well as the dissemination of sound regulatory policy.

My firm and I appreciate the opportunity to provide an investor's perspective to policy makers overseeing FERC and we hope this might improve outcomes in the future for all stakeholders.

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In a similar vein, FERC and its constituents might also benefit by soliciting investor input to make sure the cost of financing is considered as part of their notices of inquiry and proposed rulemaking processes.

Questions from Senator Joe Manchin III

<u>Question 1</u>: Increased shale gas production is driving the expansion of energy infrastructure. Industry projections show a need for additional capacity of natural gas pipelines to meet projected market demand. One industry analysis estimates 26,000 miles of new natural gas pipelines between now and 2035. And 24,000 miles of transmission pipeline has been built since 2014. As you discussed in your testimony, electric transmission spending has increased slightly over the last few years. In 2016, utilities spent $35 billion on transmission expenditures and new investments made up 61 percent of that total.

Do you feel the expansion of transmission has kept pace with the expansion of natural gas pipeline infrastructure? If so, is that because of the differences in authority FERC has over pipelines and electric transmission?

<u>Mr. Murchie's Answer to Senator Manchin III's Question 1:</u>

As discussed in my answer to Question 1 from Senator Murkowski, the mix of competitive and regulated structures generally does a good job of balancing supply and demand. If there is a lack of infrastructure capacity, it is reflected in the price of natural gas, electricity, or both. New England is a good example; the retirement of older coal and nuclear generation has made the region much more dependent on natural gas to generate electricity, but as discussed in my answer to Chairman Murkowski's second question above, gas pipeline capacity cannot meet heating and generation demand during peak periods, forcing generators to rely on more costly oil-based fuels. As a result, New England consumers pay some of the highest prices for electricity and natural gas in the nation[5].

The industry has attempted to respond to these price signals with proposed new natural gas pipeline projects into New England, but these have failed due to a lack of creditworthy counterparties willing to sign long-term contracts, local opposition to new pipeline development, or both. While the Natural Gas Act does give FERC siting authority for gas pipelines, forcing a new pipeline on the region would likely be met with staunch local opposition that a prudent pipeline operator would likely be loath to challenge. Siting of electric transmission and distribution infrastructure falls under state, not federal, jurisdiction, and state opposition has

[5] Source: U.S. Energy Information Administration, State Electricity Profiles, January 2018

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effectively blocked a new electric transmission line into the region. So, the while the industry has proposed infrastructure solutions to ease New England's energy shortages, it is at the state and local—not the federal—level that they have been stopped.

Each year FERC releases a staff report that analyzes transmission metrics in order identify imbalances in the transmission system relative to supply and demand for power. That report relies, in part, on regional market prices in order to identify mismatches between supply and demand. Independent System Operators (ISOs) and their members conduct similar studies. Again, the blend of competitive market forces combined with informed regulation of natural monopoly infrastructure has worked, in our view, exceptionally well in balancing supply and demand for infrastructure while also balancing the interests of the public, consumers and investors who finance this infrastructure. This is not to say there are no areas where supply and demand imbalances exist. But so long as they are measured, and the data made available to all stakeholders, the combination of state regulated utilities that have an obligation to serve, state public utility commissions, regional ISOs and FERC have, in our view, sufficient tools to add appropriate levels of infrastructure.

Question 2: What is the biggest obstacle to increasing transmission infrastructure? Is it FERC Order 1000?

Mr. Murchie's Answer to Senator Manchin III's Question 2:

As discussed above, we believe the largest obstacle to increasing all energy infrastructure is local opposition due to the real or perceived impacts the new project will have on local residents, perhaps emboldened by national special interest groups opposed to any and all energy development that use local regulations as a tool to block development. The Northern Pass high voltage DC transmission proposal is a good example; its source of electricity would be non-emitting hydro power generated in Canada, consistent with the stated objectives of many who advocate reducing dependence on fossil fuels. Local opposition to siting a new transmission line ultimately blocked the project[6].

A secondary obstacle is continued uncertainty about the allowed rates of return on electricity transmission projects. Equity returns are based on security prices for a narrow set of publicly traded energy infrastructure companies (rather than equity markets as a whole) and interest rates at the time the project is approved despite the project having an economic life of over 40 years. Investors committing capital to publicly traded electric utility companies have other options in the capital markets. Allowed ROEs need to recognize this competition for capital from other industry sectors while being less vulnerable to short term capital market fluctuations. Since 2006, FERC has allowed enhanced equity returns to incentivize the development of new electric

[6] Source; Eversource Energy Investor Presentations, New Hampshire Public Radio website

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transmission under the purview of independent regional transmission organizations (RTO). Those incentives have worked; investment in electric transmission grew at a 10.2% compound annual growth rate between 2006 and 2018, roughly double the growth rate over the nine years preceding FERC's 2006 order[7]. However, incentives and overall equity returns for electric transmission are being called into question. Financial markets respond to uncertainty and risk by charging more for capital.

Question 3: One of the major criticisms I hear from folks in my state that oppose various pipelines and other energy infrastructure is that the FERC and associated permitting agency processes do not allow for enough public engagement. As you know, there are several major pipelines being developed in the mid-Atlantic and Northeast – several in my state. I support the environmentally responsible development of energy infrastructure as long as that development includes public engagement – particularly for landowners along the pipeline route. As Governor, I found that when owners and communities were "dealt in", they were more likely to become partners in the process.

How do you suggest improving opportunities for the public to get a better opportunity to be heard and for comments to be registered while not sacrificing an efficient and timely permitting process?

Mr. Murchie's Answer to Senator Manchin III's Question 3:

As discussed in my answer to Question 1 from Senator Murkowski, our view is that local support is critical for successful development of new infrastructure, and that the industry needs to do more to engage its opponents and tell its side of the story. Well-run companies make sure the local interests are "dealt in" in a number of ways. Pipeline operator Williams, for example, has had success because of their attention to local concerns. In the case of one pipeline in Pennsylvania, the company engaged 35 Native American tribes to determine locations of cultural significance while also working with the Pennsylvania Historic Museum Commission to ensure that no prehistoric archaeological deposits existed within the construction footprint. Williams also funded a program to sustain and improve stewardship of natural resources in a northern Pennsylvania county.

Impact fees paid by real estate developers to counties and municipalities to compensate for costs the new development incurs on local traffic, additional sewer and water facilities, etc. provide an example of a more direct way of "dealing in" local communities. However, such a mechanism applied to regulated pipelines and electric transmission risks allocating these costs to energy

[7] Source; U.S. Energy Information Administration, FERC Order 679

consumers in different states, effectively creating an unintended tax on interstate commerce. It also risks providing another avenue for interest groups determined to "leave it in the ground" to kill a project with fees and taxes.

Question 4: In your comments regarding the 1999 FERC review, will you be looking at ways to enhance the role of the public? Ensure landowners are appropriately compensated and – if not – seek ways to improve that?

Mr. Murchie's Answer to Senator Manchin III's Question 4:

We have not submitted any comments to FERC regarding the NOI concerning the 1999 policy review. Nonetheless, as noted in our prior answers, we believe the process needs to increase public engagement and participation as a broader strategy to address opposition to infrastructure development. We have no expertise in compensation levels for land taken under eminent domain.

Questions from Senator Catherine Cortez Masto

Questions: Energy infrastructure can sometimes contribute to local economies even more directly than other large infrastructure projects through competitive rates and operation as a business partner – what is the best way that the federal government can engage with local governments and encourage local investment?

A. What alternatives can the federal government consider to encourage growth and local project development rather than walking back regulations more broadly?

Mr. Murchie's Answer to Senator Cortez Masto's Question:

As investors we find comfort in the governance of federal regulatory bodies provided by the Administrative Procedures Act. FERC follows its legislative mandate to balance the interests of all parties in determining the need for new infrastructure projects. To the extent evidence of the economic benefits and costs to local communities are made available as part of the public record, FERC is bound by law to consider those factors. As discussed in my answer to Chairman Murkowski's first question above, we believe that broader and more robust dissemination of a proposed infrastructure project's societal benefits as well as costs would better inform the discussion and potentially cut through intractable partisan division that continues to frustrate the development of needed and mutually beneficial infrastructure.

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Questions from Senator Shelley Moore Capito

Question 1: The Utica and Marcellus shale plays under production in West Virginia contain significant quantities of natural gas liquids (NGLs) such as ethane. Stakeholders are looking into creating a natural gas liquids storage hub to facilitate a regional market for NGLs and downstream processing and manufacturing in Central Appalachia. I believe that the economic benefits of this downstream economic opportunity is certainly within the "national interest" but may be outside the current analyses of FERC certificate reviews. The case is similar to the indirect economic and foreign policy benefits from the export of liquid natural gas (LNG) that may not be appropriately reflected by the current regulatory procedures of the Commission.

As FERC considers reopening the 1999 Pipeline Policy Statement, do you believe that it would be appropriate for FERC to promote a more expansive national interest analysis into the benefits of downstream NGL processing and LNG exports in its certificate reviews for relevant project applications? Is this something FERC is currently doing and, if so, are these benefits weighted appropriately in these reviews? Does FERC have adequate policy tools, personnel, and resources necessary for reviewing applications for projects related to serving NGL storage, processing, and downstream manufacturing? How about for LNG export terminals?

Mr. Murchie's Answer to Senator Capito's Question 1:

As investors in energy infrastructure, we do not see a market failure in the area of NGL separation, fractionation and storage as these are competitive markets. FERC does have jurisdiction over interstate NGL transportation via pipeline. Unlike natural gas (methane) which can only be transported economically via pipeline, NGLs can be transported via truck, rail and barge, making this a competitive market. FERC generally allows competitive markets to work where no natural monopolies exist. If Congress determines that the benefits of NGL infrastructure development other than interstate pipelines is in the national interest and therefore requires additional incentives, then we believe it would be necessary to pass new legislation. Numerous businesses in the U.S. provide benefits that are in the national interest, but absent a market failure, we do not see the need for government intervention.

That said, as we have discussed at length in answers to other questions above, the more comprehensive the consideration of costs and benefits of new energy infrastructure, the better. Based on the language from the *Sabal Trail* opinion (quoted above), the courts seem to share this view with respect to the costs and benefits FERC should consider when approving new projects. Whether FERC has at its disposal adequate staff and resources to conduct this analysis is not something we feel qualified to answer.

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Question 2: In your testimony, you cited Germany's *Energiewende* ("Energy Transition") as an example of how government policies mandating the use of renewable energy sources beyond what the market can bear have driven up costs for industry and consumers, while creating uncertainty about electric reliability. Australia has undergone a similar policy failure that has led to rolling blackouts and I am concerned that New England – unable to secure additional natural gas pipelines (thanks to New York's abuse of its Clean Water Act Section 401 authority) nor transmission lines from Canadian hydropower – may face similar challenges due to ill-gotten energy policies.

Can you please elaborate on your testimony on the German experience and compare and contrast it and other international examples with our domestic energy policy, particularly as relates to the situation New England?

Mr. Murchie's Answer to Senator Capito's Question 2:

Our testimony referenced Germany's experience with Energiewende to illustrate the risks of policies that prescribe *solutions* rather than policy *objectives*. In our verbal testimony we discussed the need to identify market failures as justification for regulatory intervention in a manner that ultimately leads to public acceptance of new infrastructure. Since most would agree - ourselves included - that a reliable energy infrastructure system is a public good, there are numerous indicators of potential market failures that might call for intervention. Among these are reliability, diversity of supply and mitigation of environmental externalities, all of which are embodied in the challenges facing the New England region.

Germany's approach to the externalities of carbon pollution and public opposition to nuclear power was to mandate a generation mix dominated by renewable energy and attendant high voltage transmission to integrate it with the existing grid infrastructure. While nuclear opposition may have proven an insurmountable challenge, a shift to lower carbon energy could have been incentivized through the setting of national GHG emission reduction targets to which the market could have responded with the lowest cost solution. The U.S. experience with cap-and-trade in mitigating emissions of sulfur dioxide and nitrous oxide emissions, for example, is viewed by most, including ourselves, as a successful policy.

By similar logic, if the U.S. were to set targets for GHG emissions, the market could meet those objectives at the lowest cost and without the politicization and waste that attends governmental policies that predetermine solutions rather than policy objectives (so called picking of winners and losers). For example, market responses might include a combination of increased natural gas usage to displace coal while providing cheaper back up power for intermittent renewables. Firm GHG targets would also provide for economic competition between battery storage and natural gas fired power as backup providers to intermittent solar and wind generation.

Our criticism of the current U.S. approach to GHG emissions is that it is not comprehensive. Narrowly defining a new natural gas pipeline's GHG contribution without a concomitant recognition of that project's attendant offset of more environmentally harmful fuels, coupled with the facilitation of increased renewable penetration tilts the U.S. toward the German approach of pre-determined solutions (picking winners) rather than setting objectives and allowing the market to meet them with optimal economic efficiency. Worse, the debate over measuring GHG impact of new natural gas pipelines appears to observers outside Washington to have created a party-line split within FERC, potentially injecting partisan rancor into what has historically been a balanced, transparent, and apolitical regulatory process. This in turn risks driving capital away (or at least making it more costly) as investors see the four-year election cycle as a substantial risk to the business plans of publicly traded energy infrastructure companies while squandering the opportunity to achieve the true objective—the reduction of emissions of GHGs, sulfur dioxide, nitrous oxides, mercury, etc. to the benefit of all.

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Questions from Chairman Lisa Murkowski

Question 1: Over the past few years, it has become increasingly clear that this nation is facing a fundamental choice when it comes to energy policy. Down one path is a hard-edged effort to stop using fossil fuels altogether, and down the other is the continuation of our existing policy of supporting ever cleaner forms of energy, while ensuring that energy is still affordable.

- Please describe the political and regulatory risks that needed transmission facilities will not be built over the next ten years.

  RESPONSE: There are divergent views about whether enough transmission is being proposed or built, whether we are building the "right" transmission facilities, and what the Nation's transmission systems must become in the next quarter century to support the changing economy and an evolving resource base. Regardless of which path the industry takes, transmission will be the low-cost, fuel neutral solution to the technological and operational challenges posed by an economy that will become significantly more reliant on electric power in the coming decades. Given the length of time typically required for planning, permitting, siting, and construction of these facilities, and the fact that they will support and benefit society for up to a half century once installed, the risks posed by delay, underinvestment, or increased capital costs are considerable. Failure to address those risks can have significant consequences, including diminished system reliability, an electric system less able to cope with extreme weather and cyber or physical attacks, failure to integrate resources such as wind and solar power, and a system incapable of integrating and deploying new emerging technologies, including distributed energy resources.

  Without a longer term perspective, regulators and policy makers may presume that it is sufficient to plan transmission upgrades or expansions incrementally, with a principal focus on immediate reliability needs, or the next generator requiring interconnection. To be clear, transmission investment must be sufficient to address near-term demands on the system, replace aging facilities, upgrade technology and, in addition, provide significant customer benefits over time.[1] However, an emphasis on investing exclusively to meet reliability needs misses an important opportunity to plan proactively for the more demanding electric economy that is emerging. Just-in-time cannot be our only mode of transmission planning if the objective is a truly modern grid. Such an approach will be less efficient and much more costly for consumers in the long run. The high-voltage grid is becoming a more integrated, multi-jurisdictional, multi-benefit network asset than originally designed. Robust energy delivery infrastructure preserves our ability to improve the development and scale of markets, access diverse low-cost resources, and

[1] For example, transmission expansion in New England that was undertaken primarily to enhance reliability in the region has also saved customers billions of dollars in energy costs. This expansion has resulted in over $5 billion in aggregate reductions in congestion charges and out-of-market payments to generators, with additional such savings of more than $600 million per year expected going forward.

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deploy new technologies. The risks inherent in a lack of infrastructure in this case are obsolescence, lack of economic growth, increased costs to consumers, and less reliable service.

- In your view, what are the best ways to ensure that these risks do not materialize?

  RESPONSE: The proactive transmission planning that meets the needs of the changing environment for electric power should depend more heavily on scenario-based analysis, explicitly consider uncertainties faced by the industry, and evaluate a range of options, probabilities, and all important transmission benefits. However, this requires robust dialogue among stakeholders, including industry, FERC, and state policy makers and regulators. Without a shared vision, common objectives, and a strategic approach, such collaboration is destined to be prolonged and frustrating, and potentially overtaken by events as the economy becomes more highly electricity-driven. As pressures for economic efficiency, resource diversity, and larger markets for power accelerate grid integration across regions, the need for policy leadership and shared approaches to satisfying infrastructure needs will become imperative.

  Currently, there does not appear to exist a shared vision of the future grid. Proactive planning may therefore seem an elusive goal. Nevertheless, it is a worthwhile pursuit that is informed by the important ongoing work by the National Renewable Energy Laboratory, the Electric Power Research Institute, The National Academy of Science, The Brattle Group (with WIRES), and other organizations that are developing roadmaps to that future grid. Moreover, a practical grid modernization goal – an integrated North American grid, for example – can be made more achievable, timely, and consistent with environmental protections if policy makers come to terms with, and address, the costs and inefficiencies associated with the disparate laws and policies that govern the heavily regulated transmission sector today. The FAST Act is a modest but insufficient step in that direction at the federal level.

- Shouldn't FERC Commissioners be equally receptive to needed transmission infrastructure regardless of the political party of the person holding the Office of the President of the United States?

  RESPONSE: Absolutely. Modernizing and expanding energy delivery infrastructure should be a bipartisan objective. Success in the undertaking will affect customers in all states, markets, and economic or social strata. In a word, the transmission grid is a public good, although most often built with private capital. Over the course of my career in energy regulation, which spans several Administrations, the Commission has consistently made decisions based on the economic and environmental merits of a project or rate proposal. The transmission grid is agnostic about the source of electric generation that it delivers across the system. It supports competitive markets in which all fuels and suppliers of energy can participate. In this way, transmission furnishes consumers with the most beneficial products that markets have to offer at the best price. To accomplish

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this, regulators must contribute to a stable and predictable investment climate that is not especially subject to the vicissitudes of politics.

- During the eight years of the Obama Administration, FERC's policies resulted in significant investment into needed transmission infrastructure— is now the time for Commissioners at FERC to be considering major changes that could discourage needed infrastructure?

  RESPONSE: No. Energy delivery infrastructure investment remains a priority. Regulators should always hesitate to simply reverse course or intrude in the market's decision making when investors are filling an apparent need for improved infrastructure. The industry has made solid progress in the past decade, reversing a quarter century of grid underinvestment and achieving higher levels of service reliability. However, challenges remain. Resilience is more important now than ever and the system still operates with aging and outmoded components and facilities. New resources cannot be further developed because of a lack of transmission capacity. Threats to control and operation of the system are among emerging challenges to a modern grid. Equally important, because the drivers of transmission investment are in flux, project development is as risky and challenging as ever.

  In sum, it would be bad policy and worse economics to undertake major changes that could discourage the development of needed infrastructure. Speaking for WIRES, I believe that changes to some of the Commission's existing policies would encourage beneficial infrastructure. First, the Commission can bring needed certainty by ending policies that create protracted litigation over regulated rates of return. Second, FERC should be open to improving the administration of incentives affecting transmission investment. Third, the Commission can consider addressing interregional planning under Order No. 1000 in an effort to further strengthen and integrate the Nation's grid. Finally, continued Congressional oversight of FERC's transmission policies is crucial to ensure new challenges such as the need for system resilience, the electrification of the economy, and the rapidly shifting generation fleet are proactively addressed.

Question 2: Since consumers of energy should not be paying for wasteful overbuilding of pipeline and transmission infrastructure, FERC has policies to ensure that the network does not become "gold plated." But, at the same time, pipeline and transmission networks should not become outdated, unreliable, and insufficient to meet demand.

- On a one to ten scale, with one being a failing delivery network, and ten being an excessive, or "gold-plated" network, what do you think of today's pipeline and transmission networks?

  RESPONSE: Our electricity delivery infrastructure today is, in general, neither failing nor excessive. The bulk power system is working under current conditions, although there are often wide disparities in the price of power, changing sources of electrical

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generation and available fuels, and competing operating models and regimes among companies in the electricity industry. The D+ rating handed to our electric system in 2017 because of supply, security, and reliability concerns (American Society of Civil Engineers) is worrisome. Therefore, consumers should always want balance in regulatory decisions involving new transmission upgrades or expansions. They will want decisions that never obligate them to pay for transmission that is excess to the functions of the network or that do not deliver the benefits that they, their city, or region expect to obtain from investment in modern, robust transmission. Consumers want and deserve just and reasonable rates for investments that deliver real benefits. .

I believe that today's transmission network is vastly improved from the 1990s and is meeting the needs of the bulk power market economically. It is meeting reliability needs and delivering power where needed. In the existing regulatory environment, overbuilding is not a risk for several reasons. First, this sector is subject to many well-established state and regional planning and stakeholder processes. In fact, when regional transmission organizations formulate transmission plans, they analyze a range of factors (*e.g.*, transmission and generation additions or significant changes in demand) to ensure that their systems comply with applicable planning standards. Where RTOs do not exist, there is still state and regional integrated resource planning. Second, I believe that, intentionally or not, the U.S. is in the process of creating an integrated network of transmission that will ultimately provide the flexibility and innovation that the outdated "generation to load" planning concept cannot produce. However, we are doing so increment-by-increment, often without a shared vision of what will be required of the system to serve consumers cost-effectively, reliably, and safely in the future. I submit that the changes underway in the economy and in this industry indicate that transmission must be planned today to meet the foreseeable and probable requirements of the electrified economy as it will exist 10, 20, 30 years from now when those investments are in the middle of their useful lives. Unlike transmission investments historically driven only by reliability concerns and built primarily to serve identifiable or local loads for the foreseeable future, transmission investments proposed today must be planned as part of a larger network to serve generations of consumers and businesses, reach entirely new resources, meet the challenges of extreme weather, accommodate major economic changes, and support emerging technologies. It would be unwise and even imprudent for more far-sighted planning to be stigmatized as "gold-plating" so long as the benefits are demonstrable.

- On that same one to ten scale, where do you think the networks will need to be five years from now? What are the leading risks that could derail this result?

RESPONSE: Five years from now, consumers may not notice a great difference in the reliability or cost of electric power. But the transmission grid will need to add new capabilities and become more flexible in response to changing needs and public policy requirements if we are to maintain seamless service in the face of those increasing demands. It is timely to ask about transmission's role in an increasingly distributed energy environment. In many respects, it will continue to be the linchpin of the modern system and it must be capable of adapting to the operational challenges and benefits of integrating an array of resources – everything from rooftop solar and micro-grids to new storage technologies and electric generating facilities in new advantageous locations. Uncertainties associated with the future cost of capital make this a propitious time in which to make major infrastructure investments. If industry and policy makers continue to recognize and act upon the need to plan and invest for the future, I expect the transmission network could be stronger in five years than it is today.

Question from Ranking Member Maria Cantwell

Question: The Tax Cuts and Jobs Act of 2017 did not address the lack of a refund authority in section 5 of the Natural Gas Act for taxes overcollected by natural gas pipelines. Unlike the Federal Power Act, the Natural Gas Act does not authorize FERC to refund consumers when FERC-regulated companies overcharge them. With the new lower corporate tax rate, pipelines may be receiving a giant windfall at the expense of shippers and consumers across the nation.

While FERC has exercised the limited authority available to avoid this problem, including a notice of proposed rulemaking and a notice of inquiry, this action contrasts starkly with the show-cause orders issued to electric utilities whose transmission tariffs still reference the higher tax rate.

Before the new tax law was enacted, gas consumers like the American Public Gas Association had already estimated pipelines were over-collecting about $600 million each year. That number could be much higher now. For example, the Process Gas Consumers Group and American Forest & Paper Association commissioned a study recently that estimated that 20 of the largest interstate pipelines have received a $726 million annual windfall from excess accumulated deferred income taxes due solely to the change in the corporate tax rate.

Is there any sound policy reason that Congress shouldn't establish refund authority in the Natural Gas Act similar to what already exists in the Federal Power Act?

RESPONSE: My testimony and the mission of the WIRES organization that I represent focus principally on the electric transmission sector and its obligations under the Federal Power Act and various state and federal laws and regulations. Although the economics and vitality of the electric power industry are heavily influenced by the price and availability of natural gas for electric generation purposes, the natural gas and electricity delivery networks are authorized, planned, and operated very differently. For example, the electric transmission sector does not have the benefit of having to seek only a single agency's public interest determination regarding proposed new facilities equivalent to FERC's certificate authority under the NGA. This may help account for a regulatory approval timeline that can be three to five times longer than for pipelines under the NGA in many cases. I have no opinion on the tax issue outlined above, however.

Question from Senator Debbie Stabenow

Question: According to the National Renewable Energy Laboratory, the adoption of electric vehicles could increase electricity demand by as much as 38 percent.

We in Michigan are excited to be a leader in vehicle electrification – an effort that will improve vehicle efficiency and cost savings, while lowering emissions and protecting the environment and public health. This year, Ford announced an $11 billion investment to introduce 40 hybrid and fully electric vehicles by 2022, and GM is working towards a zero-emissions future with the introduction of at least 20 new all-electric models by 2023. Michigan's largest electric utilities, DTE and Consumers Energy, are also contributing to this effort through exciting pilot programs that will offer rebates for EV charging infrastructure.

The large-scale deployment and commercial viability of electric vehicles is dependent on a robust network of charging infrastructure – on public roads, commercial buildings, and private residencies.

As a former FERC chairman, what actions can lawmakers and regulators – at the federal, state, and regional levels – take to help increase electric charging infrastructure needed for mass adoption of electric vehicles?

RESPONSE: The electrification of the transportation industry – so-called eMobility – could result in major increases in electricity demand in the coming years, a change from relatively flat demand for electricity in recent years that was attributable to factors like energy efficiency and recessionary pressures. Demand growth will affect both the distribution and transmission sectors. It will be important to take a fresh look at the need for transmission level enhancements to support long-haul charging and fleet applications that may make new transmission infrastructure investment necessary.

Regulators and policy makers should be prepared to support the work of RTOs and other planning entities in proactively anticipating changes in customer demand from electric vehicles, electrical heating, and other new sources of demand. This Committee can help ensure that, under FERC's guidance, the RTOs and other entities plan for the kinds of changes that electrification could entail. The federal government should consider policies that will allow transmission providers and wholesale markets to pursue "make-ready" investments in the transmission grid to support fast charging installations. Because of its authority over the plans and rates for transmission of electricity in interstate commerce, FERC may face a new policy imperative in helping to speed and also oversee the deployment of electric vehicles.

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Questions from Senator Joe Manchin III

Question 1: Increased shale gas production is driving the expansion of energy infrastructure. Industry projections show a need for additional capacity of natural gas pipelines to meet projected market demand. One industry analysis estimates 26,000 miles of new natural gas pipelines between now and 2035. And 24,000 miles of transmission pipeline has been built since 2014. As you discussed in your testimony, electric transmission spending has increased slightly over the last few years. In 2016, utilities spent $35 billion on transmission expenditures and new investments made up 61 percent of that total.

Do you feel the expansion of transmission has kept pace with the expansion of natural gas pipeline infrastructure? If so, is that because of the differences in authority FERC has over pipelines and electric transmission?

> **RESPONSE:** The pace of improvement and development in these two delivery networks are seldom measured in relation to one another. While investment in both electric and gas delivery networks has increased in the past decade, it is important to recognize the differences in how natural gas and electric transmission infrastructure is planned, financed, and permitted. For example, in most of the country, electric transmission expansion is planned by a regional grid management entity that addresses reliability, economic, and public policy needs and allocates costs regionally to beneficiaries of the new investment. There is no equivalent planning process applicable to interstate natural gas pipelines, which are developed in response to commitments from specific entities that contract for all or a part of the pipeline's capacity. With respect to permitting, FERC is authorized to issue certificates of public convenience and necessity for the construction or upgrade of interstate natural gas pipelines, including facilities siting and environmental reviews. It does not have similar authority for electric transmission. In sum, the regulatory review and approval processes for transmission expansions and upgrades is distinctly different than for pipeline development. From that, I conclude that the pace of transmission planning, permitting, and development is likely to lag behind similar timelines for pipeline projects.

Question 2: What is the biggest obstacle to increasing transmission infrastructure? Is it FERC Order 1000?

> **RESPONSE**: There are two significant barriers to efficient transmission development. The first is a lack of policy certainty that accounts for the future demands on grid operations, combined with a tendency to default to just-in-time planning when consensus about the need for investment cannot be achieved. In addition, I believe that the continued lack of coordination and joint purpose between state and federal regulatory authorities and among the important environmental approval procedures needed at several levels of government constitute a barrier to a stronger transmission grid. In light of these, we cannot reasonably attribute transmission's challenges solely to Order No.

1000. Order No. 1000 helped make clear the breadth of FERC's authority over the planning of the transmission grid, and its requirements that transmission be planned regionally to achieve certain goals and its costs allocated to beneficiaries within regions, are often undervalued innovations. Further, the Order directs planners to at least consider encouraging transmission across regional boundaries in the interest of greater efficiency, reliability, and fuel diversity. However, the lack of interregional projects is widely regarded as indicative of the Commission's failure to provide sufficient direction or specificity in Order No. 1000 about how the industry and its planners should achieve an more integrated and efficient grid, which I perceive as its principal goal. The elaborate RTO planning processes are sometimes discounted as mere bureaucracy that reinforces parochial preferences and procedures to the detriment of timely transmission expansion, and these criticisms are not without merit. However, the central purposes of Order No. 1000 remain valid and in the public interest. After over seven years of implementation, it may be time for the Commission to decide whether selected improvements in the Order No. 1000 regime would encourage greater grid integration, grid resilience, and the anticipated economic benefits.

Question 3: One of the major criticisms I hear from folks in my state that oppose various pipelines and other energy infrastructure is that the FERC and associated permitting agency processes do not allow for enough public engagement. As you know, there are several major pipelines being developed in the mid-Atlantic and Northeast – several in my state. I support the environmentally responsible development of energy infrastructure as long as that development includes public engagement – particularly for landowners along the pipeline route. As Governor, I found that when owners and communities were "dealt in", they were more likely to become partners in the process.

How do you suggest improving opportunities for the public to get a better opportunity to be heard and for comments to be registered while not sacrificing an efficient and timely permitting process?

RESPONSE: The solicitation of public input into decision making about infrastructure development has become a necessity in modern regulatory approval processes. I agree that all stakeholders must be afforded opportunities to express views on proposed infrastructure that typically have important land use implications in addition to local economic and employment benefits. Based on my experience at the Commission, including as the proponent of the 1999 Statement of Policy on pipeline certificate reviews, regulators are both prudent and effective when they deal openly with the concerns of affected parties. My testimony for WIRES focuses principally on the electric transmission sector; and I offer no opinion on changes to the permitting processes for interstate natural gas pipelines.

Question 4: In your comments regarding the 1999 FERC review, will you be looking at ways to enhance the role of the public? Ensure landowners are appropriately compensated and – if not – seek ways to improve that?

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RESPONSE: Although the 1999 Statement of Policy regarding pipeline certificate review processes was adopted under my leadership at FERC, I have not formulated a view about its continuing relevance or appropriateness today. I am not able to conclude whether the adequacy of public procedures and opportunities for comment, however important they may be, should be considered in the pending FERC reassessment of the 1999 Statement of Policy.

Questions from Senator Catherine Cortez Masto

Question 1: Your testimony states that electricity consumers pay $4 billion each year in congestion costs, because transmission lines throughout the country are unable to transfer power according to local needs. What steps can we take in Congress to reduce these costs?

RESPONSE: Generally speaking, the solution to congestion is enhanced transmission capacity and related technological improvements. While congestion cannot be eliminated entirely, robust transmission paths between multiple resources and loads will reduce congestion costs, which are now about half of the costs of a decade ago. Congress must therefore continue its oversight of the Commission's policies affecting transmission investment and the ability of infrastructure to attract capital for further grid expansions and upgrades. In fact, well-planned transmission provides an array of economic, environmental, and operational benefits, and acts as a powerful way to save tens of billions of dollars, as demonstrated in WIRES' published studies.[2] It is noteworthy that overall electricity prices for consumers are declining and constitute only between one and two percent of the average American cost of living, *despite* the major transmission build-out that has occurred in most regions over the last decade. To ensure these trends continue, regulators must ensure that transmission planning fully accounts for both the costs and all of the benefits of transmission investment, including those benefits that are often not considered.

Question 2: You also mentioned that transmission facilities are often inadequate or non-existent in regions that have great potential to produce cost-competitive renewable energy and natural gas generation. Can you elaborate further on the location of these regions, and the challenges these areas face that keep them from utilizing more competitive and efficient energy resources?

RESPONSE: The expansion and integration of long-line transmission has become critically important in the wake of sweeping changes in the Nation's fuel mix for electric generation. Today we have major natural gas resources coming on line in regions of the country where these reserves were all but unrecognized until recently. Equally important,

[2] *See, e.g.*, Pfeifenberger and Chang (The Brattle Group), *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning Is Key To the Transition To A Carbon-Constrained Future*, June 2016, found at www.wiresgroup.com .

the vast wind and solar resources located mid-country and in the Southwest (OK, KS, WY, NE, CO, UT, NM, ND, SD, NV) are often landlocked because the existing grid lacks the capability to move these resources to distant energy-hungry markets. However, current regulatory models and just-in-time transmission planning have not supported building transmission in advance of large-scale renewable energy projects. A robust transmission system, properly planned, can optimize generation resource development and thus lower the cost of delivered energy to consumers. "Right-sizing" transmission projects or including expandability to support future renewable and natural gas generation requirements is prudent and will prove economically efficient over the long term. Finally, it is important to note that transmission of these resources to markets will entail construction of infrastructure across more than one state. Because transmission siting and permitting resides largely with state authorities, or often with federal land agencies in the West, the lack of coordination and differences in applicable laws and policies tend to delay the larger clean energy projects significantly, or thwart them altogether.

Question 3: Energy infrastructure can sometimes contribute to local economies even more directly than other large infrastructure projects through competitive rates and operation as a business partner – what is the best way that the federal government can engage with local governments and encourage local investment?

RESPONSE: Investment in transmission infrastructure is a productive near-term and long-term economic development strategy. For every $1 billion of U.S. transmission investment, approximately 13,000 full-time-equivalent ("FTE") years of employment and $2.4 billion of total economic activity are created. If U.S. investments in the transmission grid were sustained at between $12 billion and $16 billion annually (a low number by recent standards), this activity could directly and indirectly support 150,000 to 200,000 full-time jobs each year.[3] The federal government, through its regulatory and executive branch agencies can facilitate and even accelerate project development with these kinds of impacts. It will be necessary to partner with state governors, energy offices, and economic development organizations to devise workable plans about what local and regional communities need and how grid enhancements, including energy storage, microgrids, and distributed resources, fit into overall development plans. This is especially important for minority communities that are often bypassed by large infrastructure investments. That said, please note that improvements to electric generation and distribution may be a more appropriate way to approach local economic development issues in many cases.

[3] Pfeifenberger and Hou (The Brattle Group), *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada* (for WIRES), May 2011. While dated, the analysis remains a valid indicator of the economic value of projected investment through the direct (construction), indirect (supply chain and inter-industry commerce), and induced (spending on housing, food, clothing, and other services) effects of project construction. Also *see*, Frayer, et al., (London Economics International), *How Does Transmission Benefit You? Identifying and Measuring The Life Cycle Benefits of Infrastructure Investment* (for WIRES), January 2018.

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A. What alternatives can the federal government consider to encourage growth and local project development rather than walking back regulations more broadly?

RESPONSE: Because electric transmission is supported largely by private capital, the federal government's role in encouraging electric infrastructure is different from its role in ensuring adequate roads and bridges, although both are important public goods. Investment in infrastructure will promote the general welfare through jobs and commerce, as well as potential health and environmental benefits. Congress has a responsibility to ensure that the regulatory and policy prescriptions of the agencies to which it has delegated authority over private enterprises are pursuing economically and socially beneficial goals. In my view, that entails understanding the realities and vulnerabilities of the market, sensitivity to emerging environmental concerns, and openness to new technological developments. As a former regulator, I understand that undue regulation can frustrate innovation and productivity. Nevertheless, I also believe that the guidance that regulatory agencies provide can often offer a constructive and necessary way for economic activity to move forward. I need only cite the open access rules adopted by the FERC for the natural gas pipeline and electric transmission industries in the 1990s, which unleashed market forces, drove down energy prices, and permitted workably competitive energy markets to emerge, all to the benefit of consumers.

Responses to Post Hearing Questions for the Record

The Honorable Joseph T. Kelliher

Executive Vice President, Federal Regulatory Affairs

NextEra Energy, Inc.

Full Committee Hearing to Examine Interstate Delivery Networks for Natural Gas and Electricity

Thursday, July 12, 2018

Questions from Chairman Lisa Murkowski

Question 1: Over the past few years, it has become increasingly clear that this nation is facing a fundamental choice when it comes to energy policy. Down one path is a hard-edged effort to stop using fossil fuels altogether, and down the other is the continuation of our existing policy of supporting ever cleaner forms of energy, while ensuring that energy is still affordable.

- Please describe the political and regulatory risks that needed pipeline and LNG facilities will not be built over the next ten years.

Answer: The challenges facing pipeline and LNG facility development are significant, but the risks to the two project categories are different. The primary risks associated with pipeline development center on the siting process, the increased and unpredictable length of the siting process, the need in some cases to get multiple federal agency approvals, the risk of state denials of necessary permits issued under federally delegated authority, and the increased litigation risk challenging project approvals. Litigation risk has increased significantly in recent years, and now virtually every federal decision associated with a project is challenged in court by organized opposition groups. There is always some risk that federal or state authorizations will be denied on wholly political grounds and court decisions will be incorrectly decided. The challenges facing LNG projects are more economic in nature, reflecting the dynamics of both the U.S. and export gas markets, since the siting challenges are generally much lower than those facing pipelines. Anchor shippers reduce the risk of export projects. There is some risk that LNG export authorization will be denied on wholly political grounds.

- In your view, what are the best ways to ensure that these risks do not materialize?

Answer: I believe these risks are manageable as long as federal and state agencies are committed to timely and merits-based decisionmaking and federal courts follow the law and rely on the record. While I don't agree with every court decision on gas infrastructure projects, I believe the courts are trying to make merits-based decisions. Some project risks could be reduced through legislation to require federal agencies to be cooperating agencies in FERC's preparation of an environmental impact statement and prevent state abuse of federally delegated authority under Clean Water Act section 401.

- Shouldn't FERC Commissioners be equally receptive to needed energy infrastructure regardless of the political party of the person holding the Office of the President of the United States?

Answer: The U.S. Supreme Court held that "it is clear that the principal purpose of [the Federal Power Act and Natural Gas Act] was to encourage the orderly development of plentiful supplies of electricity and natural gas at reasonable prices." In my view, supporting electric and gas infrastructure development is a fundamental statutory duty of the Commission.

- During the eight years of the Obama Administration, FERC's policies resulted in significant investment into needed pipeline and transmission infrastructure—is now the time for Commissioners at FERC to be considering major changes that could discourage needed infrastructure?

Answer: Given increased concerns about the resiliency of our energy delivery systems and the evolving nature of threats to these networks, I believe there is a continued need for high levels of investment in the interstate power grid and natural gas pipeline network.

Question 2: Since consumers of energy should not be paying for wasteful overbuilding of pipeline and transmission infrastructure, FERC has policies to ensure that the network does not become "gold plated." But, at the same time, pipeline and transmission networks should not become outdated, unreliable, and insufficient to meet demand.

- On a one to ten scale, with one being a failing delivery network, and ten being an excessive, or "gold-plated" network, what do you think of today's pipeline and transmission networks?
- On that same one to ten scale, where do you think the networks will need to be five years from now? What are the leading risks that could derail this result?

Answer: On your scale, a 9 would represent a network that is resilient, fully meets customer needs, does not have persistent uneconomic constraints, but is not gold plated or excessive. Given the nature of the threats posed to our pipeline and transmission grid, five years from now both networks need to be at an 8 or 9. The networks are not at that level now. In my view, the gas pipeline network is generally more robust than the interstate electric transmission network on a national basis. But the power grids are regional rather than national networks, and the relative strength of the power grid and pipeline network would vary on a regional basis. The leading risks that threaten development of the energy delivery system our country needs are siting challenges and uncertainty regarding return on equity for large scale investments in electric transmission and natural gas pipelines.

Question from Ranking Member Maria Cantwell

Question: The Tax Cuts and Jobs Act of 2017 did not address the lack of a refund authority in section 5 of the Natural Gas Act for taxes overcollected by natural gas pipelines. Unlike the Federal Power Act, the Natural Gas Act does not authorize FERC to refund consumers when FERC-regulated companies overcharge them. With the new lower corporate tax rate, pipelines may be receiving a giant windfall at the expense of shippers and consumers across the nation.

While FERC has exercised the limited authority available to avoid this problem, including a notice of proposed rulemaking and a notice of inquiry, this action contrasts starkly with the show-cause orders issued to electric utilities whose transmission tariffs still reference the higher tax rate.

Before the new tax law was enacted, gas consumers like the American Public Gas Association had already estimated pipelines were over-collecting about $600 million each year. That number could be much higher now. For example, the Process Gas Consumers Group and American Forest & Paper Association commissioned a study recently that estimated that 20 of the largest interstate pipelines have received a $726 million annual windfall from excess accumulated deferred income taxes due solely to the change in the corporate tax rate.

Is there any sound policy reason that Congress shouldn't establish refund authority in the Natural Gas Act similar to what already exists in the Federal Power Act?

Answer: The strongest argument against legislation to revise the refund provisions of the Natural Gas Act to conform to the refund effective date in the Federal Power Act is based on the different risk profiles of investment in electric transmission and natural gas pipelines and the different relative importance of tariff versus contract rates. In general, investment in gas pipelines bears more risk than electric transmission. FERC policy encourages competition in natural gas transportation, there are relatively few captive gas markets, and pipelines aggressively compete with each other for new customers. Virtually all electric transmission service is provided under cost-based tariffs, while gas transportation is principally provided under contract. In general, cost recovery through tariff rates is more certain than through contract rates. An earlier refund effective date would be limited to gas transportation service provided under tariff rates rather than contract rates that govern most gas transportation.

Question from Senator Debbie Stabenow

Question: Thank you for your honest analysis on the challenges and opportunities for energy delivery networks. Many of the challenges you describe in your written testimony arise from the multitude of actors at play throughout the infrastructure permitting and development processes.

How can federal and state regulators more effectively oversee our nation's rapidly aging pipeline network to ensure our energy needs are met without jeopardizing the environment and public safety?

Answer: The Nation's approach towards pipeline safety has steadily strengthened over time and we have made strides towards improved safety. Effective cooperation between federal and state pipeline safety regulators is critical to the success of the safety program, since state pipeline safety personnel make up a majority of the federal and state inspection workforce. It is important that inspectors continuously share best practices, enhance communication, and raise awareness of new safety issues. The need for effective cooperation between federal and state pipeline safety regulators is reflected in pipeline safety laws that provide for state assumption of federal regulatory, inspection and enforcement responsibilities over intrastate pipelines upon federal certification. Other states can enter into agreements to undertake certain aspects of the intrastate pipeline safety program, and states play an important role in inspection of interstate gas pipelines. Nearly all states participate as partners in the pipeline safety program. The federal-state partnership has proved effective.

Questions from Senator Joe Manchin III

Question 1: Late last year, FERC announced it would undergo a review of the Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities issued in 1999. The nearly two-decade-old Policy Statement was originally meant to ensure pipeline certification decisions issued under the National Gas Act ensured a reasonable balance between responding to market demands and impacts to the environment and landowners. That process is meant to ensure that a pipeline is truly necessary. But, in light of the shale gas revolution and ongoing pipeline constraints, it seems to me there is certainly ongoing need for pipeline expansion. The transformation seen in the energy market over the last fifteen years has largely been a result of the onset of the shale gas revolution. I absolutely support examining and updating regulations as a part of good governance. I also want to make sure that progress is not unnecessarily hampered.

I am curious what you think is the ideal product that could come out of the review?

Answer: In my view, the Certificate Policy Statement is sound and should be reaffirmed. As described by the U.S. Supreme Court, the primary purpose of the Natural Gas Act is to provide for the orderly development of U.S. natural gas supplies. The Certificate Policy Statement is an effective framework to discharge that statutory responsibility. The policy goals of the Certificate Policy Statement are sound: foster competitive markets, protect captive customers, and avoid unnecessary environmental and community impacts while serving increasing demands for natural gas. Making a determination of the public convenience and necessity based on a balancing of benefits against adverse effects is a sound approach and should be retained.

I believe FERC certificate orders could be more transparent in reflecting that balancing of benefits against adverse effects. Generally, there are more public benefits from a project than meeting demand under long-term contracts, such as improved energy delivery system resilience, environmental advantages of gas over other fuels, lower fuel costs, access to new supply sources or the connection of new supply to the interstate grid, elimination of pipeline facility constraints, better service from access to competitive transportation options, and the need for an adequate pipeline infrastructure.

Question 2: Do you believe national security should be a consideration in the certification process?

Answer: No. First, I believe there are many more effective ways to assure national security than through Natural Gas Act certification decisions. Second, FERC is not a national security agency and is in a poor position to make national security determinations. Third, including national security considerations would likely make the certification process less transparent, to the detriment of landowners, communities, and other parties. Fourth, including national security considerations would upset the balancing of benefits against adverse effects, making it more difficult, perhaps impossible, for opponents to show that adverse effects outweigh project benefits.

Question 3: One of the major criticisms I hear from folks in my state that oppose various pipelines and other energy infrastructure is that the FERC and associated permitting agency processes do not allow for enough public engagement. As you know, there are several major pipelines being developed in the mid-Atlantic and Northeast – several in my state. I support the environmentally responsible development of energy infrastructure as long as that development includes public engagement – particularly for landowners along the pipeline route. As Governor, I found that when owners and communities were "dealt in", they were more likely to become partners in the process.

How do you suggest improving opportunities for the public to get a better opportunity to be heard and for comments to be registered while not sacrificing an efficient and timely permitting process?

Answer: Project sponsors know that effective public outreach is critical to the success of a project. Responding to public comments at open houses and scoping meetings and a willingness to make adjustments to address public concerns can go a long way towards developing community support and acceptance of a project. There are a great many opportunities for the public to participate in the pre-filing and certificate process. Under the current process, project sponsors ordinarily hold multiple open house meetings shortly after the informal pre-filing process has begun. The number of meetings will vary from project to project based in large part on the size and scope of the project and additional open house meetings might be added if the project scope or route changes. These open house meetings are an opportunity for landowners and communities to get information on the proposed project, ask questions, and express their views. In addition, the public has another opportunity to participate in scoping meetings held by FERC staff in the community. At these scoping meetings the public can offer their views, present written comments that will be incorporated into the formal record, and receive information about the project and FERC's review process. While the FERC certificate process is formal, it does allow for full public participation. In some cases, thousands of public comments have been filed on a single project. That reflects a process that allows participation.

Question 4: In your comments regarding the 1999 FERC review, will you be looking at ways to enhance the role of the public? Ensure landowners are appropriately compensated and – if not – seek ways to improve that?

Answer: One of the most important factors in FERC review of a proposed project is the effect of the project on landowners and communities. Under the Certificate Policy Statement project sponsors are directed to make efforts to eliminate or minimize any adverse effects on landowners and communities affected by a proposed route. Landowners and communities have a robust role in both the pre-filing and certificate process, and have ample opportunity to participate in the process. The views of landowners and communities are given great weight in the determination of project route. One aspect of the certificate process that is rarely recognized is that FERC routinely requires many changes to the original route proposed by project sponsors in response to concerns raised by landowners and communities. That shows FERC listens to the community. Landowners and communities also have the ability to challenge FERC decisions and decisions by other federal agencies in court.

Questions from Senator Mazie K. Hirono

Question 1: You testified that FERC should clarify whether and how environmental impacts should be weighed in the balancing of costs and benefits of proposed natural gas pipelines. Do you believe that FERC can accurately evaluate the public interest in a proposed pipeline without fully considering the downstream cost of greenhouse gas emissions associated with the pipeline? If so, how do you recommend that FERC address the climate change impacts of proposed pipelines?

Answer: I believe FERC should balance the benefits of a project with adverse impacts when determining whether a proposed project is in the public convenience and necessity. I also believe certificate orders should be more transparent in the discussion of benefits and adverse effects and balancing of benefits and adverse effects. However, there is a legal question about whether FERC can consider environmental impacts as part of that balancing. If FERC concludes it has discretion to do so that balancing should be limited to the direct environmental impacts particular to the route itself such as tree clearing and loss of wetlands.

I believe it is appropriate to consider the downstream greenhouse gas emissions associated with a proposed project when those emissions are foreseeable. However, consideration of those emissions should be in the context of the NEPA "hard look" analysis rather than the balancing of project benefits and adverse effects in the Natural Gas Act public convenience and necessity determination. The level of downstream greenhouse gas emissions is completely disassociated with project route and the end use of natural gas in most cases is either unknown or subject to the approval of state regulatory commissions rather than FERC. Unlike environmental effects associated with the project route, FERC has no ability to minimize or mitigate the greenhouse gas emissions associated with downstream use of natural gas that would be transported.

Question 2: Your testimony observes that "today's electric grid was developed to delivery yesterday's electricity supply." What benefits for consumers do you see from greater integration of energy storage and distributed energy, and could such integration reduce the need for new transmission lines? What more would you recommend Congress and FERC do to support access to the power markets for energy storage and distributed energy resources?

Answer: I believe greater integration of energy storage and distributed energy resources (DER) promises to improve customer choices and strengthen system resilience. But I don't think it is a matter of choosing between energy storage and DER and a stronger transmission grid. Combining greater integration of energy storage and DER with a more robust grid will deliver the most customer benefits and the greatest electric power system resilience. The sum will likely be greater than the parts.

Earlier this year, FERC took an important step to promote better integration of storage resources into regional transmission organization (RTO) and independent system operator (ISO) markets with approval of an Electric Storage Participation Final Rule. That action promises to lower barriers to energy storage development, if the rule is effectively implemented in the various RTOs. There are additional steps FERC could take to assure market access for DER, such as finalizing a rule that allows DER to aggregate in the RTO and ISO markets. Aggregations of DERs can provide services that resemble a collection of storage resources, since DERs are coordinated with fast communication and control systems.

I do not believe there is a need for additional Congressional action to assure market access for energy storage and DER.

Questions from Senator Tammy Duckworth

Question 1: In your testimony, you estimated that the United States will require "up to $100 billion in investment in interstate natural gas pipelines" between 2018 and 2035, which translates into an additional 26,000 miles of new natural gas pipeline. I understand the urgent need for natural gas projects to keep up with demand. However, I am also concerned with identifying, examining, assessing the risk of aging pipelines and replacing pipes built prior to 1970.

According to the Interstate Natural Gas Association of America, 60 percent of natural gas pipelines in the United States were built prior to 1970. These pipelines, often called pre-regulation pipe, were built before the American Society of Mechanical Engineers set minimum design, construction, operation and maintenance standards. Since then, research and development organizations, such as the Gas Technology Institute in Illinois, have worked to improve safety features, increase efficiency and advance oversight of pipelines.

Modernizing this infrastructure is critical to public safety and creates good paying jobs. As owners, operators and developers of natural gas pipelines, what investments are being devoted to replacing outdated pipelines? What variables do you use to identify dangerous or outdated pipelines that require replacement? Are you required to undergo a pipeline siting process for replacing pipelines? Is it more or less expensive to build new pipelines or repair old pipelines?

Answer: As of July 1, 2018, NextEra operates over 868 miles of pipelines, 769 of which are natural gas transmission pipelines. Of those gas transmission pipelines 80% are less than 20 years old; only 156 miles are pre-1970 pipe. Current integrity inspections and risk assessments do not indicate a need to replace portions of these systems. In accordance with federal regulations we monitor the integrity of our pipeline assets on a regular basis and if significant anomalies are discovered NextEra would immediately correct any issue that posed an immediate risk and budget to correct any issues that could lead to increased risks in the future.

Variables that we use to evaluate possible facility replacement are inline inspection findings, proximity to population, age, current requirements (to maintain proper levels of cathodic protection), leak history, pipe material, construction practices utilized to install, coating type and condition, visual inspection reports and system planning.

U.S. Army Corps of Engineers permits are required if the replacement of interstate gas pipelines disturbs waters of the U.S. With respect to intrastate pipelines in Texas and Florida, there is a state siting process in Florida if the replacement is more than 15 miles in length or crosses a county line and Texas has no additional siting requirements.

In general, it is more economic to repair pipelines than to replace them. Each operator maintains their own proprietary process for analyzing repair vs. replace economics balanced against risk factors. Many factors (discussed above) are utilized when determining if a section of pipe should be replaced or repaired.

Questions from Senator Catherine Cortez Masto

Question 1: Building on our discussion in the hearing, how can the U.S. become a leader in utilizing battery technology, and in so doing increasing grid reliability and clean energy while reducing costs to the ratepayer?

Answer: Energy storage is one of the most promising technologies being deployed in the U.S. electricity industry today, with tremendous potential to reinforce reliability and meet customer needs. The cost of batteries is falling rapidly, a trend that is expected to continue. Storage resources increase grid reliability through their flexibility and their ability to provide balancing and reliability services over their entire charging and discharging range. Batteries can provide these services much more quickly and accurately than conventional generation.

At the federal level the most important step to promote utilization of battery technology is lowering regulatory barriers to energy storage resources. FERC took an important step in that direction with approval of its Electric Storage Participation Final Rule in February 2018. This rule lowered regulatory barriers to electric storage resource participation in the organized electricity markets operated by regional transmission organizations (RTOs) and independent system operators (ISOs). The rule requires RTOs and ISOs to make tariff filings to establish market rules subject to FERC approval that recognize the physical and operational characteristics of electric storage resources and facilitate their participation in these large markets. It is important that FERC ensure the market rules proposed by the RTOs and ISOs are fully consistent with the FERC final rule.

Question 2: Energy infrastructure can sometimes contribute to local economies even more directly than other large infrastructure projects through competitive rates and operation as a business partner – what is the best way that the federal government can engage with local governments and encourage local investment?

Answer: I think the federal government can encourage effective engagement with local communities and governments on energy infrastructure development. In its 1999 Certificate Policy Statement, FERC encourages gas pipeline project sponsors to work closely with landowners and communities, and project sponsors understand that developing support and acceptance from landowners and local communities is critical to project success. In its evaluation of project benefits FERC recognizes expanding economic development opportunities by providing gas service to unserved communities is an important benefit.

A. What alternatives can the federal government consider to encourage growth and local project development rather than walking back regulations more broadly?

Answer: I believe the most important actions the federal government can take to encourage energy infrastructure development are to adhere to merits-based decision making, to make more timely decisions, to maximize coordination among federal agencies where multiple federal approvals are needed, and to ensure policies governing return on investment are transparent and predictable, to the greatest extent possible.

The Wilderness Society

July 11, 2018

The Honorable Lisa Murkowski
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

The Honorable Maria Cantwell
Ranking Member
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Subject: Hearing to Examine Interstate Delivery Networks for Natural Gas and Electricity

Dear Chairman Murkowski, Ranking Member Cantwell, and Members of the Senate Energy and Natural Resources Committee:

The Wilderness Society (TWS) writes to express views on the Senate Committee on Energy and Natural Resources hearing to examine interstate delivery networks for natural gas and electricity on July 12, 2018. We respectfully request this letter be included in the record.

As the United States renewable energy market continues to grow, providing cleaner energy sources that are now often cheaper as well, the way these power sources are transmitted to our communities must follow the same responsible siting as the energy projects themselves. Wilderness-quality lands, important wildlife habitat, and areas with important cultural resources are not appropriate for transmission lines and energy development. Thankfully, we can build regional transmission projects crucial to a clean, reliable, affordable energy future without sacrificing environmental stewardship.

Taking a smart approach to infrastructure development is good for business – it makes permitting more efficient and increases economic benefits by focusing construction in areas where there are the least amount of conflicts and projects are most likely to succeed. This realization has become apparent over the last few years with the re-evaluation of the federal West-wide Energy Corridors (WWEC) through a Regional Review process. These 6,000 miles of transmission and pipeline corridors spanning public lands in 11 western states (Arizona California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming) were originally designated by the Bureau of Land Management, U.S. Forest Service and Department of Energy (the Agencies) in 2009 as required by the Energy Policy Act of 2005.

The Regional Review process will be completed in 2019 and aims to facilitate efficient and responsible transmission and pipeline development by re-evaluating and recommending adjustments WWEC to reduce conflicts with sensitive resources and values and to increase access to areas with high potential for renewable and other energy development. Completed successfully, the Regional Review process will streamline federal siting, review, and permitting processes for transmission and pipeline developers while helping protect our natural and cultural heritage.

The agencies can plan for success and greatly reduce impacts and increase access to the growing renewable energy sector by recommending improvements to the WWEC through the Regional Review process, such as deleting or adjusting high-conflict corridors, and considering new corridors in appropriate locations. After completion of the process, the Agencies must adjust the WWEC through land use planning to realize the benefits of the Regional Review.

The Agencies' efforts to improve corridors by gathering input from local communities, stakeholders, and energy and transmission developers are providing lessons for other regional and interregional transmission planning efforts. Completing this collaborative effort will be crucial to advance responsible development, while protecting the communities and wild places that surround us.

As you work to address interstate delivery networks for natural gas and electricity, it is crucial that the policies on transmission and pipeline development take a smart, responsible approach to infrastructure development, as demonstrated in the promise of the ongoing Regional Review of the WWEC. These policies should also encourage the use of appropriate WWEC for infrastructure development. Thank you for considering our views.

Sincerely,

Alex Daue

Alex Daue
Assistant Director, Energy & Climate
The Wilderness Society